IMPROVED INCREMENTAL COST RELATED PRICING MODEL FOR USE-OF-SYSTEM PRICING

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ABSTRACT

This paper presents the findings of a project initiated in United Utilities to develop options for economic use-of-system charging at the extra high-voltage level. Following the proposal of a class of cost models, it was found that the improved incremental cost-related pricing model plays a central role because it meets a number of assessment criteria. An integral part of the pricing methodology is network expansion planning, whose aim is to determine timing, volume and cost of future reinforcements. The cost attribution is done on a nodal basis using marginal cost principles and the DC loadflow model.

INTRODUCTION

Distribution Network Operators (DNOs) are regulated in the UK by Ofgem who approves their charging methodologies and statements of charges. Ofgem is encouraging introduction of economic distribution use-of-system (DUoS) charging in order to support efficient network development and achieve reduction of costs to customers. DNOs will submit proposed new methodologies to Ofgem for approval, who will assess these against specific criteria, principally facilitation of competition, cost reflectivity, predictability/ stability and transparency.

Currently applied methodologies for transmission and distribution pricing can be classified as either *value-based*, *bid-based* or *cost-based* [1,2,3]. While value- and bid-based methodologies are most frequently used for pricing of wholesale markets and transmission systems, the cost-based methods are most suitable for DUoS charging. These methodologies are further classified as *embedded (rolled-in)* methods, *incremental/marginal* methods and *composite* (embedded and incremental/marginal) methods [4]. Embedded methods make use of the total network costs and they are based on the *average* cost concept (slope tgα in Fig. 1). Incremental and marginal methods are used where additional costs incurred by new customers need to be determined, or where economic pricing [5] is applied. Here, either finite differences (*incremental* cost) or actual tangents (*marginal* cost) are being used (slopes tgβ and tgγ in Fig. 1). These methods are further classified as either *short-run* or *long-run*, where the difference is inclusion of the capital costs in the latter case. Composite methods are often viewed as the best cost-based methods because they take advantage of both groups of methods they represent.

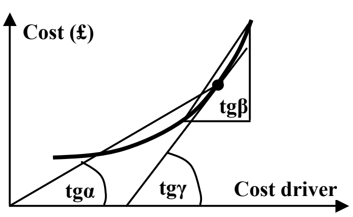

Figure 1 – Average, incremental and marginal costs

In this paper an improved incremental cost related pricing (ICRP) model is proposed for DUoS charging at the extra high-voltage (EHV) level (25 kV and above). The model is a generalisation of the "standard" ICRP model [6] in the sense that the actual network reinforcements and their timings are modelled. The marginal-cost based charges derived from the new model contain an additional term that reflects the overall utilisation of assets. Thus, the total marginal-cost based charges give "correct" economic signals to customers. The entire methodology is presented as follows: the overall approach is given first, which is followed by a brief description of the network expansion planning approaches used. Cost modelling and cost attribution are the focal points, while real-life examples and conclusions are presented in the closing sections.

OVERALL APPROACH

The main building blocks of the developed charging methodology are shown in Fig. 2. The entire United Utilities EHV network (132 kV & 33 kV), consisting of around 2000 nodes, is modelled on a nodal basis. The DC loadflow model is selected at present to model the active power flows, while it is envisaged that a decoupled linearised model could be used in future to model reactive power flows as well. Two versions of the expansion planning module are tested. The first is predictive method whereby each network component is treated separately from all other assets, while the second is a more detailed method. Cost modelling and cost attribution represent the hearth of the developed methodologies. A family of cost models was developed and it was concluded that the improved ICRP model is a viable option for implementation. Cost attribution is done by performing a full contingency analysis

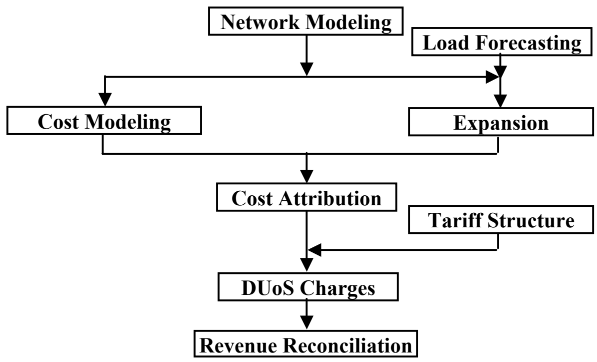

Figure 2 – Overall charging methodology

and considering multiple operating regimes. DUoS charges are generated in the next step from the locational charges (i.e. marginal-cost based), non-locational charges and tariff structure. These charges are finally adjusted to recover the total revenue allowed by regulation.

EXPANSION PLANNING

Network expansion planning is aimed at determining the timing, volume and cost of reinforcements which are then fed into the cost attribution module. Two possible approaches are briefly discussed below.

Predictive Expansion Planning Method

The timing of reinforcement of each of the network branches is found from the present power flows, assumed demand/generation growth rates and ratings of all branches [7]. It is further assumed that *each* branch is reinforced once, no matter how far in future. This method is arguably not appropriate for meshed networks (although it has been tested for comparative purposes), due to the interdependence of assets.

Detailed Expansion Planning Method

Distribution networks are designed to comply with the design standards, which are based on the concept of demand groups and set out in engineering recommendations [8]. The analysis of networks is done for each year of the planning period and the considered regimes are typically winter peak, summer peak and summer minimum (Fig. 3). Active power flow, approximate reactive power flow and fault analyses of the intact network are done first. If all constraints are met, a screening phase, aimed at finding the substations whose capacity is insufficient under the outage conditions defined by the demand class, is initiated. All demand groups and corresponding classes are established next, which determines the type of contingency (i.e. single or single and double) and restoration procedure that need to be applied. If some of the constraints are not met, a single reinforcement is applied at a time and the network analysis procedure is rerun. This method is general in nature and it gives reinforcements of *a subset* of the branches in the planning period.

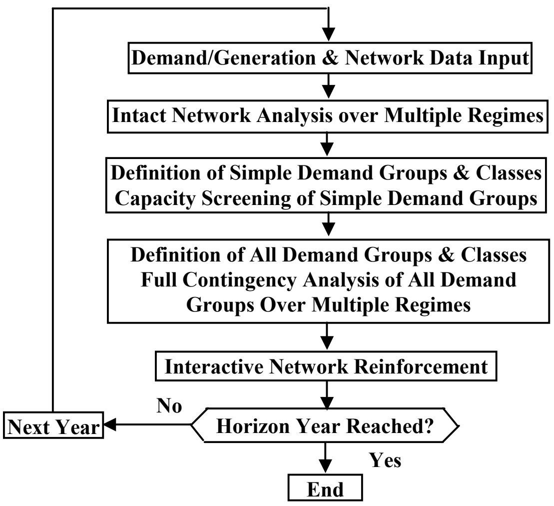

Figure 3 – Detailed Expansion Planning

COST MODELLING

Composite cost-based methods often make use of the assumption that the overall cost can be classified into two categories. The first is made of network investments that are triggered by locational investment drivers. These are typically load-related (i.e. reinforcement) costs and their attribution is done using a marginal (or incremental) cost allocation method. The second group refers to non-load related (i.e. replacement) and office costs which are treated on a non-locational basis and attributed using a variant of the averaging procedure.

The primary driver of reinforcement cost is the requirement for circuit capacity, based on peak flow in the asset, which is driven by the MVA capacity of demand and generation customers. The typical relationship, shown in Fig. 4 as the "True Cost" function, is discrete in nature due to "lumpy" investments carried out at instants when the asset capacity limit is reached. Modelling of the investment costs can be done in several ways and it is discussed in the following subsections.

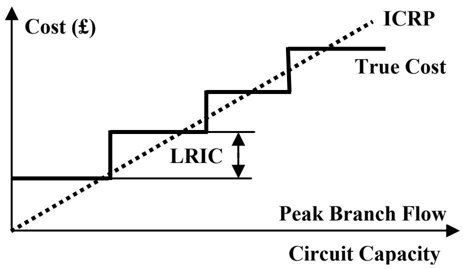

Figure 4 – Reinforcement cost – peak flow relationship

Incremental Cost Related Pricing Model

The ICRP model is based on the assumption that the investment costs can be approximated with a straight line whose slope is equal to the fixed marginal cost in £/MW (line ICRP in Fig. 4). Then, the branch cost is equal to:

$$Cost_{ij} = \frac{ACost_{ij} \cdot P_{ij}(\cdot)}{C_{ij}} = MACost_{ij} \cdot P_{ij}(\cdot), \qquad (1)$$

where subscripts ij denote branch terminal nodes, $Cost_{ij}$ is annuitised branch cost in £, $ACost_{ij}$ is annuitised modern equivalent asset cost in £, C_{ij} is branch rating in MW, $P_{ij}(\cdot)$ is peak branch flow in MW being a function of the demand and generation capacities and $MACost_{ij}$ is marginal asset cost in £/MW. If we further assume that the customer injection at node n is P_n in MW, the nodal marginal charge is calculated as the first derivative of the sum of annuitised branch costs with respect to the nodal injection:

$$NMC_n = \partial\left(\sum_{ij} MACost_{ij} \cdot P_{ij}(\cdot)\right) / \partial P_n = \sum_{ij} MACost_{ij} \cdot s_{ij}^n \quad (2)$$

where NMC_n is marginal-cost based charge at node n in £/MW and s_{ij}^n are sensitivity coefficients giving the branch i-j power flow change with unit change of injection at node n. Generation customers connected at node n are charged $NMC_n \cdot G_n$ and demand customers $-NMC_n \cdot D_n$, where G_n and D_n are, respectively, generation and demand in MW.

Long-Run Incremental Cost Model

The long run incremental cost (LRIC) model was recently proposed to model lumpiness of investments more accurately [7]. The branch cost is equal to the present worth of the actual investment cost (step change LRIC in Fig. 1):

$$Cost_{ij} = \frac{ACost_{ij}}{(1+i)^{T_{ij}(\cdot)}}, \qquad (3)$$

where i is annual discount rate in p.u. and $T_{ij}(\cdot)$ is timing of branch i-j investment in yr. It should be noted that timing $T_{ij}(\cdot)$ is a function of present customer demands and generations, as well as their envisaged growth rates over time. The instant of investment is determined from the requirement that the branch rating is reached given an assumed growth pattern. For a simple linear growth at all nodes, using the DC loadflow model gives:

$$T_{ij}(\cdot) = \frac{C_{ij} - P_{ij}(\cdot)}{\sum_n a_n \cdot s_{ij}^n} = \frac{C_{ij} - \sum_n P_n \cdot s_{ij}^n}{\sum_n a_n \cdot s_{ij}^n}, \qquad (4)$$

where a_n is annual growth of injection at node n in MW/yr and all other quantities are already defined. The nominator of eq. (4) represents the current spare capacity, while the denominator is equal to the annual *branch flow* growth. The nodal marginal charge at node n is calculated in the same way as before:

$$NMC_n = \partial\left(\sum_{ij} ACost_{ij} \cdot (1+i)^{-T_{ij}(\cdot)}\right) / \partial P_n =$$

$$\sum_{ij} \frac{ACost_{ij}}{(1+i)^{T_{ij}(\cdot)}} \cdot \ln(1+i) \cdot \frac{s_{ij}^n}{\sum_n a_n \cdot s_{ij}^n}. \qquad (5)$$

Cost function (3) is highly non-linear, nodal marginal charge equal to tgβ in Fig. 5 can be either very high or very low, consequently the recovered cost equal to $NMC_n \cdot P_n$ can be significantly different from the original cost (high over-recovery is shown in Fig. 5).

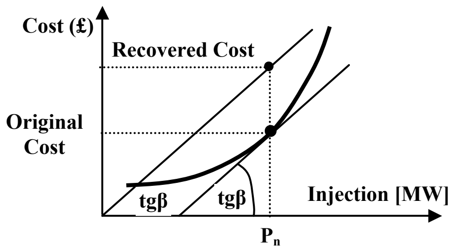

Figure 5 – Modelling of LRIC costs

Improved Incremental Cost Related Pricing Model

In the United Utilities project, the main goal set out for the development of a new cost model was to retain the good characteristics of the original ICRP model [6] and to also account for the overall utilisation of assets which is reflected in the proximity (i.e. timing) of reinforcements. The latter requirement is introduced to discourage connection of new customers at already congested network areas and to promote connection at "empty" parts. The proposed Improved ICRP model modifies eq. (1), where the annuitised asset cost $ACost_{ij}$ is discounted by the present worth factor:

$$Cost_{ij} = \frac{ACost_{ij}}{(1+i)^{T_{ij}(\cdot)}} \frac{P_{ij}(\cdot)}{C_{ij}} = MACost_{ij} \cdot P_{ij}(\cdot) / (1+i)^{T_{ij}(\cdot)}. \qquad (6)$$

Assuming that the instant of investment $T_{ij}(\cdot)$ is given by eq. (4), the nodal marginal charge is equal to:

$$NMC_n = \partial\left(\sum_{ij} MACost_{ij} \cdot (1+i)^{-T_{ij}(\cdot)} \cdot P_{ij}(\cdot)\right) / \partial P_n =$$

$$\sum_{ij} \frac{MACost_{ij} \cdot s_{ij}^n}{(1+i)^{T_{ij}(\cdot)}} + \sum_{ij} \frac{MACost_{ij} \cdot P_{ij}(\cdot)}{(1+i)^{T_{ij}(\cdot)}} \ln(1+i) \frac{s_{ij}^n}{\sum_n a_n s_{ij}^n}. \qquad (7)$$

The first term in the above equation is the ICRP charge (2) modified by the discounting factor, which gives the cost of the proportion of assets being used by the considered customer. This is clearly seen if it is multiplied by injection P_n which gives the discounted annuitised asset cost (= $ACost_{ij}/(1+i)^{Tij}$) multiplied by factor $s_{ij}^n \cdot P_n / C_{ij}$ representing the "customer power flow" to asset rating ratio. The second term is the LRIC charge (5) modified by the peak power flow to rating ratio (i.e. P_{ij}/C_{ij}). Proximity of the investment is defined by the discounting factor and it is inversely proportional to the annual branch-flow growth (= $\Sigma a_n s_{ij}^n$). This term is high for high ratios of the discount rate to branch flow growth rate and vice versa. Different weighting factors α and β could be applied to the ICRP and LRIC terms in order to find a desired balance between the ICRP and LRIC models.

COST ATTRIBUTION

Current cost attribution approach is based on the nodal marginal charges (7) and the DC loadflow model, and it is shown in Fig. 6. Full contingency analysis in line with security standards [8] is done for the most onerous operating regimes. These are, typically, winter peak in demand dominated areas and summer trough where large generators are connected. This analysis gives a critical power flow in each branch together with the corresponding outage and operation regime. Critical power flow is defined on the basis of the minimum time before reinforcement is required. Next, a sensitivity matrix whose rows correspond to all branches and columns to all nodes (other than the reference node) is determined in order to get sensitivities $s_{ij}^{n\cdot}$ - eq. (7). Each row of the matrix is calculated for the corresponding critical contingency configuration, because

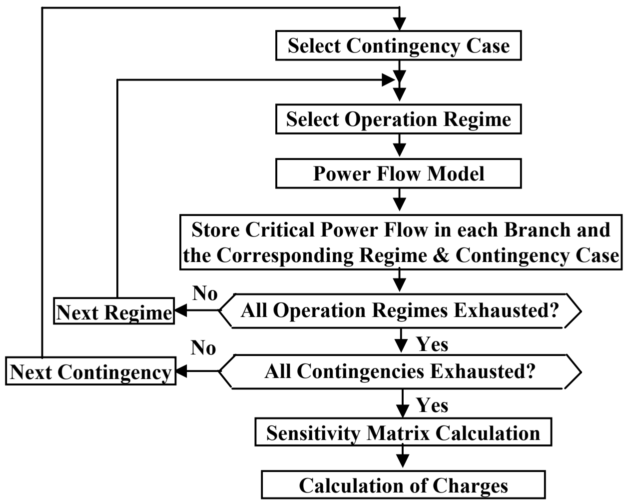

Figure 6 – Flowchart of cost attribution

attribution of a specific asset cost is based on the critical power flow. Finally, overall customer charges in £ are determined from the individual asset marginal charges (eq. (7) without summation over branches *ij*) and either the winter peak or the summer minimum demands/generations in MW, as appropriate for each individual asset peak flow condition.

The current approach can be easily extended to model both the active and reactive power flows. In this case, annual MVA growth should be used in eq. (4) and branch *apparent* power flow should be expressed as a function of active and reactive power flows in polar co-ordinates and substituted in eqs (4) and (7). The first derivatives are taken with respect to active and reactive power injections requiring calculation of two types of sensitivity coefficients. An approximate linearised reactive power – voltage model can be used for this purpose.

REAL NETWORK EXAMPLE

We have selected a well-interconnected 132 kV network with both generation and demand customers to illustrate the developed marginal pricing concept. A highly simplified diagram of the 132 kV "Cumbrian Ring" in United Utilities area is shown in Fig. 7, where "CHP" denotes generators connected directly to the 132 kV network, "G" stands for generators connected at 33 kV level and below, while "NGET" are connection points with the transmission network. It was found that the critical regime for the majority of assets is the summer trough whereby generators operate close to nominal output and demands are at circa 30% of peak demands.

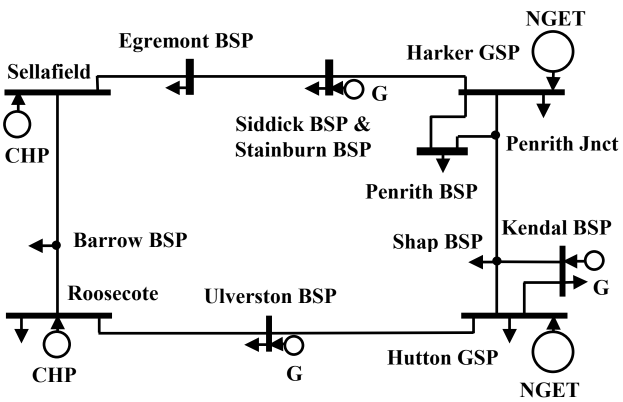

Figure 7 – A simplified part of the 132 kV test system

Detailed expansion planning produced significantly different results from the predictive method. The overall annuitised cost was for many scenarios much smaller in the former case, because of the circuit interdependence and the planning period of 20 years. Illustrative "Nodal Prices" equal to marginal-cost based charges (7) are displayed in Table 1. All nodal ICRP and LRIC terms are positive indicating that this is a generator dominated area where generators have to pay for both the asset costs and also the rewards (i.e. negative charges) to demands for their reduction of power flows. LRIC terms are significantly higher then ICRP terms giving high overall cost over-recovery (173.2%). The highest nodal prices are at nodes "Roosecote" and "Sellafield" which are furthest away from the grid supply points. Connection of new demand customers at these nodes is particularly favourable for the network development (by deferring reinforcements) and it is clearly signalled to potential customers via high *negative* nodal prices (i.e. rewards).

Table 1 – Illustrative nodal prices and charges

	ICRP Price Term (£/kW)	**LRIC Price Term (£/kW)**	**Total Nodal Price (£/kW)**	**GEN Reven (£k)**	**DEM Revenu (£k)**
Harker GSP	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Penrith Junct	**0.31**	**0.68**	**0.99**	**0.0**	**0.0**
Penrith BSP	**0.17**	**0.39**	**0.56**	**0.0**	**-11.4**
Shap BSP	**0.79**	**1.75**	**2.53**	**0.0**	**-15.9**
Kendal BSP	**0.82**	**1.82**	**2.64**	**15.4**	**-86.0**
Hutton GSP	**1.37**	**3.04**	**4.41**	**0.0**	**-352.7**
Ulverston BSP	**2.77**	**6.16**	**8.93**	**237.9**	**-128.6**
Roosecote	**3.28**	**7.29**	**10.57**	**2,420.5**	**-84.7**
Barrow BSP	**2.97**	**6.62**	**9.59**	**0.0**	**-150.7**
Sellafield	**3.21**	**7.13**	**10.34**	**1,850.8**	**0.0**
Egremont BSP	**2.67**	**5.94**	**8.62**	**0.0**	**-112.7**
Siddick/ Stainburn BSP	**2.02**	**4.49**	**6.50**	**269.2**	**-232.2**
Annual Revenue (£k)				**4,793.8**	**-1,174.9**

CONCLUSIONS

In this paper, we have presented a new DUoS charging model based on the marginal pricing concept. The nodal charges consist of two terms, the first reflecting the proportion of assets being used by the customer and the second modelling asset utilisation and proximity in time to reinforcement. The nodal charges can be either positive or negative, which is a clear economic signal to customers where they should connect. This, in turn, leads to efficient network development, as new customers connected at right locations will reduce power flows and requirements for reinforcements.

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