MARGINAL COST-BASED PRICING OF DISTRIBUTION: A CASE STUDY

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ABSTRACT

This paper presents results of a software development project carried out by the "Electricity North West" (ENW) and "TNEI" to find economic use-of-system charges for the extra high-voltage (EHV) network. Several cost-based charging models which satisfy principles set by the Regulator, such as cost reflectivity, predictability, stability and transparency were developed. In this paper, the emphasis is put on the developed software and the comparison of nodal marginal charges obtained from the proposed pricing models.

INTRODUCTION

"Expansion Planning and Pricing" (EPP) project was initiated in ENW to develop a unique software tool which would link half-hourly SCADA readings, outage planning, connections and development planning and pricing of distribution networks (Fig. 1). Half-hourly demand data are input from the SCADA database, subjected to an extensive data cleanse and stored in a SQL database to be used for outage planning and demand forecasting. Demand forecasts are done for all cleansed historic data-series and are input into the expansion planning module. This module can be run in two different modes, the first of which is automatic check-up of the compliance with the UK network design standards [1]. The results are analysed by the Planning Department and network solutions are submitted to the Regulator. The other mode does the full contingency analysis and generates network reinforcements in a simplified way using a pre-specified set of rules. The network reinforcements are then fed into the pricing module, where nodal marginal charges (NMCs) are calculated by using several developed pricing models.

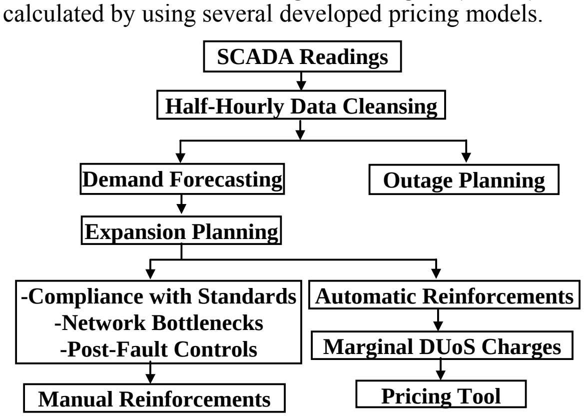

Fig. 1 – Global flowchart of the EPP project

Pricing of distribution is aimed at delivering the distribution use of system (DUoS) charges and is done using a *cost-based* method [2,3]. These methods are classified as *embedded* methods, *incremental/marginal* methods and *composite* methods [4]. Embedded methods make use of the total network costs and the *average* cost concept. Incremental and marginal methods are used where economic pricing [4] is applied. Here, either finite differences (*incremental* cost) or actual tangents (*marginal* cost) are being used. Composite methods are often viewed as the best methods and an example is a DUoS charge consisting of a locational and non-locational charging components.

The UK Regulator is encouraging introduction of economic DUoS charging in order to support efficient network development and achieve reduction of costs to customers. Some of the essential requirements set by Regulator can be formulated in the following way:

- DUoS charges shall reflect capacity usage by customers, which is equivalent to the principle "more capacity required, higher the charges".
- DUoS charges shall reflect available headroom of distribution assets, implying that charges are higher in highly loaded areas.

This paper presents the indicative results for the developed charging models applied to the ENW EHV network. It is organised as follows: developed pricing models are given first; main focus is put on the developed software and the results, while conclusions are given in the closing section.

CHARGING MODELS

All developed charging models produce nodal charges for each network node. The nodal charges can then be averaged across pre-specified zones. Nodal charges are calculated using the marginal principle, that is, by finding the first derivative of the asset costs with respect to a load or generation. Differences between charging models stem from different cost models which are briefly presented in the subsequent paragraphs.

NG Incremental Cost Related Pricing-ICRP Model

National Grid (NG) ICRP model is used to find the locational component of the transmission charges at 400kV, 275kV levels and 132kV in Scotland [6]. As the network spans the region of more than 1000km with generation concentrated in the north and consumption predominantly in the south, a charging model giving reasonable nodal charge differentials had to be adopted. The essential principle is that the total reinforcement cost is spread over all circuits. The following cost equation for branch asset cost is used:

Br_Cost=Inc_Cost(£/kmMW) x *length*(km) x *flow*(MW)

where incremental constant in £/kmMW is calculated for four asset categories: 400kV OHL, 400kV cable, 275 OHL and 275 cable. NMCs are calculated as the first derivative of the cost and branch flows are modelled with the aid of the DC loadflow.

Two NG ICRP models are developed within the software. In the first, the power flow is modelled as the base-case power flow times security factor (it is called Original NG ICRP model), while in the second case the power flow is the worst case contingent power flow in each branch (its name is Contingent NG ICRP model). The NMCs reflect the proportion of assets occupied by individual customers.

Discounted ICRP – DICRP Model

Distribution networks supply smaller areas and cost modelling can be more accurate. The basic principle used in the DICRP model is that reinforcement costs are applied in the branches which are to be reinforced in the planning period, while they are zero in all other branches. The following cost equation is used to model a branch asset cost:

$$Br\_Cost = Ann\_Cost(£)/(1+i)^{Time(yr)} \times \boldsymbol{flow}(MW) / Cap(MW)$$

where *Ann_Cost* is the reinforcement cost multiplied by annuity factor, *Time* is years to reinforcement calculated within the automatic expansion planning, ***flow*** is the highest power flow in the branch and *Cap* is the branch rating. If the DC loadflow model is applied, ***flow*** is a linear function of loads and generations and NMCs are independent of the operating point. Congestion of assets (ie available headroom) is modelled with the aid of the discount factor, while asset utilisation through the sensitivity coefficients.

Long Run Incremental Cost - LRIC Model

LRIC model [7] is based on studying each branch in isolation from the rest of the network and reinforcing it no matter how far in future. The basic cost equation is:

$$Br\_Cost = Ann\_Cost(£)/(1+i)^{\boldsymbol{Time}(yr)},$$

where time to reinforcement ***Time*** is a function of the current branch loading, loads & generations and their increase in future. Branch cost is now an exponential function of loads and generations and NMCs are highly dependent on the operating point. Available headroom of the assets is modelled through the discount factor.

Improved ICRP - IICRP Model

The basic cost equation of the IICRP model has the same form as the discounted ICRP model, but the time to reinforcement ***Time*** is now a functions of the loads and generations as in the case of the LRIC model. As there are now two functions in the cost equation, the NMCs have two terms which are approximately equal to the sum of the ICRP and LRIC charges. Both the utilisation and congestion of assets are modelled, while the magnitudes of the ICRP and LRIC charges can only be altered by introducing additional scaling coefficients multiplying the both terms.

General Model

The name of this model comes from the fact that all other models (ie cost equations) can be derived from it. The starting point is the LRIC cost which can be approximated with two terms:

$$Br\_Cost = Ann\_Cost(£)/(1+i)^{\boldsymbol{Time}(yr)} \approx$$

$$k \times Ann\_Cost(£)/(1+i)^{\boldsymbol{Time}(yr)} +$$

$$(1-k) \times Ann\_Cost(£)/(1+i)^{\boldsymbol{Time}(yr)} \times \boldsymbol{flow}(MW) / Cap(MW).$$

User-defined constant *k* can be used to control the recovered cost to some extent, because NMCs are approximately equal to a sum of the ICRP term times (1-k) and the LRIC term. Both the utilisation and congestion of assets are modelled.

Combined Model

Combined model is developed to enable influencing the size of the LRIC term. Form of the cost equation is the same as for the General model and the only difference is that time to reinforcement ***Time*** is a constant in the first cost term. As it is not a function of loads and generations, the allocation of costs is done in proportion to the share of assets occupied (power flow reduction is not rewarded). The second cost term is an IICRP cost and NMCs are approximately equal to a sum of the ICRP term and the LRIC term multiplied by (1-k). Share of assets utilised by individual customers and available headroom are again modelled.

DEVELOPED SOFTWARE

The entire EPP software is developed around the base Interactive Power System Analysis (IPSA+) tool [8]. The original IPSA+ database containing data about power system components is extended with the additional object characteristics specific to the EPP project. The Catalogue of Power Components with appropriate costs is held in a separate set of tables in the database. Both the base IPSA+ tool and the EPP software make use of the same database, but they are run independently one from the other.

Graphical user interface is done through forms, an illustrative example of which is shown in Fig. 2. All configurable settings are loaded from the database and they should be saved alongside the study results. The automatic expansion planning module is driven by several settings, the most important being the Network Analysis Type, Expansion Planning Method, Operating Regime and Load & Generation Scaling (Fig. 2). User can chose to analyse either the intact network only, or all single contingencies, or single and double contingencies completely in line with the UK planning standards [1]. Network expansion planning can be based on the year-by-year analysis of the entire network (option “Actual” in Fig. 2), or on studying each branch independently from the rest of the network (option “Predictive” in Fig. 2). Three operating regimes, namely winter peak, summer peak and summer minimum, can be analysed, or a single regime can be chosen. Within each operating regime, three different loading regimes are normally studied: primary peak demands are used to analyse 33 kV networks, primary demands scaled to bulk supply point (BSP) peaks are used for 132 kV network, while all demands scaled to grid supply point (GSP) peaks are applied for the analysis of GSP transformers and interconnecting 132 kV circuits. The user is given option not to apply scaling at all, to scale loads only, or to scale both loads and generation. Finally, all pricing models or any desired combination can be selected (Fig. 2).

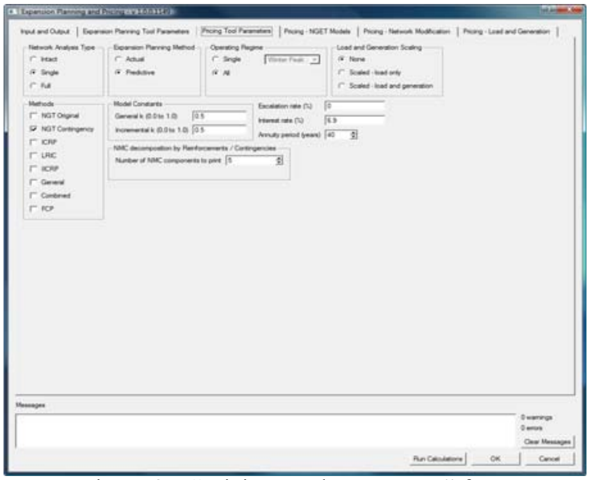

Figure 2 – "Pricing Tool Parameters" form

Pricing results are presented for each pricing model separately. A set of identifiers and other attributes is presented for each modelled load or generator first, which is followed by total annual charges in £/MWyr. Annual NMCs are then decomposed by voltage levels (132kV, 33kV and 11(6.6)kV) and transformations (x/132kV, 132/33kV, 33/11(6.6)kV). Two further breakdowns of NMCs are shown at the end of each customer's record. The first is contribution of the most significant reinforcements and the second is by dominant outage cases. The load/generator NMC is then broken by operating regimes and the same decompositions of winter peak, summer peak and summer minimum charges are given. In case of nodes without a load or generation customer, annual, winter peak, summer peak and summer minimum NMCs are only displayed.

CASE STUDY

ENW's network delivers electricity to around 2.3 million customers in the north-west of England. The EPP software was tested on the model of the entire EHV network consisting of a significant chunk of the 400kV and 275kV transmission networks, 132kV and 33kV networks down to 11(6.6)kV busbars. This network has around 3,000 nodes and more than 5,000 branches.

In this paper, pricing results for a "typical" distribution network supplied from a single GSP are presented. The network comprises around 300 nodes, out of which 60 are secondary sides of primary substations. The first comparative analysis is done for DICRP and Original NG ICRP charges (Figure 3) and it clearly indicates quite flat NG ICRP prices and higher charge differentials for the DICRP model. The letter model produces near-zero charges in areas with no reinforcements, and higher charges in congested areas. The range of variation is greater in areas where distributed generation is connected.

Pricing results typical for the LRIC model are shown in Fig. 4. Extremely high charges are presented in congested areas leading to large cost over-recovery (Fig. 4a). Inverse proportionality of NMCs with flow growth rate is demonstrated in Fig. 4b, showing the perverse incentive inherently built into the LRIC model.

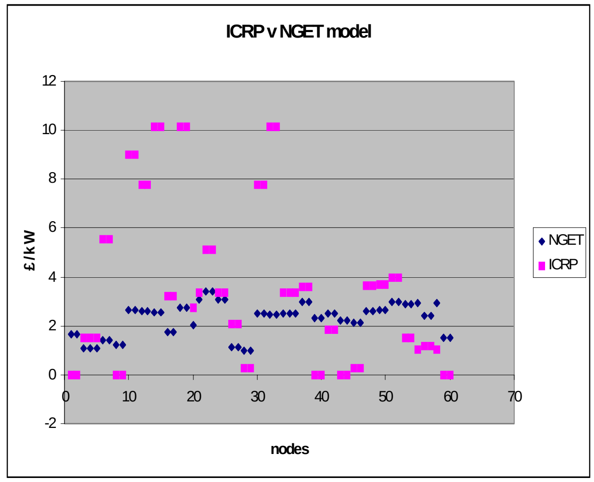

Figure 3 – Comparison of ICRP and NGET model results

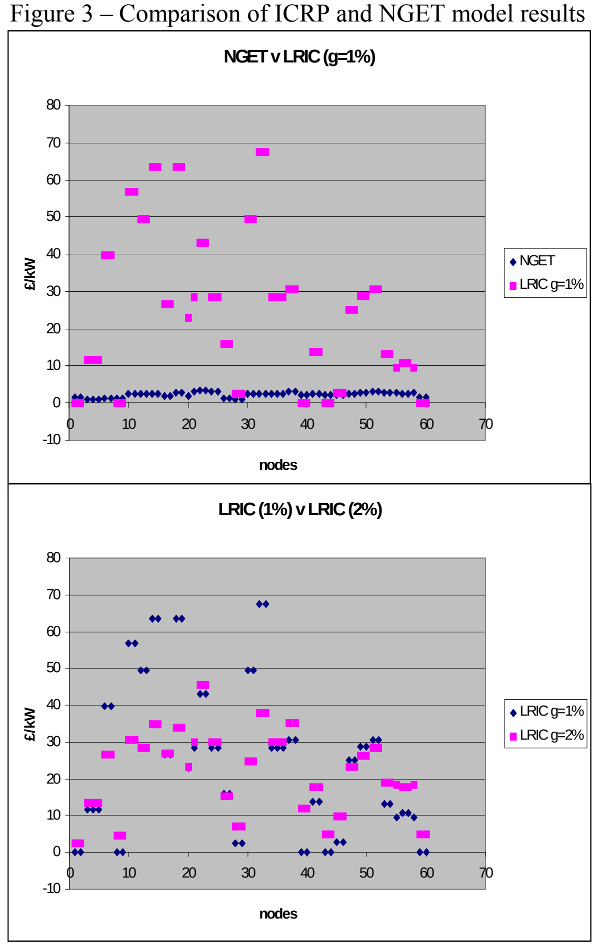

Figure 4 – a) LRIC v NGET; b) LRIC for 2 flow growths

Finally, essential features of the General and Combined models are shown in Fig. 5. User-defined setting *k* can only scale ICRP term in the General model giving relatively small variation of the total charges (Fig. 5a). On the other hand, NMCs can be very well controlled with the aid of this parameter within the Combined model (Fig. 5b).

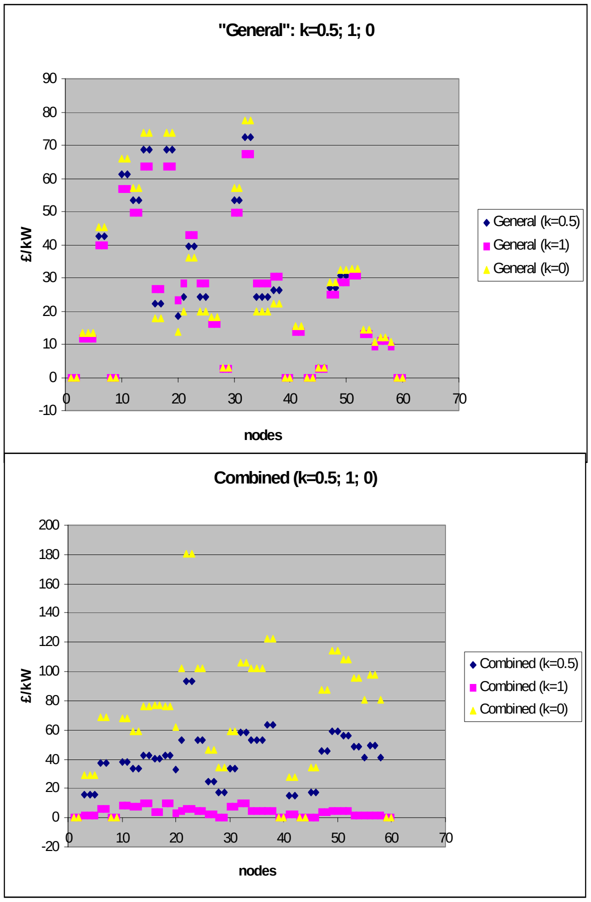

Figure 5 – a) General model; b) Combined model

CONCLUSIONS

Several pricing models for calculating the distribution use-of-system charges have been developed by applying different assumptions to a single cost equation. All models were tested on the large-scale EHV network and the main model features are presented below.

Two types if **ICRP** models are studied and in both models customers are charged in proportion to the relative asset capacity usage. Those customers with power flow in the same direction as the net flow are charged for the asset, while the customers who reduce power flow are rewarded. The total discounted reinforcement costs are smeared across all branches in the NG ICRP model and the nodal charge differentials are usually very modest. Charge differentials are driven by the incremental constants, which are, is turn, driven by the reinforcements in individual asset categories. On the other hand, DICRP charges are more locational in nature and nodal charge differentials can be greater particularly where heavily congested areas exist. Both ICRP models generally under-recover incurred reinforcement costs.

In the **LRIC** models, customers are again either charged or rewarded depending whether they contribute to or reduce the net power flow in an asset. However, the charges are now inversely proportional to the branch flow growth rate. As the time to reinforcement is also dependent on the flow growth rate, it can be shown that the NMC – flow growth function has an extreme point, which indicates that a NMC can either increase or decrease with the increase of the flow growth rate. In all cases studied, **LRIC** model has produced high charges and large over-recovery of total reinforcement costs. The results are very susceptible to the changes in the forecast growth rates and even more to the structural changes of the network.

IICRP charges consist of ICRP and LRIC terms, where the letter is dampened by the ratio of the critical power flow to the asset rating. The resulting profile can be quite different from any of them, in particular when different growth rates are used. Particularly high charges, charge differentials and cost over-recovery are obtained in areas where power flows are close to the limits.

The **General** model is a linear combination of the LRIC and the IICRP and the user defined parameter *k* can only be used to adjust the ICRP term. Large cost over-recovery due to LRIC term can only be avoided if a separate multiplier is applied to the LRIC term. Many of the features are similar to the IICRP model.

Different cost allocation principles are applied to two cost terms of the **Combined** model. The first term is allocated only to those customers who invoke positive power flow (ie the same orientation as the net flow) in an asset. If the user defined parameter *k* is set to unity, the customers are only charged for the asset costs (there are no rewards) and the recovered cost matches the reinforcement cost. Decreasing the parameter *k* strengthens the economic signals and the LTIC term can be well controlled. Generation and load connected at the same node have different nodal charges and relatively smaller charge differentials can be obtained by careful selection of parameter *k*.

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