Long-Term Framework for Electricity Distribution Access Charges

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Long-Term Framework for Electricity Distribution Access Charges

Report Prepared for and Commissioned by Ofgem

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Executive Summary

The structure of electricity distribution charges before 2005 reflects the framework inherited at privatisation, with some variation across the distribution network operators (DNOs). These charging structures treat distribution-connected generation very differently from demand customers and from transmission-connected generation. In the past this may not have been a major problem, given the limited volume of distributed generation (although it may have discouraged desirable developments). Ofgem has decided that the time has come to revisit access and DNO use-of-system charging principles to ensure that they give the right signals in an environment that is likely to have increasing volumes of distributed and often intermittent generation.

From a regulatory point of view, one important question is whether it is desirable to have a range of methodologies or whether it would be preferable to agree upon a common methodology, embodied in a standard framework model. In either case, the methodologies should be based on a set of common and economically sound principles. This report sets out such principles and their implications for access charging.

The present system of regulation of distribution network operators (DNOs) uses information about the utilities' underlying costs to develop a price control that is intended to provide good incentives to reduce costs and increase internal efficiency. To achieve overall economic efficiency, two important and inter-related issues must be addressed. First, the DNOs' allowed revenues (and targeted incentives) under the Distribution Price Control Review (DPCR) need to be set at correct levels. Second, the access charging mechanism by which the DNOs recover their allowed revenues needs to give the correct signals to generation and load connected to the network.

The standard way in which network users can be induced to make efficient connection and operating decisions is to confront them with the correct price signals (in this case access charges). While deep connection charging is a convenient basis for economic analysis, there are good practical reasons for translating these into shallow charges combined with locational generation use of system (GUoS) charges. Load, on the other hand, can continue to be treated as at present with suppliers passing on the various voltage level and (time-varying) energy (loss) charges.

These efficient prices are unlikely to recover the amount of revenue allowed under the DPCR. The efficient way to make up any short fall (or return any surplus) is to concentrate mark-ups (or subsidies) on system use that is most insensitive to price. That means new generation should probably face charges close to or at efficient prices, with most of the shortfall in revenue recovered from existing load, preferably in ways that do not influence system use.

The appropriate basis for setting the access charges is on forward-looking long-run incremental cost - as the change in the net present worth of future investment due to new entry. Our report argues that the old Electricity Association (EA) methodology has serious shortcomings. First, it is based on an ideal or virtual network using currently available best technology, but not differentiating charges locationally. Second, it only considers load and does not estimate the costs and benefits of distributed generation (DG). Third, a proper forward-looking LRIC must start from the current network and make efficient investment choices for accepting load or DG at each possible node. The formulae derived in the report suggest that the EA approach under-estimates costs for load and may under-estimate the benefits of DG.

At present, average (not the efficient marginal) losses are passed through to load, but the benefits of loss reduction offered by DG are not systematically accounted for. Passing through all changes in losses reduces the DNO's incentive to invest to reduce these losses. The DPCR proposes an incentive mechanism of £48/MWh for improvements in loss reduction beyond a DNO-specific target. The resulting investment will add to the RAB at the next DPCR, after which the loss target can be reset. This has the desirable incentive effect of encouraging the DNO to not delay investment until the end of the DPC period, and should encourage the DNO to devise GUoS charges that encourage loss reduction. GUoS access charges can be differentiated by location and time-of-use and designed to reflect locational and time-of-use differences in the value of (marginal) loss reduction. However, the current fixed incentive, while having the attraction of simplicity, is relatively crude and might distort DG supply to off-peak periods when loss reduction is less valuable. The attraction of a simple incentive may not be too serious for incentivising efficiently low-loss network capacity expansion. Management and contractual aspects of access charges will need to develop further to address issues such as sunk costs, liability, and commitment that arise from more flexible networks operation.

In principle, energy, capacity, and fixed charges are all applicable to distributed generation. For load customers without interval meters, energy use has to act as proxy for capacity. If system efficiency or energy efficiency are objectives of Ofgem, then charging fixed costs for domestic and commercial customers as energy related tariffs might contribute to these objectives.

The economic principles discussed in the above should form the basis on which a new charging model can be developed. The model should have a number of desirable attributes: (i) be calibrated to each existing network, (ii) contain an asset register, (iii) be able to determine assets needed to meet new demands, (iv) find least-cost system expansion, (v) compute losses and handle ancillary services, (vii) estimate incremental O&M costs, (viii) be available to users, and (ix) be simple enough for external users.

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1. Background

The structure of electricity distribution charges before 2005 reflects the framework inherited at privatisation, with some variation across the distribution network operators (DNOs). These charging structures treat distribution-connected generation very differently from demand customers and from transmission-connected generation. In the past this may not have been a major problem, given the limited volume of distributed generation (although it may have discouraged desirable developments). The time has come to revisit access and DNO use-of-system charging principles to ensure that they give the right signals in an environment that is likely to have increasing volumes of distributed and often intermittent generation.

Distribution networks have developed as largely passive networks designed to facilitate the transfer of electricity from the transmission system to customers' premises. The connection of distributed generation displaces energy flows from the transmission systems and will require changes to the traditional mode of operation for local distribution systems. Mismatches between distributed generation exports and local demand may create trade-offs between network reinforcement and managing local, transient constraints. They may also have implications for transmission system charges. In light of this, DNOs may be required to adjust the configuration of some or all of their networks to manage network conditions more actively.

In addition, charging structures are now beginning to diverge across DNOs without any clear evidence that the changes improve the charging structure. For these reasons, Ofgem has requested a fundamental review of the principles that should inform the structure of charges, and to develop methodologies that can be implemented at or before the 2010 Distribution Price Control Review (DPCR 5). As part of its 2005/6 business plan, Ofgem specifically identifies the need to reconsider the regulation of network monopolies. "Regulation of monopoly networks has developed significantly since the traditional RPI-X price regulation was introduced almost 20 years ago. A major challenge during the next five years will be to ensure that the regulatory regime allows for, and incentivises, increased investment where there is a need for asset replacement, network resilience and to respond to changing supply and demand patterns." (Ofgem, 2005)

2. Objectives

Two key objectives specified by Ofgem are to develop a structure of charges that reflect costs and benefits, as far as is practicable, and to facilitate competition. Ofgem considers that the structure of distribution charges can also make a significant contribution to promoting competition in related markets. If distributed generation (DG) is discouraged, or if some otherwise favourable locations for wind power face distorting access charges, then competition in generation would be adversely affected. The way in which connection charges are calculated and applied could have a significant impact on the competitiveness of new connections. It is also considered important that charging structures are responsive to the needs of network users. This requires that the charging structures can evolve over time and that the principles that guide the setting of charges are clear, so that improvements in relating charges to the underlying determinants of appropriate charges can be made as they become possible and cost-effective (e.g. because of metering or better cost modelling).

In the November 2003 *Initial Decision Document* these objectives were interpreted as requiring a suitable balance between:[1]

- ♦ cost reflectivity;
- ♦ simplicity (at the point of use);
- ♦ ease of implementation;
- ♦ transparency; and
- ♦ predictability.

This immediately raises the question whether there are other objectives that ought to play a role in setting access charges, of which the three most obvious are equity/fairness, meeting various environmental objectives (such as the total volume of renewable generation), and the consistency of the distribution charging methodology with other aspects of Ofgem's incentive regulation, notably the DPCR, transmission charging, loss reduction incentives and quality of supply incentive schemes. To make progress we assume in this report that only the objective of efficiency is to guide the charging methodology, but indicate where modifications (perhaps explicitly and separately funded) to meet these other objectives might become relevant.

[1] Ofgem (2003c).

3. Rationale for an Efficient Access Charging Framework

Since before privatisation and regulatory reform of the electricity industry, the access charging methodologies utilised by DNOs have broadly remained unchanged. The principles of this methodology are set out in Boley and Fowler (1977) - essentially a cost allocation model based on consumption profiles of different types of customer groups, discussed further below. This methodology needs to be revisited in the light of incentive regulation of networks, competition over networks, and emergence of new concepts and technologies such as distributed and micro-generation. These changes require that the cost allocation model be replaced with a cost-reflective access charging model that takes the dynamics and long-term efficiency of a market-oriented electricity sector into account.

Within the framework of Distribution Price Control Review (DPCR), the starting point for the access charges framework is that the regulator has identified break-even performance targets for the DNOs. Ofgem's incentive regulation of the DNOs for the past two DPCRs has been to set maximum allowed revenue levels for individual utilities using a methodology based on benchmarking of the DNOs' operating expenditures, together with the approval of and (in DPCR 4) incentivising capital investment plans. The allowed revenues can be thought as having a broad relationship to utilities' underlying cost structures. However, the current methodology for collecting the revenues in the form of access charges does not necessarily ensure that different types and classes of charges are cost-reflective and efficient. It is also the case that the arrangements for connections for new distributed generation (DG) under DPCR 4 blur the distinction between the bulk of the regulatory asset base and assets associated with new DG connections.

The long-term objective of the regulator is to maximise social welfare subject to a minimum level of DNO profits sufficient to motivate efficient operation and investment. The utilities are thus profit maximisers subject to an allowed revenue constraint. Given that utilities' maximum allowed revenue is pre-determined under DPCR, the main economic objective of access charging system is to send cost-reflective price signals that maximise social welfare subject to this constraint. The structure of access charges has social welfare impacts by affecting the costs incurred by utilities' (and thus their producer surplus) and distributional implications for producers and consumers as well as among different consumer groups.

4. Access Charges in Other Countries

Article 23 of the EC Directive 2003/54 states that national regulatory authorities should be responsible for approving at least the methodologies used to calculate the terms and conditions for connection and access to the national networks, including distribution tariffs.[2] The Directive states that the regulatory authorities are, at least, responsible for:

> "*the terms, conditions and tariffs for connecting new producers of electricity to guarantee that these are objective, transparent and non-discriminatory, in particular taking full account of the costs and benefits of the various renewable energy sources technologies, distributed generation and combined heat and power;*"
>
> Also, that "*The regulatory authorities shall be responsible for fixing or approving, prior to their entry into force, at least the methodologies used to calculate or establish the terms and conditions for: (a) connection and access to national networks, including transmission and distribution tariffs. These tariffs, or methodologies, shall allow the necessary investments in the networks to be carried out in a manner allowing these investments to ensure the viability of the networks; (b) the provision of balancing services*."

There are considerable differences in the structure of distribution access charging models across the countries. These differences concern most aspects of charging models such as new connections, Distribution Use of System (DUoS) time of use element, and provisions for distributed generation (DG) sources.[3] In the light of the Directive's guideline, member countries will revisit the access charging methodologies of the companies. This is also likely to result in a degree of convergence in practice and methodologies across EU countries.

Connection charging

We argue that the shallow charging principle (with appropriate locational signals) for new connections to the networks is preferable to deep charging. Ofgem has already made the decision to move away from deep to shallow charging (Ofgem, 2003b). This

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[2] Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.

[3] See CER (2004) for a brief international comparison of tariff structures for transmission, distribution, and supply and links.

is also in line with the practice in some other countries. In particular, new embedded generation is more responsive than demand to level and structure of connection charges. The main benefits of DG are reduction in energy losses and reinforcement costs to meet the maximum demand from high voltage grid.[4] The former can be regarded a reduction in variable costs and the latter a reduction in fixed costs.

Table 1 shows the status of connection charging methods in the EU member countries in 2001.[5] As shown in the table, a majority of member countries use shallow charging principles, while only one country levies DUoS charges on generators. Shallow connection charging reduces both the problem of first-comers (and arrangements for reimbursements following subsequent new entries) and required initial capital outlays.

Table 1 Charging Principles for Distributed Generators in EU Countries

	Distribution Use of System Charge Facing Generator	
Type of Connection Charge:	**No**	**Yes**
Deep	Austria, France, Greece, Ireland, Luxembourg, UK	-
Shallow	Belgium, Denmark, Italy, Germany, Netherlands, Spain*, Portugal, Sweden (>1.5MW)	Sweden (<1.5MW)
***** Spain's system is a form of shallow charging, which requires distributed generators to connect to the nearest point in the system that will not result in deeper reinforcement costs.		

Source**:** Watson (2002).

Distribution Use of System charges

DUoS charges usually consist of some combination of fixed, capacity, and energy charges. There is considerable variation in relative share of these components in the distribution access charges across the EU countries.[6] Generally, fixed charges comprise only a small share of the total access charges. In addition, most of the member countries apply some form of time-differentiation to the energy charges and a few of these apply it to capacity charges. In Finland, France, Italy, the Netherlands, and Spain some form of time differentiated charging is applied to both capacity and energy charges (Pérez-Arriaga et al., 2002).

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[4] It should be noted that a reduction in maximum demand also reduces the energy losses as they are higher during peak time and vary as the square of the current in the lines. Losses are also higher in rural areas. See e.g. IEA (2002). The implications of these facts are considered below.

[5] See also Connor and Mitchell (2002) for a comparison of the arrangement for DG in the Netherlands, UK, Denmark, and Germany.

[6] See Pérez-Arriaga et al. (2002) for a comparison of transmission and distribution tariff charges in the European Union.

5. The Current Context of UK Charging

The vision expressed by Ofgem is that DNOs should move from their traditional role as passive network managers, responsible for ensuring that the network meets reliability targets and connects passive customers, to active network managers. This has two meanings – active as in managing ancillary services more like a TSO, and active in taking a more pro-active role in stimulating profitable or desirable actions, such as encouraging distributed generation (DG) to reduce network investment and losses, encouraging demand side management, etc. The problem as always in regulation is a Principal-Agent one, although at two stages. Ofgem as Principal wishes to induce the DNOs as Agents to develop the entire system (network and DG) to maximise total benefits (to consumers, generators, and DNOs) while the DNO wishes to maximise its own profits. As Principal the DNO wishes to encourage Agents to connect and operate at least cost or greatest profit to itself.

DNOs are subject to price-cap regulation set at the periodic Distribution Price Control Reviews. In contrast to cost-of-service regulation, the motivation behind a price-cap form of regulation is to provide incentives for the efficient delivery of network services, without compromising quality of service, for which various quality standards are prescribed, with associated penalties for failure (or rewards for exceedance). Regulatory theory is concerned to design suitable charge structures taking account of asymmetric information (the DNO knows its costs and options better than Ofgem) and incentives (the DNO wishes to maximise its profit, which may not perfectly coincide with Ofgem's objectives).

Some of the incentive problems are addressed through structural requirements to legally unbundle distribution activities from generation and supply, and through restrictions on merger activity. Some are addressed by requiring the DNOs to submit detailed information on costs and quality of service, ideally in standardised formats. Business plans are requested and validated through benchmarking. Nevertheless, there are still a number of key choices that must be made about the form of regulation that remain somewhat problematic.

The first of these is the form of the price control. For some industries, notably telecoms in early years under Oftel, the price control took the form of a basket or set of baskets of services, where the price that was controlled was a base-weighted index of the prices of the elements of that basket. Such a system has agreeable incentive properties in that it encourages the utility to rebalance prices towards a Ramsey optimum – that is the welfare maximising set of service prices subject to a minimum profit requirement. In such a case the mark-up over marginal costs for each service needed to recover any fixed and common costs would be inversely proportional to the demand elasticity for that service.[7]

In contrast a revenue cap can provide perverse incentives to choose mark-ups that are the opposite of desirable Ramsey rules, with higher mark-ups on elastically demanded services, whose demand will then decrease, saving the utility costs but not reducing revenue.

The particular way in which DNO access and usage charges are set should be consistent with the overall objectives of the Distribution Price Control, which are to encourage the DNO to set efficient charges, and to recover any shortfall from marginal cost prices in the least distortionary way. The price control from 2005 continues with the same base demand revenue driver as in the previous control, updated so that the actual number of consumers will be used for the calculation and more appropriate weightings for the voltage categories will be applied. There is an additional term in the revenue driver to reflect the inclusion of EHV charges, which will not have a volume-related term. The current revenue drivers do not include distributed generation.

Whether the price control corresponds to a price basket or a revenue control depends on how over and under-recovery of revenue is treated. The incentives built in the DPCR can influence the DNOs to connect new DG and maintain the connections and their level of output through their charging methodologies. Tables 2 and 3 summarise the DG-related incentives that the current DPCR offers to DNOs.

Distribution access charges should in principle be consistent with transmission charges, particularly for DG, which may have a choice whether to connect directly to the grid or to the distribution network. The current transmission charging arrangements reflect the imbalance between load and generation in different parts of the grid but are not necessarily fully cost-reflective. The signals imply that more generation resources are desirable in London where demand exceeds generation, while the reverse case applies in the North (Table 4). Clearly it is desirable to pass these signals through to DG, so that it may be directed to areas where there is a generation deficit and not to areas with a generation surplus. This will depend on the way in which the zonally differentiated consumer and generation transmission network use of system charges (TNUoS) are passed through to generation and load within the distribution network. We discuss the relationship between transmission and distribution charges in section 6 (viii) below, noting that there may be a tension between the desirable aim of cost-reflective tariffs for connection to the distribution network and the current system of grid charges.

[7] Under simplifying assumptions, otherwise more complex formulae involving cross-price elasticities may be needed (and should still be incentivised). See Vogelsang and Finsinger (1979).

Table 2 Summary of incentives for DG in DPCR.

Incentive Type	Incentive Rates	Notes
Cost pass-through	Partial pass-through (80%) of DG-related costs incurred to DNO.	The “pass through – connection charge” differential to be recovered over 15 years on annuity basis and to enter DNO’s allowed revenue.
Revenue driver	Incentive rate at £1.5/kw/yr for connected DG.	Based on an additional ROR of 1% to allowed cost of capital i.e. 6.9% (for Scottish Hydro Electric £2/kw/yr). Incentive rate is recoverable as long as DG is connected.
O&M cost allowance	£1kw/yr of DG.	I.e. 1.22% of a capital cost of connection at £82/kw as estimated by DNOs.
Interruption incentive	HV DG: £0.002/kw/hour. LV DG: same as for demand customers.	Payment from DNO to DG.
ROR on DG portfolio	Floor rate: 4.1% real pre tax. Ceiling rate: 13.8% real pre tax.	4.1%=allowed cost of debt.
• Pass-through and incentive rate) are for generators connecting after 1 April 05. • For high-cost DG connections (> £200/kw) i.e. 4 times higher than average direct reinforcement costs, the generator should pay the excess costs through connection charges. • DG incentives will also apply to micro-generation.		

Source: Ofgem (2004).

Table 3 DG-related loss incentives in DPCR.

Incentive Type	Incentive Rates	Notes
General % energy loss targets for individual DNOs - as the difference between volume entering and exiting the system.	£48/MWh for loss reduction in general.	“An explicit adjustment to the level of reported losses may be made to reflect the impact of distributed generation with a loss adjustment factor (LAF) below 0.997. This adjustment will the aggregate product of the difference between the site-specific LAF and 0.997, multiplied by the export volume of the generator; and expenditure on low-losses equipment will be treated as any other capex, i.e. it will be eligible for inclusion in the RAV and subject to the rolling capex incentive.”

Source: Ofgem (2004).

In areas of surplus generation TNUoS charges are high for Generation and low for Load. At present the distribution load at the Grid Supply Point is charged on demand in the triad hours, and one would expect this to be passed through to final consumers in the DUoS charge. Consumers with embedded generation reduce their triad charges and thus benefit to that extent from the sum of the triad demand charge and the generation TNUoS charges. Although the balance between demand and generation TNUoS varies considerably across the grid zones, the sum of the two varies less, and mutes the location signals given to embedded DG connecting to distribution networks. If, as we argue, DG is credited with the benefits it provides to the network and network connected consumers, then logically this triad benefit should be passed through to DG in the triad DUoS charges not only automatically for embedded generation behind a customer meter, but to DG exporting to other consumers within the same distribution network. (Exporting through the GSP would involve additional generation TNUoS charges, and is in any case unlikely without considerable further investment in embedded DG.)

Table 4 Estimates of "Embedded Benefit" to Distributed Generators in the UK (in US per MWh)

Embedded Benefit	London	South Yorkshire	North
Transmission Network Use of System charges avoided (Demand)	2.73	0.99	0.20
Transmission Network Use of System charges avoided (Generation))	-2.10	0.75	1.73
Balancing System Use of System charges avoided	1.77	1.77	1.73
Transmission Losses charges avoided	0.06	0.06	1.77
Balancing system administrative costs avoided	0.29	0.29	0.29
Avoided trading charges	0.06	0.06	0.06
Total	2.80	3.92	4.10

Source: IEA (2002).

Summary: We suggest retaining the separate regulatory treatment of allowed revenue for the DNO and charges for DN users. With a shift towards more active network management the DNO has more flexibility to resolve constraints, reduce losses, enhance reliability, connect DG and minimise network investment. The incentive mechanisms used to optimise any one of these objectives might have perverse outcomes on other objectives. The DPCR revenue determination and incentive mechanism thus needs to be reviewed to assess the joint impact of the individual incentives.

6. High Level Principles for Distribution Charging

The general principle that underlies efficient charging is that charges should reflect the different marginal costs and benefits to the electricity system of connection at each node. That is likely to imply that charges will vary between nodes and over time. The charges resulting from this general principle may then have to be modified to make them consistent with the Distribution Price Control Review's allowed revenue and particular incentive schemes (e.g. for general DNO loss reduction). We examine a set of eight principles in turn:

i. The DPCR and the access charging methodology

The utility's objective is to maximise the margin between the reference maximum allowed revenues plus other targeted incentives and total costs. If the DNO could be persuaded to charge properly cost-reflective efficient access and DUoS charges, then it would have no incentive to distort its investment decisions, and the network should then be adapted and expanded in an efficient way. The problem is that either the DNO will have some discretion over setting charges, and may find it profitable to distort these away from their efficient cost-reflective level, or Ofgem will specify these charges, in which case they are unlikely to be properly efficient and/or cost-reflective, and may again lead to inefficient decisions.

In addition, there is no guarantee that efficient access and DUoS charging will match the DNO's allowed revenue under the DPCR, and some further adjustments of charges are likely to be needed to reconcile the two, opening an additional source of potential inefficiency. Figure 1 shows the two pressures acting on the setting of access charges. Ofgem's current DPCR is based on benchmarking DNOs' operating expenditures and approving incentivised investment plans. It is essentially a top-down approach based on average, not marginal costs, that determines DNOs' allowed revenues. From an economic efficiency point of view, it is desirable that the DNOs cover their allowed revenue through cost-reflective access charges that send correct economic signals. The charging methodology is a bottom-up approach that follows from the main cost drivers. There is, however, potential for mismatch between the objectives and outcomes of the bottom-up and top-down methodologies.

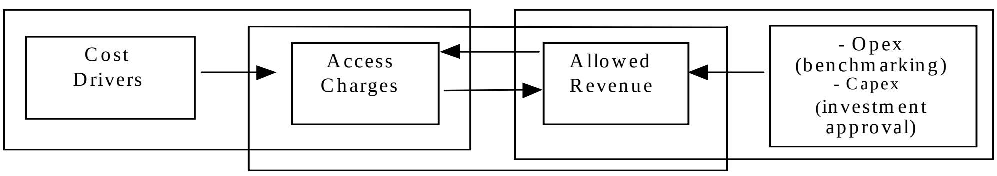


Figure 1: Factors influencing the setting of access charges

Economic theory (based on Ramsey pricing rules) is clear on how best to adjust efficient prices to ensure an overall revenue objective, of the kind specified in the DPCR. In effect Ofgem (or the DNO) should levy mark-ups on the efficient prices to meet the revenue target. If the efficient charges would over-recover the allowed revenue then these mark-ups will be negative (in effect, subsidies). These mark-ups are like taxes (or subsidies) on the various underlying efficient prices and should be chosen to minimise the distortion in the decisions that will be affected by the charges. Distortions will be serious if agents (generators or consumers) make a decision on the base of the charges that is more costly than the efficient decision (the one that the efficient charges should have signalled). The most costly decisions are likely to be locational decisions that will be hard to change and could lead to considerably higher network costs. Existing load is unlikely to move and here a considerable mark-up on the fixed element of the efficient charge may have little adverse effect, but DG, before it makes its locational decision, is potentially more mobile and may respond strongly to charging signals. These charges should therefore only attract a low or possibly zero mark-up (or subsidy).

Summary: Cost-reflective and efficient DN charges minimise distortions for investment and location of DG and load. The incentives of DNOs to distort such charges have to be balanced against the incomplete information of the regulator to set the charges. The difference between (marginal) cost-reflective charges and allowed DNO revenue has to be allocated in a way that minimises locational distortions and distortions between different generation technologies and connection to different voltage levels. Ramsey pricing suggests that this difference should therefore be allocated to the least price responsive group – commercial and domestic consumers – and collected through the fixed charge.

ii. Connection boundary

The connection “boundary” question concerns the scope of connection charges (specifically what costs it is legitimate to include in these charges) and what charges are left to distribution use-of-system (DUoS) charging. These latter charges may require quite a refined structure (e.g. kWh charges by voltage level and/or customer type, kW charges, maximum demand charges, etc) and will be considered separately once the boundary has been defined. One central question is whether the same boundary should apply equally to demand and generation.

In the *Initial Decision Document* outlining the interim charging arrangements applicable from 1 April 2005, at para 4.6-7 Ofgem stated that it “considers that, in principle, the charging framework should treat demand and generation users on a consistent and cost-reflective basis. In light of this, Ofgem proposes that DNOs should adopt a common connection charging policy for new demand and generation connections. The decision on the boundary between connection charges and use of system charges needs to take account of the desirability of:

- reflecting costs to users on a forward-looking long run incremental cost (LRIC) basis rather than solely in relation to costs incurred. This should minimise the problems of free-rider and first-comer/second-comer;
- providing cost-reflective locational signals;
- avoiding unduly volatile or unpredictable charges; and
- avoiding undue or unmanageable complexity in use of system charges."

The first point to make is that the charges should be made up of two elements – the cost-reflective part, where a sensible apportionment of forward-looking LRIC should give the correct signals to demand and generation, and a cost-recovering mark-up, which can be seen as a tax (or possibly subsidy) on the efficient price. This mark-up should minimise distortions, subject to other objectives that Ofgem may wish to take account of (such as equity, or offering additional encouragement to certain forms of generation connection). The Ramsey rule (i.e. the least socially costly mark-up) implies that generation and demand might legitimately be treated differently if they have different price elasticities of response. Thus if distributed generation (DG) is footloose, a high mark-up may discourage it to locate at the least-cost node in the most appropriate DNO, while if demand below a certain size is immobile, a high mark-up may have no adverse efficiency impact. An additional consideration is that large loads are more likely to consider embedded generation, and their choice of size and technology may be distorted if they are subject to different mark-ups on their load and generation. Efficiency may therefore argue that such consumers are indeed treated symmetrically for load and generation. For most other consumers, differential responses to charges would justify a differential charging regime for generation and load, unless considerations of equity over-rode the efficiency argument.

How important this issue is will depend on the size of the shortfall in revenue from LRIC charging, and whether the equity issue only impacts certain consumers (e.g. domestic customers).

The next question to address is how best to ensure that the DNO signals the optimal location and chooses the most efficient investment plan to accommodate new entry of generation (and load). Here it is worth considering the theoretical issue at a fairly abstract level, before considering how best to implement a system that best achieves the objectives. We seek a set of charges that will ensure that the network is upgraded efficiently to meet new demands placed on it, and that generation and load locate in the most efficient locations, so that they balance locational advantages against the extra network costs involved.

Properly computed deep connection charges appear to correctly signal location, in that there will be cost-reflective differentials across locations. In a world in which the DNO can correctly foresee the future set of entrants, their needs (connection capacity) and the values they place on each location, the DNO could optimally plan the network and specify who should locate where by setting each entrant a whole set of location-specific and entrant-specific deep connection charges. Each entrant would then be satisfied with the location (which would be profit maximising allowing for the charge), and the total collected from each entrant at each location would exactly add up to the total connection cost. Where the connection assets are shared by several users, the costs would also be shared, but as the assets would be quasi-public goods, efficient charges would not necessarily be the same for all users at the same location if their willingness to pay differ appreciably. Note that in theory this deals with the issue that in an interconnected network, investments occasioned by one connection may benefit others now and in the future.

Practical schemes will inevitably fall short of this ideal, for a number of reasons, of which the most obvious is that the future is not known with certainty and may be hard to predict. That is inevitable and one solution would be for the DNO to make the best guess and compute appropriate deep location-specific connection charges, trading off the benefits of larger increments against the risk of oversizing connection capacity and hence having to over-charge for connection. It might then charge the first entrant the full cost and encourage subsequent entrants to rebate some fraction (either by granting the right to the first entrant to charge successors, or making a charge and rebating it to the first entrant). Such a scheme is used in various jurisdictions and was (essentially) the model used in Britain before 2005. It suffers from various drawbacks:

1. the charge to be paid by each entrant depends on both the capacity of the connection and the number of subsequent entrants, neither of which is controlled by (or known to) the entrant;
2. there is no guarantee that the DNO will have an incentive to select the efficient level of network reinforcement, and
3. it is unlikely that a complete set of such charges (one for each location) will be available to guide location decisions; an issue related to *transparency*.

Even if the DNO chooses the efficient investment, there remains the question of allocating the costs over the current and future entrants efficiently. This could theoretically be done by allocating the first entrant the rights to allow in subsequent entrants for a charge. Efficient bargaining between potential entrants and the first mover should then lead to a satisfactory outcome, but only on the strong assumption that the first entrant can accurately foresee the volume of subsequent entry and the willingness to pay for connection. Entrants are likely to be less well-informed than the DNO and in the case of some DG not in a position to raise the capital to pay for more than their own network reinforcement. There is potentially an advantage in the DNO charging for the cost of the connection in proportion to the use made. If subsequent entrants arrive as predicted and if their willingness to pay for connection are similar, and if the correct capacity were chosen, this should lead to a satisfactory outcome.[8]

The second point is general to all charging models and will require separate discussion.

The third transparency point might be solved if there were an auditable model (like the ICRP model for NGC charges, or Transcost for the gas NTS entry-exit prices) and if this were fine-grained enough to give location-specific cost estimates. Only then would footloose agents (largely generators) have the information to guide their location decisions. Again, any charging system that signals location properly will need this information. We discuss this below.

Summary: Locational elements should be added to generation connection charges. Their calculation could be guided by the cost calculated for deep connection charges of an asset. However, as the scale of individual DG projects can be small relative to the scale of DN expansion, lumpy costs should not be attributed entirely to the first project. Similarly, an individual connection that does not precipitate a network upgrade can nevertheless increase losses or advance the date of future upgrades and thus add to expected network costs. This suggests that a more refined calculation of DN access charges is required.

iii. Deep vs. shallow charges

The form of access charging for DG until 2005 was described as deep, but it excluded any potential benefits (such as loss reduction), as the network had to be constructed to meet standards that ignored the presence of any DG. As such it was an imperfect measure of the net costs that any DG connection might impose on the network. Correctly defined deep charging involves estimating all the extra investment costs needed to efficiently accommodate this and subsequent relevant entrants and netting off any benefits that would not be captured in the energy or DUoS charges. The less significant are indivisibilities and economies of scale in upgrading, the smaller the spare capacity created at each entry and the simpler it will be to determine a fair share of the cost to attribute to the entrant. In some regions, like PJM in the US, the transmission expansion required to accommodate large power plants is of the same scale as the power plants. In such cases, deep connection charges avoid most of the problems facing

[8] The charge would probably have to include a mark-up to cover the expected average cost, as there is a chance of too few entrants raising average costs, but if the capacity is limited, no offsetting above average number of entrants.

smaller connections, and are therefore frequently adopted (as, for example, in PJM). In contrast, the capacity of distributed generation projects can be small relative to the efficient incremental capacity, and so problems of lumpiness and indivisibilities raise more problems for DNOs.

Locational connection charges can send better cost signals by reflecting the actual costs in different parts of the network. The marginal cost of distribution capacity expansion and reinforcement in a given network is often location-specific and can vary across the utilities and within the service area of a given company. The cost differences are largely a function of past investment decisions and development of demand. Local factors (population density, urban infrastructure) and geographic conditions can affect these expansion costs. It follows that the marginal costs in a given part of the system are likely to vary over time. This property of marginal distribution costs has also implications for provision and promotion of access for DG. A better understanding of dynamics of marginal costs of a network can signal where and when DG can be a cost-effective alternative to distribution capacity expansion.[9]

In regulated vertically integrated electricity sectors these cost signals are internalised and incorporated in corporate decision making. However, in liberalised electricity sectors efficient entry by DG will depend on the price signals contained in the access and DUoS charges. This makes their predictability and transparency critical to the efficient development of the network.

Shallow charging aims to limit the connection assets attributed to the entrant (e.g. up to the next voltage level) and to recover the balance by DUoS charges. If it is to signal location efficiently, then the DUoS charges will have to be location specific. Otherwise there will be a tension between the entrant wishing to connect to the nearest grid point from his most favourable location and the DNO wishing to encourage connection at points which minimise total network costs. That could lead the DNO delaying or otherwise obstructing entry at some points without it being clear which points were in fact cost-minimising.

The guiding principle in determining the access charges under a shallow connection charge regime is that their present discounted value should be equivalent to the correctly determined deep connection charge (i.e. granting due credit to any network benefits, in contrast to the past approach. If the deep connection charge were correctly computed and if the location element of the DUoS were also computed as the annualised shortfall between the deep and shallow charge, then the shallow charge plus the locational DUoS would give the correct signals. It is worth asking what would be

[9] Heffner (1995) illustrates the locational (and time varying) inter and intra-utility differences in marginal distribution capacity costs for two US utilities and discusses their implications for DG investments. The paper also discusses that after major investments in capacity expansion the marginal cost of further expansions can fall and that it can be cost effective to enter DG before, rather than after, high cost expansions.

needed to achieve that, and whether it would work better in practice than the deep charging method:

1. The shallow charges would presumably be relatively easy to define and if sufficiently shallow would be contestable (i.e. could be competitively supplied). This has a major advantage in that one of the major barriers to entry of DG is the lengthy and non-transparent negotiation needed to secure a connection and determine the cost.
2. The location element would still require an estimate of the reinforcements needed that could be attributed to the entrant. This would best be derived from an auditable model. The incentive to develop or acquire such a model might be greater if location DUoS charges for all nodes or groups of nodes are required, rather than a system in which the DNO estimates the costs only in response to specific connection requests. This would both aid transparency and also give clearer signals, assuming that the location DUoS charges were published. Again, pressure for transparency is an important factor in favour of this approach. A standard network model capable of local calibration might usefully be commissioned and paid for collectively by the DNOs, perhaps using the good offices of the Electricity Association or even Ofgem. Such a model is discussed further below, and will be assumed in what follows.
3. In some cases the connection of DG may *reduce* network reinforcement costs, and logically under deep connection charging the entrant should be *paid* for entry, or rather for delivering generation when needed to avoid the otherwise necessary reinforcement. Shallow charges would then require a negative locational DUoS element conditional on delivery under specified conditions (e.g. a triad or some DNO equivalent). Deep charges would need a contractual obligation to deliver at these times and a penalty regime (as with NGT's negative grid charges).
4. The location DUoS charges would be based on the actual demand made rather than the size of the upgrade that appears justified, but see below under the discussion on LRIC. The demand made would have to be suitably measured (simultaneous sub-network peak demand, for example), but the entrant would no longer have to make any predictions about future rebates, reducing the risk and therefore financing costs. Negative locational element charges need additional conditions and obligations, as remarked above.
5. There is a question whether the locational DUoS charge element would be subject to a contract of a defined period (e.g. for 5 or 10 years), so that there would be predictability for each entrant at each time, but not necessarily the same contract terms offered each year, in the light of new information about system reinforcement needs. There is a related issue about liability for on-going charges for premature exit or failure. This is discussed separately below.

Financing costs are likely to be higher for DG project developers than for regulated DNOs. This provides an argument against deep connection charges. Total costs would therefore be reduced if DG is exposed to lower costs up front. Costs should be spread over the project life-time through suitable DUoS charges.

Overarching all these issues remains the question of whether the DNO has the right incentives to make the correct investments. This is a key issue and will be discussed at length below.

Summary: DG should be exposed to locational signals to ensure the efficient choice of location. The calculation of charges should include both costs and benefits attributed to the new location. In principle, the present value of correct and fully cost reflective deep or shallow connection charges, that recover the capital expenditures, over the project lifetime, are equivalent. Shallow charges might be preferred because they reduce risks and the financing costs of connecting parties. Shallow connection charges should be contractually fixed for a suitable period to offer greater certainty to new generators.

iv. The case for forward-looking LRIC

Connection charges, whether deep or shallow with on-going locational charges, are intended to guide the efficient expansion and use of the distribution network and connected assets, both load, L, and generation, G. Correctly computed deep connection charges raise the fewest conceptual problems. As such, it is a helpful model to guide the design of more practical alternatives.

To start with the simplest case, in a world of perfect predictability, with the complete future evolution of the network and connections already known, and optimal locations and investment plans drawn up, the extra cost imposed on the network by a new G (or L) entering a specific node is the difference in NPV of the future investment stream with and without that entrant.[10] This immediately raises a question, for if the G does not enter, how is the existing demand to be met? The answer for a DNO is that more would be taken from the grid at the grid connection point, with consequent costs. If we are considering an extra L connection, the answer is more straightforward, as the marginal load will be met from the grid.

Note that a G connection may *reduce* DNO costs by delaying otherwise needed reinforcement (e.g. from the grid connection point to the growing customer base). However, payment to a G connection typically requires an obligation to meet the demand that would otherwise be met from the grid. Similar issues arise with NGC grid charges, some of which are negative. These are annual payments made only according

[10] Changes in operating costs, particularly losses, would be accommodated in the DUoS charges.

to electricity produced at the triads. Similar incentive issues will be needed for negative deep connection charges but may be more readily accommodated within the shallow charge with locational solution, where the DUoS charges are naturally linked to energy produced or used at the relevant peak.

The change in NPV of investment costs is exactly what is meant by the forward-looking LRIC. Its computation requires a model of the relationship between locational increases in G and L, the general evolution of demand and grid disconnections, and the investment plan of the DNO. Given the model, a series of decisions will be needed to translate connection decisions into charges:

1. What is the methodology for determining LRIC for both an increment of G and L? The Electricity Association considered an initial (sub-) network with a demand 500MW and then considered the impact of connecting additional load at various voltage levels. The original network was assumed to be optimal given current equipment and the extra costs of redesigning it for larger demands could then be estimated (again using current equipment and costs). It did not compute the costs (or benefits) of connecting DG, nor did it distinguish locational costs (as it was a virtual network).
2. How is the future evolution of the network to be modelled? This becomes important as many investments precipitated by connections will advance investments whose future date may not be very far ahead (but could be). The cost of advancing an investment that is almost due will be substantially lower than one that is not required otherwise for 10+ years.
3. What assumptions are to be made about the default option of increased supply through the grid connection point? This becomes relevant if there are many potential DG applications likely to arrive in the near future, otherwise all incremental demands can be assumed supplied from the GSP.

The first question asks how LRIC should be calculated and how that may differ from the former Electricity Association (EA) methodology. The old methodology was not designed to deal with locational aspects, and is silent about generation. Even if we ignore these differences, the estimates in Appendix 1 suggest that the former approach is likely to underestimate the marginal cost of load and under-reward the benefits of DG. The reason is that the EA approach ignores the present configuration and asset endowment of the network, both of which are relevant for a forward-looking LRIC.

If a new load or generator connects and precipitates (or delays) an upgrade, there are both costs and benefits that should be taken into account. The answer to the second question is that we need to be careful about both the starting point and to have a sound counterfactual (a forecast of load growth and the optimal replacement cycle in the absence of this new demand). There are several possible cases:

1. Current and projected levels of losses are such that it is considered economic to upgrade assets to reduce losses before this becomes necessary either because of equipment failure (life expiry) or because capacity will be inadequate for the projected loads. Given the high fixed costs involved in much investment, the fact that equipment now is poorly sized for existing loads does not necessarily mean that it should be replaced early by more appropriately sized equipment, so this may be a relatively infrequent case.
2. Load growth is slow enough that the existing asset has sufficient capacity for the rest of its planned life, and there is no case for an early upgrade.
3. Load growth is fast enough to precipitate an upgrade before life expiry if the network is to continue to meet network code standards.

These cases are modelled in the appendix, which shows that the results are likely to differ from the old Electricity Association calculation. Let current demand be D, growing at rate g. The capacity of the line is k and the total cost of the losses at date t is $\mu D_t^2/K$ where D_t is the demand at date t. The cost of a replacement line is $F + cK$, where $K = K_1$ is the capacity of the new line at the first upgrade. One measure of LRIC now would be cK/D, or, as a levellised amount, acK/D, where a is the annuity factor. The current marginal cost of losses is $2\mu D/k$.

In the first case an increase in demand now (assumed to also continue to add to future demand) will advance the optimal date of upgrade, assumed to occur at date T, which in this case is *before* its normal date of replacement and before it becomes capacity constrained. For example, if r = 8% (roughly the proposed discount rate for DG connections), g = 1%, $k/K = 0.25$, T = 10 years, the correct charge to make is made up of two terms. The first term is 1.25 $\mu D/k$ (rather than the marginal loss cost of 2 $\mu D/k$). The second term is approximately *twice* the apparent net present value of the unit LRIC, at $2e^{-rT}acK/D$. With the numerical assumptions discounting will coincidentally exactly counterbalance this doubling as $2e^{-rT} = 1$. If the date of upgrade is closer than 10 years the extra term will exceed the apparent unit LRIC. To summarise, an increment in load now advances the date of a costly upgrade but reduces the losses after the upgrade. This accounts for including the LRIC of the upgrade, suitably adjusted, and not including all the costs of current losses.

The contrast with the old method of computing the access charge is interesting. In that model we suppose that the network is re-optimised to minimise the total capacity cost and cost of losses. In a static world the appendix shows that the correct charge for an increment in demand now is just the *optimised* marginal cost of losses, 2 $\mu D/k^*$, where k^* is not the current capacity but the optimal capacity (which may well be greater, lowering the marginal cost). The old method is therefore likely to underestimate the cost of additional load. DG that *delays* upgrades and *lowers* losses should be credited with these benefits, and the old approach would undervalue these benefits.

The second case is one in which T is constrained by the asset life but not the capacity. It is easy to see that this leads to the same result.

The third case, which is likely to be the case attracting most attention as it is likely to give rise to the highest access charges for load (and potentially the greatest benefits for DG that delays upgrades) has the upgrade caused by demand reaching the capacity limit before the equipment reaches the end of its planned life. This important and interesting case is dealt with at more length in Appendix 1.

Summary: The locational connection charge should reflect the DN costs/benefits attributed to a new connection. This includes the change of the expected time of network upgrade, the benefit of loss reduction from the change in network upgrade and the marginal costs of network expansion. The appendix contains a more detailed discussion and numerical modelling of the effects, both in the presence of certain and uncertain future demand evolution.

v. Management of DUoS charging

If individual DG provides a significant share of the ancillary services and/or DNO is required to avoid investing in additional distribution capacity, then a contractual obligation to deliver these services when needed for at least two years is required to ensure the distribution network operator can make alternative arrangements if DG is withdrawn from the system. This would sit well with a shallow charging methodology, in which the benefits (e.g. deferred network reinforcement, extra compensators, etc) are credited as they are delivered, and not capitalised as might happen with deep connection charges. In either case an incentive mechanism should be part of the contractual arrangement to ensure provision of the required services and minimise transaction costs in case of non-compliance. For example, if load has to be shed to ensure safe operation of the network in the event of a failure of DG to deliver, the penalty might be rather high (the Value of Lost Load can be higher than £3000/MWh).

A contract with the entrant locking in DUoS charges for an extended period (longer than the period of notice required for disconnection) has two advantages. For users it minimises risk, allowing for higher leverage of projects, easier access to capital and lower financing costs. From the regulation perspective it allows a differentiation between existing and new customers (load or DG). As the dominant impact of price signals is on the investment decision it suffices to expose new investment decisions to new price signals to ensure efficient investment. This limits windfall profits in areas with decreasing access tariffs and political opposition in areas with increasing access tariffs. Long-term contracts raise questions about liability for on-going charges for premature exit or failure. Some part of the costs recovered through the continuing DUoS charges relate to the extra assets paid for by the DNO. As DG incurred high sunk costs it is unlikely that a DG generator will withdraw from a connection. This implies that no financial guarantee is required from the DG that would guarantee future payments of shallow connection fees (saving financing and transaction costs and also avoiding the creation of entry barriers).

Summary: If DG is to provide system services, then delivery of these services has to be guaranteed for a period that is required for the DNO to contract for alternative delivery of the services (1-2 years). Longer contractual obligations (other than a fixed price level for the shallow connection) are not required as the DG is immobile and characterised by high sunk costs such that it will typically not be relocated.

vi. Locational signals for load

Households do not have half-hourly meters and are thus not able to respond to time varying charges, either for energy or losses. If they have micro-generation then their profile of net demand may be very different from normal households, and there is an issue of how best to charge them both for energy and network services (which include the right to take peak demand if the micro-generation unit fails or is not running and the opportunity to sell back to the grid). There are two separate issues to address. The first is whether there should be an additional incentive to install and operate micro-generation, both to overcome barriers to adoption and to benefit from learning-by-doing spillovers. The more households successfully adopt, the more likely other households are to adopt, and the better developed will become the servicing and installation services. The second is the underlying efficient charges and payments for network use and generation. In practice they will be combined but it is conceptually better to keep them distinct.

The generating load profile of micro-generation will depend on its type. Photo-voltaic generation obviously only generates in daylight hours when household demand may be low (mainly consisting of refrigeration load). In Britain with small amounts of air conditioning its value to the grid will be lower than during the evening peak. The profile net cost of power could probably be computed (much as existing profiles are) given the size of the micro-generation unit, if there were to be only one meter. If generation is separately metered then the payments for generation can be matched to its value to the DNO and the cost of the net supply by the supplier. Stirling or other micro-CHP systems are likely to be more peak correlated and can be suitably rewarded with either a single or double meter. Loss factors may be locationally specific but are likely to be mainly realised within a short distance of the connection. As a result loss reduction benefits may be reasonably uniform over space, and not worth the effort of more refined calculations. If the difference in charges is small relative to the cost of installing the micro-generation a uniform tariff by location probably makes sense. However we explore the economics of incentivising microgeneration further in Section 7.

Houses without micro-generation would not seem to require locational charging, unless we are discussing an entire new housing development, where any extra deep connection costs over the normal cost of connecting a similar number of houses to the existing network might reasonably be chargeable to the developer. It may be that the opportunity to optimally size the system for lower losses would offset any extra costs of less favourable locations, and this would be computed in the same way as for DG connections. On balance it may be acceptable to avoid locational charges for residential and commercial load.

Summary: Locational distribution charges for load are not required because: (a) the location of load on distribution networks is usually not based on locational price differences, (b) such charges would hinder retail competition, and (c) create unnecessary complexity.

vii. Differentiation between energy, capacity and fixed charges

Cost-reflective charging suggests that the tariffs for load and DG should reflect the fixed, capacity dependent and energy dependent components of the underlying costs. In the case of DG the implementation of this principle is straight-forward. The cost of losses and the value of loss reduction are time and energy dependent and should (where metering makes this possible) be suitably reflected in the energy charges to guide efficient operational decisions.

There are arguably two reasons for departing from the principle of allocating costs to the relevant cost drivers (annual fixed, capacity dependent and energy related costs). First, in some cases it is not possible to measure the connection capacity actually utilised and it therefore has to be either added to the energy or fixed component. Second, Ofgem is charged to foster an electricity system that achieves efficient delivery of energy services. The tariff structure can be considered as an instrument to achieve Ofgem’s energy savings objectives.

Specifically, domestic customer electricity demand is to a large extent determined by their investment choices (house insulations, installations, electric appliances, and lighting). In these decisions customers may under-value future energy savings and invest insufficiently in energy efficiency. By shifting fixed costs, either of the connection or capacity related, towards variable costs and therefore increasing the exposure of final customers to variable energy prices, some of this distortion might be avoided. As an example from the car industry, fuel efficiency standards have been introduced, because extensive US and European studies (Greene et al., 2005) have shown that consumers under-value future energy savings and fail to choose the efficient level of fuel economy.

Final consumers are not directly exposed to the DNO tariff structure, as supply companies pay these tariffs and could in theory add fixed or capacity dependent DNO tariffs to the energy tariff in order to offer a constant energy price without fixed component to final consumers. Within such an approach domestic consumers with large demand would help the supply company to recover larger amounts of the fixed costs and would cross-subsidise smaller consumers. Supply companies could not offer such a tariff mechanism if it would not be based on a similar network tariff. Because otherwise large domestic consumers would shift to a supply company that would offer lower energy tariffs and a fixed fee, unravelling the entire scheme from the top.

The homogeneous charging mechanism would have benefits like reducing fuel poverty, inducing consumers to increase separate metering and therefore increase incentives for individual energy savings.

Summary: Charges should be related to the various cost drivers and so reflect fixed, capacity dependent and energy dependent costs, particularly for generation, to ensure efficient technological, locational and operational decisions. The responsiveness of smaller and domestic loads to such signals is likely to be modest and for them so the charging method can be simplified. As domestic peak capacity is usually not measured the high correlation between demand and peak capacity suggests adding capacity related costs to energy charges. Cost-reflective charging suggests that fixed costs should be charged as fixed charges and these are better suited to carry larger mark-ups. However, Ofgem's objectives to: (a) achieve overall system efficiency and (b) energy efficiency may shift the case for allocating some or all fixed costs to energy if this compensates for biases in investment and consumption decisions of smaller consumers.

viii. The relation between access tariffs to distribution and transmission networks

Large (above 100 MW) DG has a choice between connecting directly to the grid or to the distribution network at lower voltage (132 kV). Medium (50-100 MW) and Small (up to 50 MW) embedded generation is currently entirely connected to the distribution networks but in future might be allowed to connect directly to the grid. Clearly, it is desirable that grid and distribution charges provide consistent signals to encourage connection at the correct (least overall systems cost) level. The obvious problem is that there is a significant gap between charges on generation and load connected to the grid (otherwise there would be no net revenue to the grid), and this gap may disappear if generation is treated as negative load by the DNO. Table 5 shows the sum of the Generation and Demand Use of System tariffs for 2004/5 that would be avoided by connecting large generation units to the distribution network rather than to the grid, and treating DG as negative load.

Note that the distribution tariff zones do not coincide with the generation tariff zones, so that depending on location within the distribution zone, a generator in East Midlands, for example, might have the choice of connecting to generation zones 4, 7, 8 or 10, each involving a different tariff, as the map below shows.

Provided the level of DG embedded in the distribution network is less than the minimum load, the DN would never export to the grid and would therefore avoid grid generation use of system charges. Note also that there appears to be a slightly perverse incentive for DG to connect to the North West and save £17.33/kW (where there are “Low” opportunities for new generation) rather than in the South West and save only £10.96-13.97/kW (where there are “Very High” opportunities for new generation).

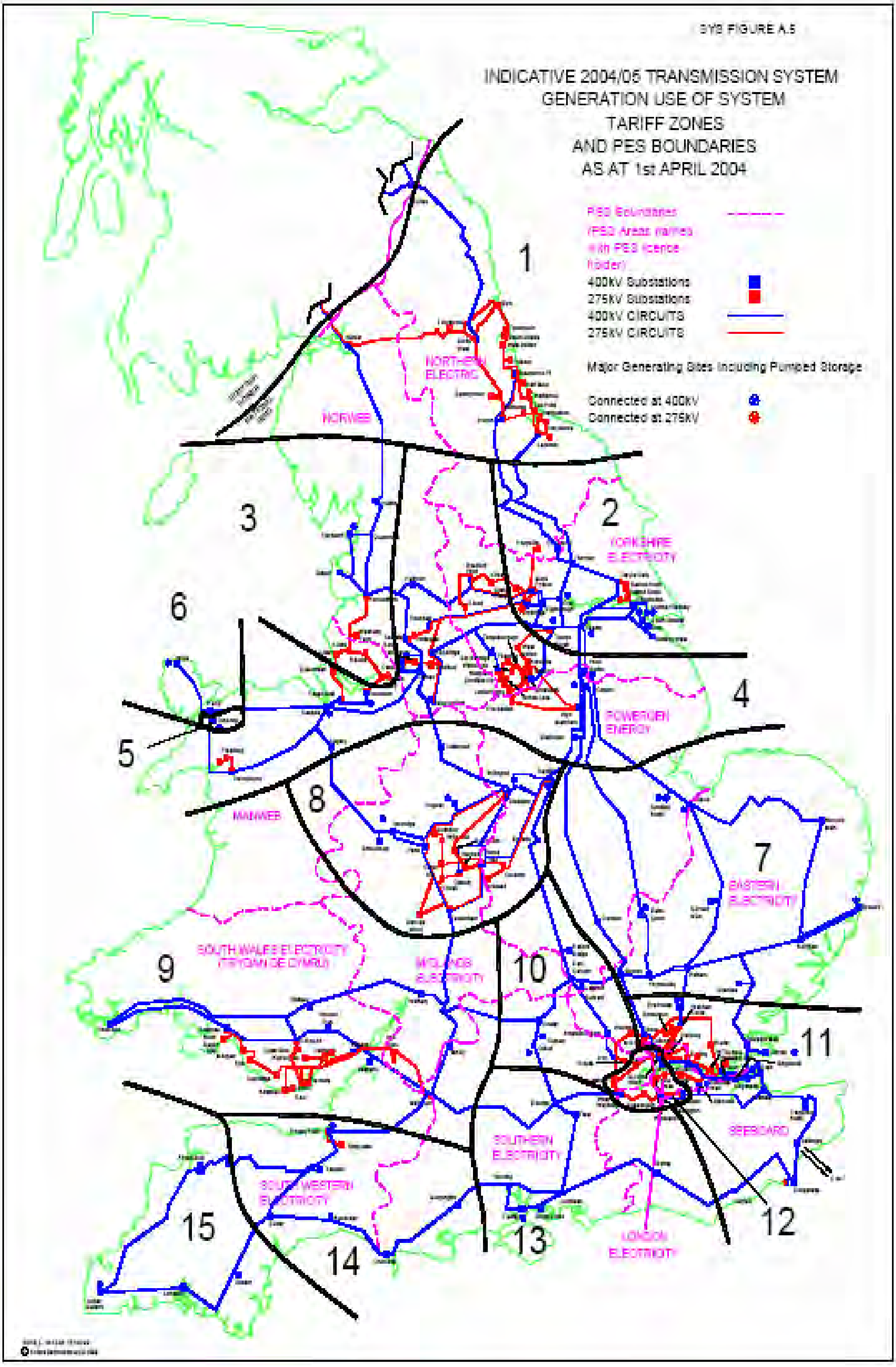
Table 5 Avoided annual costs of embedding generation

Demand Zone	Zone Name	Sum of Generation and Demand Tariff in £ per kW			
1	Northern	13.950103	10.708067		
2	North West	17.33441	14.092374	12.447085	
3	Yorkshire	14.223124	12.577835		
4	N Wales & Mersey	12.831826	19.425261	11.599662	
5	East Midlands	14.893512	13.661348	12.803689	10.77593
6	Midlands	14.632963	10.450284	12.605204	
7	Eastern	13.896852	11.011434	12.740745	
8	South Wales	13.979852			
9	South East	16.054742			
10	London	10.156747			
11	Southern	14.172841	11.85089		
12	South Western	13.969057	10.962089		

Source: NGT SYS04

In an extreme case, DG that connects on the grid side of a GSP would pay grid generation use of system charges and would supply through the GSP to load that would pay the grid demand use of system charge. If it connected immediately on the distribution side of the GSP the demand up to that connection would be exactly the same as before, but the demand on the grid would be reduced by the generation and would thus reduce its demand use of system charges. The DNO would need only construct a connection from (near) the GSP to the generator (and would charge for that as a shallow connection), but, as it would incur no higher costs elsewhere (no extra losses nor any need to reinforce the network) the DUoS charge on the generation would be essentially zero. Consumers could buy directly from the DG and avoid both the grid generation and demand charges.

It is difficult to believe that this gives the correct connection signals to the (large) generator. As our brief is just to consider charges for distribution access and use of system charges, it is not appropriate to consider how transmission charges should be adapted to an increasing share of embedded generation, but we raise this as a possible long-term consequence of cost-reflective DUoS charging without ensuring that TNUoS is equally cost-reflective.


SYS FIGURE A.5
INDICATIVE 2004/05 TRANSMISSION SYSTEM
GENERATION USE OF SYSTEM
TARIFF ZONES
AND PES BOUNDARIES
AS AT 1st APRIL 2004
PES Boundaries
(PES Areas named with PES licence holder)
400kV Substations
275kV Substations
400kV CIRCUITS
275kV CIRCUITS
Major Generating Sites Including Pumped Storage
Connected at 400kV
Connected at 275kV
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
NORTHERN ELECTRIC
NORWEB
YORKSHIRE ELECTRICITY
POWERGEN ENERGY
MANWEB
EASTERN ELECTRICITY
SOUTH WALES ELECTRICITY (TRYDAN DE CYMRU)
MIDLANDS ELECTRICITY
SOUTHERN ELECTRICITY
SEEBOARD
SOUTH WESTERN ELECTRICITY
LONDON ELECTRICITY

The issue of encouraging DG to connect to the right network and at the right location is further complicated by the failure of TNUoS to be fully cost reflective. For example, except for zones 12-15,[11] the TNUoS charge depends on declared net capacity. This has two implications:

First, electricity companies have successfully resisted the introduction of locational loss factors. TNUoS charges therefore have to carry the estimated locational loss element. There is no explicit representation of the loss factor in the calculations of TNUoS charges. But the locational differentiation of the TNUoS charges is strong. This was a result of a high applying a security factor of 1.83 for line utilisation.[12] If generation technologies like wind, solar or small CHP only produce at low load factors, then their locational loss contribution will be exaggerated. This may increase their incentive to connect to the grid in the South and South West and discourage grid connection in the North and Scotland. Note that the effect is reversed if they connect to the distribution network where they gain the sum of the demand and generation charges, which are more uniform across the country.

Second, the transmission system is designed (and connections are only granted) so that all connected generation can simultaneously use the transmission network without creating significant constraints. This is unlikely to result in an efficient use of the transmission system. For example, if wind turbines are located in Scotland, then Scottish hydro exports to the south could be reduced at times of high wind production and shifted to times of low wind output. The same transmission capacity from Scotland to the South could be shared between hydro and wind generation. This would require a shift to price-based congestion management mechanisms to allocate transmission capacity to the most valuable user (nodal or zonal pricing). As a result generation technologies that can share the use of transmission network (or are prepared to be cut off at times of peak transmission demand) would pay a lower capacity fee (effectively for non-firm connection).

The lack of explicitly charging for losses and the failure to relate TNUoS charges to capacity utilisation implies that transmission charging is not cost reflective. This results in additional distortions facing generators deciding whether to connect to the distribution or transmission network and cannot be readily dealt with just by setting generation DUoS charges.

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[11] In these zones, generation TNUoS are negative and are based on generation at the triad.

[12] TNUoS tariffs are calculated using the DC Load-flow Investment Cost Related Pricing (DCLF ICRP) transport model. They contain a locational security factor represents the incremental investment in capacity required to provide security for transmission outages on a locational basis. NGC has calculated and used an indicative value of 1.83 for use from 2005/6. (See: http://www.nationalgrid.com/uk/indinfo/charging/mn_charging.html).

7. The Importance of Efficient Incentives to Reduce Losses

The current arrangements regard energy losses as the difference between the energy that enters and exits the distribution network. Suppliers are obliged to take into account the relevant losses for the energy to be delivered to their customers. This is done by applying DNO-specific voltage and time-varying (half-hourly) loss adjustment factors (LAF) to their purchases in the wholesale generation market. This arrangement is useful for attributing losses in physical terms based on voltage and time. It encourages consumers to reduce losses (and demand more generally) when electricity is more expensive, but as it does not charge consumers the *marginal* cost of their contribution to distribution losses (which is nearly twice the losses attributed) it understates the cost of delivering electricity to them.

The DNO can in theory offset this understatement through its DUoS charges, but there is an obvious problem. Consumers can reduce losses only by reducing their demand (and should be properly encouraged to do this when it is efficient). DNOs can also reduce losses by various investments, and encouraging DG to produce counter-flows and reduce the current loading on circuits. If DNOs charge consumers marginal losses there is no obvious incentive for the DNO to reduce losses. The problem is currently addressed by rewarding DNOs £48/MWh for loss reductions below a target level (and penalising them for failure to reach the target). This is not perfect, as the value of losses varies with time of day, but as investments impact on losses at all hours of the day it may be a fair approximation to the average value that should guide such investment decisions.

This loss-reduction incentive does not remove the desirability of confronting network users from paying the difference between marginal and average losses, as such signals are still required to encourage the efficient level and timing of their use of the network.

Appendices 1 and 2 suggest ways in which optimal distribution charges may vary under different conditions. Distribution losses are an important factor to take into account when deciding on the amount and type of capacity when replacement or expansion decisions are taken, and they are also an important factor that should influence generation location decisions. Their importance is obscured by averaging their variability over time and space. The cost of network assets has apparently fallen dramatically in real terms over the last 20 years (perhaps by a factor of 5, although this seems high). The cost of undergrounding cable is roughly 90% of the total, with the wire accounting for 10%. Doubling the capacity of a line may double the line cost but raise total cost by perhaps 10%. It will halve the variable transmission losses. There are thus very considerable economies of scale in the capacity of network elements, both in fixed and running costs. The estimated optimal line utilisation is perhaps 30% (Ofgem, 2003a, 4.18) but existing networks were largely built when the apparent optimum load factor was substantially higher. When such assets need upgrading or replacement it is important that the right signals be in place to encourage DNOs to choose least lifetime cost equipment, taking full account of the losses saved.

Table 6 (Table 1.1 in Ofgem, 2003a) suggests that DNOs were quite effective in reducing losses in the first DPCR period, but losses have mostly increased since then (Midlands and East Midlands appear to be the only exceptions). This may reflect the growth in demand utilisation of the existing network, but it may reflect a failure to adopt least lifetime cost assets when they are replaced or extended. To the extent that DG stimulates new investments that offer the prospect of lower losses, it is clearly important to provide DNOs with incentives to choose such assets. We shall return to this when proposing the form that the access and DUoS charges should take.

Table 6 Development of losses

DNO	1990/91 (%)	1995/96 (%)	20002/01 (%)
Eastern	7.0	6.9	7.1
East Midlands	6.6	6.1	6.0
London	7.8	6.7	7.3
Manweb	9.8	8.8	9.1
Midlands	6.3	5.5	5.4
Northern	7.5	6.8	6.6
Norweb	7.1	4.8	6.2
Seeboard	7.9	7.1	7.6
Southern	7.1	7.2	7.2
South Wales	8.9	6.7	7.2
South Western	8.6	7.2	7.9
Yorkshire	6.3	6.5	6.6
ScottishPower	8.5	6.7	7.2
Hydro Electric	9.3	8.9	9.1
Average	**7.6**	**6.7**	**7.0**

Source: Ofgem (2003a)

The evidence from other countries shown in Table 7 (Table 4.2 in Ofgem, 2003a) suggests that losses in Britain are surprisingly high compared with comparably developed densely populated countries, again suggesting under-investment in loss reduction. Losses (and their associated costs and benefits) are caused by injecting, transmitting or withdrawing power, and it is desirable that these costs be appropriately reflected in usage charges. Those with interval (half-hourly) meters can in principle be charged by time of use or supply, but not those with periodically read cumulative meters. In practice, it is more important to charge (or reward) DG and large (metered) loads, as they are more likely to be able to vary their generation or demand in response to price signals.

Table 7 Transmission and Distribution Losses in selected countries

Country	1980	1990	1999	2000
Finland	6.2	4.8	3.6	3.7
Netherlands	4.7	4.2	4.2	4.2
Belgium	6.5	6.0	5.5	4.8
Germany	5.3	5.2	5.0	5.1
Italy	10.4	7.5	7.1	7.0
Denmark	9.3	8.8	5.9	7.1
United States	10.5	10.5	7.1	7.1
Switzerland	9.1	7.0	7.5	7.4
France	6.9	9.0	8.0	7.8
Austria	7.9	6.9	7.9	7.8
Sweden	9.8	7.6	8.4	9.1
Australia	11.6	8.4	9.2	9.1
United Kingdom	**9.2**	**8.9**	**9.2**	**9.4**
Portugal	13.3	9.8	10.0	9.4
Norway	9.5	7.1	8.2	9.8
Ireland	12.8	10.9	9.6	9.9
Canada	10.6	8.2	9.2	9.9
Spain	11.1	11.1	11.2	10.6
New Zealand	14.4	13.3	13.1	11.5
Average	**9.5**	**9.1**	**7.5**	**7.5**
European Union	**7.9**	**7.3**	**7.3**	**7.3**

Source: Ofgem (2003a).

As losses increase as the *square* of the current (or final load), marginal variable losses are twice the average. Following the economic rationale that efficient charges should reflect *marginal* not *average* costs, it is the marginal loss that should guide access and DUoS charges. Not all losses vary with current, and the balance between fixed and variable losses is shown in Table 8, together with the non-technical losses (theft or unmetered consumption). If we assume that on average two-thirds of total losses vary with current, then because marginal losses are twice the average, the marginal loss for the typical DNO will be five-thirds the average loss. Thus for the average DNO marginal losses will be five-thirds of 7% = 11.67% (made up of 2.3% fixed loss + 9.33% variable losses, ignoring the rather low typical value for the non-technical loss). At the end of the network this number should be doubled to 23% (at least if the fixed losses also vary with distance from the GSP) but will be correspondingly less for locations closer to the grid supply point. In the case of Manweb, whose average losses are 9.1%, the calculation would be an average marginal loss of 15%, which translates into 30% at the extremities of the network.

Table 8 shows where these losses occur by voltage level. Average marginal losses in the EHV (132 kV) network are relatively small, at 2 x 8% of 7%. Put another way, EHV consumers are under-charged by suppliers 8% of 7% as suppliers only pass through the average loss factor. This under-charging amounts to just over ½ of 1%, and can be included in the DUoS energy charge. In fact, the same LAF could reasonably be used together with the half-hourly spot price to determine the DUoS energy charge.

Table 8 Breakdown of losses (in percentage of total losses)

Company	**A**			**B**			**C**			**D**		
Losses	Fix	Var	Tot	Fix	Var	Tot	Fix	Var	Tot	Fix	Var	Tot
132kV network	1	8	9									
132/ 33kV transformers	4	4	8									
33kv network	1	10	12	0	6	6						
33/ 11 & 6.6kV transformers	4	4	8	5	4	8						
11kV network	1	18	19	0	10	10						
11&6.6kV/ LV transformers	10	6	16	18	6	24						
LV circuits & Services	2	23	26	0	31	31						
Meters & T-Sw's				3		3						
Total technical losses	23	73	97	33	68	100	24	67	91	>35	>55	>80
Non-technical losses			3						9			<20*

* Non-technical losses reported as being considerably less than 20 per cent.

Source: Ofgem (Appendix Table 2, 2003a).

Table 8 also shows that the largest losses occur in the LV circuits (and clearly also in delivering power to the LV level). If the typical LV circuit is connected at the "mid-point" of each higher level circuit, then the fixed loss to deliver to LV will be between 23% and 33% of the overall 7% loss, say 2%. This part is charged for by suppliers. About 44% of 7% is the variable loss of delivering power to the LV transformer, so the uncharged part is on average 44% of 7% = 3%. In addition, the LV itself has uncharged average marginal losses of 27% of 7% = 1.9%. From one end of the LV circuit to the other losses might double, so those near the transformer are under-charged only 3%, while those at the far end are under-charged 6.8%. If we take £48/MWh and an average domestic load of 3,300 kWh/year, the two figures are £4.75/year and £10.8/year, but charged through DUoS in the energy rate. Whether it is worth differentiating this DUoS energy charge by location (which end of the street) is doubtful but will be considered below when discussing micro-generation.

DG can reduce system losses and should be credited with that, just as load typically increases losses. If we were to take account of the ratio of the peak to average energy, the peak loss factors would be considerably higher. Figure 2, reproduced from Ofgem (2003a) shows that the peak loss cost can be twice the average. Let us assess the quantitative significance of this averaging. Consider DG connected at 11 kV. This would typically be a 1MW plant supplying a commercial property or a fitness centre with a heated swimming pool or spa. Smaller units would likely be connected at lower voltages where losses are higher. Variable losses down to transformer are about 24% of 7% = 1.7% (and marginal losses are twice that). The variation by location in the 11 kV network range from 0 (at the transformer) to 28% of 7% = 2% at the end of the 11 kV line (and marginal losses are twice that). Fixed losses are about 11% of 7% = 0.8%. Thus the average marginal loss at the end of an 11kV line is 8.2% (for an average DNO). Assume that the day is divided into four equal periods: off-peak, shoulder, peak, and shoulder, as in table 9 below.

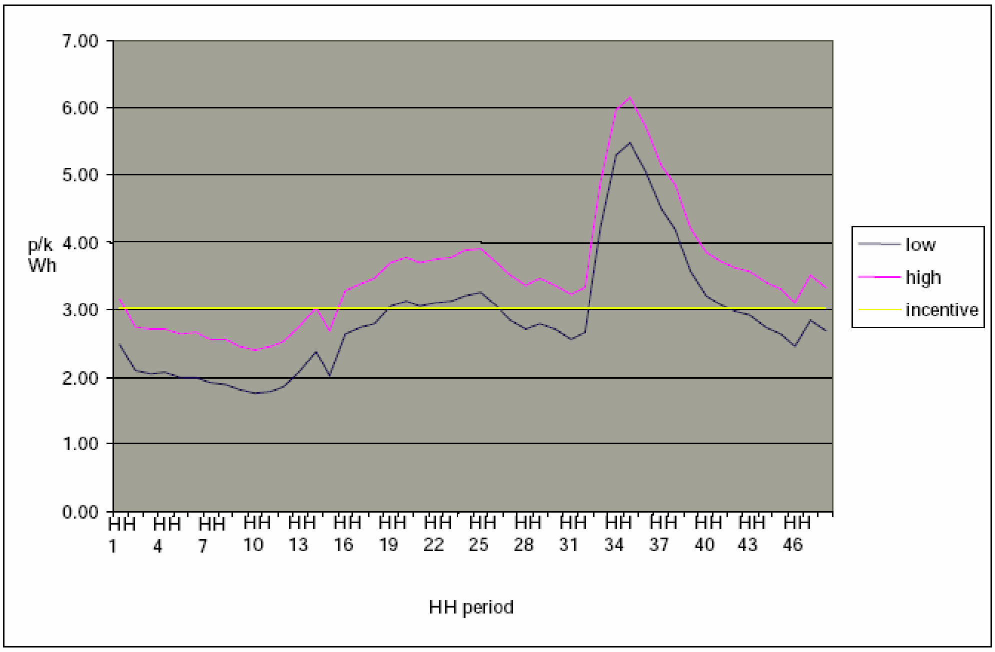

Figure 2 Half-hourly profile of average unit cost of losses

Losses will be about 4%, 7% and 15% respectively during off-peak, shoulders and peak demand periods (assuming demand off peak is half of peak demand). Even for DG operating all the time, some care is needed in computing the losses. This becomes more important to DG that operates mainly in the peak and part of shoulder periods, as it would not receive the full benefit of the loss reductions if paid just the average.

The value of loss reduction is calculated in Table 9 for two different generation output profiles per MW of capacity. If rewarded at the average marginal loss factor (8.2%) on the average energy price (£20/MWh), base-load DG would receive £1.64/MWh delivered (in addition to the spot or contract price of wholesale electricity). Base-load DG will, however, actually save £1.90/MWh. If the DG is only running at the peak and one shoulder period the value of losses saved will be £2.90/MWh. Of course, if the loss factor applied is the *average* loss for the 11 kV connection (5%) then there is a danger of further under-rewarding DG, as the extra payment for loss reduction would then be only 5% of £20/MWh or £1.00/MWh or only one-third the value for peaking DG. The distortion would be less for DG connected close to the transformer – the calculations are for the most valuable connection to the 11 kV system. It would also be considerably less for DG connected at higher voltages.

Table 9 Value of loss reduction to DG with varying profiles

	Off-Peak	Shoulder	Peak	Shoulder	Average
Time	¼	¼	¼	¼	1
Losses	3.6%	7.1%	14.6%	7.1%	8.2%
Energy price	£10 /MWh	£20 /MWh	£30 /MWh	£20 /MWh	£20 /MWh
Saved losses £/hr/MW capacity.	£0.36	£1.42	£4.39	£1.42	£1.90
Average base					£1.64
Peak DG		£1.42	£4.39		£2.90

The proposal for DPCR4 is that DNO should be charged for any losses above a target level at £48/MWh (and be rewarded by £40/MWh for reducing losses below the target). In the table above, in which generators are rewarded for loss reductions in proportion to their marginal loss reduction times the spot price of energy, the actual payment will vary by time of day (in the table from £10/MWh of loss reduction off-peak to £30/MWh at the peak. (The comparable values for calendar year 2004 range from £15 to £25/MWh.) The proposed incentives thus over-reward DNO loss reduction in terms of energy cost saving, and are thus primarily to be seen as incentives on the DNO to reduce network losses by suitable choice of its investment during replacements and upgrades. However, this may be less the case once savings in the capacity of the distribution and transmission network are taken into account.

Nevertheless, we should ask whether paying more than the spot price encourages the DNO to offer DG more than the spot price for its estimated contribution to loss reduction. (We are assuming that estimating losses should be reasonably straightforward if current flows in that part of the network can be measured or modelled.) There might be an incentive for the DNO to pay a higher amount than the spot price in periods where the DG could make extra contributions to loss reductions at a cost between the spot price and £48/MWh.

The old system of charging probably under-rewarded DG for its contribution to loss reduction. As such it probably distorted the value attributed to DG in distribution networks, possibly significantly. The result would have been

- Under-investment in DG – as it receives less revenue than the value provided to the network
- inefficient scheduling of DG – if it is not rewarded with the benefits of exporting more during peak hours, then DG generators (particularly CHP) might operate on base-load, instead of varying e.g. the heat/electric balance when economically attractive.

The new system of incentivising loss reduction would encourage DNOs to possibly over-compensate DG for its contribution to loss reduction, thus stimulating DG but possibly also distorting scheduling (perhaps towards off-peak hours). The first effect is compatible with an approach that attempts to overcome perceived barriers to DG and can be readily justified. Whether the second problem is an issue can be perhaps investigated after a period of monitoring and can readily be corrected by adjusting the payments at the following DPCR.

Some of the benefits of DG should be relatively easy to pass through. The DNO will be charged for its demand from the grid at the triad, and should pass these charges through to half-hourly metered net load. As discussed earlier the current system for losses measures these on half hourly basis. DNOs can design location based DTNUoS charges that reflect the benefits of loss savings at different parts of the network more accurately. If DG is embedded behind the meter, then the reduced load will reduce the charges, and directly benefit the DG-owning entity. DG that exports to the rest of the DNO will reduce the charges to be recovered from the non-HH metered customers, and properly should be credited with that amount, rather than allowing it be captured by these customers. Losses are more problematic, and have yet to be properly addressed in British transmission charging, mainly because of the difficulty of changing licence conditions. How accurately the costs and benefits of impacts of DG and L on losses can be captured by metering, modelling and profiling, is an empirical question.

Incentivising microgeneration

Household microgeneration technologies are available which may have a significant impact on domestic electricity demand and supply over the next 30 years. A typical 1.2 kW Stirling engine micro CHP can generate both heat and electricity for a household. This generator might produce 2400 kWh of electricity in a typical year. If these boilers were installed in 30% of households in the next twenty years they would generate 8.3m*2400 kWh, or 19.9 TWh. Such generation could have a large effect on distribution system marginal losses. As discussed earlier, the marginal DG at the end of the network creates a system benefit (not reflected in the supply cost of electricity) of 3% up to a maximum of 6.8% and losses also vary by time of day (in Table 9). As most micro-generation will be running at system peak times in the morning and the evening for winter heating we might assume that saved marginal losses could be as high as 10%

and as low as 5% of the electricity generated. The annual energy saving would be £2.4-4.8 at 2400kWh (and £20 per MWh) in addition to the savings in capital cost to a DNO. At 6.9% discount rates the energy savings have an NPV of £35-70 per installation. Distribution capital cost savings will add to this and there are the associated additional carbon savings which can be valued at £0.004/KWh giving £0.48-0.96 per year (NPV=£7-14). In higher loss DNO networks these figures can be increased by 30%.

These numbers illustrate two things. First that micro-generation may yield non-trivial benefits to the electricity network and to the government's carbon reduction targets which are not reflected in the average electricity prices faced by households. They provide a reason to offer an up-front subsidy to micro-generation of £42-84 on carbon and energy loss grounds alone. In Appendix 3 we conservatively estimate the distribution capital cost savings at £50/kW. Given that the current cost of Stirling engine mCHP is currently £1250 more expensive than a conventional boiler this may be a significant incentive for the roll-out of micro-generation.[13] Second, the variation in the energy benefits between the end of the LV line and the near transformer part of the line is significant (£42). This may provide an incentive to zone the micro-generation installation incentive by distance to the local substation (e.g. by a red, green and blue zone), or to vary the rolling out of the incentive by encouraging those located in particularly lossy places to install micro-generation first. It is worth pointing out that the capacity of household micro-generation to reduce carbon emissions is significant both directly via relatively clean and efficient gas generation and indirectly via system loss reduction. An upfront subsidy would yield significant benefits and be a very attractive measure to promote public awareness of climate change policies.

Summary: The majority of transmission and distribution losses occur in the distribution network. While the current mechanism to charge losses to supply companies for their domestic customers seem to be appropriate, the current methodology does not credit DG with the substantial loss reductions it can offer. In order to ensure efficient dispatch decisions these losses should not only be spatially but also temporally differentiated for DG. This could result in significant loss reductions.

[13] The consumer benefits are the saving on electricity costs. 2400 kWh at 6p/kWh is £144/year which might be enough to motivate an extra investment of £1250.

8. A New Charging Model

The first (in the UK) and arguably the best example of the use of forward looking LRIC to derive regulated access charges is probably Oftel's various models developed initially for regulating BT and subsequently for setting mobile phone termination charges. Developing these models required considerable interaction between Oftel and the telcos to agree a satisfactory model and to populate it with parameter estimates and cost data. It was recognised as the only legitimate way to compute forward-looking LRIC estimates for setting particular elements of the charges (and specifically access charges). A similar model-based approach was adopted by Ofgas in setting the entry and exit prices for the National Transmission System (NTS, the high pressure gas pipeline system delivering gas from the beach to off-take points for large customers or the lower pressure Local Distribution Zones).

In the past, Transco used a large and sophisticated computer simulation model called Falcon to help identify the least-cost expansion needed to provide a sustained increase in demand between an inlet and off-take point. The model was designed to model the gas flows through each part of the NTS. Transco's systems engineers could then simulate changes in the pattern of demands and supplies and the effects of possible investments to determine the required investment plan in considerable detail. Falcon was designed to be as realistic as possible and to take account of all known relevant factors. As a result, it was cumbersome to use and time consuming to evaluate alternative possible investments to meet expansion demands. This was not too serious for the original purpose of Falcon, which was to design the system expansion given forecasts of demand and supply. Its size and complexity greatly limited its ability to perform counter-factual experiments of the kind required to find the costs of expanding the system to meet particular changes in flows compared to the baseline forecast, of the kind required to determine the forward-looking LRIC of specific types of expansion. Something simpler was needed, and Cap Gemini developed the Transcost model for Transco in 1996. The idea was to replace the opaque, cumbersome mainframe Falcon model with a transparent, fast, PC-based version that could be made available to Ofgas, shippers, and consultants.

Transcost allows the LRIC (described as long-run marginal cost or LRMC) of an increase of 100mcfd (about 10% of the typical route flow) in injection at any entry point and withdrawal of that amount at any exit point. These pair-wise LRMCs are then converted into entry and exit prices, so that the sum of an entry and exit price correspond as closely as possible to the LRMC of the reinforcements needed to meet that entry and exit demand. These raw prices are then scaled to produce the target revenue for the NTS.

The exit prices are used to set exit charges but the entry prices are used to determine the floor price for the auctions for entry capacity.

One of the advantages of the Transcost model is that external users would be able to check these charges themselves, reassure themselves that they were securely founded and robust to reasonable alternative assumptions, and make their own forecasts of likely future tariffs (on the assumption that the realised market value of the entry capacity should correspond to the cost of providing capacity and hence ultimately to the LRMCs).

A similar philosophy has guided NGT in determining Transmission Network Use of System (TNUoS) charges. Again regulatory and industry pressure argued for a reasonably simple and replicable model of the cost of reinforcing the grid to meet an increase in demand or to accommodate an increase in supply at any node. The ICRP model takes existing way-leaves as given but optimises the transmission system required to meet a given pattern of G and L specified by their nodal connection points. Changes then give point-to-point LRMCs, and as with Transcost, regression analysis is then used to translate these LRMCs into zonal charges. As such the charges can readily be audited (the model is available from NGT) and are intended to provide locational signals for new generation. The approach can be contrasted with the real-time nodal pricing of e.g. PJM where the locational element in TNUoS emerges from a solution to the least cost dispatch (Brunekreeft, Neuhoff and Newbery, 2005).

In the electricity industry, perhaps the best-known example is the use of models for setting the price controls for DNOs in Chile. When the regulatory framework was designed, it was decided to delink the price control completely from the actual costs of the DNO to give better incentives for efficiency (Pollitt, 2004). The revenue for the distribution companies was to be set on the basis of the costs of a model company. Two independent consultants reports would be commissioned to model the network which a distribution company with given demands and sources of supply would require and to assess the cost of running that model network. These reports would be averaged (2/3 weight on the regulator’s consultant report, 1/3 weight on the company’s consultant report) to fix prices for distribution. The models are not used to compute detailed access prices, as with the Oftel and Transcost examples above, but rather are used to determine the revenue for the Price Control.

In Britain, DNOs have used a distribution reinforcement model (DRM) developed by the Electricity Council and set out in their *Tariff Formulation Manual* in 1984 to set tariffs. This is a cost allocation model that attempts to determine the LRMC of the investments needed to deliver service to each customer class defined by voltage level, using standard (but currently available and priced) assets. These costs are then allocated according to customer contribution to simultaneous maximum demand (for higher voltage assets) and aggregate maximum demand (for assets within the voltage level). All costs are attributed to demand, and there is no method for handling distributed generation. The models do not appear to be designed to give locationally differentiated charges, but have the merit of providing a suitable modern equivalent asset register (at least if they kept up to date). (More details are available in DTI, 2002). Appendix 3 suggests that the benefits from a location varying model of distribution charging could be substantial and would almost certainly outweigh the costs of model development for current reasonable scenarios for DG growth.

Locational signals in charging models

The DRM models used by DNOs generally recover the shallower demand driven costs through £/kVA charges. Deep network costs that have weaker correlation with connected capacity are recovered by p/kWh charges. The two types of capital costs correspond roughly to load-related (the former) and non-load-related expenditures (the latter) often treated separately by Ofgem (Williams and Strbac, 2001). Absence of a locational component in the charging methodology for DG, can reduce the system efficiency as the benefits and costs of DG can vary in different parts of networks. While a move from deep to shallow connection can remove financing constraints and therefore facilitate DG entry, the DNuS charge should be made locational differentiated to retain the accurate locational signal of connection charges.

DG is likely to be cost effective where the network is constrained and alternative transmission network expansions are costly. Also, the potential for loss reductions by DG varies in different parts of network. Currently, there is no explicit locational charging scheme in place and the DG capacity, volume, and loss-saving incentives are separate. For load customers, however, locational charging would result in similar customers paying different charges something, which, from a political point of view, may not be feasible.

In principle, the optimal solution for locational cost signals involves calculating the relevant costs at each node on the network. The cost of developing and maintaining the database to support a suitable model capable of handling few thousand nodes can, however, be substantial. A broad cost and benefit evaluation may favour a simpler solution that can deliver most of benefits of the optimum approach (see e.g. CRA, 2004). This has not prevented the development and use of some large and detailed models of distribution networks in price controls.

The Swedish Energy Authority (EM) has used the Network Utility Model (NUM) in ex-post regulation of distribution charges. The NUM model took a few years to develop and test and was first used in 2004 to assess the 2003 charges. The model constructs a reference or ideal utility based on actual firm data, and calculates benchmark tariffs that can then be compared with the actual tariffs charged by the utility. The data used by the model include detailed technical and economic information for the companies as well as customer-specific information such as geographic co-ordinates, energy demand, capacity, voltage level, and the amount of the bill for each connection. Another example of models that use geographic information to assess the cost of reference firms is the PECO model which has been applied to some Latin American utilities (González, 2004). In addition to estimating the cost of reference firms, such models can be further developed and adapted to estimate the cost of network extensions and/or calculate locational cost differences.

Adopting locational charging for different zones of a distribution network has been proposed earlier (see e.g. Tyndall Centre, 2002). One example of locational pricing at the time of writing is that of UnitedNetworks Limited. The methodology used is based on attributing, to the extent possible, the assets as well as transmission exit charges incurred to different parts of network. These can then be further attributed to specific customer groups and different voltage levels (see e.g. PAWG, 2005; UnitedNetworks, 2002). The main issue is to define and decide the appropriate number and size zones in particular those differ from the norm. An advantage of zonal models is that they can be relatively simpler and less costly and serve almost as well as larger and more complex models.

The use of large and complex models, for locational charges, however, requires a careful evaluation of all their costs and benefits. Relative simplicity of the access charging framework and models is important for maintaining the openness of the regulatory process and in particular that of incentive regulation. To the extent that model complexity reduces transparency, it limits the openness and clarity of incentive regulation. Complex models are likely to be comprehended only by the companies who develop and own them and by the regulator. Such models can, however, be exclusive rather than inclusive in nature in that the ability of third parties to gain insight in the workings of tariff models regulatory process will be considerably limited. It is also unlikely that these models will be available to interest parties and public.

Desirable attributes of a DNO model

Any model that is to be used to determine access and use-of-system charges must satisfy a number of criteria:

- It should be able to start from a description of the existing network with its grid connections, customer base (specified by their relevant characteristics, such as peak demand, power factor, etc), and any generation connected to the network, and from this compute and attribute losses.

- It should have an asset register with the capacities, ages, and expected remaining asset lives capable of determining when asset renewal (to maintain standards or avoid failure) is required.

- It should be able to determine the additional assets needed to meet new demands (G and L at any node, specified by the relevant parameters such as peak demand, load profiles, loss of load probability (LOLP) at critical moments such as at the peak, maximum generation, power factors, etc).

- It should be able to optimise and cost expansion plans to find the least-cost way of meeting a specified increment of demand or generation at any node (for different sizes of increment). This should be able to take account of constraints such as whether lines need to be undergrounded, whether there are space constraints at existing sub-stations, etc.

- It should be able to compute losses for plausible load and generation profiles, and hence compute and attribute incremental losses.

- If additional distribution network ancillary services are considered important (i.e. in addition to those secured by and paid for by the DNO customers from NGT), then the model should be able to represent and attribute the cost of these services.

It should be able to measure incremental O&M costs caused by increments in G and L.

- It should be simple enough to allow LRICs to be computed with minimal technical expertise on the part of the user, while being able to predict actual costs within an acceptable error margin (e.g. 10%).

- The model should ideally be available to users (preferably free to facilitate independent validation) so that they can validate the computations, as with Transcost.

Predictions about future evolution of demand and generation are core inputs to the model and are likely have significant impacts on the model results as they impact losses and might change the requirement of early network upgrade. While we think information about the transmission network could be freely accessible without compromising commercial interests, information about expected load patterns of industrial customers might be commercial sensitive. In such a case Ofgem or an external auditor would need to be in a position to verify the tariffs calculated by the DNO.

It would clearly be desirable if the DNOs were able to agree on a common model structure and to commission its construction in consultation with Ofgem. This would certainly economise on the costs, and give consumers greater confidence that the model was designed to best reflect actual costs, rather than to exploit possible informational advantages of any DNO. It would also simplify verification of tariffs calculated by DNOs; the auditor (or Ofgem) does not need to learn how to operate various models. Each DNO would nevertheless need to calibrate the model to its existing network. It may be that each DNO has a different set of constraints limiting expansion choices, so there is no guarantee that LRICs would necessarily be the same, but the existence of a common model structure should allow the costs of these constraints to be estimated (and audited). As a final assurance of the lack of bias in the model, it should be a requirement that the assets determined by the model as required for (and used to charge for) expansions are available for comparison with the expansion plan chosen. The model should be able to compute the LRIC of the actual expansion plan chosen. For example, it may be that the LRIC of modelled expansions are high because the expansions are of sub-optimal size compared with the actual expansion chosen, and this fact may be relevant for adjusting DUoS charges.

Summary: In order to calculate LRIC as basis for locational charges a numerical model of the specific DN with its expected expansion plans and load evolution is required. Positive experiences with models of the gas and electricity transmission networks suggest that such a model should be transparent and freely accessible. If commercial sensitivity prevents publication of future demand and generation patterns, then an external monitor (e.g. Ofgem) should receive access to the data to verify the calculated tariff structures. While in theory each DNO might develop its own network model, development costs can be reduced and verification by DG investors and independent bodies can be simplified if one standard model is developed and then adopted to specific DNOs.

9. Problems of Implementation of Optimal Tariffs

There are a number of issues to resolve in implementing optimal location varying distribution charges. These include:

The need to offer contractual guaranteed tariffs

To enhance the locational signals, to simplify project calculations and to reduce the volatility of future DG DUoS charges and hence net revenue (and therefore financing costs) DG should be offered a contract at the time of the investment decision as an alternative to annually varying charges. The contract should be for a period that is reasonable compared to the project life. This period is likely to exceed the periods of the DPCR (5 years), especially if the project is initiated later in a price control period and might only benefit from the remainder of the DPCR. In order for the DNO to be equally happy to offer such contracts at any point within the DPCR period, the existence of such contracts should be recognised at the next DPCR. This should not cause a problem in adjusting the allowed revenue stream for the DNO, as contracts with DG will only contribute a small fraction of total revenues and costs.

There is less need to offer long-term contracts to most consumers (although large loads may find such contractual certainty advantageous, particularly if they have embedded generation). The DNO should also benefit from the security offered by such contracts, which might have penalty clauses for early termination (or for the option to switch to annual contracts). The terms of the contract will effectively be the annuitised value of the correctly determined deep connection cost determined in the model.

Avoiding distorting incentives effecting DG connections

The future is not predictable, and the scale of local DG connection may be considerably less predictable than load growth. This has the implication that waiting to see what DG may bring has an option value. If, reasonably, the DNO has to quote connection charges and respond within a short time frame, then the equivalent to delay is to undersize capacity expansions. Incentives for the DNO to not unreasonably undersize such connections may be needed, and possibly conversely if the DNO could collect the full cost of any connection in the price control, either directly through access charges or in the additional charges allowed to make up the price control total. The standard solution is to have a target allowed network connection investment with cost-sharing at some rate (e.g. 50%, positive and negative) above and below this target. If the DNO were able to build bigger connections at lower unit cost and were good at predicting future demand, then it would achieve a lower cost level of investment per MW extra connected and would receive a share of the cost saving e.g. 50%.

It has been remarked that at present DNOs face no incentive to expedite quotes and connections, and to the extent that the network investment only enters the RAB after the next DPCR, there is an apparent incentive to delay investment until the end of the control period. This is a general issue that requires a general solution, but the obvious approach is to define standards of speed of response with penalties for delay.

Should DNOs be allowed to own DG in their own networks?

Obviously, this raises the issues of information asymmetry between the DNO and potential DG operators. As technical standards and time lags in the connection procedure are difficult to monitor it has to be ensured that DNOs to not have incentives to prevent connection of independent DG. If DNOs are allowed to pursue new DG investment within their area, then they might discriminate against competing DG trying to connect within the area. This suggests that DNOs should be restricted from participating in new (but may retain old) DG projects within their area. The expertise and capital of DNOs might however be usefully applied by allowing DNOs to build DG in neighbouring distribution networks.

Summary: To ensure investment is guided and facilitated through locational signals they should be contractually guaranteed for a suitable period. To ensure that DNOs provide timely connections DNOs should not face adverse incentives, from the DPCR or other incentive mechanisms. Allowing DNOs to construct DG in their own DN might create incentives to exclude competing DG.

10. Conclusions

We structure this section based on our answers to a set of specific questions that were presented by Ofgem:

1. *What type of charging model would you advocate and why?*

We suggest retaining the separate regulatory treatment of allowed revenue for the DNO and charges for DN users. With a shift towards more active network management the DNO has more flexibility to resolve constraints, reduce losses, enhance reliability, connect DG and minimise network investment. The incentive mechanisms used to optimise any one of these objectives might have perverse outcomes on other objectives. The DPCR revenue determination and incentive mechanism thus needs to be reviewed to assess the joint impact of the individual incentives.

2. *Is the use of forward looking long run incremental costs appropriate? If so, how would these be determined?*

We argue that there is a strong case for location-specific DUoS with shallow access charges based on forward-looking Long-run Incremental Cost (LRIC). This would seem to be particularly important for generation use of system charges. This reflects the significance of the variation in costs and benefits of connection at a particular node in any given distribution network. A major element in computing LRIC is (a) the impact of the timing of upgrades to resolve thermal and voltage constraints (b) the impact of connections on losses and (c) the effect that has on the timing of future upgrades to reduce losses. The old Electricity Association methodology is ill-suited to this calculation, both because it ignores location and because it fails to capture some of these important costs and benefits.

3. *Is there a need for an economic model and what level of detail in this model would provide adequate economic messages?*

There are significant benefits of accountability and transparency in basing cost estimates on a standard economic model calibrated to the specific asset endowment and topology of each DNO's network. While the complexity of such a model may seem initially hostile to the need for transparency and comprehensibility, we suspect that any model will be able to develop a manageable number of charging bands as a function of a modest number of characteristics (e.g. voltage level, asset characteristics and their assignment, and distance from relevant assets such as transformers). While in theory each DNO might develop its own network model, development costs can be reduced and verification by DG investors and independent bodies can be simplified if one standard model is developed and then adapted to specific DNs.

4. *Is marginal pricing appropriate across the entire DNO network?*

It is important to distinguish between the *efficient* charge, which will be based on LRIC for fixed costs, and SRMC for variable costs (related to energy), and the tariff, which will be related to but not necessarily equal to the efficient charge. Specifically, mark-ups to recover the allowed revenue will be required and should not all be equal. Cost-reflective tariffs are more important for larger loads and DG with appropriate meters, and simpler tariffs will be the only feasible choice for those with cumulative meters. This is particularly the case for micro-generation installed in domestic premises. Some customers should be offered long-term contracts that lock in best estimates of forward looking LRIC for a period (of perhaps up to 5 years or possibly more), while for other customers this may have little benefit but restrict the ability of the DNO to adjust tariffs in line with changing costs, as desirable.

The responsiveness of smaller and domestic loads to tariff price signals is likely to be modest and for them so the charging method can be simplified. As domestic peak capacity is usually not measured the high correlation between demand and peak capacity suggests adding capacity related costs to energy charges. Cost-reflective charging suggests that fixed costs should be charged as fixed charges and these are better suited to carry larger mark-ups. However, Ofgem’s objectives to (a) achieve overall system efficiency and (b) energy efficiency may shift the case for allocating some or all fixed costs to energy if this compensates for biases in investment and consumption decisions of smaller consumers.

5. *Are there any constraints that need to be considered, e.g. metering?*

At present, average (not the efficient marginal) losses are passed through to load, but the benefit of loss reduction offered by DG is not systematically accounted for. Passing through losses to network users reduces the DNO’s incentive to invest to reduce these losses. The DPCR proposes an incentive mechanism of £48/MWh for improvements in loss reduction beyond a DNO-specific target. The resulting investment will add to the RAB at the next DPCR, after which the loss target can be reset. This has the desirable incentive effect of encouraging the DNO to not delay investment until the end of the DCP period, and should encourage the DNO to devise DUoS and GUoS charges that encourage loss reduction. GUoS access charges can be differentiated by location and time-of-use and designed to reflect locational and time-of-use differences in the value of (marginal) loss reduction. However, the current fixed incentive, while having the attraction of simplicity, is relatively crude and might distort DG supply to off-peak periods when loss reduction is less valuable. The attraction of a simple incentive may not be too serious for incentivising efficiently low-loss network capacity expansion.

To ensure that DNOs are exposed effective incentives for loss reduction, losses in the distribution network have to be measured consistently. This might require some regulatory attention to ensure a robust methodology that also accounts for commercial losses and not metered demand like street lighting.

6. *Is it appropriate to treat demand and generation in the same manner?*

There is a good case for treating load and generation similarly when it comes to determining the costs they impose on the network. For example, suppliers have an incentive to pass through the cost of losses in their tariffs as they are charged for the estimated losses for each half-hour. Generation can influence the timing of its contribution to losses, and this needs to be encouraged to minimise system costs. In that sense generation should be put on the same footing as (half-hourly metered) load. However, there are important differences that need to be taken into account when adjusting these initial cost-based estimates to recover the allowed DPCR revenue and determine the access charges. Generation has a choice of where to enter (and even to which DNO to connect). Load is less footloose. Mark-ups to recover shortfalls are therefore better directed to load than generation. The main qualification to this is that if the mark-ups on LRIC required to make up the revenue shortfall are significant, then loading these equally onto the kind of large customer most likely to install embedded generation behind the meter may excessively encourage such DG (possibly at the expense of larger free-standing or net exporting DG). There is a case for treating load and generation connected to the EHV (132 kV) network equally, and increasing the divergence between mark-ups for load and generation as voltage levels decrease.

7. *How are cost drivers best reflected within models?*

Our calculations also show that uncertainty about future demand might significantly change the marginal costs of adding additional load or the marginal benefit of offering additional generation. Additional calculations with more realistic network data are required to quantify the effect and to determine the best method of including it within the loss calculation. Our estimates suggest that losses can vary significantly by location, so that costs should be location-specific.

Estimating the costs will require the development of a standard model of a distribution network that can be calibrated for each distribution network with its specific assets and network configuration, capable of identifying the system benefits/costs of connection at different points in the network. Such models are already in use in other countries (such as Sweden and New Zealand) for electricity distribution and in other sectors in the UK (such as gas and electricity transmission).

8. *What is the best method of scaling the model outputs to achieve regulatory revenue?*

As a general principle, any scaling to achieve regulatory revenue should minimise the distortions to decisions. Durable decisions (where to connect) are the most important to get right and should attract the lowest mark-ups, followed by use decisions (when and how much to generate or consume), and finally, the least sensitive decisions (fixed costs associated with existing locations) are those best able to carry higher mark-ups. It is also be necessary to consider the implications for the implementation of the DPCR, the loss reduction scheme, the quality incentive scheme and transmission charging contingent on any new charging regime for electricity distribution. The general principle of efficient pricing suggests that mark-ups should be inversely proportional to the responsiveness of the connecting party. In practice that is likely to mean small or zero mark-ups on the LRIC for footloose DG when making its connection decision, and recovering most of the revenue shortfall from fixed charges on immobile load.

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Technical Appendices

Appendices 1 and 2 contrast the results of a proper forward-looking LRIC calculation of access charges with the former Electricity Association methodology. Appendix 3 sketches a social cost benefit analysis of location varying distribution charges for distributed generation. It suggests that the benefit of increasing the overall amount of DG and its location within the network could be large.

Appendix 1: Timing of the Increment -

Forward-Looking LRIC and the Electricity Association Method for Determining Connection Charges

The former Electricity Association methodology determines the incremental cost of meeting an increase in load on the assumption that the network is optimised (with modern equipment and costs) to meet the original load and the incremented load *at various voltage levels*. The forward-looking LRIC starts from the current network configuration and asks what is the incremental cost of accommodating the load *or* generation optimally *at various locations*. The old methodology cannot therefore deal with locational aspects, and is silent about generation. Even if we ignore these differences, the estimates below suggest that the former approach is likely to underestimate the marginal cost of load and under-reward the benefits of DG.

If a new load or generator connects and precipitates (or delays) an upgrade, there are both costs and benefits that should be taken into account. It is important to have a sound counterfactual (a forecast of load growth and the optimal replacement cycle in the absence of this new demand). There are several possible cases:

1. Load growth is such that the date at which an upgrade to a less lossy line occurs before the end of the life of the asset. This is assumed to occur before the full capacity of the line is reached (i.e. when the line would otherwise breach network code standards). Given the high fixed costs involved in much investment, the fact that equipment now is poorly sized for existing loads does not necessarily mean that it should be replaced early by more appropriately sized equipment, so this may be a relatively infrequent case.
2. Load growth is slow enough that the existing asset should be allowed to reach the end of its planned life.
3. Load growth is fast enough to precipitate an upgrade before life expiry if the network is to continue to meet network code standards.

A 1.1 Early replacement of line to reduce losses

These cases are modelled as follows. Let current demand be D, growing at rate g. The capacity of the line is k and the total cost of the losses at date t is $\mu D_t^2/K$ where D_t is the demand at date t. The cost of a replacement line is $F + cK$, where $K = K_1$ is the capacity of the new line at the first upgrade. One measure of LRIC now would be cK/D, or, as a levellised amount, acK/D, where a is the annuity factor. The current marginal cost of losses is $2\mu D/k$. The first case can now be evaluated.

The date of first replacement is $T = T_1$, and both T and K are choice variables. The present value of the costs to be minimised is

$$C = \mu D^2\left(\frac{1}{k}\int_0^{T_1} e^{(2g-r)t}\,dt + \sum_{i=1}\frac{1}{K_i}\int_{T_i}^{T_{i+1}} e^{(2g-r)t}\,dt\right) + \sum_{i=1}\left((F + cK_i)e^{-rT_i}\right).$$

The first order condition for the choice of $T = T_1$ is

$$e^{2gT} = \frac{r(F + cK)Kk}{\mu D^2(K - k)}.$$

The first order condition for the choice of $K = K_1$ is

$$K^2 = \frac{\mu D^2 e^{rT}}{c}\int_{T_1}^{T_2} e^{(2g-r)t}\,dt = \frac{\mu D^2 e^{2gT}\left(1 - e^{(2g-r)(T_2-T_1)}\right)}{(r - 2g)c}.$$

These two equations can be solved for T and K. (Note that if in future the time period between upgrades is designed to be 40 years, and r = 8%, g = 1%, the last bracket in the numerator is 0.9 rather than 1, which it would be if the next upgrade lasted for ever.) If the resulting T is greater than the asset life, or if $De^{gT} > k$, then the asset will have to be replaced earlier than the solution to this equation. This case is considered below.

A permanent step change in the level of initial demand, D, will increase costs by

$$\frac{\partial C}{\partial D} = 2\mu D\left(\frac{1}{k}\int_0^{T_1} e^{(2g-r)t}\,dt + \sum_{i=1}\frac{1}{K_i}\int_{T_i}^{T_{i+1}} e^{(2g-r)t}\,dt\right) + \sum_{i=1}\left(\frac{\partial C}{\partial T_i}\frac{\partial T_i}{\partial D} + \frac{\partial C}{\partial K_i}\frac{\partial K_i}{\partial D}\right),$$

where the last two terms are zero by the earlier optimisation, provided T_1 does not violate the two constraints above (and therefore loss reduction drives network upgrade before the end of asset life). In this case the annuitised charge for the new increment in demand will be

$$a\frac{\partial C}{\partial D} = 2a\mu D\left(\sum_{i=0} \frac{e^{(2g-r)T_i} - e^{(2g-r)T_{i+1}}}{K_i(r-2g)}\right),$$

where a is the interest plus amortisation factor (i.e. the levellised capital charge), and $K_0 = k$, the current capacity. If we substitute the optimised value for K we get

$$a\frac{\partial C}{\partial D} = \frac{2a\mu D}{k}\left(\frac{1-e^{(2g-r)T}}{(r-2g)}\right) + \frac{2acKe^{-rT}}{D} + 2a\mu D\left(\sum_{i=2} \frac{e^{(2g-r)T_i} - e^{(2g-r)T_{i+1}}}{K_i(r-2g)}\right),$$

The last term will be small, and at a discount rate of 8% and a future life of 40 years will only add about 4% to the previous term.

We can now compare this with the instantaneous marginal cost of losses, $2\mu D/k$. For example, if r = 8%, g = 1%, k/K = 0.25, T = 10 years, the first term is 1.25 $\mu D/k$ (rather than the marginal loss cost of 2 $\mu D/k$). The remaining terms are approximately *twice* the apparent net present value of the unit LRIC, acK/D. With the numerical assumptions discounting will coincidentally exactly counterbalance this doubling. If the date of upgrade is closer than 10 years the extra term will exceed the apparent unit LRIC. An increment in load now advances the date of a costly upgrade but reduces the losses at the upgrade. This accounts for including the LRIC of the upgrade, suitably adjusted, and reducing somewhat the current marginal cost of losses.

We can compare this with the alternative in which the connection cost assumes (as in the old Electricity Association model) that the network is optimised at the time of the connection. Assume also that there is no growth in demand. Suppose that this involves investing in capacity k with a life of L (40 years, say) and the capacity is optimised to minimise capital costs and losses. The cost would be

$$C = \mu D^2\left(\frac{1}{k}\int_0^L e^{-rt}\,dt\right) + \left(F + ck\right).$$

The solution to the choice of k (= k^*, say) is given by

$$k^2 = \frac{\mu D^2(1-e^{-rL})}{rc} = \frac{\mu D^2}{ac},$$

At 8% discount and 40 years life, D/k^* is $\sqrt{(ac/\mu)} = 0.29\sqrt{(c/\mu)}$. The marginal cost of losses is $2\mu D/k^*$, while the optimised levellised marginal cost of an increment in demand is $a\partial C/\partial D = 2\,\mu D/k^*$, bearing in mind that k^* is the optimal capacity (not necessarily the same as the current capacity). This is exactly equal to the marginal cost of (optimised) losses, apparently ignoring the cost of future investment (whose date is not affected by demand in this set up). However, this cost is based on the optimal capacity which is likely to be greater than the current capacity, lowering the marginal cost. The old method is therefore likely to underestimate the cost of additional load. DG that *delays* upgrades and *lowers* losses should be credited with these benefits, and the old approach would undervalue these benefits.

To summarise, an increase in load that advances the date of capacity expansion in with growing demand can be charged more or less than the unit LRIC for that expansion (depending on whether the upgrade is earlier or later than about 10 years), *and* rather less than the current increase in losses, in contrast to the old approach which in effect just counts the optimised marginal losses. DG that delays the investment and reduces losses should be credited with these amounts.

A 1.2 Assets are used for full lifetime

The second case is one in which T is constrained by the asset life but not the capacity. It is easy to see that this leads to the same result.

A 1.3 Early replacement because of voltage/thermal constraint

The third case, in which T is determined by the date at which demand is constrained by capacity limits, is more interesting. An (sustained) increase in current demand will require an earlier upgrade when capacity or voltage constraints would otherwise be violated. In this case we have to consider the impact of uncertainty. The following figure illustrates the evolution of capacity utilisation over the lifetime of an asset (the analysis equally applies to voltage constraints on the line).

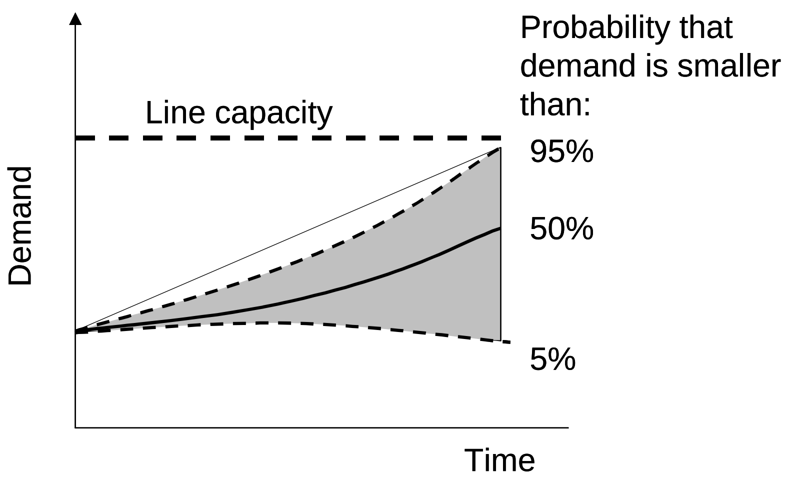

Figure A1.1 Demand growing until it reaches the capacity limit

Without uncertainty the solid line illustrates the predicted utilisation. Additional load will shift the solid line upward and reach the upper capacity limit earlier, advancing the date of the upgrade. Suppose that we are 15 years before the anticipated upgrade and that the expected load growth is 1% per year (17% over 15 years). An initial and sustained demand increase of 1% then means that full capacity is reached one year earlier. What are the additional capital costs of the earlier replacement?

Assume the initial asset was optimised such that annuitised marginal costs of additional capacity equals marginal losses of additional load. Combine this with the stylised fact that the capacity-independent cost of new capacity is roughly ten times the capacity-dependent costs of typically sized new capacity and note that marginal losses equal twice the average losses. This gives that annualised capacity-independent costs equal five times the marginal losses or – according to calculations above – roughly five times the locational element. This additional cost can be spread over the fifteen years before the update is required, but has to be carried by 1% of total load, and is therefore multiplied by 100. The marginal cost for additional load is thus roughly (5 / 15) * 100 times the marginal locational signal in the absence of the capacity constraint (ignoring for the moment discounting). This (admittedly back-of-the-envelope) estimate suggests that advancing the upgrade can be expensive for the marginal load, because advancing the high fixed capital cost element (even for one year) is high compared to the small increment in load. This also implies the potential for significant benefits of using DG to avoid such upgrading.

In practice it is difficult to accurately forecast load growth, so future demand is only known with some probability distribution. The figure above shows that in 95% of demand realisations by year 15 there is adequate capacity, but an initial increase in demand now will affect the whole fan of possible demand paths and hence the probable date at which an upgrade is required. The following simulation shows how demand uncertainty averages the impact.

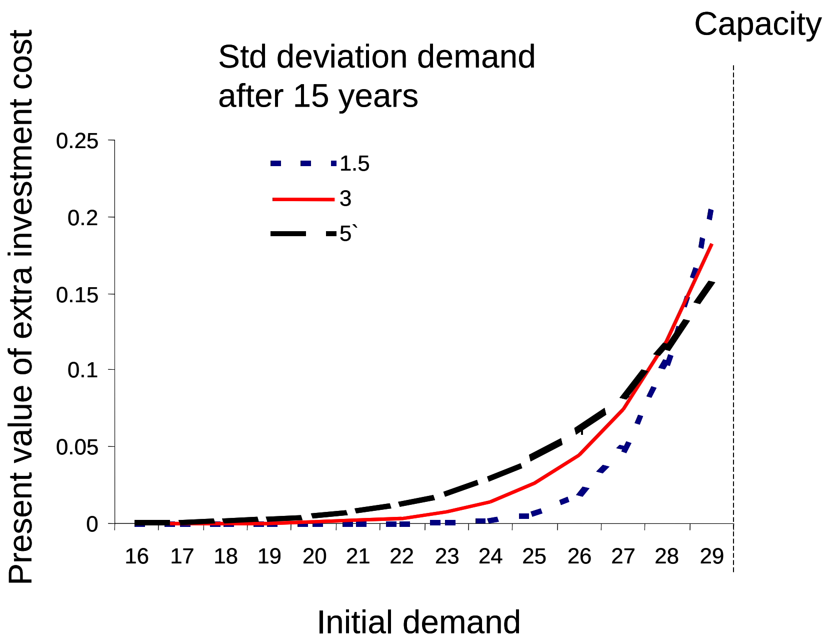

Figure A1.2 Uncertainty about future demand evolution smoothens cost of marginal unit

Figure A1.2 shows the results of a simulation model. It assumes demand growth of 1% per year, discount rate 8% and remaining asset life of 15 years. The capacity of the asset is assumed to be 30 units. For different demand levels the discounted expected cost of earlier asset replacement are calculated if additional load of 1 unit is added (multiply y-axis with fixed costs of replacement). If initial load levels are below 18, then the additional load does not increase the risk of earlier asset replacement even under high uncertainty of future demand growth. At initial load level of 25 and high uncertainty about future demand uncertainty, the additional load of one unit creates a significant increase in the risk that the asset has to be replaced earlier. The discounted fixed costs of the earlier replacement equal 5% of the fixed costs. If demand uncertainty were smaller, then this value can drop below 1%. The simulation did not attempt to calculate the benefits in loss reductions, which were already discussed before. This effect that higher uncertainty about future demand results in costs for additional units already at lower load levels is compensated at higher load levels. The addition of a marginal unit at load level of 28 is less costly with demand uncertainty, because even without the marginal unit there is a high probability that the asset has to be replaced before the end of the lifetime. This simulation illustrates, that uncertainty about future demand growth results in a smoother marginal cost function (or marginal benefit function for DG).

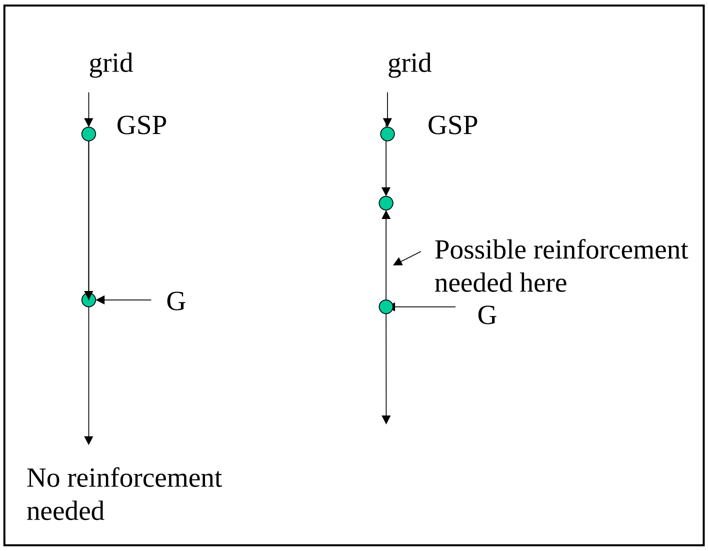

Figure A 1.3 Embedded generation and reinforcement

The real world is like always more complicated – and we might incur combinations of effects. For example a case to consider that is likely to be important for significant connections of new generation, which may require early upgrades. If the new generation is located at point G with consumers between its connection and the path back to the GSP, and if its output is less than the existing load beyond point G, then consumers between the GSP and G will enjoy a reduction in losses and the formula above can be used. This is shown in the left hand part of Figure A1.3. Consumers beyond G will presumably continue to consume as before, and their losses between G and them will be unchanged, giving no credit to the generator. If, however, the additional output exceeds the load beyond G, then the flow from G back to the GSP will reverse, and the capacity of the line may need to be increased (the right hand side of Figure A1.3). If so, then there is an opportunity to reoptimise the capacity upstream of G, and to reduce losses for all customers between G and the GSP, and these benefits should be counted against the extra cost of upgrading the line earlier than would otherwise have been the case.

Appendix 2: The Scale of Increment (Where Losses Are Not the Main Driver)

Appendix 1 dealt with the case in which the one of the main reason for an upgrade is that it offers the opportunity to change the balance between capacity and losses – spare capacity lowers losses as well as providing more flexibility for future load and generation connection. The assumption was that the size of the fixed costs and the relative cost of losses relative to incremental capacity costs would normally lead to a considerable excess of capacity relative to current and forecast likely demands. Assuming that capacity can be varied around this optimal size may not raise many issues of indivisibility. If it does, then the problem reduces to considering the minimum increment allowing for these indivisibilities, and there may be some trade-off between an earlier upgrade to one capacity size, and a slightly later upgrade to the next size up. The cost model should be able to determine the least-cost solution and compute the relevant LRIC.

A second possibility is that the main case for the investment is not to reduce losses but to accommodate a possible sequence of new demands (e.g. from DG), and there are economies of scale in expanding capacity. In this case the size of the increment should be informed by an examination of the degree of indivisibility and economies of scale in the connection investments, and the likely size of aggregate connections to be made at the node. To give some sense of the calculation, suppose one were to expect at a given node (or within the relevant catchment area, if the same reinforcements serve a number of nodes), that increments in G are expected to be of size k, at intervals of n years, so that after N years the total increment is kN/n. Suppose that the connection upgrade has a minimum size, K, at cost C, but above that size has constant unit cost, so that an upgrade of size $X > K$ costs CX/K, if chosen at the time of investment. If not, then each increment of K will cost C. Compare the cost of choosing each upgrade of size X, which will need to be done every $T = Xn/k$ years at cost CX/K, with the alternative of upgrading by the minimum scale K. The NPV of the first stream of investments is $F(X) = (CX/K)/(1\text{-}\beta^T)$, where β is the discount factor, $1/(1+r)$. The object is to minimise $F(X)$ by the choice of X subject to the constraint $X \geq K$.

The derivative of F is $F\{1/X + n\,\beta^T\, log(\beta)/(k[1\text{-}\ \beta^T])\}$, which, since $\log(\beta)$ is negative, is not always positive, and could fall to zero for some $X > K$. However, simulations suggest this is most unlikely, and so on this model the minimum *economic* increment is the minimum actual upgrade. Consider next a model in which there were a fixed cost C for any upgrade, whose total cost for size X might be $C + cX$. This time $F(X) = (C+ cX)/(1\text{-}\beta^T)$, and $(1\text{-}\beta^T)\ dF/dX = c + F(X)\ n\ \beta^T\ log(\beta)/(k[1\text{-}\ \beta^T])$. In this case it is entirely possible for the minimum economic upgrade to involve delay relative to the size of the entrant's immediate capacity needs.

These arguments should then inform the choice of the size of reference increments of capacity reinforcement. Suppose nevertheless that the result of determining the minimum increment for assessing LRIC and hence connection charges is large compared to the likely G entry at any node or area served by the upgrade. Suppose also that initially, before upgrades are made, all nodes are comparably expensive to reinforce. It seems likely that further connections at the first entry point would be cheaper than locations elsewhere, each of which requires a minimum large upgrade. If this is to be signalled in the connection charge there is an immediate problem, in that before any entry, all locations may have a similar quote, but after entry that node should be made to appear cheaper than elsewhere. This could be achieved by requiring any entrant precipitating an upgrade to pay an additional first mover cost, *if* there is spare capacity at some nodes suitable for DG connection, but not otherwise.

Appendix 3: Towards a Social Cost Benefit Analysis of Location Varying Distribution Charges for DG

Locational distribution charges for distributed generation (DG) should bring appreciable benefits if they have a significant impact on the quantity and location of DG connected to the distribution network. However, they will imply extra costs for the DNOs in calculating the charges and providing information to potential generators. These costs could be appreciable. First, we have argued for the development of a standard model framework that could be used by all DNOs. Its construction will be costly (Transcost apparently cost somewhat less than £500,000). Second, each DNO would need to adapt and calibrate the model of its distribution system capable of delivering nodal connection charges. These models have significant set-up and running costs, perhaps as high as £10-20m in Net Present Value (for all DNOs together). These models might have other benefits, for instance they could be adapted for model-based comparisons of distribution costs within the DPCR. If this was the case some of the costs could be allocated to the DPCR.

This appendix attempts a back-of-the-envelope calculation of the benefits of locational Generation Use of System (GUoS) charges by DNOs. A categorisation of costs and benefits of Distributed Generation has been attempted by Rawson (2004) for the California Energy Commission. He does this in the context of encouraging more DG connection to distribution networks. His framework can be adapted to consider locational charging. Rawson identifies seven significant benefits of DG: reduction of emissions, improved reliability of distribution system, enhanced electricity price elasticity, avoided T+D capacity, reduced system losses and improved provision of ancillary services. On the cost side he identifies seven costs in the US context: utility revenue reduction, increased standby charges, increased control costs, effects on emissions offsets, increased emissions from DG, and fuel delivery challenges. We can ignore these costs as these are either US specific or wholly internalised by the connecting DG in the UK context.

The starting point for quantification has to be an estimate of the elasticity of total DG with respect to location varying charging vs. uniform charging. Assuming that location varying charges vary by +/-10% of capital cost and that the elasticity of total DG with respect to capital cost is -0.3, then we might expect a maximum of 3% less total DG as a result uniform charging (as DG would lose the chance of locating at nodes that lower capital cost by 10%). This may be a high estimate. More significant in terms of quantity is the location effect of DG charging, assuming that this is three times more elastic than the total, we would expect that 9% of DG would change its location as a result of location specific DUoS charges.

For purposes of illustration consider four of Rawson's benefits of DG with some assumptions about their quantification in Table A3.1.

Table A3.1 Assumptions behind benefits of locational pricing for DG

Category of Benefit	**Assumptions and Sample Calculations**
Reduction of emissions	0.12 tC/MWh for saved carbon (see Ofgem 2004). We ignore location specific environmental effects. Assume carbon costs £35 per tonne (£9.5/t CO_2 or 15 Euros/t CO_2 compared to ETS of below 10 Euros/t CO_2. Thus extra DG has an emission benefit of £4 / MWh. DG has an average load factor of 0.35, thus 1MW DG has an annual carbon benefit of 8760*0.35*4 = £12.26/kW
Enhanced electricity price elasticity	DG increases price elasticity of loads. Assume that this translates to an elasticity of total system peak capacity with respect to DG of 0.1. We assume this benefit is not location specific. Assume avoided capacity costs £500/kW. Thus DG saves the system = 0.1 x £500 = £50/kW
Avoided T+D capacity	This is in line with total peak generation saved. Assume that avoided T and D capacity costs £50/kW, then DG saves £5/kW
Reduced system losses	Average system losses in DNOs are 7%. Of these 9% (8% variable) are at 132 kV network 20% (14% variable) are in the 32 kV network and associated step down transformers. 27% (22% variable) are in the 11 kV network and associated step down transformers. 42% (29% variable) are in the LV network and associated step down transformers. Source: Ofgem (2003a). Marginal losses are fixed plus twice average variable losses. This implies extra DG capacity at 132 kV has a loss reduction benefit of 1%, at 32KV ((0.08*2+0.01)*0.07) has a loss reduction benefit of 3.5% ((0.22*2+2+0.07)*0.07) etc. Assume the cost of electricity generation is £20/MWh. Thus DG at 132 KV saves 8760*20*0.01/1000=£1.75kW At 32 kV saves 8760*20*0.035/1000=£6.13/kW If DG is connected 50:50 at 132 and 32 kV the average DG saves £3.94/kW/year. Benefits increase if DG connects at even lower voltages. If these benefits are halved if DG locates at the wrong place in the network then we have additional savings from locational pricing of £1970 per annum on each 1MW relocated to a sub-optimal location.

From the above assumptions we now outline two scenarios, assuming a 6.9% discount rate where necessary: total DG with location charging is 2000 MW or 5000 MW (taken from Ofgem, 2004). For simplicity we ignore the discounting issues to do with the time taken to install the effected quantity of DG.

Table A3.2 Benefits of locational charging (LC) for DG

Category of Benefit	**Amount of DG = 2000MW 3% extra as result of LC = 60 MW extra**	**Amount of DG = 5000 MW 3% extra as result of LC = 150 MW extra**
Reduction of emissions	£(12,264*60)/0.069=£10.7m	(£12,264*150)/0.069=£26.7
Enhanced electricity price elasticity	=60*50000=£3m	=150*50000=£7.5m
Avoided T+D capacity	=60*5000=£0.3m	=150*5000=£0.9m
Reduced system losses	=(3940*60)/0.069=£3.4m 180MW in wrong location =(1970*180)/0.069=£5.1m	=(3940*150)/0.069=£8.6m 450MW in wrong location =(1970*450)/0.069=£12.8m
Total NPV of benefits of locational charging	£22.5m	£56.5m

We conclude that there are significant benefits to locational pricing, around a quarter of which are directly related to the locational benefit and three quarters are related to the overall effect on the total quantity of DG. These benefits would be significantly increased if more DG is connected at lower voltages and if some of the other unquantified benefits such as the effect on system reliability and ancillary services were included. If the costs of implementing the charging system were to be significantly less than £10m then there is a strong case for locational charging.