Method for Monetarisation of Cost and Benefits of DG Options

D. Pudjianto, D.M. Cao, S. Grenard, G. Strbac
(University of Manchester and Imperial College London)

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Project objectives
The objectives of the DG-GRID project are to:
- To review the current EU MS economic regulatory framework for electricity networks and markets and identify short-term options that remove barriers for RES and CHP deployment.
- To analyse the interaction between economic regulatory framework, increasing volume share of RES and CHP and innovative network concepts in the long-term.
- To assess the effects of a large penetration of CHP and RES by analysing changes in revenue and expenditure flows for different market actors in a liberalised electricity market by developing a costs/benefit analysis of different regulatory designs and developing several business models for economic viable grid system operations by DSOs.
- To develop guidelines for network planning, regulation and the enhancement of integration of DG in the short term, but including the opportunity for new innovative changes in networks in the long-term

Project partners
- ECN, NL (coordinator),
- Öko-Institut e.V., Institute for Applied Ecology, Germany
- Institute for future energy systems (IZES), Germany
- RISØ National Laboratory, Denmark
- University of Manchester, United Kingdom
- Instituto de Investigación Tecnológica (ITT), University Pontificia Comillas, Spain
- Inter-University Research Centre (IFZ), Austria
- Technical Research Centre of Finland (VTT), Finland
- Observatoire Méditerranéen de l'Energie (OME), France

For further information:
Martin J.J. Scheepers
Energy research Centre of the Netherlands (ECN)
P.O. Box 1, NL-1755 ZG Petten, The Netherlands
Telephone: +31 224 564436, Telefax: +31 224 568338,
E-mail: scheepers@ecn.nl,
Project website: http://www.dg-grid.org/
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1. Introduction

This report aims to provide a description of the network model, methodology, and scenarios that will be used in further studies to quantify and analyse the costs and benefits of DG (RES\textsuperscript{1}/CHP\textsuperscript{2}) options and deploying active management in distribution networks. The work develops a platform to assess the impact that DG will have on the overall operation and investment performance of the entire distribution network.

In order to enable the assessment without necessarily conducting the studies on many specific and real but complex distribution systems, representative or called as generic distribution network models were developed. Such models are presumed to be simple enough yet capable to be used for accurate investigations involving a variety of operating conditions in order to capture the temporal and spatial impacts of DG on the network. The developed models were designed to capture the principal characteristics of distribution networks. The parameters of the models were tuned to mimic UK distribution network’s characteristics.

Then, a number of load flow studies can be performed on the generic network models to assess the impact of DG on losses, flows and voltages, network investment schemes, and network management approaches in the distribution network. The studies include evaluation of network operation within a year time span.

Moreover, a methodology for quantifying the value of various active distribution network management approaches in the entire UK distribution network was also developed. Active management approaches range from local to area voltage and flow control achieved by means of a coordinated voltage control policy and by curtailing distributed generation output, if necessary. Furthermore, fault level management was also included and achieved by splitting substation busbars to reduce fault levels.

In order to understand the impact of the volume of RES/CHP supply on the costs and possible benefits for a DSO this situation will be studied in four different situations. There are four reference cases which have been identified so far:

- Rural electricity network with low RES/CHP supply
- Rural electricity network with medium/high RES/CHP supply
- Urban electricity network with low RES/CHP supply
- Urban electricity network with medium/high RES/CHP supply

More detailed discussions will be presented later.

The report is organised as follows:

- Section 2 describes the detailed design philosophy of generic distribution network model.

\textsuperscript{1} Renewable Energy Sources
\textsuperscript{2} Combined Heat and Power
- Section 3 explains the main technical barriers for DG deployment in distribution networks concerning voltage and thermal limits. A number of active management approaches were proposed to minimise the cost of accommodating DG. Active management can avoid or defer investment required as generally taken according to “fit and forget” approach.

- Section 4 describes the scenarios used to quantify the benefits of active management in distribution network for typical urban and rural networks in UK. Some preliminary results are also presented and analysed.

At the end of the report, a summary is given.
2. Generic Distribution Network Model

The basic topology and design philosophy of the distribution network in the UK is similar in each company area. All companies have multi-voltage systems with substations and transformers between each of these levels. All companies also have a multitude of overhead lines and underground cables to convey power between system levels and eventually down to end users. Substations, cables and lines may vary in capacity and length and the detailed design may affect resistance and reactance values but, to a large extent, all of the Distribution System Operator (DSO) networks are similar. They are similar enough in topology and design philosophy to allow the adoption of a common modelling approach, on a Grid Supply Point (GSP) basis.

In all DSOs’ GSPs in the UK, power is transferred through a number of well-defined system levels, which operate various “standard” voltages. For the purposes of the analysis in this study, it is assumed that all GSPs are run in parallel and a simplified four-voltage-level network is used for all distribution areas: 132kV/33kV/11kV/0.4kV. The operating voltage of 6.6kV is sometimes used instead of 11kV because of the way the system was developed. It seems, however, to be universally accepted that the preferred level is 11kV and replacement strategies endeavour to achieve the phasing out of 6.6kV (Aquila, 2002) and (EME, 2002). Consequently, any other voltage levels used by some DSOs, such as 6.6kV and 66kV, could be reclassified to align them with one of the standard voltages specified above.

While most distribution networks are operated in radial, some DSOs operate part of their networks in meshed configuration. Modelling meshed networks would however require the implementation of advanced load flow calculation, which is not the purpose of this model. It is therefore assumed here that each distribution network in the UK is operated in radial, from the GSP point to the end users. Furthermore, it is assumed that the model is composed of well-balanced three-phase circuits and transformers. A graphical representation of a generic distribution network with various loads and distributed generators connected is shown in Figure 1.

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3 * GSP: A point of supply from the national transmission system to the local system of the distribution network operator.
Each voltage level of the network is modelled by different modules; a module being composed of a substation, the low voltage busbar of that substation and the feeders connected to that busbar as described in Figure 2. When modelling the UK distribution network, one can therefore either define as many modules as substations in the real network in order to obtain a totally precise but large model, or define a smaller number of modules that would capture the key characteristics of the network. Such a decoupling of voltage levels also enables us to control the voltage in each substation.
transformers (capacity, impedance, no-load losses at rated power and load losses at rated power), the number of feeders connected to the busbar, their type (overhead line, cable or mixed), their length as well as different tapering configurations and load connections. As a result, two modules differ if any of the previous inputs are different.

Owing to the differences existing between each voltage level, particularly with regard to the connection of load, DG and lower voltage substations to the feeders, the main configuration of the modules is slightly dissimilar for each voltage level as highlighted below.

2.1. Inclusion of security standard in the design of generic distribution network

When designing their network, DSOs are subject to different standards and recommendations included in the Distribution Code and in their Licence. One of the main examples is the Engineering Recommendation P2/5 covering security of supply. For a range of group demand up to 1MW, the recommendation is that after a first circuit outage the demand is supplied within the repair time. For group demands of between 1MW and 12MW, group demand minus 1MW should be met within 3 hours and total group demand should be met in repair time. Hence, the generic distribution model tool was developed taking into account these recommendations.

2.2. Module configuration for each voltage level

2.2.1. 0.4kV network

The 0.4 kV network in one GSP network is composed of Under Ground (UG) cables with various sizes as follows:

- 500 circuits of 70 mm² UG cables
- 2000 circuits of 95 mm²
- 500 circuits of tapered 185/95 mm²

Typical reactance of each UG circuit is 0.1 Ω/km. Typical average length of each circuit is 0.35 km. The 0.4 kV network also consists of 250 x 100 kVA, 500 x 250 kVA, and 250 x 630 kVA 11/0.4 kV transformers.

2.2.2. 11kV Network

The 11 kV network in one GSP network is composed of Over Head Lines (OHL) with various sizes as follows:

- 48 circuits of 70 mm²
- 120 circuits of 95 mm²
- 24 circuits of tapered 300/185 mm²

Typical reactance of each OHL circuit is 0.4 Ω/km. Half of the circuits are 8 and another half are 20 km long. The 11 kV network also consists of 12 x 2 x 7.5 MVA, and
12 x 2 x 17 MVA 33/11 kV transformers. It is important to note that each substation has 2 transformers to meet security standards.

2.2.3. 33kV Module in GSP network

The 33 kV network in one GSP network is composed of Over Head Lines (OHL) with 24 circuits of 185 mm². Typical impedance of each circuit is 0.4 Ω/km. One third of the circuits are 6 km, another one third are 12 km and the rest are 18 km long. The 33 kV network also consists of 4 x 2 x 66 MVA 132/33 kV transformers.

2.2.4. 132kV module in GSP network

The 132 kV network in one GSP network is composed of Over Head Lines (OHL) with 4 circuits of 300mm². Typical impedance of each circuit is 0.4 Ω/km. Typical length of each circuit is 17 km. The 132 kV network also consists of 2 x 240 MVA 400/132 kV or 275/132 kV supergrid transformers.

2.3. Load data

Figure 3 below shows typical annual load profiles in nine characteristic days used in the studies. Hourly and seasonal load variations were captured and used for load flow analysis.

![Figure 3 Annual load profiles](image)

This figure is obtained by aggregating different type of loads, i.e. residential, industrial and commercial loads in the network. Distribution of the loads at each voltage level and along feeders was also modelled.
2.4. DG (RES/CHP) output profiles

Two DG technologies will be evaluated: (i) domestic micro CHP and (ii) PV generation technology.

2.4.1. Micro CHP output profile data

Combined Heat and Power (CHP) is the simultaneous production of electrical power and useful heat. In the case the electrical power of domestic micro CHP is consumed inside the host premises although any surplus or deficit is exchanged with the utility distribution system. The heat generated by micro CHP is used for space heating inside the host premises. Therefore the electrical energy output of micro CHP is driven by the heat requirements of consumers. Figure 4 illustrates the normalised generation profile of micro CHP that will be used for further studies. It is assumed the output of micro CHP is nil during the summer. Furthermore, it is assumed that 25% of the customers with micro CHP has a technology with a capacity of 3kW and 75% with a capacity of 1.1kW.

![Figure 4 Normalised CHP output during winter](image)

2.4.2. PV output profile data

Photovoltaic generation corresponds to the direct conversion of sunlight to electricity. Interest is now focused on incorporating the photovoltaic modules into buildings and houses. Thus these small PV installations would be connected directly into customers’ circuits and so interface with the low-voltage distribution network. Figure 5 describes the normalised energy profile used in this study based on (Jenkins, N., 1995) to model the output of PV. It is assumed that customers would have a 1m² module with a capacity of 1kW.
Figure 5 Normalised PV output profiles
3. Identifying network constraints and applying active management

Even if there may be a multitude of technical considerations associated with the connection of increased levels of DG, the main technical barriers recognised in (Jenkins, N., et al., 2000) are as follows:

- Voltage management and thermal rating issues in rural areas
- System fault level issues in urban areas

Based on these main technical issues, it is assumed that the reinforcement costs are limited to the upgrade costs of circuits and substations in rural networks, and the replacement cost of switchboards in urban networks.

3.1. Voltage rise and thermal rating issues

In most cases, the distribution network is designed for unidirectional flows of power from the high voltage levels to the lower voltage levels, and from the substation end of distribution circuits down to the connected load at the extremities of the circuits. When power is required to flow in the opposite direction, then voltage management and thermal rating difficulties can arise. These are most often encountered when there is insufficient local load to absorb the output from circuit connected DG and power is pushed "back up" in the circuit. Voltages rising to unacceptably high levels, in excess of the statutory limits, occur particularly in long overhead lines because of their high impedance.

The voltage rise effect is illustrated in Figure 6 on an 11kV module composed of two feeders, one with DG and load lumped at the end and the other one with a single load lumped at the end, and a 33/11kV on-load tap-changing transformer (OLTC).

![Figure 6 11kV distribution network module composed of two feeders](image_url)
Load flow equations can be used to quantify the amount of generation that can be connected to the distribution network without triggering any reinforcement cost, as well as the impact of alternative control actions.

As indicated earlier, the general practice in the distribution networks is to limit the capacity of the connected DG based on the extreme conditions of minimum load ($P_{L1}=0$, $Q_{L1}=0$) and maximum generation ($P_{G}=P_{G\text{MAX}}$). The maximum size of generation that can be accommodated, $P_{G\text{max}}$ without reinforcing the network, is thus limited by the voltage limit, $V_{i\text{max}}$.

If a generation capacity larger than $P_{G\text{max}}$ requires a connection, the basic solution chosen under passive management to overcome voltage rise issues is to upgrade the existing circuit in order to decrease its impedance. It is supposed in the methodology that increasing the cross-section of a feeder at a given voltage level will only influence its resistance while the reactance remains generally constant. The upgrade costs of overhead lines used in this study are provided in £/MW/km in Table 1 for each voltage level.

Similarly, if the circuits’ thermal load capacity is exceeded, network reinforcement is costed using Table 1. Furthermore, the cost of upgrading any transformer at any voltage level is assumed to be 19,400£/MVA.

<table>
<thead>
<tr>
<th>Voltage level</th>
<th>132kV</th>
<th>33kV</th>
<th>11kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrade cost of overhead circuits (£/MW/km)</td>
<td>837</td>
<td>785</td>
<td>2,637</td>
</tr>
</tbody>
</table>

Under active management approach, there are two means of controlling system voltages in the operational time scale as described in Liew, S.N., et al., 2002a. One approach is by curtailing generation to limit the voltage rise effect and another approach is using coordinated voltage control by adjusting tap changers and reactive compensators.

### 3.1.1. Problem formulation

The methodology developed in the generic distribution-network design tool enables us to perform an optimal power flow with simple linearised load flow equations in each module in order to find the optimum between annualised investment (network investment and reactive power investment) and generation curtailment taking into account losses.

The optimisation task when applying voltage management in this research is to minimise the cost of generation that needs to be curtailed in order to mitigate voltage and thermal violation limits for each individual settlement period independently, as stated mathematically in Equations (1) to (8). However, if the annual energy curtailed for any DG is more than 0.5% of the energy delivered then the decision is to reinforce the corresponding feeder, as shown in the flowchart of Figure 7, in order to decrease the
amount of energy curtailed.

Objective function:

\[
\text{Minimise } \phi = \sum_{i=1}^{N_g} \left( e_{pi} \times P_{GiG}^{\text{cur}} \right)
\]  

(1)

Subject to:

\[
P_{GiG}^{\text{sch}} - P_{GiG}^{\text{cur}} - P_{Li} - \sum_{j=1}^{\text{NBus}} P_{ijG}^{\text{inj}}(V, \theta) = 0
\]  

(2)

\[
Q_{GiG}^{\text{sch}} - Q_{GiG}^{\text{cur}} - Q_{Li} - \sum_{j=1}^{\text{NBus}} Q_{ijG}^{\text{inj}}(V, \theta) = 0
\]  

(3)

\[
\sqrt{(P_{ijG}^{\text{inj}}(V, \theta))^2 + (Q_{ijG}^{\text{inj}}(V, \theta))^2} \leq S_{ij}^{\text{max}}
\]  

(4)

\[
V_{iG}^{\text{min}} \leq V_i(P_{GiG}) \leq V_{iG}^{\text{max}}
\]  

(5)

\[
P_{GiG}^{\text{min}} \leq P_{GiG}^{\text{sch}} - P_{GiG}^{\text{cur}} \leq P_{GiG}^{\text{max}}
\]  

(6)

\[
Q_{GiG}^{\text{min}} \leq Q_{GiG}^{\text{sch}} - Q_{GiG}^{\text{cur}} \leq Q_{GiG}^{\text{max}}
\]  

(7)

\[
Q_{GiG}^{\text{cur}} = f(P_{GiG}^{\text{cur}})
\]  

(8)

\forall i = 1..\text{Nbus}

Where

- \( P_{Li} \), \( Q_{Li} \) Active and reactive load at node \( i \), at time \( t \).
- \( P_{GiG}^{\text{sch}}, Q_{GiG}^{\text{sch}} \) Maximum active and reactive generation of the DG at node \( i \), at time \( t \).
- \( P_{GiG}^{\text{cur}}, Q_{GiG}^{\text{cur}} \) Active and reactive generation curtailment at node \( i \), at time \( t \).
- \( P_{ij}, Q_{ij}^{\text{inj}} \) Active and reactive power flow from node \( i \) to node \( j \) at time \( t \).
- \( e_{pi} \) Price of generation curtailment for generator \( i \) at time \( t \).
- \( V \) Voltage at the substation low voltage busbar at time \( t \).
- \( V_i \) Voltage at node \( i \), at time \( t \).
- \( S_{ij}^{\text{max}} \) Maximum load flow in branch \( ij \).
- \( V_{iG}^{\text{min}}, V_{iG}^{\text{max}} \) Statutory voltage limits at node \( i \).
- \( \theta_i \) Voltage angle at node \( i \), at time \( t \).

The non-linear problem formulated above is linearised and solved using linear programming method. The objective function (1) is to minimise the total cost of generation curtailment. Nodal power balance equations are represented by Equations (2)
and (3). The optimisation is also subject to the branch thermal constraint (4) and network voltage limits (5). The maximum amount of active and reactive generation curtailed will be limited by the capacity of DG connected and will not be negative (6) and (7). Reactive power curtailment could be modelled to have a correlation with the active power curtailment (8).

![Figure 7 Problem flowchart](image_url)

3.2. Fault level issues

3.2.1. Contribution of DG to system fault level

In general, the connection of rotating machinery (both generators and motors) to distribution networks contributes to system fault levels. This additional “fault in-feed” can result in system fault levels being increased beyond the rating of existing switchgears, in which case the switchgear is required to be replaced with equipment of a higher fault rating.

The model assumes that all machines’ symmetrical fault contribution is equivalent to
five times the rating of the generator. Moreover, contribution to the lower voltage levels from DG connected at higher voltage levels is not considered, on the basis that it would be significantly lower due to the relatively high impedances of transformers at the lower voltage levels. For simplification, it is assumed in this study that the contribution to the 132kV system fault level from generators connected at 33kV is one third (33%) of the contribution to fault level at 33kV. Also the contribution to the 33kV system fault level from generators connected at 11kV is three quarters (75%) of the contribution to fault level at 11kV. These figures are based on (ILEX and UMIST, 2002), and where the fault level contribution passes up through more than one voltage level, it is appropriately attenuated as it passes through voltage levels.

In most cases, a rise in system fault level requires the switchgear to be replaced with equipment of a higher fault rating. In the developed model, the entire switchboard of a substation is replaced if the fault rating at that location is exceeded. The costs of new switchboards used for each voltage level are presented in Table 2.

<table>
<thead>
<tr>
<th>Substation</th>
<th>GSP</th>
<th>132/33kV</th>
<th>33/11kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>New switchboard cost (£)</td>
<td>3,146,000</td>
<td>1,079,000</td>
<td>497,350</td>
</tr>
</tbody>
</table>

**3.2.2. Effective management of fault levels**

A high fault level is an indicator of the strength of the system, suggesting close proximity to generating stations or a highly connected system. However high fault levels come at a price: they require the installation of expensive switchgears with high rupturing capacities. A balance must therefore be struck between the benefits of high fault levels and the cost of necessary switchgears. In the event that the connection of DG causes the fault level to rise above the existing switchgear rating, which is particularly the case in urban areas where short cables are installed, it becomes necessary to find ways to reduce the fault level as a cheaper alternative to replacement of the switchgear, which is the costly solution chosen in the passive management policy. The method used in this study is to split substations busbars as explained in (Wu, X., et al., 2003). In Figure 6, fault level management uses the 11kV bus section circuit breaker. By splitting the network in this way, the impedance between the 33kV and 11kV systems doubles, reducing the fault current coming from the upper voltage levels.
4. Benefits of active management in UK’s distribution network

4.1. Presentation of the case studies

The average generic distribution network described previously has been used to model the 200 GSPs in the UK. Driven by the need for using renewable energy sources due to environmental concern, it can be foreseen that penetration of DG in the UK distribution network will increase. However, the views on the UK picture of DG capacity, and DG location in the future are not yet clear. For that reason, four different penetrations of DG in the UK distribution network at 11kV were studied: 2.5GW; 5GW; 7.5GW and 10GW. It is expected that these high penetrations of DG will lead to technical problems especially when DG is connected to a weak distribution network, which is the case of the 11kV voltage level in the UK, particularly in rural areas. Therefore, for each of the penetrations chosen above, four different allocation scenarios were investigated:

- DG connected over 50% of GSPs and 2/3 of the 11kV feeders (L)
- DG connected over 50% of GSPs and 1/3 of the 11kV feeders (LM)
- DG connected over 25% of GSPs and 2/3 of the 11kV feeders (HM)
- DG connected over 25% of GSPs and 1/3 of the 11kV feeders (H)

For each scenario, active management is applied in each 11kV module of the GSP model, and DGs are assumed to have a unity power factor. In the case of the “fit and forget” philosophy, the distribution feeders are upgraded so that they can accommodate the full DG capacity without encountering any voltage or thermal issues. In the case of active management, two cases are studied for network reinforcement:

- “Non-intermittent case”: a flat output is used for all DGs installed in the UK. Reinforcement of equipment attached to a generator is required if more than 0.5% of the energy delivered is curtailed (as presented in Figure 7).
- “Intermittent case”: in this case, it is assumed that the energy curtailed is equal to 10% of the energy curtailed in the non-intermittent case. Investment is required if more than 2.5% of the energy delivered is curtailed.

These two cases are described in this section as non-intermittent and intermittent generation respectively.

The study compares the incremental cost of upgrading feeders and substations under the “fit and forget” design and under active management of the network. However, implementing the latter comes at a cost. Therefore, under active management, to the incremental cost of upgrading feeders and substations must be added the cost of generation curtailment, and also the cost of implementing active management which includes investment cost in voltage measurement units and investment cost in control and communication systems.

Even though the average GSP network was used, the costs due to voltage rise and thermal problems are defined as the costs in rural system because these problems occur typically in the weak 11kV rural feeders characterised by long and thin diameter of
overhead line sizes. On the other hand, the costs associated with fault level issues are linked with urban networks where short cables are required.

4.2. Cost information

In order to find the optimal design of the region, several simulations with different transformer and circuit characteristics are needed. The equipment used, with its economical and electrical characteristics, is presented in the tables below. They are chosen from a set of standard available equipment (Green, J.P., et al., 1999), so therefore the cost, capacity and impedance of the equipment in the design are realistic rather than theoretical. When calculating the annuity of equipment cost, a period of 20 years has been used with a discount rate of 7%. The annuity calculation is used to give the payment for each year of the review period which can be compared with the cost of losses, also calculated on a yearly basis by multiplying the losses occurring at each hour in the network by the corresponding energy price of electricity.

<table>
<thead>
<tr>
<th>Capacity (kVA)</th>
<th>Z (%)</th>
<th>Pcu (W)</th>
<th>Pfe (W)</th>
<th>Maintenance cost (£/year)</th>
<th>Substation’s investment cost (£/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>50</td>
<td>4</td>
<td>1,100</td>
<td>190</td>
<td>53</td>
<td>177</td>
</tr>
<tr>
<td>100</td>
<td>4</td>
<td>1,750</td>
<td>320</td>
<td>68</td>
<td>253</td>
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<tr>
<td>200</td>
<td>4</td>
<td>2,860</td>
<td>550</td>
<td>83</td>
<td>354</td>
</tr>
<tr>
<td>315</td>
<td>4</td>
<td>4,000</td>
<td>730</td>
<td>98</td>
<td>1,055</td>
</tr>
<tr>
<td>500</td>
<td>4</td>
<td>5,500</td>
<td>1,100</td>
<td>106</td>
<td>1,095</td>
</tr>
<tr>
<td>1,000</td>
<td>6</td>
<td>10,500</td>
<td>1,700</td>
<td>143</td>
<td>1,297</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Size (mm²)</th>
<th>Capacity (A)</th>
<th>R (Ω/km)</th>
<th>X (Ω/km)</th>
<th>Installation and investment cost (£/km.year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>185</td>
<td>0.443</td>
<td>0.0705</td>
<td>3,062</td>
</tr>
<tr>
<td>95</td>
<td>220</td>
<td>0.320</td>
<td>0.0690</td>
<td>3,223</td>
</tr>
<tr>
<td>185</td>
<td>320</td>
<td>0.164</td>
<td>0.0685</td>
<td>3,868</td>
</tr>
<tr>
<td>300</td>
<td>420</td>
<td>0.100</td>
<td>0.0675</td>
<td>4,029</td>
</tr>
</tbody>
</table>

4.3. Percentage of lines and substations to be upgraded in rural networks

Figure 8 to Figure 10 present the percentage of 11kV and 33kV lines and 33/11kV substations that need to be upgraded for the different penetration scenarios of DG and for both types of management philosophy: “fit and forget” (F&F) and active management (AM). The case of 2.5GW penetration is not presented since none of the penetration scenarios of DG triggers any reinforcement costs.
For capacities of 5GW and 7.5GW of DG installed over 50% of the GSPs in the UK, less lines require upgrade when DGs are allocated along 2/3 of the circuits than over 1/3 of the circuits, because the capacity of DG installed per line in the first case is low enough to not require reinforcement, whereas when the concentration increases a larger number of reinforcements are required.

On the other hand, as the installed capacity of DG increases to 10GW in the UK, it is the opposite case. The capacity of DG installed per line is such that most of the lines where DG is installed require an upgrade, whatever the penetration density of DG. The higher the density of DG as in scenario H, the lower the number of 11kV lines which need to be upgraded. For the same reasons, when DG is installed over 50% of the GSPs, the number of lines to be reinforced for any penetration of DG is higher for high-density allocation of DG.

Similar comments can be made for 33/11kV substations and 33kV lines: for high penetration of DG, the higher the generators concentration in the GSP network, the lower the number of equipment to upgrade. However, the capacity upgrade required is higher for high density of DG and the costs associated are higher, as will be shown in the next sub-section.

![Figure 8 Percentage of lines and substations to be upgraded in the UK for a DG penetration of 5GW and for different penetration scenarios](image-url)
Figure 9 Percentage of lines and substations to be upgraded in the UK for a DG penetration of 7.5GW and for different penetration scenarios

The results obtained with this study also indicate that reinforcement of 11kV lines is driven by voltage constraints as 11kV feeders are characterised by long overhead lines, while the reinforcement of 33/11kV substations and 33kV lines is driven by thermal constraints. As described in the figures above, active management has a positive impact on the percentage of 11kV lines that need upgrading.

4.4. Upgrade cost in rural networks

Figure 11 to Figure 12 illustrate the total UK upgrade costs disaggregated per voltage level and per scenario, and for both passive and active management. They reveal that upgrading 11kV lines is the main cost for all scenarios of penetration of DG. Nevertheless, the cost of upgrading 33/11kV substations increases with the capacity and
the density of penetration of DG, and forms a large part of the reinforcement cost in scenario H, and for a penetration of 10GW. These figures also demonstrate how the upgrade costs can be reduced by using active management in 11kV modules.

Figure 11 Upgrade costs for a DG penetration of 5GW

Figure 12 Upgrade costs for a DG penetration of 7.5GW
4.5. Costs associated with active management

4.5.1. Curtailment costs

The first cost associated with generation curtailment is the cost of energy non-produced by the distributed generator, in order not to violate voltage or thermal constraints in times of low demand. Figure 14 shows the energy curtailed for each scenario of non-intermittent DG penetration. The cost associated is obtained by multiplying the amount of energy curtailed by the cost of electricity, which is assumed to be 20€/MWh in this study.
4.5.2. Implementation cost

The second cost associated with active management is its implementation cost. Implementation of generation curtailment necessitates the installation of voltage measurement schemes at the generator point of connection as described in (Liew, S.N., 2002). A reliable communication link between the terminal of the DG and the DSO centre is also required. Besides, in a co-ordinated area-based voltage control, measurements and communication are also required between a 33/11kV substation and the DSO centre. In this study we suppose that the cost of active management is flat irrespective of the considered level of DG penetration. This is because the cost of active management is assumed for simplicity to be fixed, irrespective of the number of feeders with voltage rise problems as long as there is at least one problem feeder. In rural areas, the cost of implementing active management is therefore supposed to be £10,000 per DG. In urban areas, the cost of implementing active management is assumed £100,000 per substation. However, in practice, the cost of active management has variable cost components and depending on the number of problem feeders, the cost of enabling active management varies.

4.6. Benefits of active management in rural networks

Table 5 and Figure 15 compare the range of reinforcement costs for different penetrations of DG in the UK distribution between passive management and active management with all its associated costs described above: cost of curtailment, cost of implementing active management and cost of reinforcement if required. In Table 5, the first row in the active management column corresponds to the reinforcement costs for the intermittent case while the second row corresponds to the non-intermittent case. The underlined figures correspond to the cost of implementing active management.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>L</th>
<th>LM</th>
<th>HM</th>
<th>H</th>
</tr>
</thead>
<tbody>
<tr>
<td>DG capacity</td>
<td>P IC</td>
<td>A IC</td>
<td>CoI</td>
<td>P IC</td>
</tr>
<tr>
<td>2.5GW</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>126</td>
</tr>
<tr>
<td>5GW</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>126</td>
</tr>
<tr>
<td>7.5GW</td>
<td>100</td>
<td>0</td>
<td>80</td>
<td>295</td>
</tr>
<tr>
<td>10GW</td>
<td>243</td>
<td>0</td>
<td>160</td>
<td>482</td>
</tr>
</tbody>
</table>

Table 5 Incremental cost (IC) of upgrading feeders and substations in rural system (in M£) for Passive (P) and Active (A) management (considering the intermittent and non-intermittent cases) and cost of implementing (CoI) active management.
The benefits of active management are clearly illustrated in Figure 15 for each penetration of DG. For an installed capacity of 5GW, up to 50% of the cost of upgrading the system could be saved by applying active management, while this figure varies between 15 and 40% for a penetration of 10 GW.

Table 5 also suggests that reinforcement costs required in the intermittent case are smaller than for the non-intermittent case. This is due to the lower occurrence of the worst-case situation of high output of DG at times of low demand in the intermittent case.

### 4.7. Benefits of active management in urban networks

Average system fault levels are assumed at each voltage level; 350MVA at 11kV and 1,000MVA at 33kV, and two different fault level headrooms available at each voltage level are examined. The headroom is used to determine how much DG can be added to various parts of the DSO networks before switchgear fault ratings are exceeded. The two following cases are investigated:

- 0% headroom; in this case the introduction of DG at 11kV requires the upgrade of the switchgear in the 33/11 kV substation for passive management.
- 10% headroom; in this case the introduction of DG at 11kV requires the upgrade of the switchgear in the 33/11 kV substation only if its contribution to fault level is superior to 10% of the switchgear rating for passive management.

Table 6 and Figure 16 provide the range of full cost of upgrading switchboards in all the penetration scenarios of DG in urban systems. For active management, the cost of implementing an active managed network is added to the cost of upgrading switchboards. As for rural systems, the benefits of active management can be clearly identified. For low DG penetration, more than half of reinforcement costs could be saved by applying active management.
### Table 6 Reinforcement cost of switchboards (RC) for two different headrooms for passive (P) and active (A) management in urban system (in £M) and cost of implementing (CoI) active management

<table>
<thead>
<tr>
<th>Scenario ⇒</th>
<th>L</th>
<th>LM</th>
<th>HM</th>
<th>H</th>
</tr>
</thead>
<tbody>
<tr>
<td>DG capacity↓</td>
<td>Headroom</td>
<td>P RC</td>
<td>A RC</td>
<td>CoI</td>
</tr>
<tr>
<td>2.5GW 0% 10%</td>
<td>796 0 0</td>
<td>320</td>
<td>0 0 160</td>
<td>398 0 0</td>
</tr>
<tr>
<td>5GW 0% 10%</td>
<td>796 0 0</td>
<td>320</td>
<td>0 0 160</td>
<td>398 0 0</td>
</tr>
<tr>
<td>7.5GW 0% 10%</td>
<td>796 0 0</td>
<td>80</td>
<td>0 0 160</td>
<td>398 0 0</td>
</tr>
<tr>
<td>10GW 0% 10%</td>
<td>796 0 0</td>
<td>80</td>
<td>0 0 160</td>
<td>398 0 0</td>
</tr>
</tbody>
</table>

**Figure 16 Ranges of reinforcement costs in urban areas**
5. Conclusions

The methodology discussed in this report has demonstrated and quantified the benefits of active network controls in the UK distribution network for different penetration scenarios of DG at 11kV using generic network models. The models were designed to have the typical characteristics of UK distribution networks and hence eliminating the need of real distribution network data for analysing the benefits of active management in the distribution networks. The studies show that until certain level of penetration, adopting active management approach reduces the cost for accommodating DG by deferring the need of network reinforcement. The study also confirmed that the costs of upgrading the distribution network generally increase with higher penetrations of renewable generation, and that these costs are driven by the concentration of generation capacity.
6. References

- ILEX and UMIST (G. Strbac) (2002) Quantifying the System Costs of Additional Renewables in 2020, a report to the DTI.