ECONOMIC CHARGING METHOD FOR ELECTRICITY DISTRIBUTION NETWORKS

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ABSTRACT

A long run forward looking incremental cost charging methodology has been developed to apply to the 132, 66 and 33kV networks in South West England and South Wales. It utilises a full AC load flow and N-1 security assessment to identify reinforcement needs and timings. Increments of demand and generation are added to the model to identify the change in timing of future investment which is used to derive incremental annual charges for both demand and generation connections. The method has been integrated with the existing method for setting charges for lower voltage networks and approval from Great Britain's Gas and Electricity Market's Regulator, Ofgem, is currently being sought to implement the revised method from 1st April 2007.

INTRODUCTION

The main purpose of this work was to identify and implement an economic charging method for setting prices for the use of the Western Power Distribution (WPD) electricity distribution networks in South Wales and South West England. These networks cover all voltages from 132kV down to customer terminals and provide supplies to 2.5m customers. The method needs to meet the criteria in WPD's Licence, overseen by Great Britain's Gas & Electricity Market's Regulator, Ofgem, which include cost reflectivity and facilitating competition. A particular aim was to reflect the 'lumpiness' of distribution system reinforcement and pass this cost message onto system users so that they can factor this in to their decisions on location and changes to the demand requirements or generation output that they place on the network.

BACKGROUND

The method for setting prices for use of the distribution network within WPDs service territory is based on the 500MW Distribution Reinforcement Model (DRM). The DRM uses an approach outlined by TA Boley and GJ Fowler in 1977 [1] for cost reflective retail tariffs in England and Wales.

The DRM model measures the costs of an additional 500MW of capacity at the time of peak demand and averages this cost across users at each voltage level. Therefore, the DRM represents most closely an average cost for customers at given voltage levels at peak demand within the marginal 500MW increment.

The model is used to determine yardstick costs by customer class. The contribution of a customer group to peak demand (the coincidence) is the method by which costs are divided between groups, taking into account diversity factors and load profile. This method is used because consumption for non half hourly metered customers is not measured at times of peak. Coincidence factors based on load research therefore form the basis for different tariffs to take account of different usage at peak.

Whilst the DRM approach has served well, its continued use at 132, 66 and 33kV levels has been criticised due to the lack of locational message and its inability to reflect the costs and benefits that distributed generation provides.

When the DRM was developed, there were few distributed generators and on privatisation of the Electricity Industry in England and Wales in 1990, distributed generation continued to pay a deep connection charge and no use of network charge. The Industry Regulator changed this from 2005 [2] so that distributed generators now pay a shallowish connection charge (calculated in the same way as the connection charges for demand connections) and an ongoing use of network charge.

This approach is intended to ensure that generators are exposed to the ongoing costs and benefits that they impose on the network and hence result in the most economic development of the network over the long term by influencing the location and connection/disconnection decisions made by all system users. To ensure that this revised framework gives the desired outcome, a new economic charging method is needed to impose the appropriate network costs onto users.

APPROACH TAKEN

To assess possible methods that could be used, we place a research contract with the University of Bath. The contract had the specific objectives of developing a model of the WPD distribution network for the purpose of evaluating different methodologies for charging users for use of the distribution system.

The University of Bath initially assessed an Investment Cost Related Pricing method [3] however the symmetrical nature of this approach gave strong incentives for generators to connect to remote parts of the network and gave little incentive to connect to heavily utilised urban networks where generation can be beneficial. Additionally, it did not reflect the 'lumpiness' of distribution reinforcement where quite small increases in the use of the network can trigger large increments of reinforcement capacity.

Subsequently, the Long Run Incremental Cost approach was developed specifically to look at the time horizon until reinforcement is needed and to factor in the cost of that reinforcement. This method was also used in a piece of research that the University of Bath undertook for Ofgem [4] which argued that economic method of charging like the LRIC approach are likely to result in significant savings in network reinforcement costs that will be to the long term benefit of end customers.

The basic method developed by the University of Bath has been further developed by the addition of a full N-1 contingency analysis and the use of system studies at both winter peak and summer minimum conditions.

ADOPTED APPROACH

Outline of Long Run Incremental Cost (LRIC) Method

The LRIC method calculates the brought forward (or deferred) reinforcement cost as a result of the addition of an increment of demand or generation at each node. The objective is to link the impact of the behaviour of a user to reinforcement of the assets they utilise.

An initial load flow is used to determine the time it would take for each asset to reach its capacity assuming underlying utilisation levels and growth rates. Given these timings, and the future reinforcement costs, a net present value of the future reinforcements cost for the network is calculated using a discount rate equal to the cost of capital assessed by Ofgem as part of the price control (currently 6.9%).

For each node, an increment of demand/generation is added and a new load flow generated. The evaluation of the net present value of the future reinforcement is repeated for the network with this increment present. The difference between the initial and incremental study represents the impact on future reinforcement investment and this is represented as an annual £/kVA at each node by multiplying the difference by an annuity factor.

The above analysis is undertaken for both winter loading conditions and summer loading conditions using the appropriate ratings for the season. A combination of the winter and summer studies is used to determine the prices for demand and generation.

Basis of calculation

If a network component has a capacity of C, and supports a power flow of D, then the number of years it takes to grow from D to C for a given load growth rate r can be determined from the equation:

$$C = D \times (1+r)^n$$

where n is the number of years D takes to reach C.

i) Assuming a yearly load growth of r, a starting loading on the asset of D and an asset capacity of C, then the following investment time horizon until reinforcement is determined:

$$n = \frac{\log C - \log D}{\log(1+r)} \text{ years}$$

ii) If the future investment is the same value as the current circuit, its present value, with a discount rate of d, after n years will be:

$$PV = \frac{Asset}{(1+d)^n}$$

where *Asset* is the MEA value of the asset

iii) New reinforcement time horizon post injection of demand or generation

$$n_{new} = \frac{\log C - \log D}{\log(1+r)} \text{ years}$$

iv) Present value with the earlier future reinforcement:

$$PV_{new} = \frac{Asset}{(1+d)^{n_{new}}}$$

v) Difference in present value:

$$\Delta PV = PVnew - PV$$

vi) Charges are then annuitised:

$$\Delta U = \Delta PV * annuityfactor$$

Detailed data assumptions

The following data is needed for the analysis:

- The EHV network expected to exist in the year that charges are being calculated for. The network is detailed in our Long Term Development Statement (published in accordance with Standard Distribution Licence Condition 25)
- The security factors applicable to each asset derived from a full N-1 contingency analysis of the network
- A modern equivalent asset (MEA) value for each element of the EHV network
- An assessment of future reinforcement costs for each element of the EHV network
- Network demands expected for the year that charges are being calculated for.
- Generation exports consistent with the export that can be used to support system security in accordance with our security standard expected for the year that charges are being calculated for
- The underlying demand and generation growth forecast for the medium term

The method is sensitive to the growth assumption and the security factor. To facilitate stability, a long term growth assumption is used and the sensitivity to security factor, necessitates a full N-1 contingency analysis of the network.

The full method is described in the methodology change request report to Ofgem [5] and in the proposed methodology statement [6], both available from www.westernpower.co.uk.

Integration of LRIC method with continued use of DRM at lower voltages

Consideration was given to the use of the LRIC methodology at lower voltages (11kV and LV) however the volume of data needed coupled with the lack of customer billing and settlement systems to charge location prices at these voltage levels results in few benefits being gained from changing the existing method at these voltage levels.

Use of the two methods (LRIC at EHV and DRM at lower voltages) requires the required revenue to be split between the voltage levels. This is split in proportion to the modern equivalent asset (MEA) values of the networks.

The marginal charges that result from the LRIC methodology are reconciled to the required revenue by the use of a £/kVA adder to minimise distortion of the marginal charges.

Results

The resulting distribution of EHV nodal prices for winter peak conditions for the network in South Wales is shown in the following graph:

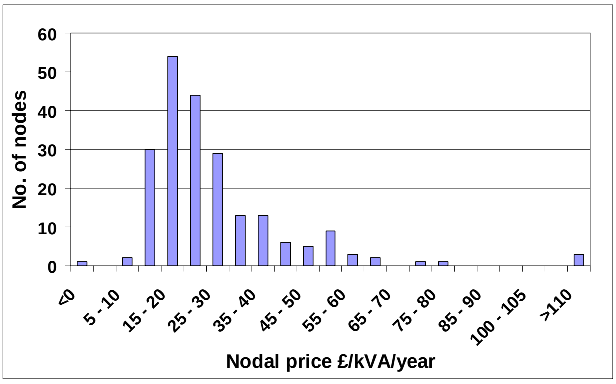

Chart 1: Distribution of EHV nodal prices for winter peak conditions

For existing demand connections to the EHV network, there will be price disturbance between -99% and +582% compared to prices derived from the existing methodology on implementation of the revised methodology. Whilst these are large, the use of network charge comprises around 15% of these customers electricity charges and hence the effect on overall charge is reduced.

Generators connected prior to April 2005, the vast majority, do not currently pay use of network charges and Ofgem are currently considering how these should be brought into line with those that connected after April 2005. The following table shows the range of charges that generators in South Wales would be subject to if they were liable for use of network charges.

Generation Technology	Installed Capacity (kVA)	£/kVA/ year
Biomass	13,000	0.5
CCGT	240,000	7.3
Hydro	5,600	7.9
Land fill gas	2,300	-20.4
Land fill gas	5,100	-10.7
Land fill gas	4,400	-1.6
Other generation	10,000	-4.0
Other generation	10,000	0.0
Other generation	9,600	0.1
Waste Incineration	5,000	-2.8
Wind	50,700	0.0
Wind	75,000	0.0
Wind	8,800	0.4
Wind	30,000	0.4
Wind	9,000	0.6
Wind	10,590	0.8
Wind	10,400	1.3
Wind	6,860	2.1
Wind	3,700	5.8
Wind	33,700	7.0
Wind	12,000	9.5
Wind	44,200	15.6

Table 1: Illustrative charges for generators connected to the EHV network

It should be noted that whilst some generators will be paid as they benefit the network; no windfarms receive payment as the security standard used in Great Britain does not give windfarms any contribution to system security for first fault conditions at winter peak loading.

IMPLEMENTATION

The method has been fully developed and applied to the distribution networks in both South West England and South Wales. An application has been made to the sectors Regulator, Ofgem, to implement the method from 1st April 2007. Ofgem have issued a draft impact assessment for views prior to making a decision on whether to allow implementation to proceed.

CONCLUSIONS

Building on the research work that the University of Bath undertook for WPD, a detailed methodology for setting use of network charges at the 132, 66 and 33kV voltage levels has been developed that:

- Produces cost reflective forward looking charges
- Reflects the ‘lumpiness’ of distribution system reinforcement
- Has been integrated with the method used to set charges at lower voltage levels

The sector Regulators approval is currently being sought to implement the revised method from 1st April 2007.

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