MODIFICATION PROPOSAL ENW/2009/001.1

Electricity North West Limited

Proposal to amend the Distribution Reinforcement Model
to deliver Licensed Distribution Network Operator tariffs and
HV and LV Distributed Generation tariffs

Date of Issue: 16th July 2008

FOR APPROVAL BY THE GAS AND ELECTRICITY MARKETS AUTHORITY

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1. Description of the modification

Electricity North West (ENW), under its Structure of Charges programme, published a consultation paper on a Charging Methodology for the Longer Term in March 2007. The consultation paper outlined a forward looking, incremental costs methodology that utilised the actual network at Extra High Voltages (EHV) and representative models (in essence the Distribution Reinforcement Model (DRM)) at High Voltage (HV) and Low Voltage (LV). This modification combines our proposed developments to the DRM in terms of cost allocation and revenue reconciliation.

In August 2007 United Utilities (the predecessor of ENW) submitted a modification proposal to introduce Asset Adoption Payments. After consulting on the issue the Authority issued a veto decision in October 2007. In November 2007 United Utilities informed Ofgem and the industry of its intention to submit a DRM modification proposal that sought to modify the DRM methodology and introduce new Licensed Distribution Network Operator (LDNO) tariffs, new HV and LV Distributed Generation (DG) tariffs and Asset Adoption Payments. Throughout the informal discussions on our proposal statement Ofgem has urged ENW to submit a number of modification proposals to simplify the passage of proposed changes through the modifications process. ENW has carefully considered this and has chosen to develop a stand alone Asset Adoption Payments modification proposal which will follow this submission. Therefore this modification statement contains proposals for re-drawing the connection boundary within the DRM to take account of the average costs recovered in connection charges.

This modification proposal seeks the introduction of:

Licensed Distribution Network Operator (LDNO) tariffs – ENW is proposing to create and introduce new LDNO domestic[1] only tariffs. ENW proposes to use the DRM to model the costs of the distribution network to the point of connection where an LDNO connects to our distribution network. This will provide tariffs that exclude the typical costs avoided by us in our network provision to an LDNO.

HV and LV Distributed Generation (DG) tariffs – ENW is proposing to create and introduce new HV and LV DG tariffs. ENW proposes to use the DRM to model the costs of the distribution network, both incurred and avoided, by DG connected to our distribution network.

The proposed changes will be implemented in ENW's Licence Condition Statements, 4 and 4A.

2. Reasons for the change with an explanation of how the proposed change better meets the relevant objectives

As part of the Structure of Charges project the DRM has been redeveloped for the introduction of a charging methodology for the longer term arrangements. The revised DRM will form the foundation for charge setting in the future and has been amended structurally for the acceptance of EHV nodal/zonal costs from ENW's proposed Expansion Planning and Pricing software. In re-structuring the DRM a review of the costs, cost allocation and revenue reconciliation has been undertaken and it is proposed to amend the DRM methodology in these areas.

[1] ENW will treat all LDNO networks which provide connections to customers who would have had a non-maximum demand tariff had they connected to the ENW network as domestic for this purpose.

These changes, detailed below in section 3, are being proposed to achieve greater cost reflectivity across all tariffs. For example, the proposed adjustment of the network level yardsticks to represent costs typically recovered in connection charges better reflects the boundary between connection and use of system charges; the proposed linkage of the operation and maintenance costs from the Regulatory Reporting Pack (RRP) to the DRM better reflects actual cost apportionment; the proposed change in the percentage apportionment for availability charges better reflects the local assets included within use of system charges; and the explicit inclusion of licence fee costs and the separation of Business Rates into its constituent elements means there is greater transparency as to the cost allocation. The current multiplier revenue reconciliation methodology distorts the cost message. In contrast the proposed fixed adder revenue reconciliation methodology applies a fixed adder, expressed in £/kW, at the GSP network level which doesn't interfere with the cost message at the lower voltage levels. These change better meets relevant objective 3(c) of Standard Licence Condition 4 which requires the charging methodology to reflect the costs incurred. As a consequence the change will also better meets objective 3(b) of Standard Licence Condition 4 which requires that the charging methodology does not restrict, distort or prevent competition in the distribution of electricity.

ENW proposes to introduce new LDNO tariffs for embedded networks, servicing domestic customers only. This change better meets relevant objective 3(c) of Standard Licence Condition 4 which requires the charging methodology to reflect the costs incurred; it also better meets objective 3(b) of Standard Licence Condition 4 which requires that the charging methodology does not restrict, distort or prevent competition in the distribution of electricity; and this change also better meets relevant objective 3(d) of Standard Licence Condition 4 which requires the charging methodology to take account of developments in the licensees distribution business, as the number of LDNO networks is increasing but were not significant when the methodology was first introduced.

ENW proposes to introduce new HV and LV DG tariffs to ensure that the charges levied for Use of System are cost reflective, transparent and facilitate competition in the generation of electricity by encouraging Distributed Generation to locate on networks where they can provide maximum benefit. This change better meets relevant objective 3(c) of Standard Licence Condition 4 which requires the charging methodology to reflect the costs incurred; it also better meets objective 3(b) of Standard Licence Condition 4 which requires that the charging methodology should facilitate competition in the generation of electricity; and this change also better meets relevant objective 3(d) of Standard Licence Condition 4 which requires the charging methodology to take account of developments in the licensees distribution business, as the number of distributed generators is increasing compared to when the methodology was first introduced. The changes also, in our opinion, satisfy the requirements of the Competition Act 1998 due to the cost reflective nature of the charging.

3. Proposed Methodology Changes

3.1. Introduction

The re-structuring of the DRM enables greater transparency of the allocation of costs. This has facilitated a review of the costs and cost allocation and revenue reconciliation methodologies. The sections 3.2 and 3.3 below describe these changes to the DRM methodology. The changes relating to LDNOs and DG are described in section 3.4 and 3.5 respectively below.

3.2. Costs and Cost Allocation

During the tariff formulation process, the DRM produces a matrix of network level yardsticks, shown in £/kW/year, which reflects the marginal costs of providing network assets at each voltage and transformation level to support load connected at each of the network levels in turn. There are seven defined network levels in the model as used by ENW:

- 132kV circuits
- 123kV/33kV transformation
- 33kV circuits
- 33kV/HV transformation
- HV circuits
- HV/LV transformation
- LV circuits

The network level yardsticks values, when uplifted for Operation and Maintenance (O&M) costs, form the base costs from which use of system tariffs are developed. It is proposed to derive the O&M percentage applied within the model from the costs identified in the Revenue Reporting Pack (RRP). This approach enables an auditable check between RRP and the O&M costs applied within the DRM.

It is proposed that each network level yardstick is reduced by an amount which represents the costs typically recovered in connection charges. The reduction in each network level yardstick is determined for each service model/connection type and is calculated from a survey of connections projects. This better defines the connection boundary introduced in 2005 and the removal of tariff support payments (see note later in Appendix A on the assumptions on the connection boundary). As a consequence where tariffs include an availability charge component then this will include 100% of the next voltage level, an increase from 20%. This is because costs up to the voltage level above are included in connection charges and reflect the capacity requested and the methodology now takes account of costs typically recovered through connection charges.

NGET Connection charges and Business Rates are currently allocated on a p/kWh basis, with no distinction made between the Network and Metering elements of Business Rates. NGET Connection charges and Business Rates are divided by the annual kWh figure and added to the unit rates derived from network asset and operation and maintenance costs. The derived p/kWh element from the Business Rates is included in the revenue reconciliation process whereas the derived p/kWh element from NGET Connection Charges is not.

It is proposed to separate Business Rates into Network Business Rates and Metering Business Rates. NGET Connection charges and Network Business Rates are grouped at the 132kV level and converted into a £/kW/year by dividing by actual system maximum demand. These costs are attributed to the tariffs through each tariff's maximum demand in relation to the system maximum demand, expressed in £/kW/year. This approach recognises that in the longer term both costs are marginal and vary with system maximum demand. The inconsistent treatment within the revenue reconciliation process will be removed.

The costs of holding a Distribution Licence are not currently identified and allocated and so these unallocated costs are subject to the revenue reconciliation process. It is proposed to identify Metering Business Rates and the Licence Fees costs and combine with the Customer Service, Billing and Administration costs for allocation on a £/customer/year basis.

In addition to the network level models, the DRM also includes a series of service models that define the minimum cost connection for each standard customer group. It is proposed to create four new models, two new service models for LDNO connections and two new service models for DG connections. The new group of service models will be:

- *Low voltage single phase demand connection:*
  1. Domestic and small commercial supplies;
  2. Unmetered supply.
- *Low voltage three phase demand connection, less than 60kVA:*
  3. Small commercial supply;
- *Low voltage three phase demand connection, greater than 60kVA:*
  4. Medium sized commercial supply (from network);
  5. Medium sized commercial supply (from substation);
- *Low voltage three phase demand connection:*
  6. LDNO supply.
- *High voltage three phase demand connection:*
  7. Large commercial supply (from network);
  8. Large commercial supply (from substation);
  9. LDNO supply.
- *Generation connection:*
  10. Low voltage three phase generation connection
  11. High voltage three phase generation connection

For example the minimum cost connection for an LV MD customer requiring greater than 60kVA fed from LV network is a small section of LV mains cable terminated onto a fused metering panel (see Appendix B for a diagram). The service model costs are utilised to determine the future asset replacement cost of the minimum cost connection and the operation and maintenance costs for each customer group.

3.3. Revenue Reconciliation

Revenue reconciliation is the process of matching the projected income to be collected from the unscaled draft tariffs to the total estimated allowed revenue. Where there is a mismatch we currently apply a multiplier to unit rates only. This means that revenue reconciliation is undertaken after the development of tariff structures and that the other tariff components (and hence some costs) form no part of the revenue reconciliation process. It is proposed to apply revenue reconciliation on the cost matrix before development of tariff structures and to introduce two revenue reconciliation stages within the charge setting process to

first match demand charges to Allowed Demand Revenue and second match generation charges to Distributed Generation Allowed Revenue:

1. The first stage is to identify the Allowed Demand Revenue (including the Incentives Revenue[2] associated with demand charges) that is to be recovered from demand charges and apply a fixed adder revenue reconciliation approach. This approach adds/subtracts a fixed adder, expressed as £/kW, to the costs to achieve the target revenue. This approach aims to minimise any distortion to the marginal cost message derived through the cost attribution process. In practice a total cost matrix identifies all the costs by tariff per network model level (including a service model level and a GSP level for NGET, Network Business Rates and Fixed Adder costs) and other cost level (e.g. Customer Service, Billing & Administration) expressed in £s per annum with the sum of the matrix being the estimated income to be collected from the tariffs. The amount to be reconciled from demand tariffs is determined and is attributed to each tariff at the GSP level in proportion to the tariff's maximum demand to the network maximum demand.
2. The second stage is to identify the value of the Distributed Generation Allowed Revenue[3] and apply a fixed adder revenue reconciliation approach. This approach adds/subtracts a fixed adder, expressed as £/kW, to the costs to achieve the target revenue, again to minimise any distortion to the marginal cost message. In practice the total costs matrix is used as described above to identify the costs and benefits attributed to the generation tariffs. The reconciliation is undertaken in the same manner as described above.

3.4. Introduction of LDNO Tariffs

Existing Arrangements

Over the past three years ENW has seen the introduction, construction and connection of embedded networks, owned by other Licensed Distributors, to its distribution network. The embedded networks have predominantly been connected at HV and LV with no mixed developments i.e. either all end customers are domestic or all commercial in nature.

In January 2007 ENW drafted a Policy Statement describing how it would manage the relationship with LDNOs connecting to its distribution network. The statement explained that ENW would apply the appropriate commercial tariff based on the voltage of connection. For example a small housing development taking a supply from our low voltage distribution network would be charged a LV MD NHH or HH commercial tariff. As at March 2008 ENW has forty two agreements in place for the same number of LDNO embedded networks. The first network was connected in April 2005, and there are thirty four network connected at LV, nine connected at HV and one network connected at EHV. Of the forty two networks only three networks supply commercial customers with the remainder supplying all domestic premises. As all these sites were fitted with half hourly metering when energised therefore ENW and the LDNOs have a good record of the consumption patterns of the embedded networks.

In our bilateral meetings LDNOs have expressed reservations over the cost reflectiveness of the commercial tariffs as boundary tariffs to LDNO networks

[2] Includes Losses Incentive, Quality of Supply Incentive and Innovation Funding Incentive.
[3] Distributed Generation Incentive.

supplying domestic premises. There appear to be three areas of concern; the first area of concern is the application of commercial load and coincidence factors; the second is the calculation of avoided costs, namely the lack of recognition that the LDNO provides an element of the distribution network and that the LDNO does not utilise some of the services provided for and charged by ENW in its use of system tariffs; the third is that the levying of a capacity charge is inconsistent with the structure of charges for domestic customers. The LDNOs have argued that these issues detract from the cost reflectiveness of the boundary tariff and impact the margin available to the LDNOs. ENW is proposing to address these issues as part of this modification proposal. A considerable amount of the development has been progressed by Western Power Distribution in their series of modification proposals WPD/UOS001 to WPD/UOS006. Where applicable, ENW has utilised the developed approach.

Proposed Arrangements

LDNOs are different from other demand customers as they are direct competitors of ENW for the provision of distribution networks and associated services. With this in mind it is appropriate to recognise LDNO connections as a new customer group within the DRM. ENW must define certain data inputs to create the new LDNO tariffs (for network servicing domestic only customers) using the DRM.

It is proposed:

- to create a new LDNO customer group within the DRM; and
- to identify two new service models for LDNO connections at HV and LV (as described earlier);
- to apply domestic load factors and coincidence factors, currently utilised within the DRM, to create new LDNO domestic only tariffs. Note, LDNO networks which supply commercial end customers will receive a commercial tariff as the boundary tariff. Charges for EHV connections are site specific and are determined using ENW's EHV Charging Methodology[4];
- to identify the avoided costs for the LDNO network from the DRM, in terms of network provided by the LDNO and the cost of other services not utilised by the LDNO.

ENW has seen the connection of embedded network at all voltage levels with a wide range of capacity requirements servicing either solely commercial or solely domestic customers (i.e. no networks servicing a range of customer types). The new LDNO tariffs are being created to address the connection of embedded networks at HV and LV voltage levels servicing only domestic customers. LDNO networks connected at HV or LV that service commercial customers will be charged from ENW's appropriate existing commercial tariff.

The two new LDNO service models represent the minimum cost connection for a LDNO connection to ENW's distribution network by defining the assets employed (either constructed by and/or adopted by ENW) at the connection boundary of an LDNO network.

ENW has reviewed the metered data from the LDNO connections. Although ENW has data for this new customer type, in relative terms it is only data collected over a short period of time. This is evident in the range of calculated

[4] Section 4 of ENW Limited's Licence Condition 4 Statement available at www.unitedutilities.com.

load factors across the networks which show the sites are in varying stages of development. It is clear from the analysis of metered data that as the network develops the consumption patterns and day/night split gravitate to typical domestic customer characteristics. It seems inappropriate at this stage to utilise the calculated values from the currently connected LDNO sites within the DRM as the data does not yet reflect the completed developments. Therefore ENW will apply the domestic load and coincidence factors for the development of LDNO tariffs but keep this decision under review as further data is collected and analysed.

It is proposed to divide the average length of LV underground main into four equal sized bands, measured in length from the substation. The bands represent the percentage of the network cost to be attributed to the LDNO as a result of an LDNO network connecting to the network. The proposed bands are 0% to 25%, 26% to 50%, 51% to 75%, 76% to 100% and the cost allocation of each band as if at the start point of the band (see Appendix C for further details on the banding). The distance between the distribution substation and the point of supply to the LDNO network is determined and the band selected. For example an LDNO supply which is connected 75 metres from the local substation will fall within Band 2 and therefore will receive twenty five percent of the LV network level cost.

Four bands have been chosen to balance the cost reflectivity of the tariff against simplicity of application. Fewer bands do not provide an appropriate level of cost granularity and although more bands increase the granularity the application costs increase as does the potential for misapplication and calculation error.

ENW has reviewed the Customer Service, billing and administration processes and identified costs that should be excluded from the new LDNO tariffs generated by the DRM. The costs of the services and systems not applicable to new LDNO tariffs are currently: Data Flow Management service, MPAS service, and Business User Support costs.

It is proposed to reduce the current Customer Service, billing and administration costs by £14.86 to reflect these avoided costs. At this early stage of the management of commercial arrangements with LDNOs ENW manually processes the calculation of the monthly charges and the production of the monthly transactional bills. This is costlier than using the current automated billing processes. ENW intends to cap the cost for this functionality to the level of the current automated billing processes as in the longer term it is expected that LDNO charges will form part of the standard process.

New LDNO specific tariffs will be published as:

- LV LDNO tariff:
  - Band 1, 2, 3, or 4
- HV LDNO tariff.

The new tariffs will contain the following components:

- A fixed charge to recover the costs attributable from the Service Model and Customer Services, Billing and Administration costs;
- A unit charge, in kWh, to recover all other costs attributed to the LDNO connection.

Appendix D details analysis of the margins available to LDNOs utilising the new LDNO tariffs as compared against the current commercial tariffs applied to LDNO networks. Charts 1 to 4 show the margin, expressed in £/kVA, for the LV LDNO tariffs and the HV LDNO tariff when compared against Domestic Unrestricted and Domestic Restricted tariffs. These charts show that the margins available to LDNOs are comparable at LV with the current but importantly the current negative margin is removed at lower numbers of customers. The margins available to LDNOs are increased at HV. Charts 5 to 8 show the margin expressed in £/kVA, for the LV LDNO tariffs and the HV LDNO tariff compared against Domestic Unrestricted and Domestic Restricted tariffs for a 50 plot site with a range of day/night consumptions. These charts show that the margins available to LDNOs are significantly increased over the expected band of 30% to 80% of day consumption at both LV and HV. The assumptions for the analysis are shown in the table in section D1.

3.5. Introduction of HV and LV DG Tariffs

Existing Arrangements

In April 2005 ENW (formerly United Utilities) introduced a simple methodology for the creation of generation use of system tariffs applicable for Distribution Generation at HV or LV. The methodology, approved by the Authority[5] in March 2005, generates an average charge applicable to a generator connected at HV or LV and is based on an estimated average cost of connection for HV and LV DG. This simple approach does not recognise the potential benefits that DG may bring in terms of delaying or avoiding the need for reinforcing the network. In February 2008 ENW applied to update this methodology to introduce a charge applicable for DG connections with no associated reinforcement costs, to better reflect costs applicable to use of system. The modification proposal, ENW/2008/004, was approved by the Authority in February 2008 for implementation on 1st April 2008. This means that ENW has two HV/LV DG tariffs during 2008/9; a charge of £5.21/kW pa for DG customers that incurred reinforcement and a charge of £2.77/kW pa for DG customers that did not incur reinforcement.

Proposed Arrangements

ENW now proposes to introduce a methodology change for HV and LV DG connections to our distribution network which recognises the benefits DG connections can provide to the distribution network. ENW believes that over the longer term the addition of generation will serve to defer or offset the need for future reinforcement, to the extent that it reduces existing power flows at each network level. Thus, at a given network level if existing flows at the network level are Demand Dominated (DD), the generator will receive a credit as the generator will reduce power flows to the extent that it is exporting power at times of demand peak power flows. If existing flows at the network level are Generation Dominated (GD), the generator will be allocated a cost as the generator will increase power flows to the extent that it is exporting power at times of generation peak power flows. These proposed changes mirror the philosophy of ENW's proposed Expansion Planning & Pricing software and aim to form the basis of an enduring solution.

It is proposed:

[5] GEMA - The Gas and Electricity Markets Authority.

- to identify two new service models for DG connections at HV and LV (as described earlier); and
- to identify new coincidence factors for use within the DRM to create new tariffs for exporting DG.

The value of the cost or credit is determined from the marginal costs identified in the DRM model. At each network level, the same £/kW values are relevant to the incremental costs for generation connections as for demand.

The new DG service models represent the minimum cost connection to ENW's distribution network by defining the assets employed (either constructed by and/or adopted by ENW) for a DG connection. It is only the additional costs over and above those costs identified in the minimum cost connection for a similar sized demand connection that are recovered in the DG tariff. For example additional protection is generally required by ENW's engineering designs and specifications for a DG connection.

ENW do not hold sufficient DG dataset to develop a robust method for the calculation of load and coincidence factors. Until there are significant numbers of DG connected to ENW's distribution network to calculate a robust load and coincidence factor for each DG technology type ENW proposes to apply the following simple approximations:

- Two generic DG coincidence factors will be applied within the DRM; and
- All network levels are assumed to be DD and so negative coincidence factors are applied within the DRM for DG tariffs. In principle, at a given network level, the sign of the coincidence factor for exporting DG will depend on whether the flow of power is on a GD or DD network.

It is assumed that for each type of DG the coincidence factor is equal in magnitude to the load factor as there is no direct correlation between the export profile and the network peak power flow. It is assumed that the voltage of connection there is zero coincidence. Analysis of data relating to existing generators reveals a range of load factors, dependant on technology, but with some clustering around 30% (wind, some CHP), and 70% (landfill gas, biomass, waste, fossil generation). The proposal is to generate two coincidence factors as follows:

- For DG with a load factor of less than or equal to 50% the coincidence factor is set at -0.3; and
- For DG with a load factor of greater than 50% the coincidence factor is set at -0.7.

These factors will be applicable to DG connected at both HV and LV voltage levels. The DG tariffs will be published as follows:

- HV DG (>50% load factor) export tariff;
- HV DG (<50% load factor) export tariff;
- LV DG (>50% load factor) export tariff; and
- LV DG (<50% load factor) export tariff.

The new DG tariffs will contain the following components:

- A fixed charge to recover the costs attributable from the Service Model and Customer Services, Billing and Administration costs; and
- A kW charge to recover all other costs attributed to the DG connection.

ENW will continue to charge EHV DG customers on a site specific basis with these charges determined using ENW's EHV Charging Methodology[6]; and ENW will continue to apply a zero charge to SSEG[7] connections.

4. Illustrative charges and payments and details of which customers will be affected by the proposed change

4.1. Introduction

The DRM methodology changes have an impact on all tariffs. The following sections show the impacts on the most common tariffs demand tariffs, the new LDNO tariffs and the new HV and LV DG tariffs respectively compared against the tariffs as at 1st April 2008.

4.2. Demand Tariffs

The tables below show the impacts on the most common demand tariffs resulting from the proposed changes in methodological approach and assumptions, ceteris paribus, within the current methodology. Note the tariffs shown below recover the same target allowed revenue as the current published tariffs. With exception of 4.2.2 the tariffs are reconciled to the target allowed revenue using the approved unit rate multiplier revenue reconciliation approach.

4.2.1 Connection Boundary and Service Models

The table below shows the impact of the introduction of a connection boundary within the DRM to represent the average costs recovered in connection charges, following the removal of the Asset Adoption Payments concept and the recovery of the future asset replacement of the service models.

		PROPOSED CHARGES				CHANGE			
Name	Period	Standing Charge pence	per	Unit Rate p/kWh	Availability Charge £/kVA per month	Standing Charge pence	per	Unit Rate p/kWh	Availability Charge £/kVA per month
Domestic UR	All	2.32	day	1.61	-	-53.5%	day	20.0%	
Domestic E7	Day	2.32	day	1.82	-	-53.5%	day	20.8%	
	Night	-	day	0.13	-		day	11.3%	
Non-Domestic UR	All	6.33	day	1.58	-	-20.1%	day	18.6%	
Non-Domestic E7	Day	6.33	day	1.76	-	-20.1%	day	18.8%	
	Night	-	day	0.10	-		day	12.1%	
LV MD NHH	Day	672	month	0.64	0.99	-46.5%	month	49.7%	-32.6%
	Night	-	month	0.09	-		month	-2.2%	
LV MD HH	Day	886	month	0.64	0.99	-60.5%	month	49.7%	-32.6%
	Night	-	month	0.09	-		month	-2.2%	
SS MD NHH	Day	936	month	0.38	1.12	-62.1%	month	45.5%	-15.5%
	Night	-	month	0.13	-		month	15.8%	
SS MD HH	Day	936	month	0.38	1.12	-62.1%	month	45.5%	-15.5%
	Night	-	month	0.13	-		month	15.8%	
HV MD NHH	Day	3,561	month	0.32	1.09	-75.5%	month	31.6%	-6.3%
	Night	-	month	0.08	-		month	29.2%	
HV MD HH	Day	3,561	month	0.32	1.09	-75.5%	month	31.6%	-6.3%
	Night	-	month	0.08	-		month	29.2%	
HVP MD HH	Day	6,199	month	0.32	0.97	-76.8%	month	26.4%	-1.4%
	Night	-	month	0.08	-		month	33.7%	

[6] Section 4 of ENW Limited's Licence Condition 4 Statement available at www.unitedutilies.com.
[7] Small Scale Embedded Generation

4.2.2 Revenue Reconciliation

The table below shows the impact resulting from the change in approach to revenue reconciliation.

		PROPOSED CHARGES				CHANGE			
Name	Period	Standing Charge pence	Per	Unit Rate p/kWh	Availability Charge £/kVA per month	Standing Charge pence	Per	Unit Rate p/kWh	Availability Charge £/kVA per month
Domestic UR	All	4.98	day	1.46	-	0.1%	day	9.3%	
Domestic E7	Day	4.98	day	1.64	-	0.1%	day	8.6%	
	Night	-	day	0.18	-		day	47.4%	
Non-Domestic UR	All	7.92	day	1.55	-	0.0%	day	16.4%	
Non-Domestic E7	Day	7.92	day	1.69	-	0.0%	day	14.5%	
	Night	-	day	0.13	-		day	48.3%	
LV MD NHH	Day	1,256	month	0.38	1.47	0.1%	month	-12.5%	0.2%
	Night	-	month	0.14	-		month	51.8%	
LV MD HH	Day	2,242	month	0.24	1.47	0.0%	month	-43.4%	0.2%
	Night	-	month	0.14	-		month	51.8%	
SS MD NHH	Day	2,471	month	0.40	1.33	0.0%	month	55.0%	0.3%
	Night	-	month	0.16	-		month	47.0%	
SS MD HH	Day	2,471	month	0.04	1.33	0.0%	month	-84.4%	0.3%
	Night	-	month	0.16	-		month	47.0%	
HV MD NHH	Day	14,561	month	- 0.05	1.16	0.0%	month	-121.4%	0.2%
	Night	-	month	0.09	-		month	52.6%	
HV MD HH	Day	14,561	month	0.05	1.16	0.0%	month	-80.4%	0.2%
	Night	-	month	0.09	-		month	52.6%	
HVP MD HH	Day	26,709	month	0.02	0.98	0.0%	month	-90.7%	-0.1%
	Night	-	month	0.09	-		month	50.4%	

4.2.3 Availability Allocation

The table below shows the impact of the proposed allocation of network costs to the availability charge to 100% for the three network levels above the voltage of connection.

		PROPOSED CHARGES				CHANGE			
Name	Period	Standing Charge pence	per	Unit Rate p/kWh	Availability Charge £/kVA per month	Standing Charge pence	Per	Unit Rate p/kWh	Availability Charge £/kVA per month
Domestic UR	All	4.98	day	1.28	-	0.1%	day	-4.6%	
Domestic E7	Day	4.98	day	1.45	-	0.1%	day	-4.1%	
	Night	-	day	0.12	-		day	-2.8%	
Non-Domestic UR	All	7.92	day	1.27	-	0.0%	day	-4.2%	
Non-Domestic E7	Day	7.92	day	1.42	-	0.0%	day	-4.3%	
	Night	-	day	0.09	-		day	-2.1%	
LV MD NHH	Day	1,256	month	0.19	2.01	0.1%	month	-57.0%	36.6%
	Night	-	month	0.09	-		month	0.2%	
LV MD HH	Day	2,242	month	0.19	2.01	0.0%	month	-57.0%	36.6%
	Night	-	month	0.09	-		month	0.2%	
SS MD NHH	Day	2,471	month	0.04	1.76	0.0%	month	-85.8%	32.6%
	Night	-	month	0.11	-		month	-3.0%	
SS MD HH	Day	2,471	month	0.04	1.76	0.0%	month	-85.8%	32.6%
	Night	-	month	0.11	-		month	-3.0%	
HV MD NHH	Day	14,561	month	0.12	1.51	0.0%	month	-48.4%	30.1%
	Night	-	month	0.06	-		month	0.7%	
HV MD HH	Day	14,561	month	0.12	1.51	0.0%	month	-48.4%	30.1%
	Night	-	month	0.06	-		month	0.7%	
HVP MD HH	Day	26,709	month	0.18	1.18	0.0%	month	-26.1%	20.8%
	Night	-	month	0.06	-		month	-0.7%	

4.2.4 Operation and Maintenance Percentage

The table below shows the impact of the proposed change in operation and maintenance percentage across the network levels.

		PROPOSED CHARGES				CHANGE			
Name	Period	Standing Charge pence	per	Unit Rate p/kWh	Availability Charge £/kVA per month	Standing Charge pence	per	Unit Rate p/kWh	Availability Charge £/kVA per month
Domestic UR	All	4.72	day	1.37	-	-5.3%	day	2.3%	
Domestic E7	Day	4.72	day	1.55	-	-5.3%	day	2.8%	

	Night	-	day	0.13	-		day	4.5%	
Non-Domestic UR	All	7.15	day	1.37	-	-9.7%	day	2.8%	
Non-Domestic E7	Day	7.15	day	1.52	-	-9.7%	day	2.6%	
	Night	-	day	0.09	-		day	5.2%	
LV MD NHH	Day	1,236	month	0.45	1.43	-1.5%	month	4.0%	-2.6%
	Night	-	month	0.10	-		month	7.6%	
LV MD HH	Day	2,195	month	0.45	1.43	-2.1%	month	4.0%	-2.6%
	Night	-	month	0.10	-		month	7.6%	
SS MD NHH	Day	2,418	month	0.26	1.30	-2.1%	month	1.1%	-2.4%
	Night	-	month	0.11	-		month	4.2%	
SS MD HH	Day	2,418	month	0.26	1.30	-2.1%	month	1.1%	-2.4%
	Night	-	month	0.11	-		month	4.2%	
HV MD NHH	Day	14,182	month	0.25	1.13	-2.6%	month	4.3%	-2.6%
	Night	-	month	0.06	-		month	8.2%	
HV MD HH	Day	14,182	month	0.25	1.13	-2.6%	month	4.3%	-2.6%
	Night	-	month	0.06	-		month	8.2%	
HVP MD HH	Day	26,003	month	0.26	0.95	-2.6%	month	3.8%	-2.9%
	Night	-	month	0.06	-		month	6.7%	

4.2.5 Cost Allocation

The table below shows the impact on the most commonly used tariffs from the proposed changes to the allocation methodologies for NGET and Network Business Rates and Licence Fees and Metering Business Rates compared against 1st April 2008 published tariffs.

		PROPOSED CHARGES				CHANGE			
		Standing Charge		Unit Rate	Availability Charge	Standing Charge		Unit Rate	Availability Charge
Name	Period	pence	per	p/kWh	£/kVA per month	pence	per	p/kWh	£/kVA per month
Domestic UR	All	5.20	day	1.30	-	4.5%	day	-3.1%	
Domestic E7	Day	5.20	day	1.48	-	4.5%	day	-2.0%	
	Night	-	day	0.12	-		day	-0.4%	
Non-Domestic UR	All	8.14	day	1.32	-	2.7%	day	-1.0%	
Non-Domestic E7	Day	8.14	day	1.48	-	2.7%	day	-0.3%	
	Night	-	day	0.09	-		day	0.2%	
LV MD NHH	Day	1,381	month	0.44	1.52	10.1%	month	1.3%	3.7%
	Night	-	month	0.09	-		month	3.0%	
LV MD HH	Day	2,367	month	0.44	1.52	5.6%	month	1.3%	3.7%
	Night	-	month	0.09	-		month	3.0%	
SS MD NHH	Day	2,596	month	0.25	1.37	5.1%	month	-2.9%	3.2%
	Night	-	month	0.11	-		month	-0.5%	
SS MD HH	Day	2,596	month	0.25	1.37	5.1%	month	-2.9%	3.2%
	Night	-	month	0.11	-		month	-0.5%	
HV MD NHH	Day	14,687	month	0.22	1.20	0.9%	month	-6.4%	3.8%
	Night	-	month	0.06	-		month	3.7%	
HV MD HH	Day	14,687	month	0.22	1.20	0.9%	month	-6.4%	3.8%
	Night	-	month	0.06	-		month	3.7%	
HVP MD HH	Day	26,834	month	0.23	1.01	0.5%	month	-6.5%	3.0%
	Night	-	month	0.06	-		month	2.0%	

Appendix F shows the illustrative prices of the new tariff set, including the detail of the tariff components for each proposed tariff compared against the tariffs as at 1st April 2008 and the impact of the proposed changes on average bills.

4.3. LDNO Tariffs

The following tables show the impact of the proposed changes in the new LDNO tariffs resulting from changes in methodological approach and assumptions, ceteris paribus, within the current methodology against the existing commercial tariffs[8] applied to licensed distributors using 1st April 2008 published tariffs. Note the tariffs shown below recover the same target allowed revenue as the current published tariffs. With exception of 4.3.2 the tariffs are reconciled to the target allowed revenue using the approved unit rate multiplier revenue

[8] The new LV LDNO tariffs are compared against the LV MD HH tariff and the new HV LDNO tariff is compared against the HV MD HH tariff.

reconciliation approach[9]. The large increases in the unit rates shown below reflect the removal of the availability charge tariff component from the new LDNO tariffs combined with the unit multiplier approach for revenue reconciliation. The proposal to move to unit and standing charge tariff components aligns with the approach advocated by the Authority in previous decisions on new LDNO tariffs.

4.3.1. Connection Boundary and Service Models

The table below shows the impact of the introduction of a connection boundary within the DRM to represent the average costs recovered in connection charges, following the removal of the Asset Adoption Payments concept and the change to the recovery of the future asset replacement of the service models.

		PROPOSED CHARGES				CHANGE			
		Standing Charge		Unit Rate	Availability Charge	Standing Charge		Unit Rate	Availability Charge
Name	Period	pence	per	p/kWh	£/kVA per month	pence	per	p/kWh	£/kVA per month
LV LDNO Band 1	Day	480	month	1.68		-78.6%	month	290.5%	-100.0%
	Night	-	month	0.09			month	-2.7%	
LV LDNO Band 2	Day	480	month	1.72		-78.6%	month	299.9%	-100.0%
	Night	-	month	0.10			month	11.6%	
LV LDNO Band 3	Day	480	month	1.76		-78.6%	month	309.3%	-100.0%
	Night	-	month	0.11			month	25.8%	
LV LDNO Band 4	Day	480	month	1.80		-78.6%	month	318.7%	-100.0%
	Night	-	month	0.13			month	40.1%	
HV LDNO	Day	2,894	month	1.19		-80.1%	month	397.2%	-100.0%
	Night	-	month	0.14			month	141.2%	

4.3.2. Revenue Reconciliation

The table below shows the impact resulting from the change in approach to revenue reconciliation.

		PROPOSED CHARGES				CHANGE			
		Standing Charge		Unit Rate	Availability Charge	Standing Charge		Unit Rate	Availability Charge
Name	Period	pence	per	p/kWh	£/kVA per month	pence	per	p/kWh	£/kVA per month
LV LDNO Band 1	Day	790	month	1.45		-64.8%	month	237.6%	-100.0%
	Night	-	month	0.12			month	30.3%	
LV LDNO Band 2	Day	790	month	1.50		-64.8%	month	248.5%	-100.0%
	Night	-	month	0.13			month	46.9%	
LV LDNO Band 3	Day	790	month	1.55		-64.8%	month	259.5%	-100.0%
	Night	-	month	0.15			month	63.4%	
LV LDNO Band 4	Day	790	month	1.59		-64.8%	month	270.4%	-100.0%
	Night	-	month	0.16			month	80.0%	
HV LDNO	Day	11,907	month	0.83		-18.2%	month	247.6%	-100.0%
	Night	-	month	0.17			month	184.7%	

4.3.3. Availability Allocation

The table below shows the impact of the proposed allocation of network costs to the availability charge to 100% for the three network levels above the voltage of connection.

		PROPOSED CHARGES				CHANGE			
		Standing Charge		Unit Rate	Availability Charge	Standing Charge		Unit Rate	Availability Charge
Name	Period	pence	per	p/kWh	£/kVA per month	pence	per	p/kWh	£/kVA per month
LV LDNO Band 1	Day	790	month	1.32		-64.8%	month	208.0%	-100.0%
	Night	-	month	0.08			month	-14.0%	
LV LDNO Band 2	Day	790	month	1.37		-64.8%	month	218.9%	-100.0%
	Night	-	month	0.09			month	2.5%	
LV LDNO Band 3	Day	790	month	1.42		-64.8%	month	229.8%	-100.0%

[9] The shortcomings of the unit rate multiplier revenue reconciliation approach are discussed in sections 2 and 3.3.

	Night	-	month	0.11			month	19.1%	
LV LDNO Band 4	Day	790	month	1.47		-64.8%	month	240.7%	-100.0%
	Night	-	month	0.12			month	35.6%	
HV LDNO	Day	11,907	month	0.92		-18.2%	month	282.0%	-100.0%
	Night	-	month	0.11			month	87.9%	

4.3.4. Operation and Maintenance

The table below shows the impact of the proposed change in operation and maintenance percentage across the network levels.

		PROPOSED CHARGES				CHANGE			
		Standing Charge		Unit Rate	Availability Charge	Standing Charge		Unit Rate	Availability Charge
Name	Period	pence	per	p/kWh	£/kVA per month	pence	per	p/kWh	£/kVA per month
LV LDNO Band 1	Day	779	month	1.42		-65.2%		230.2%	-100.0%
	Night	-	month	0.08				-7.6%	
LV LDNO Band 2	Day	779	month	1.47		-65.2%		240.8%	-100.0%
	Night	-	month	0.10				8.5%	
LV LDNO Band 3	Day	779	month	1.51		-65.2%		251.4%	-100.0%
	Night	-	month	0.11				24.6%	
LV LDNO Band 4	Day	779	month	1.56		-65.2%		262.0%	-100.0%
	Night	-	month	0.13				40.7%	
HV LDNO	Day	11,596	month	0.98		-20.4%		309.0%	-100.0%
	Night	-	month	0.12				101.9%	

4.3.5. Cost Allocation

The table below shows the impact from the proposed changes to the allocation methodologies for NGET and Network Business Rates and Licence Fees and Metering Business Rates.

		PROPOSED CHARGES				CHANGE			
		Standing Charge		Unit Rate	Availability Charge	Standing Charge		Unit Rate	Availability Charge
Name	Period	pence	per	p/kWh	£/kVA per month	pence	per	p/kWh	£/kVA per month
LV LDNO Band 1	Day	907	month	1.35		-59.5%		214.1%	-100.0%
	Night	-	month	0.08				-12.9%	
LV LDNO Band 2	Day	907	month	1.40		-59.5%		225.6%	-100.0%
	Night	-	month	0.09				4.5%	
LV LDNO Band 3	Day	907	month	1.45		-59.5%		237.1%	-100.0%
	Night	-	month	0.11				21.9%	
LV LDNO Band 4	Day	907	month	1.50		-59.5%		248.6%	-100.0%
	Night	-	month	0.13				39.3%	
HV LDNO	Day	12,024	month	0.94		-17.4%		289.6%	-100.0%
	Night	-	month	0.12				93.5%	

Appendix F shows the illustrative prices of the new tariff set, including the detail of the tariff components for each proposed tariff compared against the tariffs as at 1st April 2008 and the impact of the proposed changes on average bills.

4.4. HV and LV DG Tariffs

The new HV and LV DG tariffs are only applicable for generation exporting onto Electricity North West's distribution network. The following table shows the differences in the proposed DG tariffs as compared against the existing DG tariffs on 1st April 2008. Those current DG customers that do not export onto Electricity North West's distribution network will receive no generator use of system charge on the implementation of the new HV and LV DG tariffs.

		PROPOSED CHARGES				CHANGE			
		Standing Charge		Unit Rate	Availability Charge	Standing Charge		Unit Rate	Availability Charge
Name	Period	pence	per	p/kWh	£/kVA per month	pence	per	p/kWh	£/kVA per month
New DG tariffs compared against current DG (with reinforcement) tariff									
LV Gen Export < 50% LF	Gen	0.38	day		0.39		day		-10%
LV Gen Export	Gen	0.38	day		0.39		day		-10%

>50% LF						
HV Gen Export < 50% LF	Gen	0.38	day	0.48	day	10%
HV Gen Export >50% LF	Gen	0.38	day	0.39	day	-10%
New DG tariffs compared against current DG (without reinforcement) tariff						
LV Gen Export < 50% LF	Gen	0.38	day	0.21	day	-10%
LV Gen Export >50% LF	Gen	0.38	day	0.21	day	-10%
HV Gen Export < 50% LF	Gen	0.38	day	0.25	day	10%
HV Gen Export >50% LF	Gen	0.38	day	0.21	day	-10%

Appendix F shows the illustrative prices of the new tariff set, including the detail of the tariff components for each proposed tariff compared against the tariffs as at 1st April 2008. Note, the illustrative figures shown above are the constrained outputs from the DRM. The charging methodology for DG tariffs restricts price changes in a year to plus or minus ten percent from the existing tariff, currently at £5.21/kW per annum (with reinforcement) and £2.77/kW per annum (without reinforcement).

5. Proposed wording for the methodology and charges statements

The proposed changes to the Licence Condition 4 and 4A Statements are detailed in Appendix G and ENW has attached tracked changed versions of its statements to this proposal to show the updated statements for the implementation for this modification proposal. The proposed changes are summarised as:

Licence Condition 4

The revisions to the Use of System Methodology for Regulated Demand Charges and the Charging Methodology for Generation Charges are to be embedded in Sections 3 and 5 respectively.

Licence Condition 4A

A new table detailing the LDNO tariffs is to be embedded in Section 3 and an updated table 4.1 is to be embedded in Section 4.

6. A timetable for the implementation of the modification and charges changes

ENW intends to publish the amended Licence Condition 4 Statement within one month following the non-veto decision from the Authority and introduce the new LDNO and DG tariffs at the next available price change. ENW expects to implement the new tariffs on 1st April 2009.

Appendix A - Proposed methodology for determining the connection boundary within the DRM

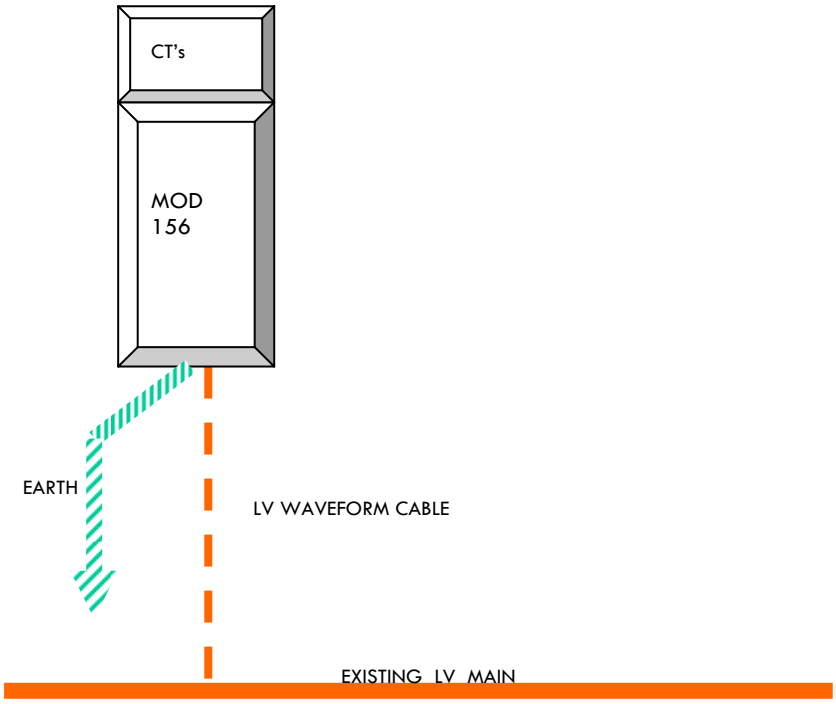
It is proposed that a certain percentage of each network level yardstick cost is excluded within the DRM charging model to better reflect the connection boundary introduced in 2005 and the removal of tariff support. The network level percentages are determined from a survey of a range of connections schemes quoted for within ENW's distribution services areas over a three month period.

Our initial assessment is that the following percentages should be applied within the DRM. These values are utilised to generate the illustrative prices within this modification proposal:

Network Level within DRM	Percentage network level reduction factor
LV	50%
HV/LV	20%
HV	10%
33kV/HV	2.5%
33kV	0%
132kV/33kV	0%
132kV	0%

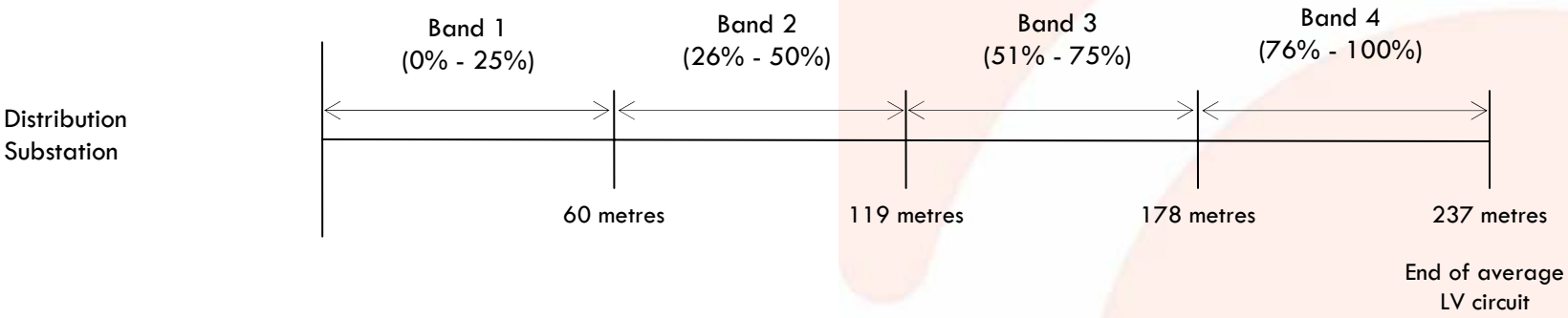
A detailed survey will determine the percentage of the each network level yardstick by analysing a sample of connections projects covering the full range of commercial and domestic connection types across the voltage levels, excluding EHV. Each network level percentage reduction factor is calculated as the percentage of the sum of the network level costs per connection and the sum of the total costs per connection.

Appendix B - Schematic of LV MD from network Service Model



Appendix C - LV LDNO network costs

1. The average LV circuit length is 237 metres.
2. The LV LDNO tariffs are set to reflect the costs avoided when customer connect to an LDNO network.
3. It is assumed that, on average, the LDNO owns networks similar in size and length to the networks owned and operated by ENW.
4. The distance between the substation and the point of supply will be measured.
5. ENW has assumed that any point of supply within a band will be treated as if at the start of the band.
6. Comparison of costs in LDNO tariff based on 1st April 2008 indicative prices.



Appendix D - Illustrative margins for a notional LDNO development

D1 Illustrative assumptions

Illustrative assumptions	
Number of households	50
Average household consumption	3,900 kWh
Average household capacity	2 kVA
Day Units	75%
Night Units	25%

D2 Illustrative graphs showing change in LDNO margin with number of households connected

Chart 1 – LDNO margins at LV based on proposed LDNO tariffs and ENW domestic unrestricted tariff

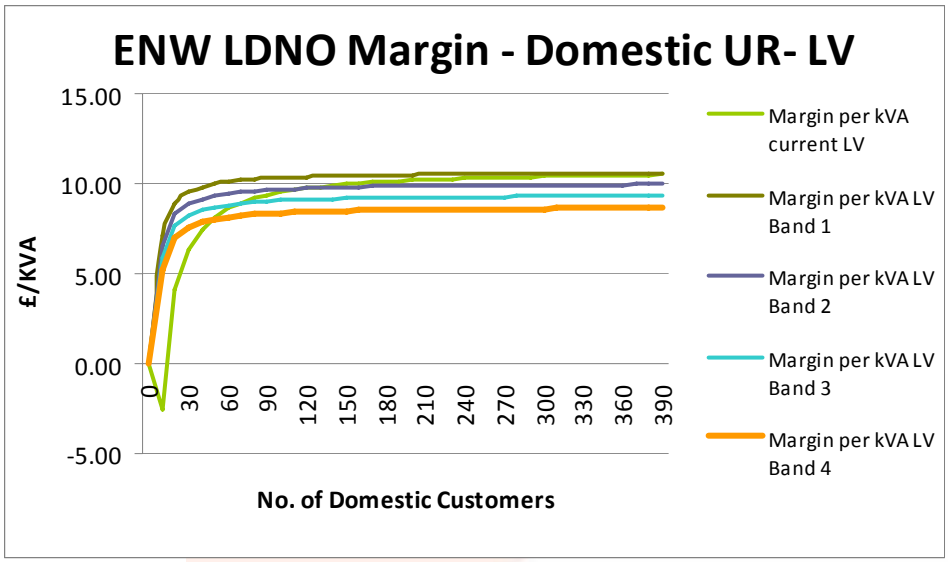


Chart 2 – LDNO margins at LV based on proposed LDNO tariffs and ENW domestic restricted tariff

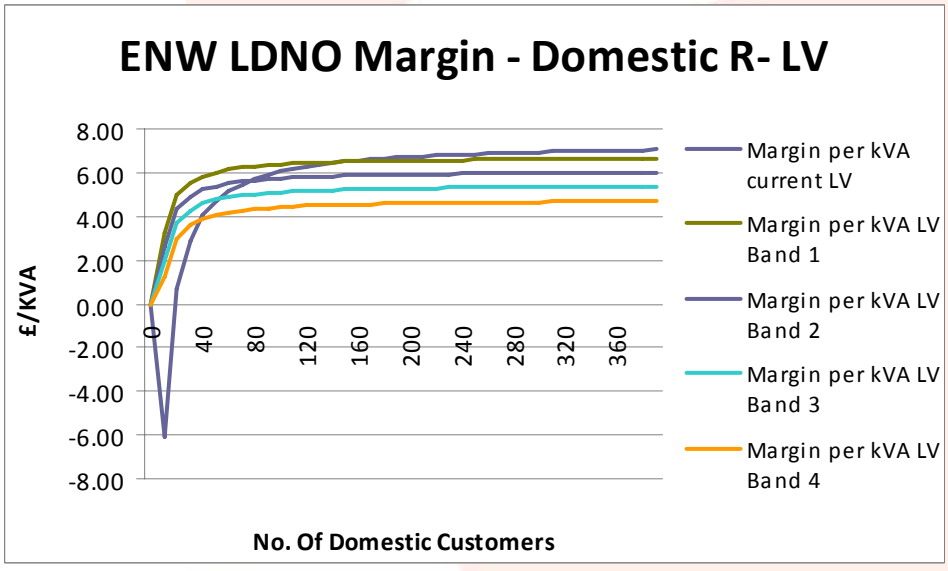


Chart 3 – LDNO margins at HV based on proposed LDNO tariffs and ENW domestic unrestricted tariff

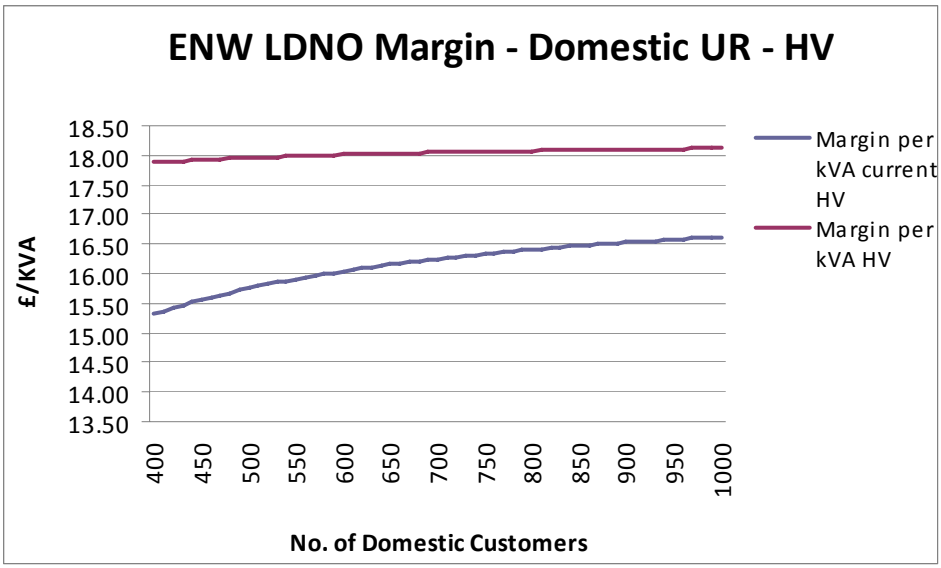
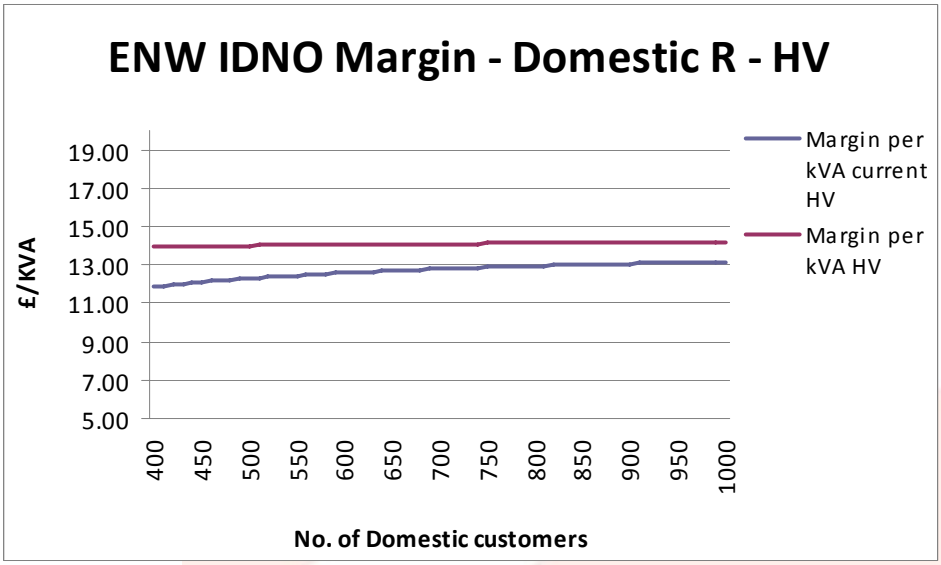


Chart 4 – LDNO margins at HV based on proposed LDNO tariffs and ENW domestic restricted tariff



D3 Illustrative graphs showing the change in LDNO margin for changes in day/night consumption

Chart 5 – Impact on LDNO margins at LV based on proposed LDNO tariffs and ENW domestic unrestricted tariff for changes in day/night consumption

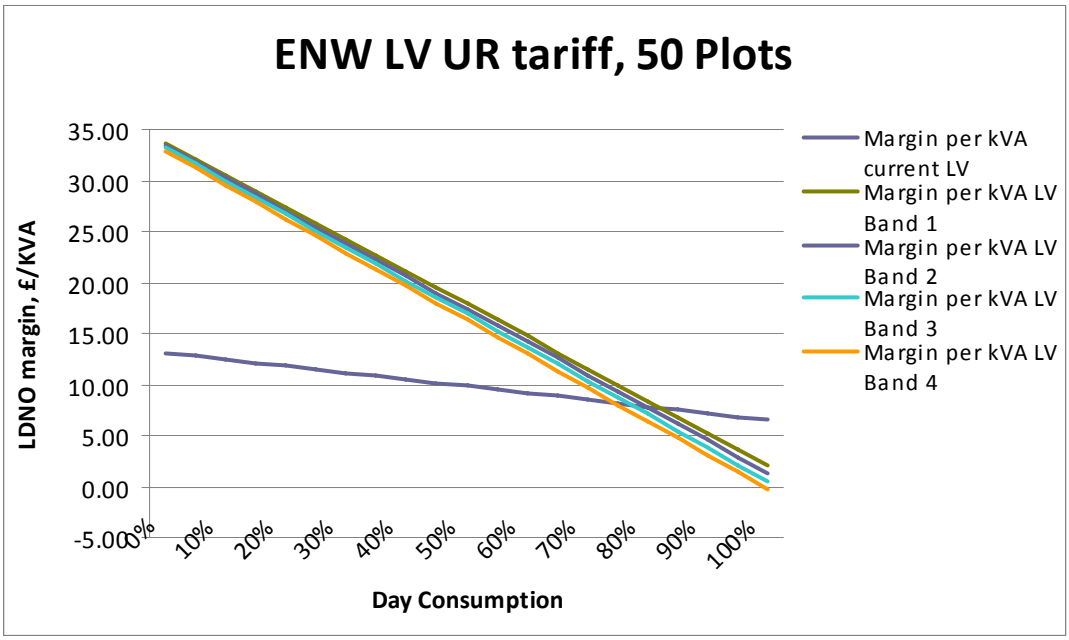


Chart 6 – Impact on LDNO margins at LV based on proposed LDNO tariffs and ENW domestic restricted tariff for changes in day/night consumption

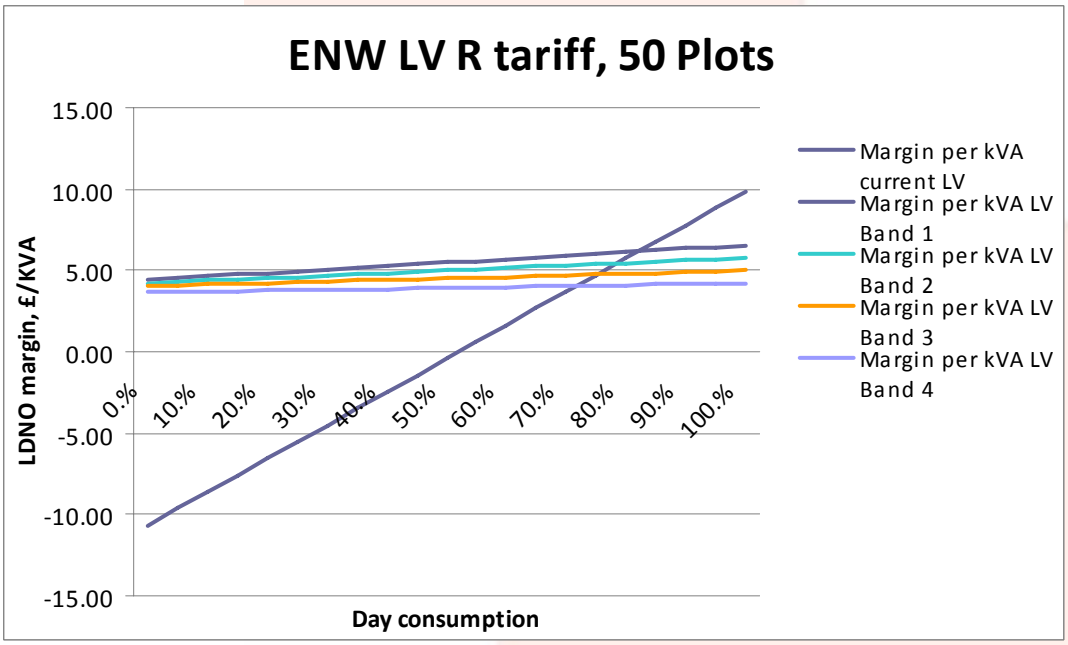


Chart 7 – Impact on LDNO margins at HV based on proposed LDNO tariffs and ENW domestic unrestricted tariff for changes in day/night consumption

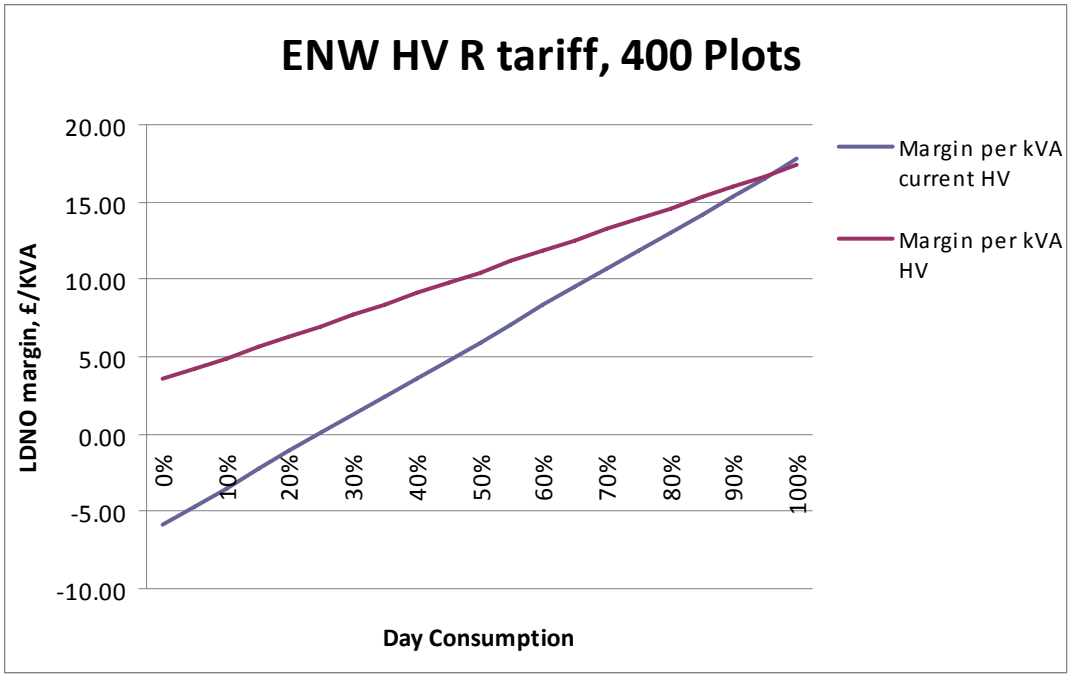
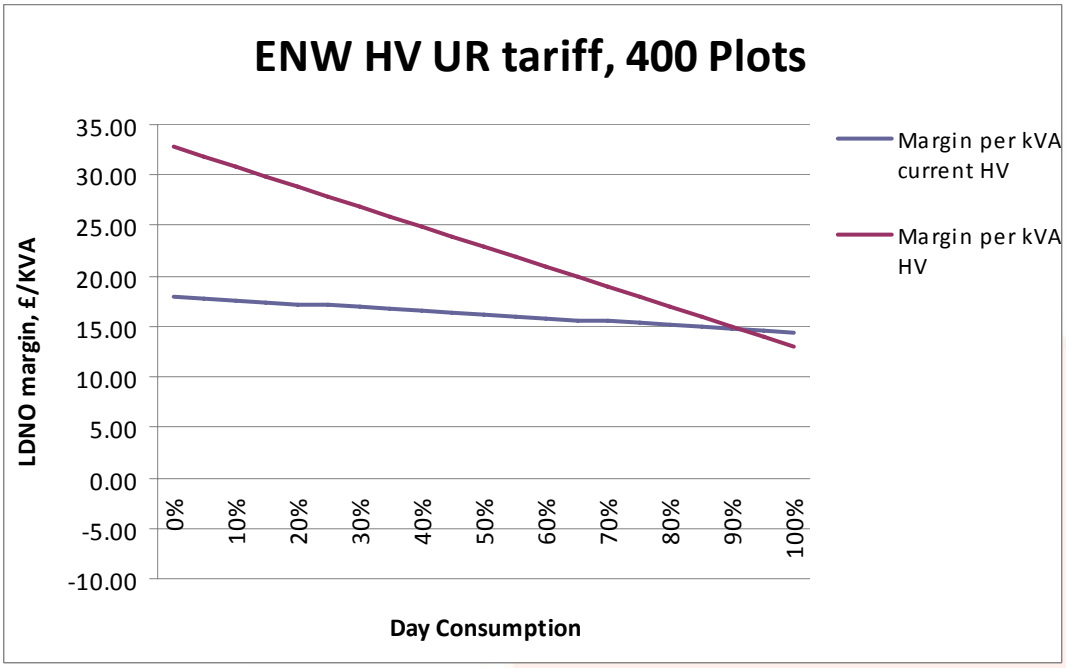


Chart 8 – Impact on LDNO margins at LV based on proposed LDNO tariffs and ENW domestic restricted tariff for changes in day/night consumption



Appendix E - Illustrative Charges

E1 Illustrative LDNO Tariffs

Illustrative LDNO tariffs are shown below:

		PROPOSED CHARGES		
		Standing Charge		Unit Rate
Name	Period	pence	per	p/kWh
LV LDNO Band 1	Day	587	month	1.72
	Night	-	month	0.10
LV LDNO Band 2	Day	587	month	1.76
	Night	-	month	0.11
LV LDNO Band 3	Day	587	month	1.80
	Night	-	month	0.12
LV LDNO Band 4	Day	587	month	1.84
	Night	-	month	0.14
HV LDNO	Day	2,701	month	1.18
	Night	-	month	0.16

E2 Illustrative HV and LV DG Tariffs

Illustrative HV and LV DG tariffs are shown below:

	CONNECTION VOLTAGE			
	HV		LV[10]	
	≤ 50% load factor	> 50% load factor	≤ 50% load factor	> 50% load factor
Standing Charge, pence/day	0.38	0.38	0.38	0.38
£ per annum per kW of Maximum Export Capacity	£4.69	£4.69	£5.73	£4.69

These illustrative figures are the constrained[11] outputs from the DRM. For avoidance of doubt, it is these prices that would be applicable from 1st April 2009. The table overleaf shows the illustrative unconstrained HV and LV DG tariffs to help show the price change resulting from revenue reconciliation.

Illustrative unconstrained HV and LV DG tariffs are shown below:

[10] Excludes LV connected SSEG

11 Clause 5.20 of Standard Licence Condition 4 Statement (titled 'Statement of Charging Methodology for Use of Electricity North West Limited's Electricity Distribution Network') restricts the change in charges to plus or minus ten percent per annum.

	CONNECTION VOLTAGE			
	HV		LV[12]	
	≤ 50% load factor	> 50% load factor	≤ 50% load factor	> 50% load factor
Standing Charge, pence/day	0.38	0.38	0.38	0.38
£ per annum per kW of Maximum Export Capacity	£1.04	-£20.81	£8.60	-£3.17

The illustrative figures shown above are the unconstrained outputs from the DRM. The charging methodology for DG tariffs restricts price changes in a year to plus or minus ten percent from the existing tariff, currently at £5.21/kW per annum (with reinforcement) and £2.77/kW per annum (without reinforcement).

[12] Excludes LV connected SSEG

Appendix F - Full illustrative tariff analysis

F1 Illustrative tariffs

		PROPOSED CHARGES						CURRENT CHARGES						CHANGE					
Name	Period	Standing Charge pence	per	Unit Rate p/kWh	Demand Charge £/KW per month	Availability Charge £/KVA per month	Reactive Charge p/kVARh	Standing Charge pence	per	Unit Rate p/kWh	Demand Charge £/KW per month	Availability Charge £/KVA per month	Reactive Charge p/kVARh	Standing Charge pence	per	Unit Rate p/kWh	Demand Charge £/KW per month	Availability Charge £/KVA per month	Reactive Charge p/kVARh
Domestic UR	All	2.27	day	1.65	-	-		4.98	day	1.34				-54.5%	day	23.0%			
Domestic E7	Day	2.27	day	1.88	-	-		4.98	day	1.51				-54.5%	day	24.5%			
	Night	-	day	0.15	-	-			day	0.12					day	23.5%			
Domestic Smart 7	Weekday	2.27	day	2.67	-	-		4.98	day	2.10				-54.5%	day	27.0%			
	E&W	-	day	1.58	-	-			day	1.24					day	27.0%			
	Night	-	day	0.15	-	-			day	0.12					day	23.5%			
Domestic E10	Day	2.27	day	2.45	-	-		4.98	day	1.95				-54.5%	day	25.6%			
	Night	-	day	0.17	-	-			day	0.14					day	23.1%			
Restricted Hour 7	All	0.38	day	0.15	-	-		0.16	day	0.12				138.4%	day	23.5%			
Restricted Hour 8	All	0.38	day	0.14	-	-		0.16	day	0.12				138.4%	day	18.9%			
Restricted Hour 9	All	0.38	day	0.21	-	-		0.16	day	0.16				138.4%	day	28.5%			
Restricted Hour 10	All	0.38	day	0.21	-	-		0.16	day	0.16				138.4%	day	28.5%			
Restricted Hour 11	All	0.38	day	0.21	-	-		0.16	day	0.16				138.4%	day	28.5%			
Non-Domestic UR	All	5.78	day	1.67	-	-		7.92	day	1.33				-27.0%	day	25.8%			
Non-Domestic E7	Day	5.78	day	1.88	-	-		7.92	day	1.48				-27.0%	day	26.8%			
	Night	-	day	0.11	-	-			day	0.09					day	24.3%			
Non-	Peak		day			-			day					-27.0%	day	27.9%			

Domestic E&W		5.78		2.48	-			7.92		1.94								
	E&W	-	day	0.22	-	-			day	0.18					day	24.4%		
Non-Domestic E7 E&W	Weekday	5.78	day	2.48	-	-		7.92	day	1.94				-27.0%	day	28.0%		
	E&W	-	day	0.28	-	-			day	0.23					day	20.9%		
	Night	-	day	0.11	-	-			day	0.09					day	24.3%		
Crop Drying	All	0.38	day	0.15	-	-		0.16	day	0.12				138.4%	day	24.8%		
LV MD NHH	Day	777	month	0.65	-	1.05	0.74	1,255	month	0.43		1.47	0.62	-38.1%	month	50.3%	-28.7%	19.4%
	Night	-	month	0.10	-	-			month	0.09					month	7.8%		
LV MD HH	Day	965	month	0.55	-	1.05	0.74	2,241	month	0.43		1.47	0.62	-57.0%	month	28.3%	-28.7%	19.4%
	Night	-	month	0.10	-	-			month	0.09					month	7.8%		
SS MD NHH	Day	1,008	month	0.67	-	1.01	0.65	2,470	month	0.26		1.33	0.54	-59.2%	month	158.0%	-24.2%	20.4%
	Night	-	month	0.14	-	-			month	0.11					month	29.0%		
SS MD HH	Day	1,008	month	0.40	-	1.01	0.65	2,470	month	0.26		1.33	0.54	-59.2%	month	52.6%	-24.2%	20.4%
	Night	-	month	0.14	-	-			month	0.11					month	29.0%		
HV MD NHH	Day	3,308	month	0.13	-	1.12	0.33	14,560	month	0.24		1.16	0.28	-77.3%	month	-45.1%	-3.5%	17.9%
	Night	-	month	0.09	-	-			month	0.06					month	44.7%		
HV MD HH	Day	3,308	month	0.23	-	1.12	0.33	14,560	month	0.24		1.16	0.28	-77.3%	month	-5.7%	-3.5%	17.9%
	Night	-	month	0.09	-	-			month	0.06					month	44.7%		
HVP MD HH	Day	5,618	month	0.16	-	1.12	0.14	26,708	month	0.25		0.98	0.14	-79.0%	month	-36.9%	14.1%	0.0%
	Night	-	month	0.09	-	-			month	0.06					month	49.7%		
Public lights (demand)	All	767	month		4.46	-		717	month	-	5.23			6.9%	month	#DIV/0!	-14.8%	
Public lights (no demand)	Day	25	day	1.87	-	-		24	day	1.51				6.8%	day	24.2%		
	Night		day			-			day						day	17.2%		

		-		0.12	-					0.10									
LV Gen Export < 50% LF	Gen	0.38	day			0.09			day			0.43			day			-80.1%	
LV Gen Export >50% LF	Gen	0.38	day			- 1.73			day			0.43			day			-499.5%	
HV Gen Export < 50% LF	Gen	0.38	day			0.72			day			0.43			day			65.1%	
HV Gen Export >50% LF	Gen	0.38	day			- 0.26			day			0.43			day			-160.8%	
LV Gen Export < 50% LF	Gen	0.38	day			0.09			day			0.23			day			-62.5%	
LV Gen Export >50% LF	Gen	0.38	day			- 1.73			day			0.23			day			-851.4%	
HV Gen Export < 50% LF	Gen	0.38	day			0.72			day			0.23			day			210.5%	
HV Gen Export >50% LF	Gen	0.38	day			- 0.26			day			0.23			day			-214.4%	
LV LDNO Band 1	Day	587	month	1.72				2,241	month	0.43		1.47		0.62	-73.8%	day	299%		-100%	-100%
	Night	-	month	0.10				-	month	0.09						day	7%			
LV LDNO Band 2	Day	587	month	1.76				2,241	month	0.43		1.47		0.62	-73.8%	day	309%		-100%	-100%
	Night	-	month	0.11				-	month	0.09						day	21%			
LV LDNO Band 3	Day	587	month	1.80				2,241	month	0.43		1.47		0.62	-73.8%	day	318%		-100%	-100%
	Night	-	month	0.12				-	month	0.09						day	36%			
LV LDNO Band 4	Day	587	month	1.84				2,241	month	0.43		1.47		0.62	-73.8%	day	328%		-100%	-100%
	Night	-	month	0.14				-	month	0.09						day	50%			
HV LDNO	Day	2,701	month	1.18				14,560	month	0.24		1.16		0.28	-81.4%	day	391%		-100%	-100%
	Night	-	month	0.16				-	month	0.06						day	170%			

Notes:

1. Proposed DG tariffs compared against DG tariff (with reinforcement) (ie £5.21/kW pa) and DG tariff (without reinforcement) (ie £2.77/kW pa) respectively;
2. Proposed LV LDNO tariff is compared against LV MD HH tariff;
3. Proposed HV LDNO tariff is compared against HV MD HH tariff.

F2 Illustrative average bills

The following table shows the change in average bills resulting from the proposed changes to the DRM methodology.

Change to Average Annual Bills				
	Current Average DUoS Bill 1st April 2008 Baseline	Proposed Average DUoS Bill Proposed Prices	Variance Per Customer	Percentage Change
Domestic Unrestricted	£67.80	£69.31	£1.52	2.2%
Domestic E7	£75.72	£79.88	£4.16	5.5%
Non-Domestic Unrestricted	£227.30	£270.61	£43.31	19.1%
Non-Domestic E7	£251.17	£302.77	£51.60	20.5%
LV MD HH	£4,128.24	£3,519.99	-£608.24	-14.7%
SS MD HH	£7,127.37	£6,408.39	-£718.98	-10.1%
HV MD HH	£19,058.12	£17,190.36	-£1,867.76	-9.8%
LV MD NHH	£1,472.84	£1,371.94	-£100.90	-6.9%
SS MD NHH	£1,428.76	£1,553.41	£124.65	8.7%
HV MD NHH	£7,171.48	£5,118.81	-£2,052.67	-28.6%
HVP MD	£193,159.72	£185,710.70	-£7,449.02	-3.9%

Appendix G - Proposed changes to Licence Condition Statements

G1 Licence Condition 4 Statement

Section 3 Use of System Methodology – HV and LV Demand and Generation Charges

3.1 The methodology to calculate tariffs is designed to secure cost reflectivity. This is achieved through a three stage process. The first of these is to determine yardstick costs for each class of customer. The second is to modify these costs to ensure that the revenues generated through Use of System charges match the relevant allowed revenue. The third stage is to determine the tariffs for each class of customer.

Network Model

3.2 The Distribution Reinforcement Model (DRM - also known as the 500MW model) is used to calculate yardstick costs. Originally developed in the 1980s by the Electricity Council it has been modified to represent Electricity North West's electricity distribution network. The DRM is a theoretical model, intended to approximate long run marginal costs, based on an additional 500MW of load at each distribution system level on a greenfield site. It consists of an appropriate mix of underground and overhead cables at each voltage level, to reflect the existing urban and rural network structure and the required mix of transformer capacity, at each voltage level, to comply with security of supply requirements and standard equipment. The Electricity North West's DRM consists of the mix of network levels of 132kV, 33kV, 11kV and LV and the transformation levels of 132/33kV, 33/11kV and 11kV/LV.

Service Models

3.3 Electricity North West models the assets required to provide the minimum cost connection for each customer class. The twelve service models are defined by voltage of connection, number of phases, capacity, and customer class.

Costs

3.4 The capital costs for each network level of the network model from 132kV to LV and the service models are calculated, using current costs based on an analysis of the last three years' actual data from Electricity North West's unit costs estimating package. The capital costs of the relevant network levels are reduced by an amount which represents the typical costs recovered in connection charges. The annuitised capital costs for each network level and the annuitised future asset replacement of each service model are calculated based on the allowed rate of return over an assumed 40 year lifetime of the assets.

3.5 The models build in annualised operation and maintenance costs for each network level and each service model. The operation and maintenance percentage is derived from the costs identified in the Revenue Reporting Pack.

3.6 The network model takes into account the costs at each level of the system, from 132kV to LV, building in diversity factors to reflect the usage of network remote from the connection point and once divided by the maximum demand of that network level, derives the network level yardstick cost, expressed in £/kW pa. The network model assumes an average power factor within the range 0.95 leading and 0.95 lagging, so for customers whose power factor deviates from the norm, excess reactive power charges are also levied to recover the extra costs of providing the additional capacity needed to deliver their requirements.

3.7 NGET Connection costs and Network Business Rates are identified and grouped at the 132kV level and expressed in £ pa. Other annualised costs, such as License Fees, Metering Business Rates and Customer Service, Billing and Administration costs are identified and expressed in £ pa.

Cost Attribution

3.8 Customer Service, Billing and Administration costs are allocated dependent upon the billing engine and associated systems employed for different customer types, expressed in £/customer pa. License Fees and Metering Business Rates are also expressed in £/customer pa.

3.9 The future asset replacement of service models, which define the minimum cost connection costs, are expressed in £/customer pa.

3.10 NGET Connection charges and Network Business Rates are grouped at the 132kV level and converted into £/kW pa by dividing by actual system maximum demand. These costs are attributed to the tariffs through each tariff's maximum demand in relation to the system maximum demand, expressed in £/kW pa.

3.11 A tariff's load factors and assumed coincidence factors are utilised, to turn the network level yardstick[13] expressed in £/kW into a cost reflective unit rate, expressed in £/kWh.

Distributed Generation Charges

3.12 The network model is assumed to be demand dominated and so as Distribution Generation connects and exports to the distribution network it is expected, over the longer term, to defer or offset the need for future reinforcement. The benefits of Distributed Generation connecting to the distribution network are defined through the application of a negative coincidence factor.

Matching Charges to Allowed Demand Revenue

3.13 Price controls limit the charges Electricity North West can make. Following identification of the costs and the production of yardstick prices revenue checks are made to compare the aggregated projected revenue with the level of revenue allowed under price controls. Where there is a mismatch between the total Allowed Demand Revenue and the revenue produced by the yardstick prices, a fixed adder revenue reconciliation approach is applied.

[13] The LV network level yardstick is identified in four bands based on distance from the distribution substation and the point of supply, for LDNO tariffs only.

Reactive Power Charges

3.14 The excess reactive power charge expressed in pence/kVArh is calculated as the incremental cost of providing one unit of reactive power over the norm. Reactive power charges are only applied to those kVArh units in excess of a third of the kWh units supplied, equivalent to a power factor less than 0.95. Excess reactive power charges are derived from the same network yardstick costs used for other DUoS components. However those elements of the yardstick that are recovered through kVA based availability charges are excluded. What remains are network yardstick costs that are recovered on a kW or kWh basis. Since standard kW and kWh charges assume a power factor of 0.95, the excess reactive power charge is based on the variation in the appropriate yardstick costs as power factor varies below 0.95. These costs are converted into a p/kVArh charge using the customer class load factor and the weighted average power factor for qualifying customers.

Format of Charges

3.15 Tariff structures are developed to accurately recover the costs identified from the cost modelling. Wherever possible Electricity North West will apply Maximum Demand metering to recover the costs associated with the provision of the distribution network. Electricity North West specifies metering equipment that fulfils the data requirements of the settlements process.

3.16 Those tariffs, without Maximum Demand metering and tariffs specifically for LDNO connections, consist of the following tariff components:

- Standing charge; and
- Unit charge(s).

3.17 Those tariffs, with Maximum Demand metering, consist of the following tariff components:

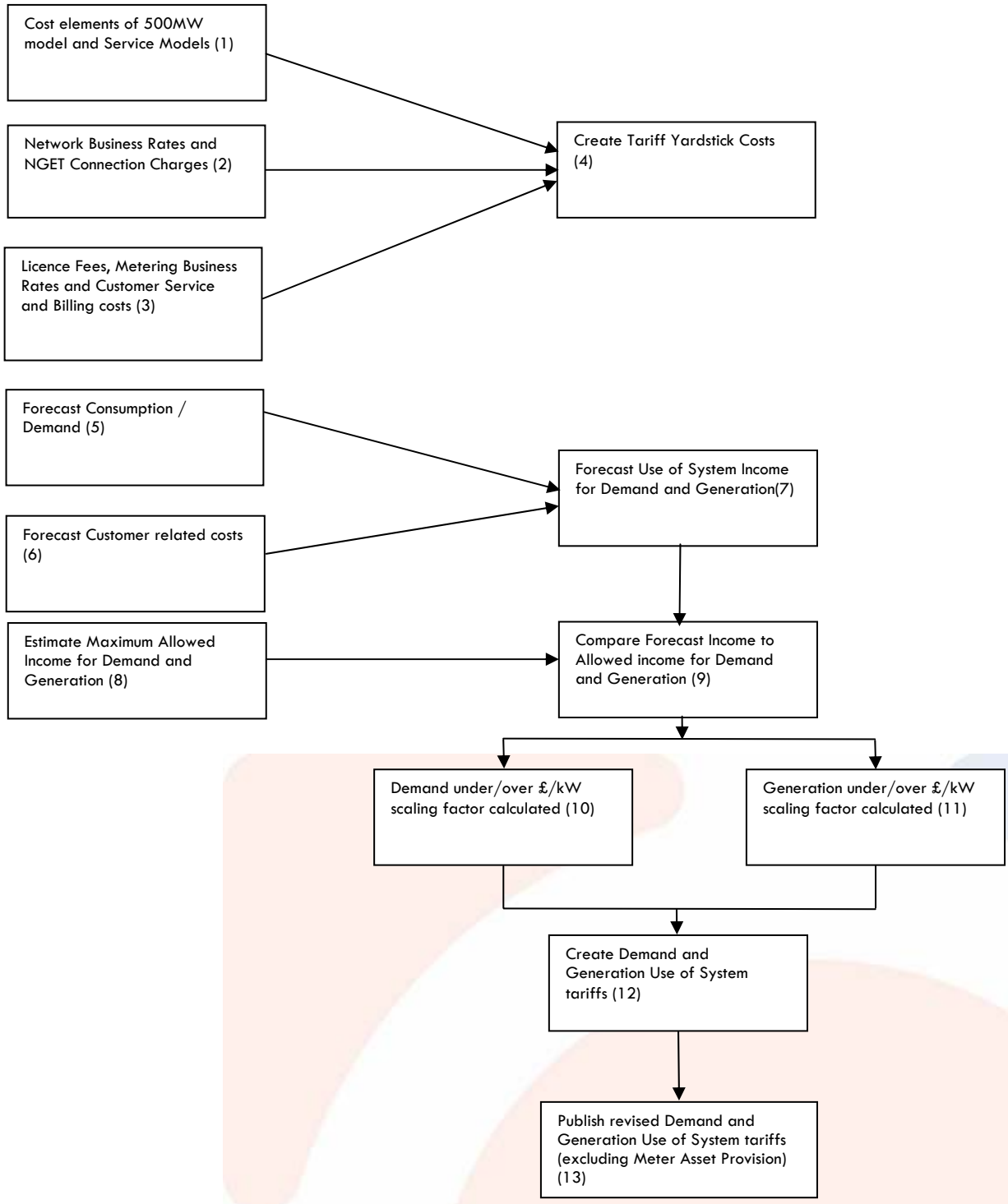
- Standing charge;
- Unit charge(s);
- Capacity charge; and
- Excess reactive power charge.

For these tariffs the network level yardstick, expressed in £/kW, is allocated into a capacity charge component based on the users' assumed utilisation of the local network of:

- 100% relating to voltage level of connection;
- 100% next level of transformation; and
- 100% next voltage level.

The unit rate tariff component is the derivation of the tariff yardstick excluding the elements of the network levels recovered by the capacity charge.

3.18 The flowchart below shows steps taken in the development of use of system tariffs using the defined models.


Cost elements of 500MW model and Service Models (1)
Network Business Rates and NGET Connection Charges (2)
Licence Fees, Metering Business Rates and Customer Service and Billing costs (3)
Create Tariff Yardstick Costs (4)
Forecast Consumption / Demand (5)
Forecast Customer related costs (6)
Forecast Use of System Income for Demand and Generation(7)
Estimate Maximum Allowed Income for Demand and Generation (8)
Compare Forecast Income to Allowed income for Demand and Generation (9)
Demand under/over £/kW scaling factor calculated (10)
Generation under/over £/kW scaling factor calculated (11)
Create Demand and Generation Use of System tariffs (12)
Publish revised Demand and Generation Use of System tariffs (excluding Meter Asset Provision) (13)

Example - Domestic Unrestricted DUoS Charge

3.14 The domestic unrestricted charge has a mixture of unit rate and standing charge components. Unit rates are derived from the yardstick price calculation, explained above, including NGET Connection Charges and Network Business Rates, whilst Standing charges are derived from 'Customer Related Costs'. These are classified as being the future asset replacement of the service model i.e. sole use assets relating to service position and a percentage of local mains (not already covered by connection charges), and the Customer Service, Billing and Administration costs.

Electricity North West adopts a shallowish connection boundary policy. This charging concept is aimed at customers contributing to local assets to allow them to connect to our distribution system, whilst any upstream asset costs would be recovered through Use of System. A domestic unrestricted charge would pick up all the costs attributable to all system levels, except those costs recovered in connection charges, as they are connected at Low Voltage. The table below shows illustrative domestic unrestricted tariff's yardstick costs per network level.

Network Level Costs (£/kW/y)						
132 kV	132/33 kV	33 kV	33/11 kV	11 kV	11 kV/LV	LV

These costs are then apportioned, according to the average class load factor and coincidence factors relating to time of day usage. The table below shows illustrative domestic unrestricted tariff's unit charge per network level.

Network Levels Costs (p/kWh/y)							
132kV	132/33kV	33 kV	33/11 kV	11kV	11kV/LV	LV	Total
p/kWh	p/kWh	p/kWh	p/kWh	p/kWh	p/kWh	p/kWh	p/kWh

Section 5 Charging Methodology - Generation Charges

Introduction

5.1. Ofgem has determined that distribution businesses should introduce use of system charges for Distributed Generation, rather than relying on full recovery of all asset related costs in an up-front connection charge.

Parties Liable for Distributed Generation Charges

5.2. All Relevant Distributed Generation is liable for Generator Use of System (GDUoS) charges. This methodology explains the calculation of Generation Use of System (GDUoS) charges for Distributed Generation customers connected after 1st April 2005 and for any upgrade or expansion to existing Distributed

Generation plant also after 1st April 2005. For the avoidance of doubt, Distributed Generation customers will also be charged Use of System for their demand requirements, in accordance with Section 3 of this statement.

Principles and Basis of Charges

5.3. Electricity North West aims to produce cost reflective charges for Relevant Distributed Generation within the parameters of Ofgem's Distributed Generation Incentive Regulatory Instructions and Guidance.

5.4. The calculation of the charges to be recovered from Relevant Distributed Generation customers, connected at HV or LV, is based on the costs incurred or avoided as derived from the DRM methodology described in Section 3. Whilst the calculation of the charges to be recovered from Relevant Distributed Generation customers connected at EHV is based on the costs of the reinforcement works required to connect their Installed Generation Capacity.

5.5. Electricity North West shall discuss with the Distributed Generation customer and their nominated Supplier whether generation charges will be recovered either directly from the Distributed Generation customer, or from their nominated Supplier.

5.6. At the time of the connection application the Distributed Generation customer will inform Electricity North West of the MW capacity of his Distributed Generation plant. This declaration forms the basis of Electricity North West's assessment of the type and size of network assets required to be installed to connect the Distributed Generation to Electricity North West's distribution network. It will also set the level of on-going chargeable Installed Generation Capacity. The Distributed Generation customer will be charged at the level of his declared Installed Generation Capacity for the first five years.

5.7. The Distributed Generation will be expected to operate, with an export power factor within the band between 0.95 lagging and 0.95 leading power factor. If the Distributed Generation operates outside of this range area of operation the customer it will incur reactive power charges, unless the mode of operation has previously been agreed, in which case the customer is entitled to request a refund of any charges incurred. The value of the excess reactive power charge to be levied on Distributed Generation customers is set at the same value as that levied on demand customers.

HV and LV Charging Methodology

5.8. The calculation of the charges for HV and LV Relevant Distributed Generation that exports on the distribution network is described in Section 3. The DRM methodology defines the costs incurred or credited to exporting HV and LV Distributed Generation through the definition of:

- a new Distributed Generation customer class;
- two new service models; one for HV connected Distributed Generation and one for LV connected Distributed Generation; and
- two generic load and coincidence factors applicable to both HV and LV Distributed Generation.

5.9. The following tariffs will be available:

- HV Distributed Generation Export tariff (load factor less or equal to 50%)
- HV Distributed Generation Export tariff (load factor greater than 50%)
- LV Distributed Generation Export tariff (load factor less or equal to 50%)
- LV Distributed Generation Export tariff (load factor greater than 50%).

5.10. It is assumed that SSEG[14] connected to the distribution network does not export.

EHV Charging Methodology

5.11. As the costs of each EHV Distributed Generation connection are individual to each customer the Use of System charges for each customer will be considered on a site-specific basis. A charging model will be created per EHV customer.

5.12. The framework of EHV Distribution Generation charges for the interim period is dictated by the allowed revenue as provided in the Distributed Generation Incentive that Ofgem introduced from 1st April 2005. The allowed revenue calculation is made up of the following elements:

- **Asset annuity charge** – An annuity charge based on 80 percent of the total cost of the reinforcement works required to connect the Installed Generation Capacity of the Distributed Generation plant, over a 15 year life, with a rate of return of 6.9 percent
- **Capacity Charge** – A standard £1.50[15] per kW per annum of Installed Generation Capacity of the Distributed Generation plant. An additional £3[12] per kW of Installed Generation Capacity of the Distributed Generation plant will be included for any connections distributed generation connected in an RPZ (Registered Power Zone).
- **Operation, Repair and Maintenance Charges** – A standard £1[12] per kW per annum of Installed Generation Capacity of the Distributed Generation plant to recover the allowable operation, repair and maintenance on the sole use and reinforcement assets of the connection.

5.13. Note, for Distributed Generation connections only, the cost apportionment factor rules detailed in our Licence Condition 4B document titled "Statement of Methodology and Charges for Connection to Electricity North West Limited's Electricity Distribution Network' will only be applied to reinforcement costs up to a cap of £200[12] per kW of Installed Generation Capacity. All reinforcement costs in excess of this cap will be charged in full to the connecting generator alongside other connection charges.

Matching Distributed Generation charges to Distributed Generation Allowed Revenue

5.14. Electricity North West shall set its Distributed Generation charges on an annual basis to recover and not to exceed the projected Distributed Generation Allowed Revenue (adjusted for the previous year's under/ over-recovery and any allowed transfer of assets into the main distribution price control).

5.15. Where the projected income from setting Distributed Generation charges is expected to over-recover or under-recover the forecast Distributed Generation

[14] SSEG - a Small Scale Embedded Generator is a source of electrical energy rated up to and including 16 Ampere per phase, single or multiphase, 230/400 Volt ac.
[15] All values are indexed by RPI (July to December).

Allowed Revenue generation charges will be varied using a fixed adder revenue reconciliation approach, subject to the following clause 5.16.

5.16. It is recognised that due to the proposed structure of the Distributed Generation charging methodology generation charges may vary over time. In order to provide some stability and predictability of generation charges over this Price Control period it is proposed to minimise the any disturbance by capping the change in nominal generation charges to plus or minus ten percent per annum (except where the current charge is zero).

Format of Charges

5.17. The models deliver charges to be applied to Distributed Generation customers in the following manner:

- EHV Distributed Generation tariff in:
  - pounds per kW per annum (based on Installed Generation Capacity)
- HV, & LV Distributed Generation Export tariff in:
  - pounds per customer; and
  - pounds per kW per annum (based on Maximum Export Capacity)

5.18. Distribution Generation charges are published in Table 4.1 of Section 4 of our Licence Condition 4A document titled 'Statement of Charges for Use of Electricity North West Limited's Electricity Distribution Network'.

Interruption Standard Payment

5.19. Ofgem has proposed that Electricity North West offer an interruption standard payment to Distributed Generation customers when their connection to our distribution network is unavailable, subject to the terms and conditions of the connection agreement with the Distributed Generation customer.

5.20. The facility to receive the interruption payment for Distributed Generation customers connected at LV is covered by The Electricity (Standards of Performance) Regulations 2005.

5.21. Electricity North West will offer a standard interruption payment, of £0.002 kWh^{-1} for every whole hour without network availability (except for pre-arranged outages), to HV and EHV Distributed Generation customers that they have a firm (secure) connection to our distribution network.

G2 Licence Condition 4A Statement

The following sections detail the proposed changes to Licence Condition 4A Statement for the introduction of new LDNO and DG tariffs.

The new table 3.8 to be embedded within Section 3 of Licence Condition 4A statement is shown below.

UoS Charges for Licensed Distributor Connections – available from [1st October 2008/ 1st April 2009]

Table 3.8 Licensed Distributor Tariffs for embedded distribution networks

Description	LLFC	Market	PC	Fixed charge (p/site/month)	Day unit Charge (p/kWh)	Night unit Charge (p/kWh)	Other unit charge (p/kWh)	UMS charge £/kW/month	Reactive Power charge (p/kVArh)	Tariff closed to new customers
LV LDNO Band 1										
LV LDNO Band 2										
LV LDNO Band 3										
LV LDNO Band 4										
HV LDNO										

Accompanying Notes

- The criteria for deciding suitability are:
  - a) Above tariffs only applicable to Licensed Distributor connections, servicing only domestic customers (domestic customers in this context includes connections to customers who would have had a non-maximum demand tariff had they connected to the ENW network);
  - b) LV LDNO applies to LV connections;
  - c) The banding relates to the distance from ENW's local distribution substation to the point of supply to the Licensed Distributor measured along the Low Voltage main; and
  - d) HV LDNO applies to HV connections.
- A Maximum Demand meter is to be installed to confirm the site's maximum demand.
- No excess reactive power charges will be applied to the above tariffs.

Metering functionality for Licensed Distributor Connections

DUoS TARIFF	APPLICATION	DUoS METERING FUNCTIONALITY
LV LDNO (small)	Three phase low voltage connection to Licensed Distribution Network taking 60kVA or less, servicing domestic only customers	kWh 2 rate Maximum demand, kW kVArh
LV LDNO (large)	Three phase low voltage connection to Licensed Distribution Network taking greater than 60kVA, servicing domestic only customers	kWh 2 rate Maximum demand, kW kVArh
HV	Three phase high voltage connection to Licensed Distribution Network servicing domestic only customers	kWh 2 rate Maximum demand, kW kVArh

The amended table 4.1 to be embedded within Section 4 of Licence Condition 4A statement is shown below.

Table 4.1 Distributed Generation Charges

	CONNECTION VOLTAGE					
	EHV	HV		LV[16]		LV - SSEG[17]
		≤ 50% load factor	> 50% load factor	≤ 50% load factor	> 50% load factor	
Standing Charge						£0[18]
£ per annum per kW	Site Specific: range[19]: £2.77 to £20.22[20]	21	18	18	18	£0[15]

[16] Excludes LV connected SSEG
[17] SSEG - a Small Scale Embedded Generator is a source of electrical energy rated up to and including 16 Ampere per phase, single or multiphase, 230/400 Volt ac.
[18] Electricity North West assumes that small scale embedded generation does not export onto its distribution network and therefore no charge will be levied on these generators.
[19] Electricity North West shall calculate a site-specific generation charge for each EHV connected generator. An EHV connected generator can expect to pay a value of between £2.77 and £20.22/kW per annum, depending on the extent of the reinforcement works required to connect it and his/her proportionate share of the reinforcement costs. The lower level is derived from the allowable Operation & Maintenance (O&M) value of £1.11/kW pa and the fixed capacity allowance for Distributed Generation of £1.66/kW pa. The upper level of £20.22/kW pa is derived from the cap of £221/kW (above which the connecting generator will be required to pay the cost of reinforcement in the form of connection charges), assuming the generator pays no proportionate share of the reinforcement costs below this cap.
[20] £/kW of Installed Generation Capacity.
[21] £/kW of Maximum Export Capacity.