UK Power Networks
Business plan (2015 to 2023)
Annex 18: Revenue and Pricing

March 2014

"A reliable... an innovative... and the lowest price electricity distribution group."

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Document History

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Contents

1 Executive summary

1.1 The purpose of this document

This document has been produced to provide information on how UK Power Networks recovers its Allowed Revenue in the form of use of system charges applied to the users of its distribution systems.

1.2 Context

Distribution Use of System Charges will be used to recover price control revenue during the RIIO-ED1 duration. The price control revenue is mainly recovered from energy suppliers who use the distribution systems to transport electricity to their customers. These costs are passed on to their customers as part of their overall electricity charges. Understanding these costs and how they might change is an important part of the business cycle for energy suppliers and many large energy users.

Customers are increasingly seeking energy contracts where the charges are fixed. This can create a risk for energy suppliers if they find it difficult to manage or predict their costs.

1.3 Key proposal

UK Power Networks are active contributors and supporters of the open governance arrangements which underpin the charging methodologies. We will continue to bring forward and support measures that help mitigate charging volatility.

1.4 Benefit summary

UK Power Networks have been actively working to support the open governance arrangements since their introduction in 2010. We are supportive of the current proposal to set Use of System charges with a notice period of 15 months in order to provide more certainty for suppliers and consequently consumers. Advance notice of charges will lower the risk that suppliers face, especially at the start of a price control period. This increased notice is expected to result in lower charges to end consumers as energy suppliers will have more certainty of the level of DUoS to apply to their tariffs and will not need to apply a risk premium for this aspect of their costs.

2 Introduction

2.1 Revenue and pricing activities

UK Power Networks undertakes revenue and pricing activities to ensure that its Allowed Revenue, which is determined through the price control process, is collected from end users in an equitable manner.

The calculation of Allowed Revenue is undertaken using the price control formulae. This calculation is reviewed on a regular basis as or when the supporting data changes. Tariff prices are calculated to recover this Allowed Revenue in accordance with the relevant codes and agreements in place with both Ofgem and users of the distribution system.

Ofgem sets out its obligations for UK Power Networks in the form of a Licence. Conditions of the Licence determine the methodologies that we must use for calculating the charges for users of the distribution system. These methodologies are the Common Distribution Charging Methodology for users connected at either LV or HV and the EHV Distribution Charging Methodology for users connected at extra high voltage.

These common methodologies are incorporated into the Distribution Connection and Use of System Agreement (DCUSA). The DCUSA forms a contractual relationship between the DNOs and energy suppliers and includes the governance arrangements of the common methodologies.

2.2 Structure of this document

The remainder of this document is set out in two chapters. The two chapters provide more detail on how we use our Allowed Revenue and calculate tariffs and what we are proposing to implement, as part of our RIIO-ED1 submission, to help manage volatility in tariffs.

Chapter 3 provides an overview of the pricing process. It includes an explanation of the arrangements that sit behind the common charging methodology and the tariff structures used.

Chapter 4 provides an overview of distribution charging tariff volatility and the open governance arrangements which supports the use of system charging methodology.

3 Collecting our revenue

3.1 Allowed revenue to DUoS (Distribution Use of System) tariffs

Distribution Network Operators (DNOs) such as UK Power Networks are set an Allowed Revenue to cover a price control period. The Allowed Revenue is set at a level to cover most aspects of UK Power Networks' on-going business including maintaining, repairing and replacing network assets. It also includes the costs of reinforcing some network assets. However, the Allowed Revenue does not include costs directly paid for by customers, such as those for new connections.

The boundary between the on-going costs in the Allowed Revenue and those directly paid for is called the Connection and Use of System Boundary. This boundary is currently set at what is termed a 'shallowish' boundary and it is the same for both demand and generation users. The 'shallowish' boundary essentially means that new connections are required to pay for the assets required to connect them to the network and where required to contribute towards the reinforcement of the existing network.

The Allowed Revenue is mainly recovered from the electricity suppliers who use the electricity networks to distribute energy to their customers. The Allowed Revenue is collected through the application of Distribution Use of System (DUoS) tariffs. These charges are then recovered from end users as part of their total energy bill. A smaller proportion of the Allowed Revenue is recovered from other network operators that have their own networks embedded and use part of UK Power Networks network.

The DUoS tariffs are calculated using a combination of two charging methodologies. The first methodology is called the Common Distribution Charging Methodology (CDCM) and it is used to calculate charges to users who are connected to the LV and HV levels of the network. The second methodology is the EHV Distribution Charging Methodology (EDCM) and it is used to calculate site specific charges to users who are connected to the EHV levels of the network.

The methodologies are incorporated into the Distribution Connection and Use of System Agreement (DCUSA). This agreement governs the contractual relationship between DNOs and users of the networks. This agreement also sets out the methodologies and the procedure for interested parties to propose changes.

This paper has been prepared to provide further information on how the DUoS charges are calculated.

3.2 Pricing process overview

The method for determining tariffs starts with the level of the Allowed Revenue which is required to be collected. The Allowed Revenue is calculated using the price control formula as determined by the industry regulator, Ofgem. This formula sets out the Allowed Revenue in annual amounts which includes adjustment for performance against any incentives and for over/under recovery of previous years charges.

This annual Allowed Revenue is then entered into the CDCM and EDCM models, along with other inputs to create the DUoS tariffs.

The DUoS tariffs are then charged to suppliers and the charges collected during the year. The charges collected will not exactly match the Allowed Revenue due to the difference between estimated consumption and actual consumption, and other factors. The difference, over/under recovery, is then an adjustment to the revenue calculation for future years.

3.3 Common methodology

Both the CDCM and EDCM are common charging methodologies that are used across Great Britain by all DNOs. The methodologies were developed through joint collaboration between DNOs, Ofgem and interested stakeholders. The CDCM was implemented in April 2010 for both demand and generation users connected at LV and HV. The EDCM was implemented in April 2012 for demand users connected at EHV and in April 2013 for generation users connected at EHV.

While the methodologies are identical across all DNOs the inputs to the methodologies reflect the characteristics of the network and the number and mix of consumers in each DNO area. Therefore the London network will reflect that there are no overhead lines while the Eastern and South Eastern networks will reflect that there are both underground cables and overhead lines.

Charging commonality has brought a number of benefits to Suppliers and other users of the distribution networks. The biggest benefits have been:

- The move from more than seven different charging methodologies for LV / HV tariffs and site specific charges to one for HV / LV and site specific
- The consolidation of more than seven sets of tariff structures including many legacy tariffs to one condensed set of common tariff structures
- The incorporation of the charging methodologies into DCUSA so that any interested parties can bring forward change proposals through the governance process.

Since the incorporation of the methodologies approximately forty five change proposals have been initiated. These proposals have been progressed to bring further enhancements to the methodologies including changes to reduce volatility in the movement of tariffs from one year to the next.

3.4 Tariff structures

The CDCM and EDCM apply tariff structures based on four tariff components. The application of a tariff to a particular customer will depend on the voltage of connection and then whether the customer is half hourly metered and settled, non-half hourly metered and settled or an unmetered connection. If the customer is non-half hourly metered and settled then the customer's profile class will also be considered. The profile class provides further information about the type of customer and metering, for example domestic or non-domestic and single rate or multi rate meter.

Customers that are half hourly metered are typically larger commercial and industrial sites, with greater than 100kW of maximum demand. At these sites half hourly metering is mandatory.

Customers that are non-half hourly metered are the domestic and smaller commercial and industrial sites with maximum demands less than 100kW. These customers are split into 'profile classes' which provide further information of the type of customer.

Customers that are unmetered have predictable load that is less than 500W. Typically this type of load is street lights and other road side equipment. However, some users choose to 'pseudo meter' these supplies and their usage is measured using a sample meter and then the measurement is multiplied by the aggregated number of similar equipment.

The four tariff components are listed in Table 1.

Table 1 List of tariff components and restrictions on their application

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

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

Unit rates are used to recover the 'upstream' cost of using the network, furthest from the customer's point of connection. These are typically costs that can't be attributed to any one user. With unmetered supplies unit charges are used to recover all costs.

Capacity charges and reactive power charges are only applied to half hourly settled tariffs. Capacity charges are allocated to reflect local assets that have to be sized to meet the specific needs of the connected customer.

The fixed charge typically reflects the cost of maintaining the service connection which is between the point of connection and the nearest main conductor. Additionally for non-half hourly metered sites because they do not have capacity charges then the fixed charge will also be used to recover some local asset costs.

For users that are acting as embedded licensed distribution network operators, tariffs are "portfolio tariffs" with the same tariff components as the corresponding "all the way" end user tariff, excluding reactive power charges.

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

3.5 Tariffs

The CDCM currently has twenty five tariffs and the vast majority of these are for non-half hourly metered sites. The increased number reflects the need to differentiate between different customer groups to reflect the different consumption patterns.

The demand tariffs for metered sites are detailed in Table 2. There are additional tariffs for unmetered connections and generation connections.

Table 2 List of CDCM tariffs for metered sites

Tariff	Time Bands	Use
Domestic Unrestricted	One	Used for domestic supplies where there is only one meter register.
Domestic Two Rate	Two	Used for domestic supplies where there is more than one meter register and often used for off peak heating.
Domestic Off Peak (related MPAN)	One	Used for domestic supplies where there is an additional meter with a restricted register meter.
Small Non Domestic Unrestricted	One	Used for non-domestic supplies where there is only one meter register.
Small Non Domestic Two Rate	Two	Used for non-domestic supplies where there is more than one meter register and often used for off peak heating.
Small Non Domestic Off Peak (related MPAN)	One	Used for non-domestic supplies where there is an additional meter with a restricted register meter.
LV Medium Non-Domestic	Two	Used for the larger non half hourly metered sites.
LV HH Metered	Three	Used where half hourly metered sites is connected to the LV network.
LV Sub HH Metered	Three	Used where half hourly metered sites is connected at an LV substation.
HV HH Metered	Three	Used where half hourly metered sites is connected to the HV network.

The EDCM has charge rates that are site specific and therefore different for each customer. The structure of these tariffs is the same with each customer receiving a fixed charge, capacity charge and one 'super-red' unit rate. The 'super-red' unit rate only covers consumption in the peak demand period which is November – February 16.00 – 19.00 (except in London where an additional period June to August 11.00 – 14.00 also applies).

3.6 CDCM and EDCM applicability

The charging methodology applicable to any site depends on the point of connection of the site to the network. All LV sites and most HV sites have their charges calculated using the CDCM. These properties are called 'designated properties' for the purposes of DUoS charging.

All EHV sites have their charges calculated using the EDCM. Some eligible HV sites will have their charges calculated using the EDCM. These sites must be connected to and metered at an HV Substation and therefore while they are connected at HV they do not make use of any HV network. EDCM properties are called 'designated EHV properties' for the purposes of DUoS charging.

LV represents voltages below 1000V and typically 230V single phase and 415V three phase. HV represents voltages between 1000V and below 22,000V, typically 11,000V. EHV Is all voltages from 22,000V and will normally be voltages of 33,000V and 132,000V.

3.7 CDCM methodology overview

This section provides a brief overview of the CDCM methodology. For a more detailed description the methodology is contained in Schedule 16 of DCUSA.

Figure 1 gives a general overview of the four main steps in the CDCM methodology.

Step 1 involves the gathering of information about the network, the costs of assets and operations, the users of the network, and the forecast level of use and level of allowed revenue in the charging year.

Overall there are twenty seven tables that require populating with information. The basis of cost data is the distribution reinforcement model otherwise known as the '500MW' model.

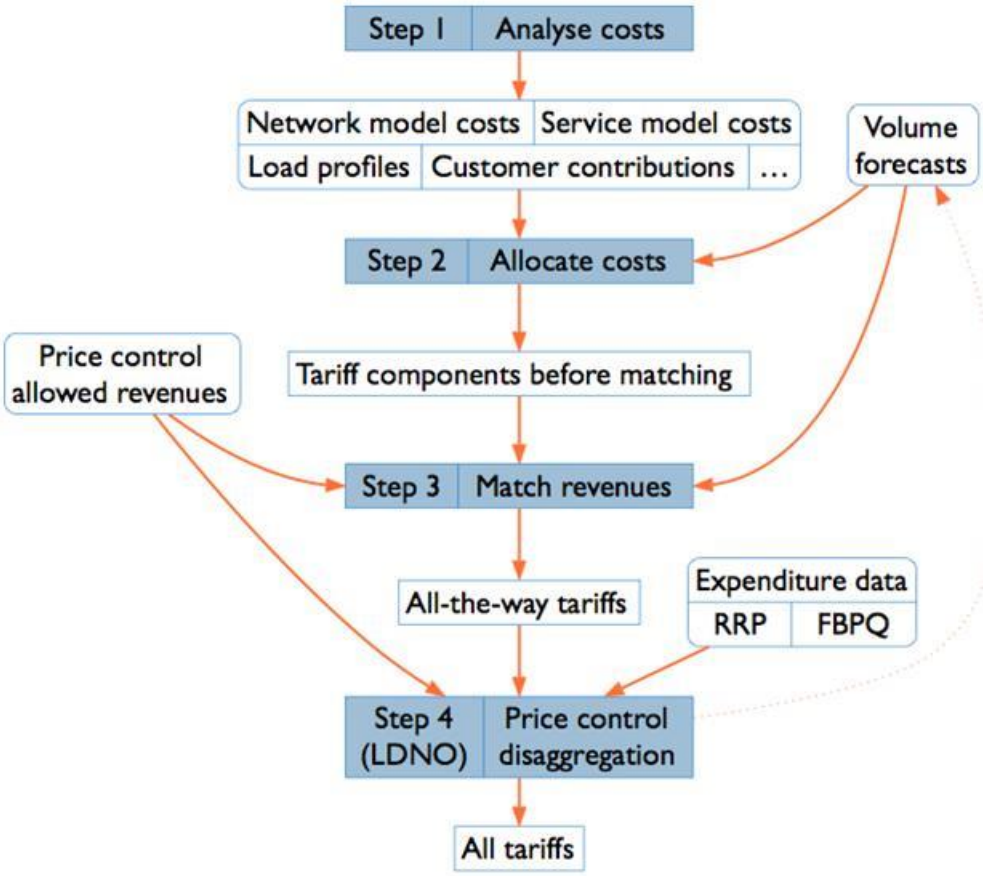
The 500MW model consists of a costed design for a hypothetical increment to the licensee's distribution system. At each network level, the model is sized to provide secure capacity to meet demand that, aggregated up to individual grid supply point (GSP) level, amounts to 500 MW of simultaneous maximum demand.

The assets included in the network model are modern equivalent assets of the kind that the licensee would normally install on new networks. The nature, quantity and size of assets in the model is such as to meet demand and security to the licensee's design and planning standards, allowing for the use of standard size equipment and typical utilisation factors.

The proportion of assets of different types at each network level, e.g. overhead and underground circuits, reflects the mix of users and the topography in the licensee's area. The cost assumed for each asset type reflects total purchase and installation cost in the charging year, using the licensee's normal procurement methods.

The extent that customers contribute to the cost of their connections is taken into consideration. These contributions, which are calculated for the charging year, are then used to reduce the charge to customers to avoid double charging.

Figure 1 CDCM Overview



Service models are established to reflect the modern equivalent asset value of the typical or average type of service connection for each customer group. These are then used to establish the cost of maintaining those assets. These costs are generally recovered through a fixed charge.

An estimate of the DNOs allowed revenue and an estimate of other associated costs are included. These other costs include transmission exit charges and network rates and a breakdown of direct and indirect costs. Another input is the revenue collected outside the CDCM which will also include the revenue collected from the EDCM.

Finally a variety of consumption data is used to provide network usage data and tariff group consumption data including volume forecasts for the charging year. This data is used for a variety of uses and includes establishing; the three network time bands for half hourly tariffs, the load characteristics and the times when the network peaks.

Step 2 is the application of the cost allocation rules. These rules are only for all-the-way tariffs and do not apply to Licensed Distribution Network Operator (LDNO) tariffs. The cost and revenue allocation is driven by a representation of the different voltage and transformation levels in the network and by a distinction between the elements of cost related to assets and those related to operations.

Within the model there are eight levels of network cost allocation representing the network levels from 132kV down to LV. The various cost inputs are allocated to each level using appropriate allocation methods. The costs are converted to annuitised values using the current regulatory rate of return and a 40 year depreciation period.

Using the tariff group data the different tariff groups can be costed at each network level. This cost allocation takes into consideration loss adjustment factors, diversity and the impact of each group at each level. Generation users are seen to offset the demand costs at the each of the network levels above the point of connection.

At the end of **step 2** the methodology calculates 'yardstick' tariffs which are identical in structure to the final tariffs. These 'yardstick' tariffs now need to be adjusted to match the allowed revenue recovery requirement.

Step 3 involves these adjustments to the tariff components calculated in **step 2** in order to match revenue recovered from the CDCM to the amount of revenue allowed under the price control conditions.

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

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

The final tariffs for demand (before rounding and application of LDNO discounts) are determined on the basis of an allocation with the single adder included in costs. Tariffs for generation do not have any revenue matching element. This is on the basis that generation only offset cost allocated and that they do not offset other costs which haven't been allocated.

Step 4 uses a price control disaggregation model in order to determine discount percentages, which are then applied to all-the-way tariffs in order to produce LDNO tariffs. The model calculates the discount percentages by allocating price control cost data to four network levels: LV, HV/LV, HV and EHV.

The discount percentages are applied to all tariff components in all-the-way tariffs in order to determine embedded network portfolio tariffs. These tariffs are then charged to embedded network operators to reflect the cost of the network that they are using upstream of their network.

3.8 EDCM methodology overview

This section provides a brief overview of the EDCM methodology. A more detailed description of the methodology used by UK Power Networks and covering both Demand and Generation is contained in Schedule 18 of DCUSA.

Schedule 18 of DCUSA sets out the principles and detail that should be adopted as the common approach to EDCM Use of System Charging based on the Long Run Incremental Cost (LRIC) model, which is used in all three of the UK Power Network regions.

The LRIC model calculates Nodal incremental costs. These costs represent the brought forward (or deferred) reinforcement costs caused by the addition of an increment of demand or generation at each network Node. The method models the impact changes in Connectees' behaviour have on network costs.

In particular, the LRIC model uses AC power flow analysis, which enables the calculation of the time needed before elements of the network require reinforcement and subsequently the net present value (NPV) of the future costs of reinforcement. The incremental cost is equal to the difference in the NPV of reinforcing under existing conditions and when an increment of new demand or generation is added.

To calculate Use of System Charges for EDCM Connectees (demand and generation), the LRIC EDCM method involves four main steps;

Step 1 is the application of load flow techniques and the LRIC methodology to determine the EDCM tariff elements, known as charge 1.

Charge 1 (£/kVA/year). The charge 1 is broken down into two components:

- One related to the voltage level of connection (Charge 1 Local)
- The other related to all other levels (Charge 1 Remote)

Charge 1, if positive, relates to future demand-led reinforcement costs associated with demand at the relevant location. It is therefore expected to drive charges to demand and corresponding credits to generation, where generation can be considered to avoid or defer the need for future demand-led reinforcement.

Step 2 involves the allocation of DNO Party costs to Connectees using appropriate cost drivers. Most of these inputs are the same inputs as used in the CDCM.

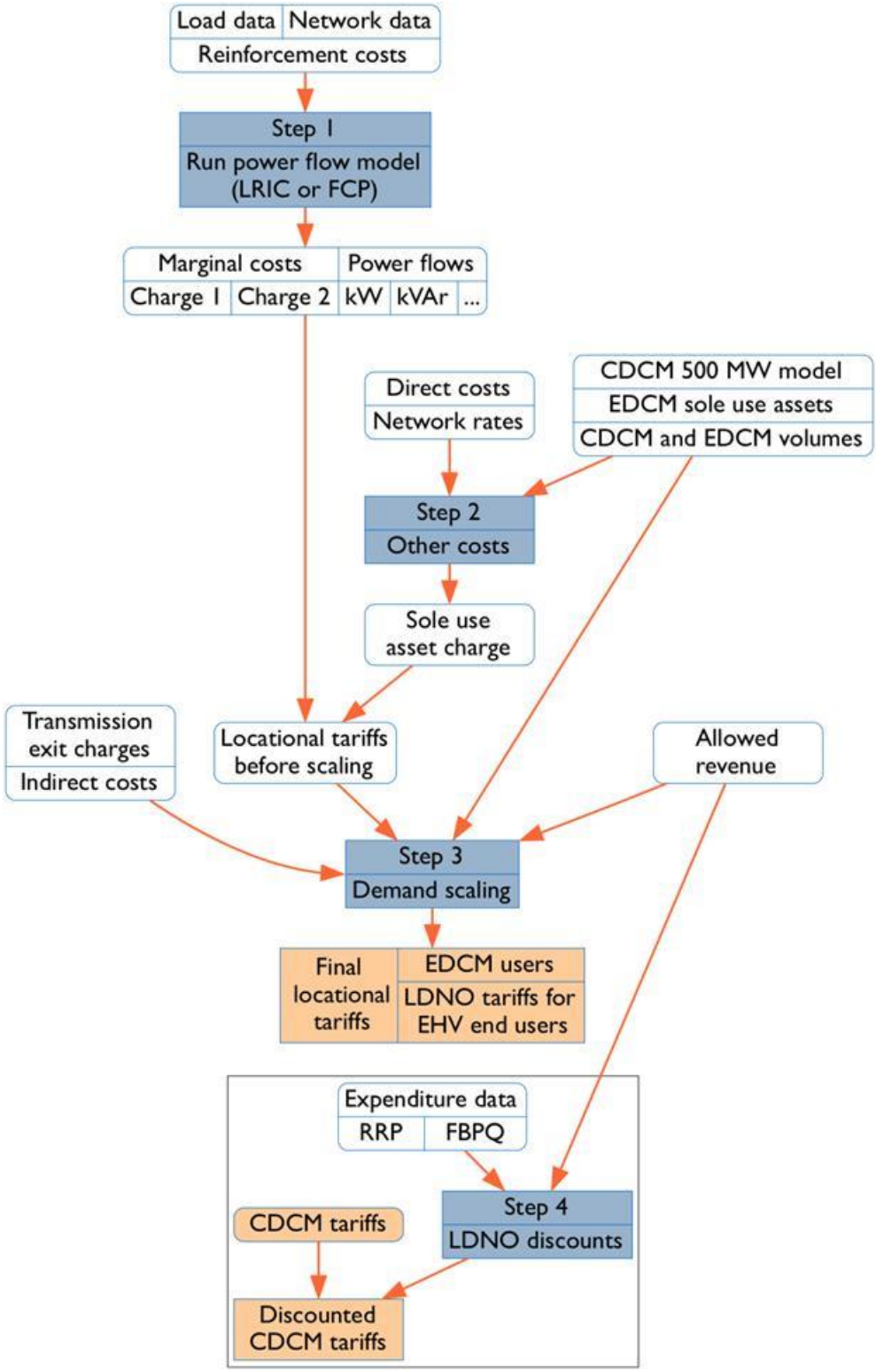
Step 3 adds a scaling element to tariffs which is related to Allowed Revenue.

Step 4 uses CDCM tariffs and a price control disaggregation model to determine the element of portfolio tariffs to be applied in the case of embedded LDNOs who are supplied from the DNO Party's network at voltages higher than the scope of CDCM tariffs.

The discount percentages are applied to all tariff components in all-the-way tariffs in order to determine embedded network portfolio tariffs. These tariffs are then charged to embedded network operators to reflect the cost of the network that they are using upstream of their network.

These steps are shown in Figure 2.

Figure 2



The EDCM is designed to produce cost reflective use of system charges to encourage existing and new users of the electricity distribution networks to use existing network capacity more efficiently; and avoid prompting inefficient network reinforcement. Where the EDCM leads to lower investment in the distribution network, this will result in lower use of system charges for all customers over time.

4 Managing DUoS charging volatility through ED1

4.1 Context

Distribution Use of System (DUoS) charging volatility is a concern to suppliers and end consumers. This is especially true at the start of a price control period, when a large step change in revenues may be experienced within a very short notice period, and when the outcome of any incentive mechanisms is uncertain.

Suppliers have indicated that they manage uncertainty by applying a risk premium to their tariffs which consequently impacts the price consumers pay for their energy. Suppliers have stated that if there was more notice of future price change then this would be reflected in lower prices to consumers.

4.2 Background

UK Power Networks' price control revenue requirements are mainly recovered from the electricity suppliers who use the electricity networks to distribute energy to their customers. The revenue is collected through the application of DUoS tariffs. These charges are then recovered from end users as part of their total energy bill. A smaller proportion of the Allowed Revenue is recovered from LDNOs that have their own networks embedded within and use part of our network.

The current licence and use of system agreements establish a requirement to hold an annual review of charges and to provide notice to Ofgem and users when a change is required. The current notice period for indicating a change is 3 months, with the actual charges finalised with a minimum notice of 40 days.

Due to a combination of factors the minimum notice periods are increasingly seen by suppliers and end consumers as being too short. The combination of factors is:

a) Allowed revenue has become more volatile due to price control incentive and uncertainty mechanisms and the removal of volume drivers
b) Suppliers are increasingly offering longer fixed term contracts to meet consumers' needs
c) Tariff movement volatility between DUoS tariffs and tariff components due to changes to the common charging methodologies

Suppliers have indicated that reducing the volatility possibly by providing more notice would help them by reducing the uncertainty that they experience and thereby helping to reduce costs on end consumers by allowing suppliers to remove the risk premiums that they apply to tariffs to mitigate their risk exposure.

In April 2012 Ofgem consulted, seeking views on network charging volatility. In their decision document, published in October 2012, Ofgem set out several changes that will be implemented as part of ED1. These include:

a) Improved information to suppliers and customers
b) Restricting mid-year charge changes
c) Increasing the lag on incentive reward/penalties
d) Increasing the lag on some uncertainty mechanisms

UK Power Networks realises that it has a major part to play in ensuring that costs to consumers are minimised. We remain supportive of restricting mid-year changes and increasing the lag on incentive and uncertainty mechanisms.

It is also our belief that the decision taken by Ofgem in December 2013, to finalise revenues for 2015/16 for slow tracked companies in July 2014, will assist Suppliers to manage the impact of the introduction to a new price control.

4.3 DUoS charging volatility

DUoS charging volatility is experienced either through unforeseen change to the year to year allowed revenue or through year to year changes between individual tariffs.

Allowed Revenue price volatility is somewhat inherent in the current price control mechanism due to the nature of relatively predictable fixed base revenues moving due to the combined effect of incentive mechanisms, pass-through costs and over/under recovery. These changes in revenue are then recovered at the next price change opportunity due to the requirement to set prices so that the DNO is not in an over recovery position at the end of the following regulatory year.

Additional volatility has been experienced at the start of price controls due to changes in DNOs' allowances and due to the timing of the settlement of the price control reviews.

Tariff movement volatility has been a 'feature' of the DNOs' common charging methodologies. This is especially noticeable with the site specific charges applied to EHV sites, whereby changes to network configuration and power flows of electricity used can materially affect a user's charges. Tariff volatility can also occur in generic LV & HV tariffs where unexpected increases or decreases in individual tariff components can be caused by year on year changes to modelling characteristics.

Work is progressing between DNOs and industry stakeholders to minimise volatility through methodology changes, and further work is progressing through the governance process. Overall, suppliers have stated that they can manage volatility if it is predictable or foreseen.

UK Power Networks is an active supporter of industry working groups and has put forward or has provided the chairperson for many change proposals aimed at improving the charging methodologies for the benefit of end consumers. These change proposals include:

a) DCP133 - 500MW Network Common Model for CDCM Input
b) DCP137 - Introduction of locational tariffs for the export from HV generators in areas identified as generation dominated
c) DCP169 - Seasonal Time of Day (SToD) HH Metered Tariffs in the CDCM
d) DCP178 – Notification Period for Change of Use of System Charges

4.4 Managing tariff movement price volatility

Tariff movement volatility is a consequence of the charging methodologies used to calculate prices. Since the methodologies were implemented, work has been undertaken through DCUSA to reduce the level of volatility and further work is being progressed.

The work already implemented has involved the smoothing of some inputs over three years and the result is that intra-tariff volatility has reduced. Previously data movements between years could cause fairly large changes between tariffs that were hard for Suppliers and Consumers to understand. For example, HV tariffs would reduce while other tariffs would increase (or vice versa). The smoothing has reduced these aspects.

DNOs are also currently looking at implementing changes to the EDCM in order to reduce the level of volatility. It is expected that some change will be progressed to smooth some of the inputs over three years. Any change brought forward will compromise Ofgem's original desire for cost reflective charges with users' needs for more stable predictable costs. DNOs are currently reviewing the responses to a consultation on the options that could be implemented to reduce volatility.

UK Power Networks is also actively supporting the DCUSA change proposal to set charges with a notice of 15 months (DCP178) which is believed will provide more certainty for suppliers and consequently consumers. Advance notice of charges will lower the risk that suppliers face. This increased certainty is expected to result in lower charges to end consumers as suppliers will know the level of DUoS to apply to their tariffs and will not need to apply a risk premium for this aspect of their costs. A final decision on whether or not to implement DCP178 is likely to be known in early summer 2014, based on current work projections.

4.5 Conclusion

There is an expectation from both Ofgem and stakeholders that volatility of DUoS charges needs to be managed so that overall costs to consumers can be reduced. Volatility can be managed through providing improved predictability by increasing the notice given of price changes. The decision taken by Ofgem in December 2013 to finalise the DNO revenues for 2015/16 in July 2014 will also greatly assist all parties in managing the transition to a new price control period.

UK Power Networks remains committed to working with other DNOs and stakeholders to address volatility within the DUoS tariffs. Some work in this area has already been undertaken and has reduced intra-tariff volatility, however further work is progressing and we feel that this is the appropriate route for additional improvements.