Modification Proposal
UoS Mod 21

Introduction of a power flow/LRIC based methodology and implementation in EDF Energy Networks' South East Region

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For approval by the Gas & Electricity Markets Authority

CONTENTS

1. SUMMARY

1.1. EDF Energy Networks are proposing implementation of the Power Flow/Long Run Incremental Cost (LRIC) based Use of System Charging Methodology that EDF Energy Networks' has been developing. This methodology establishes a hybrid of the LRIC approach for EHV networks with the current Distribution Reinforcement Model[1] (DRM) based approach.

1.2. This is the first stage implementation of the new methodology into one of the three regional distribution networks operated by EDF Energy Networks, namely the South East. It details the forward looking economic Use of System charging methodology that has been developed for use in the three distribution regions run by EDF Energy Networks. The approach is designed to replace the current methodology which is a combination of the Distribution Reinforcement Model (DRM) applied to High Voltage (HV) and Low Voltage (LV) tariffs and an asset based site specific model applied to calculate charges to sites connected at Extra High Voltage (EHV).

1.3. The methodology developed will attribute allowed revenue to users based on the cost reflection of marginal/avoidable reinforcement costs. These will be calculated using a Long Run Incremental Cost (LRIC) approach which will utilise network power flow studies for the EHV assets used by all users.

1.4. The new approach seeks to reflect the impact on future reinforcement costs of an increment/decrement in load/generation at each node on the EHV distribution network. The use of the LRIC approach (and associated power flow modelling) will be applied to calculate the charges for the EHV network only with the current approach being retained for calculating the HV and LV component of network charges. The restriction of the LRIC approach to the EHV network is being done due to the added data and computational complexity of using the technique on HV and LV networks.

1.5. Key inputs and processes of the methodology are:

- an EHV network model on which power flow and security factor studies are performed on all EHV assets down to and including the HV busbars at primary substations
- the costs used for reinforcing key assets
- the costs of NGC exit charges
- the demand/generation growth rates that the network is experiencing
- the consumption patterns and impact on the network made by different tariff groups
- the apportioning of network reinforcement cost to the different parts of the model
- the method of scaling the modelled (yardstick) revenue to allowed revenue

1.6. The methodology, especially as applied to EHV connected customers, is designed to measure the impact of demand and generation on an equitable basis. Notably, if user activity causes reinforcement cost to be deferred then charges will reduce, if activity causes reinforcement cost to be brought forward then charges will increase.

1.7. The methodology has been developed for implementation in the SPN network area for charges to be implemented on 1st April 2009, subject to non veto by the Authority. The models will then be developed and populated with data for the LPN and EPN network areas, with implementation following similar non veto by the Authority.

[1] Colloquially known as the Boley and Fowler model or the 500MW model. This approach was outlined by TA Boley and GJ Fowler in a 1977 paper titled "The basis for cost-reflective retail tariffs in England and Wales" presented at the IEE Third International Conference on Metering, Apparatus and Tariffs for Electricity Supply.

2. INTRODUCTION AND BACKGROUND

2.1. This modification proposal is submitted by EDF Energy Networks Ltd ("EDF Energy Networks"). EDF Energy Networks is responsible for the three licensed electricity distribution businesses serving the whole of London, the South East and the East of England. Our Electricity Distribution Licences ("Licences") are issued under the Electricity Act 1989 as amended by the Utilities Act (2000), the Sustainable Energy Act (2003) and the Energy Act 2004 ("the Act").

2.2. EDF Energy Networks has a licence obligation (Standard Licence Condition 4 (SLC4)) to have in place a use of system charging methodology statement. This statement outlines the method by which distribution use of system charges are calculated. Further, EDF Energy Networks has a requirement to keep the methodology under review and bring forward proposals to modify the methodology that it considers better achieves the relevant objectives.

2.3. The relevant objectives for the use of system charging methodology, as contained in paragraph 3 of SLC4 of the distribution licence, are:

- that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Electricity Act 1989 and by this licence;
- that compliance with the use of system charging methodology facilitates competition in 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, so far as is consistent with sub-paragraphs above, the use of system charging methodology, as far as reasonably practicable, properly takes account of developments in the licensee's distribution business.

2.4. Before making any modifications to its charging methodology EDF Energy Networks must give Ofgem a report detailing the proposed modification and how the modification would better achieve the relevant objectives. Each licensee then implements the modification unless (within 28 days of receiving the report) Ofgem vetoes the modification or notifies the licensee that it intends to consult on the proposal.

2.5. EDF Energy Networks has developed its charging methodology in order to bring about improvements to the economic signals that are delivered through its use of system charges to all users of the network. Our objectives in carrying out this work are two fold:

- To implement cost reflectivity based on the expected impact of customer actions on future network reinforcement costs. Material to this is the change in expected future reinforcement costs which have been calculated using power-flow modelling.
- To calculate the charges applied to both demand and generation users of the network on an equitable basis.

2.6. In particular, this development will involve a move away from the 'site specific assets used' approach currently implemented for Extra High Voltage (EHV) connected customers and a change in the way that EHV costs are used in deriving tariffs for HV and LV connected customers.

2.7. This methodology has been developed in response to the Ofgem initiated Structure of Charges review and builds on the principles outlined in the work of the Ofgem sponsored Network charging study undertaken by the University of Bath[2].

[2] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/12617-1206a.pdf

3. Existing Charging Methodology

3.1. The current EDF Energy Networks methodology for deriving Use of System charges for general non-EHV demand tariffs is a derivative of the DRM. Only reinforcement costs are used in calculating the network asset component of costs, replacement costs are not used. It functions by apportioning the costs to customer groups differentiated by voltage of connection and meter type. The cost of reinforcement on a £/kVA basis at each voltage level is apportioned to tariff groups dependant on their level of demand and the number of units. The yardstick charge calculated is then scaled to meet the target revenue.

3.2. For EHV users the current methodology determines site specific charges that are set to recover the users proportion of costs associated with the provision and the operation and maintenance of, all network and connection assets plus the cost of billing and administration, in so far as this has not been recovered as part of the initial connection charge.

3.3. A fuller description of the current methodology is given in the Statement of the Use of System Charging Methodology for EDF Energy Networks' Electricity Distribution Systems which can be downloaded from http://www.edfenergy.com/hold/regulatory/connection.html .

3.4. Perceived shortcomings of existing DRM based methodology

3.5. The existing DRM assumes power flows from Grid Supply Point (GSP) to customer and does not deal with reverse power flows. Because of this it does not recognise any cost/benefit that distributed generation (DG) might bring to future network development costs.

3.6. It does not provide locational signals in the Use of System charge. (This approach assumes that a locational signal is provided in the connection charge).

3.7. This current approach is not compatible with shallowish generator connection charges. A separate method is used to derive generator use of system charges now that there has been a move away from deep connection charges for generators.

4. Consultation Process

4.1. EDF Energy Networks' have conducted two public consultations on its methodology development, one in June 2007 and one in January 2008.

June 2007 Consultation

4.2. The June 2007 consultation sought comments on the principles behind the new Use of System Charging Methodology which was currently under development. Given the potential impact of the change to all network users EDF Energy Networks believed it was appropriate to consult with interested/affected parties prior to finalising the principles of the new methodology.

4.3. Following the June consultation we issued a response document detailing the nature of the comments received. There were nine responses and the following summarises the nature of the responses.

4.4. Our proposal to adopt the LRIC model for the EHV network appears to be generally supported. No respondents argued in favour of retaining the existing asset based site specific approach for EHV customers and none offered alternatives to the LRIC method for the EHV networks. There were a number of specific comments on the LRIC methodology which were addressed in the response.

4.5. The approach to be used for the HV and LV networks had more generally varying responses with some respondents favouring a continuation of the status quo DRM approach and others who argue that a methodology is needed that caters for the expansion, encouraged by Government, of micro-generation in the HV and LV networks. However, only the Renewable Energy Association (REA) proposed an approach that they believe might deliver some benefits at the HV and LV networks that it is hoped the LRIC will deliver at the EHV network. The REA-favoured approach is consistent with the future approach that we outlined in the consultation and based on applying the LRIC model to reference HV and LV networks.

4.6. Several respondents urged that we adopt an approach at the HV and LV level that does not involve major disruptions to prices. However, there were no major objections to the approach that we proposed to be implemented in the immediate future using the average nodal cost outputs from the EHV network as marginal cost inputs to the DRM approach for the HV and LV tariffs.

4.7. Zonal growth rates, rather than nodal growth rates or a single universal growth rate, were generally endorsed by respondents.

4.8. There was general agreement on the proposed basis for splitting allowed revenues between the EHV and HV/LV networks. The REA objected to the splitting of allowed revenue between generation and demand. We understand this objection but recognise that it is derived from the current structure of the price control and will continue at least for the term of the current price control period which runs until March 2010.

4.9. There were several comments on our proposal to use a fixed adder to scale the marginal cost charges to allowed revenues. Western Power Distribution (WPD) endorsed this approach. Others, while not rejecting it, noted some concerns. The REA unequivocally rejected this approach and proposed instead a scaling approach that targets the adjustments at those parties likely to be least responsive to price – i.e., demand customers. This has some economic justification and we propose to consider it further at a later stage.

4.10. There was general support in favour of the adoption of negative charges where appropriate.

4.11. We believe that the responses support the approach described in our consultation and, while taking into account the comments expressed, we will continue with the development of the charging methodology as it was outlined.

January 2008 Consultation

4.12. The January 2008 consultation restated the principles behind the new and included more detail on the process and calculations. It also included indicative prices which could be used to compare the effect of the new methodology against the existing methodology for different customer charges in the EDF Energy Networks SPN area. These indicative charges compared the revenue recovery for the October 2007 charges modelled on a ‘like for like’ basis.

4.13. Following the January consultation we issued a conclusion document detailing the nature of the comments received. We received seven responses and the following summarises the nature of the responses.

4.14. This second consultation included illustrative charges. Most respondents focused on the impact that they foresee these charges as having on their businesses. Previously the principles of the methodology were generally supported and consequently the responses do not repeat points previously made. Responses this time are mainly directed towards specific issues which are of direct concern to the respondent.

4.15. The responses to the general proposal involved comments aimed at charging methodology development in general and comments aimed specifically towards EDF Energy Networks’ charging development including the provision of illustrative charges.

Charging Methodology development in general

4.16. The comments aimed at the charging methodology development in general covered the following four main areas:

1) Multiple DNO development

- That these involve wide ranging approaches, different terminologies and assumptions
- That the methodologies have been presented at different times and with varying degrees of consultation
- That they lack full and consistent transparency, making it impossible for suppliers to fully understand, compare and respond to them; and
- That the quality of consultation undertaken by DNOs is inconsistent and questionable

2) Split of allowed revenue
  - Current split of allowed revenue hampers cost reflective charging
  - Modifications should be framed within the current price control

3) Minimised change vs. coordinated change
  - Changes to an existing methodology should be minimised where possible
  - Sudden disturbance to charges to be avoided
  - A common approach is essential

4) Simplistic solution unless clear benefits
  - Simplest, most transparent, stable and predictable methodology unless there are clear and substantiated benefits

4.17. We indicated that while EDF Energy Networks are generally supportive of a more coordinated approach to charging development we felt that the work required to design and develop a common methodology would add significant delay to the implementation timescales. We believe that the current proposal offers the best mix of implementing an improvement to cost reflectivity while meeting the needs of the other relevant objectives and the timescale requirements.

Charging Methodology development specific to EDF Energy Networks

4.18. The comments aimed at the development of the charging methodology specific to EDF Energy Networks are directed to the following five main areas:

1) Concern over price movement
  - Helpful to have the average change for PC 1-4 but not provided for 5-8 and HH
  - Some unit charges peaking at 600% change
  - Most concern with LV HH due to 2 year fixed price deals
  - Increases in fixed charge are not conducive to energy saving

2) Cost elements not considered
  - Fault level costs should be considered
  - Generation tends to be lumpier and more thinly spread (than demand) and as such believe the proposed methodology is not cost reflective

3) Not sufficiently robust
  - Not clear whether change will cause volatility
  - Believe that there are fundamental flaws
  - Indicted that [LRIC] would not work at 0% growth

4) Effect on IDNOs
  - There are no IDNO [specific] charges proposed
  - Fear proposals will exacerbate margin squeeze

5) Support of principles
  - In favour of introducing methodology to HV/LV networks as soon as possible
  - Broadly supportive to EDF Energy Networks' strategic approach to changing its methodology

4.19. To support the consultation we provided the annual charge information for average PC 1-4 tariffs. We accepted that it would have been helpful to have provided this information for a larger sample of customers. We noted that some unit rates will have a large change as the rate is currently very low so even a small monitory increase will have a large percentage effect. The effect on any unit rate also needs to be taken in context with any change in total annual charges.

4.20. We believe that the cost elements which are materially more significant to the effective signalling of long term costs are included. The ability for other cost elements to be included can be considered for future methodology enhancements.

4.21. It is important to take into account that the methodology has been developed to make improvements in the reflection of long run marginal costs. The licence requirements for a methodology change are that the new methodology 'better meets' the relevant objectives. The very nature of charging methodologies and implementation timescales restricts the ability to provide a 'perfect' solution at the first attempt. Imperfections/blemishes will need to be accepted, and approved methodologies will still have a requirement to be reviewed on an annual basis with the expectation that refinements are made to improve the modelling. We believe that the model is sufficiently robust to cope with the initial implementation and refinements to handle some of the known issues can follow in future years.

4.22. We believe that our charges are fair to all users that have the same connection characteristics and do not believe that we should treat IDNOs any differently than other users who are connected at the same voltage level. We have conducted our own assessment on the accusations of margin squeeze based upon actual IDNO developments connected to our networks. These examples, shown in Appendix B of the Consultation Conclusion document, demonstrate significant margins between the charge at the point of connection and the revenue recovered by the IDNO from their customers. We do not believe that the margin examples provided by the IDNO respondent are representative of an actual development. We are willing to work with IDNOs to identify industry 'example books' to help demonstrate any issues with our charges.

4.23. We believe that the responses highlight issues and impacts that are of concern to individual companies and, while we will take these issues into account as we develop the methodology in the future, our priority is to obtain approval at this stage so that the improvements can be implemented as soon as possible.

Ofgem involvement

4.24. Since issuing the January consultation we have had three extended meetings with Ofgem. During the course of these meetings we have discussed the methodology and the application of the methodology through the modelling in detail. Our model has been shared with Ofgem and this proved to be a useful process to improve Ofgem's understanding and any help resolve any remaining issues with the methodology.

4.25. As part of this submission we will seek to satisfy Ofgem over the robustness and appropriateness of our charging methodology approach.

Consultation Process Conclusion

4.26. After consideration of all the responses, and in the context of our licence objectives and wider industry developments, EDF Energy Networks believe that the proposed methodology 'better meets' the relevant objectives.

4.27. We have conducted further enhancements during the later stages of development of the methodology since the consultations and meetings with Ofgem. These enhancements have been done to address some of the concerns raised.

4.28. Overall we believe that the approach that we have developed has support within the industry. We also acknowledge that there are users who have concerns over the introduction of the parts of this methodology that they are unfamiliar with. However, the new methodology will continue to be developed, addressing these concerns, as and when we find appropriate improvements to implement.

5. Overview of the Proposed Arrangements

5.1. The methodology applies an LRIC approach, using power flow modelling, to provide the basis for calculating the economic cost of the EHV network (including EHV/HV transformation). The current approach of estimated marginal reinforcement costs will be retained for the cost of the HV and LV part of the network.

5.2. The LRIC approach allows generation and demand charges to be determined using a common methodology for the EHV network. Our LRIC approach utilises AC power flow modelling which we believe provides an improved reflection of the costs of the network taking into account real and reactive power flows.

5.3. AC power flow modelling is practical for the EHV network only and extending AC power flow modelling to the HV & LV networks is likely to result in an exponential increase in the complexity and cost of building and maintaining the model. Future enhancements would likely be built to incorporate HV/LV modelling based on a representative network.

5.4. The methodology will, in principle, allow for demand or generation charges to be negative (i.e. a demand/generation user might be paid if their use of the network defers overall reinforcement expenditure).

5.5. The charges for users connected to the EHV network will be calculated using network costs modelled using the LRIC approach and charges for users connected to the HV & LV networks calculated using network costs from a combination of the LRIC approach and our existing DRM based approach. The nodal cost outputs from the EHV approach will be averaged and used as marginal cost inputs to the DRM approach when calculating the HV & LV tariffs. It is not envisaged that locational charges will be derived for the HV & LV network at present.

5.6. The simplified schematic of the approach is provided in Figure 1 below.

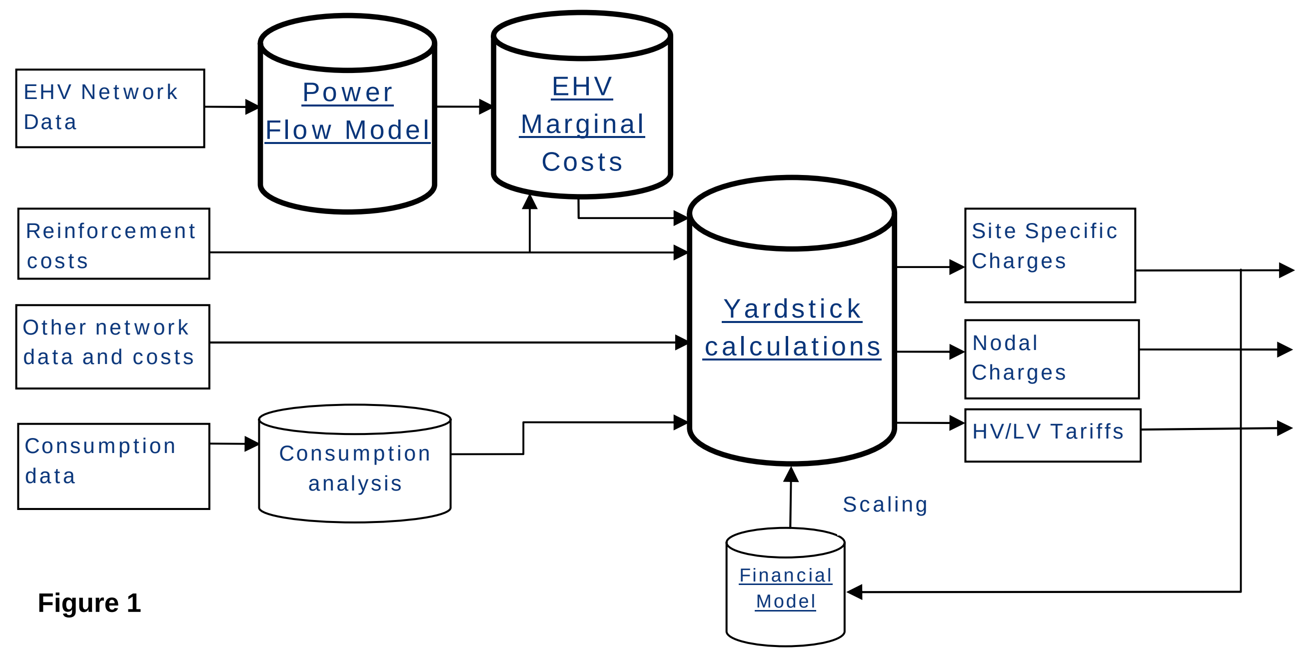


Figure 1

6. PROPOSED POWER FLOW/EHV MARGINAL COST ARRANGEMENTS

Power flow modelling

6.1. The power flow modelling is conducted using PSS™E software a Siemens proprietary product, although any suitable power flow modelling software could have been utilised. We have automated use of this software using two custom built modules.

- The security module which conducts the security factor analysis and base case power flows.
- The sensitivity module which provides the sensitivity coefficients.

6.2. The power flow model is populated with network data which mirrors the data published in the Long Term Development Statement (LTDS) produced in accordance with distribution licence condition 25. It needs to be noted that the LTDS and power flow model are snapshots of the network produced at different points in time and may therefore differ slightly.

Time band based network data

6.3. Underpinning our modelling process is the use of five network time bands, these time bands are common throughout our pricing modelling and are also used in our tariff modelling and to define the Half Hourly tariff charges. The five time bands that are used are:

1. Between midnight and 07:00 hours all year – Night
2. Between 16:00 and 20:00, Monday to Friday, November to February – Winter Peak
3. Between 07:00 and 16:00, Monday to Friday, November to February and between 07:00 and 20:00, Monday to Friday in March – Winter shoulder
4. Between 07:00 and 20:00 Monday to Friday, June to August – Summer Peak
5. All other times

6.4. The power flow model is populated with nodal demands for each time band with data extracted from EDF Energy Networks' SCADA[3] information database. The data is extracted for three maximum periods and three minimum periods for each of our 5 time bands. The dates and times that the data is extracted is determined from the three highest demands and the three lowest demands, separated by 10 complete days, for each of our 5 time bands using the annual GSP group take as the reference data. For each node the load data is extracted and then averaged to generate the value used at each node in the power flow model. The result of these extracts is to populate each node and each time band, where energy either enters or exits the EHV network, with a maximum (peak) power flow value used for the calculation of demand charges and a minimum power flow value used for the calculation of generation charges.

6.5. Within this document each of the processes are described for one time band. In operation each process will be repeated for each time band using appropriate network configurations and loading data.

6.6. The current date analysis is based on the GSP group take between 1st April 2006 and 31st March 2007. The date and the time at the end of the half hour time period for the highest system demands are:

Table 1

	Highest	2nd	3rd
Night	26/03/2007 07:00	25/01/2007 07:00	09/02/2007 07:00
Winter Peak	24/01/2007 18:30	20/12/2006 19:00	07/02/2007 18:30
Winter Shoulder	20/03/2007 19:00	05/03/2007 19:00	21/12/2006 16:00
Summer Peak	13/06/2006 16:30	25/07/2006 16:30	31/08/2006 19:30
Other	25/01/2007 20:30	07/02/2007 20:30	20/12/2006 20:30

6.7. The date and the time at the end of the half hour time period for the lowest system demands are:

[3] SCADA is the acronym for Supervisory Control And Data Acquisition. The SCADA system gathers data from the monitored asset and transfers the data to a central data store.

Table 2

	Lowest	2nd	3rd
Night	09/07/2006 04:30	25/06/2006 05:00	28/05/2006 04:30
Winter Peak	25/12/2006 20:00	21/02/2007 16:30	01/11/2006 16:30
Winter Shoulder	01/01/2007 08:00	01/11/2006 07:30	13/11/2006 07:30
Summer Peak	28/08/2006 07:30	14/07/2006 19:30	09/06/2006 20:00
Other	02/10/2006 00:00	26/06/2006 00:00	10/07/2006 00:00

6.8. This approach assumes that the network is operating in an intact mode at the extracted times. There are, therefore, no manual adjustments to the nodal demands where the loadings are significantly higher at a node due to the node supporting an outage or the nodes minimum demand is zero due to an outage.

6.9. The use of the average maximum and minimum values at each node provides for five time band based network modelling scenarios based on maximum power flows for demand charging use and five time band based network modelling scenarios based on minimum power flows for generation charging use.

6.10. Each of the model scenarios is then processed using the custom built modules to obtain base case power flows, security factors and sensitivity coefficients.

Security Module

6.11. The output from the security module provides both the base case power flow and the security factors for each asset on the network. All power flow output data is presented in the form of a comma separated file, which is then loaded into the charging model.

6.12. The process flow outline of the security module is as indicated in the diagram below, Figure 2.

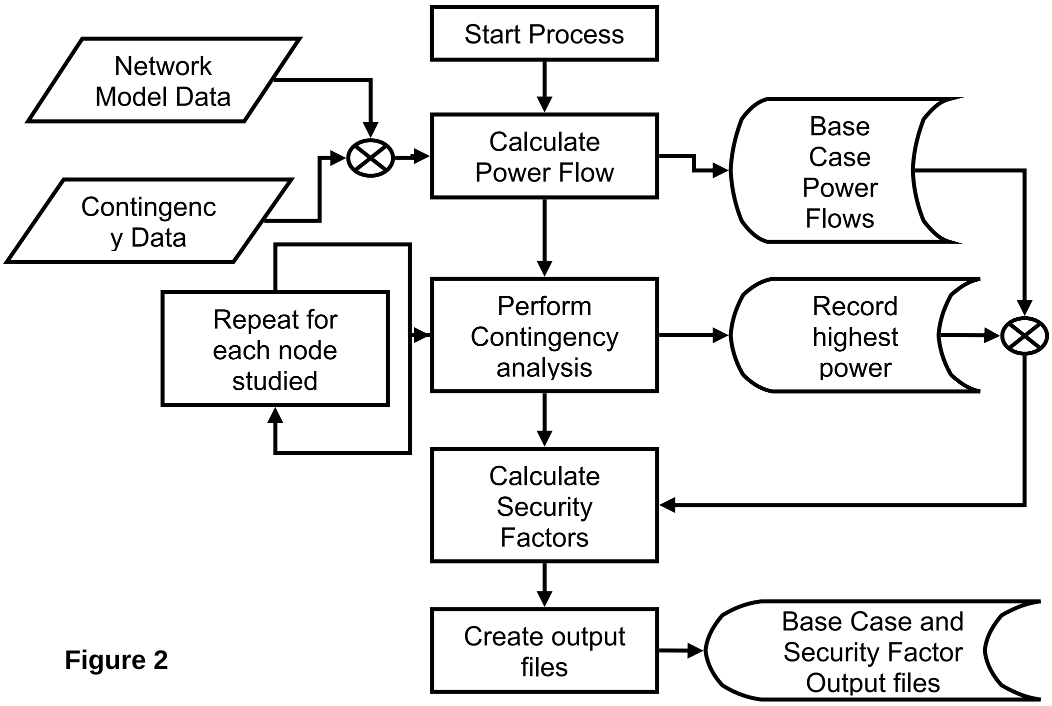


Figure 2

6.13. The base power flow is calculated then the power flows are calculated for each contingency case. During the contingency process the highest power flow on each remaining branch is stored. At the end of the contingency process the final highest power flow in each branch is divided by the base case power in each branch to provide the security factor. It is this security factor which is then used to de-rate the branch's actual capacity to an approximate Engineering Recommendation P2/6[4] compliant capacity.

6.14. The contingency data file holds outage instructions for each branch and is processed sequentially during the contingency analysis. For each branch the statement will instruct the tripping of that branch and then the other actions which would be performed during that branch outage. These additional actions may include closing circuits or bus bars and transferring load to other nodes. These other actions are typical of how the network is managed on an operational basis.

6.15. A sample of the base case output file is provided below. This sample excludes the additional header information which contains supplementary details including the version of software, network model and time band.

Table 3

From Bus Name		FV	To Bus Name		TV	Circuit ID	P(MW)	Q(MVAr)
83391	BUHL31	33	83393	BUHL51	11	1	13.059	5.508
83391	BUHL31	33	91820	GODG31	33	1	13.115	5.555
83392	BUHL32	33	83393	BUHL51	11	1	13.054	5.506
83392	BUHL32	33	91820	GODG31	33	1	13.110	5.553

6.16. A sample of the security factor file is provided below. The additional header information has been excluded from the sample.

Table 4

From Bus Name		FV	To Bus Name		TV	Circuit ID	Security Factor
83391	BUHL31	33	83393	BUHL51	11	1	2
83391	BUHL31	33	91820	GODG31	33	1	2
83392	BUHL32	33	83393	BUHL51	11	1	2
83392	BUHL32	33	91820	GODG31	33	1	2

6.17. The methodology for calculating the security factor has already been provided in Appendix 1 under section 5.1. A limitation of this approach is that anomalous values will be calculated on lightly loaded assets or 'dead swinger' assets. An example of a lightly loaded asset would be a circuit which provides an inter-link and under system normal conditions will only carry an energisation power flow. A 'dead swinger' is an asset which under system normal conditions is de-energised and, therefore, has zero power flow and 'swings' into operation for defined contingencies. These situations either cause very high security factors, or divide by zero errors, which are not representative of the ER P2/6 running arrangements which the network is designed to meet. It is proposed that to solve these anomalies that the erroneous values are overwritten with logically calculated values for the specific branches. For example 'dead swinger' branches will be allocated a security factor of 1.

6.18. Additional anomalies can be caused when under contingency conditions the power flows in an asset reduce. This happens due to network configuration and/or power flow modelling accuracies. This has the effect of recording a security factor of slightly less than 1. In these circumstances it is proposed to collar security factors below 1 at 1 when they are used in the charging model.

Sensitivity Module

6.19. The output from the sensitivity module provides a set of coefficients that enable the calculation of the effect to a power flow in a branch caused by an increment or decrement

[4] Engineering Recommendation P2/6 (ER P2/6) is the current distribution network planning standard. The Distribution Network Operators (DNOs) have a licence obligation to plan and develop their systems in accordance with ER P2/6.

applied to a node. The resultant coefficient is used to calculate the new power flow by multiplying it with the increment or decrement and adding it to the original branch power flow.

6.20. The output file contains data for every branch within each node under study. Therefore, each branch has a separate pair of coefficients for each node on the network. There are approximately 900 nodes and 1,300 branches generating a file with approximately 1.2 million rows of data. For each branch there is one coefficient for nodal MW changes and one for nodal MVAr changes.

6.21. The process flow of the sensitivity module is as indicated in the diagram below, Figure 3.

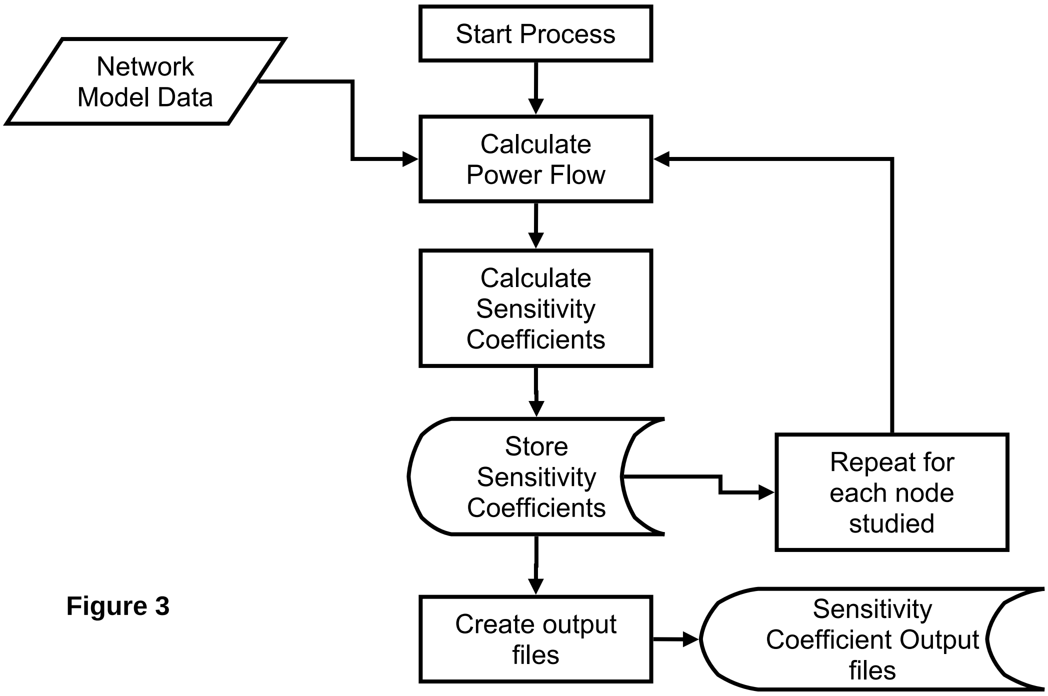


Figure 3

6.22. For a particular operating point of interest and the full intact network topology model the power flow will be calculated.

6.23. The approach uses the standard output from the load flow, i.e. for each node i the following values: Pi, Qi, Vi and θi (active power node injection, reactive power node injection, node voltage magnitude, and node voltage angle). Then, for each branch ij (between node i and node j) of interest the set of sensitivity coefficients will be calculated using the set of equations here presented in matrix format, Figure 4.

Figure 4

$$
\left[\begin{array}{cccc|cccc}
\frac{\partial P_1}{\partial \theta_1} & \frac{\partial P_2}{\partial \theta_1} & \cdots & \frac{\partial P_N}{\partial \theta_1} & \frac{\partial Q_1}{\partial \theta_1} & \frac{\partial Q_2}{\partial \theta_1} & \cdots & \frac{\partial Q_N}{\partial \theta_1} \\
\frac{\partial P_1}{\partial \theta_2} & \frac{\partial P_2}{\partial \theta_2} & \cdots & \frac{\partial P_N}{\partial \theta_2} & \frac{\partial Q_1}{\partial \theta_2} & \frac{\partial Q_2}{\partial \theta_2} & \cdots & \frac{\partial Q_N}{\partial \theta_2} \\
\vdots & & & & \vdots & & & \\
\frac{\partial P_1}{\partial \theta_N} & \frac{\partial P_2}{\partial \theta_N} & \cdots & \frac{\partial P_N}{\partial \theta_N} & \frac{\partial Q_1}{\partial \theta_N} & \frac{\partial Q_2}{\partial \theta_N} & \cdots & \frac{\partial Q_N}{\partial \theta_N} \\
\hline
\frac{\partial P_1}{\partial V_1} & \frac{\partial P_2}{\partial V_1} & \cdots & \frac{\partial P_N}{\partial V_1} & \frac{\partial Q_1}{\partial V_1} & \frac{\partial Q_2}{\partial V_1} & \cdots & \frac{\partial Q_N}{\partial V_1} \\
\frac{\partial P_1}{\partial V_2} & \frac{\partial P_2}{\partial V_2} & \cdots & \frac{\partial P_N}{\partial V_2} & \frac{\partial Q_1}{\partial V_2} & \frac{\partial Q_2}{\partial V_2} & \cdots & \frac{\partial Q_N}{\partial V_2} \\
\vdots & & & & \vdots & & & \\
\frac{\partial P_1}{\partial V_N} & \frac{\partial P_2}{\partial V_N} & \cdots & \frac{\partial P_N}{\partial V_N} & \frac{\partial Q_1}{\partial V_N} & \frac{\partial Q_2}{\partial V_N} & \cdots & \frac{\partial Q_N}{\partial V_N}
\end{array}\right]
\times
\left[\begin{array}{c}
\frac{\partial P_{ij}}{\partial P_1} \\ \frac{\partial P_{ij}}{\partial P_2} \\ \vdots \\ \frac{\partial P_{ij}}{\partial P_N} \\ \hline \frac{\partial P_{ij}}{\partial Q_1} \\ \frac{\partial P_{ij}}{\partial Q_2} \\ \vdots \\ \frac{\partial P_{ij}}{\partial Q_N}
\end{array}\right]
=
\left[\begin{array}{c}
\frac{\partial P_{ij}}{\partial \theta_1} \\ \frac{\partial P_{ij}}{\partial \theta_2} \\ \vdots \\ \frac{\partial P_{ij}}{\partial \theta_N} \\ \hline \frac{\partial P_{ij}}{\partial V_1} \\ \frac{\partial P_{ij}}{\partial V_2} \\ \vdots \\ \frac{\partial P_{ij}}{\partial V_N}
\end{array}\right]
$$

or, in a more concise way:

A□x = b and

x = A^{-1}*□b*

where x represents the sensitivity coefficients we want to calculate

6.24. All elements of matrix A and vector b can be calculated from the load flow outputs and the electric parameters of the network model. The system of equations presented above is of a generic nature. In its practical application, it should be noted that:

- at the slack node any ∂P and any ∂Q will be compensated at the slack node thus causing for any *ij* branch to be $\partial P_{ij} = 0$ for these ∂P and ∂Q ; thus the corresponding rows and columns, as in matrix presentation would be omitted; and

- at PV nodes any ∂Q will be compensated at that PV node (as long as the node remains PV node, i.e. as long there is reactive power capacity to regulate the voltage) thus causing for any *ij* branch to be $\partial P_{ij} = 0$ for this ∂Q ; thus the corresponding row and column, as in matrix presentation would be omitted.

6.25. A sample of the sensitivity coefficient file is provided below. The additional header information has been excluded from the sample.

Table 5

Node		From Bus Name		FV	To Bus Name		TV	ID	Sensitivity Coefficient (Xp)	Sensitivity Coefficient (Xq)
83393	BUHL51	83391	BUHL31	33	83393	BUHL51	11	1	-0.5169	-0.1949
83393	BUHL51	83391	BUHL31	33	91820	GODG31	33	1	-0.5219	-0.1979
83393	BUHL51	83392	BUHL32	33	83393	BUHL51	11	1	-0.5166	-0.1948
83393	BUHL51	83392	BUHL32	33	91820	GODG31	33	1	-0.5217	-0.1978

6.26. Due to the nature of whole network power flow modelling, branches which are normally electrically isolated from the node under study within the distribution system but which are connected through the transmission system will have sensitivity coefficients which indicate a power flow change. This movement is unlikely to be realised in the real network. One of the causes is the use of a slack node[5] in the power flow study, whereas in reality power flow variations would be balanced across a range of nodes.

6.27. To reduce the amount of computed data and avoid the calculation of insignificant charges on branches which are to all practical purposes electrically isolated from the node under study we are intending to filter sensitivities. The proposal is to remove sensitivity coefficients smaller than 0.005. This equates to power flows changes of less than 5kW when using an increment equivalent to 1000kW. Filtering the results will provide a set of charges which are more concentrated to the reinforcement which would be likely to occur due to changes at any given node.

Network Asset Capacities

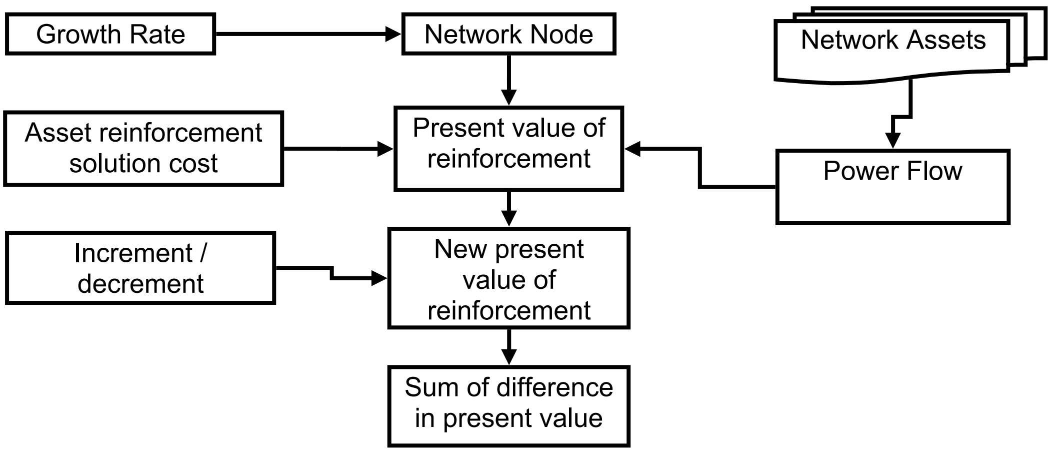
6.28. Network asset capacities are taken from the LTDS and used to provide the capacity of the assets. The LTDS contains data for Circuits in table 1 and Transformers in table 2. The data has two capacity ratings, summer and winter. The winter rating is used for the Night, Winter Peak, Winter Shoulder time bands, while the summer rating is used for the summer peak and other time band.

6.29. The ratings provided in the LTDS are maximum continuous ratings. The maximum continuous ratings when used in the cost calculation for transformers are increased to their cyclic ratings by increasing the maximum continuous capacity by 30%. The use of cyclic ratings is inline with the ER P2/6 planning standard. The same cyclic application cannot be done for the circuits due to the differences in the installations (particular when looking at their variances in age) which will make average assumptions unreliable. In practice both circuits and transformers would only have cyclic ratings applied after design studies indicate that criteria such as load duration and installation conditions make a cyclic rating feasible.

6.30. The network capacities are de-rated during the calculation process by dividing the rating by the security factor. This is de-rating is to allow for the capacity that is already taken in order to meet circuit outages under the ER P2/6 planning standard.

Marginal cost calculation

6.31. Costs are calculated for each node which have exit points to customer connections. These exit points can either be for EHV connected customers or at the boundary between the EHV network and the HV/LV network. The latter costs are used as input costs to the HV/LV tariffs.



[5] The slack node is a defined point in the network model which adjusts to balance the difference between demand and generation. In reality the balancing of demand and generation is a complex operation across many participants.

6.32. The charge calculated is based on a predicted future timescale of reinforcement requirement and how this future timescale will change following the application of a marginal increment or decrement to the node under study. The charge for an asset is based on the demand growth of the node under study and is the difference between the net present value of the future cost of reinforcement and the net present value of the future cost of reinforcement after allowing for the application of the marginal increment or decrement in power flow has been placed. The charges for each asset for a node under study are then summed to achieve a nodal charge.

6.33. The network configuration used for modelling is a snapshot of the current operational network and does not take into consideration reinforcement schemes that are under construction when the snapshot is taken. As such some modelled branch power flows are higher than the modelled branch assets capacity. Two other components contribute to this, firstly our use of unadjusted SCADA data to establish the demands and secondly that our model is unable to take account of the "time to restore" aspects of ER P2/6.

6.34. If the model includes branches where the demand appears to exceed the capacity then the resultant negative years to reinforcement cause excessively high prices which have the consequent effect of creating exponentially high and unstable charges. Therefore, to solve this issue we propose to establish a scaling factor to the power flows so that no capacities are exceeded. The same power flow scaling factor will be applied consistently to all power flows and all time bands.

6.35. Alternatives to this approach include modelling the future network configuration or manual adjustment of the demands. Exploring these options would require significant extra work to be applied to the process and some degree of modelling assumptions to be made. We consider this additional work would delay implementation of the methodology and so outweigh the benefits in the short term.

Forecasts

Growth Rates

6.36. The nodal demands are based on extracts taken from the SCADA system. The detail of these extracts is described in the previous 'Time based network data' section of this Appendix. These demands are used to populate the power flow modelling which then provides the power flow data for each asset. These power flows are increased by an annual growth rate to determine the time when reinforcement is required.

6.37. The growth rates used are calculated from the Table 3 load data provided in the LTDS. These values represent the sum of the demands forecast at the exit points from the EHV system for each of the GSP operating configurations. The growth rates currently used and their corresponding GSPs are listed in the following table.

Table 6

GSP (Demands in MW)	2005-2006	2010-2011	Annualised Growth
Beddington	509	572	2.1%
Bolney	1,006	1,067	1.0%
Kemsley / Canterbury / Sellindge	881	950	1.3%
Chessington	304	311	0.4%
Kingsnorth	236	248	0.9%
Laleham	82	89	1.3%
Ninefield	269	277	0.5%
Northfleet & Littlebrook	627	692	1.7%
West Weybridge	422	436	0.5%

6.38. The network nodes will be attributed to the GSPs based on their normal operating configuration. This arrangement is also detailed in Table 3 load data provided in the LTDS.

Asset Reinforcement Solution Costs

6.39. The application of asset reinforcement solution costs is based on generic assets using a weighted representation of typical solution costs.

6.40. The generic assets types used are set out in the following table. The assets are further split by the main distribution voltages and transformation levels.

Table 7

Generic Assets Items
Dual Circuit Cable
Dual Circuit Composite (cable and overhead line)
Dual Circuit Overhead line
Single Circuit Cable
Single Circuit Composite (cable and overhead line)
Single Circuit Overhead line
Voltage Transformation

6.41. The generic asset assigned to each branch represents the majority of the assets used in that branch. Where a combination of cable and overhead line are used a 'composite' asset type is used.

6.42. Examples are given below:

Table 8

Branch assets	Length	Generic asset
1 circuit of 132kV dual circuit overhead line 1 circuit of 132kV underground cable	5km 0.5km	1 circuit of 132kV dual circuit overhead line
1 no. 132/33kV transformer 6 no. 33kV circuit breakers	- -	132/33kV substation
1 circuit of 33kV single circuit overhead line 1 circuit of 33kV underground cable	8km 8km	33kV Single circuit composite

6.43. The reinforcement costs used in the net present value calculations will be a weighted representation of the solution costs that are used to reinforce the generic asset type. The use of weighted solution costs is to improve the cost reflection of how the current asset type will be reinforced when an actual solution has not been planned. The solution weighting will reflect the best practise range of economic solutions that are currently being implemented. So the best economic solution will already be factored into the weighting.

6.44. An example of the approach is given below:

Table 9

Asset Type	Reinforcement solution	Cost per km (non representative examples)	Solution weighting	Weighted Cost
132kV Overhead line (load-flow branch one of dual circuit)	Re-conductor line	£80,000	30%	£24,000
	Upgrade line (Re-conductor line, strengthen towers, re-profile etc)	£150,000	30%	£45,000
	New Overhead line	£250,000	0%	£0
	New Underground cable	£800,000	20%	£160,000
	New interconnection	£700,000	20%	£140,000
Example cost for reinforcing asset type - £369,000 per km				

Calculation Process

6.45. The calculations for the marginal costs are conducted for each node. These nodal costs are then either used as the 'shared asset' component of an EHV site specific charge or, if the node is an HV/LV exit point, aggregated with other relevant 'tariff' nodes to calculate a weighted average cost to be taken forward into the tariff yardstick calculation.

6.46. The marginal cost for a node is the sum of the change in brought forward reinforcement costs at each branch which has been triggered by the change in power flow at the node and is represented by the following formula.

$$\text{Marginal cost at Node } n = \sum_{i=1}^{B} \Delta Ci$$

Where:
n = the node under study
B = number of branches in the network
ΔCi = Change in reinforcement costs of the asset in branch i due to marginal increment /decrement at the node

6.47. The change in reinforcement costs due to the application of the increment/decrement of demand is derived from the following formula.

$$\Delta Ci = \text{Net present Value(Inc)} - \text{Net Present Value(base)}$$

Where:
Net present Value (Inc) = the brought forward cost of reinforcement after the increment /decrement has been applied and derived from the following formula

$$\text{Net present value (Inc)} = \frac{\text{Cost of reinforcement solution}}{(1 + \text{Discount Rate})^{\text{Number of years until reinforcement (Inc)}}}$$

And,
Net present Value (base) = the current brought forward cost of reinforcement for the base case

$$\text{Net present value (Base)} = \frac{\text{Cost of reinforcement solution}}{(1 + \text{Discount Rate})^{\text{Number of years until reinforcement (base)}}}$$

6.48. Both of the net present Value calculations use the same cost of reinforcement solution which is dependant on the generic asset type. The discount rate is also the same for both present Value calculations. The regulatory rate of return for the price control period will be used for the discount rate as this is a proxy for the DNOs cost of borrowing.

6.49. The number of years until reinforcement is the time it will take, assuming the forecast growth rates, to 'use up' any spare capacity in the asset and therefore when the asset should be reinforced. The number of years until reinforcement is calculated using the following formula.

$$\text{Number of years until reinforcement} = \frac{\log(\text{rated capacity}) - \log(\text{power flow})}{\log(1 + \text{growth of utilisation})}$$

Where:
Rated capacity = the ER P2/6 capacity. This is the network asset capacity de-rated by the security factor,

Growth of utilisation = the forecast growth rate of the load at the supporting GSP, and power flow, for the base case power flow, calculated from the following formula

$$\text{power flow (MVA)} = \sqrt{P(MW)^2 + Q(MVAr)^2}$$

Where the values for P and Q are the branch outputs from Table 3

6.50. To establish the 'new' number of years until reinforcement the power flow is adjusted to take account of the effect of the increment or decrement at the node where the charge is being calculated.

6.51. The new power flow taking the increment or decrement into account is calculated using the following formula.

$$\text{new power flow (MVA)} = \sqrt{(P(MW) + \Delta P * X_p)^2 + (Q(MVAr) + \Delta Q * X_q)^2}$$

Where ΔP = -1MW for demand increments and 1 MW for generation decrements
and ΔQ = -0.33MVAr for demand increments and 0 MVAr for generation decrements
and Xp and Xq are the sensitivity coefficients from Table 5

6.52. ΔQ assumes a power factor of 0.95 for demand connection and unity for generation connections. These power factors are typical of those expected of new connections.

6.53. On completion of the calculations a matrix of charges are held for each node. These comprise the five time band charges used to compile charges to demand connections and the five time band charges used to compile charges to generation connections.

Nodal Cost Aggregation for tariffs

6.54. One set of nodal costs are used in the tariff yardstick process. This set of costs is presented as the weighted average of all the nodes where there is an entry to the HV/LV network. The weighting of the costs is conducted by multiplying the nodal cost by the nodal demand and then summating the result and dividing by the sum of nodal demands. This calculation is as shown in the following formula.

$$\text{Timeband cost for Tariff} = \frac{\sum_{i=1}^{Nt} Ci.Di}{\sum_{i-1}^{N} Di}$$

Where:
C_i = Nodal cost for time band at a HV/LV entry/exit point
D_i = Nodal demand for time band at a HV/LV entry/exit point
N_t = Number of nodes where there is an entry to the HV/LV network from the EHV network

6.55. On completion there are five demand costs, one for each time band and five generation costs, one for each time band. These costs feed in to the tariff yardstick model for application in to the tariff setting and revenue scaling process. These costs could be either positive or negative.

Nodal Costs for Site Specific EHV charges

6.56. The nodal cost used in the calculation of site specific EHV charges is from the nodal cost at the boundary between the shared network assets and the sole use EHV connection assets. The costs of the remaining sole use assets are calculated separately and depend on the connection charge contribution.

6.57. At each shared use connection node there will also be five demand costs, one for each time band and five generation costs, one for each time band. These costs will then feed into the charge calculation process for the site specific charge. These costs could be either positive or negative.

7. Yardstick Modelling

7.1. The yardstick modelling for demand users remains largely the same under the new methodology. However the addition of the power flow/LRIC modelling of EHV marginal costs into the yardstick model has led to movement in costs from EHV to HV/LV due to the allocation of cost between the two components. In non half hourly tariffs this reflects as higher fixed costs and lower unit rates.

7.2. Work has been conducted since the last consultation to enable the marginal cost signal to be reflected correctly in the unit rates. This work involves the attribution of marginal costs to unit rates for all half hourly metered connections. The main concept adopted enables the cost signal profile seen in the £/kW time band charge to remain in the p/kWh time band charge. Essentially the highest marginal cost time band has the highest unit charge and this continues for the next highest until the lowest cost time band.

7.3. The modelling of generation tariffs utilises the same approach as used for demand users except using generation derived costs from the marginal cost calculations. If the HV/LV modelled cost are deferred then these will be seen as a credit. Costs which have already been attributed through demand charges are excluded from the generation attribution. An equivalent credit is given to generators for the potential offsetting of NGET Exit charges.

Application of Marginal EHV Network Costs

7.4. The marginal costs derived from the EHV power flow modelling and those derived from HV/LV asset management information are applied to the yardstick model. With regard to HV/LV tariffs the yardstick is supplied with 5 time band demand costs for the EHV network and five time band generation costs for the EHV network. There are separate HV/LV costs for the different layers of the HV/LV network namely; HV network, HV/LV transformation and LV network. These costs are allocated to the five demand time bands in the same proportion as that calculated for the EHV time bands. These costs are applied as negative costs (benefit) to the HV/LV generation time bands. With regard to site specific charges the yardstick for each EHV connection is supplied with the costs specific to the node of common (shared) connection. Any connection spur (sole use) assets are treated separately until the point of common connection changes.

7.5. Scaling adders are applied to the marginal costs which are initially set to zero prior to the final matching of forecast revenue to allowed revenue.

7.6. The marginal costs are annuitised at the regulatory rate of return over an average expected asset life of 40 years. Operation and maintenance costs are applied expressed as a percentage of the marginal cost. The percentage used is published in our connection charging statement.

7.7. The £/kVA charges are converted to £/kW using a power factor average of 0.95p.f. Additional reactive charges are applied where customer's power factor deviates from this average.

7.8. NGET costs are applied as a £/kW cost to the time band when system peak occurs as a function of total NGET cost (less any site specific NGET charges) divided by the system peak demand. This cost is also allocated to generation charges as a benefit in the equivalent generation time band.

7.9. The yardstick charges are calculated, based on the marginal costs, for each tariff group and EHV connected user. For each time band the charges calculated take into consideration the network coincidence of the tariff group's demand to the network demand. For EHV connections actual half hourly data specific to the site is used. The HV/LV level costs are adjusted for network losses for each tariff group to account for the higher demand requirement required to adjust for losses.

HV/LV tariff yardstick

7.10. The yardstick for HV/LV tariffs then apportions these marginal charges between fixed and variable costs.

7.11. The fixed charge (availability for half hourly metered) comprises of 100% of the costs at the point of connection and for LV connections 50% of the cost of the assets above, while HV connections 20% of the EHV marginal costs. The marginal costs for unmetered supplies tariff groups are attributed solely to variable costs.

7.12. The fixed charges for non half hourly metered connections are based on the average demand for the tariff group multiplied by the sum of the apportioned marginal cost and include a cost for operation and maintenance on the service connection. The fixed charges for non half hourly unmetered supplies include the cost of running the unmetered supplies office and include the cost of operation and maintenance on the service connections. The fixed charge for half hourly connections recovers the cost of operation and maintenance on the service connection assets.

7.13. The remaining costs are allocated to unit charges based on the tariff group's average unit consumption and the ratio of kW/kWhs for each time band. Additionally, for non half hourly connections the percentage use that the tariffs (market domain data) time band makes of the cost allocated to each of the 5 modelling time bands is allocated. For example the varieties of two rate 'off peak' time bands means that a small proportion of winter shoulder costs have to be allocated to the two rates 'off peak' unit rate. The half hourly tariff time bands match the modelled time bands and therefore the cost allocation is directly applied.

7.14. The HV/LV network marginal costs are based on average network provision. Where charges are calculated for half hourly metered sites the cost are allocated based on a smaller proportion of the network being used.

EHV charges yardstick

7.15. The fixed charges for EHV sites are based on the connection spur (sole use) costs. The default charge is based on the current connection charging policy. This includes for the operation and maintenance of the connection assets to be recovered through the use of system charge. Variations to this default are only made where there is evidence that different connection charges were made.

7.16. The availability and unit charges are based on a total charge which is calculated from the product of the demand values and the marginal costs, and include the allocation of NGET charges. A capacity charge equivalent to the product of the agreed capacity and the peak marginal cost is allocated on a £/kVA/month basis. The remaining charge is then allocated to the 5 time bands based on the time bands remaining marginal cost and their kW/kWh ratio.

Generator charge yardstick

7.17. The charges allocated to generators are applied using the same principles as those that have been used for demand tariff groups. Where HV/LV demand marginal costs are offset or deferred the charge will be seen as a credit. Appropriate coincidence factors and kW/kWh ratios are applied each generation tariff group.

Allowed Revenue

7.18. Forecasts of our expected allowed revenue and expected user consumptions and productions for the year that prices are set are made. The yardstick charges are then calculated against the expected user volumes to determine the revenue that would be recovered from the yardstick charges. The scaling adders are then adjusted on an iterative basis until the forecast charged revenue matches the allowed revenue. It is at this point that the prices are set.

Scaling to allowed revenue

7.19. The methodology calculates yardstick charges for the EHV network using an LRIC approach and yardstick charges for the HV and LV network using a combination of LRIC and our existing DRM based approach.

7.20. The alignment of the yardstick charges with allowed revenue will take part in three stages. The first stage would involve splitting the allowed revenue into that recovered from demand and generation customers. However, allowed revenue for Demand and Generation is currently separate in the distribution price control. Therefore, we do not propose to have any transfer of revenue between these two allowances.

Demand Charges

7.21. For demand customers the second stage is to split the allowed revenue between EHV network modelled yardsticks and HV & LV network modelled yardsticks. This is done in the same proportion as the MEA values of the EHV networks and the HV & LV networks.

7.22. The third stage involves aligning the yardstick charges with the allowed revenue in each relevant network. A fixed adder approach is used to scale the modelled revenue to match the allowed revenues for the different networks.

Generation Charges

7.23. For generation customers the second stage is to split the allowed revenue between EHV and HV & LV network users. This is done by splitting the allowed generation revenue in the same proportion as the effective metered generation demand on the network.

7.24. The third stage involves aligning the yardstick charges with the allowed revenue in each relevant network. A fixed adder approach is being proposed to scale the modelled revenue to match the allowed revenues for the different networks.

8. Modelling update since January 2008 consultation

8.1. A criticism of the LRIC method is that under certain circumstances potentially excessive or erroneous charges will be produced as a consequence of the calculations applicable to low growth rates and high utilisation. It can be observed that as the power flow exceeds 60% utilisation then the level of cost rises exponentially from what would be expected. Similarly it can be seen that the cost behaviour is as expected below 60% utilisation. This is demonstrated in the chart shown below (Figure 5). We believe that this issue is addressed in our model. Notably in our marginal cost calculations we scale all of the demands evenly across all time bands so that the highest utilisation is not greater than 60% of the asset.

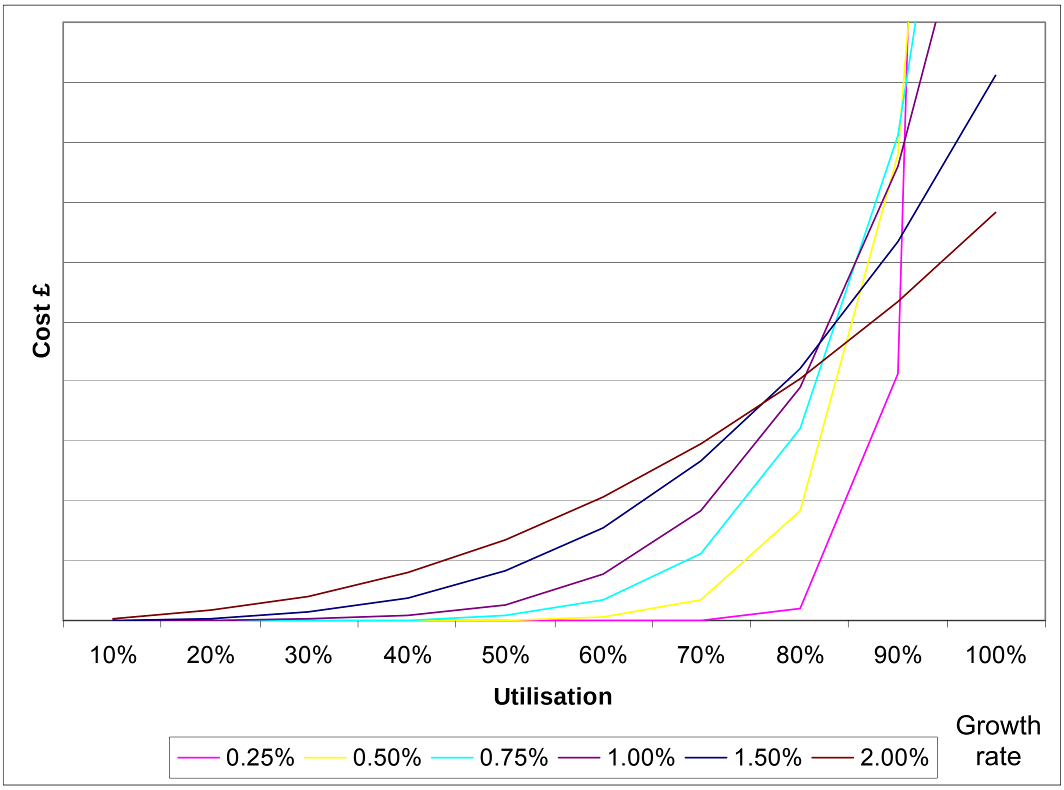


Figure 5

8.2. We originally scaled here to solve the problem of high costs having to be scaled in the yardstick model. We now understand that the scaling that we were applying evenly across all demands was actually solving the underlying issue that was creating the high cost. It is also noted that due to this demand scaling being used the yardstick revenues calculated are nearer to the expected level of reinforcement costs compared to allowed revenue and that the revenue scaling that is then carried out in the yardstick model results in a positive adder, whereas prior to this a negative adder was required.

8.3. The illustrative prices utilise a 0.6 demand scaler. Comparison scenarios are provided to compare the effect of a 0.8 demand scaler and no demand scaler. These comparisons are detailed in Appendix 3 – Demand Scaler Comparisons.

8.4. A comparison has been provided to compare the effect of using a smaller 1kVA incremental value against the sensitivity coefficient rather than the 1MVA that has been used. The final difference is very small and is likely to be due to calculation rounding differences. The incremental comparison is detailed in Appendix 4 – 1kVA Increment Comparison.

8.5. An 'instantaneous if' function is used as part of the marginal cost calculation. The function forms part of the demand weighting calculation for the marginal costs. The demand weighting is conducted because some charges are based on the costs of more than one node. Without demand weighting of these costs some charges would be unfairly biased by high or low nodal costs. The function has the effect of replacing any load that is less than 1MW with 1MW as the load. The effect of the load is cancelled out when the sum of cost is divided by the sum of demand, but it allows the cost to be considered in the calculation. This is particularly important when calculating illustrative charges for a node which has no load entering or exiting it or where charges for a particular connection utilises more than one node.

8.6. A validation exercise has identified that the version of the power flow model that was used for the illustrative charges in the consultation had an incorrect network loadings file for the generation 'winter shoulder' time band. This only effected the marginal costs for the generation 'winter shoulder' time band and was identified due to the higher benefit that was indicated in the marginal £/kW charge to generators at 'winter shoulder' as opposed to the charge at 'winter peak'. This was caused by using the 'winter shoulder' maximum load file used instead of the 'winter shoulder' minimum load file when calculating the marginal costs. This error had no effect to the illustrative demand charges and the new illustrative generation charges have been corrected.

8.7. We have reviewed and modified the method used to convert marginal £/kW cost to p/kWh charges. To incorporate p/kWh charges to half hourly metered connections we had converted the marginal cost to p/kWh using a kW/kWh factor based on the number of units used per kW specific to each time band. However, this approach has the effect of changing the price signal seen in the marginal cost and producing a p/kWh signal that would have encouraged network use during time periods indifferent to the marginal signal. We have now changed the allocation approach and now utilise the same kW/kWh factor across all time bands. This method allows the unit charge to mirror the marginal signal.

8.8. It was recognised that for some EHV connected charges the calculated capacity charge was greater than the initial total charge. The initial total charge is calculated as the product of the marginal charge and the forecast demand. Whereas the capacity charge component is the product of the peak marginal cost and the agreed capacity level. The amount of the capacity charge is then removed evenly from all of the unit charges. We believe that this is a fair method of charging for capacity. However, where a connection has a capacity requirement that is significantly greater than their expected demand (normally seen where standby capacity is provided) the cost calculated for capacity in this manner would be greater than the marginal costs would indicate. We believe that it is an appropriate principle to maintain a capacity cost signal in this manner to each connection as this addresses the risk that the connection may utilise the full capacity at time of peak marginal cost and is, therefore, reflective of cost.

8.9. The average demand used for the allocation of fixed charges has been reviewed for non half hourly tariff groups. The fixed charge component in PC 5-8 tariff groups were previously averaged across this group of customers. The average demand is now individual to the profile class.

8.10. We will implement a half hourly metered low voltage substation tariff with this methodology. This will have the effect of improving the cost reflectivity of the current half hourly metered low voltage tariff. The new substation tariff will be available to those half hourly metered low voltage connections which are fed directly from a substation and do not make use of any low voltage network. Existing half hourly metered low voltage connections will be assessed to determine applicability to the new tariff. Inevitably those remaining on the half hourly metered low voltage tariff will face the costs of providing the low voltage network for their connection requirements.

9. Proposals in the context of Licence Obligations

9.1. As of 1 April 2005, DNOs methodologies must conform to the objectives set out in paragraph 3 of SLC 4.

9.2. The relevant objectives for the use of system charging methodology, as contained in paragraph 3 of SLC4 of the distribution licence, are:

- that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Electricity Act 1989 and by this licence;
- that compliance with the use of system charging methodology facilitates competition in 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, so far as is consistent with sub-paragraphs above, the use of system charging methodology, as far as reasonably practicable, properly takes account of developments in the licensee's distribution business.

9.3. Ofgem in its Structure of Charges documents and in particular in the May 2005 Consultation paper has indicated the importance of deriving a charging model which delivers economic efficiency. Economic efficiency as defined by Ofgem means "that consideration should be given to ensuring lowest cost provision of the system which would include the requirement for the provision of efficient investment signals to customers such that future network needs are met efficiently."

9.4. The Ofgem May 2005 Structure of Charges paper also identified the following high level charging principles:

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

9.5. The power flow/LRIC method allows locational prices to be determined taking into account both the extent that assets are used to supply a node on the network and also the spare capacity that exists in those assets. This compares with the existing DRM based approach that uses average £/kW per voltage level or the capacity based approach used for EHV connected connections that uses solely the cost of capacity and not the extent of use. Hence the power flow/LRIC method is more cost reflective than both existing approaches.

9.6. The power flow/LRIC approach is a method of attributing cost to users, which while appearing complex allows the familiar tariff structures to remain and the nature of these tariff structures to continue to provide additional cost reflection of the marginal cost messages. Therefore, the application of Use of System charges will remain relatively easy to understand and apply.

9.7. This paper and the proposed methodology statement set out improved details of the methodology, formulae and data used to attribute charges. This is a greater level of transparency then is currently provided under our present approach. Our intention is to make available details of the model in a form which will further increase transparency and predictability. We will continue to work with interested parties to improve their knowledge and skills in understanding and forecasting use of system charges.

9.8. Power flow/LRIC prices will vary due to changes to users' demands on the network, their exports to the network, the network configuration and the projections of future load growth used. Our use of the LTDS provides a publicly available source of information to assist users with the transparency and predictability of information used.

9.9. Given the method's improved cost reflectivity and transparency, we believe that it will better facilitate competition in the supply and generation of electricity and will not restrict competition in transmission or distribution. We also believe that the improved cost reflectivity at the EHV level will reduce perverse incentives to connect to the distribution or transmission network due to the use of averaged charges on the distribution network and zonal charges on the transmission system.

9.10. Ofgem in its April 2008 'Delivering the Structure of Charges' consultation provided further detail and guidance on use of system charging methodologies. This detail and guidance has been provided in the form of Relevant Principles and these are detailed in Appendix 4 of the consultation. Of these Relevant Principles we believe that this methodology fully meets the following principles:

- A charging model for both generation and demand customers
- A forward looking incremental cost model
- The charging model should reflect all significant cost drivers
- The charging model and use of system tariffs shall accurately reflect network costs incurred
- The charging model shall recognise the costs and benefits of using the system
- The charging methodology shall use a scaling approach that minimises distortion of cost signals
- The charging methodology shall use power flow modelling
- Predictability (with regard to facilitation of LTDS based modelling)

9.11. Of these Relevant Principles we believe that this methodology partially meets:

- Transparency and predictability

We have an aspiration to continue to improve transparency and predictability, working with interested parties to deliver improvements to the information that they need to enable them to make improvements to their capabilities with regard to understanding and forecasting use of system costs.

9.12. We acknowledge that this methodology does not meet the Relevant Principle of:

- A common charging model adopted by all DNOs

It is our intention that this methodology will be implemented in our East of England and London service areas. When this has been completed the methodology will be common to over 8 million connections and which will account for over 25% of licenced connections charges being calculated based on a common model. Consequently we have no objection in principle to other DNOs adopting this approach as a common methodology for all distributors.

10. Impact of the Proposed Arrangements on Prices

10.1. The tables in Appendix 1 detail the existing distribution use of system charges, effective October 2007 and set using the existing methodology, with charges set using the proposed methodology. These comparison charges are calculated to achieve the same allowed revenue in order to provide an illustration of the new charges.

10.2. The tables in Appendix 2 detail the changes in annual distribution use of system charges for customers on typical usage patterns. The consumptions that have been used for these comparisons provide typical annual charges for low, medium and high users.

11. Proposed Methodology Statement

11.1. The proposed methodology statement forms Appendix 5. An additional tracked change version is also included in the modification pack.

APPENDIX 1 – ILLUSTRATIVE CHARGES

1.1. The followings series of tables compare the existing distribution use of system charges, effective October 2007 and set using the existing methodology, with charges set using the proposed methodology. These comparison charges are calculated to achieve the same allowed revenue in order to provide an illustration of the new charges.

Illustrative Demand Tariff Rates

Illustrative demand tariff rates		Current Prices	Proposed Prices	Percentage Difference
Domestic profile Class 1 & 2				
Unrestricted				
Network Charge	p/day	5.64	7.47	32%
Unit	p/kWh	0.779	0.631	-19%
Two Rate				
Network Charge	p/day	5.64	7.47	32%
Unit Day	p/kWh	0.957	0.761	-20%
Unit Night	p/kWh	0.366	0.332	-9%
Three Rate				
Network Charge	p/day	5.64	7.47	32%
Unit Day	p/kWh	0.97	0.809	-17%
Unit Night	p/kWh	0.283	0.225	-20%
Unit Other	p/kWh	0.426	0.333	-22%
Off Peak				
Network Charge	p/day	1.41	1.87	33%
Unit	p/kWh	0.359	0.307	-14%
Profile Class 3 & 4				
Unrestricted				
Network Charge	p/day	7.72	11.44	48%
Unit	p/kWh	0.81	0.656	-19%
Two Rate				
Network Charge	p/day	7.72	11.44	48%
Unit Day	p/kWh	0.74	0.598	-19%
Unit Night	p/kWh	0.283	0.259	-8%
Three Rate				
Network Charge	p/day	7.72	11.44	48%
Unit Day	p/kWh	0.846	0.696	-18%
Unit Night	p/kWh	0.367	0.339	-8%
Unit Other	p/kWh	0.459	0.351	-24%
Off Peak				
Network Charge	p/day	1.93	2.86	48%
Unit	p/kWh	0.288	0.248	-14%

Illustrative demand tariff rates		Current Prices	Proposed Prices	Percentage Difference
Profile Class 5				
Unrestricted				
Network Charge	p/day	193.50	219.24	13%
Unit	p/kWh	0.757	0.628	-17%
Two Rate				
Network Charge	p/day	193.50	219.24	13%
Unit Day	p/kWh	0.777	0.64	-18%
Unit Night	p/kWh	0.21	0.206	-2%
Profile Class 6				
Unrestricted				
Network Charge	p/day	193.50	239.70	24%
Unit	p/kWh	0.711	0.596	-16%
Two Rate				
Network Charge	p/day	193.50	239.70	24%
Unit Day	p/kWh	0.686	0.565	-18%
Unit Night	p/kWh	0.186	0.183	-2%
Profile Class 7				
Unrestricted				
Network Charge	p/day	193.50	249.93	29%
Unit	p/kWh	0.559	0.468	-16%
Two Rate				
Network Charge	p/day	193.50	249.93	29%
Unit Day	p/kWh	0.548	0.452	-18%
Unit Night	p/kWh	0.163	0.16	-2%
Profile Class 8				
Profile Class				
Network Charge	p/day	193.50	260.15	34%
Unit	p/kWh	0.487	0.409	-16%
Two Rate				
Network Charge	p/day	193.50	260.15	34%
Unit Day	p/kWh	0.468	0.387	-17%
Unit Night	p/kWh	0.129	0.127	-2%
Half Hourly Pseudo metered				
Network Charge	p/day	23.50	23.50	0%
Night Unit	p/kWh	0.289	0.918	218%
Peak Unit	p/kWh	9.087	1.851	-80%
Winter Shoulder Unit	p/kWh	2.122	1.433	-32%
Summer Peak Unit	p/kWh	0.526	0.811	54%
Other Units	p/kWh	0.545	1.345	147%

Illustrative demand tariff rates		Current Prices	Proposed Prices	Percentage Difference
Half Hourly Metered Low Voltage				
Network Charge	p/day	69.46	69.46	0%
Availability	p/kVA/Month	184.6	88.8	-52%
Night Unit	p/kWh	0.041	0.301	634%
Peak Unit	p/kWh	1.215	0.899	-26%
Winter Shoulder Unit	p/kWh	0.27	0.614	127%
Summer Peak Unit	p/kWh	0.075	0.316	321%
Other Units	p/kWh	0.069	0.532	671%
Half Hourly Metered Low Voltage Sub-station				
Network Charge	p/day	69.46	92.98	34%
Availability	p/kVA/Month	184.60	86.70	-53%
Night Unit	p/kWh	0.04	0.16	283%
Peak Unit	p/kWh	1.22	0.63	-48%
Winter Shoulder Unit	p/kWh	0.27	0.36	32%
Summer Peak Unit	p/kWh	0.08	0.15	103%
Other Units	p/kWh	0.07	0.41	494%
Half Hourly Metered High Voltage				
Network Charge	p/day	148.85	130.77	-12%
Availability	p/kVA/Month	109.8	74.5	-32%
Night Unit	p/kWh	0.014	0.07	400%
Peak Unit	p/kWh	0.459	0.385	-16%
Winter Shoulder Unit	p/kWh	0.09	0.16	80%
Summer Peak Unit	p/kWh	0.028	0.053	89%
Other Units	p/kWh	0.029	0.141	386%

Illustrative Annual EHV Site Specific Demand Charges

Site ID	Forecast Total Charge Per annum	Current Oct 07 total	Difference	% diff
1	£124,267	£875,677	-£751,409	-86%
2	£3,865	£9,270	-£5,405	-58%
3	£39,466	£38,810	£656	2%
4	£1,499,906	£1,499,906	£0	0%
5	£90,930	£739,631	-£648,701	-88%
6	£85,133	£399,362	-£314,229	-79%
7	£241,350	£693,802	-£452,452	-65%
8	£3,085	£2,551	£534	21%
9	£26,257	£30,577	-£4,320	-14%
10	£229,045	£199,243	£29,802	15%
11	£4,875	£4,365	£510	12%

Site ID	Forecast Total Charge Per annum	Current Oct 07 total	Difference	% diff
12	£167,974	£336,006	-£168,032	-50%
13	£56,104	£306,416	-£250,312	-82%
14	£79,825	£291,094	-£211,270	-73%
15	£70,515	£236,528	-£166,014	-70%
16	£78,160	£223,991	-£145,831	-65%
17	£41,691	£70,062	-£28,371	-40%
18	£172,445	£374,316	-£201,872	-54%
19	£72,388	£212,533	-£140,145	-66%
20	£31,770	£130,448	-£98,677	-76%
21	£26,174	£168,688	-£142,514	-84%
22	£37,508	£41,881	-£4,373	-10%
23	£49,065	£186,884	-£137,819	-74%
24	£105,509	£231,161	-£125,652	-54%
25	£62,977	£155,696	-£92,719	-60%
26	£4,309	£13,062	-£8,753	-67%
27	£62,781	£230,878	-£168,097	-73%
28	£40,124	£209,019	-£168,895	-81%
29	£587,248	£423,258	£163,990	39%
30	£50,157	£208,684	-£158,527	-76%
31	£42,538	£120,835	-£78,297	-65%
32	£53,237	£304,694	-£251,457	-83%
33	£6,389	£16,729	-£10,341	-62%
34	£290,928	£421,791	-£130,863	-31%
35	£108,449	£520,614	-£412,165	-79%
36	£217,134	£279,804	-£62,670	-22%
37	£90,026	£115,493	-£25,467	-22%
	£5,031,449	£10,323,760	-£5,305,444	-51%

Illustrative Generation Tariff Rates

1.2. We plan to continue to cap at zero the generation charges for all non half hourly metered sites, until further work has been completed on the separate demand and generation price controls.

1.3. Generation connected sites will have the following charges. The availability charge will be applied where the export capacity is higher than the import capacity and will be based on the excess export available capacity.

Illustrative generation tariff rates		**Current Prices**	**Proposed Prices**	**Notes**
Non Half Hourly Metered Low Voltage Generation				
Network Charge	p/day	0	0	
Unit Charge	p/kWh	0	0	
Half Hourly Metered Low Voltage Generation				
Network Charge	p/day	0	0.00	
Availability	p/kVA/Month	39	8.30	
Night Unit	p/kWh	0	0.43	
Peak Unit	p/kWh	0	-0.63	Credit
Winter Shoulder Unit	p/kWh	0	0.04	
Summer Peak Unit	p/kWh	0	0.47	
Other Units	p/kWh	0	0.18	

Illustrative generation tariff rates		Current Prices	Proposed Prices	Notes
Half Hourly Metered Low Voltage Substation Generation				
Network Charge	p/day	0	0.00	
Availability	p/kVA/Month	39	8.30	
Night Unit	p/kWh	0	0.34	
Peak Unit	p/kWh	0	-0.55	Credit
Winter Shoulder Unit	p/kWh	0	0.05	
Summer Peak Unit	p/kWh	0	0.35	
Other Units	p/kWh	0	0.17	
Half Hourly Metered High Voltage Generation				
Network Charge	p/day	0	0.00	
Availability	p/kVA/Month	39	8.30	
Night Unit	p/kWh	0	0.14	
Peak Unit	p/kWh	0	-0.37	Credit
Winter Shoulder Unit	p/kWh	0	0.02	
Summer Peak Unit	p/kWh	0	0.11	
Other Units	p/kWh	0	0.09	

Illustrative Nodal charges

1.4. The following table presents an illustration of the marginal £/kVA cost of reinforcement at several 33kV locations across the SPN area. The costs have not been annualised or scaled and do not include NG costs. They are presented for identifying the variety of movement that could be experienced depending on the location of connection.

1.5. As there are no applicable generators connected at EHV at the current time we have not been able to include any Illustrative annual EHV site specific generation charges for actual sites. How the following costs will materialise into charges will depend on the production at the site and the allowed generation revenue at the time the charges are set.

1.6. It will be our intention to produce this table including a more extensive list of locations on an annual basis.

	Time bands									
	Demand					Generation				
Location	1	2	3	4	5	1	2	3	4	5
Ashford	£2.62	£9.58	£6.78	£1.35	£5.19	-£0.12	-£2.79	-£1.50	-£0.49	-£0.15
Brighton	£3.86	£28.39	£14.29	£1.77	£14.71	-£0.04	-£2.71	-£1.36	-£0.41	£0.10
Crawley	£3.16	£13.93	£11.30	£1.68	£7.93	-£0.34	-£4.24	-£1.92	-£0.94	-£0.39
Croydon	£1.57	£3.56	£2.97	£1.83	£3.25	-£0.53	-£3.16	-£2.24	-£1.17	-£0.70
Eastbourne	£0.42	£1.75	£1.06	£0.22	£0.89	-£0.04	-£0.59	-£0.29	-£0.13	-£0.03
Folkestone	£1.60	£7.46	£4.70	£0.72	£4.21	-£0.06	-£2.01	-£0.78	-£0.35	-£0.23
Kingston	-£0.09	-£0.38	-£0.26	-£0.05	-£0.20	£0.01	£0.14	£0.06	£0.02	£0.01
Leatherhead	-£0.08	-£0.39	-£0.27	-£0.05	-£0.20	£0.01	£0.13	£0.06	£0.02	£0.01
Maidstone	£11.21	£35.99	£16.22	£4.89	£18.52	-£1.93	-£10.21	-£6.21	-£3.13	-£1.67
Tunbridge Wells	£61.08	£145.57	£123.39	£33.06	£91.59	-£8.60	-£58.21	-£35.04	-£21.76	-£9.61
Worthing	£1.39	£5.25	£3.64	£0.72	£2.87	-£0.13	-£1.72	-£0.90	-£0.32	-£0.05

Where:
Period 1 – Night
Period 2 – Winter Peak
Period 3 – Winter Shoulder
Period 4 – Summer Peak
Period 5 – All other times

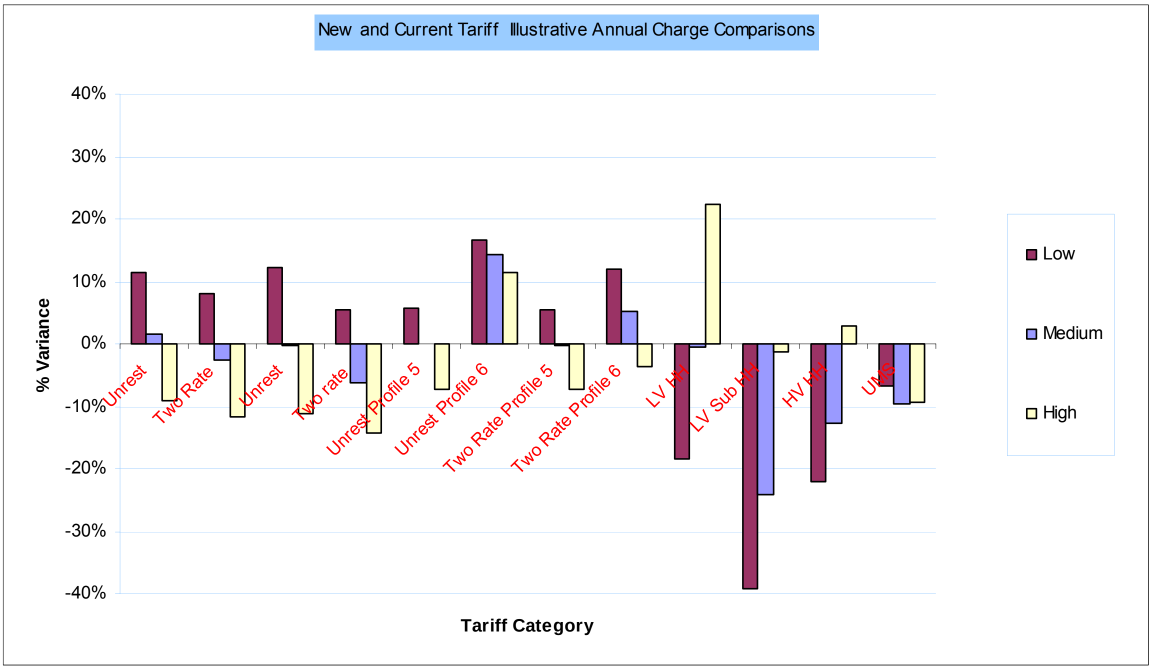
Appendix 2 – Annual Charge Comparison

1.1. The following illustrative annual charge comparisons table and chart have been provided to demonstrate the price movement across a variety of tariffs and consumption levels.

Annual charge comparison table

Low consumption				
Tariff	£s Value		Variance	
Name	Current	New	£s	Percent
Domestic Unrestricted	£33	£37	£4	12%
Domestic Two Rate	£39	£42	£3	8%
Profile Class 3 Unrestricted	£57	£65	£8	12%
Profile Class 4 Two rate	£79	£84	£4	5%
Profile Class 5 Unrestricted	£927	£984	£56	6%
Profile Class 6 Unrestricted	£908	£1,089	£182	17%
Profile Class 5 Two rate	£949	£1,004	£55	5%
Profile Class 6 Two rate	£950	£1,080	£130	12%
Half Hourly Metered Low Voltage	£2,788	£2,354	-£434	-18%
Half Hourly Metered Low Voltage Substation	£4,816	£3,461	-£1,355	-39%
Half Hourly Metered High Voltage	£12,046	£9,860	-£2,186	-22%
Unmetered inventory	£120	£113	-£8	-7%
Medium consumption				
Domestic Unrestricted	£52	£53	£1	1%
Domestic Two Rate	£66	£64	-£2	-2%
Profile Class 3 Unrestricted	£101	£101	£0	0%
Profile Class 4 Two rate	£156	£147	-£9	-6%
Profile Class 5 Unrestricted	£1,259	£1,259	£0	0%
Profile Class 6 Unrestricted	£1,209	£1,411	£202	14%
Profile Class 5 Two rate	£1,313	£1,310	-£3	0%
Profile Class 6 Two rate	£1,316	£1,387	£71	5%
Half Hourly Metered Low Voltage	£4,541	£4,520	-£22	0%
Half Hourly Metered Low Voltage Substation	£7,936	£6,394	-£1,542	-24%
Half Hourly Metered High Voltage	£19,410	£17,225	-£2,186	-13%
Unmetered inventory	£4,373	£3,994	-£379	-10%
High consumption				
Domestic Unrestricted	£98	£90	-£8	-9%
Domestic Two Rate	£133	£119	-£14	-12%
Profile Class 3 Unrestricted	£210	£189	-£21	-11%
Profile Class 4 Two rate	£348	£305	-£43	-14%
Profile Class 5 Unrestricted	£2,088	£1,946	-£141	-7%
Profile Class 6 Unrestricted	£1,964	£2,216	£252	11%
Profile Class 5 Two rate	£2,224	£2,075	-£149	-7%
Profile Class 6 Two rate	£2,232	£2,156	-£76	-4%
Half Hourly Metered Low Voltage	£6,990	£9,003	£2,012	22%
Half Hourly Metered Low Voltage Substation	£12,217	£12,074	-£143	-1%
Half Hourly Metered High Voltage	£28,483	£29,299	£817	3%
Unmetered inventory	£147,544	£134,812	-£12,732	-9%

Annual charge comparison chart



Appendix 3 – Demand Scaler Comparisons

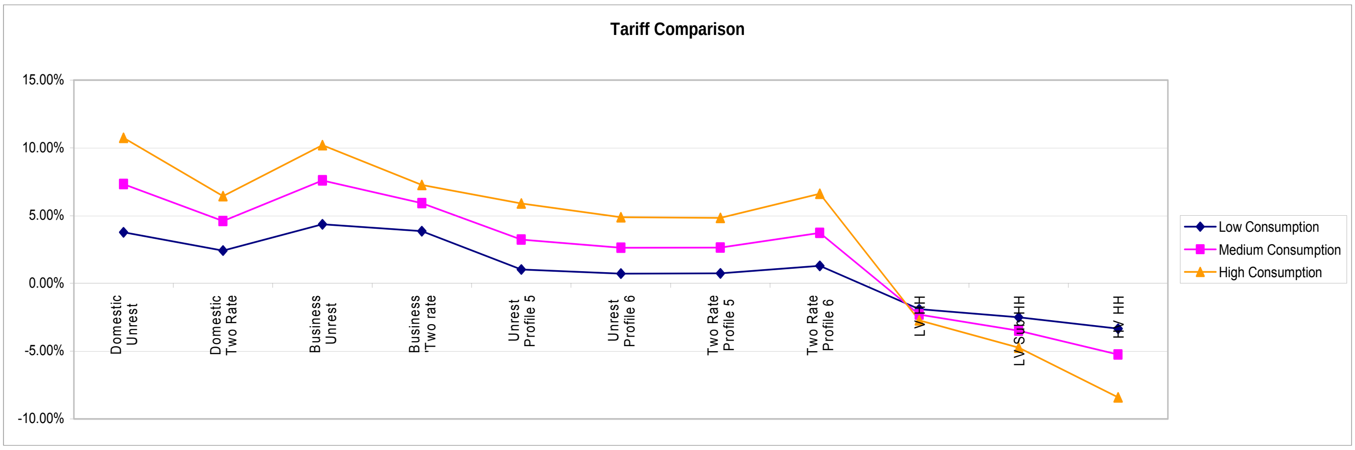
1.1. The marginal costs have been recalculated using a demand scaler of 80%. The tariffs have then been recalculated to the same allowed revenue. The following chart shows the results from the proposed methodology (60% scaled) compared to the 80% scaled results.

Tariff Comparison

Load Flow Input Data:- Proposed methodology vs 80% demand scaling

	Domestic Unrest	Domestic Two Rate	Business Unrest	Business 'Two rate	Unrest Profile 5	Unrest Profile 6	Two Rate Profile 5	Two Rate Profile 6	LV HH	LV Sub HH	HV HH
Low Consumption											
£s/Annum - Total on Variant	38.83	43.06	68.32	87.22	993.71	1097.32	1011.62	1093.79	2310.32	3376.35	9541.26
% from proposed	3.77%	2.41%	4.36%	3.86%	1.02%	0.72%	0.74%	1.29%	-1.89%	-2.51%	-3.34%
Medium Consumption											
£s/Annum - Total on Variant	56.66	67.24	108.98	156.23	1300.75	1449.40	1345.52	1440.57	4417.97	6178.33	16364.55
% from proposed	7.33%	4.60%	7.59%	5.91%	3.24%	2.63%	2.64%	3.72%	-2.30%	-3.49%	-5.26%
High Consumption											
£s/Annum - Total on Variant	101.24	127.70	210.63	328.76	2068.35	2329.60	2180.27	2307.53	8763.83	11527.21	27026.39
% from proposed	10.74%	6.44%	10.21%	7.27%	5.90%	4.88%	4.84%	6.61%	-2.73%	-4.75%	-8.41%

Min Consumption	-8.41%
Max Consumption	10.74%



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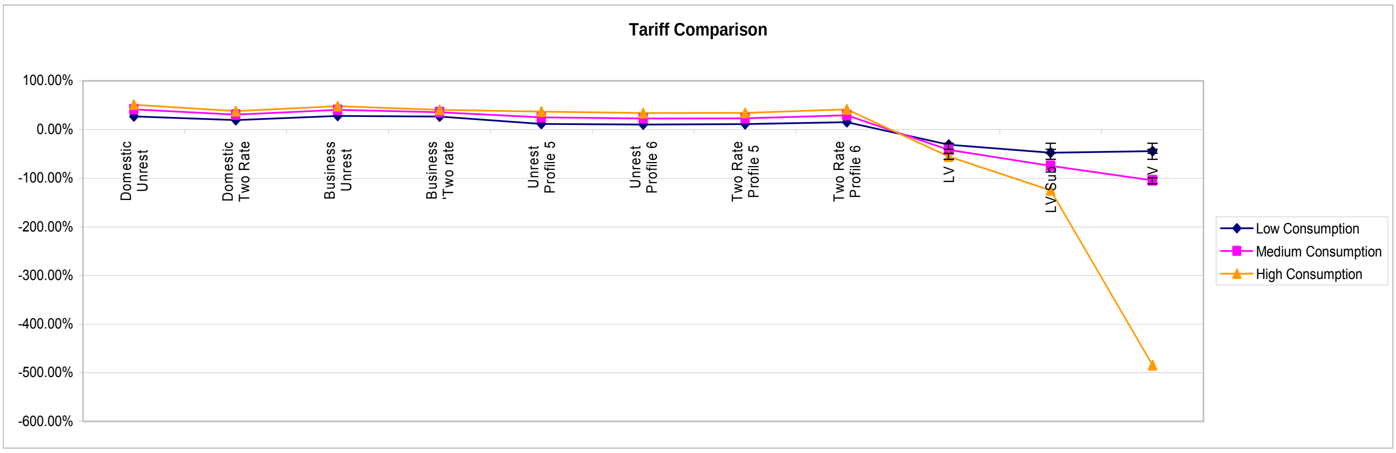
1.2. The marginal costs have then been calculated without using a demand scaler. The tariffs have then been recalculated to the same allowed revenue. The following chart shows the results from the proposed methodology (60% scaled) compared to the results without scaling.

Tariff Comparison

Load Flow Input Data:- Proposed methodology vs no demand scaling

	Domestic Unrest	Domestic Two Rate	Business Unrest	Business Two rate	Unrest Profile 5	Unrest Profile 6	Two Rate Profile 5	Two Rate Profile 6	LV HH	LV Sub HH	HV HH
Low Consumption											
£s/Annum - Total on Variant	51.10	52.25	90.93	114.27	1113.65	1214.85	1126.82	1268.81	1796.53	2342.34	6813.62
% from proposed	26.88%	19.57%	28.15%	26.62%	11.68%	10.32%	10.89%	14.90%	-31.03%	-47.76%	-44.71%
Medium Consumption											
£s/Annum - Total on Variant	89.30	92.18	168.96	227.31	1673.85	1823.43	1706.78	1958.32	3185.63	3661.90	8428.68
% from proposed	41.21%	30.41%	40.40%	35.33%	24.80%	22.60%	23.25%	29.18%	-41.87%	-74.61%	-104.36%
High Consumption											
£s/Annum - Total on Variant	184.82	192.02	364.03	509.91	3074.36	3344.88	3156.68	3682.11	5784.39	5369.56	5015.24
% from proposed	51.11%	37.78%	48.05%	40.21%	36.69%	33.75%	34.28%	41.47%	-55.64%	-124.86%	-484.21%

Min Consumption	-484.21%
Max Consumption	51.11%



APPENDIX 4 – 1KVA INCREMENT COMPARISON

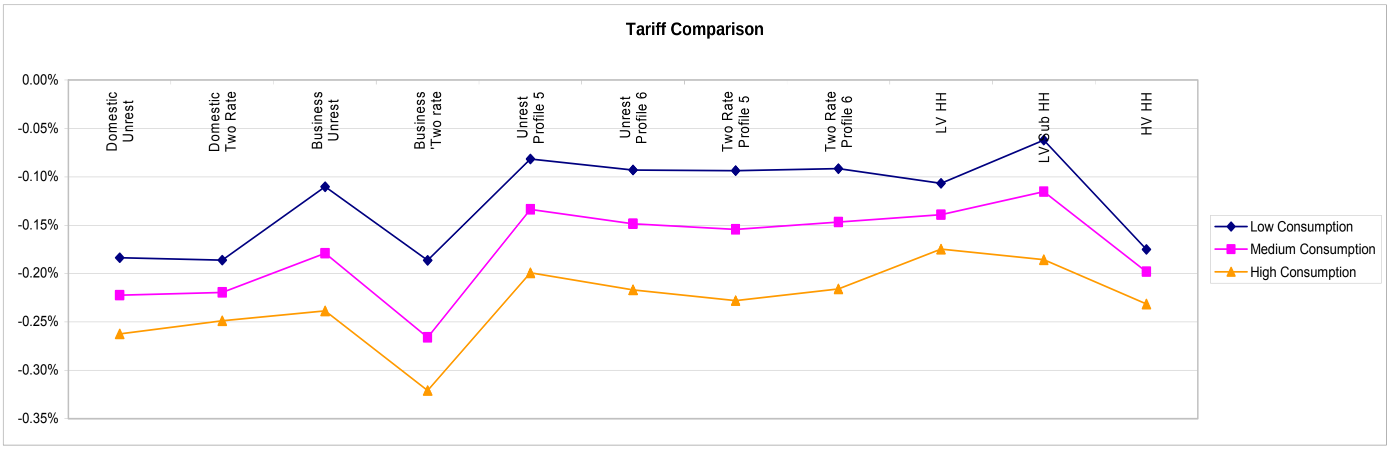
1.1. The marginal costs have been recalculated using an incremental value of 1kVA as opposed to the proposed 1MVA increment. The tariffs have then been recalculated to the same allowed revenue. The following chart shows the results from the proposed methodology compared to the 1kVA increment results.

Tariff Comparison

Load Flow Input Data:- Proposed methodology vs 1kVA

	Domestic Unrest	Domestic Two Rate	Business Unrest	Business 'Two rate	Unrest Profile 5	Unrest Profile 6	Two Rate Profile 5	Two Rate Profile 6	LV HH	LV Sub HH	HV HH
Low Consumption											
£s/Annum - Total on Variant	37.29	41.94	65.26	83.70	982.80	1088.45	1003.21	1078.74	2351.55	3458.85	9842.88
% from proposed	-0.18%	-0.19%	-0.11%	-0.19%	-0.08%	-0.09%	-0.09%	-0.09%	-0.11%	-0.06%	-0.18%
Medium Consumption											
£s/Annum - Total on Variant	52.39	64.01	100.53	146.61	1256.99	1409.21	1308.01	1384.93	4513.27	6386.61	17190.65
% from proposed	-0.22%	-0.22%	-0.18%	-0.27%	-0.13%	-0.15%	-0.15%	-0.15%	-0.14%	-0.12%	-0.20%
High Consumption											
£s/Annum - Total on Variant	90.13	119.18	188.68	303.88	1942.46	2211.11	2070.01	2150.41	8986.99	12051.85	29231.75
% from proposed	-0.26%	-0.25%	-0.24%	-0.32%	-0.20%	-0.22%	-0.23%	-0.22%	-0.17%	-0.19%	-0.23%

Min Consumption	-0.32%
Max Consumption	-0.06%



APPENDIX 5 – PROPOSED METHODOLOGY STATEMENT

Statement of the Use of System Charging Methodology for EDF Energy Network's Electricity Distribution System

South East Region

Effective From: [1 April 2009]

Published: [1 October 2008]

[This Statement has been approved by the
Gas and Electricity Markets Authority]

Contents

General Introduction

Who we are

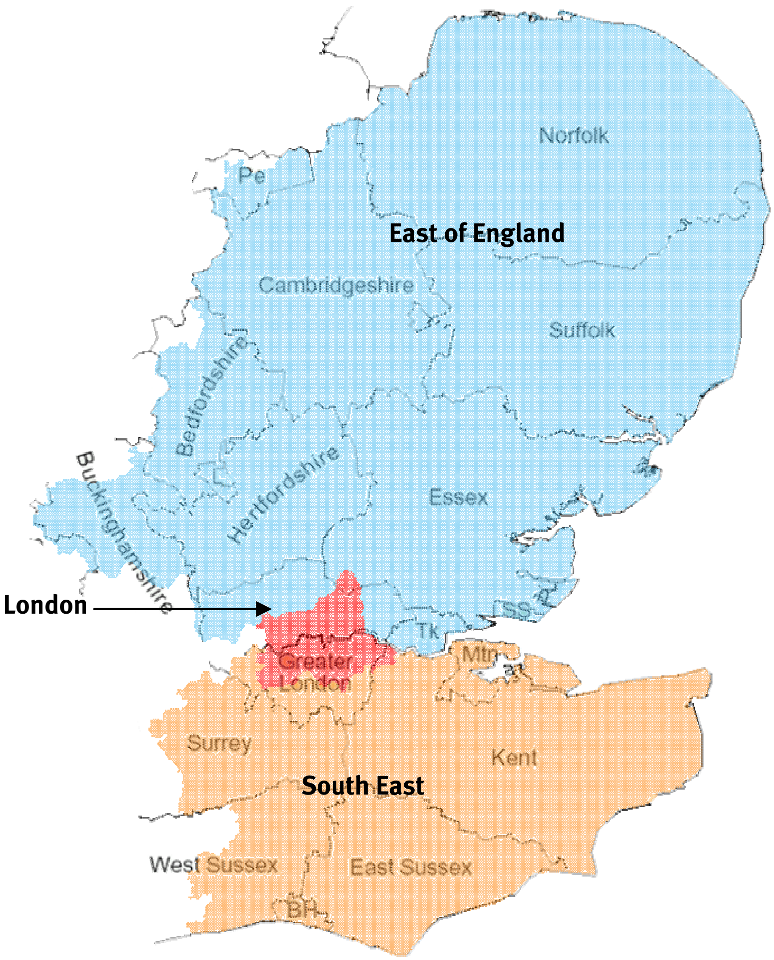
EDF Energy Networks Ltd ("EDF Energy Networks") is responsible for the three licensed electricity distribution businesses serving the whole of London, the South East and the East of England. Our Electricity Distribution Licences ("Licences") are issued under the Electricity Act 1989 as amended by the Utilities Act (2000), the Sustainable Energy Act (2003) and the Energy Act 2004 ("the Act").

This statement is produced by EDF Energy Networks, although certain responsibilities may be undertaken by associated companies or agents. Reference to EDF Energy Networks throughout this document is with regard to EDF Energy Networks (SPN) plc ONLY.

Important Note

The Use of System Charging Methodology described in this statement is only applicable to the South East Distribution Systems operated by EDF Energy Networks, indicated in tan on the map below.

The Use of System Charging Methodology applicable to London and East of England Distribution System areas operated by EDF Energy Networks (indicated by 'London and East of England ' on the map below) is described in a separate Statement[1]



[1] Statement of the Use of System Charging Methodology for EDF Energy Network's Electricity Distribution System | London and East of England Regions.

Licence Obligations

This statement describes the Use of System Charging Methodology under which authorised persons will be charged for use of EDF Energy Networks' electricity distribution system.

Notwithstanding our obligation to set Use of System charges in line with the special conditions of our Licences (as amended from time to time), EDF Energy Networks is obliged, under Licence Condition 4[2], paragraph 1(a), of its Licences, to prepare a statement approved by the Gas and Electricity Markets Authority ("the Authority") setting out the methodology upon which charges will be made for the provision of Use of System. We are also obliged to review our Use of System Charging Methodology statement annually.

Words and expressions used in this statement have (unless specifically defined herein) the definitions given to them in the Act or the Licences and shall be construed accordingly. Charges are current at the time of publication and will not be changed, except as provided for in the relevant agreement for use of system (see below) and subject to Condition 4 of the Licences.

Additional copies of this statement can be obtained from our web-site at www.edfenergy.com, or alternatively are available on request, at a cost of £10, via the contact details on page 5. To locate this (and other) Statements on the website; on the home page select "Networks" from the orange menu bar that runs across the screen below the logo; then select the "Go to Public Networks" link from the centre of the webpage; then select "Publicly Available Information" from the menu down the left hand side of the screen; then select "Click here for our complete statutory documents" in the yellow bar approximately a third of the way down the screen; finally select Connection, Use of System and Metering Services Documents from the list in the centre of the page.

Price Control

EDF Energy Networks is a licensed distribution business regulated by the Authority. The regulation is applied via the Licences and their price control mechanism. The price control period is five years and Ofgem prescribe the amount of revenue that EDF Energy Networks is allowed to recover from its customer base annually over the price control period. Use of system charges may vary year on year as EDF Energy Networks sets its charges to recover its allowed revenue.

Use of System

EDF Energy Networks will levy use of system charges for utilisation of its network for the supply of electricity to end users and/or the transportation of electricity across its network from entry points. EDF Energy Networks' Use of System tariffs are published in our Use of System Charging Statement[3] issued under Licence Condition 4A. These can be obtained from our web-site at www.edfenergy.com, or alternatively are available on request, at a cost of £10, via the contact details on page 5.

Connection and Use of System Boundary

EDF Energy Networks splits the recovery of costs between those associated with connection to the distribution network and those associated with on-going use of system for utilisation of the network. This boundary point is common for both demand and generation customers. This statement details the

[2] A copy of Licence Condition 4 is provided in Appendix 1.

[3] Charges for Use of the Electricity Distribution System | EDF Energy Networks (SPN)

charging methodology that is applied for the calculation of on-going use of system charges. In addition the Use of System Charging Statements detail the use of system charges that are applied.

The Basis and Methodology of Charges for Connection statement[4] issued under Licence Condition 4B details the Connection Charging Methodology that is used as the basis for calculation of connection charges. This statement also contains indicative charges and examples to aid understanding of Connection charges.

This statements can be obtained from our web-site at www.edfenergy.com, or alternatively are available on request, at a cost of £10, via the contact details on page 5.

Terms and conditions for connection of premises or other electrical systems to EDF Energy Networks' electricity distribution system are contained in our Basis and Methodology of Charges for Connection statement. Persons seeking use of the system with respect to a new supply must apply for connection in accordance with the terms and conditions described in that statement.

Where a person requires a connection to EDF Energy Networks' electricity distribution system pursuant to Section 16 of the Act, the provisions of this statement are without prejudice to the provisions of sections 16 to 21 & 23 of the Act (those sections which deal with the rights, powers and duties of EDF Energy Networks, as an electricity distributor) in respect of the distribution of electricity to owners or occupiers of premises.

The Contractual Framework

Persons entitled to use EDF Energy Networks' electricity distribution system are those who are authorised by Licence or by exemption under the Act to supply, distribute or generate electricity ("Authorised Electricity Operators"). In order to protect all users of the system, EDF Energy Networks will require evidence of authorisation before agreeing terms for use of the system.

NOTE: In the rest of this commentary, requirements applying to authorised users or Authorised Electricity Operators should be taken to mean Licensed Suppliers, Licensed Electricity Distributors or Licensed Generators only.

Persons seeking to use the system will be required, prior to using the system, to enter into an agreement with EDF Energy Networks setting out the obligations of both parties. The party seeking use of the system will be required to:

- pay all charges due in respect of use of the system as described in this statement and the accompanying schedules;
- be a party (where the user is a Licensed Supplier or a Licensed Distributor) to the Master Registration Agreement (MRA) for the provision of metering point administration services within EDF Energy Networks' authorised area;
- enter into the National Grid Electricity Transmission (NGET) Connection and Use of System Code and any necessary Bilateral Agreement, governing connections to and use of NGET's transmission system, unless EDF Energy Networks is informed by NGET that this is not required in any particular case;
- be a party to the Balancing and Settlements Code; and

[4] Published in a single document covering all three EDF Energy Networks regions:

- Statement of Basis and Methodology of Charges for Connection to the Electricity Distribution System | EDF Energy Networks (EPN) plc, EDF Energy Networks (LPN) plc, EDF Energy Networks (SPN) plc

- comply with the provisions of the Distribution Code.

If the applicant and EDF Energy Networks fail to agree contractual terms, or any variation of contractual terms proposed by EDF Energy Networks, either party may request settlement by Ofgem.

While the terms and conditions in the agreements will be consistent with those in this statement, the agreement will take precedence. Where an Authorised Electricity Operator, having entered into an agreement for use of EDF Energy Networks' electricity distribution system, ceases for whatever reason to be an Authorised Electricity Operator with respect to that use of the system, then the entitlement to use of the system will cease forthwith, but the operator will continue to be liable under the agreement unless and until the agreement is terminated. In order to avoid any liability in this regard, an Authorised Electricity Operator wishing to terminate his agreement or wishing to notify a change should give EDF Energy Networks no less than 28 days' notice. EDF Energy will normally respond within 28 days of a notification of change.

Contact Details

This statement has been prepared in order to discharge EDF Energy Networks' obligation under the Licences. If you have any questions about the contents of this statement please contact us at the address shown below. Also provided below are contact details for Ofgem, should prospective users wish to enquire separately on matters relating to this statement.

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Networks Use of System General Principles

Pursuant to the requirements of Condition 4 of the Electricity Distribution Licence, the following numbered paragraphs relate to the transport of electricity on EDF Energy Networks' system by Authorised Electricity Operators to exit points from the system, and to the transport of electricity on the system for supply to Authorised Electricity Operators and to/from generators including customers with on-site generation.

1. Where a supply of electricity is provided over electric lines or electrical plant comprising a part of EDF Energy Networks' electricity distribution system, a charge for use of the system will be levied either on the Supplier of the electricity or the Distributor. The relevant charges are described in our Use of System Charging Statements and are payable by reference to the characteristics of the supply, in accordance with the categories of supply described in the section headed 'Notes on Use of System Tariffs'.

2. The charges for each category of supply depend upon the criteria that determine eligibility for that category, including the voltage of connection to the system, the characteristics of the load, and installation of the appropriate use of system metering.

3. The charges for use of the system reflect:

   - the costs of providing, operating and maintaining the electricity distribution system to the standards prescribed by the Act other than those costs which are recovered through charges paid to EDF Energy Networks in respect of connection to the system, such that electricity can be transported efficiently through the system to exit points or from entry points; and
   - the costs to EDF Energy Networks of providing certain services and performing functions for Authorised Electricity Operators, on terms which EDF Energy Networks is under a duty to offer under its Electricity Distribution Licence, in order to support the operations of a fully competitive supply market in its authorised area. These services include: Metering Point Administration Services; Energisation, De-energisation and Re-energisation services; Revenue Protection Services; and Radio Teleswitch Services. EDF Energy Networks is either wholly or partly remunerated through use of system charges or through transaction charges for these services. The cost for provision of these services is detailed in our Use of System Charging Statements.

   All charges for use of the system include a reasonable return on the relevant assets, and the revenues arising from the charges are subject to regulation in accordance with the terms of the Licence.

4. Demand use of system charges to Suppliers and Licensed Embedded Electricity Distributors are evaluated as if from EDF Energy Networks' Grid Supply Points. These charges reflect real electrical flows on the system and the need to provide adequate capacity at all voltage levels to protect the security of the system. Paragraph 11 may also be relevant. Charges are applied to the electricity as measured at the exit or entry points, as indicated in paragraph 5 below.

5. The charges for use of the system may include some or all of the following elements:

   - a **Network Charge** to cover the costs which do not vary with the extent to which the supply is taken up. This consists of a daily charge per MPAN or monthly charge per site;
   - an **Availability Charge** per kVA to cover the system capacity at each voltage level which is attributed to the sites import capacity. Availability Charges shall be calculated using the declared Maximum Power Requirement (MPR) or, if it is higher, the highest demand (measured in kVA) made in any of the preceding 12 months commencing from the date of using EDF Energy Networks' distribution system;

- an **Export Charge** per kVA, for half-hourly metered customers or a pence-per-day for non-half hourly metered customers, covering the contribution to system reinforcement due to Distributed Generation and ongoing operation and maintenance. This charge will be applied to the Export MPAN and charged on that capacity over and above the import capacity level.
- a **Unit Charge** per kWh unit delivered to the exit point from the system, designed to reflect utilisation of the system at all relevant voltage levels. Units for metered supplies are based on actual meter readings or profiled consumption derived from actual meter readings and/or estimated annual advances. Units for unmetered supplies are based on the certified estimated annual consumption of an inventory of unmetered equipment or pseudo half hourly readings;
- an **Export Unit Charge** per kWh unit accepted onto the system at the 'exit' point. Units for metered supplies are based on actual meter readings or profiled consumption derived from actual meter readings and/or estimated annual advances;
- an **Excess Reactive Unit Charge** per kVArh unit delivered to the exit point from the system (see paragraph 15 below). The excess reactive power charge, applied in bands according to the level, provides a behavioural pricing signal to customers to improve their power factor; and
- **Transactional Charges** for certain services provided by EDF Energy Networks on an individual basis to Licensed Suppliers or Licensed Distributors. Details are given in our Licence Condition 4A Statement.

Which tariff element applies to each customer is determined by the supplier's choice of metering. Further details of tariff structures are provided in detail within the Charging Statement. Any modification to the elements of tariff structures would form part of a methodology change.

6. The network charge for use of system noted in paragraph 5 above may include, (dependant on tariff), an amount to reflect the cost of the service cable to the premises and its termination, a contribution to the cost of the local network except as recovered within the connection charge, the costs of the registration service in accordance with the Master Registration Agreement, the cost of use of system billing and an element of system capacity which is attributable to the supply.

7. The availability charge recovers an amount, other than that recovered through the connection charge, towards the costs of providing and maintaining the network. During the first five years, following the commencement of a new supply or the provision of increased capacity, the capacity upon which the charge is calculated will not be less than the original agreed capacity. The basis for the minimum capacity arrangement is to ensure that any upstream reinforcement expenditure or network extension is supported equally by a commitment to utilise that extra provision and to encourage efficient and accurate connection sizing.

8. Unit charges and export unit charges may be positive or negative. Positive charges are applied where after scaling the modelling suggest users will bring forward the need to reinforce the network. Negative charges are applied where after scaling the modelling suggest users will defer the need to reinforce the network. In addition unit charges recover the costs of elements such as operational rates and NGET GSP exit charges, where these costs have not been recovered elsewhere.

9. Details of metering provision are not included as part of this statement. The details of EDF Energy Networks' metering provision can be found in our Statement of Charges for the Use of EDF Energy Networks' Metering Services[5], issued under Licence Condition 36B. These can be obtained from our web-site at www.edfenergy.com, or alternatively are available on request, at a cost of £10, via the

[5] Charges for Legacy Basic Meter Asset Provision | EDF Energy Networks (SPN)

contact details on page 6. Where an Authorised Electricity Operator wishes to use meter providers other than EDF Energy, their agents must ensure that the data provided by the metering meets EDF Energy Networks' requirements for use of system billing purposes. Whether EDF Energy Networks is appointed to carry out this task or the supplier installs his own energy metering, EDF Energy Networks reserves the right to install use of system metering equipment and apply an additional charge for this equipment.

10. Charges for use of system will be payable in accordance with the billing period and payment terms agreed with the party using the system. EDF Energy Networks reserves the right to require appropriate security in respect of the charges estimated to arise, depending on the circumstances of the supply and on the basis of the agreed payment terms. Interest may be applied to late payments. Invoices for residential and non half hourly metered business supplies will generally be calculated according to the Supercustomer Methodology for Use of System Billing, a description of which is given in our Use of System Charging Statement.

11. Where a supply is to be provided wholly or partly over EDF Energy Networks' electricity distribution system to an exit point from that system, the Supplier or Distributor must demonstrate that at all times the quantity of electricity entering the system for the purpose of providing that supply equals the metered quantity delivered from that exit point plus the amount of electrical losses appropriate to the voltage at which the supply is delivered and to the source of the supply, as shown in the schedule of loss adjustment factors in our Use of System Charging Statement. Relevant metering information or being a party to the Balancing and Settlement Code will be considered to be adequate demonstration. Suppliers should apply the loss adjustment factors to calculate the amount of electricity that they must provide. The same loss adjustment factors are reflected automatically in the settlement system.

12. Where the supply is to be provided over EDF Energy Networks' electricity distribution system on either an intermittent or continuing basis to any premises with own generation, charges for use of the system will be levied with respect to the system capacity provided to meet the maximum power required as requested by the party seeking use of the system and the extent to which that supply is taken up.

13. Where EDF Energy, after evaluation of the characteristics of the requested use of the system, accepts that none of the categories of charges in the schedules of our Use of System Charging Statement are appropriate or where supplies are to be provided at Extra High Voltage (EHV), as defined in the section headed 'Statement of Charges for the Use of EDF Energy Networks' Distribution System' in that statement, EDF Energy Networks may offer special arrangements. Such charges will be calculated according to the Site Specific Charging within this methodology. In most cases, EDF Energy Networks will make its offer of terms within 28 days of receipt of the application, including the full and final information necessary for the preparation of the terms.

14. Where use of the system is sought at a standard of security different from that referred to in the Distribution Code, EDF Energy Networks may consider special arrangements with respect to that supply.

15. Where the power factor of the supply is less that 0.95, it will normally be possible for EDF Energy Networks to offer use of system, subject to paying appropriate charges. In such cases, specially assessed loss adjustment factors may apply at EDF Energy Networks' discretion.

16. For all classes of demand customer the charges for use of the system include a contribution to recovery of NGET's exit charges. These amounts are calculated to be appropriate to each class of customer. This is on the basis that the total contribution to NGET exit charges paid by any class of customers is in proportion to the demand of that class of customer.

17. On occasion applicants will wish to reserve capacity on the Distribution System ahead of their planned usage. Where such situations arise the applicant will be required to pay a reservation fee. The reservation fee will be payable in advance of the period to which it pertains as either a capitalised sum or an annual payment. Failure on the part of the Applicant to pay the reservation fee will release us from an obligation to reserve the capacity and it may be allocated to other parties.

Reservation fees will reflect the value of the assets reserved. In most circumstances this will be represented by a proportion of the availability charge, HV or LV as appropriate. Where the reservation takes place at EHV or there are special circumstances then project specific charges will be developed.

18. For the avoidance of doubt, charges to generators for use of EDF Energy Networks' distribution system will be made for use of the system in respect of electricity that the generator imports from and exports to the system. The generator will be charged for use of the system in respect of such imports or exports in accordance with the preceding paragraphs.

19. EDF Energy Networks makes compensation payments to customers for network outages under two schemes.

The majority of customers are compensated under the Guaranteed Standards[6] arrangements. Customers who are off supply for greater then defined periods of time are entitled to a payment. This scheme applies to all demand customers and to all generators not included in the scheme described below.

For customers with generators connected at more than 1,000 volts and commissioned after 1 April 2005 (and who will, therefore, pay Generator Use of System Charges as defined in this Statement) the following scheme will apply. This scheme is known as Distributed Generation Network Unavailability (DGNU) and payments will be calculated for each generator on the following basis:

$$Payment = A \times B \times (C - D)$$

Where:

A = the network unavailability price of £2 per MW per hour (in 2005/06 subject to RPI indexation in future years), or some other value agreed between the customer and EDF Energy Networks and recorded within the connection agreement.

B= incentivised generator capacity; the highest active electrical power that can be generated (or the relevant incremental change of this amount in cases of the expansion of existing generation plant) by the generator for the year, according to the connection and/or use of system agreement(s).

C = network interruption duration; the total duration of all occurrences (in minutes) on the distribution system each of which involves a physical break in the circuit between itself and the rest of the system or due to any other open circuit condition, which prevents the generator from exporting power. It excludes:

- 50 per cent of the total duration of cases where EDF Energy Networks takes pre-arranged outages of its equipment for which the statutory notification has been issued to the generator;

[6] Statutory Instrument 2005 No. 1019 The Electricity (Standards of Performance) Regulations 2005 as amended or replaced from time to time.

- the cases where the generator has specific exemption agreements with EDF Energy Networks in the connection and/or use of system agreement(s); and
- the cases which are part of exempted events in the quality of service incentive or the Guaranteed Standard Statutory Instrument (such exemptions include interruptions of less than three minutes duration and industrial action).

D = the baseline network interruption duration for the relevant year which either has a default value of zero or some other value agreed between the customer and EDF Energy Networks and recorded within the connection agreement and/or use of system agreement(s).

DGNU scheme payments will be calculated by EDF Energy Networks on an annual basis (1st April - 31st March) and payments made shortly after the end of each year. Payments may also be made on an interim basis during the year on each occasion that the payment due to a generator exceeds £250. This payment is automatic and does not need to be claimed by the generation Customer.

20. The introduction of Generation Use of System charges into a developing market creates the potential for volatility in prices. In order to provide some stability and predictability of generation charges it is proposed to minimise the upwards disturbance of generation charges by capping the change in nominal generation charges in any year up to March 2010 (other than by agreement with the individual generator). The cap will be plus ten percent per annum, except where the current charge is zero, in which case the cap will be plus £1.00 per export MPAN per annum.

Use of System Methodology

Rationale

Demand and Generation

The methodology for deriving Use of System charges functions by apportioning the target allowed revenue to typical groups of customers depending on their connection capability and use of the network. Essentially we calculate a theoretical cost using our models and then scale the result to meet the target allowed revenue.

This methodology applies an LRIC approach, using power flow modelling, to provide the basis for calculating the economic cost of using the EHV network (including EHV/HV transformation). In addition to this approach for the use of the EHV network, estimated marginal reinforcement costs are used for the deriving the remaining cost for those users who connect to the HV and LV network.

The LRIC approach on the EHV network allows generation and demand charges to be determined using the same basis. Our LRIC approach utilises AC power flow modelling which we believe provides an improved reflection of the costs of the network taking into account real and reactive power flows.

The methodology will, in principle, allow for demand or generation charges to be negative (i.e. a demand/generation user might be paid if their use of the network defers overall reinforcement expenditure).

The charges for users connected to the EHV network will be calculated solely using network costs modelled using the LRIC approach and charges for users connected to the HV & LV networks calculated using network costs from a combination of the LRIC approach and our existing DRM based approach. The nodal cost outputs from the EHV approach will be averaged and used as marginal cost inputs to the DRM approach when calculating the HV & LV tariffs.

Format of tariffs

Demand and generation

Charges are applied to customers through the application of tariffs. Tariffs are designed to send cost reflective price signals to users in order to encourage efficient use and development of the network. The basis for our tariff structures is to recover our costs in a manner appropriate to that cost. Costs which do not vary with how much electricity is used will be recovered through ‘fixed’ Network Charges and, for half hourly metered customers, Availability Charges. Costs which do vary as electricity is used will be recovered through Unit Charges.

Specific tariff structures are then formulated in relation to the metering installed at the point of connection. This is driven by the settlements data requirements and can result in restriction of the format of tariff that may be offered.

Those tariffs relating to connections without half hourly metering consist of the following components:

- Connection related in an MPAN charge – **Network Charge**;
- Consumption related within a Unit charge - the maximum number of unit rates being determined by the number of registers (time pattern regimes) on the metering system – **Unit Charge**.

Those tariffs relating to connections with half hourly metering consist of the following components:

- Connection related in an MPAN or site charge – **Network Charge**;
- Connection capacity related charge – **Availability Charge**;
- Consumption related within a Unit charge - according to times set by EDF Energy Networks – **Unit Charge**;
- Reactive power charge - applied in multiple blocks depending on the level of the power factor – **Excess reactive unit charge**.

These components are described on page 5.

Charges are calculated to recover costs on an annual basis and except for seasonal unit rates the same rate is used to average the charge over the year. Availability charges are set to recover an amount appropriate to the highest required annual capacity. In choosing to vary their agreed capacity, a customer's application for a decrease will only be accepted on an annual basis and generally to a level no lower than the preceding year's maximum demand. This option to reduce agreed connection capacity is not applicable to new or enhanced connections in the first three years.

Unit related charges are based on Active Power measured in watts (kW's or kWh's). Where sites have a poor power factor the kWh charge does not recover the extra costs of providing higher rated equipment needed to meet the larger Apparent Power, measured in volt-amperes (kVA's or kVAh's). Reactance (inductive or capacitive) in load causes poor power factors and the more this reactance increases compared to resistive load the further the current will lag or lead the voltage, further increasing the Apparent Power. To recover the extra costs associated with poor power factors a charge related to reactance or Reactive Power, measured in kVAr or kVArh, is applied. Reactive Power charges are applied when the level exceeds an efficiency boundary. This boundary is an appropriate balance point between the costs of an efficient network and the cost of corrective equipment. The Reactive Power consumption can be avoided with management of inductive or capacitive power flow through the use of corrective equipment.

The Reactive Power charge (p/kVArh) is based on the calculation of extra volt-ampere units required to deliver the Apparent Power. The calculation is conducted in Power Factor Bands using a midpoint power factor for each band. At this power factor the number of kVAh's exceeding the kWh's (extra units) is calculated against the average modelled pence per unit charge for the tariff group to derive an extra cost. This extra cost is then divided by the number of Excess Reactive Units at this power factor, to derive a reactive power charge (p/kVArh).

Reactive power charges are only applied to half hourly metered customers.

The Charging Model

General Structure

The charging model comprises three main processing elements. These are:

- Power-flow model utilising proprietary electricity network simulation
- EHV marginal cost – processing data relating to EHV power flow and reinforcement solution costs producing nodal £/kVA marginal values.
- Tariff Yardstick Calculations taking marginal costs and attributing usage characteristics to provide site specific charges and HV/LV tariffs

Data relating to the network assets, the use of our networks and the costs is input at various stages of the model. This data is provided from a number of sources largely falling into categories relating to:

- Network infrastructure – The collective assets used to distribute electricity over a given geographical area. This data reflects the data published in the Long Term Development Statement (LTDS).
- Network usage – Data relating to Customer connections and their consumptions; EHV connected customers, nodal load, GSP growth and HV/LV connected tariff groups.
- Capital and operational expenditure – Including costs of network reinforcement solutions and other costs to be attributed into charges.

Underpinning our modelling process is the use of five network time bands, these time bands are common throughout and are also used in our tariff modelling and to define the Half Hourly tariff charges.

Final scaling of charges to the allowed revenue involves aligning the revenue calculated from the yardstick charges to recover the allowed revenue for the network. A fixed adder is applied to the marginal costs to scale the modelled yardstick revenue to match the allowed revenue.

A simplified schematic of the charging model is provided in Figure 1 below.

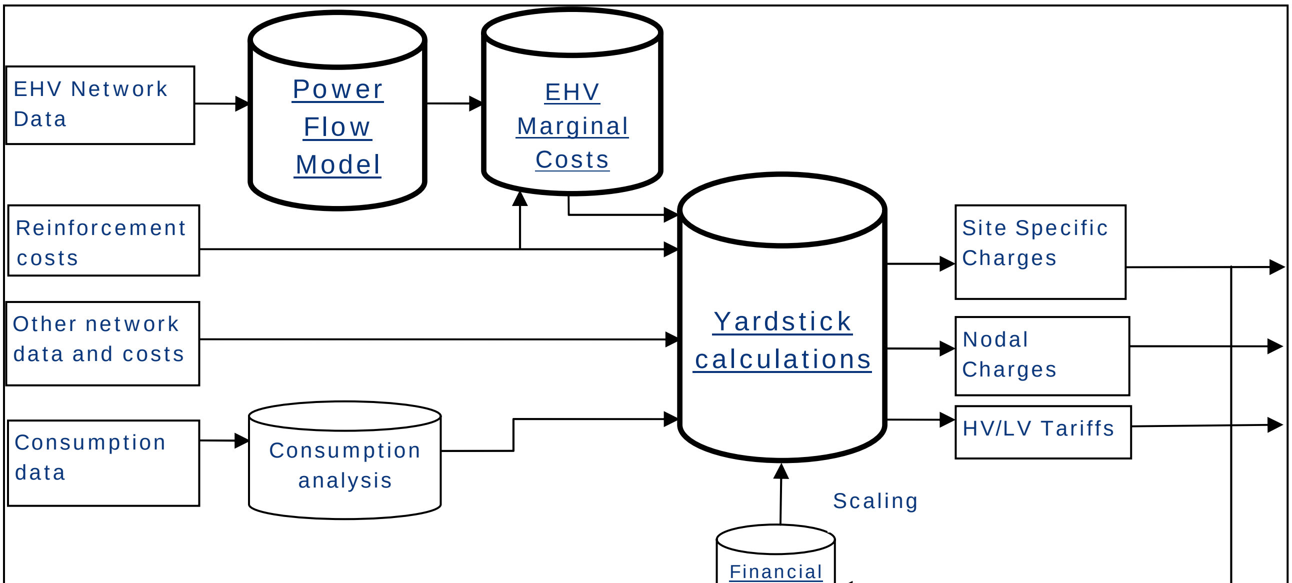


Figure 1

Model Inputs

The network is split for modelling purposes to derive costs for the Extra High Voltage (EHV) and cost for the High Voltage / Low Voltage (HV/LV) network.

Network data

The EHV power flow model is populated with network data which mirrors the data published in the Long Term Development Statement (LTDS) produced in accordance with distribution licence condition 25. It needs to be noted that the LTDS and power flow model are snapshots of the network produced at different points in time and may therefore differ slightly.

An EHV network contingency data file is established containing details of any events that take place during an outage. This could include load transfers and the switching in or out of additional circuits.

Network usage data

Cost modelling and half hourly tariff charges are conducted using time bands covering daily and seasonal demand times. There are five time bands that are used in the modelling for both half hourly, and non half hourly metered tariff charges. The five time bands that are used are:

1. Between midnight and 07:00 hours all year – Night
2. Between 16:00 and 20:00, Monday to Friday, November to February – Winter Peak
3. Between 07:00 and 16:00, Monday to Friday, November to February and between 07:00 and 20:00, Monday to Friday in March – Winter shoulder
4. Between 07:00 and 20:00 Monday to Friday, June to August – Summer Peak
5. All other times

These time bands have been identified as being representative of times to signal avoidance of network use through a higher than average charge or encourage network use through a lower than average charge for demand users. Similarly they are used to provide the reverse signal for generation users.

The EHV power flow model is populated with nodal demands for each time band with data extracted from EDF Energy Networks' SCADA[7] information database. The data is extracted for three maximum periods and three minimum periods for each of our 5 time bands. The dates and times that the data is extracted is determined from the three highest demands and the three lowest demands, separated by 10 complete days, for each of our 5 time bands using the annual GSP group take as the reference data. For each node the load data is extracted and then averaged to generate the value used at each node in the power flow model. The result of these extracts is to populate each node and each time band, where energy either enters or exits the EHV network, with a maximum (peak) power flow value used for the calculation of demand charges and a minimum power flow value used for the calculation of generation charges.

The growth rates that are used in the net present value calculations are derived from the forecast consumer requirements on the network. A zonal growth rate based on the allocation of a node to its connected grid supply point is calculated based on the forecast growth in demand published in the LTDS.

[7] SCADA is the acronym for Supervisory Control And Data Acquisition. The SCADA system gathers data from the monitored asset and transfers the data to a central data store.

Customer consumption data is collected and analysed individually for EHV connected customers and at tariff group level for all HV/LV connected customers using either actual half hourly data for half hourly metered sites or profiled half hourly data for non half hourly metered sites.

Customers are allocated to tariff groups according to the nature of metering and voltage of connection to the network.

Network loss adjustment to uplift customer demand requirements to account for energy losses when using upstream network assets are applied either through the power flow modelling or using loss factors derived form our published losses.

Capital and operational expenditure

The capital costs for reinforcement scenarios at each level of the electricity distribution system from 132kV to LV are calculated, using current modern equivalent asset costs, from EDF Energy Networks' asset management information. The reinforcement costs used in the marginal cost calculations at EHV will be a weighted representation of the solution costs that are used to reinforce the generic asset type expressed as the capital cost to reinforce the asset. While at the HV network, HV/LV transformation and LV network the reinforcement costs will be based on the cost of delivering new load including an appropriate mix of underground and overhead cables and other assets at each voltage level, this is to reflect the broad spectrum of network variations encountered. The cost at HV/LV level are derived from our asset management information and are expressed as a marginal £/kVA capital cost.

An annuitisation factor to convert capital cost to annual cost based on the regulated allowed rate of return is used over the assumed lifetime of the asset.

NGET grid supply point exit charge cost are established for the charge year based on NGET illustrative charges and our own forecast of additional cost which will materialise during the year.

Calculations and Processing

Power flow modelling

The power flow modelling is conducted using PSS™E software (a Siemens proprietary product), although any suitable power flow modelling software could have been utilised. We have automated use of this software using two custom built modules.

- The security module which conducts the security factor analysis and base case power flows.
- The sensitivity module which provides the sensitivity coefficients.

The output from the modules provides the base case power flow, sensitivity coefficients and the security factors for each asset on the network. All power flow output data is presented in the form of a comma separated file, which is then used to calculated the nodal £/kVA values prior to being loaded into the charging model.

The base power flow is calculated then the power flows are calculated for each contingency case. During the contingency process the highest power flow on each remaining branch is stored. At the end of the contingency process the final highest power flow in each branch is divided by the base case power in each branch to provide the security factor. It is this security factor which is then used to de-rate the branch's actual capacity to an approximate Engineering Recommendation P2/6[8] compliant capacity.

The contingency data file holds outage instructions for each branch and is processed sequentially during the contingency analysis. For each branch the statement will instruct the tripping of that branch and then the other actions which would be performed during that branch outage. These additional actions may include closing circuits or bus bars and transferring load to other nodes. These other actions are typical of how the network is managed on an operational basis.

The modules can be described as operating in steps following which the outputs are then used in the charging model. The steps of operation are described below:

Step 1 – Calculation of base case power flow and security factors for 1st analysis timeband

A – Base case power flow calculated for each branch on an intact network.

B – Highest power flow calculated for each branch during the process of 'removing' (under simulated ER P2/6 conditions) other branches in the otherwise intact network.

$$\text{Branch security factor} = \frac{\text{Highest power flow under N - 1 conditions}}{\text{Normal power flow}}$$

The branch security factor is used to determine the usable headroom capacity from the maximum capacity to allow for N-1.

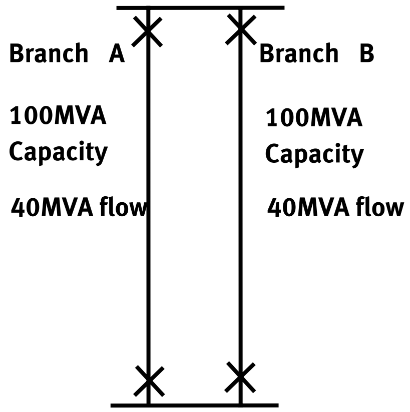
[8] Engineering Recommendation P2/6 (ER P2/6) is the current distribution network planning standard. The Distribution Network Operators (DNOs) have a licence obligation to plan and develop their systems in accordance with ER P2/6.

In a simple two circuit network the branch security would be as follows. The highest power flow in Branch A will be when Branch B is isolated.

Therefore highest power flow in Branch A = 80MVA. Normal power flow in Branch A = 40MVA.

Branch security factor = 80/40 = 2.

The usable head room capacity would then be calculated as follows. This calculation is conducted in the charging model.



$$\text{Usable headroom capacity} = \frac{\text{maximum capacity}}{\text{branch security factor}} - \text{current power flow}$$

Step 2 – Calculation of sensitivity coefficients for 1st analysis time band

Step 3 – to final step – Repeat steps 1 and 2 for remaining analysis time bands

The output from the sensitivity module provides a set of coefficients that enable the calculation of the effect to a power flow in a branch caused by an increment or decrement applied to a node. The resultant coefficient is used to calculate the new power flow by multiplying it with the increment or decrement and adding it to the original branch power flow. For a particular operating point of interest and the full intact network topology model the power flow will be calculated. The approach uses the standard output from the load flow, i.e. for each node i the following values: P_i, Q_i, V_i and θ_i (active power node injection, reactive power node injection, node voltage magnitude, and node voltage angle).

Due to the nature of whole network power flow modelling, branches which are normally electrically isolated from the node under study within the distribution system but which are connected through the transmission system will have sensitivity coefficients which indicate a power flow change. This movement is unlikely to be realised in the real network. One of the causes is the use of a slack node[9] in the power flow study, whereas in reality power flow variations would be balanced across a range of nodes.

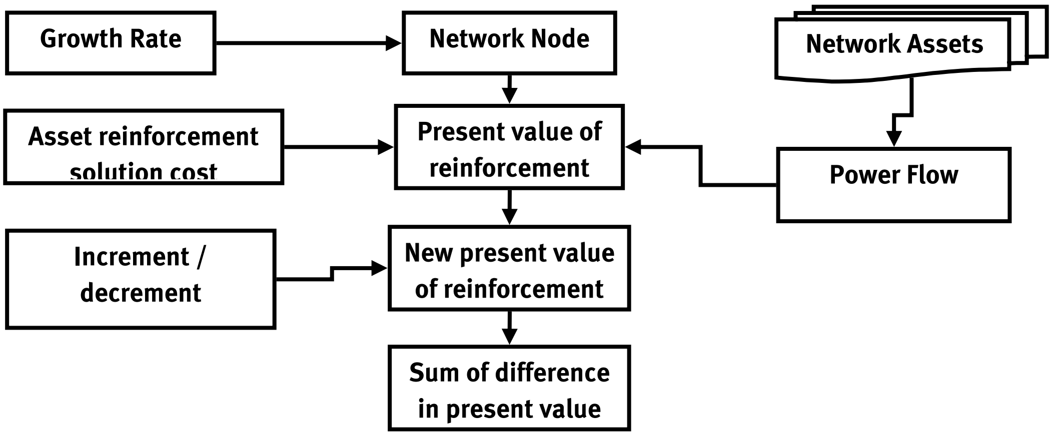
To reduce the amount of computed data and avoid the calculation of insignificant charges on branches which are to all practical purposes electrically isolated from the node under study we will filter sensitivities smaller than 0.005.

Marginal cost calculation

Costs are calculated for each node which have exit points to customer connections. These exit points can either be for EHV connected customers or at the boundary between the EHV network and the HV/LV network. The latter costs are used as input costs to the HV/LV tariffs.

[9] The slack node is a defined point in the network model which adjusts to balance the difference between demand and generation. In reality the balancing of demand and generation is a complex operation across many participants.

The charge calculated is based on a predicted future timescale of reinforcement requirement and how this future timescale will change following the application of a marginal increment or decrement to the node under study. The charge for an asset is based on the demand growth of the node under study and is the difference between the net present value of the future cost of reinforcement and the net present value of the



future cost of reinforcement after allowing for the application of the marginal increment or decrement in power flow has been placed. The charges for each asset for a node under study are then summed to achieve a nodal charge.

A scaling factor is applied to the power flows adjusting utilisation values. The same power flow scaling factor will be applied consistently to all power flows and all time bands. This is conducted to avoid the erroneous charge values which can be calculated at low growth rates where utilisation is high and where capacities are exceeded within a short term time frame.

The calculations for the marginal costs are conducted for each node. These nodal costs are then either used as the 'shared asset' component of an EHV site specific charge or, if the node is an HV/LV exit point, aggregated with other relevant 'tariff' nodes to calculate a weighted average cost to be taken forward into the tariff yardstick calculation.

The marginal cost for a node is the sum of the change in brought forward reinforcement costs at each branch which has been triggered by the change in power flow at the node and is represented by the following formula.

$$\text{Marginal cost at Node } n = \sum_{i=1}^{B} \Delta Ci$$

Where:

n = the node under study

B = number of branches in the network

ΔCi = Change in reinforcement costs of the asset in branch i due to marginal increment /decrement at the node

The change in reinforcement costs due to the application of the increment/decrement of demand is derived from the following formula.

$$\Delta Ci = \text{Net present Value(Inc)} - \text{Net Present Value(base)}$$

Where:

Net present Value (Inc) = the brought forward cost of reinforcement after the increment

$$\text{Net present value (Inc)} = \frac{\text{Cost of reinforcement solution}}{(1 + \text{Discount Rate})^{\text{Number of years until reinforcement (Inc)}}}$$

/decrement has been applied and derived from the following formula

and,

Net present Value (base) = the current brought forward cost of reinforcement for the base case

$$\text{Net present value (Base)} = \frac{\text{Cost of reinforcement solution}}{(1 + \text{Discount Rate})^{\text{Number of years until reinforcement (base)}}}$$

Both of the net present Value calculations use the same cost of reinforcement solution which is dependant on the generic asset type. The discount rate is also the same for both present Value calculations. The regulatory rate of return for the price control period will be used for the discount rate as this is a proxy for the DNOs cost of borrowing.

The number of years until reinforcement is the time it will take, assuming the forecast growth rates, to 'use up' any spare capacity in the asset and therefore when the asset should be reinforced. The number of years until reinforcement is calculated using the following formula.

$$\text{Number of years until reinforcement} = \frac{\log(\text{rated capacity}) - \log(\text{power flow})}{\log(1 + \text{growth of utilisation})}$$

Where:

Rated capacity = the ER P2/6 capacity. This is the network asset capacity de-rated by the security factor,

Growth of utilisation = the forecast growth rate of the load at the supporting GSP,

and power flow, for the base case power flow, calculated from the following formula

$$\text{power flow (MVA)} = \sqrt{P(MW)^2 + Q(MVAr)^2}$$

Where the values for P and Q are the branch outputs

To establish the 'new' number of years until reinforcement the power flow is adjusted to take account of the effect of the increment or decrement at the node where the charge is being calculated.

The new power flow taking the increment or decrement into account is calculated using the following formula.

$$\text{new power flow (MVA)} = \sqrt{(P(MW) + \Delta P * X_p)^2 + (Q(MVAr) + \Delta Q * X_q)^2}$$

Where ΔP = -1MW for demand increments and 1 MW for generation decrements

and ΔQ = -0.33MVAr for demand increments and 0 MVAr for generation decrements

and Xp and Xq are the sensitivity coefficients

ΔQ assumes a power factor of 0.95 for demand connection and unity for generation connections. These power factors are typical of those expected of new connections.

On completion of the calculations a matrix of charges are held for each node. These comprise the five time band charges used to compile charges to demand connections and the five time band charges used to compile charges to generation connections.

Nodal Cost Aggregation for tariffs

One set of nodal costs are used in the tariff yardstick process. This set of costs is presented as the weighted average of all the nodes where there is an entry to the HV/LV network. The weighting of the costs is conducted by multiplying the nodal cost by the nodal demand and then summating the result and dividing by the sum of nodal demands. This calculation is as shown in the following formula.

$$\text{Timeband cost for Tariff} = \frac{\sum_{i=1}^{Nt} Ci.Di}{\sum_{i-1}^{N} Di}$$

Where:

C_i= Nodal cost for time band at a HV/LV entry/exit point

D_i= Nodal demand for time band at a HV/LV entry/exit point

N_t = Number of nodes where there is an entry to the HV/LV network from the EHV network

On completion there are five demand costs, one for each time band and five generation costs, one for each time band. These costs feed in to the tariff yardstick model for application in to the tariff setting and revenue scaling process. These costs could be either positive or negative.

Nodal Costs for Site Specific EHV charges

The nodal cost used in the calculation of site specific EHV charges is from the nodal cost at the boundary between the shared network assets and the sole use EHV connection assets. The costs of the remaining sole use assets are calculated separately and depend on the connection charge contribution.

At each shared use connection node there will also be five demand costs, one for each time band and five generation costs, one for each time band. These costs will then feed into the charge calculation process for the site specific charge. These costs could be either positive or negative.

Tariff Yardstick Calculations

The marginal costs derived from the EHV power flow modelling and those derived from HV/LV asset management information are applied to the yardstick model. With regard to HV/LV tariffs the yardstick is supplied with 5 time band demand costs for the EHV network and five time band generation costs for the EHV network. There are separate HV/LV costs for the different layers of the HV/LV network namely; HV network, HV/LV transformation and LV network. These costs are allocated to the five demand time bands in the same proportion as that calculated for the EHV time bands. These costs are applied as negative costs (benefit) to the HV/LV generation time bands. With regard to site specific charges the yardstick for each EHV connection is supplied with the costs specific to the node of common (shared) connection. Any connection spur (sole use) assets are treated separately until the point of common connection changes.

Scaling adders are applied to the marginal costs which are initially set to zero prior to the final matching of forecast revenue to allowed revenue.

The marginal costs are annuitised at the regulatory rate of return over an average expected asset life of 40 years. Operation and maintenance costs are applied expressed as a percentage of the marginal cost. The percentage used is published in our connection charging statement.

The £/kVA charges are converted to £/kW using a power factor average of 0.95p.f. Additional reactive charges are applied where customer's power factor deviates from this average.

NGET costs are applied as a £/kW cost to the time band when system peak occurs as a function of total NGET cost (less any site specific NGET charges) divided by the system peak demand. This cost is also allocated to generation charges as a benefit in the equivalent generation time band.

The yardstick charges are calculated, based on the marginal costs, for each tariff group and EHV connected user. For each time band the charges calculated take into consideration the network coincidence of the tariff group's demand to the network demand. For EHV connections actual half hourly data specific to the site is used. The HV/LV level costs are adjusted for network losses for each tariff group to account for the higher demand requirement required to adjust for losses.

HV/LV tariff yardstick

The yardstick for HV/LV tariffs then apportions these marginal charges between fixed and variable costs.

The fixed charge (availability for half hourly metered) comprises of 100% of the costs at the point of connection and for LV connections 50% of the cost of the assets above, while HV connections 20% of the EHV marginal costs. The marginal costs for unmetered supplies tariff groups are attributed solely to variable costs.

The fixed charges for non half hourly metered connections are based on the average demand for the tariff group multiplied by the sum of the apportioned marginal cost and include a cost for operation and maintenance on the service connection. The fixed charges for non half hourly unmetered supplies include the cost of running the unmetered supplies office and include the cost of operation and maintenance on the service connections. The fixed charge for half hourly connections recovers the cost of operation and maintenance on the service connection assets.

The remaining costs are allocated to unit charges based on the tariff group's average unit consumption and the ratio of kW/kWhs for each time band. Additionally, for non half hourly connections the percentage use that the tariffs (market domain data) time band makes of the cost allocated to each of the 5 modelling time bands is allocated. For example the varieties of two rate 'off peak' time bands means that a small proportion of winter shoulder costs have to be allocated to the two rates 'off peak' unit rate. The half hourly tariff time bands match the modelled time bands and therefore the cost allocation is directly applied.

The HV/LV network marginal costs are based on average network provision. Where charges are calculated for half hourly metered sites the cost are allocated based on a smaller proportion of the network being used.

EHV charges yardstick

The fixed charges for EHV sites are based on the connection spur (sole use) costs. The default charge is based on the current connection charging policy. This includes for the operation and maintenance of the connection assets to be recovered through the use of system charge. Variations to this default are only made where there is evidence that different connection charges were made.

The availability and unit charges are based on a total charge which is calculated from the product of the demand values and the marginal costs, and include the allocation of NGET charges. A capacity charge equivalent to the product of the agreed capacity and the peak marginal cost is allocated on a £/kVA/month basis. The remaining charge is then allocated to the 5 time bands based on the time bands remaining marginal cost and their kW/kWh ratio.

Generator charge yardstick

The charges allocated to generators are applied using the same principles as those that have been used for demand tariff groups. Where HV/LV demand marginal costs are offset or deferred the charge will be seen as a credit. Appropriate coincidence factors and kW/kWh ratios are applied each generation tariff group.

Allowed Revenue

Forecasts of our expected allowed revenue and expected user consumptions and productions for the year that prices are set are made. The yardstick charges are then calculated against the expected user volumes to determine the revenue that would be recovered from the yardstick charges. The scaling adders are then adjusted on an iterative basis until the forecast charged revenue matches the allowed revenue. It is at this point that the prices are set.

Scaling to allowed revenue

The methodology calculates yardstick charges for the EHV network using an LRIC approach and yardstick charges for the HV and LV network using a combination of LRIC and our existing DRM based approach.

The alignment of the yardstick charges with allowed revenue will take part in three stages. The first stage would involve splitting the allowed revenue into that recovered from demand and generation customers. However, allowed revenue for Demand and Generation is currently separate in the distribution price control. Therefore, we do not propose to have any transfer of revenue between these two allowances.

Demand Charges

For demand customers the second stage is to split the allowed revenue between EHV network modelled yardsticks and HV & LV network modelled yardsticks. This is done in the same proportion as the MEA values of the EHV networks and the HV & LV networks.

The third stage involves aligning the yardstick charges with the allowed revenue in each relevant network. A fixed adder approach is used to scale the modelled revenue to match the allowed revenues for the different networks.

Generation Charges

For generation customers the second stage is to split the allowed revenue between EHV and HV & LV network users. This is done by splitting the allowed generation revenue in the same proportion as the effective metered generation demand on the network.

The third stage involves aligning the yardstick charges with the allowed revenue in each relevant network. A fixed adder approach is being proposed to scale the modelled revenue to match the allowed revenues for the different networks.

Use of System Charges – Further Information

Where our Use of System Charges are published

EDF Energy Networks' Use of System tariffs for general demand and generation sites are published in our Use of System Charging Statements. These can be obtained from our web-site at www.edfenergy.com, or alternatively are available on request, at a cost of £10, via the contact details on page 5. To locate these statements on the website; on the home page select "Networks" from the orange menu bar that runs across the screen below the logo; then select "Publicly Available Information" from the menu down the left hand side of the screen; then select "Click here for our complete statutory documents" in the yellow bar approximately a third of the way down the screen; finally select Connection, Use of System and Metering Services Documents from the list in the centre of the page.

Site-specific charge schedules are issued to the customer and current supplier only. Copies of the schedules are provided, on request, to Licensed Suppliers subject to any agreement with the customer. Schedules will only be released to other parties with the customer's approval.

Appendix 1. Licence Condition 4 – Use of System Charging Methodology

1. The licensee shall, by 1 April 2005:

   (a) determine and prepare a statement of a use of system charging methodology, approved by the Authority, that achieves the relevant objectives; and

   (b) comply with the use of system charging methodology at that date and as modified from time to time thereafter in accordance with the provisions of this condition.

2. The licensee shall, for the purpose of ensuring that the use of system charging methodology continues to achieve the relevant objectives:

   (a) review the use of system charging methodology at least once in every year; and

   (b) subject to paragraph 4, make such modifications (if any) of the use of system charging methodology as are necessary for the purpose of better achieving the relevant objectives.

3. For the purposes of this condition, the relevant objectives are:

   (a) that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence;

   (b) 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;

   (c) 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

   (d) that, so far as is consistent with sub-paragraphs (a), (b) and (c), the use of system charging methodology, as far as is reasonably practicable, properly takes account of developments in the licensee's distribution business.

4. Except with the consent of the Authority, before making a modification of the use of system charging methodology the licensee shall:

   (a) give the Authority a report which sets out:

      (i) the terms proposed for the modification;

      (ii) how the modification would better achieve the relevant objectives; and

      (iii) a timetable for implementing the modification and the date with effect from which the modification (if made) is to take effect, being not earlier than the date on which the period referred to in paragraph 6 will expire; and

   (b) where the Authority has directed that sub-paragraph (a) should not apply, comply with such other requirements (if any) as the Authority may specify in its direction.

5. Subject to paragraph 6, where the licensee has complied with the requirements of paragraph 4, it shall, before making the modification:

   (a) revise the statement (or the most recent revision thereof) issued under paragraph 1(a) of this condition so that the statement sets out the changed use of system charging methodology and specifies the date from which it is to have effect; and

   (b) give the Authority a copy of the revised statement.

6. The licensee shall make the modification to the use of system charging methodology unless, within 28 days of receiving the licensee's report under paragraph 4, the Authority, having particular regard to the relevant objectives, has either:

(a) directed the licensee not to make the modification; or

(b) notified the licensee that it intends to consult and then within three months of giving that notification has directed the licensee not to make the modification.

7. The licensee shall give or send a copy of any statement under paragraph 1(a) or report under paragraph 4 to any person who requests it.

8. The licensee may make a charge for any statement or report given or sent pursuant to paragraph 7 of an amount which does not exceed the amount specified in directions issued by the Authority for the purposes of this condition based on the Authority's estimate of the licensee's reasonable costs of providing the document.

9. Subject to paragraph 10, an approval by the Authority pursuant to paragraph 1(a) may be granted subject to such conditions as the Authority considers appropriate, having regard, in particular, to:

(a) the need for any further action to be undertaken by the licensee to ensure that the use of system charging methodology would facilitate the achievement of the relevant objectives; and

(b) the time by which such action must be completed.

10. An approval granted under paragraph 9 will only be effective if the Authority has informed the licensee of its intention to impose such conditions in a notice which:

(a) sets out the nature and contents of the conditions; and

(b) specifies the period (not being less than 28 days from the date of the notice) within which representations with respect to the conditions may be made, and has considered any representations or objections which have been duly made by the licensee and have not been withdrawn.

11. The provisions of this condition are wholly without prejudice to:

(a) the application of any charge restriction conditions (within the meaning given in paragraph 3 of special condition A (Definitions and Interpretation) (England and Wales) or paragraph 2 of special condition B (Definitions) (Scotland) of distribution licences as at 1 April 2004); or

(b) the application of any charging arrangements condition (within the meaning of standard condition BA1 (Charging Arrangements) of the distribution licence as modified from time to time).

12. The Authority may (following consultation with the licensee and, where appropriate, with any other authorised electricity operator likely to be materially affected thereby) issue directions relieving the licensee of its obligations under paragraph 1 to such extent as may be specified in the directions.

Appendix 2. Glossary

Authority The Gas and Electricity Markets Authority – the regulatory body for the gas and electricity industries established under the Utilities Act 2000.

Active Power - The product of voltage and the in-phase component of alternating current measured in units of watts, W, kW, MW, etc.

Apparent Power - The product of voltage and of alternating current measured in units of volt-amperes, VA, kVA, MVA etc. Apparent power is that which is actually utilised, as a function of volts multiplied by amps, rather than the metered active power.

Authorised Electricity Operator means Persons entitled to use EDF Energy Networks' electricity distribution system by Licence or by exemption from the Electricity Act 1989.

Balancing and Settlement Code (BSC) means the agreement containing the rules and procedures under the new electricity trading arrangements (NETA).

CT means current transformer.

Data Aggregator (DA) means an organisation that aggregates consumption data supplied by the Data Collector or Data Processor. The DA may be half hourly or non-half hourly.

Data Collector (DC) means an organisation carrying out the roles of Data Retrieval and Data Processing.

Data Processing (DP) means the processing, validation and (if necessary) estimation of meter reading data and the creation, processing and validation of data in respect of consumption at premises with an unmetered supply, together with delivery of such data to the Data Aggregator.

Data Retrieval (DR) means the retrieval and validation of meter reading data from electricity meters and the delivery of such data to the relevant person for the purpose of data processing.

De-energisation means the removal of supply for a Metering System such that the Metering System is considered to be temporarily "inactive" for the purposes of settlement. This definition applies irrespective of the method used to effect the de-energisation - e.g. removal of fuse at the connection point or other method.

Distribution Code means the Distribution Code of Licensed Distribution Network Operators of England and Wales prepared pursuant to standard condition 9 (Distribution Code) and approved by the Authority as revised from time to time with approval of the Authority.

Distribution Licence The Electricity Distribution Licence granted to EDF Energy Networks (SPN) plc under Section 6(1)(c) of the Act.

Distribution System The whole of our interconnected distribution equipment, including cables, overhead lines and substations, which we operate in accordance with our Distribution Licence.

DNO means Distribution Network Operator

Elexon The Balancing and Settlements Code Company

Energisation means the commencement of supply to a Metering System, such that the Metering System is considered to be "active" for the purposes of settlement. This definition applies irrespective of the actual method used - e.g. insertion of fuse at the connection point or other method.

Excess Reactive Units – for each power factor band, the number of reactive units (kVArh) delivered in excess of: the number of kVArh at the start of the power factor band divided by the kWh's, then multiplied by the kWh's.

Exit Point means the point of connection at which electricity may flow between EDF Energy Networks' electricity distribution system and a customer's installation.

Exit Point Type is a generic description of similar exit points used by EDF Energy.

Extra High Voltage means equal to or more than 22,000 volts.

Grid Supply Point means a metered connection between the National Grid Company's transmission system and EDF Energy Networks' distribution system at which electricity flows on to the distribution system.

GSP Group means Grid Supply Point Group; a distinct electrical system, consisting of all or part of a distribution system, that is supplied from one or more Grid Supply Points for which total supply into the GSP Group can be determined for each half hour.

High Voltage means more than 1,000 volts and less than 22,000 volts.

kVA means kilovolt-amperes.

kVArh means kilovolt-ampere reactive hour.

kW means kilowatt.

kWh means kilowatt hour (equivalent to one "unit" of electricity).

LLFC (Line Loss Factor Class) identifies the loss adjustment factors and Use of System prices for a metering point.

Loss Adjustment Factor means the factor by which supplies of electricity taken from a Grid Supply Point must exceed the take at the exit point from EDF Energy Networks' electricity distribution system, varying according to the voltage of connection, month, day and time of day.

Low Voltage Interconnection means an electrical connection by a Low Voltage electric line to EDF Energy Networks' distribution system.

Low Voltage means 1,000 volts or less.

Low Voltage Substation Supply means a Low Voltage supply to premises from an on-site ground mounted substation through an electric line, both of which are situated wholly within the boundary of those premises, including the site of the substation, where there is no Low Voltage Interconnection.

Maximum Power Requirement or *MPR* means the maximum power in kVA which for the time being the customer has required and EDF Energy Networks has accepted as the maximum rate of consumption that may be reasonably anticipated.

Metering Point means the point at which a supply of electricity to (export) or from (import) EDF Energy Networks' distribution system is measured, is deemed to be measured, or is intended to be measured. (For the purposes of this statement Grid Supply Points are not 'metering points').

MPAS (Meter Point Administration Service) is EDF Energy Networks' service for meter point registration, established pursuant to its Licence and the MRA.

MRA (Master Registration Agreement) means the national agreement prepared in accordance with condition 37 of the Licence.

MTC (Meter Timeswitch Code) means a code that uniquely identifies meter characteristics.

NGET means National Grid Electricity Transmission plc (formerly National Grid Company or NGC) .

Ofgem The Office of Gas and Electricity Markets.

Power Factor Bands – The grouping of power factor by impact on network. For example; Band 1, unity to 0.95; Band 2, 0.95 to 0.75; Band 3, 0.75 to … and so on.

Profile means a pattern of consumption of electricity, by half hour, across a year.

Reactive Power - The product of voltage and current and the sine of the phase angle between them measured in units of volt-amperes reactive, VAr, kVAr, MVAr etc.

Re-energisation means the resumption of supply to a Metering System following a period of de-energisation, such that the Metering System is considered to be "active" for the purposes of settlement. This definition applies irrespective of the actual method used - e.g. insertion of fuse at the connection point or other method.

Revenue Protection Service is the service provided by EDF Energy Networks for the investigation and follow up of cases of suspected meter faults or interference.

Settlement Class means the combination which defines the level at which non half hourly Data Aggregators must supply aggregated consumption values, that is for Profile, Line Loss Factor Class, Time Pattern Regime and Standard Settlement Configuration, by supplier within a GSP Group.

Settlement Day means the period from midnight to midnight to which consumption in a settlement run relates.

Settlement Run means a full run of the Settlement System Administrator Settlement system and the Initial Settlement and Reconciliation Settlement system for all GSP Groups within the settlement timescale.

SSC (Standard Settlement Configuration) means a standard metering configuration supported by SVAA relating to a specific combination of TPRs.

Standby Supply means the provision of electricity on a periodic or intermittent basis, to replace a primary source of supply which is temporarily unavailable.

Statement (Supercustomer) means the daily summary of unit and Network charges to be invoiced for Use of System through the Supercustomer process, for each settlement class, sent electronically to each supplier as appropriate.

Supercustomer means the method of billing suppliers for Use of System on an aggregated basis, grouping consumption and Network charges for all similar customers together.

Supplier means an organisation with a Supply Licence which can register itself as supplying electricity to any metering point.

SVAA (Supplier Volume Allocation Agency) means the agency which uses aggregated consumption data from the Data Aggregator to calculate supplier purchases by settlement class for each settlement day, and then pass this information to the relevant distributors and suppliers across the national data transfer network.

TPR (Time Pattern Regime) means the pattern of switching behaviour through time that one or more registers follow.

UoSA (Use of System Agreement) or *Agreement* means the contract between the supplier and EDF Energy Networks agreeing the terms and conditions under which the supplier may use EDF Energy Networks' distribution system to supply electricity to customers.

Appendix 3. Statement of Loss Adjustment Factor Methodology for EDF Energy Networks' Electricity Distribution Networks

1. General Information

1.1 This appendix describes the methodologies applied by EDF Energy Networks in the calculation of its loss adjustment factors (LAF's)[10] for authorised users of its distribution network.

1.2 EDF Energy Networks is providing this statement as an appendix to the Statement of the Use of System Charging Methodology. It details the methodology that is used for the calculation of its published loss adjustment factors and is made available in order to provide clarity and transparency for users of its distribution network. This statement does not form part of EDF Energy Networks' Statement of the Use of System Charging Methodology and is not subject to approval by the Authority.

1.3 EDF Energy Networks is obliged under Standard Condition 4A of its Distribution Licence to publish a statement of charges for the use of the distribution system that is in a form approved by the Authority. The statement is required to contain "a schedule of adjustment factors to be made for distribution losses". EDF Energy Networks' loss adjustment factors are made available to Elexon (and therefore all market participants) through the provision of the dataflow, D0265 for SVA loss adjustment factors and an Elexon prescribed data format for CVA loss adjustment factors.

1.4 Loss adjustment factors are determined through the application of two methodologies. The generic loss adjustment factors are calculated using the methodology developed in a joint project between EA Technology and the majority of distribution businesses. The site specific loss adjustment factors are calculated using a substitution method. These methodologies are described in detail in sections 2 and 3 below.

2. Generic Loss Adjustment Factors

2.1 Generic loss adjustment factors are calculated for the majority of SVA registered authorised users. The allocation model developed by EA Technology is utilised to calculate the generic loss adjustment factors. The generic loss adjustment factors are reviewed annually but only changed periodically to reflect a confirmed trend.

2.2 In principle the model takes into account the units entering EDF Energy Networks' distribution system from Grid Supply Points (GSPs), distribution system connection points and distributed generators, etc known as the system entry volume and the units leaving the system, known as units distributed. The total system losses are then given by the following expression.

Total system losses = system entry volume - units distributed

[10] Loss Adjustment Factors (LAF's) are sometimes referred to as Line Loss Factors (LLF's) and vice versa.

2.3 The total system losses are, therefore, fixed by the recorded metered data and the model seeks to allocate these losses across the whole network equitably using estimates of the likely loss at each voltage level.

2.4 The voltage levels at EHV, HV and LV and the transformation levels of EHV/EHV, EHV/HV and HV/LV are represented within the model. The model is populated with a set of standing data. For example, the fixed loss constant and the variable loss constant for each voltage and transformation level are contained within the standing data. These loss constants are derived from a network model, based on a network equivalent representation of the EDF Energy Networks distribution system. The fixed loss constant reflects primarily the iron losses in transformers and dielectric losses in cables. The variable loss constant reflects the losses in plant that vary with the magnitude of the current such as ohmic losses in conductors and transformer windings.

2.5 The model is also populated with the estimated metered volumes of energy imported or exported per annum for the year in question at each of the various voltage level, including the energy entering at the connection points with National Grid Electricity Transmission (NGET), other distributors and the contribution from distributed generation within EDF Energy Networks' distribution network. The populated metered data is transformed into half-hourly data using the settlement profiles (Profile Classes 1 to 8), user defined profiles and profiles for generation based on recent historical data.

2.6 A 'Top-Down' approach is used for estimating network losses starting from the bus-bar at GSPs. The energy delivered from the higher voltage level is used to deduce the losses on the assets and thus the energy passed through to the lower voltage level.

2.7 The model calculates the power passed through the network into the next voltage level below using the following empirical equation:

$$P_{out} = P_{in} - v.P_{in}^2 - f - L$$

where P_{in} = Power into voltage level from higher voltage level,
P_{out} = Power out of voltage level into lower voltage level,
f = Fixed loss constant for voltage level,
v = Variable loss constant for voltage level,
L = Half-hourly metered demand at voltage level.

This is illustrated by the following example:

Power input at 132kV for a particular half hour	2,000MW
Fixed losses on the 132kV network	0.5MW
Variable losses on the 132kV network for 2,000MW	3.5MW
LAF_{132kV} equals 2,000/(2,000 – 3.5– 0.5)	
LAF_{132kV} calculated as equal to	1.0020
If net sales from the 132kV network	200MW
Then power flowing into the 132/33kV transformation level	1,796MW
Fixed losses at the 132/33kV transformation level	8MW
Variable losses at the 132/33kV transformation level	2MW
$LAF_{132/33kV}$ equals LAF_{132kV} x 1,796/(1,796 – 8 – 2)	
$LAF_{132/33kV}$ calculated as equal to	1.0076

2.8 This is repeated through the voltage and transformation levels until the LV network is reached. This produces the first estimate of the LV network non half-hourly metered load in every half-hour. As we have used the settlement profiles, these values will differ from the forecast annual volume of the non half-hourly metered load. The program, therefore, undertakes a series of iterative cycles to match the two values.

2.9 The model adjusts the variable losses by amending the variable loss constants. Greater weight is assigned to the 11kV network, 11kV/LV transition and LV network as the greatest losses are generated at these networks and there is greatest uncertainty in estimating the loss constants.

2.10 This results in the losses for the whole period and the losses for each half-hour for each voltage and transformation level being calculated and therefore the half-hourly loss adjustment factors are calculated.

2.11 To calculate the loss adjustment factor for a particular tariff class and tariff period, the half-hourly loss adjustment factors are weighted by half-hourly demand of that tariff class and then averaged over all half-hours in that period.

2.12 Note that the overall loss is not derived from the model but based upon an extrapolation from the historic recorded losses.

3. Site Specific Loss Adjustment Factors

3.1 Site specific loss adjustment factors are calculated when necessary for EHV users. These loss adjustment factors are reviewed annually and re-calculated following a material change to network data (for example a change to a customer's maximum capacity, for the addition of a new customer etc.)

3.2 The site specific loss adjustment factor comprises a fixed loss element and a variable loss element. The variable loss element of the loss adjustment factor is calculated using the substitution method, whilst the fixed loss element is calculated by a proportionate approach.

3.3 The fixed loss element is the energy required to energise the effective network between the user and the NGET interface point without any demand or generation connected. Typical loss values per km are used for the network circuits, while the nameplate data on "iron" losses are used for the transformers. Where an asset is shared between several users, the fixed losses are attributed to individual users based on the user's maximum capacity expressed as a percentage of the aggregate maximum capacities.

3.4 The fixed loss element of all the assets supplying the user are then summated to give the total fixed loss element, in kilowatts, for the considered user. This figure is then multiplied by the number of hours in a year to give the losses allocated to the user per annum.

3.5 The variable loss element is calculated using a network model constructed for each user representing all relevant parts of the distribution network between the user and assigned NGET interface point. The network model assumes a normal operating configuration and is populated with system loads that are 60% of the maximum demand (i.e. average system demand). An alternating current (AC) load flow program is utilised to calculate the variable loss element of the network model.

3.6 The AC load flow program is run against the network model without the user connected to calculate the base variable loss element. Then the user is added with its ASC and the AC load flow program is run again to calculate the new variable loss element. The difference in the variable loss element of the two results is attributed to the user. This procedure is repeated for each user in turn.

3.7 A user's calculated variable loss element is then multiplied by the number of hours in the year and by the user's loss load factor to produce the losses figure, per annum. A loss load factor is employed to produce an annual variable loss element, as the user will not continuously operate at its ASC and would therefore not be contributing to losses on a continuous basis.

3.8 The user's loss load factor is calculated from the formula:

$$\text{loss load factor} = A.LF + (1\text{-}A).LF^2$$

where LF = load factor and A normally takes the value 0.2, based on empirical data. The user's load factor is calculated from its actual or assumed half hourly metered data or assumed profiles.

3.9 The user's calculated fixed and variable loss elements are added together. The loss adjustment factor attributable to a site specific user is calculated from the formula:

$$\text{Loss Adjustment Factor} = 1 + (\text{Total losses} / \text{Units Distributed})$$

where Units Distributed are the user's historic or estimated import/export annual metered values and are positive for demands and negative for generation.

4. Contact Details

4.1 This statement has been prepared to provide clarity and transparency for users of EDF Energy Networks' distribution network. If you have any questions about the contents of this statement, please contact us at the address shown below.

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