METHODOLOGY FOR PRICING OF DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

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INTRODUCTION

This paper describes a methodology for cost reflective pricing of distribution networks with distributed generation. Time of Use and Location Specific Entry-Exit based network pricing model has been developed taking into account multi-directional power flows driven by the presence of distributed generation, network design practices specific for various voltage levels, network topology, and corresponding load and distributed generation characteristics that are relevant for driving network reinforcement.

BACKGROUND

In relation to the UK Government's targets for renewable generation and CHP, Distribution System Operators (DSOs) are required to develop network access for distributed generation on non-discriminatory and transparent terms. This should include rewards to generators for benefits that they may create in terms of providing system security, deferring the need for system investment, reduction of losses, etc.

At present, distributed generation pays deep connection charges, with network reinforcement cost incurred by the connection being recovered through a one-off up front charge. On the other hand, connection charges for demand customers do not take into account network reinforcement costs more than one voltage level above the voltage of connection. Reinforcement cost beyond this level is recovered via Distribution Use of System (DUoS) charges.

Since deep connection charges could be very significant, it has been suggested that this may be preventing distributed generation from entering the market. In the light of this, Ofgem (electricity regulator in UK) stated that, in the long term, distributed generation should face shallower charges for connection to the distribution system.

This initiative opens up the question of designing a DUoS charging methodology that takes into account the impact of distributed generation on distribution network costs. At present, current methodologies only recognise demand growth as the main driver for network reinforcement. In response to this initiative, the paper proposes an alternative cost reflective DUoS charging methodology for distribution networks with distributed generation.

OVERALL APPROACH

The overall philosophy of the proposed approach is based on the concept of reference network [1]. The reference network has the same topology and loading conditions as the real system, while the capacity of various items of the plant is optimal. Since the loading of the plant is the main design parameter, the reference capacity (rating) will be equal to the

maximum loading of the plant. By comparing ratings of individual plant items in the reference and the existing network, both over-invested and under-invested components of the network can be easily identified.

Given the reference distribution model, cost reflective investment related charges for the use of the distribution network are calculated, for both load and generation customers, using the concept of marginal investment pricing. These reference charges are then applied on the real system. The reference charges will exactly recover the cost of the reference network. Hence, some form of revenue reconciliation will be required to recover the approved level of existing network costs.

In accordance with the marginal costing approach, the use of the individual plant items, such as lines and transformers, is charged only during the period of maximum loading of the plant. If an additional unit of power is imposed on the plant during its maximum loading, this will require reinforcement of the plant capacity (the reference capacity of the plant considered is equal to its maximum loading). When the plant is loaded below its maximum capacity, an additional unit of power will not require reinforcement, and hence the plant capacity charge is zero.

Each distribution plant, during its maximum loading, relevant for the plant design, is characterised as being either generation dominated or demand dominated, depending on the direction of the flow critical for its design. If the direction of flow is downstream, that is, from a higher voltage level towards a lower voltage level, the plant concerned is characterised as being demand dominated. The opposite is true for the generation-dominated loading of the plant.

Since generators and demand have opposite effects on the plant loading during the period of critical loading of the plant, both positive and negative charges will be present. Users that tend to reduce the loading of the plant during this period will be rewarded for the use of the network. In the case of a demand dominated plant downstream generators get paid, while downstream demand pays for the use of the plant. Similarly, if the plant is generation dominated, demand gets paid, while the generators pay for the use of the plant. On the other hand, charges outside of the period of maximum plant loading are zero since the incremental change in plant loading does not require plant reinforcement and hence does not impose any capacity related cost.

One of the findings of the work carried out is that positive and negative charges for a particular user will be imposed during different periods. Hence, a generator customer may be rewarded for the use of one plant during times of maximum loading driven by demand customers and may be charged for the use of another plant during the periods of critical plant loading driven by generation. For example, for a plant that is

characterised as demand dominated, positive demand charges will be based on maximum demand, while any negative generation charges that are applied will be based on the contribution that the generator makes to plant security. On the other hand, for a plant that is characterised as generation dominated, positive generation charges will be based on maximum generation output, while negative demand charges will be based on minimum demand condition.

The philosophy of the concept is introduced with the aid of an example on which the main features of the approach are illustrated and discussed. Furthermore, the example is used to illustrate how the proposed methodology would work in practice. Time of use location specific DUoS tariffs are also evaluated.

EXAMPLE

Test system and loading conditions

Consider a part of a radial distribution network supplied from a 132kV/33kV substation with two transformers (Figure 1). Two 33kV out-going circuits are shown, while the rest of the 33kV network is represented by a lumped load of 50MW maximum demand, connected at the 33kV busbar. The two 33kV circuits supply a 33kV/11kV substation with two 33kV/11kV transformers. At the 33kV busbar of the substation a 15 MW CHP plant is connected.

From this substation, two 11kV feeders are explicitly represented, while the rest of the 11kV network is represented by a lumped load of 10MW maximum demand. Each of the 11kV circuits supplies four 11kV/0.4kV transformers with a maximum demand of 400kW. The LV systems can consist of microgrids and other ordinary LV networks. A Wind Farm of 1MW is connected to the circuit to the left.

In practice, a distribution network is designed to cope with the expected maximum loading condition, which likely occurs at a time of maximum demand with minimum local generation. With DG, another extreme condition needs to be considered, i.e. the condition where DG produces maximum output and demand is minimum. Therefore, in this example, these two critical loading conditions are considered. The system loading is shown in Figure 1. The first number (without brackets) is the loading or generation during maximum demand minimum generation period and the second number (in brackets) is the loading or generation during minimum demand maximum generation period.

Since the design of the distribution networks should take into account security, information regarding the contribution of distributed generation to network capacity (security) is required. For the sake of this illustrative example, effective contribution of 5MW (30% of installed capacity) is allocated to CHP, and 200kW (20% of installed capacity) to the Wind Farm. In the context of DUoS pricing, it could be interpreted simply that the CHP and Wind Farm are capable of replacing a distribution circuit of the capacity of 5MW and 200kW respectively. This means that the firm capacities of these generators in the minimum generation regime are 5 MW and 200 kW respectively.

Minimum demand is assumed to be 25% of the maximum demand. This information is important since the condition of maximum generation and minimum demand may be critical

for design/reinforcement of some of the items of plant in the network. It is important to note that the loading condition taken for the pricing calculation should be consistent with the loading scenarios taken in the network design process.

Figure 1 Test system and loading conditions of the network

Reference network

The flows in both loading conditions can be obtained by simple inspection. Critical flows are summarised in Figure 2. The arrow shows the direction of the flows. The critical loading of plants can be determined by the largest power flows between two loading periods.

Figure 2 Computation of critical flows

It can be observed that critical loading for the 11kV feeder, 33kV/11kV and 132kV/33kV transformers is driven by maximum demand, while critical loading of the 33kV circuits is driven by maximum generation, and these occur at different periods (time of use). The assets whose capacity is driven by maximum demand condition such as 11kV feeders, 33kV/11kV and 132kV/33kV transformers, are then classified as Demand Dominated (DD), while the 33kV feeders are classified as Generation Dominated (GD). Note that the critical flows determine the reference (optimal)

ratings of the corresponding plant. The reference rating of 11 kV and 33 kV circuits are 2x3 MW and 2x12.7 MW respectively. Due to topology of 11 kV circuits, one feeder must cope with all 11 kV loads when one of the 11 kV feeders loses supply from the 33kV/11kV substation and the Normally Open point is closed. The optimal rating of the 132kV/33kV substation is 2x58MW. These reference ratings of the individual network components (transformers and lines at various voltage levels) can be compared with the plant ratings of the existing network.

Polarity of exit and entry DUoS charges

Given the direction of the critical flows and knowing the direction of demand and generation driven flows (Figure 2), the polarity of exit and entry DUoS charges can now be determined. If the direction of the critical flow in the plant coincides with the direction of the flow imposed by a particular network user, this user will be charged for the use of the plant. On the other hand, if the direction of the critical flow is opposite to the flow created by a particular user, this user will get paid for the use of the plant. This is presented in Table 1 and Table 2, for demand (exit) and generation (entry) respectively.

TABLE 1 - Polarity of DUoS exit charges for demand

Load	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	Pay	Pay	Get paid	Pay
33/11 kV	0	Pay	Get paid	Pay
33 kV	0	0	0	Pay

TABLE 2 - Polarity of DUoS entry charges for generation

Generation	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	Get paid	Get paid	Pay	Get paid
33 kV	0	0	Pay	Get paid

Basis for evaluation of charges

Observe that positive and negative charges for a particular user are imposed during different periods. This is because the basis for the evaluation of positive charges is different to one for the evaluation of negative charges. For example, an positive incremental change in load of the demand connected to an 11kV feeder, during the maximum demand periods, will increase the loading on the 11 kV feeder, 33kV/11kV and 132kV/33 transformers. Therefore, charges for the use of the plant concerned (DD) will be based on maximum demand of 3.2MW.

Regarding the use of the GD 33kV circuit, the relevant critical period is determined by the coincidence of maximum generation and minimum demand. Hence, demand connected at 11kV will be rewarded for the use of this 33kV circuit, based on the load during minimum demand of 0.8MW. This is illustrated in Table 3.

Consider now charges for the wind farm. The wind farm will be rewarded for the use of the 11kV network and 33kV/11kV and 132kV/33kV transformers and will be charged for the use of 33kV circuits. Again, the basis for the evaluation of positive charges is different to that of the evaluation of

negative charges. The rewards for using the plant concerned will be based on the generator effective contribution (0.2MW). On the other hand, the charges for the use of 33kV circuit will be based on the maximum output (1MW). This is illustrated in Table 4.

TABLE 3 - Basis for DUoS exit charges at various voltage levels

Note: values are in MW unless stated otherwise

Load	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	3.2	3.2	0.8	3.2
33/11 kV	0	10.0	2.5	10.0
33 kV	0	0	0	50.0

TABLE 4 - Basis for DUoS entry charges at various voltage levels

Note: values are in MW unless stated otherwise

Generation	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	0.2	0.2	1.0	0.2
33 kV	0	0	20.0	10.0

It can also be observed that the proposed pricing approach captures correctly the interactions between network users and their composite impact on network use, and hence cost. The charges imposed to an individual user will depend on the critical loading of the plant upstream from the point of connection concerned. For example, the presence of CHP plant impacts on the charges for the wind farm and demand connected to the 11kV network (at and beyond 33kV), while the presence of the CHP plant does not impact on the charges at 11kV.

Given the annuitised cost of individual plant expressed in £/kW/year, annual charges for individual network users can be evaluated. The exit and entry charges that are calculated on this basis will be cost reflective. This is achieved by the design of charges that are location and time-of-use specific. It is important to note that the revenue accrued by imposing such charges will recover the cost of optimal plant capacity, driven by the critical flows, as presented in Figure 2.

Calculation and allocation of network charges

In order to evaluate network charges for individual users, per unit annuitised capacity costs (£/kW/year) are allocated to each plant in the network. For illustrative purposes, the estimate annuitised yardstick costs of 132kV circuits, 132kV/33kV transformers, 33kV circuits and 33kV/11kV transformers for typical urban network in UK were used in this example.

Given a generic entry-exit pricing model of the distribution network relevant to a particular network user, its DUoS charges can be easily evaluated by identifying the character of the upstream assets, in the sense of being demand or generation dominated. For example, a demand customer will pay for the use of all upstream assets that are demand dominated and get rewarded for the use of all upstream assets that are generation dominated. Of course, the basis for the evaluation of the corresponding DUoS charges and rewards will be different, as demonstrated previously. The opposite is valid for generation customers.

The developed entry-exit pricing model is applied to the test

system. The system is presented again in Figure 3 with all critical loadings highlighted.

FIGURE 3 - Evaluation of DUoS exit charges

Next to the network model in Figure 3, the estimate annuitised yardstick costs of individual plant items are presented. Furthermore, DUoS exit charges for demand customers connected at various points in the network are also listed. The polarity of charges is adopted to be positive for downstream and negative for upstream power flows respectively.

In this example the notional balancing point is the 132kV busbar of the 132kV/33kV substation. The balancing point chosen represents the boundary between the transmission and distribution networks at which all electricity is considered to be exported and imported. DUoS charges for demand and generation customers connected at this point are pre-specified. In this case, the charges at the balancing point are set to zero. However, it is also possible to have non-zero charges at the balancing point. This feature will be useful especially if it is required to pass charges from transmission to distribution network users.

Consider now the 132kV/33kV transformer. This is demand-dominated plant since the direction of the power flow is downstream. Hence, all downstream demand and generation customers pay and are paid 5.2£/kW/year respectively for the use of this particular plant during maximum-demand conditions while charges are zero during the minimum demand period.

The next plant to be considered is the 33kV circuit. This is a generation-dominated plant since the direction of the critical power flow is upstream. Hence, all downstream generation and demand customers pay and are paid 6.7£/kW/year respectively for the use of this plant during maximum generation condition while zero is charged during the maximum demand period.

Hence, as shown in Figure 3, the total DUoS exit charges for demand customers connected to the 33kV busbar of the 33kV/11kV transformer is 5.2£/kW/year applied during the maximum demand period (5.2£/kW/year for the use of the 132kV/33kV transformer and 0£/kW/year for the use of the

33kV circuit) and DUoS entry charges of 6.7£/kW/year during minimum demand period (0£/kW/year for the use of the 132kV/33kV transformer and 6.7£/kW/year for the use of the 33kV circuit use).

The 33kV/11kV transformer is demand-dominated plant since the direction of the critical power flow is downstream. Hence, all downstream demand customers are charged and all downstream generation customers are paid 4.3£/kW/year for the use of this particular plant during maximum demand conditions while the charges are zero during the minimum demand period.

Therefore, the total entry charges for the generation connected to the 11kV busbar of the 33kV/11kV transformer are -9.5 £/kW/year during maximum demand period (-5.2£/kW/year for the use of the 132kV/33kV transformer, 0£/kW/year for the use of the 33kV circuit and -4.3£/kW/year for the use of the 33kV/11kV transformer) and 6.7£/kW/year during minimum demand period (0£/kW/year for the use of the 132kV/33kV transformer, 6.7£/kW/year for the use of the 33kV circuit and 0£/kW/year for the use of the 33kV/11kV transformer).

Finally, the 11kV feeder is demand-dominated plant since the direction of the critical power flow is downstream. Hence, all downstream generation customers are paid 11£/kW/year for the use of this particular plant during maximum demand conditions while the charge is zero during the minimum demand period. Therefore, the total charge for generation customers connected to the 11kV circuit is -20.5£/kW/year during on-peak period (-5.2£/kW/year for the use of the 132kV/33kV transformer, 0£/kW/year for the use of the 33kV circuit, -4.3£/kW/year for the use of the 33kV/11kV transformer and -11£/kW/year for the use of 11kV circuit) and DUoS entry charges of 6.7£/kW/year during minimum demand period (0£/kW/year for the use of the 132kV/33kV transformer, 6.7£/kW/year for the use of the 33kV circuit, 0£/kW/year for the use of the 33kV/11kV and zero for transformer and for the use of 11kV circuit). All of this information is presented in Figure 3.

Cash flows

The DUoS charges (assuming positive polarity for demand customers) and revenues collected from various users during peak demand and off-peak demand conditions are given in Table 6 and Table 7 respectively. The connection point G corresponds to the balancing point. Note that 58MW is imported under peak demand conditions while 0.2MW is exported under minimum demand condition from the Grid Supply Point (point G).

Note that during the peak load condition, the annual revenue is collected for all demand-dominated assets, while for the generation-dominated plant revenue is recovered during peak generation periods. The costs of the individual plant items for the reference rating are given in Table 8.

Observe that, in this particular case, the total annual revenue received for the demand-dominated plant is £390,500/year, as shown in Table 6. (This is exactly equal to the total costs of the individual plant items as shown in Table 8, i.e. £390,500 = £301,600+55,900+33,000.) On the other hand, the total annual revenue received from DUoS charges during the off peak demand period is £85,090, as shown in Table 7. This is

exactly equal to the total cost of generation dominated asset shown in Table 8.

TABLE 6 - On peak demand DUoS prices and revenues from demand and generation customers

Connection point	Price £/kW	Demand MW	Generation MW	R Demand £	R Gen £	Total £
G	0	0	58	0	0	0
F	5.2	50	0	260000	0	260000
E	5.2	0	5	0	-26000	-26000
D	9.5	10	0	95000	0	95000
C	20.5	3.2	0.2	65600	-4100	61500
				420600	-30100	390500

TABLE 7 - Off peak demand (peak generation) DUoS prices and revenues from demand and generation customers

Connection point	Price £/kW	Demand MW	Generation MW	R Demand £	R Gen £	Total £
G	0	0	-0.2	0	0	0
F	0	12.5	0	0	0	0
E	-6.7	0	15	0	100500	100500
D	-6.7	2.5	0	-16750	0	-16750
C	-6.7	0.8	1	-5360	6700	1340
				-22110	107200	85090

TABLE 8 - Annuitised cost of individual plant items

Plant	Yardtick £/kW	Max flow MW	Cost £
Transf 132kV/33kV	5.2	58	301600
Circuit 33 kV	6.7	12.7	85090
Transf 33kV/11kV	4.3	13	55900
Circuit 11 kV	11	3	33000
			475590

TABLE 9 - Annual DUoS charges for individual network users

User	On Peak Charge £	Off peak charge £	Total Charge £
Demand connected at F	260,000	0	260,000
Generator connected at E	-26,000	100,500	74,500
Demand connected at D	95,000	-16,750	78,250
Demand connected at C	65,600	-5,360	60,240
Generator connected at C	-4,100	6,700	2,600
			475,590

The on and off-peak demand DUoS related expenditure of individual users is presented in Table 9. It is evident that the total annual DUoS revenue equals to the total annuitised cost of the reference network.

Revenue Reconciliation

In practice, an economically optimal distribution network is practically impossible to achieve due to various reasons such as lumpiness of investment, economies of scale, standard line and cable conductor sizes, load and generation forecast uncertainty etc. Therefore, the capacity of the existing network is likely to be higher than optimal.

Apart from the difficulty of achieving optimal capacities in practice, there are certain cost elements associated with the operation and management of distribution systems that are independent of network capacity. These costs can only be recovered through revenue reconciliation. Examples of capacity independent costs include overheads and taxes. Therefore revenue reconciliation is an important and inevitable aspect of network pricing to allow network companies to recover adequate revenue for the sustenance of their businesses. Since revenue reconciliation aims to balance revenue requirements against economic efficiency, the approved revenue targets should be achieved with as little deviation as possible on economic signals. More detailed discussions of revenue reconciliation methods can be found in

[2,3].

SUMMARY

A cost reflective pricing methodology to compute time of use and location specific DUoS exit and entry charges for demand and generation customers respectively has been described and illustrated on a generic distribution system. The methodology is based on marginal investment pricing concepts applied on a reference network ensuring cost reflective allocation of optimal network costs to all network users. The methodology takes into account multi-directional power flows driven by the presence of distributed generation, network design practices specific for various voltage levels, network topology, and corresponding load and distributed generation characteristics that are relevant for driving network reinforcement. Costs from upper voltage network can be passed and reflected into charges for downstream customers applied at relevant time periods. Total revenue will always be equal to total cost of reference network. Hence, some form of revenue reconciliation will be required to recover an appropriate level of revenue to cover existing network costs.

It should be pointed out that in this methodology a fundamental assumption is made that the optimal capacity of network components is driven by demand. This may not always be the case as there could be other drivers such as losses, for example, which have been shown to drive investment in overhead and underground cables if an optimal balance is struck between the cost of losses and network investment. [4]. Clearly if network design is based on different principles the cost allocation scheme would have to reflect the investment driver [5].

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