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Exploring the Trade-offs Between Incentives for Distributed Generation Developers and DNOs

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***Abstract*—Regulators are aiming to incentivize developers and Distribution Network Operators to connect distributed generation (DG) to improve network environmental performance and efficiency. A key question is whether these incentives will encourage both parties to connect DG. Here, multi-objective optimal power flow is used to simulate how the parties' incentives affect their choice of DG capacity within the limits of the existing network. Using current UK incentives as a basis, this paper explores the costs, benefits and trade-offs associated with DG in terms of connection, losses and, in a simple fashion, network deferral.**

***Index Terms*—incentives, distributed generation, losses, optimization methods, power generation planning.**

I. Introduction

MEDIUM and long term targets have been set by the United Kingdom (UK) Government to lower the carbon intensity of energy supply. The Renewables Obligation requires 10% of electricity to be supplied from renewable sources by 2010. A further 10 GW of 'good quality' combined heat and power (CHP) is required by the same period. In the decade up to 2010, these challenging targets will require the connection of up to 20 GW of distributed generation (DG), much within distribution networks.

Connection of DG is known to be technically challenging with a wide variety of well-documented impacts including voltage rise, which tends to be the dominant effect in rural networks [1]. While the mitigation of adverse impacts is well established, there have been concerns that deep-connection charging models which oblige developers to fund, upfront, the full capital costs of connection, are acting as a disincentive to DG [2]. Further concerns included the fact that the developers were not being rewarded for benefits that DG could provide [2]. These include improved environmental performance, reduced losses and the opportunity to defer network reinforcement arising from increasing loads.

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One of the key ways of reducing barriers to DG is through the use of Distribution Use of System (DUoS) charges that apply shallower connection charges and reflect the costs and benefits associated with DG. Borrowing from transmission methods, several approaches have been proposed to allocate the costs of network development and losses between demand and generation [3]-[5].

In the UK, Ofgem regulates DNOs through five-year distribution price controls. It considered introducing a full DUoS system for the 2005 to 2010 period [6] but, instead, adopted an interim scheme that provided some incentives for DNOs to connect DG and develop their systems economically. With this scheme in place for much of the period to 2010, it is important that it incentivizes *both* DNOs and DG developers to maximise connections of DG.

This paper explores the current incentives available for developers of DG and the DNOs in the UK and offers a brief international comparison (Section II). In Section III it presents a multi-period multi-objective Optimal Power Flow (OPF), as a means of examining whether current UK incentives will facilitate the connection of greater volumes of DG. Section IV and V present and discuss the implications of a case study.

II. Incentives And Distributed Generation

This section takes a closer look at the incentives for DNOs and developers, the two main players in the DG market.

A. Network Connection and Use

Assuming rational economic behaviour, the objective of DG developers will be to maximise returns from electricity sales or, in the case of CHP, minimise the cost of energy imports. Broadly speaking, these will tend to be met with increased installed capacity but they will be significantly influenced by DNO policies on connection and use of system charges.

Internationally, the incentives and practices for connecting DG are very diverse. Many countries use deep charging (e.g., Australia, Ireland) while others (e.g., Italy, France, Norway) apply shallower charges [7]-[8]. In the United States, customers are liable to pay costs exceeding a regulator-determined connection 'allowance' [7]. Most systems do not currently apply DUoS charges to DG except in a few cases, including Sweden (DG>1.5 MW [3]) and the UK.

Before April 2005, DG connecting to UK distribution networks was charged the full capital costs of connection, and capitalised O&M costs instead of DUoS charges. As part of the price control, DG connecting post-April 2005 pay the following DUoS charges [6]:

1. a 15 year annuity charge based on 80% of the cost of reinforcement works required to connect the DG, if any.
2. an annual capacity charge of £1.50/kW of DG capacity installed in lieu of remaining reinforcement cost.
3. an annual operations and maintenance (O&M) charge of £1/kW of DG capacity to recover appropriate costs.

The charges incentivize the DNO to connect DG by providing a return in excess of the normal regulated rate of return, provided there is a reasonable level of take up and use of connected generation and the costs of connection are relatively low [8].

Ultimately, the cost of network connection and usage is primarily driven by the match between the capacity of the DG and the network to which it is connecting. Where a DG development is larger than can be accommodated at a given location, the traditional approach has been to upgrade the network to the detriment of scheme economics. Given the UK incentives for DNOs, there is benefit to DNOs and developers in reducing the capital costs associated with reinforcement. While active network management [9] will make a significant contribution, there remains a need to identify and encourage DG connections at locations and capacities that make best use of the existing network [10]-[13]. With UK DNOs publishing network data in Long Term Development Statements, such analyses are increasingly within reach of developers.

The current UK DUoS appears to offer both developers and DNOs incentives that tend to encourage increases in DG capacity. However, the picture is complicated by other incentives, not least those relating to losses.

B. Losses

7% of electricity generated in Great Britain is lost as distribution losses [14]. Marginal losses are higher and may be up to 30% at the extreme edges of the networks [3]. While losses are inevitable, they can be managed through investment in low loss equipment, more effective network configuration and energy efficiency [14]. Additionally, losses can be significantly influenced by DG: injections of power at lower voltages tend to reduce losses but, where these greatly exceed demand, losses may increase overall. Although the DG impact on losses is site and time specific, losses tend to follow a U-shaped trajectory [15].

Until 2005 the only DNO incentives for reducing losses were through loss adjustment factors (LAFs) [16] with site-specific LAFs applied at 33 kV and above. The price control incentivizes DNOs to manage losses by providing rewards for loss reductions and penalties for increases relative to a target level. Each DNO's annual target is set by Ofgem and values losses at £48/MWh (in 2004 values). This is aimed at encouraging DNOs to undertake the necessary investment to reduce losses [6]. However, given the relationship between losses and DG penetration, DNOs may be exposed to DG-induced losses where larger volumes of DG connect. As such, the ability of modest penetrations of DG to reduce losses could incentivize DNOs to limit connections within their networks. This potential is important given the larger relative loss incentive (£2.50/kW per year is equivalent to £48/MWh for a source operating only 51 hours/year). The other major area of concern is that developers are not fully incentivized for their impact on losses.

Among the wide range of practices internationally, most European countries require DNOs to purchase losses with the rest tending to specify standard loss levels backed by penalties for non-compliance [8]. Spain and Portugal have a hybrid approach that rewards reductions below a standard level whilst requiring increases to be purchased from the energy pool. As in the UK, the DNOs bear the risk of DG impacts on losses.

C. Deferral of Network Upgrades

A further major area where DG can have a significant impact is through deferment of network reinforcement that would otherwise be required to meet load growth. The value of substituting DG for network capacity can be significant. A study of four US DNOs [17] suggested average marginal distribution capacity costs range from US$74 to US$556/kW with individual area marginal costs of up to US$1,795/kW. These are similar to the AUS$1500/kW reported for parts of Sydney, Australia [18]. While the value attributed to the deferral of network upgrades is heavily dependent on the reliance that can be placed on the DG to produce power at times of peak load, rewarding DG that defers network reinforcement would provide a valuable locational signal.

Although mechanisms for recognising network deferral benefits of DG are being developed for the UK, there is no formal mechanism within current network costing models. Primarily, this is due to the demand-oriented security standard, Engineering Recommendation (ER) P2/5 mandatory in DNO planning. Developed in the 1970s, ER P2/5 defined the network capacity required to meet demand for predefined outage conditions and simply did not recognise the potential for security contributions from newer DG [4]. Although a new standard ER P2/6 now provides a basis for quantifying contribution to system security [19], it still does not provide a mechanism for recognising the benefit.

D. Coherent Incentives?

The loss incentive for DNOs appears to contradict the connection incentives for developers and DNOs. With a more cost reflective distribution charging model in development it is also important to examine the incentives offered by network deferral and explore the impact of these on the desire to connect DG to distribution networks.

III. Defining Optimal DG Capacity Using Multi-Period Multi-Objective OPF

The basic assumption is that both developers and DNOs will aim to maximise their benefits from connecting DG whilst minimising any costs. These objectives can be simulated using techniques used to optimally locate DG capacity within the operational or planning constraints of existing networks [10]. The constraints typically include voltage limits, thermal limits of circuits, fault levels, stability and protection. By constraining the optimisation within existing technical limits the cost of network reinforcement that otherwise would be required to connect larger DG can be avoided by both developers and DNOs.

Here, a multi-period multi-objective optimal power flow has been developed to determine optimal DG capacity. It is derived from the OPF methods of [10] and [11] and the ε-constrained multi-objective OPF technique of [20]. The major change here is the extension to a multi-period formulation. This is designed to capture the impact of varying demand levels on losses and other network factors and allows a more realistic estimate of the value of the loss incentive. To limit the computational burden, the load curve is discretized into appropriate loading bands. Fig. 1 shows an example with four load bands: maximum, normal work hour, medium and minimum. A further extension has been the representation of network deferral benefit.

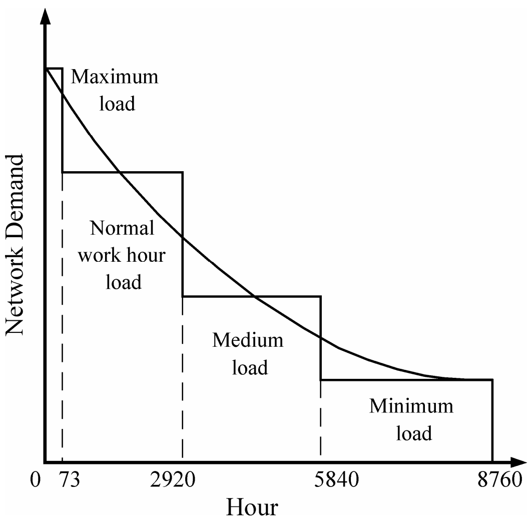

Fig. 1. Load duration curve

A. Multi-Objective Optimal Power Flow

A multi-objective optimal power flow (MO-OPF) problem simultaneously maximises several objective functions amongst a set of feasible solutions, Ω [20]:

$$\max\ f(\mathbf{x}) = [f_1(\mathbf{x}), f_2(\mathbf{x}), \ldots f_m(\mathbf{x})]^T \tag{1}$$

such that

$$\mathbf{x} \in \Omega \tag{2}$$

$$c_j(\mathbf{x}) = 0 \qquad j = 1,2,\ldots,n \tag{3}$$

$$h_k(\mathbf{x}) \le 0 \qquad k = 1,2,\ldots,p \tag{4}$$

The vector **x** consists of a set of controllable quantities, e.g., generator output, and dependent variables. $f(\mathbf{x})$ is the vector of objective functions and $c_j(\mathbf{x})$, $h_k(\mathbf{x})$ represent the equality and non-equality constraints, respectively. Here, the objective functions are the developer's and DNO's.

1) DG Representation and Capacity

It is assumed that the DG offers a firm supply of energy and operates continuously at rated capacity. In maximising DG capacity the objective function is constructed such that coefficients reflect the benefits and costs of DG capacity:

$$f_g = C_g(P_g) \tag{5}$$

Here, C_g is the benefit derived from generator g with a capacity P_g (MW). The DG capacity at a location may be limited by the energy resource available:

$$P_g^{\min} \le P_g \le P_g^{\max} \tag{6}$$

While distributed voltage control or active management allows larger DG capacities [9], [21] by flexibly controlling reactive power (Q_g), most DG currently operate in power factor control mode. An appropriate constraint ensures this:

$$\cos\phi_g = P_g \Big/ \sqrt{P_g^2 + Q_g^2} = const. \tag{7}$$

2) Network Constraints

To date, only the major network constraints on DG capacity of voltage, thermal and fault level constraints have been incorporated within the OPF formulation. For simplicity, only the first two are considered here. While this might limit its application in fault-level dominated urban networks it is acceptable for voltage dominated rural systems.

Quality of supply standards require voltages to be maintained close to nominal:

$$V_b^{\min} \le V_b \le V_b^{\max} \tag{8}$$

where $V_b^{\min}$ and $V_b^{\max}$ are the lower and upper bounds of the bus voltage V_b. The thermal capacity, $S_t^{\max}$, of circuit t also limits the maximum apparent power transfer, S_t:

$$|S_t| \le S_t^{\max} \tag{9}$$

3) Network Deferment

The deferment model assumes a very simple case where specified network elements have been identified as requiring reinforcement to cope with demand increases. Importantly, the benefit that arises from connecting DG is independent of the DG location within the network, i.e. all DG capacity contributes equally. An example of this would be where transformers at grid supply sub-stations are approaching capacity and, without DG contributing to peak load, would otherwise require early upgrading. With the DG units assumed to provide a firm supply, the benefit applies to the entire DG capacity.

4) Objective Functions

The incentives given to developers and DNOs to encourage DG connection will vary from system to system. Here, the arrangements currently applicable to the UK are used to illustrate the analysis, although other systems could be represented in a similar fashion.

Earlier versions of the OPF approach [10]–[11] used an objective dependent only on DG capacity connected and giving a good approximation to the benefit (i.e., net revenue) earned by the developer. It has been extended to cater for the DNO, offer a multi period approach, as well as explicitly representing current UK DUoS and the more general case incorporating network deferment benefits.

The developer's annual objective function is computed from a weighted sum across all four load bands (B), each of $h(B)$ hours duration:

$$f_{DG} = \sum_B h(B) \sum_g \left(C_g^{DG}(B) - C_g^{CC} + D_{DG}\right) P_g \tag{10}$$

Here C_g^{DG} represents the developer's net revenue per kW of DG capacity connected (£/kW), C_g^{CC} is the combined capacity and O&M charge per kW of DG capacity (£/kW) payable to the DNO and D_{DG} is the portion of the benefit arising from deferral of network upgrades that accrues to the developer (£/kW). There is no cost associated with network reinforcement as the analysis constrains DG capacity within the network limits.

The DNO objectives are significantly different. It receives an annual payment, C_g^{CC}, from the developer for every kW of DG connected. The loss incentive values losses at C_L (£/MWh) and rewards or penalizes losses relative to the target level. The DNO objective function is also computed from a weighted sum across all four load bands according to:

$$f_{DNO} = \sum_B h(B)\begin{pmatrix} \sum_g \left(C_g^{CC} + D_{DNO}\right)P_g \\ + C_L\left(L_T(B) - L_A(B)\right) \end{pmatrix} \qquad (11)$$

Here, $L_A(B)$ and $L_T(B)$ are, respectively, the actual and target losses (kW) and D_{DNO} is the portion of the benefit arising from deferral of network upgrades that is retained by the DNO (£/kW of DG installed).

As the DNO and developer incentives are different it is likely that each will perceive different 'optimal' locations and capacities for DG. By comparing the two outcomes, and through the use of trade-off techniques, it may be possible to define a range of compromise solutions offering a potentially better arrangement for DG under the current incentive scheme.

B. Trade-off analysis

With multi-objective problems an infinite number of non-inferior solutions can be generated where improvement in one objective would result in degradation in the other. The decision-maker must subjectively choose the final compromise solution and different methods have been proposed to assist with this task [22]-[24]. There are two approaches: (1) a single criterion of choice automatically defining the compromise, e.g., max-min [25]; and (2) interactive procedures which allow the decision-maker to follow the decision process.

Here, an interactive approach based on the ε-constrained technique [20], [26] is adopted to obtain a set of non inferior solutions from which the most satisfactory solution can be subjectively chosen. In the technique, one objective function (N) is selected as the 'master' objective and the other 'slave' objectives become new constraints. The formulation becomes:

$$\max \quad f_N(\mathbf{x}) \qquad (12)$$

such that

$$f_i(\mathbf{x}) \geq \varepsilon_i \quad i = 1,2,...,m \text{ and } i \neq N \qquad (13)$$

with constraints (2)-(4) applying as before. ε_i represents the lower limit of the ith objective, given by $\varepsilon_i = \varepsilon_i^* - \Delta\varepsilon_i$ where ε_i^* is the global non-inferior value of the ith objective in (1)-(4) and $\Delta\varepsilon_i$ represents the trade-off preference of the decision-maker.

The procedure then applies the concept of significant dominance to reduce the number of comparisons. One alternative solution, X, significantly dominates another, Y, if at least one attribute of Y is 'much worse' than the corresponding one of X and if no attribute of Y is 'significantly better' than X's [27]. This definition is used to rule-out significantly dominated alternatives leaving a 'knee set' containing those that are not. These would then be analysed by the decision-maker in making their final subjective choice or using a direct method like max-min [25].

C. Implementation

The method was implemented in Matlab® using some features of the approach in the MATPOWER suite [28]. Its use is illustrated in the following case study.

IV. Case Study

The technique was applied to a 69-bus 11 kV radial distribution system having two substations [29]. The voltage limits are taken to be ±6% of nominal and the thermal limits for lines are 1.5 MVA. The complete network data are given in [29] but the network diagram is shown in Fig. 2 along with seven potential DG locations. All DG are assumed to have fixed power factors of 0.9 lagging.

TABLE I
ORIGINAL AGGREGATE NETWORK LOADING AND LOSSES

Load Band	Duration [h]	Active Power [MW]	Reactive Power [MVA]	Losses [MW]
Minimum	2920	1.788	1.224	0.034
Medium	2920	2.682	1.836	0.078
Normal	2847	3.576	2.448	0.142
Maximum	73	4.470	3.060	0.228

The loading at each bus is assumed to follow the load curve in Fig. 1, with four distinct loading levels considered. The mean aggregate network load is just under 2.7 MW and the loading levels for each band are given in Table I. The maximum load levels for each bus are given in [29]. The initial levels of losses in each band are also given in Table I; the weighted average of 85 kW is 3.2% of consumption.

The DNO incentives from the UK are applied with the DNO receiving £2.50/year for every kW of DG connected (C_g^{CC}), and losses valued at £48/MWh (C_L). For illustration, the target loss level has been taken to be the initial loss levels with no DG connected.

The developer receives the proceeds of energy and carbon credit sales net of the fuel costs, annual payments to the DNO, O&M, etc. The fixed cost of each DG is taken to be £1/hour and the linear net benefit function offers 1p/kW per hour at buses 13, 27, 35, 40 and 65 and 0.8p/kW per hour at buses 5 and 57.

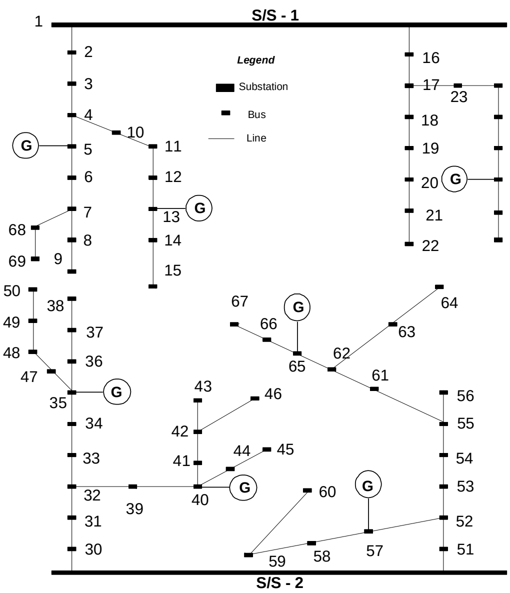

Fig. 2. 69-bus Network with DG unit locations

Three separate analyses have been conducted to assess the implications of these differing incentives for preferences for DG capacity. The first applies the benefits and costs for the developer and DNO as specified for the UK and does not recognise any benefit arising from network deferral. The second recognises a network deferral benefit for the DNO in addition to the initial incentives. The third examines the case where the network deferment benefit is shared between the DNO and developer. In each case, the opportunities for compromise between the parties are explored using trade-off analysis.

A. Optimal DG Capacities with Current UK Incentives

The OPF was run to capture the viewpoints of the developer and the DNO using their respective objective functions, (10) and (11). With network deferral benefits for both parties (D_{DG} and D_{DNO}) set to zero, the DG capacities that would be selected for each of the seven locations are given in the middle columns of Table II.

TABLE II
OPTIMAL DG CAPACITIES (MW): NO DEFERRAL BENEFIT

LOCATION	**DNO**	**DEVELOPER**	**MAX-MIN SOLUTION**
5	0.413	1.353	0.784
13	0.165	0.307	0.277
27	0.459	1.049	0.751
35	0.477	1.307	0.762
40	0.465	0.623	0.945
57	0.531	1.188	1.270
65	0.399	0.696	0.492
Total	**2.909**	**6.524**	**5.281**

It is apparent that the total capacity that would be added by the DNO is only 45% of that deemed optimal by the developer. Here, the developer's desired capacity of over 6.5 MW is limited only by network voltage constraints which explains the larger spread of capacities. 6 of the 7 DGs would be larger than 0.6 MW and the developer would tend to concentrate capacity in fewer DG: 3 DGs account for 60% of the total. By contrast, the DNO would opt to connect roughly equal-sized DGs (0.4–0.5 MW).

If the loss incentive was not present, the DNO's optimal connection would be broadly that of the developer. It would be identical only if the developer had specified equal benefits (i.e. no preference between locations); in this case the value of the benefit is arbitrary [10]. As such, it is the inclusion of the loss incentive that alters the benefit of DG as perceived by the DNO. It results in a far more even spread of capacity which is logical given the U-shaped loss trajectory: the loss incentive is tending to promote a more modest penetration of capacity to avoid the large losses associated with the reverse power flows experienced with the larger DG favoured by the developer.

The influence of plant capacity and siting on losses can be clearly seen in Table III. Relative to the target losses of 85 kW, the DNO's optimal arrangement sees losses reduce by 83% to an average of 15 kW. The developer's optimal scheme results in losses that exceed target by a third. The impact on losses across the load bands is more complex: the DNO would opt for losses at minimum load of around half the original value with the changes for the middle two bands slightly higher than the average. For the developer, losses at minimum load would be 125% higher than original, the middle two bands showing modest increases while losses at peak would show a slight (8%) drop: this emphasises the benefit of DG operating during peak load.

TABLE III
LOSSES (MW): NO DEFERRAL BENEFIT

LOAD	**DNO**	**DEVELOPER**	**MAX-MIN SOLUTION**
Minimum	0.017	0.077	0.004
Medium	0.009	0.107	0.044
Normal	0.017	0.152	0.069
Maximum	0.042	0.210	0.108
Average	**0.015**	**0.113**	**0.039**

TABLE IV
DNO AND DEVELOPER REVENUE: NO DEFERRAL BENEFIT

	DNO	**DEVELOPER**	**MAX-MIN SOLUTION**
DEVELOPER REVENUE [£/YEAR]	176,920	465,640	365,290
DNO REVENUE [£/YEAR]	37,035	-13,405	18,120

The value attributed to losses has a significant impact on the revenue accruing to the parties under their respective, optimal, schemes (Table IV). With the DNO scheme the loss reduction provides cash inflows in excess of £37,000. The developer's optimal set up results in an outflow for the DNO as losses significantly exceed the target; the net loss to the DNO relative to its own optimal exceeds £50,000/year. Imposition of the DNO optimal capacity sees developer revenue fall by 62% or just under £290,000.

Essentially, these two contrasting situations see either the developer or DNO benefiting at the expense of the other. As such, using trade-off analysis it may be possible to find suitable compromises.

B. Trade-off Analysis

Fig. 3 shows the large number of non-inferior solutions found by varying the trade-off preference of the decision maker ($\Delta\varepsilon_i$) for both developer and DNO objectives. The smaller knee set was extracted by defining 'much worse' as 6.5% of the difference between the values of the worst and best alternatives for the DNO objective, and defining 'significantly better' as 6.5% as the equivalent for the developer objective. These solutions are concentrated towards the centre of the Pareto front (Fig 3). The knee set compromises imply relative reductions in both parties' revenue: for the developer the reductions are 20-25% (with £18,000 spread) while the DNO's fall by 45-54% (£3,500 spread).

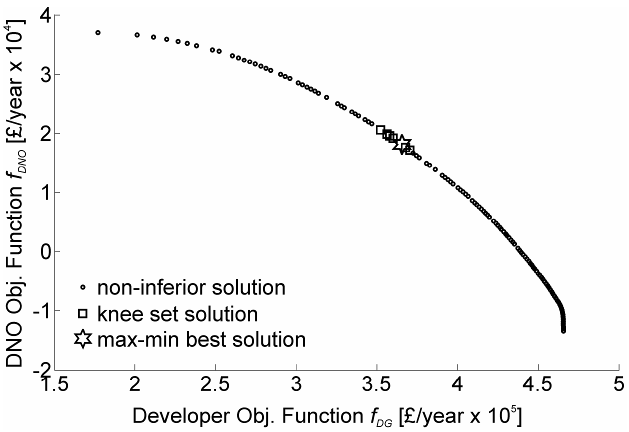

Fig. 3. Pareto solutions for DNO and developer objectives with no deferral benefit.

To illustrate the changes in DG capacity and location implied within the knee set, details of one of the solutions has been extracted and the detailed capacities, losses and revenues are given in the fourth column of Tables II to IV. This represents the max-min solution and was found by applying an adapted version of the max-min method of [25]. In overall capacity terms, the knee set solutions are lower than developer's optimal but much larger than the DNO's optimal. For the max-min solution, the developer's revenue is 22% lower while the DNO's revenue is 51% lower than its optimal. For most of the locations the DG capacities lie between the original optimal values. Losses follow a similar pattern with losses raised by 1.8 times relative to the DNO arrangement but down by one fifth from the developer's optimal. The changes in capacity and losses have a significant impact on both parties' revenues: the developer's falls by £100,000 relative to its own optimal but up £190,000 on the DNO arrangements. For the DNO the magnitude of the revenue changes are smaller but more significant in that the worst case under the developer's arrangements would turn a loss into a modest profit.

It appears that for this case the non-inferior solutions of the knee set offer compromises that tend to raise the installed capacity without penalising either party excessively.

C. Impact of Network Deferral Benefit

The assessment was repeated for two cases to capture situations where the benefits of deferring network investment are specifically recognised:

(a) £250/kW annual deferral benefit retained by the DNO
(b) £250/kW annual deferral benefit split between the DNO and developer in the ratio of 60%:40%.

As necessitated by the simple model of network deferral it was assumed that these are associated with upgrading the sub-station transformers.

The results for case (a) are given in Table V and VI. Where the DNO retains the benefit the developer's incentives and, consequently, the capacities, revenues and losses remain as before. However, the additional £250/kW of DG has a major impact on the DNO as it effectively raises the connection incentive by two orders of magnitude. The incentive is now sufficiently large to relegate the loss incentive with the DNO opting to connect almost as much DG as the network technical constraints allow, i.e., it effectively matches the developer's optimal arrangements. The very slight differences in capacity between the two parties (13 kW overall) can be attributed to the residual effect of the DNO loss incentive and the variation in benefit across the developer's sites. These factors are also reflected in the slight differences in losses and revenue (Table VI). The most significant change is in DNO benefit which rises to more than £1.6 million; this is clearly driving the DNO's change in behaviour. The DNO's new optimal arrangement has a minimal impact on the developer's revenues given the minimal differences.

With the parties now apparently incentivised to act in effectively the same way, the trade-off is of minimal value. However, for completeness the max-min solution is given in the fourth column of Tables V and VI. The entire knee set covers a range of DNO and developer objective values of £200 and £800, respectively.

TABLE V
OPTIMAL DG CAPACITIES (MW): £250/KW DEFERRAL BENEFIT FOR DNO

LOCATION	DNO	DEVELOPER	MAX-MIN SOLUTION
5	1.367	1.353	1.353
13	0.293	0.307	0.307
27	1.049	1.049	1.049
35	0.977	1.307	1.125
40	0.943	0.623	0.798
57	1.231	1.188	1.188
65	0.651	0.696	0.696
Total	**6.511**	**6.524**	**6.517**

For case (b) where £250/kW is split in the ratio of 60%:40% between the DNO and developer there are relatively few differences with the DNO benefit case. For the developer, as the value is equal for all DG units and the capacity is constrained by the technical limits of the network, there is no change in optimal arrangement. However, the additional revenue boosts developer benefit by £650,000 to over £1.1 million. Although the deferral benefit for the DNO is lower it is still sufficiently large to promote significant connection (6.504 MW) of DG that essentially match the developer's. Again, this implies similar levels of losses (104 kW). The DNO's optimal revenue stands at £967,590, well above the original amount. Due to the similarity of both parties' optimal arrangements, the knee set spread is very narrow: £5,000 and £2,000 for the DNO and developer, respectively.

To check the validity of the deferral benefit cases, several other values for the deferral benefit were tried. While the revenues were significantly impacted the capacity outcomes were not significantly affected.

TABLE VI
REVENUE AND LOSSES: £250/KW DEFERRAL BENEFIT FOR DNO

	DNO	**DEVELOPER**	**MAX-MIN SOLUTION**
DEVELOPER REVENUE [£/YEAR]	463,490	465,640	465,020
DNO REVENUE [£/YEAR]	1,618,200	1,617,600	1,618,000
AVERAGE LOSSES [MW]	0.105	0.113	0.108

V. DISCUSSION

It is clear from this analysis that the incentives provided to DG developers and DNOs have a major impact on the parties' opinion of optimal penetrations of DG. Under the current UK incentive schemes, which do not formally recognise the potential benefits for network deferral, there are significant differences in terms of the amount of DG that the developer and DNO would optimally connect. It appears that for the DNO, the more significant incentive associated with loss reduction outweighs the direct benefit of connecting DG. The trade-off analysis applied in this case indicated that a series of compromises are available that could promote lower losses and higher DG capacities. However, as long as developers are not exposed directly to their impact on losses they will seek to connect as much capacity as possible and in the least number of units.

There is the issue of whether the DNO has the ability to constrain generation at the planning stage for reasons other than system security. The only lever the DNO has currently is the LAF which allows location-specific loss charging at 33 kV and above. Should there be only minor differences between locations it would be unlikely to fundamentally alter the developer's choices. As such, where a developer opts to connect a large generator that gives rise to significant losses, the DNO must look for alternative means of minimising losses.

A deliberately simple approach was taken in considering the effect of recognising network deferral benefit. However, a clear result is that network deferral benefits offer a potentially significant means of promoting appropriate behaviour from the DNO and developer. This is linked to the relative size of the benefit compared to other DNO considerations. It is clear that while the simple approach was effective in examining the impact on DNO incentives, a uniform benefit throughout the network is most unlikely to be applicable in all cases. One extension would be to attribute different deferral benefits to each DG where they are evidently contributing to separate deferral cases. However, a more sophisticated approach that automatically detects and accounts for each deferral opportunity is required. With further work an approach similar to [30] could be implemented within the OPF framework.

Although this paper is based primarily on the current UK incentives, many of the outcomes should be applicable elsewhere. The objectives of DG developers will be broadly similar, particularly in liberalised systems. The incentives for DNOs are perhaps not too dissimilar as some systems levy capacity charges which are similar to the kW charges levied on UK DGs. Additionally, the aim of the incentives offered by standardised loss levels and loss purchasing is to reduce or at least control losses, which is the same as the UK. The inclusion of the deferral benefit should extend the applicability of the results further. Clearly application of the analysis to other countries would require adjustments to the values of the costs and benefits recognised. For example, systems with time-dependent loss costs could be modelled using several loss values.

Overall, the work highlights the need for a proper distribution pricing scheme for the UK. Such a pricing scheme would provide economically efficient network prices and incentives arising from the marginal impact of each user on network costs [4]. It would need to be based on an auditable method that considers both marginal loss coefficients and DG investment deferral benefits. While several approaches meeting these requirements are outlined in the literature [31]-[32], a number of specific schemes are currently being considered for the UK. These include Long Run Incremental Cost [3], Time of Use Location Specific [4], and Distribution Investment Cost Related Pricing [5]. These methods more fully reflect the costs and benefits of DG and should promote equitable connection.

VI. CONCLUSIONS

This paper examines the different incentives for developers and DNOs and how these influence the optimal connection of DG within existing networks. Despite the use of UK mechanisms, the approach should be broadly applicable elsewhere. Using a multi-objective OPF, it was shown that developers and DNOs would tend to connect DG in significantly different locations and capacities. A major factor was the influence of a DNO loss reduction incentive and a trade-off analysis identified several opportunities for compromise between the parties. The incentive offered by DG deferring network reinforcement was shown to have a major impact on the behaviour of the parties. Overall, the work highlights the need for a proper distribution pricing scheme that fully reflects the costs and benefits in order to promote equitable connection for DG.

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