ScottishPower EnergyNetworks

MODIFICATION PROPOSAL

Implementation of 'G3' Use of System Charging Methodology, including IDNO tariffs.

Date of Issue: 2 July 2008

FOR APPROVAL BY THE GAS & ELECTRICITY MARKETS AUTHORITY

This Modification Proposal sets out SP Distribution Ltd's (SPD) and SP Manweb Plc's (SPM) proposal to replace their Use of System Charging Methodology

Executive Summary

ScottishPower EnergyNetworks (SPEN), SSE Power Distribution and Central Networks agreed to work together under the 'G3' banner to develop a common charging methodology based upon the joint DNOs' work. The G3 methodology for Use of System Charges is comprehensive and integrated, it addresses both demand and generation and recognises the costs and benefits of each. The G3 companies took the view that it was not appropriate to include IDNO tariffs under the remit of the G3 work. Therefore, SPEN as a separate submission for approval by the Authority, have proposed to modify its charging methodology by incorporating IDNO charging principles into the G3 long-term charging methodology. The Authority is requested to make a decision on the proposal on this basis.

G3 has developed a Forward Cost Pricing (FCP) methodology, based on network load flow analysis for Extra High Voltage (EHV) networks and a generic pricing methodology for High Voltage (HV) and Low Voltage (LV) networks. The combined methodologies are incorporated into an integrated G3 Tariff Model. For IDNO tariffs, we propose that:

(1) IDNO charges are derived from HV and LV IDNO yardsticks, using domestic demand profiles and typical administrative costs imposed on SP by IDNOs;
(2) Capacity charges do not apply to IDNO HV and LV connections;
(3) No reactive charges will be imposed on IDNO HV and LV connections;
(4) Half-hourly meter is not required for IDNO HV and LV connections.

The costs allocated to the IDNO yardsticks reflect the proportion of the components of the yardstick costs that are avoided through connection to the IDNO network. *Please note that IDNO connections, which are solely, or predominantly supplying I&C customers may be charged as per the equivalent I&C customer.*

It is SPEN's view that the G3 methodology better meets both the relevant licence objectives and the high level principles set up by the Implementation Steering Group in 2005 when compared to our current charging methodology. Moreover, it facilitates competition by improving cost reflectivity of IDNO charges and avoiding potential instances of margin squeeze. ScottishPower EnergyNetworks proposes to adopt the common methodology and tariff model developed by G3 and expanded to include IDNO charges, subject to the decision of the Authority, with a view to implementation of tariffs derived from the new methodology on 1 April 2009.

Table of contents

1 Issue Authority

Authors	Owner	Issue Authority
María Isabel Liendo Senior Pricing Analyst Garth Blundell Senior Regulatory Analyst	Jim McOmish Distribution Policy Manager	Scott Mathieson Regulation Director

2 Introduction and background

2.1 This Modification Application is submitted by ScottishPower EnergyNetworks on behalf of SP Distribution Ltd and SP Manweb Plc. ScottishPower EnergyNetworks (SPEN) is the public facing identity of SP Distribution Ltd (SPD), SP Manweb Plc (SPM) and SP Transmission Ltd (SPT). SPD is a licensed electricity distribution business, which owns and operates networks in south and central Scotland. SPM is a licensed electricity distribution business, which owns and operates networks in Merseyside, Cheshire and North Wales.

2.2 Following completion of the joint DNOs work under the Energy Networks Association's Commercial Operations Group (COG) at the end of 2006, ScottishPower EnergyNetworks, Scottish and Southern Energy Power Distribution and Central Networks agreed to work together as a group known as 'G3' to further develop the work of the joint DNOs and to create a new methodology for use of system charges.

2.3 With effect from 1 April 2005, the DNOs' distribution Use of System charging methodologies have to conform to the objectives set out in Standard Licence Condition (SLC) 4 (3), which states:

- that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Act[1] and by the licence;

- that compliance with the use of system charging methodology facilitates competition in the generation and supply of electricity, and does not restrict, distort, or prevent competition in the transmission or distribution of electricity;

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

- that, as far as is consistent with the sub-paragraphs above, the use of system charging methodology, as far as is reasonably practicable, properly takes account of developments in the licensee's distribution business.

2.4 SPD and SPM are obliged under SLC 4(2) of its distribution licence to keep the use of system charging methodology under review and make such modifications as necessary for the purpose of better achieving the relevant licence objectives.

2.5 Ofgem has expressed its wish to see further development of the DNOs' distribution charging methodologies for the longer term. As a first step in the process of

[1] The Electricity Act 1989 as amended by the Utilities Act 2000, the Sustainable Energy Act 2003 and Energy Act 2004.

determining this future framework, Ofgem set up an Implementation Steering Group (ISG), which considered high level charging principles intended to sit alongside the licence objectives. The group concluded that these principles were[2]:

- Cost reflectivity;
- Facilitation of competition;
- Predictability;
- Simplicity; and
- Transparency.

2.6 The ISG recognised that there may be tensions between some of these principles. For example, while cost reflectivity is a licence objective, this needs to be balanced by evidence of benefits if more complex charging structures are to be introduced. The principles also interact, for example transparency and predictability may both facilitate competition.

2.7 The DNOs have an obligation under section 9 of the Electricity Act to develop and maintain an efficient, coordinated and economical system of electricity distribution. This obligation means that consideration should also be given to ensuring lowest cost provision of the system, which would include the requirement for the provision of efficient investment signals to customers so that future network needs are met accordingly.

2.8 Investment signals contained in DNOs' charges should be proportional and must comply with general competition law. It is important to note that any decision by the Authority not to veto a proposed methodology would offer no protection to a DNO in this respect.

2.9 Customers' long term decisions will be based on expectations of future costs, rather than solely on current charges, so it is important that, as far as possible, future charges are reasonable and predictable. Hence the level of cost recovery is matched to the total cost of reinforcement assuming the current level of growth according to the algorithms described later. The same algorithms can be used by customers to predict future charge rates.

2.10 G3 has taken on board a number of the conclusions reached during the joint DNOs' work. In particular, these relate to the connection boundary, cost attribution and allocation and the recognition of common customer groups. The G3 have also built on the joint DNOs' conclusions in respect of revenue reconciliation.

2.11 **Connection boundary**. Following consultation in 2006, the DNOs decided to retain a shallowish connection charging boundary for both demand and generation. Under this methodology an applicant for connection pays for the new assets required to connect them to the existing network, along with a proportion of network reinforcement if any is required. In developing the common charging methodology G3 has retained this assumption.

[2] These are listed in alphabetical order; no particular order of precedence is implied.

2.12 **Cost attribution and allocation**. G3 recognise that at EHV level a relatively sophisticated modelling approach based on load flow analysis and taking into consideration the impact of distributed generation is appropriate for determining network reinforcement.

2.13 G3 consider that a generic methodology, which is simpler and more transparent than the current methodologies, is appropriate for the calculation of use of system charges at the lower voltage network levels. Following on from the joint DNO work, G3 has refined and improved the generic methodology.

2.14 G3 has developed the Forward Cost Pricing (FCP) methodology for determining forward looking costs.

2.15 **Customer groups**. G3 has adopted the concept of generic customer groups, based around traditional tariffs and common customer characteristics and which are widely used by the industry settlement processes. These customer groups were identified by the joint DNOs. Following consultation G3 has standardised on a set of customer groups, though not all are applicable to every licensee.

2.16 **Revenue reconciliation**. G3 has reviewed the four approaches considered by the joint DNOs and the approach taken by Western Power Distribution. G3 believes the most appropriate method to revenue reconciliation for demand, which does not distort the costs signals and better meets the objectives set out in 2.3, is a development of the 'fixed adder' approach. The G3 approach determines different 'adders' for each voltage level by using the value of network assets, which to a large extent drive the need for revenue reconciliation. Generation charges however have been developed using a simpler single fixed adder approach across all voltages.

Proposed methodology

2.17 This document sets out proposals to replace SPD and SPM's current use of system charging methodology with the G3 methodology. We believe that this approach better meets the relevant objectives set in the licence (as listed in 2.3 and explained further in Chapter 12) and will thus encourage a more efficient use of the network.

3 Existing Charging Methodology

3.1 Our current model for determining distribution use of system demand charges is based on the costs per kVA of providing additional network and transformer capacity based on current design and network security standards. Other costs such as service, customer related and billing costs are added to the network costs and then allocated to the appropriate yardsticks depending on customer groups. These are then scaled to meet target revenue.

3.2 Our current generator use of system charges are derived from a model, which identifies costs associated with accommodating embedded generation in the network, which are not recovered through connection charges, using as inputs the known investments in the networks at the time of setting the tariffs. As with demand, the generation use of system charges are scaled to match the DG target revenue.

3.3 Our current methodology (in force at the time of submitting this modification) states that the DUoS charges applicable to IDNO connections are those applicable to HH commercial customers either at LV or HV voltage level[3].

3.4 A description of our current charging methodology is given in the statement of charging methodology for use of system, available from our website at http://www.scottishpower.com/ConnectionsUseMetering.htm

Perceived shortcoming of existing Methodology

3.5 For both demand and generation our current methodology is based on an average cost model, therefore it does not provide locational signals to customers but estimates an average cost for each voltage level. Furthermore, it does not take into consideration actual demand growth and network available capacity. In addition, the existing charging model does not allow for the recognition of costs and benefits associated with distributed generation and therefore does not encourage connection of generation in locations where it can contribute to the efficient development of network.

3.6 The existing charges for IDNO customers were developed on the basis of the characteristics of SPEN's own commercial customers and therefore may not reflect the characteristics of IDNO connections. As the characteristics of the IDNO networks reflect those of their own end-customers, it is appropriate to develop additional yardsticks for IDNOs, as in general these will be different from directly connected business customers of a similar size. In particular, the load shapes of IDNO sites will be different. Also, the costs incurred in distributing units to the IDNO boundary may be different from those to the end-customer. Furthermore, the IDNO's own charges to its LV customers, particularly domestic, are unlikely to include a capacity charge

[3] Note that SPEN has submitted a modification report, PR-08-001a which modifies the current methodology and creates IDNO-specific tariffs, following the same approach as described later in this report. However that modification will not come into effect until October 2008, unless vetoed by the Authority, and therefore this chapter refers to the SPEN charging methodology without taking into account PR-08-001a.

component, which leads to a potential mis-match in the structure of the host DNO's and the IDNO's charges.

4 Consultation process

4.1 In the development of this charging methodology, G3 conducted an open consultative process, seeking the feedback of key stakeholders at a public workshop and through a formal consultation paper. In terms of the G3 tariff model (described in section 7), G3 also took into account the consultations sponsored by the ENA during the COG structure of charges working group. In addition to this there have been 'one to one' discussions with various interested parties (at their request) and several meetings with Ofgem. As a result of these consultations and discussions some significant improvements have been made to arrive at the current proposed methodology.

4.2 A G3 consultation was carried out in May 2007. A workshop was also hosted by G3 to clarify the proposed methodology in June 2007. This workshop presented a detailed explanation of the integrated approach and of the models used. Notes from the workshop were prepared and made available to a wide distribution list to facilitate responses to the consultation.

4.3 A total of twelve responses to the May consultation were received. Of these responses: one was from Energywatch, four were from electricity suppliers, one was from a electricity generator, two were from electricity distributors, one was from a electricity industry trade association, two were from specialist consultants and one, marked confidential, was from an EHV customer.

4.4 The G3 considered all issues raised in the consultation and published a summary document addressing the queries raised and indicating where it was the intention of the G3 to undertake further work in order to address the issues pointed out in the responses.

4.5 The G3 consultation, responses and summary document, as well as notes from the workshop are all available from the following weblink http://www.scottishpower.com/StructureOfChargesProjectG3.htm.

4.6 G3 has also commissioned two separate firms of specialist consultants to test the proposed methodology, available from the link above. The conclusions of these studies are included in Appendix 1.

4.7 In terms of IDNO charging, SPEN has been actively developing more cost reflective charging arrangements. SPEN issued a consultation in October 2006 and held a workshop in January 2007 with interested parties and stakeholders. In May 2008 SPEN submitted a modification to our current charging methodology for implementation from October 2008, unless vetoed by the Authority. Ofgem have consulted on this modification (PR-08-001a)[4], however at the time of submission of this report the decision of the Authority is still not known.

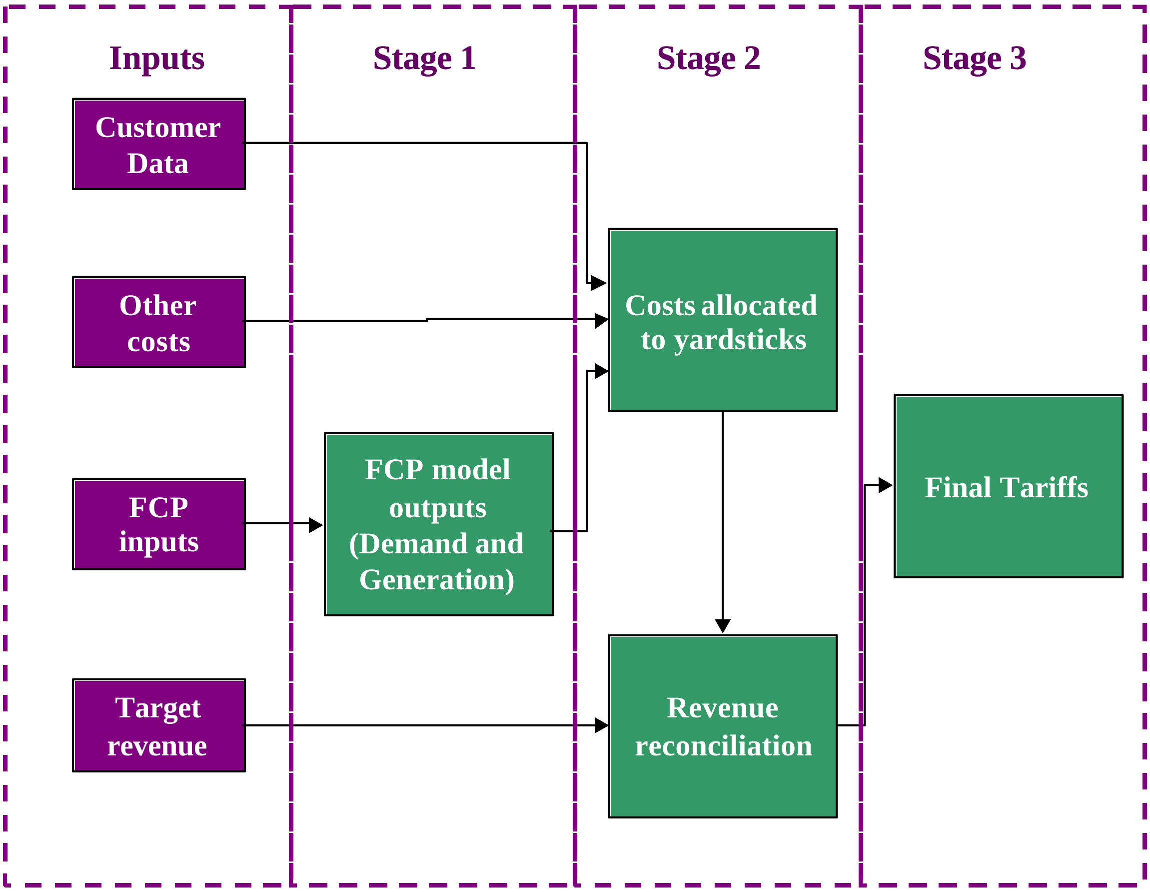
---

[4] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/PR-08-001a%20SP%20Consultation%20FINAL.pdf

5 Overview of the G3 Common Methodology

5.1 The G3 methodology can be described as a three stage process, as set out in the diagram below.

Flowchart - High level architecture of G3 methodology



5.2 In the **first stage**, forward-looking FCP rates (£/kVA/annum) for reinforcement of the network are determined by the G3 Forward Cost Pricing (FCP) methodology. For demand, the FCP methodology forecasts future reinforcement using load flow contingency analysis based on the actual configuration of the network, demand data and growth assumptions for EHV, down to the EHV/HV level of the network. These forecasted reinforcements are then converted into the forward-looking costs for these voltage levels, which provide economic locational signals to current and prospective EHV customers. For the High Voltage (HV) and Low Voltage (LV) levels of the network the FCP methodology uses historic reinforcement data to build a forecast of future reinforcement costs. The EHV proportion of costs which are allocated to HV and LV costs is cascaded from the FCP costs on an averaged basis.

5.3 The FCP methodology for generation identifies both the generation costs and generation benefits. The costs are determined by performing a fault level and reverse power analysis of the real network, down to the 33/11 kV level. Benefits are calculated in relation to the demand costs that generation would offset.

5.4 The **second stage** of the G3 methodology is the application of the G3 tariff model, which is a direct development from the COG model and the approaches agreed with the other DNOs at the COG group. This model brings together the FCP rates and benefits determined by the FCP methodology in the first stage of the process, and all other relevant costs (such as O&M, refurbishment, NGET Connection (Exit) and Licence costs). It then uses other inputs such as demand and volume data to profile these costs and allocate them to the appropriate customer groups, producing yardstick costs. These yardstick costs are then put together with other costs, such as site-specific sole-use asset costs and scaled to match the target revenue.

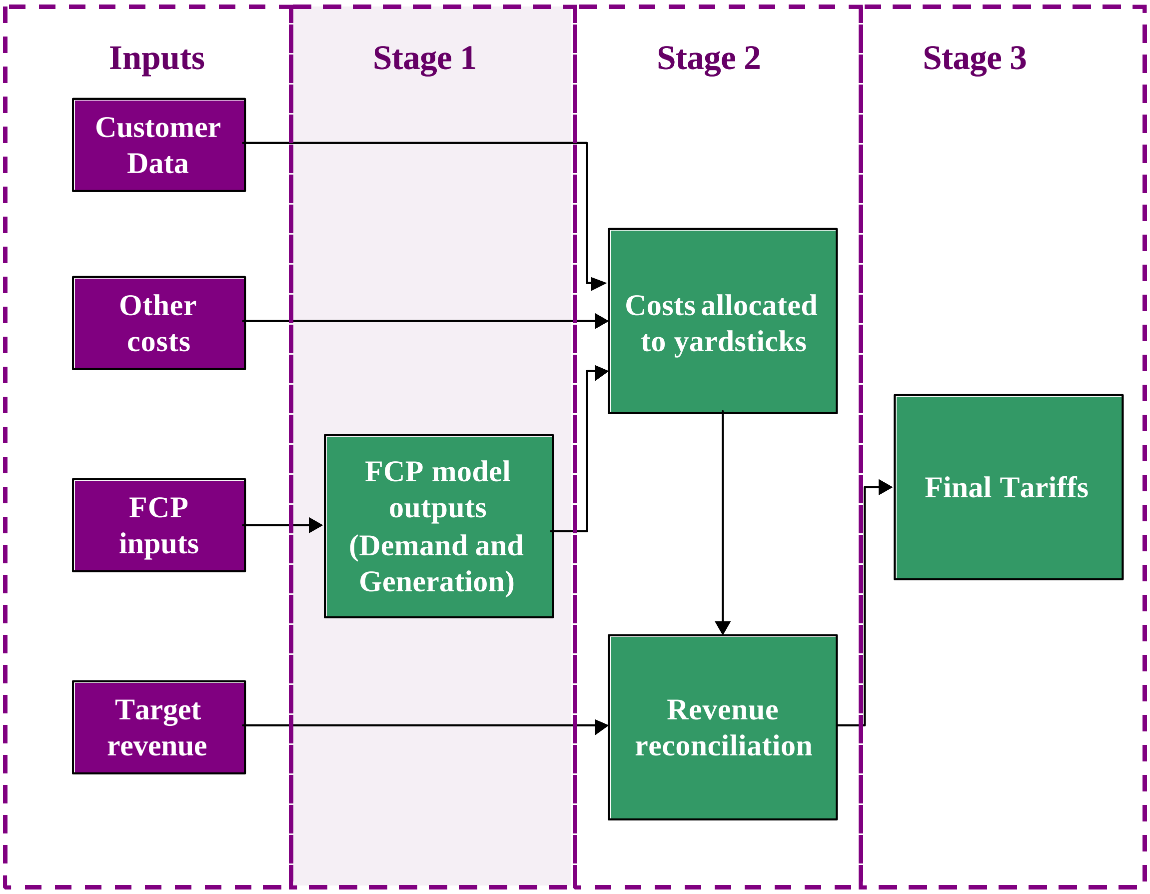
5.5 From the yardstick costs, the final tariffs are produced in the **third stage** of the process according to a predetermined allocation method as explained in chapter 7.

5.6 Wherever possible the G3 methodology makes use of auditable data such as the Long Term Development Statement (LTDS), regulatory reporting information and other publicly available data, in order to comply with the principle of transparency.

5.7 The following chapters explain the methodology in more detail.

6 Forward Cost Pricing (FCP) Methodology

STAGE 1: FCP MODEL

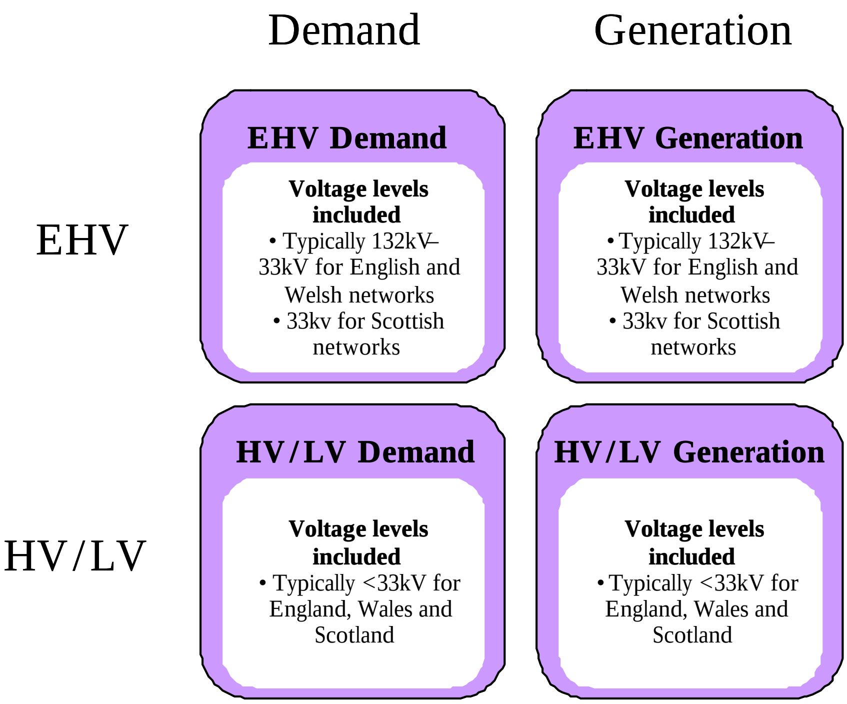


6.1 The FCP approach constitutes the core of the G3 methodology: it generates estimates for reinforcement costs over the next 10-years for different Network Groups and then uses these estimates to generate the pre-scaling £/kVA/annum charges that are later converted to final output tariffs in stages 2 and 3.

6.2 The FCP model is a combination of four semi-autonomous sub-models, which separately generate £/kVA/annum estimates for:

- Demand connected at EHV levels;
- Generation connected at EHV levels;
- Demand connected at the HV and the LV levels; and
- Generation connected at the HV and the LV levels.

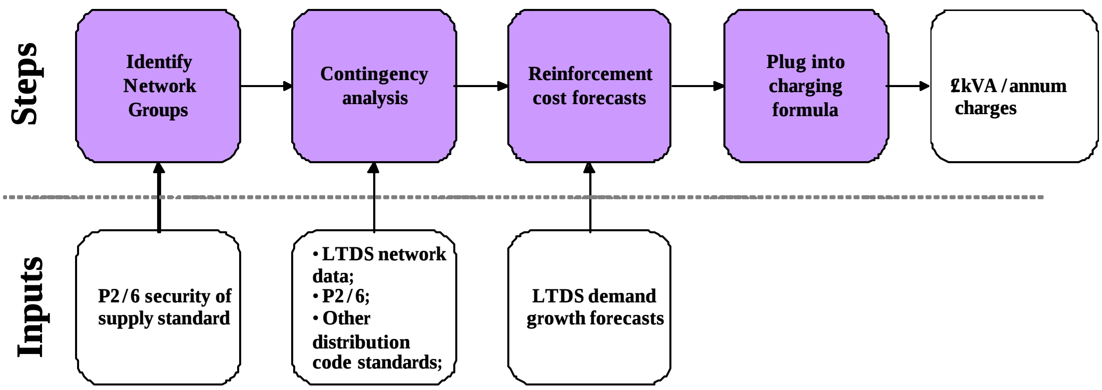
6.3 The diagram below illustrates the four sub-models of the FCP:



6.4 There are differences between these four sub-models, in particular between the methodologies for arriving at £/kVA/annum charges for EHV and HV/LV networks. Given these differences, we analyse each of these four sub-models separately.

EHV Demand

6.5 The approach set out below is used for forecasting future reinforcements at the EHV levels, typically 132kV and 33kV for networks in England and Wales and 33kV for networks in Scotland. The following diagram illustrates how for EHV demand, the FCP model derives £/kVA/annum charges in four steps:



6.6 For the purpose of forecasting future reinforcement the network is broken down into a number of Network Groups. The use of Network Groups for analysis is an important stage in assessing Security of Supply requirements and is consistent with the security of supply standard, P2/6, which also defines the required network capability in terms of the same 'demand groups'. Each Network Group is a part of the distribution system that, under normal system conditions, is not connected electrically to adjacent Network Groups at the same voltage level.

6.7 A Network Group is the distribution network normally supplied by a Grid Supply Point (GSP), or Bulk Supply Point (BSP). In situations where GSPs or BSPs are operated in parallel, these are considered as a single Network Group. In Scotland there is only a single layer of Network Group from GSP to 33/11kV substation. In England and Wales two layers of Network Groups are considered (GSP to BSP and BSP to 33/11kVsubstation). This reflects the distribution network topology.

6.8 Within a Network Group, all the circuits, transformers and substations are modelled and individual reinforcements are identified for each asset. For the SPD network there are 77 GSP supplied Network Groups. For the SPM network there are 15 GSP supplied Network Groups and 34 BSP supplied Network Groups. On average a GSP supplied Network Group has 40 branches, 18 transformers and 8 substations.

6.9 The method of determining the need for future reinforcement is based on Alternating Current (AC) load flow analysis of each Network Group. This takes into account network security requirements[5] by analysing each Network Group under both normal operating conditions (intact network), and various combinations of network component outage. This 'Contingency Analysis' essentially seeks to identify the weakest links in each Network Group – i.e. to identify which components exceed their capability at various demand levels. Planning processes then identify the reinforcement requirements of these overloaded circuits, transformers and switchgear.

6.10 Analysis is based on mechanistic and deterministic processes using planning information published annually in the LTDS. This information includes network data, demand forecast tables and embedded generation data (the inclusion of embedded generation data is a voluntary additional submission, commonly made by DNOs in the LTDS). The analysis also utilises publicly available planning standards such as ER P2/6.

6.11 The analysis is first carried out using present loading conditions to produce a set of baseline data. For demand, the baseline is assessed using current maximum loading conditions, while for generation the baseline is assessed using current minimum loading conditions. The base network demand is then incremented in small steps, up to fifteen percent above their current maxima. At each increment the various contingency analyses are repeated to identify limiting components. Fifteen percent over the current maximum demand is what G3 see appropriate at the moment to capture reinforcements required within the next 10 years (see paragraph 6.15).

6.12 The contingency analyses identify which network components require reinforcement. Reinforcements are provided by adding suitably sized standard components in a

[5] Network security is a licence condition embodied in Engineering Recommendation P 2/6 (ER P2/6)

mechanistic way, according to current engineering practice. Reinforcements are sized to remove the limitations as identified and are assumed to have no effect on the need for other reinforcements.

6.13 For the very largest Network Groups, P2/6 also requires contingency analysis under second circuit outage conditions, such as might occur typically during periods of maintenance outage. Contingency analysis assesses network capability under these conditions using the peak maximum demands scaled to 67% and incremented as before.

6.14 Once the network contingency analysis has been performed, the resulting levels of demand at which various network components require reinforcement, are used to estimate the length of time when the reinforcement will be needed from the present day, by reference to the relevant network group's demand growth rate. The demand growth rates are taken from the LTDS data and are specific to each individual network group.

6.15 All reinforcements found to be required within the time horizon of ten years are included in forward cost estimates. There is a need to strike a balance between allowing enough time for pricing signals to make it possible for the customers to react and using reliable data. Reinforcements beyond a time horizon of ten years are considered too speculative to be included in realistic forward cost estimates.

6.16 The cost of each standard reinforcement, identified as described in para 6.12 and 6.13, is estimated using the same available design data currently used by the engineers to prepare connection offers, and this is used to derive the FCP rate per kVA for each Network Group as described later.

6.17 The process for forecasting future reinforcement for EHV networks is set out in greater detail in Appendix 2.

6.18 The output from the network load analysis consists of asset reinforcement costs, *A* (£); current demand, *D* (kVA); capacity at which reinforcement would be required, *C* (kVA); and annual growth rate as a proportion of the demand, *g* (this final variable being taken from the LTDS data, as mentioned above). In the following analysis *i* represents the discount rate.

6.19 The fundamental concept behind the FCP approach for the EHV level is that the cost of the reinforcement is recovered between initial time *T* prior to reinforcement and the time of reinforcement. This can be expressed as

Charge | Demand | Reinforcement

$$\int_0^T p(t).D(t).\exp(it).dt = A$$

6.20 The function $p(t)$ could take a wide variety of forms. A constant value, corresponding to fixed repayments of a mortgage is not appropriate as the pricing signal should increase as the time to reinforce the network approaches. A linear variation from zero at $t = T$, increasing linearly to $t = 0$ would give a better representation. The 'accountancy' formula exp(-*it*), which corresponds to constant contributions to the accumulated value by the time of reinforcement, has been considered. However, this curve only captures the financial change in value of the income and not the increasing importance of discouraging growth as reinforcement approaches. Since the value of the integral is fixed, a steeper curve with lower charges at larger values of t results in higher charges as reinforcement approaches. In the limit, all costs could be recovered in the final year prior to reinforcement, with no prior warning and no possibility of customers changing behaviour to avoid the need to reinforce.

6.21 The method chosen by the G3 to provide appropriate pricing signals as the time of reinforcement approaches derives the form of $p(t)$ from the change in net present value of the cost of reinforcement as t varies. This determines a shape consistent with the NPV approach and it has a set of desirable properties as described below. This not only provides a shape with desirable properties but gives a stronger signal than the 'accountancy' formula, exp(-*it*), whilst keeping the peak rates to an acceptable level.

6.22 Essential or desirable properties required of the function $p(t)$ are:

- If the reinforcement costs doubles then the FCP rate should double, implying a linear variation with reinforcement cost.
- The FCP rate should increase as reinforcement approaches.
- For a given demand, the FCP rate should increase with increasing growth rate to give stronger signals.
- Increasing the discount rate should give lower FCP rates at more distant times prior to reinforcement.
- The decrease of FCP rate with increasing discount rate should be stronger than exp(-*it*).
- As the growth rate tends to zero the FCP rate should tend to zero for all demands less than the capacity at which reinforcement is required.

To capture the first criteria and to obtain the required dimensions for $p(t)$ of £/kVA/annum, the FCP rate can be written in the form:

$$p(t) = i(A/C) f(g/i, it)$$

The variables within the function f are dimensionless expressions of the original variables.

A very general form for $p(t)$ is:

$$p(t) = i(A/C)(g/i)^m (it)^n \exp(-k_1 it) \exp(k_2 gt)$$

Where *m, n, k1* and *k2* are arbitrary constants to be determined. A consideration of the behaviour of p as i, g, or it tend to zero rules out the power terms and it remains to determine the coefficients of the exponential terms. The final bullet point indicates that k_1 should be greater than 1 whilst k_2 should be positive to meet the property that the FCP rate increases with increasing growth rate. A default value of unity for k_2

would match the form which defines the demand in terms of growth rate and time. This leaves a suitable value of k_1 to be chosen, the actual numerical scaling being determined by the overall criterion of recovering the reinforcement cost over the cost recovery period.

6.23 Two approaches to derive *p(t)* have been considered, the second, described in Appendix 3, is based on the analytical form of the standard LRIC method. It is important to point out that the second derivation gives the identical functional form as the method described here.

6.24 Thus let the FCP rate per kVA at time $t=x$ years prior to the time of reinforcement be $p(x)$. The demand at this time is $C\exp(-gx)$. Therefore the rate of cost recovery is $p(x) C\exp(-gx)$. The value of this by the time of reinforcement will be increased by the factor $\exp(ix)$.

6.25 The total recovered by the time of reinforcement starting from an initial time t prior to reinforcement is set equal to the change in NPV of the cost of the reinforcement, giving:

$$\int_0^t p(x) C \exp(-gx)\exp(ix)dx = A(1-\exp(-it))$$

(This formula is used generically - we are now merely deriving the functional form of $p(t)$ applicable for all t with both sides zero for $t = 0$ and tending to A as t tends to infinity.)

6.26 The unique functional form of $p(t)$ which satisfies this equation for all values of t, can be obtained by differentiating both sides of the above equation with respect to t, giving;

$$p(t) C \exp(-gt)\exp(it) = iA\exp(-it)$$

i.e.

$$p(t) = i(A/C)\exp((-2i+g)t) = i(A/C)(D/C)^{2i/g-1}$$

6.27 In order to satisfy the fundamental equation in 6.19 recovering the reinforcement costs over a finite period of T years, the above formula is rescaled. The NPV for the time prior to T, $A\exp(-iT)$, is not recovered within the integration. Therefore for total cost recovery the FCP rate is multiplied by the factor $1/(1-\exp(-iT))$.

$$FCP = i(A/C)\exp((-2i+g)t)/(1-\exp(-iT)) = i(A/C)(D/C)^{2i/g-1}/(1-\exp(-iT))$$

6.28 The above FCP formula is that for a single time period. The same principle is applied when there is more than one time period, but the multiplying factor is adjusted to ensure that the annual revenue from charges applied to all time periods is equal to the revenue that would be recovered by charging only the period of maximum demand.

6.29 Let there be N time periods and the demand in time period j be denoted by D_j. Then the FCP formula gives the charge rate for each time period separately as:

$$FCP_{\text{single}}(D_j) = i\,(A/C)\,(D_j/C)^{2i/g-1}/(1 - \exp(-i\,T))$$

(set to zero if $D_j < C \exp(-gt)$)

6.30 This single period charge rate is then scaled to ensure that the total revenue recovered through a multi-period approach is equal to the revenue recovered with a single charge rate calculated at the time of maximum demand. The post-scaled charge for a given time period j is:

$$FCP(D_j) = [FCP_{single}(D_j)\ FCP(D_{max})\ D_{max}] / \Sigma\ (FCP_{single}(D_j)\ D_j)$$

6.31 It can be readily seen that by multiplying the charge rate for each time period by the corresponding demand and summing that the total revenue, is the same as that derived from charging the time period of maximum demand alone. The method is illustrated in the following example:

FCP Example

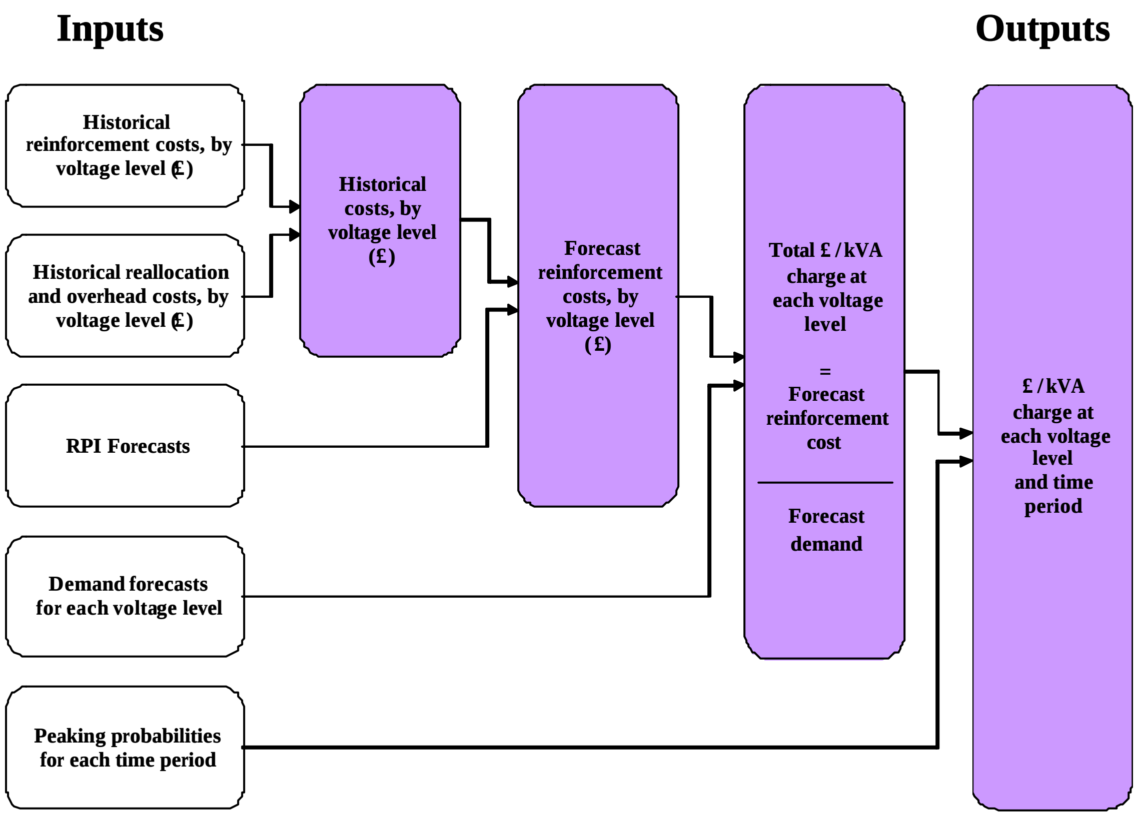
Max Years =	10
Discount Rate =	6.90%
Growth Rate =	1.00%
Reinforcement Cost £ =	333000
Capacity kVA =	79383

Time Period	Demand	Years to reinforcement	FCP single Rate £/kVA	FCP single Revenue £	Multi Period Rate £/kVA	Multi Period Revenue £
1	76357	3.89	0.353	26963	0.180	13755
2	79383	0.00	**0.581**	**46099**	0.296	23518
3	73941	7.10	0.234	17301	0.119	8826
4	65091	19.85	0.000	0	0.000	0
Total				90363		**46099**

6.32 In the G3 methodology, when setting EHV charge rates, the charge rate calculated for the single period of maximum demand is used. The rates for the separate time periods averaged over all network groups are used in calculating rates for HV and LV within the Tariff model. The total charge rate for each Network Group is the sum of the rates for all forecast reinforcements in that Network Group within the 10-year period. Note that the algorithm uses the current forecast growth rate to estimate the cost recovery period and hence the amount of revenue already assumed to have been recovered.

HV/LV Demand

6.33 The more sophisticated model used for the EHV level cannot, at the moment, be practically implemented by G3 throughout the entire network. A simpler approach is therefore used for determining reinforcement costs at HV and LV levels. The following chart outlines the process to derive the £/kVA/annum charges, for HV/LV demand.



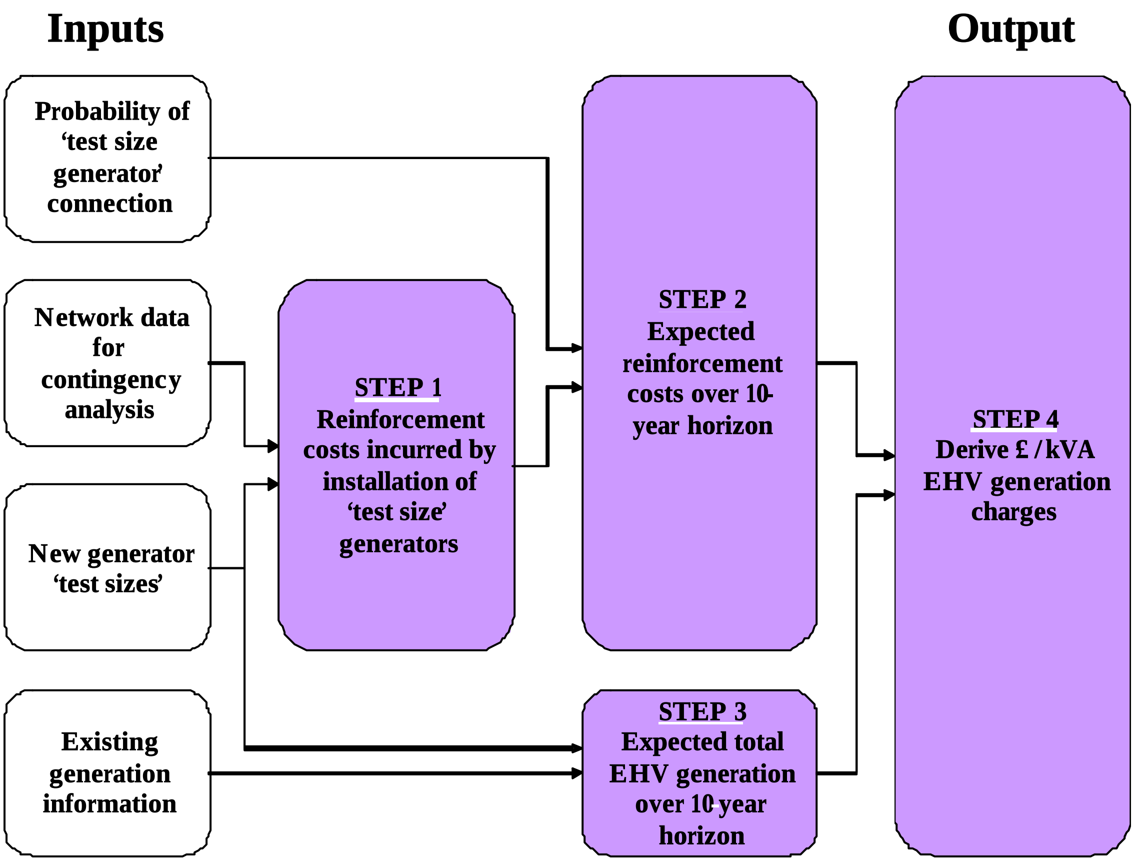
6.34 The annual run rate of reinforcement expenditure is obtained from transparent and auditable information included in the Regulatory Reporting Pack (RRP) sent to the Authority annually, as required by our Distribution Licence[6]. This information is used to project the annual reinforcement expenditure for future years. G3 proposes to use the most recent available HV and LV reinforcement data on a rolling average basis to forecast future years.

6.35 The forward-looking costs are derived from the expected annual reinforcement expenditure at the lower voltage levels typically 11kV, 11/LV, LV. This approach is explained further in section 7.

EHV and HV – Generation Costs

6.36 The following chart outlines the process to derive the £/kVA/annum Generation costs.

[6] Distribution Licence Condition 52: “Price Control Review Information”.



6.37 For generation it is not currently realistic to make meaningful forecasts of when and where capacity will connect, due to the relatively small number of new connections, and it would not be cost reflective to assume an incremental growth spread evenly throughout each Network Group. The addition of each new generator represents a significant step-change, which cannot be adequately described by average growth rates on a locational basis. This 'lumpiness' is captured in the charging model by a 'test size' generator for each voltage level. The probability of such a generator being attached to a Network Group is based on forecasts for total GB DG capacity used in the joint DTI/OFGEM report titled "Review of Distributed Generation", published in May 2007 together with the Energy White Paper,[7] and an estimate of the total ratio of DG as a proportion of demand. National Grid's electricity demand projections as per their 7-year statement[8] have been used to provide the GB future demand data.

6.38 Once this probabilistic approach has been used, the resultant methodology is similar to that for demand. A test size generator is used per voltage level, and it is chosen to be the 85th percentile of existing and committed future generation[9]. The basis for using the 85th percentile is the assumption that no charge should be levied if the majority of the likely sizes of generators would not require any reinforcement in each particular

---

[7] "Review of Distributed Generation Report, May 2007", para 152 & 153. Available at http://www.berr.gov.uk/files/file39025.pdf

[8] http://ww.nationalgrid.com/uk/sys%5F07/default.asp?sNode=SYS&action=&Exp=Y

[9] "Committed future generation" is defined as generators that have accepted a connection offer.

Network Group. It is desirable to exclude the upper tail of the distribution as a few large generators could lead to the imposition of charges, which would not be required for the majority of generators. In the Normal distribution, the tail (where the rate of decrease stops increasing and the slope starts to level out) starts at one standard deviation above the mean, about the 85th percentile. This latter criterion is used rather than one standard deviation, as in general the distribution is not Normal and non-parametric methods (using a percentile rather than the standard deviation parameter) are considered to be statistically more robust, especially when the distribution is not known. The probability P_V of a 'test size' generator attaching to a Network Group is evaluated by matching the total forecast increase in generation over the next 10 years with this distribution of generation. Appendix 4 shows the calculation of P_V based on the forecast that new generation capacity will be equal to 30% of current demand as described in the previous paragraph.

6.39 The output from the network Contingency Analysis gives the headroom, H (kVA), which can be accommodated by the network before reinforcement would be required. If this is greater than the 'test size', S_V, then the FCP rate is set to zero. Otherwise the G3 methodology determines the probability that a test size generator will be connected to a Network Group within the next 10 years. It is assumed that there is an equal probability in each of the 10 years. This gives a linear (or stepwise) function of the amount connected multiplied by the probability of connection rising from zero at time zero to the Test Size at the end of the 10 years. On this basis reinforcement is required at $Y = 10\, H/S_V$ years.

6.40 Choosing the FCP rate to be proportional to $k \exp(-iY)$, where k is a constant of proportionality, gives equal contributions to the final cost and hence a total cost recovery of :

$$10k(G + S_V/2)$$

where G is the level of existing generation.

6.41 To recover the total cost, allowing for the probability of connection, the FCP rate is set to:

$$A\, P_V \exp(-iY)/(10(G + S_V/2))$$

where £A is the cost of the asset reinforcement.

6.42 An example of the FCP rate calculation for generation at the HV source busbars is given below:

Generation	HV
Test Size (kVA) =	3400
Pv =	0.27
Headroom (kVA) =	2300
Existing generation (kVA) =	568
Reinforcement cost (£k) =	336
Years to reinforcement =	6.76
Charge rate (£/kVA) =	2.508

6.43 For EHV Network Groups the existing generation is that pertaining to the specific Network Group. Since only average generation costs are used in the Tariff model to calculate HV FCP rates, it is the average generation per HV generation location which is used in the above table.

LV Generation Costs

6.44 For LV generation, forward-looking costs are determined from the typical costs of reinforcing the network to connect generation at this voltage level. At the present time, G3 does not foresee any generator reinforcement costs due to generator connections at LV. More sophisticated approaches to determining reinforcement costs may be considered in future as part of the general requirement to keep charging methodologies under review.

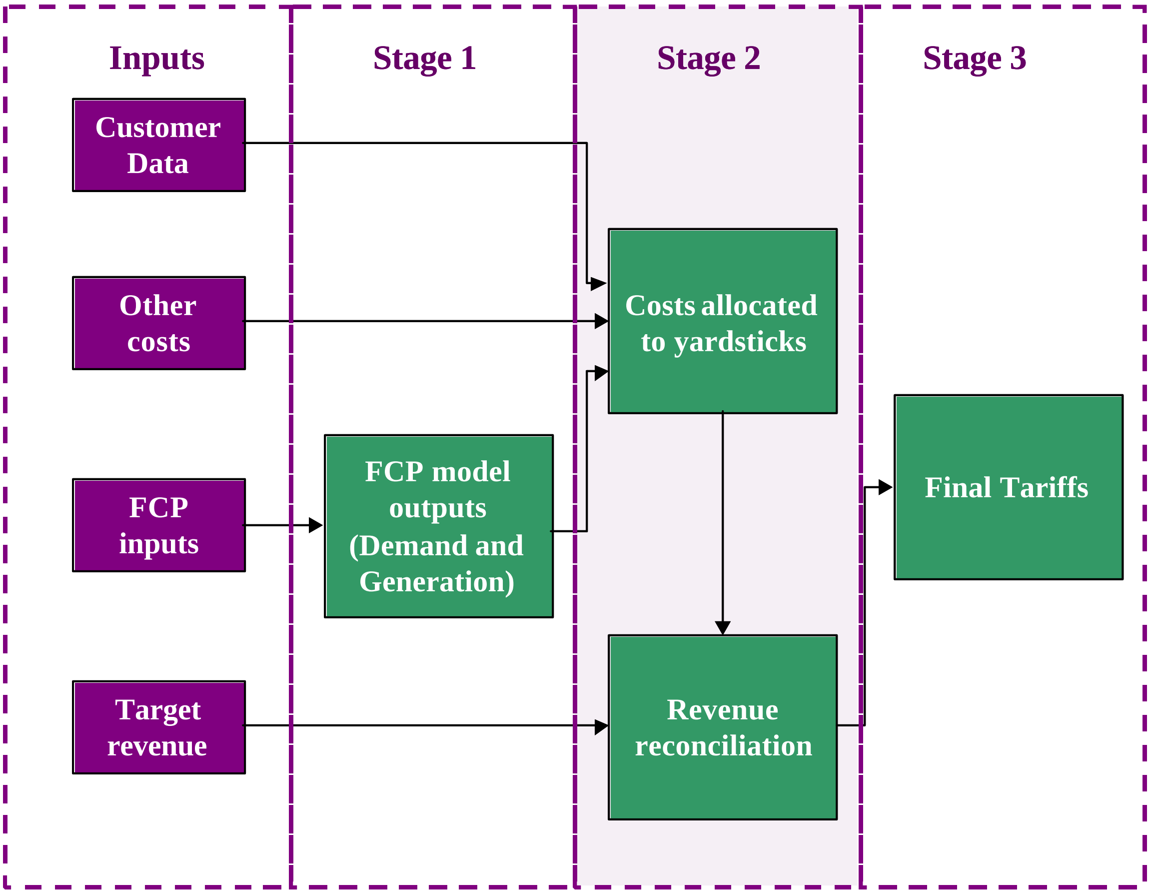
Generation Benefits

6.45 The addition of generation to the network can reduce the requirement for network reinforcement due to increases in demand. The generation benefit corresponds to the extent to which generation is considered to contribute to the reduction in demand when assessing system security at each voltage level. Generation benefits are calculated by multiplying together the demand costs for the voltage of connection as well as the voltages above the point of connection, and the P2/6 Generation Contribution Factors at the voltage of connection. It is proposed that the benefits of connecting generation, include the benefits of all voltage levels above the point of connection up to the highest level at which generation can contribute to network security. The overall approach to the costs and benefits included in the generation yardstick is provided in Appendix 5.

6.46 G3 proposes to base the allocation of benefits on the factor that drives costs at the network voltage of connection – i.e., the P2/6 security factor. However it takes cognisance of recent development in the industry, such as the recent presentations by EDF and WPD at the DCMF meetings as well as the recent WPD consultation in relation to recognising the benefits that generation can have in the voltages above the level of connection in terms of reducing perceived demand at those levels. In order to determine benefits calculated this way it would be necessary to take into account the coincidence factors. In accordance with our licence requirements, we will continue to look into these developments and, if appropriate, will bring forward a further proposal in this regard.

7. The G3 tariff model

STAGE 2: DERIVATION OF 'YARDSTICK' COSTS



7.1 The FCP model described in the previous chapter produces a series of £/kVA/annum charges for each network voltage and transformation level and for different times of use. The next step is to calculate yardstick £/kVA/annum charges for sets of customer groups. This is done within the G3 tariff model.

7.2 The G3 tariff model is a direct development of the 'COG model' as developed and consulted upon by the joint DNOs working group during the course of 2006. The high level architecture of the G3 model is the same as the COG model, however, G3 have made significant further development and refinement of this model. The most significant change is the extension of the model to accommodate generation costs and benefits.

7.3 The G3 tariff model allocates all the appropriately identified costs to the various customer groups (yardsticks) using the most relevant cost driver. The model then applies a voltage-level fixed kVA adder (described in more detail later) to reconcile the overall tariff model revenue with the allowed revenue as per the price control.

7.4 The first step is to identify the relevant yardsticks or customer groups. The objective is to band together for charging purposes customers that exhibit broadly similar characteristics. Each yardstick customer group relates to either demand or generation and will be associated with a specific voltage of connection.

7.5 The following list shows the yardsticks which are used to determine tariffs. Note that this list represent the major types of customers, as identified widely in the industry. Within the G3 group each licensee will have its own set of yardsticks, taken from the list below, depending on the starting position of each company. Where applicable, yardsticks are also split into substation and network connected customer groups.

- LV Demand domestic unrestricted (PC1)
- LV Demand domestic restricted (PC2)
- LV Demand Off Peak
- LV Demand non-domestic small unrestricted (PC3)
- LV Demand non-domestic small restricted (PC4)
- LV Demand non-domestic medium unrestricted (PC5-8)
- LV Demand non-domestic medium restricted (PC5-8)
- LV Demand unmetered supplies
- LV Demand non-domestic large unrestricted (HH)
- LV Demand non-domestic large restricted (HH)
- HV Demand non-domestic medium unrestricted (PC5-8)
- HV Demand non-domestic medium restricted (PC5-8)
- HV Demand non-domestic large unrestricted (HH)
- HV Demand non-domestic large restricted (HH)
- EHV Demand 132kV - site specific
- EHV Demand 132/33kV - site specific
- EHV Demand 33kV - site-specific
- LV IDNO, Band 1 (up to 25% of average LV feeder length[10])
- LV IDNO, Band 2 (from 25% to 50% of average LV feeder length)
- LV IDNO, Band 3 (from 50% to 75% of average LV feeder length)
- LV IDNO, Band 4 (above 75% of average LV feeder length)

[10] The average LV feeder length is calculated as the total length of LV mains divided by the number of LV feeders, calculated separately for SP Manweb and SP Distribution.

- HV IDNO
- LV Generation (NHH)
- LV Generation (HH)
- HV Generation (HH)
- EHV Generation (site-specific)

7.6 In compliance with the obligation to keep the charging methodology under review, we may identify additions or changes to this list. This may include, for instance, the addition of IDNO tariffs where relevant.

Cost allocation to demand customer yardsticks

7.7 The G3 tariff model identifies and allocates the following costs to each of the customer groups listed above:

7.8 **Forward-looking Costs.** These are the output of the forward cost pricing methodology described in Chapter 6. These costs, in £/kVA, are provided by network voltage and transformation level, as well by time of use. For EHV customers, the FCP costs used are those for the specific network group to which the customer is connected. For HV and LV yardsticks, the costs are allocated on an average basis (i.e. they are not locational). The multiple time period charge rates calculated as described in paragraphs 6.28 to 6.31 are used to allocate costs for day and night units for the relevant HV and LV customers. For EHV customers, the charge rate at the time of maximum demand is used. As demand is the cost driver, the forward-looking costs allocated to each customer group are derived by multiplying that customer group's forecast demand, for each of the specified time periods at each voltage and transformation level, by the cost calculated for that voltage level/time period.

7.9 **Operation & Maintenance Costs (O&M).** These consist of inspection, maintenance and fault costs. To ensure transparency and auditability, the historic cost information is taken from the Regulatory Reporting Packs (RRPs) that are submitted to Ofgem each year. The model uses a rolling average of historical O&M costs to smooth out year on year fluctuations, and then costs are uplifted using inflation to estimate the relevant year's costs. The applicable RRP tables also allow the total cost to be accurately split between each voltage and transformation level. The forecast O&M costs for each level of the network are converted into a £/kVA, by dividing this by the forecast maximum demand at each voltage/transformation level. These costs are then equitably attributed to each customer group by using their contribution to the forecast maximum demand.

7.10 **Refurbishment Costs**. These are identified for each level of the network in a similar way as O&M costs. A rolling average of historical RRP Refurbishment cost data (split by network voltage/transformation level) is uplifted for inflation to the relevant year. Similarly to O&M costs, these costs are converted into a £/kVA using the forecast maximum demand at each network level and the costs attributed to each customer group, by reference to their contribution to this forecast maximum demand.

7.11 **Pass-through Costs.** NGET Exit Charges and Licence Fees are both pass-through costs within the distribution price control. Forward looking estimates of NGET Exit

Charges are used and converted into £/kVA by using the total calculated maximum demand at the boundary with the transmission system. Each customer group is then allocated its equitable share of exit charges by reference to their contribution to the maximum demand at the NGET boundary. Forward looking estimates of Licence Fee costs are used and converted into a £/customer, using the total number of customers connected and allocated to each customer group on the basis of their forecast customer numbers.

7.12 **Customer Service Costs**. These costs (e.g. call centre costs, MPAS costs) are also sourced from the RRP tables. They are converted into £/customer values for the main billing approaches/systems used by the DNO, and allocated to the customer groups based on their forecast customer numbers.

7.13 In order to allocate the costs above the G3 tariff model also requires a range of other inputs. These include: -

7.14 **Peaking Probabilities.** These represent the likelihood that demand at each voltage level will peak in a particular time period. These are used to allocate FCP costs at the lower voltages to the different time periods.

7.15 **Demand Estimation Coefficients (DECs)**. These are profiling tools used to forecast a customer group's maximum demand in the different time periods from their forecast annual unit consumption. These forecast maximum demands are the basis for the kVA related cost allocations explained above. The DECs are obtained from analysis of historical HH kWh data (either actual or profiled) for each customer group. The formula for calculating a DEC is as follows:

DEC = maximum demand in time period / total annual MWh

A separate DEC is calculated for each time period and for each customer group. These can then be used to forecast the maximum demand in each time period for the relevant charging year given the forecast of total annual MWh for each customer group.

7.16 **Loss Adjustment Factors.** These are obtained from the G3 members' LAF models and published standard loss adjustment factors, as submitted to Elexon and published on their web site. The loss adjustment factors are used to uplift customer groups' demand at the various network levels, this will affect their allocation of kVA related costs as described above.

7.17 **Forecast Usage Data**. Customer Numbers, consumption (by time of use where appropriate) and maximum capacities (where appropriate) are obtained for each customer group. This is determined independently by each G3 member, using their tariff forecasting techniques.

7.18 For each yardstick group a demand matrix is estimated, detailing the group's forecast kVA peak demand at each voltage level and each time period. These demand estimates are derived by multiplying forecast annual consumption by the Demand Estimation Coefficients, described in paragraph 7.15. This provides demand estimates for the voltage level at which each yardstick group is connected. These estimates are then scaled up by the appropriate published LAFs to estimate the demands placed on higher voltage levels by each yardstick group. The charge rates for each of the five sets of costs described in the paragraphs above are then multiplied by these demand forecasts to generate total cost forecasts for each cost component (marginal, O&M, refurbishment etc.). Finally, these costs are tallied to arrive at a total cost recovery target for each yardstick group. This analysis produces the total cost for each of the customer groups and also provides the split of this cost by network level.

Cost allocation to IDNO yardsticks

7.19 There are five IDNO yardsticks: One for HV IDNO connections and four for LV IDNO connections. At LV, four distance bands are proposed, which are measured as the distance to the IDNO point of connection from the source substation. The proposed bands are up to 25%, from 25% to 50%, from 50% to 75% and above 75% of the average LV feeder length, calculated separately for SP Manweb and SP Distribution. *IDNO connections, which are solely, or predominantly supplying I&C customers may be charged as per the equivalent I&C customer*.

7.20 For these IDNO yardsticks the general principles of cost allocations, described in paragraphs 7.8 to 7.18 above, apply. There principles are adapted to take into account the avoided costs associated with IDNO connections. This is described in detail in the following paragraphs.

7.21 **Forward-looking, Operation & Maintenance and Refurbishment Costs.** These costs are defined as described in paragraphs 7.8 to 7.10. The difference between the yardsticks for demand “end users” customers and IDNO connections is that the cost allocation to IDNOs reflects the corresponding proportion of the costs that are avoided through connection to the IDNO network. For LV IDNO connections, SPEN will charge as if, within each band, the point of connection is at the band boundary closest to the substation. Thus, in band 1 no FCP cost is allocated; within band 2: 25%; within band 3: 50%; and within band 4: 75%. This ensures that no individual IDNO network is charged for more than the proportion of the LV costs than it incurs. For HV connections the cost savings are greater, as the DNO provides none of the LV network and does not provide the HV/LV transformer.

7.22 **Pass-through Costs.** These are allocated in accordance with customer numbers, as described in paragraph 7.11.

7.23 **Customer Service Costs**. For an IDNO connection, no data is received via the settlement systems and the automated “supercustomer” processes and systems cannot be used. These therefore represent avoided costs. However, separate manual processes are required for IDNO billing and these costs need to be reflected in the tariffs in the proposed IDNO yardsticks. The IDNO customer service cost are therefore based on budgeted staff costs and exclude IT costs.

7.24 In term of the other inputs used for costs allocation, the IDNO yardstick are no different to the other demand yardsticks for **peaking probabilities**, **forecast usage data**, and **loss adjustment factors.** The **Demand Estimation Coefficients (DEC)** used to profile the IDNO yardsticks are those for a domestic profile in all cases as this is the best fit derived from the information available for existing IDNO sites.

7.25 The total IDNO yardstick costs are finally calculated as described in paragraph 7.18.

EHV site-specific costs

7.26 The site-specific charges applicable to EHV connections for both demand and generation reflect the actual sole use assets comprising each particular connection. The other elements of EHV charges are calculated according to the same principles described for the other customer groups. The charges relating to sole use assets are calculated using the methodology explained in Chapter 9.

7.27 For EHV customers, the forward-looking costs are taken directly from the actual FCP costs for the Network Group (as defined in the forward cost pricing model, section 6) to which they are connected. In order to provide locational price signals to existing and prospective EHV customers, G3 members intend to publish a list of FCP costs per Network Group together with the DUoS tariffs, as part of the DUoS charging statement.

Revenue reconciliation for demand

7.28 The next step in the tariff setting process is to reconcile the costs obtained using the approach described above with the allowed revenue forecast for the relevant year. The difference between modelled costs and allowed revenue, reflects costs that are not taken into account in the modelling. These are principally network asset related historic costs, such as depreciation and return on capital employed. Given the nature of these costs, it is inappropriate to add them equally to all tariffs, as it would effectively impose costs relating to the lower network voltages onto higher voltage customers, making their charges disproportionately high. G3 has developed a ‘per kVA, per voltage level’ adder, calculated on the basis of the estimated Modern Equivalent Asset Value (MEAV) of the regulated assets at the various network voltage levels. The MEAV of assets deemed to be associated solely with the customers connected at each voltage level are excluded from this calculation, as these assets are likely to have been paid for up-front through connection charges. This results in a different per kVA adder at each particular network voltage level, ensuring that forward-looking cost price messages remain undistorted within each voltage level, whilst avoiding unfairly allocating costs to classes of customer that do not use specific network levels.

7.29 For IDNO connections it is not clear that the level of indirect costs is directly related to the length of the LV circuit. In order to avoid introducing potentially discriminatory differences in apportionment of indirect costs through scaling of LV charges across the four bands, we propose to cap the scaling of LV IDNO connections to the HV level. Therefore the LV and LV Substation £/kVA components are not included in the post-scaling LV IDNO yardstick costs. The effect of this is to cap the total amount of scaling per LV IDNO end-customer at a level (approximately) equivalent to that of an end-customer connected at HV.

Cost allocation to generation customer yardsticks

7.30 A yardstick cost is produced for each network group. This is determined by multiplying the appropriate FCP generator costs, determined in section 6, by the total amount of generation capacity forecast for that yardstick. As described, generator costs are only included at the voltage of connection whereas benefits include voltage levels above the point of connection. This produces a yardstick for each generator group. The other costs used in the demand yardsticks are not allocated to generation as these costs are recovered through the demand price control.

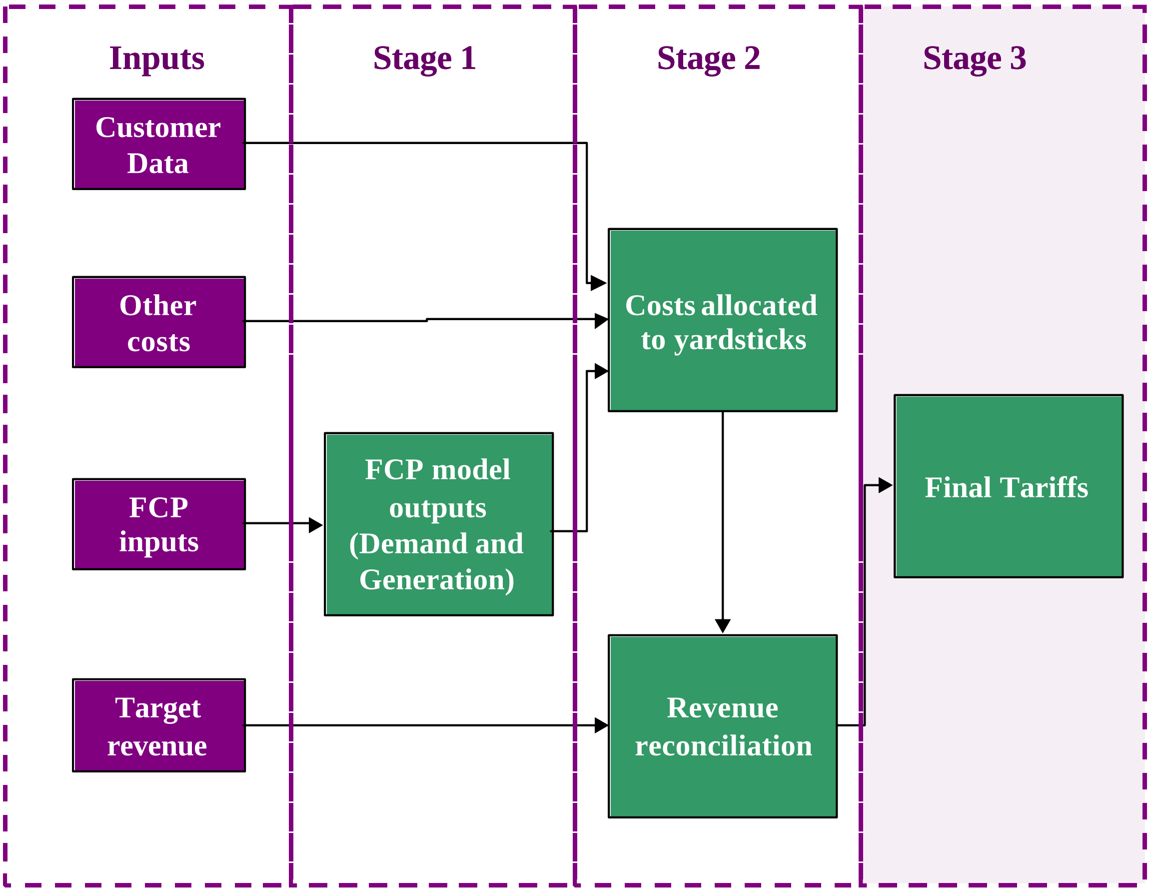
7.31 This analysis of generation costs and generation benefits produces the total net cost for each generator customer group.

Revenue reconciliation for generation

7.32 To reconcile the net costs obtained using the approach described above to the generation allowed revenue, a similar approach to revenue reconciliation for demand is used. A fixed kVA adder is applied to each voltage yardstick, with the exception of LV until the allowed revenue is achieved. The LV yardstick is not currently included in the revenue reconciliation for generation, as G3 are not forecasting generation driven investment in the LV network for the foreseeable future, and benefits are zero according to P2/6. This is a policy decision aimed at encouraging LV generation by preventing it receiving scaling costs while it is in its infancy and not creating any network costs.

7.33 G3 propose that any negative charges identified in the modelling are passed through to customers. There is therefore potential for generation connected at all voltages (including LV) to enjoy negative charges where they bring benefit to the network.

Stage 3. Setting of final tariffs



7.34 Once the total costs per customer group are determined, they are converted into final tariffs by allocating each cost element to the most appropriate tariff component. The structure of the final tariffs will normally be made up of the following elements:

For NHH demand sites:

7.35 Fixed charges. The proportion of pre-scaled costs attributable to the customer service costs and asset-related costs at the voltage of connection and the following level of transformation up is applied to the post-scaled total cost recoverable from the customer group and converted to a fixed charge by reference to the number of customers in the customer group.

7.36 Unit charges. The unit charge will represent the remaining cost. Where the tariff splits the unit rate into a day and night tariff the cost is apportioned between the day and night rates in the same proportion derived from the forward cost allocations.

For HH demand sites (LV & HV):

7.37 Fixed charges. The proportion of pre-scaled costs attributable to the customer service costs only is applied to the post-scaled total cost recoverable from the customer group and converted to a fixed charge by reference to the number of customers in the customer group.

7.38 Capacity charges. The proportion of pre-scaled costs attributable to the assets-related costs at the voltage of connection and the following level of transformation up is applied to the post-scaled total cost recoverable from the customer group and converted to a capacity charge by reference to the forecast chargeable capacities of the customer group.

7.39 Unit charges. The unit charge will represent the remaining cost. Where the tariff splits the unit rate into a day and night tariff the cost is apportioned between the day and night rates in the same proportion derived from the forward cost allocations.

For IDNO customers:

7.40 Fixed charges. The proportion of pre-scaled costs attributable to the IDNO customer service costs only, is applied to the post-scaled total cost recoverable from the customer group and converted to a fixed charge by reference to the number of customers in the customer group.

7.41 Unit charges. The unit charge will represent the remaining cost. As the IDNO tariffs split the unit rate into day and night charges, the cost is apportioned between the day and night rates in the same proportion as derived from the forward cost allocations. The use of separate day and night charges in IDNO tariffs allows charges to be more cost reflective, as the majority of costs arise from day-time use of the network. A single charge throughout the 24 hours would not reflect this differential in costs.

7.42 There are no capacity charges, which avoids any potential mis-match in the structure of the host DNO's and the IDNO's charges. Also at this stage SPEN is proposing not to include Reactive Charges for IDNOs. SPEN may review this position if we believe that IDNOs are not including appropriate charges for poor power factors in their end-user DUoS tariffs, in accordance with the Ofgem guidance.

For Generation sites:

7.43 Capacity charges. All of the net costs/benefits attributable to a customer group are converted to a capacity charge by reference to the forecast generation capacities of the customer group[11].

For EHV sites:

7.44 The process of setting the final tariffs for EHV sites is described in section 8.

Reactive charges:

7.45 The tariff model also derives the excess reactive power charges applicable to half-hourly LV and HV sites. Refer to section 9 for details.

7.46 The graphic below shows a summary of the tariff structure for demand and generation customers.

[11] Generator charges only apply to 'Relevant DG', as defined in the distribution licence. Further development may be necessary should charges be extended to cover all DG in the future.

NHH Demand Charges

Fixed
Recover proportion of pre-scaled costs attributable customer service and asset-related costs at the voltage of connection and one transformation up

Unit
Recover remaining costs

HH Demand Charges

Fixed
Recover proportion of pre-scaled costs attributable to customer service costs only

Capacity
Recover proportion of pre-scaled costs attributable to asset-related costs only at the voltage of connection and one transformation up

Unit
Recover remaining costs

HV/LV Charges

Capacity
Recover all of the net costs (or net benefits) attributable to each yardstick group

EHV Site-Specific Demand Charges

Fixed
Recover proportion of pre-scaled costs attributable customer service and sole-use assets maintenance costs (derived by applying the average EHV network maintenance cost % to Gross Asset Value of sole use assets)

Capacity
Recover remaining costs (marginal FCP demand and other business scaled costs)

EHV Site-Specific Generation Charges

Fixed
Recover proportion of pre-scaled costs attributable customer service and sole-use assets maintenance costs (derived in the same way as for EHV site-specific demand charges)

Capacity
Recover remaining costs (FCP generator marginal net costs and other business scaled costs)

Excess Reactive Power Charges

Applied only to HH demand where total kVArh exceeds 33% of total kWh

EHV customers do not require separate reactive power charges since they are charged on a kVA basis.

8 EHV site-specific charges

8.1 An EHV site is defined in our licence as being connected to the distribution system at a voltage at or higher than 22kV or at a substation with a primary voltage of 66kV or above. As the costs and circumstances of each EHV site are individual to itself, the use of system charges are determined on a site-specific basis. The site-specific charges are designed to recover the costs (other than those which are recovered through the connection charge) of providing, operating and maintaining the relevant assets between the Grid Supply Point (GSP) and the metered connection exit/entry boundary. The site-specific charge includes the FCP derived costs which provides cost-reflective forward looking locational charge and price signals to the customer to encourage better utilisation and efficient use of the network.

EHV demand site-specific charges

The site-specific charges for an EHV demand site are in general calculated as follows:

8.2 Fixed charge - This charge recovers customer service costs (a) and sole use assets maintenance costs (b). The customer service costs are derived on the same basis as for lower voltage customers and recovers customer service, billing and administration costs. The sole use assets maintenance charge is calculated by applying the average EHV network maintenance cost % to the Gross Asset Value (GAV) of the sole use assets. The GAV of the sole use assets is revised annually to take into account inflation (regulatory RPI July – Dec average) and any asset modifications.

Fixed charge (£ / year) = £ (a) + £ (b)

8.3 Capacity charge - This charge recovers FCP demand costs (a) and other business scaled costs derived on the same basis as for lower voltage networks customers (b). The capacity charges are applied to contracted maximum capacity.

Capacity charge (£/kVA) = (a) + (b)

EHV generation site-specific charges

The site-specific charges for an EHV Generator with registered export are calculated as follows:

8.4 Fixed charges. In general, fixed charges are recovered through import charges. However, in cases where there is no import connection or the import is done via a separate supply (i.e., with an LV or HV connection), the GDUoS will contain a fixed charge element calculated as per paragraph 8.2.

8.5 Capacity charge - This charge recovers FCP Generator cost(s) associated with the connection (a), FCP Generator benefit which is the FCP charge rate multiplied by the P2/6 F-Factor for site (b) and the Generation Scaling Adder cost (c).

Capacity charge (£/kVA) = (a - b) + (c)

Sole Use Assets

8.6 For existing EHV sites the methodology treats all sole use assets as being fully contributed in line with our current charging policy, unless there is evidence of assets not having been fully contributed. In the later case, the outstanding cost is also recovered from the customer over the nominal life of the assets through a charge comprising of: depreciation calculated on a straight-line basis from the Gross Asset Value of the outstanding sole use assets, a nominal life of 40 years; and a return on capital calculated from the depreciated value of the asset and the cost of capital. In these cases, the sole use charges are added to the fixed charges mentioned in 8.2 above

8.7 EHV customers would fund replacement of the sole use assets as and when required and the charges would be based on the connection charging policy as detailed in our connection charging statement prevailing at the time. SPEN's current connection charging statement is available from SPEN's website at http://www.scottishpower.com/ConnectionsUseMetering.htm.

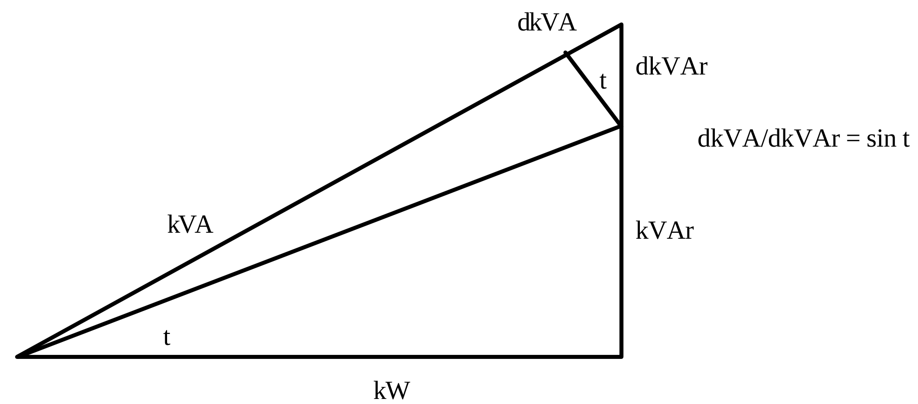
9 Reactive Power charges

9.1 Excess reactive power charges apply to half-hourly demand where total kVArh exceeds 33% of total kWh in a particular charging period (this boundary being equivalent to the average power factor of 0.95 assumed in the pricing model).

9.2 EHV demand customers and generators are charged on a per kVA basis and hence no separate reactive charges are to be levied as the costs are already reflected in the kVAcapacity charge. The FCP locational based kVA charge provides strong incentive for the customer to better utilise his contracted capacity.

9.3 The methodology for HV and LV half-hourly metered customers broadly follows that already approved for another DNO[12]. For each customer class the Network Cost and Capacity charges are derived from the tariff model as £/kVA/year (as described in chapters 6 and 7). The Capacity charge is subtracted from the Network Cost as capacity charges (kVA) recover part of the reactive cost element. Furthermore, the Fixed Cost is also removed from the Network Cost.

9.4 The Load Factor for each voltage level is used to derive a cost in p/kVAh. The incremental cost of reactive power is calculated by multiplying this p/kVAh by the rate of increase of the kVA with kVAr. This is sin(t) where the power factor is cos(t). This defines the excess charge rate p/kVArh.



The power factor for which sin (t) is derived is the average power factor weighted by volume for that customer class for all months in which their power factor is worse than 0.95 based on a previous year's metered data (generators are excluded). The excess charge rate is then applied to all kVArh in excess of one third of the kWh.

9.5 The use of the incremental cost to set reactive charges for HV and LV half-hourly metered customers gives a clear and realistic signal of the costs and benefits of them changing their power factor. Customers may choose to install power factor correction

[12] Electricity North West's methodology.

equipment as an alternative to paying the reactive charges, thus diminishing the kVA imposed on the network.

10 Proposed Methodology Statement

10.1 The proposals set out above would require very substantial changes to our current methodology statement and we therefore intend to replace the current methodology statement in its entirety. The proposed methodology statements forming part of this proposal are attached as separate documents.

11 Proposals versus Licence Obligations

11.1 SP Distribution and SP Manweb are obliged to ensure that their Use of System Charging methodologies conform to the objectives set out in Standard Licence Condition 4, paragraph 3. These state that each methodology must:

- facilitate the discharge of the licensee's obligations under the Electricity Act and its licence;
- facilitate competition in the generation and supply of electricity, and does not restrict, distort, or prevent competition in the transmission or distribution of electricity;
- be cost reflective, as far as is reasonably practicable, taking account of implementation costs; and
- take into account developments in the licensee's distribution system.

11.2 In its consultation document of May 2005[13] Ofgem outlined five high level principles for distribution charges. These are:

- cost reflectivity;
- simplicity;
- transparency;
- predictability; and
- facilitation of competition.

11.3 Ofgem anticipated "the creation of new charging models which accurately reflect forward looking costs, incentivise efficient usage and development of the system, and accommodate the introduction of generator use of system charges (GDUoS) better than current models."

11.4 Ofgem also recognised that "there are practical constraints which create the potential for conflict between some of these principles" and that "[t]he principles also interact, for example transparency and predictability may facilitate competition" (paragraph 3.14).

11.5 These proposals achieve the objectives of transparency and predictability through the use of publicly available data and appropriate third party assumptions for model inputs. For example:

- The Long Term Development Statements are used for assumptions on the growth of the distribution system;
- Data from the Regulatory Reporting Pack (RRP) is extensively used; and
- Factors are taken from Engineering Recommendation P2/6.

[13] "Structure of electricity distribution charges – Consultation on the longer term charging framework", Ofgem, May 2005

11.6 Our intention is to make available details of the model in a form which will further increase transparency and predictability.

11.7 Cost reflectivity is enhanced through the use of Network Groups to derive charges at the EHV level (for both generation and demand) that vary by location. This promotes economic efficiency by signalling to users their impact on the network of their decisions regarding location and usage of the network.

11.8 The use of growth and demand data from the Long Term Development Statement allows for different growth rates and levels of spare capacity across network groups. This further enhances cost reflectivity, as future reinforcements requirements will be better assessed by network group.

11.9 Cost-reflectivity is also enhanced through the inclusion of fault-level analysis for both demand and generation to forecast reinforcement costs at EHV level. Fault level is a significant driver of reinforcement costs, in addition to thermal capacity.

11.10 The use of detailed AC load flow analysis produces a reinforcement assessment for a large number of nodes on the network, thereby improving cost reflectivity. In addition, the use of AC load flow analysis also takes into account reactive power. Account is also taken of the potential for reverse power flow arising from distributed generation. Again, both improve cost reflectivity.

11.11 The use of 'test-size' generators based on the distribution of actual sizes along with probability estimates of the incidence of additional generation allows a more sophisticated estimate to be made of the reinforcement costs for EHV generation.

11.12 Within the constraints of the current structure of separate price controls for demand and generation, the proposed approach recognises the potential benefits of distributed generation and encourages the location of generation where there is most benefit, in terms of deferring reinforcement of the network. The revised charging method for distributed generation will apply at all voltage levels, thereby facilitating distributed generation, which can reduce greenhouse gas emissions.

11.13 The proposed approach uses an integrated approach to determine charges at all voltage levels and for both demand and generation, which ensures non-discrimination.

11.14 Overall, the FCP approach:

- delivers substantial improvements in cost reflectivity;
- significantly improves transparency and predictability;
- facilitates distributed generation;
- better facilitates competition in the supply and generation of electricity;
- does not restrict, distort, or prevent competition in the transmission or distribution of electricity; and
- maintains an appropriate degree of simplicity.

11.15 The proposed methodology is compatible with current metering arrangements and tariff structures, so the implementation costs to industry participants should not be significant.

11.16 We have been advised[14] that the FCP approach avoids the potentially excessive charges that, in certain circumstances (for example, highly utilised network assets but with a low growth in demand), may arise from the LRIC calculations as set out in the November 2007 IEEE paper[15] by Li and Tolley. Such excess charges could be challenged under the Competition Act.

[14] Reckon LLP (2008) "Locational incentives under forward cost pricing", February

[15] Li, Furong and Tolley, David L. (2007) "Long-Run Incremental Cost Pricing Based on Unused Capacity", IEEE Transactions on Power Systems, Vol. 22, No. 4, November

12 Impact of new methodology on prices

12.1 The tables detailed in Appendix 6a illustrate the tariffs derived from applying the proposed methodology for the 2008-09 pricing year for SP Distribution. Appendix 6b shows the tariffs for SP Manweb.

12.2 The table shown in Appendix 7a show the changes in total annual charges to typical customers when comparing the proposed methodology to the current approved methodology for SPD. Appendix 7b show the corresponding values for SPM. It should be noted that DUoS charges typically constitute around a fifth of retail electricity bills. Consequently the average percentage changes in end customers' bills driven by the change in methodology will be significantly smaller than the illustrative changes in DUoS charges shown in the tables.

12.3 Appendix 8a shows the FCP costs and benefits (pre scaling) for the Network Groups in the SPD area, whereas Appendix 8b shows the FCP costs and benefits for SPM. G3 proposes to publish these tables together with the annual tariffs in order to help potential customers take notice of the locational signals.

12.4 Appendix 9a shows the IDNO margins as a function of the number of plots per site which may from the current modification, in the SPD area. Appendix 9b shows the equivalent data for SPM.

Appendix 1. Summary of consultants' reports on the G3 methodology.

G3 commissioned Frontier Economics ("FE") and Reckon LLP to critique its proposed use of system charging methodology based on a Forward Cost Pricing approach. Both FE and Reckon also compared the FCP with the LRIC method adopted by WPD.

Frontier Economics' conclusions

In summary, FE concludes[16] that overall the G3 proposed methodology addresses the practical shortcomings of a "pure" LRIC approach whilst at the same time retaining the key desirable features. FE recognizes that, in practice, there is a need to adopt a pragmatic approach for developing distribution charging methodologies. Hence, a departure from the pure incremental cost of reinforcement is necessary, particularly as there is currently no accepted method of implementing a "pure" LRIC approach given the indivisibility, or lumpiness, of capital investment.

In particular FE reports that G3's proposed methodology has the following key strengths:

FCP approach uses minimal internally-based assumptions and engineering based judgements in deriving charges to ensure that the methodology is relatively transparent and, to a large extent, predictable.

FCP approach uses granular data on growth rates taken from the published Long Term Development Statement and use of AC load flow analysis, including fault-level, provides enhanced cost reflectivity and transparency. Furthermore, the FCP approach is fully capable of accommodating low or negative growth in the system, a feature which is very pertinent under the current growth trends observed in the network.

FE's view is that the methodology employed to derive generator charges in which it derives a probability of a "typical" sized generator connecting at a particular location based on a set of publicly available data represents an appropriate balance between cost reflectivity and transparency.

The report whilst highlighting the above strengths also highlighted the following concerns:

FE states that they are concerned that the empirical derivation of the FCP algorithm departs from a system of pure incremental cost pricing. However, in Appendix 3 of this modification report, the G3 demonstrate that the FCP formula can also be derived using an LRIC approach.

FE has suggested that the derivation of the FCP empirical algorithm is re-written to clarify the G3's goal of having a pricing equation with a set of desirable qualities. This has addressed FE's original concern on the apparent lack of basis for the derivation.

FE has expressed concern on the potential distortion of the incremental cost signals between the voltage levels when a voltage level fixed adder is used. G3 believe that voltage level fixed

[16] Frontier Economics (2008) "Review of distribution use of system charging methodology", March

adder scaling is more appropriate and better reflects costs as it eliminates a cross-subsidy of costs from low voltage users to high voltage users, who do not use the low voltage network. FE have accepted that in practice the potential of customer switching voltage levels is very limited or non-existent.

Whilst FE has raised its concern over the use of 10 year horizon and suggest a 20 year horizon, they do acknowledge that this would be "judgemental". G3 firmly believe that forecast of demand growth rates beyond 10 years into the future are subject to great uncertainty and there is a risk that deriving charges on incorrect growth rates is likely to adversely affect cost reflectivity.

Reckon LLP conclusions

The Reckon paper[17] focuses on use of system charges (excluding any reactive power charges) for demand EHV customers. It does not consider in detail issues linked to charging for distributed generation, reactive power, or users connected at lower voltage levels. The Reckon paper also performs a comparison between the proposed G3 method and the non-vetoed WPD implementation of an LRIC method.

In summary, Reckon concludes that the G3 proposed methodology provides an improvement over the current charging methods in terms of aligning incentives for customers, and it is a possible base from which to develop better methods in the future.

Reckon states that there appear to be no simple way of addressing the G3 method's potential shortcomings in relation to fully meeting Ofgem's objectives without raising significant implementation difficulties. Reckon concludes that a similarly mixed verdict might be given for the WPD method. It concludes that the WPD method creates a risk of non-compliance with competition law, against which an Ofgem decision not to veto would offer no protection to the distribution companies. The G3 companies take the view that these risks prevent them from putting forward a method similar to WPD's as an option for the structure of charges on their networks.

Reckon states that both the WPD and G3 methods have the prospect of being developed and improved in the longer term. The risks that such developments reveal insurmountable problems in the G3 method is not strongly correlated with the corresponding risks for the WPD method, as the two methods rest on quite different concepts. This risk is probably lower with the G3 method than the WPD method, because the G3 method is less dependent on assumptions such as those related to the lumpiness of future investments or the long term growth rate. For example, sustained negative demand growth would seem to render the WPD method unworkable. It would not seem a prudent regulatory policy to channel all efforts through the WPD method.

Reckon also comments on the issue of transitional arrangements for customers subject to large price increases. The G3 proposal is likely to provide a fairly smooth transition, whereas the WPD method runs the risk of imposing very large changes in charges at some locations which may subsequently need to be reversed if the method is refined to deal the kind of problems identified.

[17] Reckon LLP (2008) "Locational incentives under forward cost pricing", February

Overall, G3 believes that the FE and the Reckon report supports its proposed use of system charging methodology based on the FCP and provides a cost-reflective, transparent, predictable and pragmatic approach which will give appropriate cost signals to users. Furthermore, G3 believes its proposed methodology will not undermine government renewable targets.

G3 also notes that the Reckon paper argues that vetoing the G3 method would have an immediate detrimental effect in at least two ways:

a) It would maintain the current structure of charges with no locational incentives.

b) It would erect unnecessary barriers to the development of better charging methods, and to the process of transition towards such methods.

Appendix 2. System Planning Methodology for Identifying the Forward-looking Cost of Reinforcement

<u>**Introduction**</u>

Forward-looking reinforcement costs are determined with respect to the following categories:

1. Load-related reinforcement costs

2. Generation-related reinforcement costs

Analysis is based on:

1. Publicly available planning information as published annually in the Long Term Development Statement (LC25 Statement), such as:
   - Network data
   - Demand forecast tables
   - Embedded generation data (this is a voluntary additional submission, commonly made in the LTDS)

2. Publicly available planning standards:
   - ER P2/6 Security of Supply standard (as specified in the Distribution Licence)
   - Other standards as specified in the Distribution Code

3. Mechanical/deterministic processes and procedures as identified in this document.

Costs are identified per Network Group and from analysis of the Bbase Nnetwork.

To Assess Load-Related Reinforcement Costs

<u>**Process**</u>

Load-related reinforcement
- For each **Network Group**, the impact of additional load is assessed by uniformly increasing the load of the Base Network by 15% in small incremental steps. - For each 1% increment, perform Contingency Analysis in accordance with P2/6 - For loadflow analysis, the Base Network is set with the maximum demand profile given the LTDS and with installed generation set with the appropriate P2/6 F-Factor. - For fault level analysis, the Base Network is set with the maximum demand profile given the LTDS and with installed generation set to nameplate output.
For each stage of reinforcement identify: 1. the percentage increase of load from the Base Network

2. the assets to be reinforced

3. the cost of reinforcement

Procedure

Load-Related Reinforcement of Transformers

1. Identify the firm capacity of each substation and the appropriate maximum demand as forecast in the LTDS (Gross demand).

2. Calculate net demand by subtracting the contribution of embedded generation (as modified by the appropriate P2/6 factor) from the gross demand.

3. Increment gross demand in small steps from 0 to 15% and compare net demand against firm capacity for each increment.

4. If net demand exceeds firm capacity, assume reinforcement is required at the first increment that demand exceeds capacity.

Load-Related Reinforcement of Circuits

1. Identify circuit outage combinations as directed by ER P2/6 for each Network Group.

2. Set the Base Network with the maximum demand profile given in the LTDS and with embedded generation modified by the appropriate P2/6 F-Factor.

3. Increment the demand in small steps from 0 to 15% and perform Contingency Analysis for each increment to identify circuit powerflows.

4. If circuit powerflow exceeds circuit rating then assume reinforcement is required at the first increment that powerflow exceeds rating.

Load-Related Reinforcement of Switchgear

1. For each Network Group identify the fault break and fault make switchgear ratings at the Principal Substation using information published in the LTDS.

2. Identify the existing fault break and fault make level at the Principal Substation using information published in the LTDS.

3. Increment the demand in small steps % from 0 to 15% and assess the contribution to fault current due to additional demand.

4. If fault break or fault make current exceeds switchgear rating then assume reinforcement is required at the first increment that fault current exceeds rating.

To Assess Generator-Related Reinforcement Costs

Process

Generator-related reinforcement
- For each Network Group, the impact of additional generation is assessed by identifying the headroom in the Base Network for additional generation before reinforcement. - New generation is assumed to connect directly to Principal Substation in the Network Group. - The headroom is assessed in terms of switchgear fault ratings and loadflow. - For loadflow analysis, the Base Network is set with the minimum demand profile given in the LTDS and with installed generation set to nameplate output. - For fault level analysis, the Base Network is set with the maximum demand profile given in the LTDS and with installed generation set to nameplate output.
Determine: 1. the existing fault break headroom for additional generation, the assets to be reinforced and the cost of reinforcement. 2. the existing fault make headroom for additional generation, the assets to be reinforced and the cost of reinforcement. 3. the existing reverse-powerflow headroom for additional generation, the assets to be reinforced and the cost of reinforcement.

Procedure

Generator-Related Reinforcement of Transformers

1. For each Network Group identify the minimum demand and maximum generator contribution to the Principal Substation using information published in the LTDS.

2. Calculate net demand by subtracting the contribution of embedded generation from the minimum demand.

3. Where generation is greater than demand, consider the transformer reverse power-flow capabilities.

4. Calculate the reverse-powerflow headroom by subtracting the existing net demand from the reverse-powerflow rating.

Generator-Related Reinforcement of Switchgear

1. For each Network Group identify the fault break and fault make switchgear ratings at the Principal Substation using information published in the LTDS.

2. Identify the existing fault break and fault make level at the Principal Substation using information published in the LTDS.

3. Calculate the fault break and fault make headroom by subtracting the existing fault levels from the switchgear ratings.

4. With respect to fault break contribution, calculate the maximum amount of additional generation that can be connected based on the typical fault current contribution from the generator at fault break time

5. With respect to fault make contribution, calculate the maximum amount of additional generation that can be connected on the typical fault current contribution from the generator at fault make time

Reinforcement Scheme and Costs

Reinforcement of sole-user assets are not considered

Transformers

1. To reinforce a transformer it is assumed an additional transformer of modern equivalent rating will be installed in parallel.

2. The cost of modern equivalent asset reinforcement is based on actual schemes of a similar nature.

3. The equivalence of scheme is assessed in terms of voltage level and transformer rating.

Circuits

1. To reinforce a circuit it is assumed an additional circuit of modern equivalent rating will be installed in parallel.

2. The cost of modern equivalent asset reinforcement is based on actual schemes of a similar nature scaled in respect to circuit length.

3. The equivalence of scheme is assessed in terms of voltage level, circuit rating and whether it is overhead or underground.

Switchgear

1. To reinforce switchgear, the numbers of limiting units of switchgear are identified and are assumed to be replaced with switchgear of modern equivalent rating.

2. The cost of modern equivalent asset reinforcement is based on actual schemes of a similar nature.

3. The equivalence of scheme is assessed in terms of voltage level and transformer rating.

Appendix 3. Alternative derivation of the FCP Demand Algorithm, LRIC approach

Let the growth rate of the demand, D kVA, be denoted by g per annum.

Then, if C kVA is the capacity at which reinforcement is required, the demand at time t years prior to the capacity being reached is given by:

$$D(t) = C \exp(-g\,t) \text{ kVA}$$

The Present Value, PV, of reinforcing the asset, cost £A, at a discount rate of i per annum is:

$$PV = £\,A \exp(-i\,t)$$

The effect of a small change in D at time t is given by:

$$d(PV)/dD = A\ d(\exp(-i\,t))/dD = A\ d((D/C)^{i/g})/dD = i\,(A/C)\,(D/C)^{i/g-1}/g \text{ £/kVA}$$

This is the analytical form of the standard formula for the LRIC incremental cost of individual asset reinforcements. It can also be expressed in terms of time rather than demand as:

$$d(PV)/dD = i\,(A/C) \exp(-i\,t) \exp(g\,t)/g \text{ £/kVA}$$

Note that the units are £/kVA and in order to determine an annual rate an additional factor needs to be introduced. Applying an annuity factor based on the lifetime of the asset is incorrect, since such a value is based on the rental rate or mortgage rate assuming that constant payments can be collected over the lifetime of the asset. Here the payments are not constant and will only be paid over the cost recovery period from the time when the previous reinforcement was carried out until the time of the next reinforcement. The factor therefore needs to be based on the cost recovery period, not on the asset lifetime. Moreover, in keeping with the concept of NPV, it is more appropriate to use repayments which contribute equal amounts to the final total rather than equal instalments. Thus, denoting the cost recovery period by T years, the annuity factor is chosen to be:

$$\exp(-it)/T$$

Denoting the initial demand by D_0:

$$LRIC2 = i\,(A/C) \exp(-2i\,t) \exp(g\,t)/gT$$

$$= i\,(A/C)\,(D/C)^{2i/g-1}/\text{Log}(C/D_0) \quad \text{£/kVA p.a.}$$

If the additional reinforcement is assumed to double the capacity then the initial demand can be taken to be half the capacity and the numerical value of the denominator gives a multiplying factor of 1.44.

Thus, the functional form is identical to that of FCP. If the formula above is rescaled to recover the the total reinforcement cost over the 10 year period, then the FCP formula is obtained:

$$\text{FCP} = i\,(A/C)\,(D/C)^{2i/g-1}/(1-\text{Exp}(-i\,T)) \quad \text{£/kVA p.a.}$$

which for T = 10 years and i = 6.9% gives a multiplying factor of approximately 2, and the formula becomes:

$$FCP = 2i(A/C)(D/C)^{2i/g-1}$$

This larger multiplying factor of 2 in FCP represents the recovery of the total cost over a 10 year period rather than the generally much longer period between the growth of demand from 50% utilisation to full capacity. As such, FCP gives sharper messages, more effectively discouraging growth in demand in the crucial period when full capacity is being approached and offering the larger incentives to generation in this period.

Appendix 4. Generation probability of connection

Generation Probabilities

10 year growth as % of demand =	30%
Total MVA =	6000
New generation =	1800

Voltage	Existing MVA	New MVA	Network Groups	Test Size	Test (MW)	**Pv**
132kV	483.6	818.4	16	75	1200	**0.68**
33kV	330.1	558.6	110	25	2750	**0.20**
HV	244.8	414.3	457	3.4	1553.8	**0.27**
LV	5.2	8.8				
Total	1063.7	1800.0				

Appendix 5. Overall approach to costs and benefits for generation

Site Specific

FCP Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	Demand point of Connection: 33kV Network	Generation: 132kV	Generation: 33kV
132kV Switchgear	Demand (D1)	D1	D1	-f x D1	-f x D1
	Generation (G1)			G1	
132kV Circuits	Demand (D2)	D2	D2	-f x D2	-f x D2
	Generation (G2)				
132/33kV Transformers	Demand (D3)		D3		-f x D3
	Generation (G3)				G3
33kV Switchgear	Demand (D4)		D4		-f x D4
	Generation (G4)				G4
33kV Circuits	Demand (D5)		D5		-f x D5
	Generation (G5)				
33/11kV Transformers	Demand (D6)				
	Generation (G6)				
11kV Switchgear	Demand (D7)				
	Generation (G7)				

Tariff Model

Tariff Model Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	Demand point of Connection: 33kV BSP Busbars	Demand point of Connection: 33kV Network	Demand point of Connection: HV Network	Demand point of Connection: LV Network	Generation: 132kV	Generation: 33kV	Generation: HV	Generation: LV
132kV Network	Demand	D1 + D2	D1 + D2	D1 + D2	D1 + D2	D1 + D2	-f x (D1 + D2)	-f x (D1 + D2)	-f x (D1 + D2)	-f x (D1 + D2)
	Generation						G1			
132/33kV Substation	Demand		D3 + D4	D3 + D4	D3 + D4	D3 + D4		-f x (D3 + D4)	-f x (D3 + D4)	-f x (D3 + D4)
	Generation							G3 + G4		
33kV Network	Demand			D5	D5	D5		-f x D5	-f x D5	-f x D5
	Generation									
33/11kV Substation	Demand				D6 + D7	D6 + D7			-f x (D6 + D7)	-f x (D6 + D7)
	Generation								G6 + G7	
11kV Circuits	Demand (D8)				D8	D8			-f x D8	-f x D8
	Generation (G8)									
11kV/LV Transformers	Demand (D9)					D9				-f x D9
	Generation (G9)									G9 *
LV Circuits	Demand (D10)					D10				-f x D10
	Generation (G10)									G10 *

* G9 and G10 = zero

Key:

(white)	= values from FCP Model
(light blue)	= values derived from RRP data
(hatched)	= marginal cost N/A

Notes:

Nomenclature **Costs are denoted D if related to demand reinforcement and G if related to generation**
Benefits are shown as negative
Benefits are proportional to generation contribution 'f' and are determined using ENA Engineering Technical Report 130 (Application Guide for Assessing the Capacity of Network Containing Distributed Generation (ETR 130) Section 6 considering
('f' for LV generation is typically zero due to the requirement for loss of mains protection and isolation)

Demand
Costs: Demand costs are cumulative from the point of connection up to the highest network voltage
These costs include switchgear, circuits and transformers

Benefits: There are no demand benefits

Generation
Costs: Generation costs are associated with the substation busbar at the point of connection only
These costs include switchgear and transformers
(Circuit costs are not included since generators are assumed to connect directly to the lower voltage side of the transforming busbar)

Benefits: Generation benefits are cumulative from the point of connection up to the highest network voltage level
Benefits are equal to the demand costs, scaled by the generation contribution factor f and include upstream circuits and transformers

Appendix 6.a. DUoS and GDUoS tariffs for SPD

No.	Tariff Description	LLFC	Market	PC	Fixed Charge p/MPAN/day	Fixed Charge p/site/day	Day Unit Charge p/kWh	Night Unit Charge p/kWh	Capacity Charge (p/kVA/day)	Reactive Power Charge (p/kVArh)	Locational Charge per Network Group
T01	Domestic Unrestricted	100, 101	**NHH - import**	**1**	10.87		1.28				
T02	Domestic Heating	110, 111	**NHH - import**	**1**	7.74		1.72				
T03	Heating	112, 113, 116, 117, 164, 165, 166, 130, 240	**NHH - import**	**2**				0.06			
T04	Domestic Day/Night	114, 115, 118, 119, 120, 162, 163	**NHH - import**	**2**	7.74		1.72	0.06			
T05	HWR Domestic Heating	160, 161	**NHH - import**	**1**	7.74		1.72				
T06	12hr Off Peak	132, 241, 133	**NHH - import**	**2**				0.91			
T07	16/20hr Off Peak	134, 242, 135	**NHH - import**	**2**				0.91			
T08	Storage Boiler	136	**NHH - import**	**2**				0.91			
T09	12hr Crop & Air Conditioning	243	**NHH - import**	**3**			0.91				
T10	16hr Crop & Air Conditioning	244	**NHH - import**	**3**			0.91				
T11	Crop Conditioning	245	**NHH - import**	**3**			0.91				
T12	Catering	246	**NHH - import**	**3**			0.91				
T13	12hr Off Peak HV	301	**NHH - import**	**4**				0.01			
T14	Business Single Rate	200, 201, 202, 203, 204, 205	**NHH - import**	**3**	51.79		1.23				
T15	Business Evening & Weekend	220, 221, 222, 224, 260	**NHH - import**	**3& 4**	42.55		1.64	0.04			
T16	Business Heating	223, 225	**NHH - import**	**4**				0.04			
T17	NHH MD LV <100kW (PC5-8)	400, 402	**NHH LV - import**	**5-8**	269.18		0.91	0.98			
T18	NHH MD HV <100kW (PC5-8)	401, 403	**NHH HV import**	**5-8**	295.01		0.24		0.00		

No.	Tariff Description	LLFC	Market	PC	Fixed Charge p/MPAN/day	Fixed Charge p/site/day	Day Unit Charge p/kWh	Night Unit Charge p/kWh	Capacity Charge (p/kVA/day)	Reactive Power Charge (p/kVArh)	Locational Charge per Network Group
M03	HH LV	500	**HH LV - import**	**0**	15.23		1.07	0.06	4.50	0.32	
M07	Embedded Generation Import LV	504	**HH LV - import**	**0**	15.23		1.07	0.06	4.50	0.32	
M04	HH HV	501	**HH HV - import**	**0**	16.96		0.36	0.00	4.13	0.10	
M08	Embedded Generation Import HV	505	**HH HV - import**	**0**	16.96		0.36	0.00	4.13	0.10	
T19	UMS, good inventory	900, 901, 902, 903	**NHH - UMS**	**1& 8**	0.00		0.63				
T20	UMS, poor inventory	904, 905, 906, 907	**NHH - UMS**	**8**	0.00		0.63				
T21	UMS, Public Lighting, good inventory	908	**NHH - UMS**	**1& 8**	0.00		1.24				
T22	UMS, Public Lighting, poor inventory	909	**NHH - UMS**	**1& 8**	0.00		1.24				
	33kV connected	801+	**HH EHV - import**	**0**	778.96	Site specific			2.31		Site specific
E06	LV connected generators with NHH metering		**NHH - export**	**1-8**					0.00		
E07	LV connected generators pre April 05	604	**HH LV - export**	**0**					0.00		
E05	LV connected generators post April 05	607	**HH LV - export**	**0**					0.00		
E08	HV connected generators pre April 05	605	**HH HV - export**	**0**					0.00		
E04	HV connected generators post April 05	606	**HH HV - export**	**0**					0.30		
	EHV connected generators	601+	**HH EHV - export**	**0**							Site specific

No.	Tariff Description	LLFC	Market	PC	Fixed Charge p/MPAN/day	Fixed Charge p/site/day	Day Unit Charge p/kWh	Night Unit Charge p/kWh	Capacity Charge (p/kVA/day)	Reactive Power Charge (p/kVArh)	Locational Charge per Network Group
	LV Band 1 IDNO				7.49		1.70	0.10			
	LV Band 2 IDNO				6.69		1.85	0.11			
	LV Band 3 IDNO				6.13		1.99	0.11			
	LV Band 4 IDNO				5.71		2.13	0.12			
	HH HV IDNO				7.56		1.68	0.09			

Appendix 6.b. DUoS and GDUoS tariffs for SPM

No.	Tariff Description	LLFC	Market	PC	Fixed Charge p/MPAN/day	Fixed Charge p/site/day	Day Unit Charge p/kWh	Night Unit Charge p/kWh	Capacity Charge (p/kVA/day)	Reactive Power Charge (p/kVArh)	Locational Charge per Network Group
T01	Domestic Unrestricted	101, 102	**NHH - import**	**1**	8.16		1.19				
T02	Domestic Heating	111, 131, 133, 147, 149, 112, 132, 134, 148, 150, 113, 114, 115, 116, 119, 120, 145, 146, 103, 105, 117	**NHH - import**	**2**	9.21		1.45	0.12			
T03	Domestic Control	104, 106, 153, 138, 143, 236	**NHH - import**	**2& 4**			0.12				
T04	Metered Cyclocontrol	155	**NHH - import**	**2**	9.21		1.31				
T05	Off Peak A	135, 140, 233	**NHH - import**	**2& 4**			1.31				
T06	Off Peak C	136, 141, 234	**NHH - import**	**2& 4**			1.31				
T07	Off Peak D	137, 142, 235, 237	**NHH - import**	**2& 4**			1.31				
T08	Business Single Rate, LVN & LVS	201, 202, 207	**NHH - import**	**3**	31.60		1.20				
T09	Business Two Rate, LVN & LVS	205, 231, 232, 210, 208, 211	**NHH - import**	**4**	50.51		1.16	0.13			
T10	Business Peak, LVN & LVS	203, 209	**NHH - import**	**3**	31.60		1.20	1.20			
T11	Business Control, Credit, LVN	212	**NHH - import**	**4**	0.00		0.13				
T12	Business MD, LVN	401, 402	**NHH LVN - import**	**5-8**	187.68		0.97	0.11			
T13	Business MD, LVS	403, 404	**NHH LVS - import**	**5-8**	119.99		0.76	0.08			

No.	Tariff Description	LLFC	Market	PC	Fixed Charge p/MPAN/day	Fixed Charge p/site/day	Day Unit Charge p/kWh	Night Unit Charge p/kWh	Capacity Charge (p/kVA/day)	Reactive Power Charge (p/kVArh)	Locational Charge per Network Group
T14	Business MD, HVN	405	**NHH HV - import**	**5-8**	125.45		0.30	0.00	0.00	0.28	
M16	Business HH, LVN	501	**HH LVN - import**	**0**	8.90		0.90	0.08	2.98	0.28	
M17	Business HH, LVS	503	**HH LVS - import**	**0**	9.26		0.65	0.06	2.36	0.28	
M26	Business HH, LVN	511	**HH LVN - import**	**0**	8.90		0.90	0.08	2.98	0.28	
M27	Business HH, LVS	513	**HH LVS - import**	**0**	9.26		0.65	0.06	2.36	0.28	
M36	Business HH, LVN Generator import	591	**HH LVN - import**	**0**	8.90		0.90	0.08	2.98	0.28	
M37	Business HH, LVS Generator import	592	**HH LVS - import**	**0**	9.26		0.65	0.06	2.36	0.28	
M18	Business HH, HVN	505	**HH HVN - import**	**0**	9.10		0.39	0.39	2.84	0.10	
M19	Business HH, HVS	507	**HH HVS - import**	**0**	9.11		0.22	0.22	2.03	0.10	
M28	Business HH, HVN	515	**HH HVN - import**	**0**	9.10		0.39	0.39	2.84	0.10	
M29	Business HH, HVS	517	**HH HVS - import**	**0**	9.11		0.22	0.22	2.03	0.10	
M38	Business HH, HVN Generator import	593	**HH HVN - import**	**0**	9.10		0.39	0.39	2.84	0.10	
M39	Business HH, HVS Generator import	594	**HH HVS - import**	**0**	9.11		0.22	0.22	2.03	0.10	
T15	UMS, good inventory	900, 901, 902, 903, 910, 912	**NHH - UMS**	**1&8**	0.00		1.59				
T16	UMS, poor inventory	904, 905, 906, 907, 913	**NHH - UMS**	**1&8**	0.00		1.59				

No.	Tariff Description	LLFC	Market	PC	Fixed Charge p/MPAN/day	Fixed Charge p/site/day	Day Unit Charge p/kWh	Night Unit Charge p/kWh	Capacity Charge (p/kVA/day)	Reactive Power Charge (p/kVArh)	Locational Charge per Network Group
	132kV connected	801+	**HH EHV - import**	**0**	78.70	Site specific			0.56		Site specific
	33kV connected	801+	**HH EHV - import**	**0**	88.76	Site specific			1.80		Site specific
	LV connected generators with non-half-hourly metering		**NHH - export**	**1-8**					0.00		
E01	LVN connected generators pre April 05	795	**HH LVN - export**	**0**							
E02	LVS connected generators pre April 05	796	**HH LVS - export**	**0**							
E05	LVN connected generators post April 05	791	**HH LVN - export**	**0**							
E06	LVS connected generators post April 05	792	**HH LVS - export**	**0**							
E03	HVN connected generators pre April 05	797	**HH HVN - export**	**0**							
E04	HVS connected generators pre April 05	798	**HH HVS - export**	**0**							
E07	HVN connected generators post April 05	793	**HH HVN - export**	**0**					0.41		
E08	HVS connected generators post April 05	794	**HH HVS - export**	**0**					0.41		
	EHV connected generators	601+	**HH EHV - export**	**0**							Site Specific
	LV Band 1 IDNO				3.22		1.53	0.12			
	LV Band 2 IDNO				3.18		1.70	0.13			
	LV Band 3 IDNO				3.14		1.91	0.14			
	LV Band 4 IDNO				3.11		2.14	0.17			
	HH HV IDNO				3.23		1.33	0.13			

Appendix 7.a. Annual charges comparison for SPD

Annual charges comparison, generic tariffs. SP Distribution

Tariff	Current £/customer/pa	Proposed £/customer/pa	£/customer Diff	% Diff
Domestic Unrestricted	£82.02	£87.43	£5.40	6.59%
Domestic Heating	£83.68	£79.71	-£3.97	-4.74%
Business Single Rate	£414.82	£416.66	£1.84	0.44%
Business MD, LV	£2,410.78	£2,157.42	-£253.37	-10.51%
Business HH, LV	£8,515.64	£9,682.43	£1,166.79	13.70%
Business HH, HV	£37,111.98	£35,776.08	-£1,335.90	-3.60%
UMS, good inventory	£147.77	£56.93	-£90.84	-61.47%
UMS 24hr, good inventory	£2,410.14	£1,895.27	-£514.87	-21.36%
LV connected generators with non-half-hourly metering	Currently no customers			
LV connected generators post April 05	£0.00	£0.00	£0.00	0.00%
HV connected generators post April 05	£5,452.20	£3,894.43	-£1,557.77	-28.57%

Note: this list is not exhaustive and only shows the major customer groups.

Annual charges comparison, Site-specific customers. SP Distribution

EHV site specific, demand	Current £/pa	Proposed £/pa	£/diff	% Diff
Customer 1	£14,240.36	£12,195.50	-£2,044.86	-14.36%
Customer 2	£10,127.36	£7,058.95	-£3,068.41	-30.30%
Customer 3	£11,167.61	£7,902.10	-£3,265.51	-29.24%
Customer 4	£18,199.70	£15,525.49	-£2,674.21	-14.69%
Customer 5	£26,251.24	£20,127.78	-£6,123.46	-23.33%
Customer 6	£13,248.11	£9,961.03	-£3,287.08	-24.81%
Customer 7	£10,647.49	£7,736.85	-£2,910.63	-27.34%
Customer 8	£7,630.76	£5,035.39	-£2,595.37	-34.01%
Customer 9	£19,723.61	£17,246.50	-£2,477.11	-12.56%
Customer 10	£6,590.51	£4,192.24	-£2,398.27	-36.39%
Customer 11	£48,616.61	£38,255.50	-£10,361.11	-21.31%
Customer 12	£12,020.86	£9,574.00	-£2,446.86	-20.36%
Customer 13	£358,854.11	£301,583.20	-£57,270.91	-15.96%
Customer 14	£157,091.11	£139,240.20	-£17,850.91	-11.36%
Customer 15	£338,447.99	£282,064.03	-£56,383.96	-16.66%
Customer 16	£158,086.86	£141,221.45	-£16,865.41	-10.67%
Customer 17	£245,438.86	£207,286.65	-£38,152.21	-15.54%
Customer 18	£485,942.61	£594,667.84	£108,725.23	22.37%
Customer 19	£62,940.61	£54,434.89	-£8,505.72	-13.51%
Customer 20	£33,503.78	£30,435.37	-£3,068.41	-9.16%
Customer 21	£33,057.65	£29,003.74	-£4,053.91	-12.26%
Customer 22	£42,869.08	£40,385.74	-£2,483.33	-5.79%
Customer 23	£127,615.40	£126,734.88	-£880.52	-0.69%
Customer 24	£92,712.41	£89,446.90	-£3,265.51	-3.52%
Customer 25	£169,690.91	£151,840.00	-£17,850.91	-10.52%
Customer 26	£18,854.51	£16,653.34	-£2,201.17	-11.67%
Customer 27	£69,425.26	£55,516.35	-£13,908.91	-20.03%
Customer 28	£223,652.36	£221,475.42	-£2,176.94	-0.97%
EHV site specific, generation	**Current £/pa**	**Proposed £/pa**	**£/diff**	**% Diff**
Generator 1	£109,503.65	£137,696.87	£28,193.22	25.75%
Generator 2	£10,910.22	£11,261.56	£351.35	3.22%
Generator 3	£134,365.63	£119,352.16	-£15,013.47	-11.17%

Appendix 7.b. Annual charges comparison for SPM

Annual charges comparison, generic tariffs. SP Manweb

Tariff	Current £/customer/pa	Proposed £/customer/pa	£/customer Diff	% Diff
Domestic Unrestricted	£71.42	£76.21	£4.79	6.71%
Domestic Heating	£96.47	£89.60	-£6.87	-7.12%
Business Single Rate, LVN & LVS	£252.34	£302.52	£50.18	19.89%
Business Two Rate, LVN & LVS	£473.24	£482.63	£9.39	1.98%
Business MD, LVN	£1,612.30	£1,770.12	£157.83	9.79%
Business MD, LVS	£1,340.89	£1,142.84	-£198.05	-14.77%
Business HH, LVN	£6,526.62	£7,219.87	£693.25	10.62%
Business HH, LVS	£7,676.45	£7,006.08	-£670.37	-8.73%
Business HH, HVN	£28,382.46	£22,227.11	-£6,155.36	-21.69%
Business HH, HVS	£54,848.94	£40,434.05	-£14,414.89	-26.28%
UMS, good inventory	£5,860.90	£5,578.57	-£282.33	-4.82%
UMS 24hr, good inventory	£2,648.13	£1,299.47	-£1,348.66	-50.93%
LV connected generators with non-half-hourly metering	£0.00	£0.00	£0.00	0.00%
LV connected generators post April 05	£0.00	£0.00	£0.00	0.00%
HV connected generators post April 05	£1,802.16	£1,802.16	£0.00	0.00%
EHV connected generators post April 2005	Currently no customers			

Note: this list is not exhaustive and only shows the major customer groups.

Annual charges comparison, Site-specific customers. SP Manweb

EHV site specific	Current £/pa	Proposed £/pa	£/diff	% Diff
Customer 1	£643,015.72	£545,863.16	-£97,152.56	-15.11%
Customer 2	£182,502.77	£146,122.71	-£36,380.06	-19.93%
Customer 3	£235,596.84	£186,334.14	-£49,262.71	-20.91%
Customer 4	£316,273.27	£300,150.71	-£16,122.56	-5.10%
Customer 5	£202,659.35	£139,269.29	-£63,390.06	-31.28%
Customer 6	£160,627.16	£124,247.10	-£36,380.06	-22.65%
Customer 7	£352,522.40	£289,132.34	-£63,390.06	-17.98%
Customer 8	£91,161.82	£53,431.26	-£37,730.56	-41.39%
Customer 9	£331,952.13	£334,677.08	£2,724.94	0.82%
Customer 10	£62,075.70	£52,705.64	-£9,370.06	-15.09%
Customer 11	£115,081.25	£90,855.69	-£24,225.56	-21.05%
Customer 12	£46,266.49	£35,874.78	-£10,391.71	-22.46%
Customer 13	£74,744.12	£107,406.53	£32,662.41	43.70%
Customer 14	£139,186.00	£249,358.81	£110,172.81	79.16%
Customer 15	£120,980.93	£132,251.14	£11,270.21	9.32%
Customer 16	£135,884.72	£146,601.03	£10,716.31	7.89%
Customer 17	£226,843.81	£246,422.52	£19,578.71	8.63%
Customer 18	£232,321.04	£236,932.93	£4,611.89	1.99%
Customer 19	£218,729.68	£261,638.35	£42,908.67	19.62%
Customer 20	£61,749.90	£66,393.10	£4,643.20	7.52%
Customer 21	£63,884.38	£74,431.26	£10,546.88	16.51%
Customer 22	£95,352.02	£89,997.06	-£5,354.95	-5.62%
Customer 23	£138,137.32	£232,246.36	£94,109.05	68.13%
Customer 24	£18,490.83	£12,783.90	-£5,706.93	-30.86%
Customer 25	£146,298.94	£147,603.43	£1,304.49	0.89%
Customer 26	£99,174.11	£117,381.05	£18,206.94	18.36%
Customer 27	£12,312.07	£11,010.76	-£1,301.31	-10.57%
Customer 28	£175,225.73	£303,530.81	£128,305.07	73.22%
Customer 29	£3,626.06	£1,953.10	-£1,672.95	-46.14%
Customer 30	£194,512.92	£265,599.93	£71,087.02	36.55%
Customer 31	£3,211.34	£587.98	-£2,623.36	-81.69%
Customer 32	£3,058.08	£456.56	-£2,601.52	-85.07%
Customer 33	£41,671.47	£36,705.15	-£4,966.31	-11.92%
Customer 34	£14,140.68	£12,084.55	-£2,056.13	-14.54%
Customer 35	£23,877.42	£23,044.83	-£832.60	-3.49%
Customer 36	£56,997.82	£113,895.93	£56,898.11	99.83%
Customer 37	£6,425.17	£4,081.52	-£2,343.65	-36.48%
Customer 38	£12,815.73	£10,487.51	-£2,328.23	-18.17%
Customer 39	£13,176.35	£10,930.83	-£2,245.53	-17.04%
Customer 40	£17,690.38	£13,055.63	-£4,634.75	-26.20%
Customer 41	£20,291.19	£17,800.03	-£2,491.16	-12.28%
Customer 42	£10,033.16	£7,682.47	-£2,350.68	-23.43%
Customer 43	£44,398.97	£40,932.36	-£3,466.60	-7.81%

Customer 44	£41,874.63	£38,985.05	-£2,889.58	-6.90%
Customer 45	£13,709.95	£10,958.62	-£2,751.33	-20.07%
Customer 46	£12,615.17	£9,692.62	-£2,922.55	-23.17%
Customer 47	£133,629.57	£147,115.38	£13,485.81	10.09%
Customer 48	£22,377.13	£33,223.87	£10,846.74	48.47%
Customer 49	£341,563.50	£306,000.16	-£35,563.34	-10.41%
Customer 50	£122,839.87	£244,160.14	£121,320.26	98.76%
Customer 51	£30,077.72	£21,383.12	-£8,694.59	-28.91%
Customer 52	£107,352.60	£117,279.17	£9,926.57	9.25%
Customer 53	£649,827.89	£646,479.99	-£3,347.90	-0.52%
Customer 54	£13,586.72	£11,320.52	-£2,266.20	-16.68%
Customer 55	£43,037.99	£56,572.64	£13,534.65	31.45%
Customer 56	£168,979.67	£341,876.24	£172,896.57	102.32%

Appendix 8.a. FCP costs per Network Group for SPD

The following tables detail the Network Group FCP costs (unscaled) used for the calculation of distribution use of system charges.

Network Group Demand FCP Costs, SP Distribution

Network Group (SPD)	Voltage	Total Unscaled FCP Demand £/kVA
Ayr	33kV	5.0907
Bainsford	33kV	1.4184
Bathgate	33kV	0.0000
Berwick	33kV	0.0000
Bonnybridge	33kV	5.9591
BraeheadPark	33kV	1.3656
Broxburn	33kV	1.5904
Carntyne	33kV	1.4869
Chapelcross	33kV	0.0000
CharlotteStreet	33kV	1.1966
Clydesmill	33kV	0.0000
Coatbridge	33kV	2.0413
Cockenzie	33kV	3.5253
Coylton	33kV	0.0000
CrookstonA	33kV	0.0000
CrookstonB	33kV	0.0000
Cumbernauld	33kV	0.0000
Cupar	33kV	5.5793
DevolMoor	33kV	0.4102
Devonside	33kV	0.6863
DewarPlace	33kV	0.0000
Drumchapel	33kV	12.7917
Drumcross	33kV	0.0000
Dumfries	33kV	0.0000
Dunbar	33kV	0.0000
Dunfermline	33kV	0.0000
Easterhouse	33kV	1.1399
EastKilbride	33kV	1.6912
EastKilbrideSouth	33kV	0.0000
Eccles	33kV	0.0000
Elderslie	33kV	3.9594
Erskine	33kV	0.0000
Galashiels	33kV	0.0000
Giffnock	33kV	2.9976
Glenluce	33kV	0.0000
Glenniston	33kV	0.0000
Glenrothes	33kV	4.6572
Gorgie	33kV	0.1022

Network Group (SPD)	Voltage	Total Unscaled FCP Demand £/kVA
Govan	33kV	1.1231
Grangemouth	33kV	0.0000
HaggsRoad	33kV	2.2284
Hawick	33kV	6.0878
Helensburgh	33kV	0.0000
HunterstonFarm	33kV	0.0000
Inverkeithing	33kV	0.3053
Johnstone	33kV	0.0000
Kaimes	33kV	0.4652
Kilbowie	33kV	0.0000
Killermont	33kV	0.9822
KilmarnockSouth	33kV	1.7077
KilmarnockTown	33kV	5.1368
Kilwinning	33kV	0.0000
Leven	33kV	0.0959
Linmill	33kV	2.0430
LivingstonEast	33kV	5.0161
Maybole	33kV	0.0000
Newarthill	33kV	1.3631
NewtonStewart	33kV	0.0000
Paisley	33kV	0.0000
Partick	33kV	1.9662
PortDundas	33kV	2.0117
Portobello	33kV	0.9465
Ravenscraig	33kV	0.0000
Redhouse	33kV	1.3042
SaltcoatsA	33kV	0.7553
SaltcoatsB	33kV	0.0000
Shrubhill	33kV	1.9592
Sighthill	33kV	0.0000
SpangoValley	33kV	0.0000
StAndrewsCross	33kV	0.0000
Stirling	33kV	1.4877
Strathaven	33kV	2.8890
Strathleven	33kV	0.0000
TelfordRoad	33kV	0.0000
Tongland	33kV	0.0000
Westfield	33kV	0.0000
WestGeorgeStreet	33kV	3.2808
Whitehouse	33kV	0.0000
Wishaw	33kV	0.0000

Network Group Generation FCP Costs and Benefits, SP Distribution

For an EHV connected Generator the benefits are calculated by multiplying the "benefit" column by the P2/6 F Factor relevant to the technology

Network Group Level 1 (SPD)	Voltage	Benefit Unscaled £/kVA	Cost Unscaled £/kVA
Ayr	33kV	5.0907	3.5379
Bainsford	33kV	1.4184	5.4662
Bathgate	33kV	0.0000	0.0000
Berwick	33kV	0.0000	0.0000
Bonnybridge	33kV	5.9591	0.9812
BraeheadPark	33kV	1.3656	0.0000
Broxburn	33kV	1.5904	0.0000
Carntyne	33kV	1.4869	0.0000
Chapelcross	33kV	0.0000	0.4051
CharlotteStreet	33kV	1.1966	8.4095
Clydesmill	33kV	0.0000	1.6819
Coatbridge	33kV	2.0413	4.3542
Cockenzie	33kV	3.5253	4.2048
Coylton	33kV	0.0000	0.0000
CrookstonA	33kV	0.0000	0.0000
CrookstonB	33kV	0.0000	3.4569
Cumbernauld	33kV	0.0000	0.0000
Cupar	33kV	5.5793	0.0000
DevolMoor	33kV	0.4102	0.0000
Devonside	33kV	0.6863	0.0000
DewarPlace	33kV	0.0000	8.4095
Drumchapel	33kV	12.7917	4.6252
Drumcross	33kV	0.0000	0.0000
Dumfries	33kV	0.0000	1.6853
Dunbar	33kV	0.0000	0.0000
Dunfermline	33kV	0.0000	0.8788
Easterhouse	33kV	1.1399	1.6819
EastKilbride	33kV	1.6912	5.4662
EastKilbrideSouth	33kV	0.0000	0.0000
Eccles	33kV	0.0000	0.0000
Elderslie	33kV	3.9594	0.0000
Erskine	33kV	0.0000	0.0000
Galashiels	33kV	0.0000	0.0000
Giffnock	33kV	2.9976	4.6252
Glenluce	33kV	0.0000	0.0000
Glenniston	33kV	0.0000	0.0000
Glenrothes	33kV	4.6572	0.0000
Gorgie	33kV	0.1022	0.0000
Govan	33kV	1.1231	5.4662

F Factors Data	
Technology type	**Factor**
Windfarm	0.24
Biomass	0.73
Landfill gas	0.77
Hydro	0.36
CHP	0.77

Network Group Level 1 (SPD)	Voltage	Benefit Unscaled £/kVA	Cost Unscaled £/kVA
Grangemouth A	33kV	0.0000	3.0132
Grangemouth C	33kV	2.2284	3.5163
HaggsRoad	33kV	6.0878	0.0000
Hawick	33kV	0.0000	0.0000
Helensburgh	33kV	0.0000	0.0000
HunterstonFarm	33kV	0.3053	0.0000
Inverkeithing	33kV	0.0000	0.0000
Johnstone	33kV	0.4652	0.0000
Kaimes	33kV	0.0000	2.8636
Kilbowie	33kV	0.9822	0.0000
Killermont	33kV	1.7077	5.4662
KilmarnockSouth	33kV	5.1368	0.0000
KilmarnockTown	33kV	0.0000	7.1481
Kilwinning	33kV	0.0959	0.0000
Leven	33kV	2.0430	0.0000
Linmill	33kV	5.0161	0.9190
LivingstonEast	33kV	0.0000	0.0000
Maybole	33kV	1.3631	0.0000
Newarthill	33kV	0.0000	2.1292
NewtonStewart	33kV	0.0000	0.0000
Paisley	33kV	1.9662	0.0000
Partick	33kV	2.0117	0.0000
PortDundas	33kV	0.9465	0.0000
Portobello	33kV	0.0000	7.1481
Ravenscraig	33kV	1.3042	0.0000
Redhouse	33kV	0.7553	0.0000
SaltcoatsA	33kV	0.0000	0.0000
SaltcoatsB	33kV	1.9592	0.0000
Shrubhill	33kV	0.0000	7.1481
Sighthill	33kV	0.0000	6.7276
SpangoValley	33kV	0.0000	0.0000
StAndrewsCross	33kV	1.4877	0.0000
Stirling	33kV	2.8890	0.0000
Strathaven	33kV	0.0000	4.2048
Strathleven	33kV	0.0000	2.7604
TelfordRoad	33kV	0.0000	3.1008
Tongland	33kV	0.0000	0.0000
Westfield	33kV	3.2808	1.9143
WestGeorgeStreet	33kV	0.0000	8.4095
Whitehouse	33kV	0.0000	5.8867
Wishaw	33kV	0.0000	8.4095

Appendix 8.b. FCP costs per Network Group for SPM

Network Group Demand FCP Costs, SP Manweb

Network Group Level 1 (SPM)	Network Group Level 2 (SPM)	Voltage	Total Unscaled FCP Demand £/kVA
Birkenhead		132kV	0.000
Capenhurst		132kV	0.000
Carr_Fidd		132kV	1.503
Cellar_Crewe		132kV	0.000
ConnQuay_Pent		132kV	0.000
Frod_Rock		132kV	0.000
Kirkby_Penw		132kV	0.000
Legacy		132kV	0.385
ListerDrive		132kV	10.080
Rainhill		132kV	0.055
Rocksavage		132kV	0.000
Shotton_Paper		132kV	0.000
SwanNorth		132kV	0.000
Trawsfynydd		132kV	0.000
Wylfa		132kV	0.000
Birkenhead	BromT3_RockFT2	33kV	0.000
Birkenhead	Hesw_Hoyl_PrenT3	33kV	4.004
Birkenhead	PrenT1_RockFT1	33kV	8.023
Birkenhead	Wall_Wood	33kV	3.917
Capenhurst	BromT2_HootT1AT2A	33kV	1.295
Capenhurst	Chest_Crane_Guild	33kV	4.123
Capenhurst	EPortT4_InceT1T2	33kV	3.553
Carr_Fidd	Dall_SankeyB_Warr	33kV	6.688
Carr_Fidd	Elw_Hart_Knut_Lost_Wins	33kV	5.726
Cellar_Crewe	Cop_Crew_RadG_WhiT2	33kV	4.633
ConnQuay_Pent	Bangor_Caernarvon	33kV	12.493
ConnQuay_Pent	BrymT2A_HawT2_HolyT2	33kV	8.891
ConnQuay_Pent	CastleCT1_HawT1_Salt	33kV	2.733
ConnQuay_Pent	ColwynBay_Dolgarrog	33kV	1.161

Network Group Level 1 (SPM)	Network Group Level 2 (SPM)	Voltage	Total Unscaled FCP Demand £/kVA
ConnQuay_Pent	Deeside_SixthAve	33kV	0.000
ConnQuay_Pent	HolyT1_Rhyl_StAsaph	33kV	1.890
Frod_Rock	Dutt_Moore_PercLane	33kV	0.361
Kirkby_Penw	AinT1_Form_Lith_South	33kV	7.073
Kirkby_Penw	AinT2_GillT2	33kV	1.700
Kirkby_Penw	BooT1_LitherT1A	33kV	6.910
Kirkby_Penw	GillT1_KirkT2_Simon	33kV	0.000
Legacy	BrymT1C_March_Wrex	33kV	9.716
Legacy	Leg_New_Osw_Wel_Whit	33kV	4.513
ListerDrive	BootlT2A_ListT2_BurlT1	33kV	12.357
ListerDrive	BurlT2_ListT1_PSt_Wav	33kV	12.428
ListerDrive	Gars_SpekeT3	33kV	13.412
ListerDrive	ListT1_PSt_SparSt	33kV	11.069
Rainhill	Bold2A_PresT1B_Wid	33kV	6.799
Rainhill	Gat_Huyt_KirkT3_PresT1A	33kV	7.989
Rainhill	Hale1B_GT3_SpekeT1A	33kV	7.853
Rainhill	Raven_StH_Windle	33kV	11.254
SwanNorth	Aberystwyth_Rhydlydan	33kV	3.578
Trawsfynydd	FourCrosses_Maentwrog	33kV	13.624
Wylfa	Amlwch_Caergeiliog	33kV	0.733

Network Group Generation FCP Costs and Benefits, SP Manweb

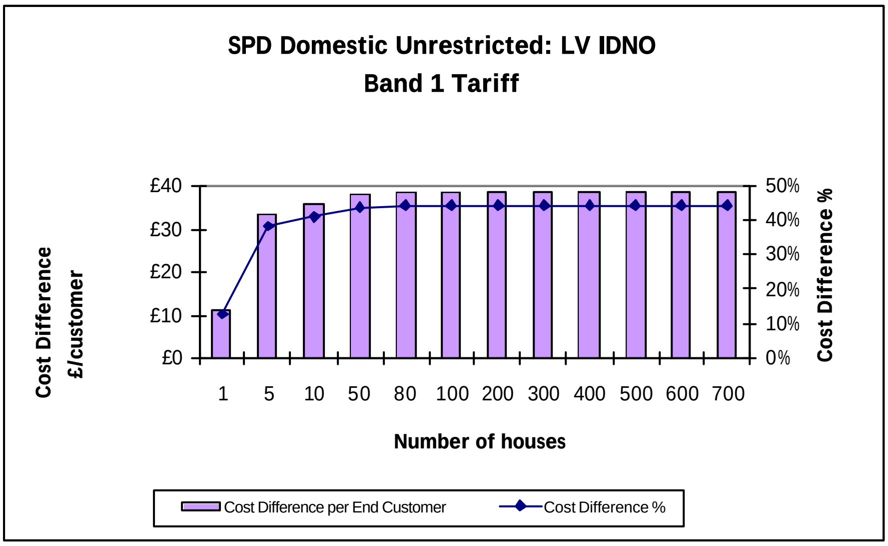
For an EHV connected Generator the benefits are calculated by multiplying the "benefit" column by the P2/6 F Factor relevant to the technology

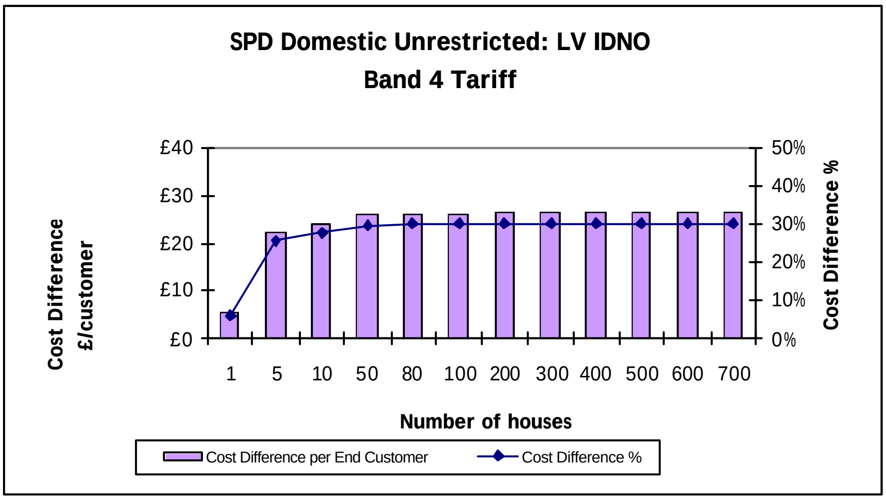
F Factors Data	
Type	**Factor**
Windfarm	0.24
Biomass	0.73
Landfill gas	0.77
Hydro	0.36
CHP	0.77

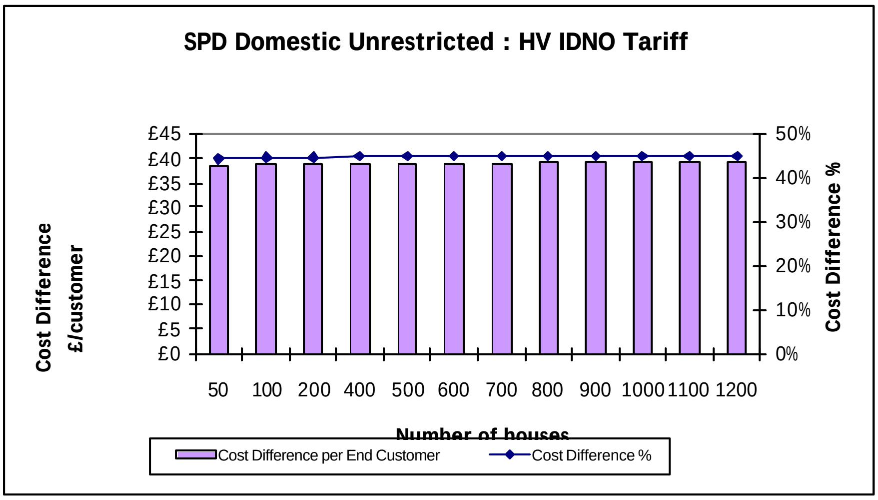
Network Group Level 1 (SPM)	Network Group Level 2 (SPM)	Voltage	Benefit Unscaled £/kVA	Cost Unscaled £/kVA
Birkenhead		132kV	0.000	0.000
Capenhurst		132kV	0.000	0.000
Carr_Fidd		132kV	1.503	0.000
Cellar_Crewe		132kV	0.000	0.000
ConnQuay_Pent		132kV	0.000	0.368
Frod_Rock		132kV	0.000	0.000
Kirkby_Penw		132kV	0.000	0.000
Legacy		132kV	0.385	0.000
ListerDrive		132kV	10.080	13.902
Rainhill		132kV	0.055	0.000
Rocksavage		132kV	0.000	0.000
Shotton_Paper		132kV	0.000	0.000
SwanNorth		132kV	0.000	0.000
Trawsfynydd		132kV	0.000	0.000
Wylfa		132kV	0.000	0.000
Birkenhead	BromT3_RockFT2	33kV	0.000	0.000
Birkenhead	Hesw_Hoyl_PrenT3	33kV	4.004	2.127
Birkenhead	PrenT1_RockFT1	33kV	8.023	1.389
Birkenhead	Wall_Wood	33kV	3.917	2.468
Capenhurst	BromT2_HootT1AT2A	33kV	1.295	0.000
Capenhurst	Chest_Crane_Guild	33kV	4.123	0.412
Capenhurst	EPortT4_InceT1T2	33kV	3.553	1.053
Carr_Fidd	Dall_SankeyB_Warr	33kV	6.688	0.697

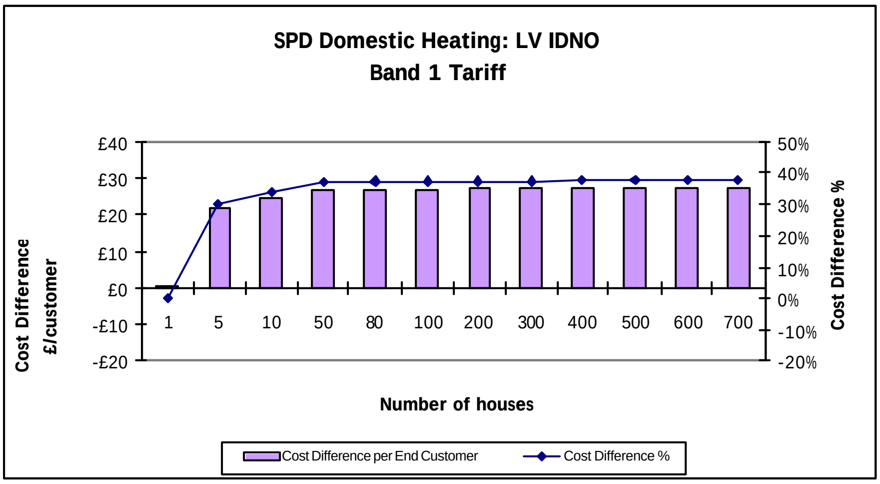
Carr_Fidd	Elw_Hart_Knut_Lost_Wins	33kV	5.726	0.153
Cellar_Crewe	Cop_Crew_RadG_WhiT2	33kV	4.633	1.276
ConnQuay_Pent	Bangor_Caernarvon	33kV	12.493	1.153
ConnQuay_Pent	BrymT2A_HawT2_HolyT2	33kV	8.891	0.548
ConnQuay_Pent	CastleCT1_HawT1_Salt	33kV	2.733	0.759
ConnQuay_Pent	ColwynBay_Dolgarrog	33kV	1.161	0.296
ConnQuay_Pent	Deeside_SixthAve	33kV	0.000	0.000
ConnQuay_Pent	HolyT1_Rhyl_StAsaph	33kV	1.890	0.747
Frod_Rock	Dutt_Moore_PercLane	33kV	0.361	0.000
Kirkby_Penw	AinT1_Form_Lith_South	33kV	7.073	2.329
Kirkby_Penw	AinT2_GillT2	33kV	1.700	0.800
Kirkby_Penw	BooT1_LitherT1A	33kV	6.910	1.033
Kirkby_Penw	GillT1_KirkT2_Simon	33kV	0.000	0.415
Legacy	BrymT1C_March_Wrex	33kV	9.716	0.509
Legacy	Leg_New_Osw_Wel_Whit	33kV	4.513	0.177
ListerDrive	BootlT2A_ListT2_BurlT1	33kV	12.357	0.580
ListerDrive	BurlT2_ListT1_PSt_Wav	33kV	12.428	0.574
ListerDrive	Gars_SpekeT3	33kV	13.412	0.502
ListerDrive	ListT1_PSt_SparSt	33kV	11.069	0.000
Rainhill	Bold2A_PresT1B_Wid	33kV	6.799	0.963
Rainhill	Gat_Huyt_KirkT3_PresT1A	33kV	7.989	2.277
Rainhill	Hale1B_GT3_SpekeT1A	33kV	7.853	1.579
Rainhill	Raven_StH_Windle	33kV	11.254	0.000
SwanNorth	Aberystwyth_Rhydlydan	33kV	3.578	0.161
Trawsfynydd	FourCrosses_Maentwrog	33kV	13.624	0.162
Wylfa	Amlwch_Caergeiliog	33kV	0.733	0.000

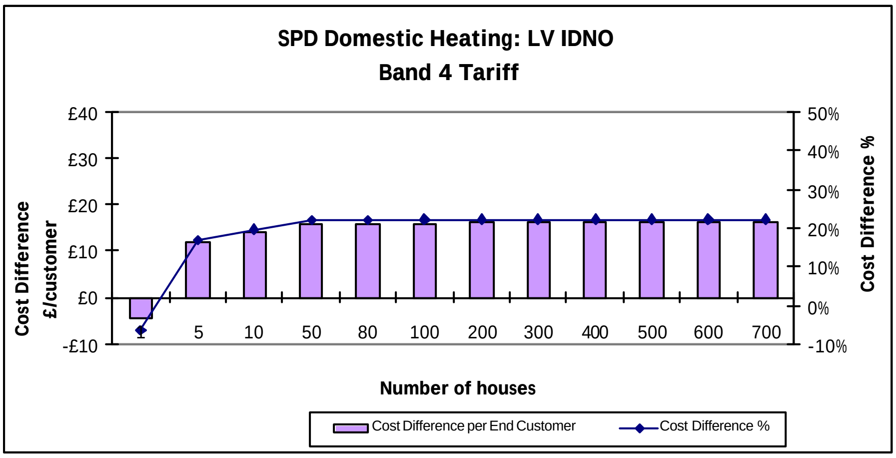
Appendix 9a. IDNO margins in the SPD area

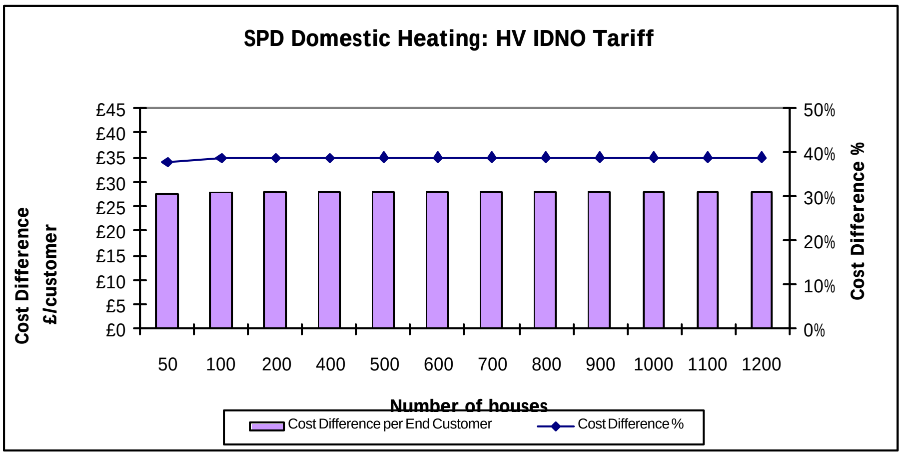




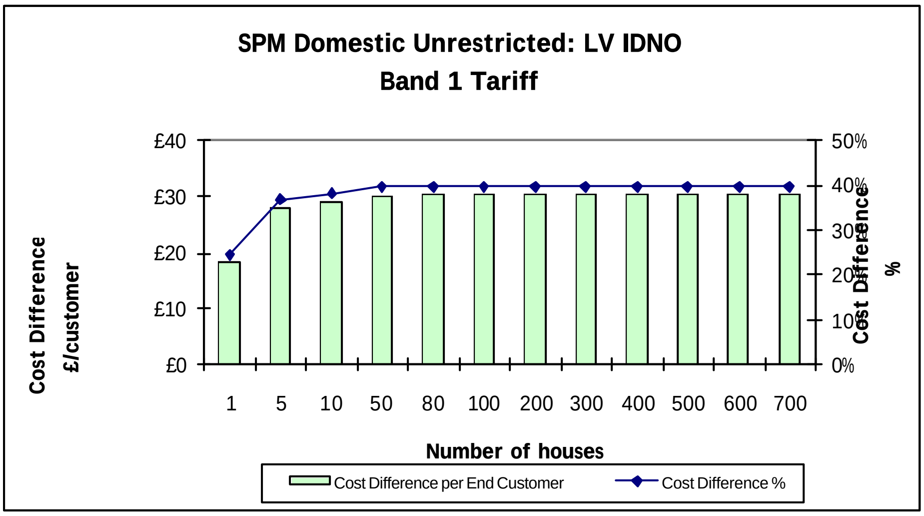


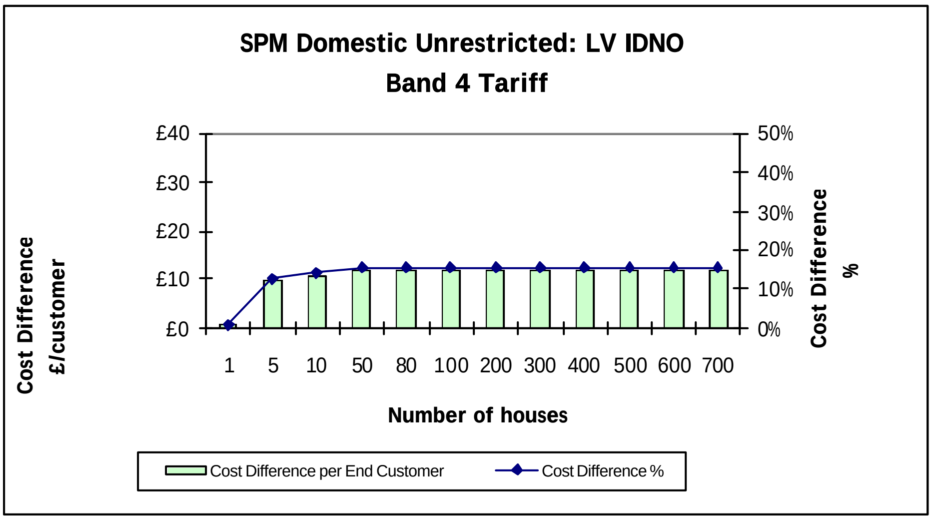

SPD Domestic Heating: LV IDNO
Band 1 Tariff
£40
£30
£20
£10
£0
-£10
-£20
50%
40%
30%
20%
10%
0%
-10%
-20%
1
5
10
50
80
100
200
300
400
500
600
700
Cost Difference £/customer
Cost Difference %
Number of houses
Cost Difference per End Customer
Cost Difference %

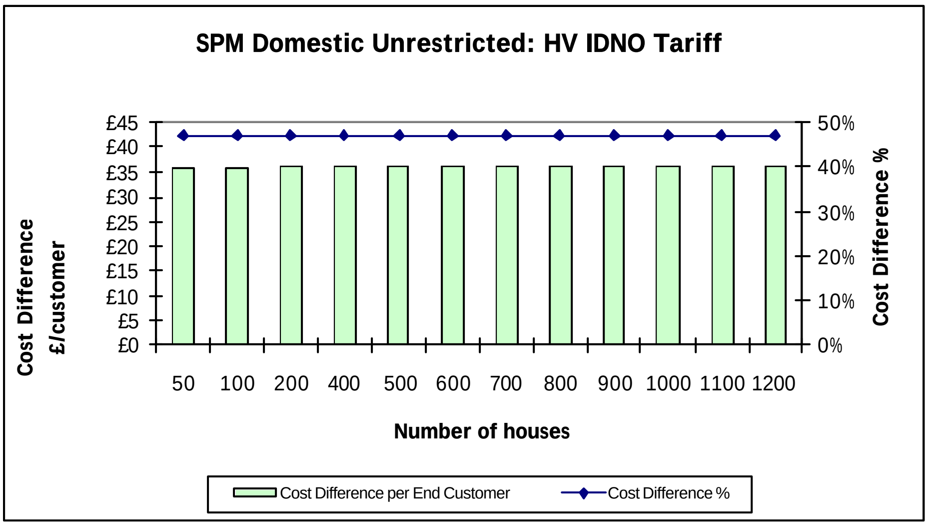

SPD Domestic Heating: LV IDNO
Band 4 Tariff
£40
£30
£20
£10
£0
-£10
50%
40%
30%
20%
10%
0%
-10%
1
5
10
50
80
100
200
300
400
500
600
700
Cost Difference £/customer
Cost Difference %
Number of houses
Cost Difference per End Customer
Cost Difference %

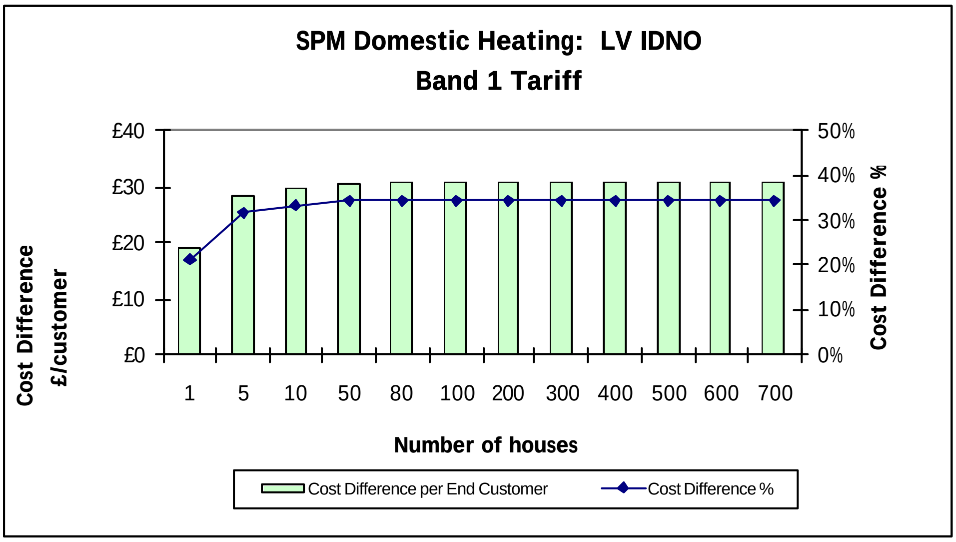

SPD Domestic Heating: HV IDNO Tariff
£45
£40
£35
£30
£25
£20
£15
£10
£5
£0
50%
40%
30%
20%
10%
0%
50
100
200
400
500
600
700
800
900
1000
1100
1200
Cost Difference £/customer
Cost Difference %
Number of houses
Cost Difference per End Customer
Cost Difference %

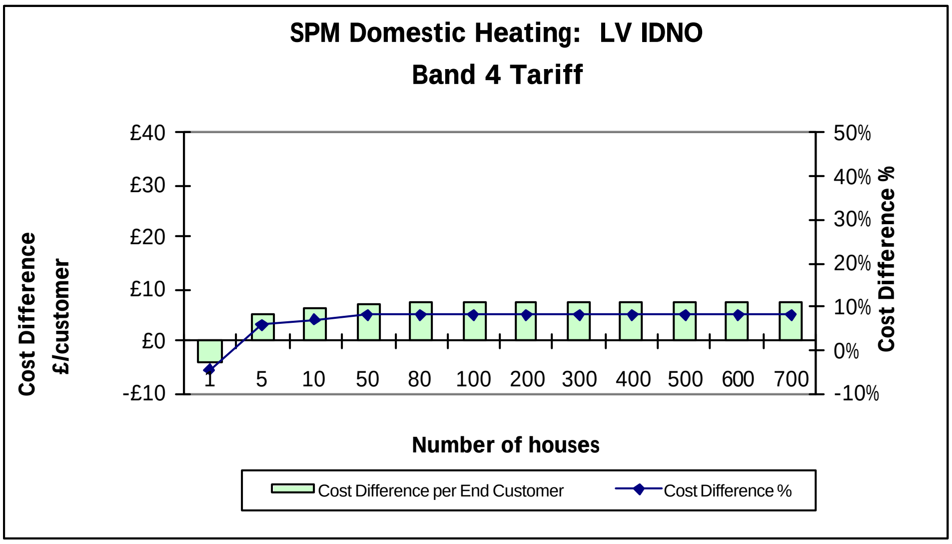
Appendix 9b. IDNO margins in the SPM area

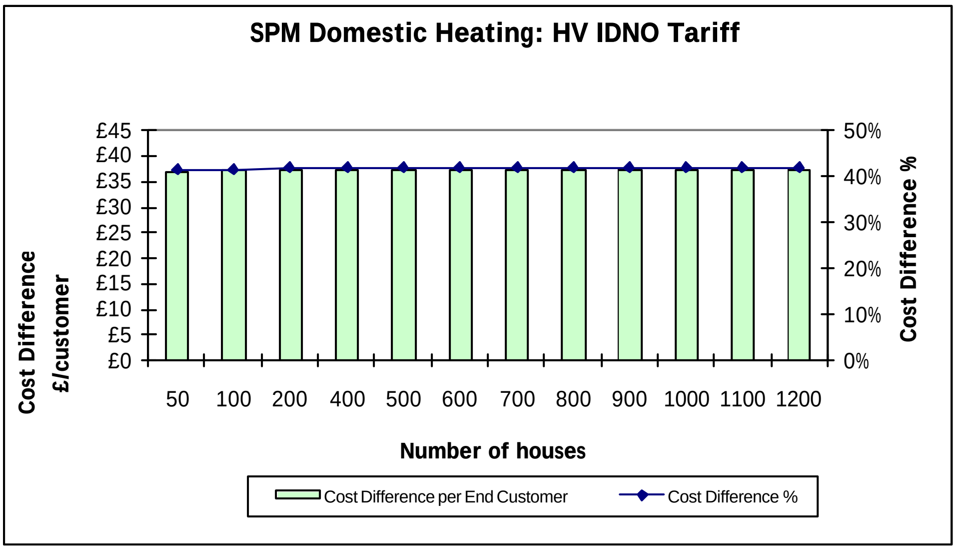







SPM Domestic Heating: LV IDNO
Band 1 Tariff
Cost Difference £/customer
£40
£30
£20
£10
£0
50%
40%
30%
20%
10%
0%
Cost Difference %
1
5
10
50
80
100
200
300
400
500
600
700
Number of houses
Cost Difference per End Customer
Cost Difference %


SPM Domestic Heating: LV IDNO
Band 4 Tariff
Cost Difference £/customer
£40
£30
£20
£10
£0
-£10
50%
40%
30%
20%
10%
0%
-10%
Cost Difference %
1
5
10
50
80
100
200
300
400
500
600
700
Number of houses
Cost Difference per End Customer
Cost Difference %


SPM Domestic Heating: HV IDNO Tariff
Cost Difference £/customer
£45
£40
£35
£30
£25
£20
£15
£10
£5
£0
50%
40%
30%
20%
10%
0%
Cost Difference %
50
100
200
400
500
600
700
800
900
1000
1100
1200
Number of houses
Cost Difference per End Customer
Cost Difference %

Appendix 10. Glossary of terms

AC	Alternating Current
Authority	The Gas and Electricity Markets Authority as established by the Utilities Act.
Base Network	This is used for determining costs and is as detailed in the Long Term Development Statement (published in accordance with Licence condition 25). The Base Network used is the existing and committed network that is expected to exist in the December of the year for which costs are calculated. The Base Network is a full model of the network from GSP to primary substation LV busbar.
BSP	Bulk Supply Point. Generally refers to 132/33kV, 132/11 or 66/22kV in England and Wales. The term BSP is not applicable in Scotland.
COG	Commercial Operations Group. Throughout 2006, the electricity distributors worked collectively to progress their thoughts on the longer-term charging framework. This group has now been replaced by the DCMF.
Contingency analysis	AC loadflow studies to model the effect of various outages on the Base Network.
DCMF	Distribution Charging Methodology Forum. A group which meets every six to twelve weeks to consider and progress policy relating to DNOs' charging methodologies. It has replaced the COG and the ISG.
DEC	Demand Estimation Coefficient. Profiling tool used to forecast a customer group's maximum demand in the different time periods from their forecast annual unit consumption.
DG	Distributed Generation. Generation connected to the Distribution networks (132 kV or lower in England and Wales and 33 kV or lower in Scotland).
DNO	Distribution Network Operator. A licensed distributor which operated electricity distribution networks in distribution service areas.
DUoS	Distribution Use of System Charges.
EHV	Extra High Voltage. It refers to sections of the network at voltages at or higher than 22kV.

Embedded Generation	An alternative name for Distributed Generation (DG).
ER P2/6	Engineering Recommendation P2/6, Security of Supply (July 2006). Sometimes referred to in the text as “P2/6”.
FCP	Forward Cost Pricing. The FCP approach constitutes the core of the G3 methodology.
FE	Frontier Economics.
G3	Group of three DNOs working together to develop a methodology for Use of System charges. The companies are ScottishPower EnergyNetworks, SSE Power Distribution and Central Networks.
GB	Great Britain.
GDUoS	Generation Distribution Use of System Charges. Charges paid by generation customers connected to a distribution network.
GSP	Grid Supply Point. Generally refers to 400/132kV or 275/66kV in England and Wales and 132/33kV in Scotland.
HH	Half Hourly. It refers to customers with Half Hourly metering arrangements.
HV	High Voltage. It refers to sections of the network with voltages exceeding 1000 Volts but lower than 22kV.
IDNO	Independent Distribution Network Operator. A licensed distributor which does not have a distribution services area and competes to own and operate electricity distribution networks anywhere within the UK.
IEEE	Institute of Electrical and Electronics Engineers.
ISG	Implementation Steering Group. The purpose of the structure of charges ISG was to facilitate discussion about the commercial, regulatory and technical aspects of Ofgem’s proposals for changes to the electricity distribution charges regime. This group has now been replaced by the DCMF.
LAF	Loss Adjustment Factors. These are factors, used in the settlement process, which account for losses in the network for each customer class.
LTDS	Long Term Development Statement. This statement is produced by the DNOs in compliance with their Licence Condition 25.
LV	Low Voltage. It refers to sections of the network with voltages not exceeding 1000 Volts.

MEAV	Modern Equivalent Asset Value.
Network Group	A practical group defined by physical, operational and technical boundaries and includes all voltage levels above HV (11kV). Network Groups are defined as the network normally supplied from a Grid Supply Point (GSP) or a Bulk Supply Point (BSP). In situations where GSP/BSPs are operated in parallel, the parallel GSP/BSP groups are considered as one Network Group. In Scotland there is only a single layer of Network Group from GSP to HV. In England and Wales two layers of Network Group are considered: GSP to BSP and BSP to HV to reflect network topology. At the charging stage, customers connected to the second layer of Network Group (BSP to HV) will also pick up a per kVA proportion of the first layer (GSP to BSP) costs.
NGET	National Grid Electricity Transmission. It is the System Operator for Great Britain and the transmission owner for England and Wales.
NHH	Non Half Hourly. It refers to customers without Half Hourly metering arrangements.
NPV	Net Present Value.
O&M	Operation and Maintenance.
OFGEM	Ofgem is the Office of Gas and Electricity Markets, regulating gas and electricity industries in Great Britain. Ofgem operate under the governance of the Authority, which sets all major decisions and policy priorities.
PC	Profile Class. Code use in Settlements to are used to group customers with similar characteristics.
Primary Substation	A 33/11, 33/6.6, 22/11 or 22/6.6 kV substation.
Principal Substation	This is the substation which connects the network group to a higher voltage level. This is typically a GSP or a BSP. In Network Groups where there is more than one substation connecting the group to a higher voltage level, the substation with the largest powerflow (in either direction) under normal Base Network conditions is considered to be the Principal Substation.
RRP	Regulatory Reporting Pack. An information pack sent by the DNO to the Authority annually, in compliance with licence condition 52: “Price Control Review Information”.
Security of Supply	Defined in Engineering Recommendation P2/6. The capability of a system to maintain supply to a defined level of demand under defined outage conditions.

SLC	Standard Licence Condition. These are conditions that licensees must comply with as part of their licences.
SPD	Scottish Power Distribution Ltd. The licensed DNO in south and central Scotland.
SPEN	ScottishPower EnergyNetworks. A division of the Scottish Power group, which is the public-facing identity of SPD, SPM and SPT.
SPM	Scottish Power Manweb plc. The licensed DNO in Merseyside, Cheshire and North Wales.
SPT	Scottish Power Transmission. The licensed transmission owner in south and central Scotland and the owner of the Scottish land-based part of the interconnector linking Scotland and Northern Ireland.
Yardsticks	Group of customers that exhibit broadly similar characteristics banded together for charging purposes. Each yardstick customer group relates to either demand or generation and is associated with a specific voltage of connection