A FRAMEWORK FOR DEVELOPMENT OF TARIFFS FOR DISTRIBUTION NETWORKS WITH EMBEDDED GENERATION

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SYNOPSIS

The importance of the interaction between embedded generation (EG) and distribution network operating and asset related costs, has been recognised and widely discussed. However, very little work has been done to quantify possible commercial implications. The benefits/costs of EG are known to be location specific and to vary in time. Therefore, only location specific time-of-use tariff regimes are capable of adequately recognising the benefits/costs of EG. This paper presents a framework for development of such tariffs. The proposed framework is based on the concept of the reference network and treats the pricing problem as a two step process involving network design in the first instance followed by allocation of the resultant network costs among users of the network. As a consequence of the shift towards real time pricing of electricity and the relative drop in the cost of cables, the cost of losses is emerging as the primary driver of investment in distribution network capacity. Therefore network use-of-system charges must reflect the variation in cost of losses in contrast to present tariff regimes based on peak demand. Under a loss based tariff regime, the availability of EG (for small penetration of EG) becomes less critical. Application of the proposed method is illustrated on a 264-node distribution network model.

INTRODUCTION

The introduction of competition and choice into electricity supply together with the growing penetration of embedded generation (EG) poses many challenges to energy policy makers as well as power system planners and operators. Foremost among these challenges is the commercial imperative to assure open non-discriminatory access to the network by all participants in the energy market. In an environment where relationships between entities are defined by commercial contracts, the issue of network open access is in essence a pricing problem. This paper presents a framework for development of cost reflective tariffs for use in distribution systems with embedded generation (EG). Tariff development for distribution network services can be decomposed into two basic processes. The first process involves determination of the allowable revenue for the network owner. Allowable revenue is a function of the costs, both operating and capital, incurred by the network owner in providing the service including an element of profit. The second process entails allocation of the costs determined in the first process to users of the network in an economically efficient manner. Because of the monopolistic nature of the distribution business, both of these processes must be, and usually are, closely supervised by a government appointed regulatory agency whose basic mandate is to protect the public interest and ensure economic efficiency in the pricing policy. Distribution tariffs in present use are not economically efficient. Furthermore, the basis upon which the tariffs are computed (allowable revenue) is not well defined, lacks transparency and is not consistent. Aside from changes brought about by industry deregulation as a strong motivation for developing new pricing methodologies, the growing penetration of EG is adding to the pressure for change. There is a steadily mounting lobby for recognition of the impacts which embedded generation has on networks both technically and commercially. For example, because of its location close to end customers, EG can potentially reduce the demand for transmission and distribution facilities and also reduce overall system losses. It is now widely acknowledged that the impacts that EG has on networks are location specific and vary in time and yet most existing distribution network tariff regimes are not capable of recognising such spatial and temporal variations.

The tariff development framework proposed in this paper is capable of recognising variations in both time and space. The framework is founded on the concept of the reference network. In the context in which it is applied here, the reference network has the same topology and voltage levels as the existing network but unlike the existing network, the reference network is characterised by optimal circuit capacities. In general determination of optimal network capacities is a two-stage process which commences with determination of the optimal capacity for pure transport of electricity at the first stage. Having established the capacity for pure transport, the extra capacity required to satisfy security constraints is then determined at the second stage. In both processes, the required capacities are determined using optimisation procedures with appropriately formulated objective functions.

Once the optimal circuit capacities for the network and therefore capital investment are established, allocation of operating and capital costs then follows. A detailed description of the concept of marginal loss coefficients for allocating network variable losses is presented. This concept is later used as the basis for developing a framework for allocating loss driven network capital costs. An important development in the design of distribution networks brought about by the fall in cable costs and the tendency to price energy use in real time, is the dominant role now played by the cost of losses in network capacity investment decisions. In order to reflect cost of losses as the investment driver, network use-of-system charges must be based on losses rather than peak demand as at present.

NETWORK DESIGN-THE REFERENCE NETWORK

The concept of a reference network is derived from economic theory and has a long history [1,2]. As stated earlier, the reference network is topologically identical to the existing network but is characterised by optimal circuit capacities. It is important to distinguish network design for pricing, as described here, from technical network design. Fundamentally, technical network design involves making decisions on network topology and on other technical issues such as voltage levels, substation layout and protection etc, where as network design for pricing always assumes a fixed network topology and voltage levels.

Optimal circuit capacities are determined through an optimisation procedure whose objective function is to minimise the total network operating and capital costs as well as the cost of not delivering the service. In practice this procedure is accomplished through a two-stage process. At the first stage the capacity for pure transport of electricity is determined. This is followed at the second stage by determination of the security driven network capacity. This paper focuses on capacity for pure transport of electricity.

Optimal network capacity for pure transport of electricity is determined through an optimisation process where annuitised network capital costs and annual network operating costs (of which network variable losses are the most significant component) are traded off. This optimisation requires a calculation of the annual network cost of losses and involves modelling of annual variations of load and generation as well as associated electricity prices including the mutual correlation between these quantities. The network costs of losses are then balanced against annuitised network capital costs to determine the optimal capacity required for economical transport of electricity. The overall problem can be formally expressed as follows:

$$Minimise: f(I_{capi}) = \sum_{i=1}^{nl} (CC_i + CL_i) \qquad (1)$$

Where $f(I_{capi})$ is the total investment and operating cost (which is a function of the current carrying capacity I_{capi} of the circuit), CC_i and CL_i represent the annuitised capital cost and total annual cost of losses for circuit i respectively and nl is the total number of circuits. The annuitised capital cost CC_i is found as the product of the annuitised incremental line investment cost k_i, line current carrying capacity I_{capi}, and line length L_i. That is:

$$CC_i = k_i . I_{capi} . L_i \qquad (2)$$

The annuitised incremental line investment cost k_i is constant and has units of £/A.km.year. The line length L_i (measured in km) is also constant since network topology is assumed fixed. Line current carrying capacity I_{capi} (in Amps) is the variable to be optimised.

The annual cost of losses has two components as given in equation (3).

$$CL_i = P_\gamma^T TC + \sum_{t=1}^{8760} P_\gamma(t).sp(t) \qquad (3)$$

The first component $P_\gamma^T TC$ represents the contribution of distribution losses to transmission costs. This cost is usually levied as an annual payment based on system peak demand. Therefore P_γ^T represents the power loss in the transmission system due to the distribution network at time of system peak where as TC is the transmission use of system charge.

The second component represents the cost of energy losses where $P_\gamma(t)$ is the power loss during hour t and $sp(t)$ is the spot price of energy during the same hour. Assuming the cross-section area A_i of a conductor is related to its current carrying capacity through the following general formula:

$$I_{capi} = \alpha A_i^{\beta} \qquad (4)$$

and the component of cost related to the impact of distribution losses on transmission operating cost is negligible in comparison to cost of losses in the distribution network, the optimal current carrying capacity is found as:

$$I_{capi} = \alpha \left(\frac{\rho_i I_{\max i}^2 C_0}{\alpha \beta K_i} \right)^{\frac{\beta}{\beta+1}} \qquad (5)$$

Where:

$$C_0 = \sum_{t=1}^{8760} \frac{I_i^2(t)}{I_{\max i}^2} sp(t)$$

$$\rho_i = \text{Resistivity of conductor}$$

The values of α and β in equation (4) can be determined from cable data sheets by least square estimation techniques. $I_{\max i}$ and $I_i(t)$ represent the maximum current and current flow at time *t* through the circuit respectively.

Preliminary results [3], given in the form of the optimal circuit utilisation (ratio of maximum flow through the circuit and optimal circuit capacity), for different voltage levels, are presented in Table 1.

Table 1: Optimal utilisation factors of cables and overhead lines in a typical distribution network

	Type of conductor	
Voltage level	Cable	Overhead line
11kV	0.2-0.35	0.13-0.2
33kV	0.3-0.5	0.17-0.25
132kV	0.75-1	0.3-0.5

These results indicate that the optimal utilisation of distribution circuits, particularly at lower voltage levels, should be quite low. Secondly, it seems that the optimal design of circuits taking the cost of losses into account satisfies the vast majority of security requirements at no additional cost, in cable networks up to 33kV and overhead lines throughout distribution systems. Further analysis indicates that this result is a combination of two effects. The first effect is the relatively large cost of losses due to the coincidence of high electricity price with high demand. The second effect is the relative fall in the price of cables and overhead lines due to maturity of the technology and increase in competition in the manufacture of this equipment.

If (as is the case) losses drive investment, then charging for use of the network on the basis of peak demand as at present may not be appropriate. And also, for small penetration of EG, availability may not be important.

In this optimisation, the capacity determined for pure transport applies to cables and overhead lines only. Ratings of other items of plant such as transformers and circuit breakers are determined on the basis of other considerations.

ALLOCATION OF NETWORK COSTS – THE PRICING PROBLEM

Pricing of network services involves the allocation of network capital and operating costs to users of the network in a fair and equitable manner taking care that each user bears only those costs for which they are responsible. In other words, network prices must be cost reflective and avoid both temporal and spatial cross-subsidies between customers. Marginal cost pricing is the most widely accepted way of achieving this. By definition the marginal cost of a good or service is the increase in the total cost of providing the good or service as a result of a relatively small increase in the rate of output of the good or service. If the required increase in output can be met solely from an increase in the degree of utilisation of the existing plant, the associated increase in cost is referred to as short-run marginal cost (SRMC). On the other hand, long-run marginal costs (LRMC) are estimated on the assumption that the capacity of the plant, and not just the degree of utilisation, is assumed to adjust in order to meet the incremental demand.

The main argument in support of SRMC is that prices should reflect prevailing costs and not the costs that would prevail on average during an indefinite period in the future. Prevailing costs depend on the relationship between the current level of output and the current capacity of the system. Thus if there is excess capacity, prices should be reduced to encourage consumption and if there is a constraint on capacity, prices should be raised to the level necessary to restrict demand to the available capacity. Under conditions of equilibrium, when the amount of capacity available is just sufficient to produce the desired level of output, long- and short-run marginal costs coincide. Outside equilibrium, prices should reflect short-run marginal costs, which (as suggested above) can be defined as the price that brings demand and supply into balance.

The reference network represents conditions of equilibrium. Capital costs associated with optimal network capacities are in essence the equivalent of long run marginal costs of the network. Because distribution networks are dominated by capital costs, it is more appropriate to apply long run marginal costs in the pricing of distribution network services. Pricing on the basis of reference networks is relatively free of the uncertainties associated with pure long run marginal costs and yet it retains the essential attribute of being cost reflective, which is the chief justification for applying marginal cost pricing.

ALLOCATION OF OPERATING COSTS

The ideal loss allocation scheme must first and foremost be accurate and equitable. For easy application it must utilise metered data (i.e. nodal injections) to compute loss contributions. Furthermore it must be consistent and minimise cross subsidies between different nodes and time-of-use. And finally it must be simple and easy to implement as well as audit.

Methods presently used to allocate network losses among users in distribution systems do not measure up to these ideal requirements. A typical example is the substitution method presently used in England and Wales to evaluate the impact on losses of EG [4]. The substitution method has been shown to be inconsistent [5]. Moreover this method lacks a sound theoretical foundation having been driven by considerations of the impact on losses of the latest user to be connected. The method can also give rise to spatial and temporal cross-subsidies which are unacceptable, especially in a competitive environment.

Marginal Loss Coefficients

A method for allocating losses based on the evaluation of marginal contributions that each user makes to the total system losses satisfies these requirements. The method applies the concept of Marginal Loss Coefficients (MLCs). When used for allocating active power losses in distribution systems, marginal loss coefficients measure the change in total active power losses due to a marginal change in consumption or generation of active and reactive power. They are calculated as follows:

$$\tilde{\rho}_{Pi} = \frac{\partial L}{\partial P_i} \quad \text{(Active power related MLCs)} \qquad (6)$$

$$\tilde{\rho}_{Qi} = \frac{\partial L}{\partial Q_i} \quad \text{(Reactive power related MLCs)} \qquad (7)$$

P_i and Q_i are real and reactive power injections at node i respectively where as L is the total active power loss in the system. If a user, for example a generator, takes part in voltage control by injecting required reactive power (PV node), charges related to losses for the reactive power are waived. This is reflected by:

$$\frac{\partial L}{\partial Q_i} \overset{def}{=} 0 \qquad i \text{ is a PV node} \qquad (8)$$

Since in load flow calculations, losses are deemed to be supplied from the slack node, the loss-related charges, for this node, are zero. In other words, total active power losses are insensitive to changes in real and reactive power injections at the slack node i.e.:

$$\frac{\partial L}{\partial P_s} = \frac{\partial L}{\partial Q_s} = 0 \qquad (9)$$

P_s and Q_s are real and reactive power injections at the slack node respectively. Because of this assumption, the choice of slack node clearly has an impact on MLCs in terms of both magnitude and polarity. Fortunately in distribution systems, this complication does not arise as the transmission network can always be taken as the slack node.

MLCs are a function of a particular system operating point. As there is no explicit relation between losses and power injections, for calculations of MLCs the standard chain rule is applied using intermediate state variables, voltage magnitudes and angles. Applying the standard chain rule, a system of linear equations can be established for calculating MLCs (see equation 10).

$$\begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial Q}{\partial \theta} \\ \frac{\partial P}{\partial V} & \frac{\partial Q}{\partial V} \end{bmatrix} \cdot \begin{bmatrix} \tilde{\rho}_P \\ \tilde{\rho}_Q \end{bmatrix} = \begin{bmatrix} \frac{\partial L}{\partial \theta} \\ \frac{\partial L}{\partial V} \end{bmatrix} \qquad (10)$$

Reconciliation. It is well known that the sum of marginal losses at all nodes is approximately equal to twice the total losses in the system. Therefore, to obtain the vector of reconciled marginal loss coefficients ρ, the reconciliation factor, κ_o, is calculated as:

$$\kappa_o = \frac{L}{\sum_{i=1}^{N-1} (\tilde{\rho}_{Pi} \cdot P_i + \tilde{\rho}_i \cdot Q_i)} \qquad (11)$$

The vector of reconciled MLCs is finally calculated as:

$$\rho = \kappa_o \cdot \tilde{\rho} \qquad (12)$$

Reconciled marginal loss coefficients enable the allocation of total active power losses to individual users such that:

$$\sum_{i=1}^{N-1} \rho_{Pi} \cdot P_i + \sum_{i=1}^{N-1} \rho_{Qi} \cdot Q_i = L \qquad (13)$$

Depending on the assumptions made in the derivation of the reconciliation factor additive or multiplicative reconciliation or a combination of both is possible. In this application multiplicative reconciliation is favoured as it is considered fair and accords with results obtained from another theoretically consistent approach, as will be demonstrated in the following section.

Direct loss coefficients

In practice, the reconciliation factor for marginal loss coefficients is of the order of 50%. This factor seems large and questions arise as to the efficacy of MLCs reconciled in this manner. Therefore another method code-named direct loss coefficients (DLCs) has been developed and used to validate reconciled MLCs. The objective of this method is to derive an expression that relates losses directly to nodal injections. A somewhat similar approach is described in [6]. Due to the complexity of AC load flow equations and their solution by iterative procedures, a closed form solution that relates losses directly to nodal injections is not possible. Therefore computation of DLCs is done after the load flow solution has converged.

Derivation of DLCs. For a given change in the operating point, the new total system losses in a power system can be evaluated using Taylor series expansion around the initial operating point. The operating point is defined in terms of state variables V and θ with P and Q representing the corresponding nodal power injections. The new loss position is therefore given by:

$$L \cong f(\theta^0 + \Delta\theta, V^0 + \Delta V) = f(\theta^0, V^0) + [\Delta\theta \quad \Delta V]\begin{bmatrix} \frac{\partial L}{\partial \theta} & \frac{\partial L}{\partial V} \end{bmatrix}^T + \qquad (14)$$
$$\frac{1}{2} \cdot [\Delta\theta \quad \Delta V][H][\Delta\theta \quad \Delta V]^T + \ldots\ldots$$

Where $[H]$ is the Hessian matrix and L is the total active loss in the network.
Applying the following initial conditions to equation (14):

$$V_i^0 = 1.0, \qquad i = 1,\ldots, N-1$$
$$\theta_i^0 = 0, \qquad i = 1,\ldots, N-1$$

We obtain:

$f(\theta^0, V^0) = L_0 = 0$ (L_0 Represents system losses under flat start conditions)

Similarly the first derivative elements $\frac{\partial L}{\partial \theta}$ and $\frac{\partial L}{\partial V}$ are zero. Therefore, the total network losses can be represented in terms of the Hessian matrix and changes in voltage magnitude and angle (see equation 15). The Hessian matrix is symmetrical and contains only the real parts of the bus admittance matrix. Losses can then be expressed directly in terms of nodal injections as follows:

$$L \cong \frac{1}{2} \cdot \begin{bmatrix} \Delta\theta & \Delta V \end{bmatrix} \cdot \begin{bmatrix} H \end{bmatrix} \cdot \begin{bmatrix} \bar{J} \end{bmatrix}^{-1} \cdot \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \tag{15}$$

Where the matrix [$\bar{J}$] is the average of the initial and final Jacobians, J^0 and J respectively, in the load flow solution (see equation 16).

$$\bar{J} = \tfrac{1}{2} \cdot (J^0 + J) \tag{16}$$

It is clear from equation (15) that the following expression represents DLCs:

$$\rho \cong \frac{1}{2} \cdot \begin{bmatrix} \Delta\theta & \Delta V \end{bmatrix} \cdot \begin{bmatrix} H \end{bmatrix} \cdot \begin{bmatrix} \bar{J} \end{bmatrix}^{-1} \tag{17}$$

Comparison of MLCs and DLCs

Case studies to compare and illustrate the application of MLCs and DLCs were performed on a 264-node generic distribution system (GDS) model. The GDS model includes all the important characteristics of a real multiple voltage level large scale mixed urban and rural distribution system. A more detailed description of GDS as well as a single line diagram of the network can be found in [5].

Figure 1 shows active power profiles of MLCs and DLCs for Node 90 at which a conventional EG is connected.

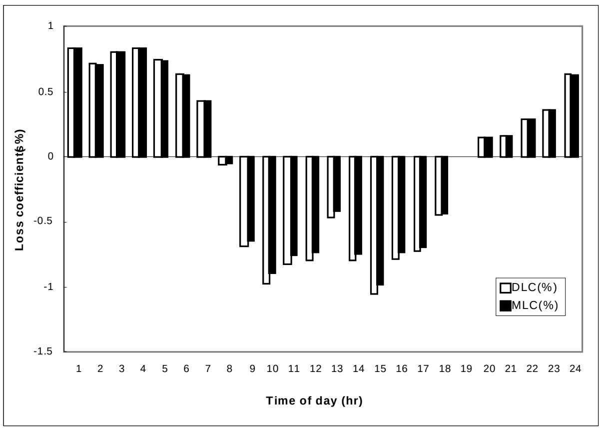

Figure 1. Winter working day active power loss coefficients for EG at node 90

Notice that during winter working days the EG is rewarded for its contribution to reduction in system losses at peak times. However, during early hours of the day, when load demand is low, it contributes to increasing losses and it is duly charged. MLCs are calculated for 9 characteristic days in the year representing working days, Saturdays and Sundays for winter, spring/autumn and summer.

ALLOCATION OF LOSS DRIVEN CAPITAL COSTS (COSTS ASSOCIATED WITH PURE TRANSPORT)

Variable capital costs are mainly composed of the cost of cables and overhead conductors. As indicated earlier, circuit capacity is mainly driven by the cost of losses. Therefore the capital cost of overhead lines and cables must be allocated so as to reflect variations in the cost of losses. As MLCs allocate losses optimally, loss driven capital costs can be allocated optimally on the basis of MLCs. It is important to restate that not all capacities are driven by losses as some circuits can be driven by security. In this work it has been assumed that all circuit capacities are driven by losses. Since marginal loss coefficients are unique to each location and time of use, use-of-system charges derived from marginal loss coefficients are also specific to location and time of use and therefore fully recognise the benefits/costs of EG.

Derivation of use-of-system charges on the basis of MLCs is relatively simple as it mainly entails computing a different reconciliation factor κ_c that will allow the required sum of money to be recovered. Therefore equation (11) can be recast as follows:

$$\kappa_c = \left(\frac{\sum_{j=1}^{nl} CC_i(t)}{\sum_{i=1}^{N-1} (\tilde{\rho}_{Pi} \cdot P_i + \tilde{\rho}_{Qi} \cdot Q_i)} \right) \tag{18}$$

Notice the loss variable is replaced with the cost of capital $CC_j(t)$ to be recovered in this time period. This cost is computed in accordance with the following formula:

$$CC_j(t) = \frac{CC_j \cdot CL_j(t)}{CL_j} \tag{19}$$

Where CC_j is the annuitised capital cost of the line, $CL_j(t)$ is the cost of losses for line *j* in hour *t* and CL_j represents the annual cost of losses for line *j*.

Network use-of-system charges resulting from this pricing framework lead to a single part energy only tariff designated in (£/kWh). The charge can be positive or negative depending on the user's impact on losses. This pricing regime is particularly suitable for embedded generators as it rewards users who reduce system losses, as embedded generators tend to.

A typical price profile for a characteristic winter working day is shown in Figure 2 for node 90 in the GDS.

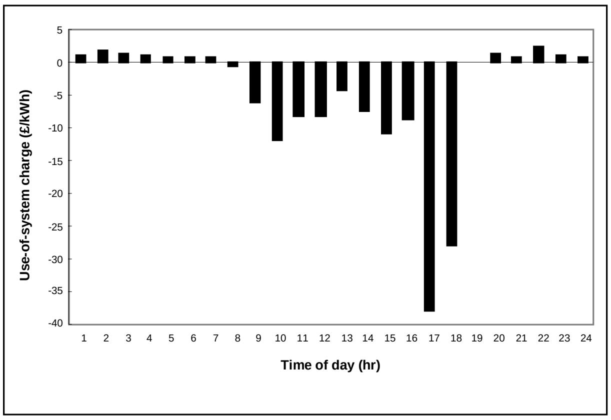

Figure 2. Winter working day active power use-of-system charges for EG at node 90

As expected the active power price profile is consistent with that of MLCs. In this case as well, the embedded generator is rewarded for using the system at time of high demand (between 9 and 18 hours) when losses and cost of losses are high. On the other the EG pays for use of the system at time of low demand because the losses are low and injecting power into the network at this time actually leads to an increase in system losses.

CONCLUSIONS

The adopted technical and network pricing frameworks are of considerable consequence to the commercial performance of both network and generation owners as well as developers. Distribution network operation and planning practices, together with the adopted pricing policies define the level of access available to participants in the electricity market place and therefore have a considerable impact on the amount of embedded generation that can be accommodated. As the adopted technical and commercial arrangements dictate the degree of openness and accessibility of distribution networks, it is vitally important to establish a coherent and consistent set of rules to guide both technical and commercial operations. It is also important to remember that distribution and transmission networks are natural monopolies and therefore the active involvement of regulatory agencies in policy formulation and definition of required standards is essential.

This paper has outlined some of the main problems faced by present network pricing arrangements and presented a framework for the development of a more equitable pricing concept. The proposed pricing concept is based on the notion of the reference network and applies marginal cost pricing principles. Tariffs derived from this concept are fully cost reflective and are suitable for systems with EG. The resultant tariffs have a simple structure although the requirements for data handling are potentially extensive as each node in the network would ideally have its own unique set of tariffs for each hour of the day. This is however in line with developments in the energy market where spot pricing is rapidly becoming the industry norm. Extensive data handling should no longer be considered a constraint as modern information technology systems together with smart meters can be deployed to deal with the required data management. A number of other steps could be considered to simplify tariff management such as creating tariff zones or reducing the number of tariff levels in a day by averaging tariff levels that are more or less the same.

This paper has discussed allocation of variable losses and loss driven capital costs. Other important aspects of networking pricing that must receive similar systematic treatment include allocation of security costs and allocation of fixed losses (such as transformer core loss) as well as fixed capital costs (such as cable trenching). Finally a sound basis must also be established for dealing with issues related to connection charges. Experience has shown that the adopted connection policy has consequences for project viability of EG.

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