MARGINAL PRICING OF DISTRIBUTION NETWORKS USING AC POWER FLOW

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ABSTRACT

The paper presents recent developments of the Expansion Planning and Pricing software addressing the specific issue of marginal cost-reflective use-of-system charging for the extra high-voltage (EHV) distribution level. The focus is the Long Run Incremental Costing (LRIC) model based on AC power flow and its further improvements. Parameter driven sensitivity analyses of LRIC nodal charges, results of the improved LRIC methodology and comparative studies of the AC and DC power flow based charges are carried out on the Electricity North West EHV distribution network.

INTRODUCTION

The 'Expansion Planning and Pricing' project is aimed at developing a unique software tool which links half-hourly SCADA readings, demand forecasting, outage and development planning and pricing of distribution networks [1]. The tool has two main modules, the first of which is the automatic check-up of compliance with UK network design standards [2]. The second module generates network reinforcements and feeds them into the pricing module, where marginal (or incremental) charges are calculated. Eight DC power flow based charging models were developed first [1], which was followed by further development of two AC pricing models to meet regulatory requirements [3].

The GB Regulator is requiring distribution companies to introduce common charging models in order to unify distribution use-of-system (DUoS) charges at all voltage levels. The Common Distribution Charging Model (CDCM) makes use of the simplified voltage level-by-voltage level radial distribution network model and average pricing principles to generate charges for low- and high-voltage connectees [4]. To support efficient network development and achieve reduction of costs to customers, the EHV Distribution Charging Model (EDCM) utilizes marginal/incremental pricing principles to find charges for EHV connectees [5,6]. Two of the essential features of the EDCM may be expressed in the following way:

- DUoS charges reflect capacity usage of individual assets by customers, ie 'more capacity required, higher the charges'.
- DUoS charges reflect the available headroom of distribution assets, meaning that charges are higher in highly loaded areas.

Because of the pronounced diversity of distribution networks in the UK, each distribution company is given the choice to incorporate one of two AC power flow based marginal/incremental pricing models in the EDCM. The Forward Cost Pricing (FCP) model calculates zonal incremental charges that correspond to pre-specified network zones [5], and the Long Run Incremental Costing (LRIC) model produces nodal marginal charges [6].

This paper presents the marginal cost-based AC LRIC model, which generates nodal charges reflective of branch reinforcement costs, overall utilization of assets (or, available spare capacity) and proximity of reinforcements. The cost model is defined on a branch-by-branch basis and expansion planning is done by considering individual branches with the aid of the AC power flow. Analysis of the original LRIC results identified some deficiencies for the practical implementation of the marginal charges within the EDCM. The remedies included filtering and modified treatment of 'problematic' branch assets and capping of LRIC charges to recover no more than actual reinforcement costs. Various sensitivity studies were also performed.

The paper firstly presents an overview of the EDCM and LRIC models, followed by improvements of the LRIC model, and finally illustrative results and conclusions.

OVERVIEW OF THE EDCM MODEL

The EDCM model involves three major steps as depicted in Fig. 1. Step 1 is application of the LRIC or FCP model to determine two marginal charges, known as Charge 1 and Charge 2, in £/kVA/annum. Charge 1 represents reinforcement costs incurred in the maximum demand scenario triggered by load connectees, and Charge 2 costs in the minimum demand scenario caused by generation connectees. Charge 1 is usually positive for loads and negative for generation implying the latter is rewarded for deferring reinforcements, while Charge 2 is positive for generation and set to zero for loads (ie there is no credit). In

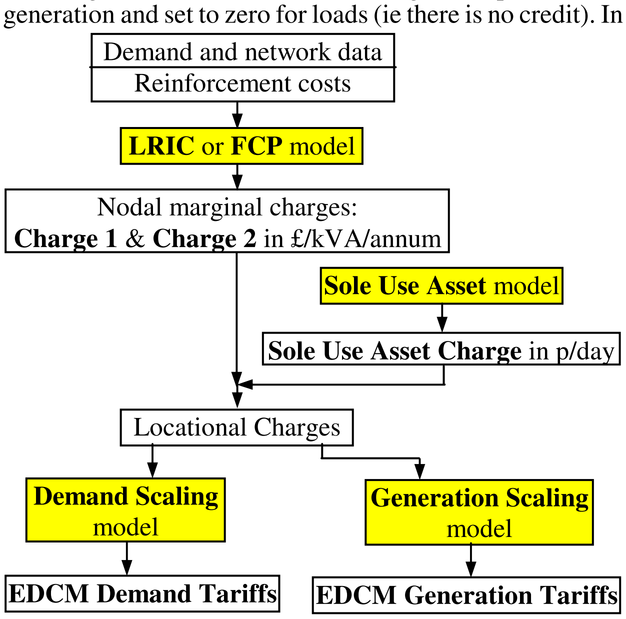

Figure 1 – Global algorithm of the EDCM model

step 2 fixed sole use asset charges in p/day are calculated, and in step 3 both locational charge components are fed into the demand and generation scaling blocks to find fixed adders in £/kVA/annum. The final load tariff has two components (sole use asset in p/day and import capacity in p/kVA/day) and generation tariff one more component that reflects Charge 1 in p/kWh (ie credit).

LRIC MODEL

The essential concept of the LRIC charging model is one of marginal pricing which is applicable to competitive markets [7]. Marginal (or incremental) LRIC charges are calculated in three main steps, which are briefly described below:

1. Find branch incremental costs in £/annum.
2. Find nodal incremental costs in £/annum.
3. Derive nodal marginal charges, Charge 1 and Charge 2, in £/kVA/annum.

The Concept

Definition of marginal and incremental costs is shown in Fig. 2 on an example of the non-linear cost–demand (load or generation) curve. Marginal cost (*tgβ*) is calculated analytically when the explicit non-linear cost–demand relationship is known (Fig. 2a). However, when the non-linear relationship is very complex or specified implicitly, it is preferable to calculate the first derivative in a numerical way (*tgγ*) using finite increments (Fig. 2b).

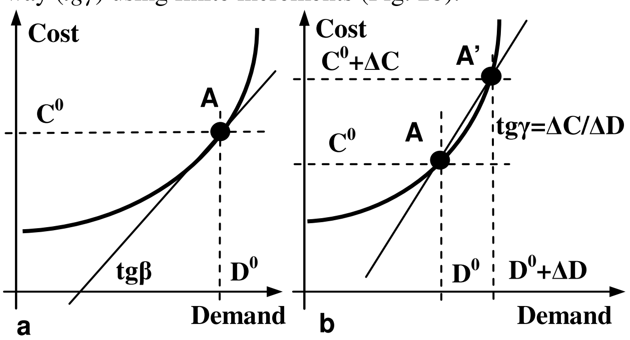

Figure 2–Concept of (a) marginal & (b) incremental costs

The LRIC cost model is specified for each individual branch as the annuitized NPV reinforcement cost:

$$BrCost_i = \frac{CostOfReinf_i}{(1+Rate)^{YearsToReinf_i()}} \cdot AnnFactor \quad £/yr, \qquad (1)$$

where i is branch index, $CostOfReinf_i$ is cost of reinforcing branch i in £, *Rate* is discount rate, $YearsToReinf_i$ is time in future (yr) when reinforcement is required and *AnnFactor* is the annuity factor. The only quantity dependent on customers' demands (both load and generation) is time to reinforcement $YearsToReinf_i$, the others are constant. Recognising that $YearsToReinf_i$ is function of the power flow in branch i, which is in turn a function of all demands D_k, $k=1,2,\dots$, the incremental form of chain rule needs to be applied to find the branch incremental cost with respect to demand at node k, D_k, in £/kVA/yr:

$$BrIncCost_i^k = \Delta BrCost_i / \Delta D_k = \frac{\Delta BrCost_i}{\Delta YearsToReinf_i} \frac{\Delta YearsToReinf_i}{\Delta flow_i} \frac{\Delta flow_i}{\Delta D_k} \quad £/kVA/yr. \qquad (2)$$

The main steps to calculate branch incremental cost (2) are:

1. (Base Power Flow) Set all demands (ie loads and generations) to the base values (point D^0 in Fig. 2b) and calculate base power flow in the considered branch $BasePowerFlow_i$ (MVA) using the AC powerflow.
2. (Base Branch Cost) From the base power flow $BasePowerFlow_i$ (MVA), branch i capacity (MVA) and assumed power flow growth, calculate base time to reinforcement $YearsToReinf_i(base)$ and then base branch cost $BrCost_i(base)$ in £/annum from (1).
3. (Incremented Power Flow) Increment demand at node k by ΔD_k (point $D^0+\Delta D$ in Fig. 2b) and recalculate power flows. This gives incremented power flow in the considered branch $IncPowerFlow_i$ (MVA).
4. (Incremented Branch Cost) From the incremented power flow $IncPowerFlow_i$ (MVA), branch i capacity (MVA) and power flow growth, calculate incremented time to reinforcement $YearsToReinf_i(inc)$ and then incremented branch cost $BrCost_i(inc)$ in £/annum.
5. (Branch Incremental Cost) Branch incremental cost in £/yr is calculated as the difference (points A' & A):

$$BrIncCost_i^k = BrCost_i(inc) - BrCost_i(base) \quad £/yr. \qquad (3)$$

Where an incremental demand ΔD_k increases branch power flow, reinforcement is brought forward and branch incremental cost (3) is positive (charge), while a decrease of branch power flow defers reinforcement leading to negative branch incremental cost (credit). As demands use several branches to offtake load or inject generation, the nodal incremental cost for a demand connected at node k is a sum of all relevant branch incremental costs:

$$NodalIncCost_k = \sum_i BrIncCost_i^k \quad £/yr. \qquad (4)$$

Finally, the nodal marginal (or incremental) charge is derived by dividing the nodal incremental cost by the assumed demand increment ΔD_k :

$$ChargeAtNode_k = NodalIncCost_k / \Delta D_k \quad £/kVA/yr. \qquad (5)$$

More Detail

The UK planning standards imply that branch thermal limits are not exceeded in case of all single and some double branch outages [2]. This means that branch i power flow shall be calculated under all contingency cases, maximum contingent power flow determined and compared against the actual branch rating. Moreover, branch i incremental costs should be calculated by considering the worst contingency case, which can imply that a different network configuration is used for allocation of reinforcement cost of each branch. To avoid this rather complex computation, the LRIC model makes use of a simplified two-step procedure:

1. Contingency analysis to find branch security factors.
2. Incremented flow analysis on intact network.

In the first step, all single contingencies are studied in turn in the maximum and minimum demand regimes in order to find the maximum contingent power flows (MVA) in each branch. A pair of security factors is calculated for each branch by dividing the maximum contingent power flow by the (intact network) base power flow. The actual branch winter (maximum demand) and summer (minimum demand) ratings are divided by the corresponding security factor in order to produce 'intact branch capacities' that can be used in conjunction with base (intact network) power flows.

Incremented flow analysis is done by considering power flows in the intact network with modified branch ratings ('intact branch capacities') for the maximum and minimum demand regimes. Branch incremental costs are calculated from eqs. (3) and (1) where time to reinforcement is determined from the generic formula:

$$PowerFlow_i \cdot (1 + GrowthRate)^{YearsToReinf_i} = BrCap_i\,, \qquad (6)$$

where $PowerFlow_i$ is either base or incremented power flow, *GrowthRate* is the assumed uniform annual branch power flow growth and $BrCap_i$ is actual branch rating divided by security factor. A pair of branch incremental costs, denoted as $(\Delta C_i^k)^{Peak}$ and $(\Delta C_i^k)^{Off\text{-}Peak}$, is calculated for each branch and connectee in both operating regimes, so that node k incremental costs in £/annum are:

$$\left.\begin{aligned} NdInCo_k^{Peak} &= \sum_{i\in\alpha} s_i \Delta C_i^{Peak},\ \alpha = \left\{1,2,...B \mid \left|\Delta C_i^{Peak}\right| > \left|\Delta C_i^{OffPeak}\right|\right\} \\ NdInCo_k^{OffPeak} &= \sum_{i\in\beta} s_i \Delta C_i^{OffPeak},\ \beta = \left\{1,2,...B \mid \left|\Delta C_i^{Peak}\right| < \left|\Delta C_i^{OffPeak}\right|\right\} \end{aligned}\right\} \qquad (7)$$

where s_i is recovery factor for branch i (see below) and B is total number of branches. Peak and off-peak nodal incremental costs are then divided by the demand increment (=105.26kVA for load and 100kVA for generation) to get the nodal marginal charges in £/kVA/annum.

IMPROVEMENTS TO THE LRIC MODEL

Application of the basic LRIC model as described above has shown that branch incremental costs can be unrealistically high in the following situations:

- Where the base power flow is very low, that is, for 'empty' branches which are built to provide security.
- Where the security factor is very high.
- Where the power flow increment (equal to the difference between the incremented and the base power flow) is outside permissible range.

The reason for getting distorted incremental costs is that power flow increment is too high compared to the base power flow indicating that contingent flows should be used instead. The thresholds on the base power flow, security factor and power flow increment were introduced and all branches which were filtered out subjected to a modified procedure. Here, base and incremented time to reinforcement are computed by comparing (base power flow * security factor) and (base power flow * security factor + flow increment) with the *actual* branch rating.

Due to the application of the marginal pricing concept to a highly non-linear cost-demand model, recovered costs are never equal to the incurred cost. It can be shown that the LRIC model gives high charges in many instances which lead to an excessive cost over-recovery. The overall cost recovery for each branch i was therefore individually examined and checked against the reinforcement cost for the branch. Recognising that load and generation increments were applied, respectively, in the peak and off-peak regimes (denoted by m and l) and generation and load decrements, respectively, in the peak and off-peak regimes (denoted by k and n), the overall annual cost recovery for branch i is:

$$\begin{aligned} &OverallCostRecovery_i = \\ &((\sum_k(-\Delta C_i^k)\cdot G_k^{peak} + \sum_l(\Delta C_i^l)\cdot G_l^{off-peak})/100) + \\ &((\sum_m(\Delta C_i^m)\cdot L_m^{peak} + \sum_n(-\Delta C_i^n)\cdot L_n^{off-peak})/105.26)\ . \end{aligned} \qquad (8)$$

The branch i recovery factor, s_i, is then calculated as the ratio of the actual reinforcement cost and the overall recovered cost (where the latter is greater than the former) or otherwise set to unity and plugged into eq. (7).

ILLUSTRATIVE RESULTS

All LRIC parameters can be entered through the interface of the EPP software. Sensitivity results with power flow growth rate set at 1%, 2% and 3% are shown in Fig. 3. Generator off-peak charges increase as the power flow growth goes up because the branches are more congested. However, this is not the case with the peak load charges (Fig. 3b). A lot of load nodes have the highest charges for 2%, while there are quite a few nodes where the highest charge is for 3%, or even for 1%. This indicates that the curve nodal charge– growth rate has a maximum point beyond which charge is inversely proportional to the power flow growth, being the perverse incentive.

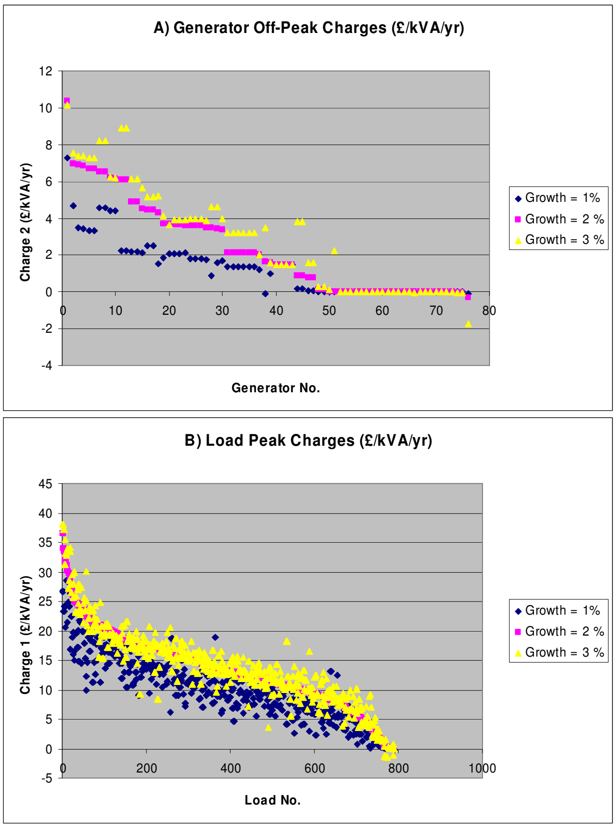

Figure 3 – Impact of power flow growth on LRIC charges

Scaling of all EHV and general loads (factors equal to 0.8, 1.0 and 1.2) was done next (Fig. 4). Generator off-peak charges generally go down with the increased loads that offset the power flows (Fig. 4a), while generator peak credits increase for similar reasons (Fig. 4b). Load peak charges are, as expected, 'proportional' to the load scaling factor (Fig. 4c).

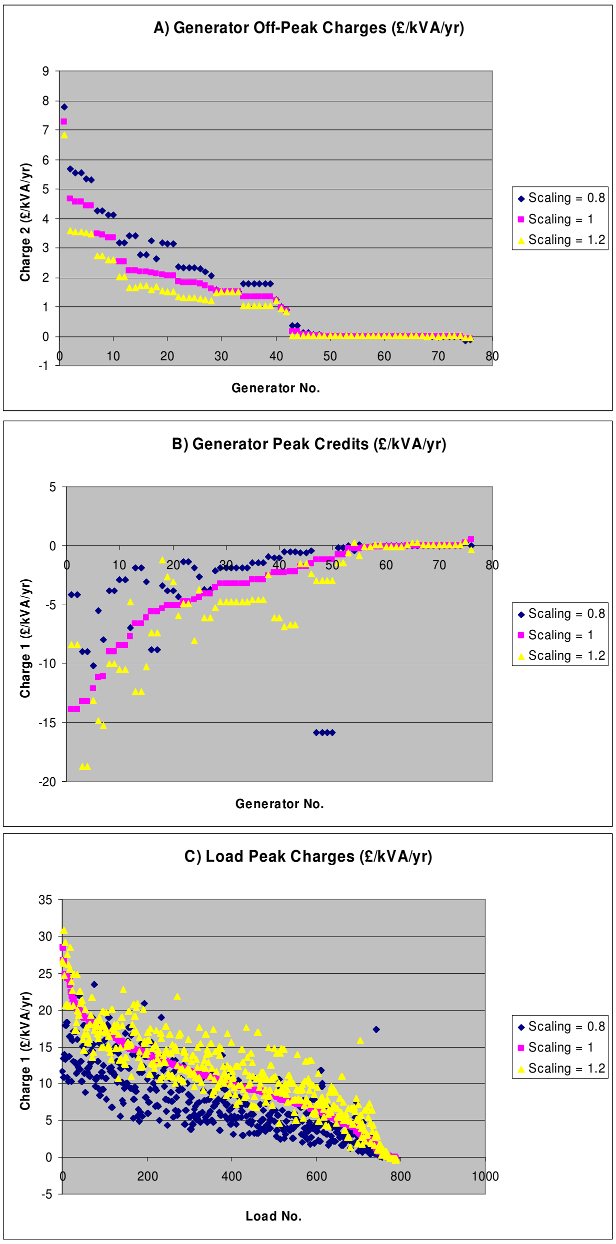

Figure 4 – Impact of load scaling on LRIC charges

Comparison of the LRIC peak load charges (Fig. 5) for the base and improved model shows very high charge differentials which is even more pronounced when power flow growth is 2% or load scaler is 1.2. Finally, DC LRIC charges in £/kVA/yr were obtained by multiplying the calculated £/kW/yr charges by a generic power factor and compared against AC LRIC charges (Fig. 6). Charge differentials are often significant and they are mainly caused by uneven distribution of MVAr flows.

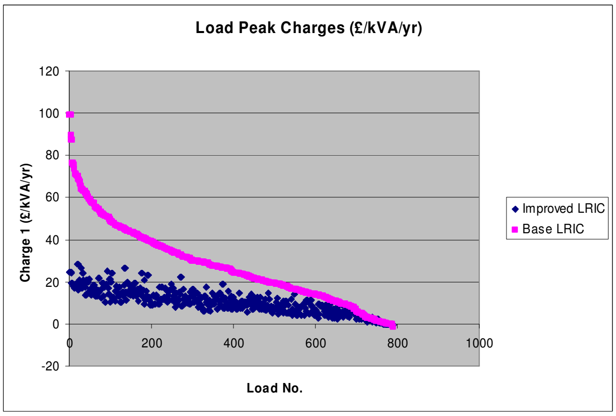

Figure 5 – Impact of improvements on LRIC charges

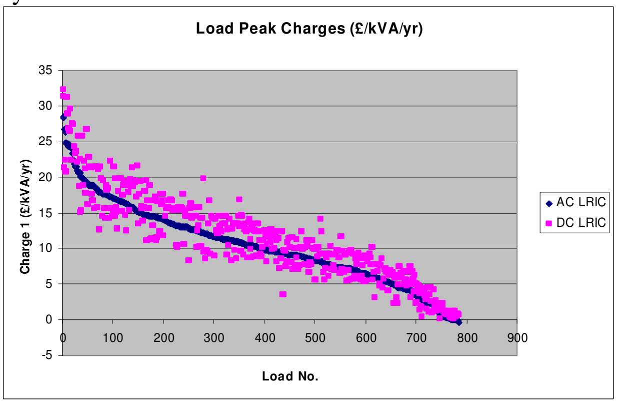

Figure 6 – AC and DC based LRIC charges

CONCLUSIONS

The paper describes the AC power flow based LRIC model which is used to develop DUoS charges for EHV customers. Some of the main features are:

- LRIC charges are highly volatile when model parameters are varied. Case studies on the Electricity North West EHV network have shown that connection/ disconnection of a connectee and network topological changes are major sources of charge variations.
- Variation of LRIC charges with power flow growth can be inversely proportional indicating perverse incentive. The point at which this occurs is dependant on the initial power flow and flow growth rate itself.
- The LRIC model can give very high charges leading to excessive cost over-recovery. The remedy is to limit the overall cost recovery to the actual cost.
- Customer exposure to tariff changes can be reduced by introducing a rolling average of LRIC charges over a 5 year period and replacing the AC with the DC loadflow

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