Advanced Architectures and Control Concepts for

MORE MICROGRIDS

Specific Targeted Project

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WPH. Impact on the Development of Electricity Infrastructure

DH2. Report on economic, technical and environmental benefits of Microgrids in typical EU electricity systems

Annex H2.C.

Fractal-based economic and environmental analysis of distribution network infrastructure development with Microgrids

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Contents

ACRONYM LIST

AM	Active Management
CHP	Combined Heat and Power
DCHP	Distributed Combined Heat and Power
DG	Distributed Generator
DNO	Distribution Network Operator
DSM	Demand Side Management
DSO	Distribution System Operator
FC	Fuel Cell
F&F	Fit-and-Forget approach (or passive management – PM – approach)
HV	High Voltage
ICE	Internal Combustion Engine
ICT	Information and Communication Technology
LV	Low Voltage
MG	Microgrids
MT	Microturbine
MV	Medium Voltage
OH	Overhead Lines
PM	Passive Management
PV	Photovoltaic
RES	Renewable Energy Sources
TSO	Transmission System Operator
UG	Under-Ground (cables)

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1. Introduction

This Annex summarizes the work performed by Imperial College to assess the technical, economic and environmental impact of DG and Microgrids on distribution network infrastructure development. The work is based on a fractal model (introduced in Deliverable DH1 [1]) able to generate generic distribution networks that mimic realistic consumer pattern aggregations [2], and is suitable to generate large-scale networks for system-level analysis.

The studies considered in this Annex refer to two basic sets of analysis, namely:

1. Greenfield system design: in this case the distribution network is designed "from scratches", and the value of DG is assessed by evaluating the relevant metrics (cost, losses, etc.) for the network as designed in the base case without DG and the network as designed in the cases with DG.
2. Assessment of DG impact through a reference network: in this case an economically adapted reference network is generated through the fractal model, and the value of DG is assessed by quantifying the relevant metrics (for fixed network) for different DG characteristics, penetration, etc.

The presence of controllability, in particular, is considered here by modulating the generation profiles of potentially controllable DG sources (namely, micro-CHP) to follow the electrical load as opposed to the base case when micro-CHP units follow the thermal load and are thus "intermittent" with reference to the electrical network.

To be more specific, the Annex is organized as follows:

- Chapter 2 discusses the analyses relevant to greenfield network design in the presence of DG and Microgrids. The studies are carried out with reference to multi-voltage distribution networks designed with the fractal tool developed by Imperial, and both urban and rural cases are addressed. The results indicate the potential value of DG for network infrastructure development, highlight the main driver for benefits, and give an order of magnitude of the additional benefits that controllability can add for system design.
- Chapter 3 contains a merge of network and environmental analyses carried out on a large scale low voltage (LV) reference networks in the presence of variable penetration of micro-CHP systems. The purpose of the studies is to gain insights into the interaction between heat and electricity and demand and generation, considering the increasing interest that the heat sector is being paid attention to. The results thus show network impact (in terms of capacity release, losses, voltage profiles, etc.) and environmental impact (primary energy saving and emission reduction) due to distributed cogeneration (DCHP) systems, and highlight the benefits and the downsides of controlling CHP to adapt their generation to the electrical load.
- Chapter 4 contains the concluding remarks on the fractal network-based studies conducted.

2. Fractal studies on the impact on Microgrids on network replacement scenarios

2.1 Multi-voltage fractal model for assessment of DG impact on distribution network development

2.1.1 Generalities on multi-voltage fractal model

As widely described in Deliverable DH1, Imperial has developed a specific methodology to assess the impact and the potential value of Microgrids on distribution network design strategies (*greenfield design*). The model is based on fractal algorithms that generate generic distribution networks mimicking realistic consumer settlements and network paths, thus enabling to get deeper insights on actual network topological characteristics with respect to other simplified geometric models. The network path generation starts at LV, with input characteristics that can be controlled by the user. An example of urban network is reported in Figure 2-1.

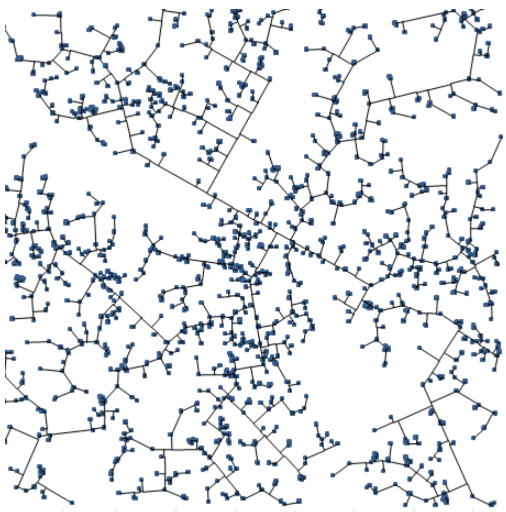


Figure 2-1. Low-voltage network paths for a typical urban area.

However, in order to evaluate system-level network replacement strategies, LV networks are not sufficient, and different voltage levels need to be modelled for distribution systems, namely, LV, MV (medium voltage, for instance the 11 kV network in the UK) and HV (high voltage, for instance the 33 kV network in the UK). Indeed, only by modelling the whole distribution cost chain is possible to fully capture the benefits associated to Microgrids, even if operating at the LV level only. Therefore, upper voltage levels are populated as well by inputting different sets of LV networks (which can have different load and substation densities). An exemplification of this is reported in Figure

2-2, recalling what shown in Deliverable DH1 for the sake of clarity. As an illustrative example, Figure 2-3 (a) shows an MV network generated by the model developed and Figure 2-3 (b) shows an actual MV network. It can be seen how the developed tool can actually resemble quite well real networks, as anticipated. The flow chart describing the main characteristics of the multi-voltage fractal model is shown in Figure 2-4.

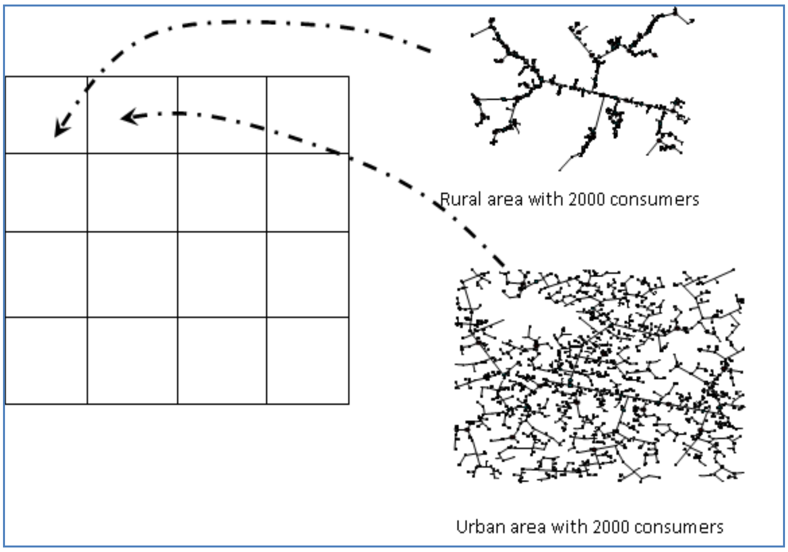
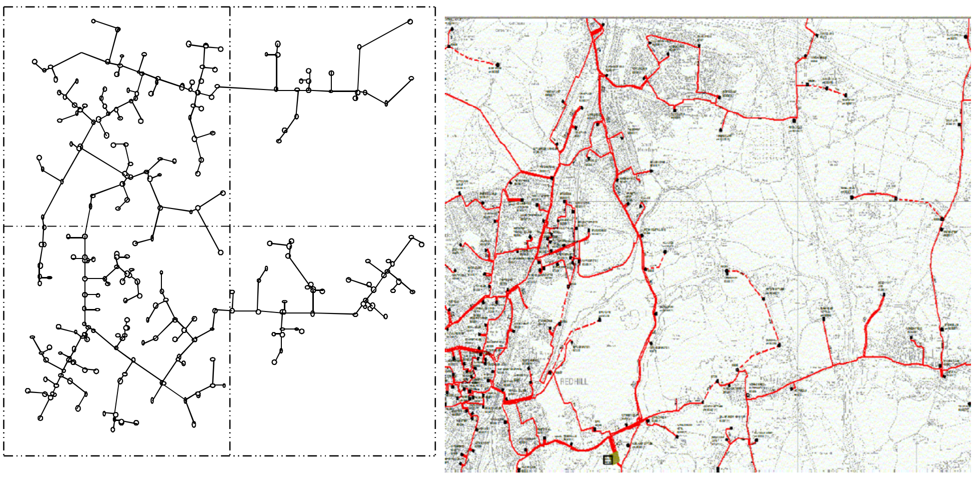


Figure 2-2. Grid-based fractal model of MV networks from LV inputs.



(a) (b)

Figure 2-3: MV network (a) model generated, (b) actual network [3]

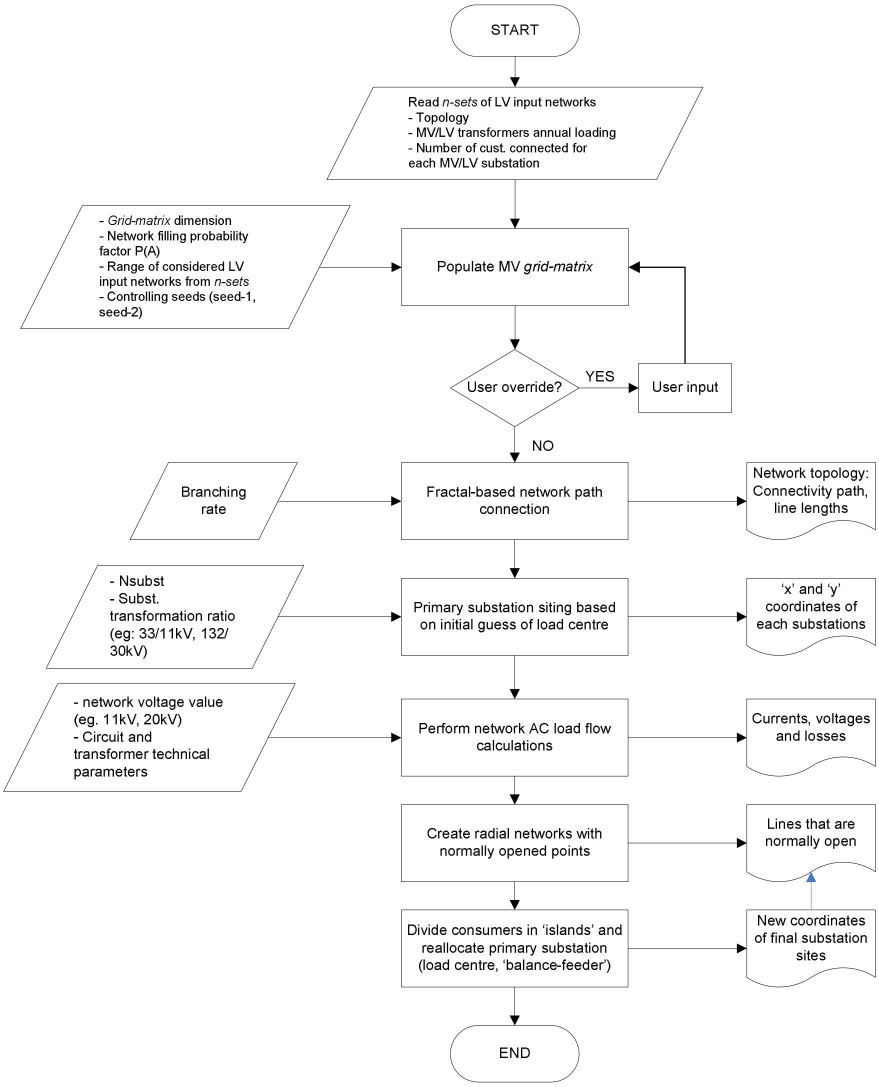


Figure 2-4. Flow chart for the multi-voltage level fractal model developed.

2.1.2 Minimum Life Cycle Cost (LCC) design criterion

Optimal economic design strategy (based on minimum Life Cycle Cost - LCC) [4] is carried out as a benchmark design to be adopted in the future, which is consistent with the information on replacement strategies received from the partners. This design approach trades off operational cost (mainly due to losses, with minor contribution from maintenance, above all in rural overhead lines) against cost of investment, so that key network performance indicators are the network costs (infrastructure and loss-related) with relevant breakdown. To be more specific, for a given voltage level the network LCC optimization problem can be stated as

$$\min(TC_N) = \min_{S_c^i}\left(\sum_{i=1}^{N_l}\left(CC_c^i + CM_c^i + CL_c^i\right)\right) \quad \textbf{(2-1)}$$

s.t. *network constraints,* $\overline{S}_c^i \in \mathbf{C}$.

In (2-1), TC_N is the annual total cost of all the circuits in the network (lines and transformers), that is, the levelised annual cash flows corresponding to the network LCC over the considered life span, whereas the optimization variables are the capacities S_c^i for each circuit; CC_c is the *annuatised cost of capital* [£/year]; CM_c is the *annual maintenance cost* [£/year], in general expressed through models developed *ad hoc*; CL_c is the *total annual cost of losses* [£/year], whose model is different whether for lines or transformers.

The sum is applied to the overall number of circuits N_l in the network, and for each circuit *i* the optimal capacity $\overline{S}_c^i$ [kVA] must be selected from the set **C** of available capacities for the considered circuit type.

Typical *network constraints* include thermal limits, feeder voltage drop constraints, and fault level requirements.

In practice, in terms of capacity optimization for lines, an optimal *continuous* circuit capacity can be calculated as a first guess through the model described in [4]; then, for the adjacent upper and lower capacity values from the available set the total cost is calculated on the basis of the known branch current and of the other input data, and the capacity yielding the overall minimum cost is selected as the optimal one. Once the hourly currents are known from network load flow analysis, transformers are heuristically selected from the available set in a similar way and independently of lines so as to minimize the LCC cost and with capacity greater than the annual peak.

For both lines and transformers, in case the circuit capacities can refer to more circuits in parallel.

2.1.3 Assessment of DG value for multi-voltage level network design

The value of DG in Microgrids is then assessed by comparing the relevant output metrics (mainly cost of investment and cost of losses) with and without microgeneration. For these purposes, the network design exercise has been carried out for a base case with no DG, and for a number of different penetration cases in which the presence of DG is taken into account when evaluating the upstream flows at MV.

In terms of circuit design, based on the LCC model illustrated above, it can be expected that the impact of DG will be such that potential reduced flows in the network branches (the *net* flows in the branches are the driver for LCC circuit design) might imply deployment of smaller circuits due to lower cost of losses. However, smaller circuits might also mean higher losses at the design stage with respect to the case without DG (where higher losses would lead to larger circuits). Therefore, it is interesting to assess the contribution of DG in terms of both flows and losses, and to analyse the final breakdown from the trade-off between optimal circuit investment cost and losses operational cost. On the other hand, it might also be the case that counter-flows occur due to DG production, with possible losses and then circuit size increase.

For upper voltage level the network has been designed taking into account the contribution from DG at LV level. In other words, the network at the upper voltage level "sees" reduced flows from the LV level as DG penetration increases. As a consequence, less network asset will be needed when there is considerable amount of DG connected at LV level. On the contrary, the presence of reduced flows owning to DG is not considered to size laterals and feeders at LV. In fact, while it is realistic to assume a certain degree of diversity provided by a large number of small-scale units aggregated at LV when it comes to sizing the upper voltage levels, sizing also the LV branches might be unrealistic. As a result, the value of DG at LV will be purely from the value of losses reduction contributed by DG. However, an estimate of the additional savings that could be obtained if also LV branches were sized based on DG-induced reduced flows was carried out in Deliverable DH1 [1] for exemplificative purposes in a typical urban case, yielding an upper value of about 1 £/kW/year for heat-driven micro-CHP penetration of 100%.

In any case, it is worth pointing out that for the sake of simplicity full availability is considered here for the DG units, in order to have an estimate of the potential effects of DG for different penetration levels and control strategies. This somehow leads to an upper boundary of the potential contribution of DG for network capacity support at upper voltage levels, while actual benefits in terms of capacity support might be slightly less. It has also to be noticed that only cost of equipment has been considered as investment, leaving out excavation costs, which might be substantial in urban cases. However, in terms of understanding the potential value of DG for network replacement or expansion, excavation costs would be roughly the same for all the scenarios considered, so that in comparative assessment would cancel out.

Large-scale typical urban areas and rural areas in the UK have been considered for exemplificative purposes of system level analyses. However, although the specific numerical results are of course case-specific, the general outputs and considerations stemming from the analysis are expected to be applicable to most networks and cases across Europe.

2.1.4 DG technologies and control strategies for network replacement analysis

As mentioned above, the objective of the study is to quantify the value of DG to support infrastructure replacement. Different technologies are considered, namely, CHP and PV, and are assumed to be only connected at LV level. More specifically:

- Heat following for uncontrolled CHP whereby CHP generator follows the thermal load and electricity is produced according to its co-generation ratio;
- Electricity following for 100% CHP whereby CHP generator follows the local electrical load and heat is produced according to its co-generation ratio;
- Uncontrolled PV whereby electricity is produced as a result of solar power.

For CHP systems, the *controllability* issue is addressed here by assuming that the CHP unit is running under electricity following strategy as opposed to the classical "uncontrolled" strategy in which heat demand is followed, corresponding to intermittent generation from a network outlook. Indeed, it can be expected that by controlling DG in order to follow the electrical load the negative network impact will be minimized and on the contrary network benefits will be maximized. In this way, "impact boundaries" can be drawn by assessing the impact for the two limit control strategies, providing indications on the additional potential value of controlling DG within Microgrids. Although these

boundaries do not envelope the maximum benefits that controllability can bring, which would be related to optimize specific objective function and each single case (see WPG for these specific types of analyses), the approach followed enables to get insights from a system-level strategic perspective on the value of different operability configurations and of increasing the correlation between local supply and demand, which has proven to be one of the main drivers for benefits.
In the analyses considered in the sequel, penetration level is defined as number of LV customers equipped with DG. Therefore, 100% penetration means all the customers have a DG unit installed at their premises. Typical electrical load patterns have been used to populate the networks with different types and number of realistic consumers. In addition, typical thermal load patterns have also been modelled to represent as close as possible the heat-following strategy of CHP systems. For the case studies considered below, the relevant network aggregated profiles (normalised with respect to the peak load) are reported in Figure 2-5 and Figure 2-6 for urban network and rural network, respectively.
In terms of technologies and sizes, relevant to the different user types, the systems considered are reported in Table 2-1.

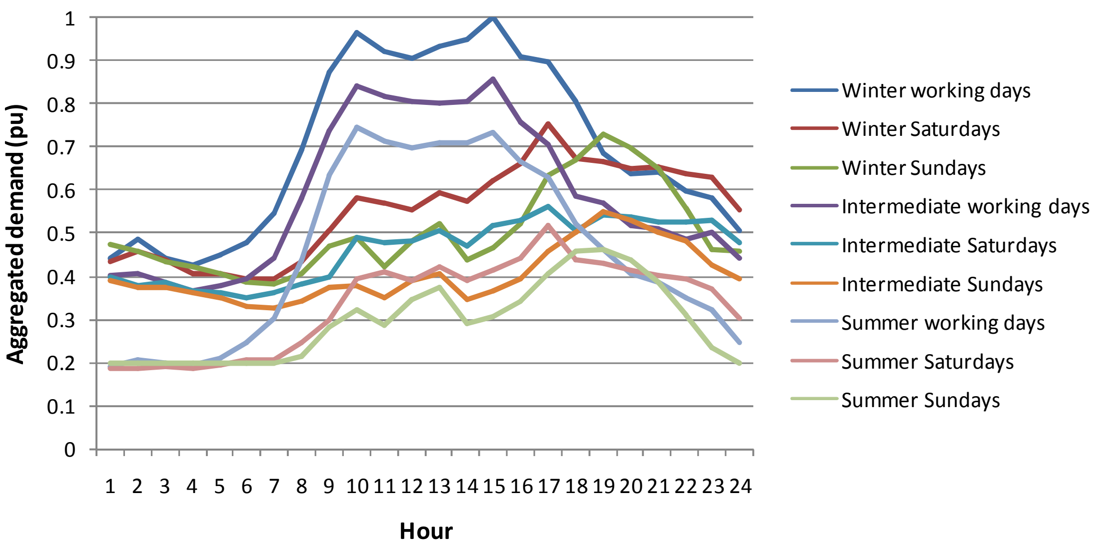


Figure 2-5: Aggregated network demand profile for LV urban system.

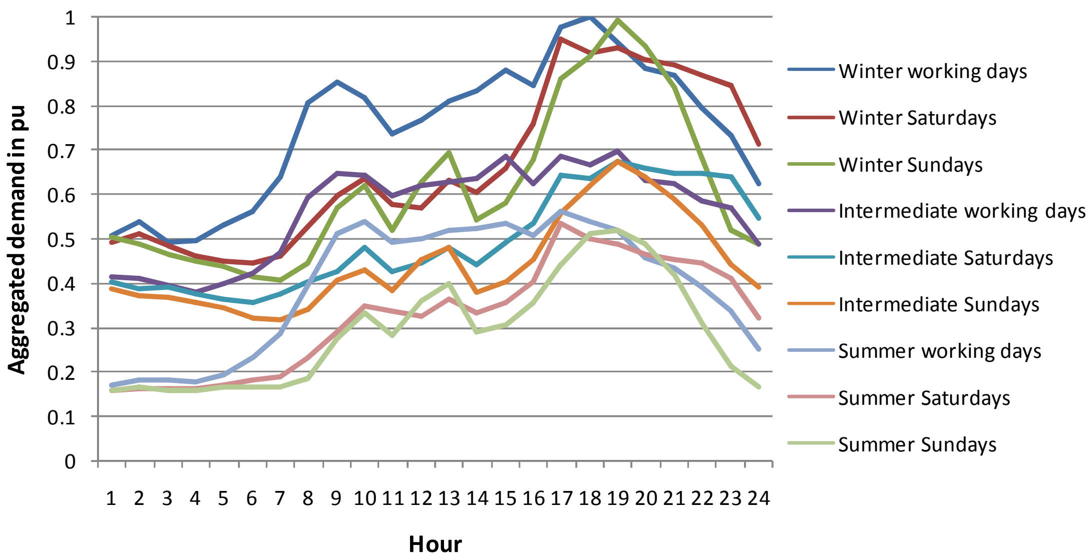


Figure 2-6: Aggregated network demand profile for LV rural system.

Table 2-1: Customer breakdown and their respective DG capacity

Customer types	*Distribution breakdown [%]*		*DG capacity [kW]*	
	Urban	Rural	CHP	PV
Residential without electric heating	80	90	1	1
Residential with electric heating	12	8	N/A	2
Commercial	5	1	10	10
Industrial	3	1	30	30

2.2 *Case study application: urban network design*

2.2.1 Urban network case study description

As anticipated in Deliverable DH1, a large UK urban network is considered here to illustrate a first example of network replacement strategies in the presence of DG. Typical UK urban load density has been used to populate the relevant network characteristics, as shown in Table 2-2. On the basis of the generic distribution system model developed, then, an 11-kV MV network of about 322 km has been generated to connect the downstream 11/0.4 kV substations as from the generated LV network. The characteristics of this large MV network with 150,000 customers are also synthesized in Table 2-2. The same approach has been applied to generate an upstream 33-kV connected to the 11-kV one, with a base case of three substations (that may also be optimally decreased with DG penetration) and an overall length of about 67 km.

Table 2-2. Urban network characteristics used in the case study.

Urban network characteristic	LV	MV
Peak demand [MVA]	5	370
Load density [MVA/km2]	5	3.7
Number of 11/0.4kV subst.	25	1,800
Number of 33/11kV subst.	-	12
Network area [km2]	1	100
Network length [km]	27	322
Number of LV consumers	2,000	150,000

2.2.2 Overall value of DG per kW of peak load

Figure 2-7 shows the overall value of DG (capitalized value of losses plus investment, given in £/year per kW of network peak demand and based on 30 years network life and 7% discount rate) for different penetration levels of PV connected at LV system, with breakdown of value per voltage level. Similarly, Figure 2-8 shows the value of DG in the case of CHP systems (in both uncontrolled and controlled cases). As mentioned above, the value of DG has been calculated as difference between base case (network designed without DG) and the DG case.

It can be easily observed that controlled CHP provides the highest value for avoided network cost with least network impact, since perfect match is achieved between local demand and supply, minimizing the flows required from the upper network as well as possible counter-flows due to load/generation un-correlation and then exporting energy. However, it has to be noticed that even when perfect local match (full controllability) occurs, it is not possible to decrease the network below certain thresholds (that also depend on the penetration levels). In fact, the circuits need to be able to stand the relevant short-circuit currents, which leads to install minimum circuit size. In addition, at MV and HV voltage levels the circuits are typically doubled due to security constraints and need for guaranteeing that enough capacity is available for network reconfiguration in the presence of downstream faults.

As for the uncontrolled CHP, the value of DG is still quite substantial owing to the good correlation between load and generation as shown in Figure 2-9. As expected, PV generation is highly uncorrelated to load profile, which can be seen from Figure 2-10 (peak production occurs in summer daytime, while consumption in the UK is prevailing in winter evenings), resulting in the lowest network value. For Southern countries, PV could instead provide suitable network support, as for instance exemplified in the Italian distribution network analyses reported in Annex H2.B.

The potential cost contribution of DG for infrastructure replacement is summarized in Table 2-3 with respect to the base case network cost with no DG. It can be appreciated that potentially up to one-third of network cost can be avoided for 100% controllable CHP scenario with 100% of DG penetration. However, also uncontrolled CHP can give a substantial contribution owing to relatively good electricity and heat demand correlation (Figure 2-9), which translates into good generation and demand correlation even for the heat following strategy. On the other hand, the extent of cost contribution from PV is more limited, and it is mostly due to cost reduction, which in turn drives towards smaller circuits according to the minimum LCC methodology adopted. However, this effect is relatively small.

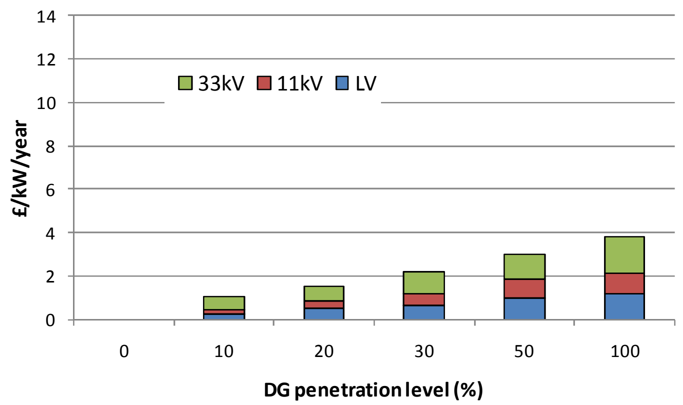


Figure 2-7: Value of DG for PV in UK urban networks.

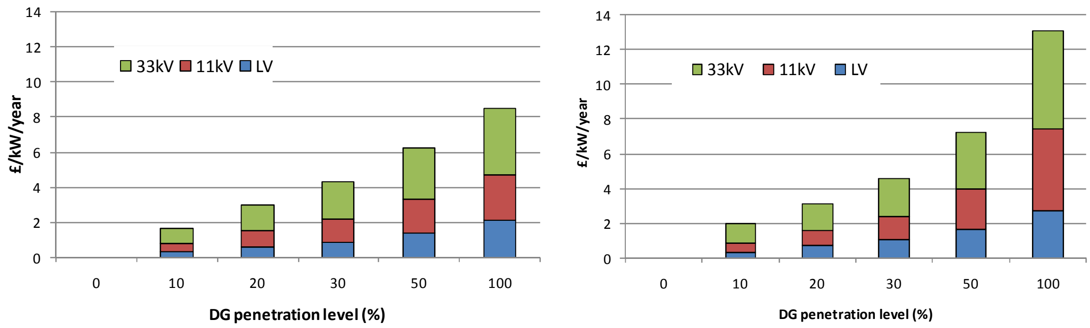


Figure 2-8: Value of DG for uncontrolled (left) and 100% controlled (right) CHP in UK urban networks.

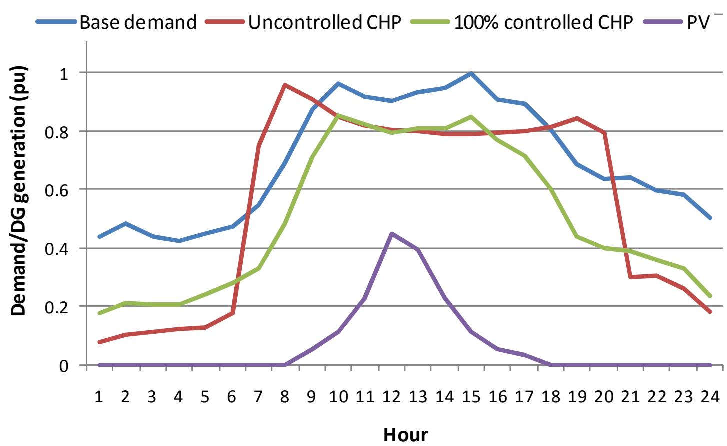


Figure 2-9: Aggregated urban winter working day customer demand versus DG generation profile.

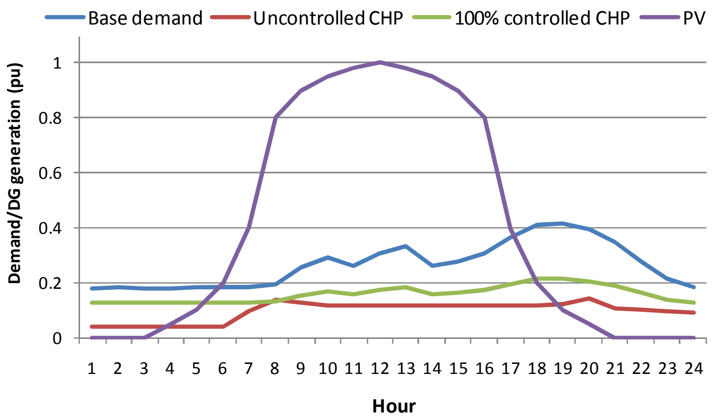


Figure 2-10: Aggregated urban summer Sunday customer demand versus DG generation profile.

Table 2-3. Overall value of DG (for LV, MV and HV) in percentage with respect to the base case (no DG) urban network cost.

	DG penetration levels (%)					
Scenarios	0	10	20	30	50	100
PV	0.0	2.8	4.2	6.1	8.4	10.6
Uncontrolled CHP	0.0	4.7	8.3	12.0	17.3	23.7
Controlled CHP	0.0	5.5	8.7	12.7	20.1	**36.3**

2.2.3 Overall value of DG per kW of DG installed capacity

While the previous analyses were based on the value of DG per kW of peak load, Figure 2-11 shows the capitalized value of DG per kW of DG installed capacity across the considered network life. The relevant figures could be for instance used to estimate possible contributions for DG owners. In this case, it is very interesting to observe that DG provides the highest value at the lowest penetration level (10%) and decreases with higher penetrations levels, with CHP of course being more valuable than PV, as expected from the above considerations. Also, the value of controllability for CHP varies non-linearly and non-monotonically across penetration levels, with higher values observable for lower and higher installed capacity range. This is a consequence of the complex dynamics occurring between local generation/demand and network flows. In fact, for very low penetration levels the DG contribution to decrease network flows and losses is immediately apparent, and the value of increasing this contribution by controlling the generation flows is quite high when weighed with respect to the installed capacity. For increasing penetration, the value tend to saturate, also considering that, besides network flows, other drivers such as short-circuit requirements influence the network design. As consequence, the marginal value per unit of installed capacity decreases, but the value of controllability slightly increases and becomes substantial (about 50 £/kW$_{DG}$) for 100% penetration of CHP, when more counter-flows might occur. However, it must also be taken into account that only discrete capacities are available when selecting the relevant pieces of equipment, and this may play a significant role above all when it comes to transformer selection at voltage levels higher than LV. In fact, in this case relatively few capacity sizes are available, so that some sort of jump in value might be observed if the incremental flows from additional DG are such as to trigger the installation of the lower adjacent size. On the other hand, this effect is not really remarkable at LV, where plenty of capacities are available and thus it is easier to approximate a continuous value function. If discrete equipment selection may generate non-linear trends, on the other hand it is important to account for that in order to provide more realistic results with respect to an ideal continuous selection.

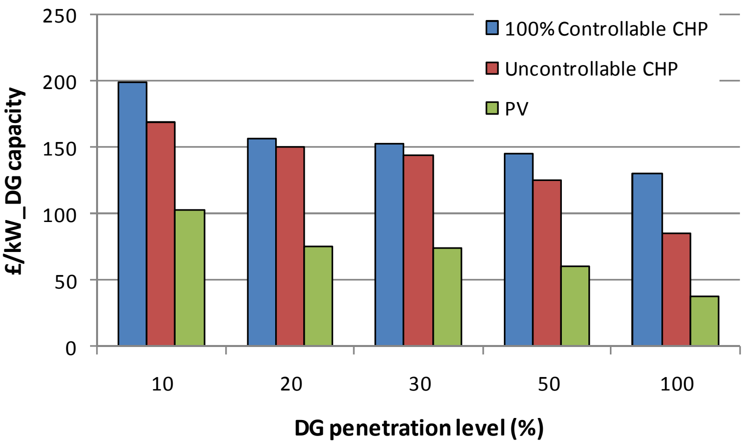


Figure 2-11. Total value of DG per installed DG capacity.

2.2.4 Breakdown of value chains per equipment and voltage levels

In terms of cost breakdown, starting from LV, since the network asset at LV was purely based on the flows induced by customer demand (without DG contribution), the cost of distribution substations and cables remain unchanged for different DG penetration levels. The cost of distribution substations (ground mounted) dominates the overall LV network cost, as it can be appreciated from Figure 2-12 and Figure 2-13, while the total cost of losses (from cables and transformers) decreases almost linearly with the increase in DG.
Starting from these considerations, and since besides losses reduction DG flows can also provide voltage support (although not explicitly illustrated within the analyses shown here), the minimum number of substations to guarantee adequate voltage standards could be tried to be reduced, in the attempt to decrease the overall network cost. Examples in this regard were shown in Deliverable DH1: the results indicate that the overall benefits

may be marginal and apparent only for relatively large penetration, since fewer substations also require larger feeders to supply the same amount of load, and the two effects tend to balance out each other. In addition, it has to be considered that, although not quantified here, higher number of substation generally means higher reliability level.

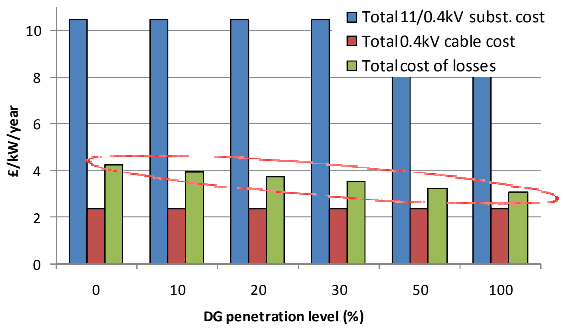


Figure 2-12. LV urban system cost breakdown for PV (excludes installation cost)

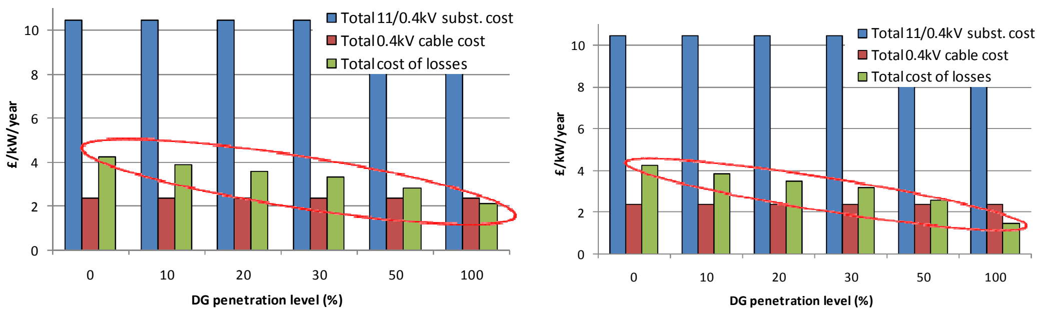


Figure 2-13. LV urban system cost breakdown for uncontrolled (left) and 100% controlled (right) CHP (excludes installation cost).

At upper voltage levels, the network assets were sized based on the net flows from the LV level (LV customer demand minus micro-DG generation). Figure 2-14 to Figure 2-17 thus show the MV and HV system network cost breakdown for PV and CHP, respectively. In this case, as expected DG contributes to network capacity and the cost for substations and MV and HV cable decrease substantially when DG penetration increases at LV. As PV generation in the UK has poor correlation with demand pattern, it only can start provide noticeable contribution at high PV penetrations, as shown in Figure 2-14 and Figure 2-16. From the analyses, it is also important to highlight that controllability in CHP is able to provide a relatively higher contribution in reducing the required network cost (substation, cable and losses) at higher penetration levels (>50%) as depicted in Figure 2-15 and Figure 2-17. As a last point, the results show that the component cost, above all for substations, is dominant for both MV and HV networks. Also at LV the equipment cost is predominant, but the weight of losses is relatively higher than at upper level, as expected.

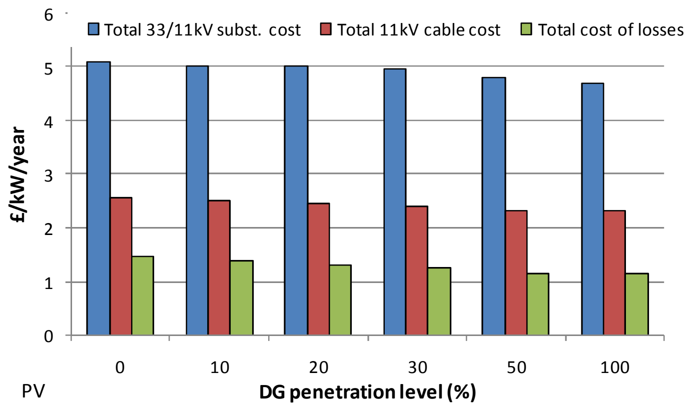


Figure 2-14: MV urban system cost breakdown for PV (excludes installation cost).

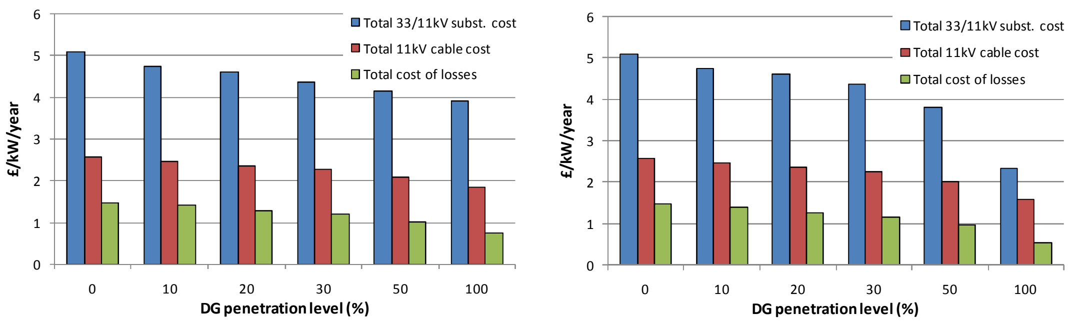


Figure 2-15: MV urban system cost breakdown for uncontrolled (left) and 100% controlled (right) CHP (excludes installation cost).

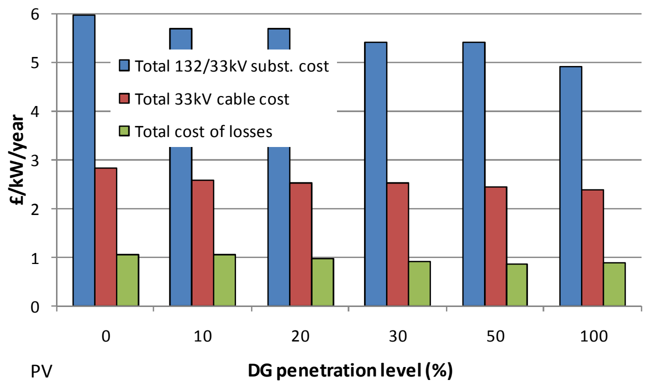


Figure 2-16: HV urban system cost breakdown for PV (excludes installation cost).

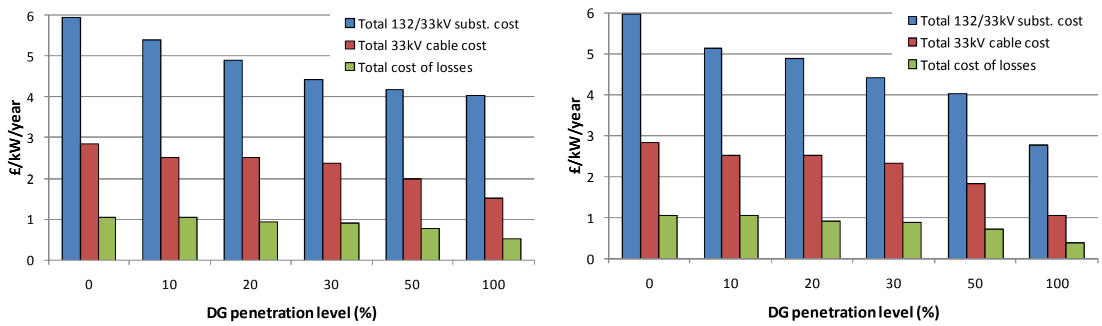


Figure 2-17: HV urban system cost breakdown for uncontrolled (left) and 100% controlled (right) CHP (excludes installation cost).

Figure 2-18 to Figure 2-20 shows the total network losses for the considered penetration scenarios and for different DG types, with breakdown per voltage level. It can be observed that the higher is the correlation between DG generation and demand profile, the greater is the network losses reduction. In particular, the losses decrease is substantial at LV, where the great majority of losses within the distribution system occur. Relative losses reduction with respect to the base case can be as high as 50% when uncontrolled CHP is used for the 100% penetration level, and in the same condition controllability can further decrease losses by an additional 15%. Hence, total distribution losses may pass from about 3.7% without DG to as little as 1.4% in the case of controlled CHP for all LV customers. On the other hand, it is very interesting to observe the effects of PV generation. For low penetration levels, the contribution to losses reduction is similar to the one from CHP. However, this reduction starts to saturate at higher PV penetrations (>50%), as apparent from Figure 2-18, whereby reverse power flows occur (PV production becomes substantial at times of low demand in the central hours of summer days, as also shown in Figure 2-10).

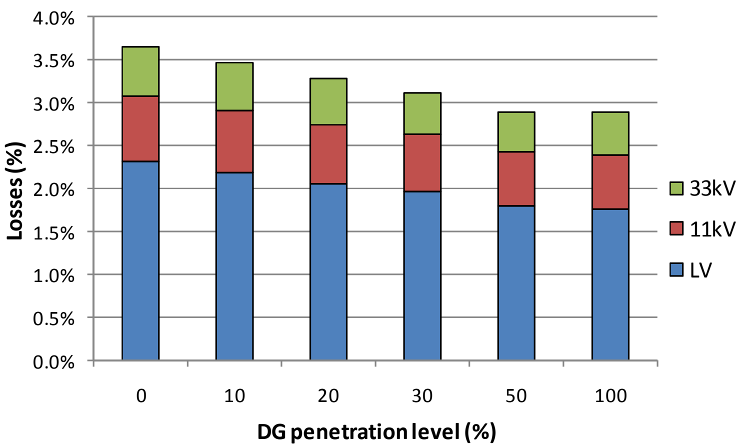


Figure 2-18: Total network losses for PV case.

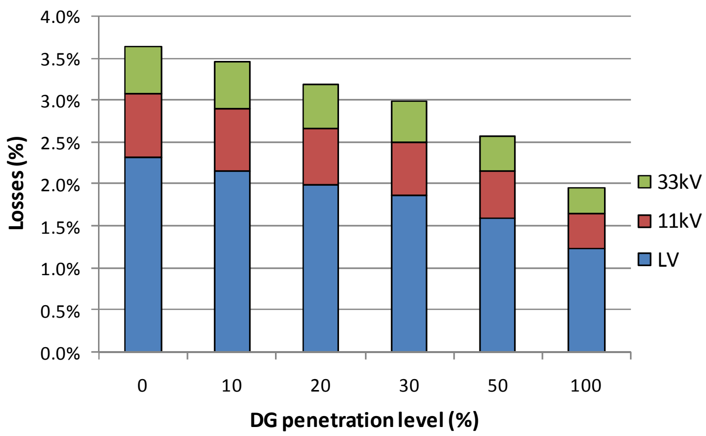


Figure 2-19: Total network losses for uncontrolled CHP.

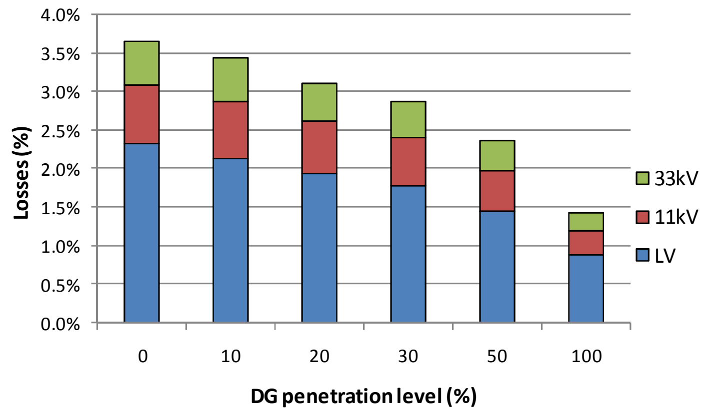


Figure 2-20: Total network losses for 100% controlled CHP.

2.3 Case study application: rural network design

2.3.1 Rural network case study description

In order to have a full picture of the potential of Microgrids for network design contribution, typical rural network analysis has been run in addition to the above urban case. A synthesis of the typical network characteristics used is reported in Table 2-4.

Table 2-4: Rural network characteristics

Rural network characteristic	LV	MV
Peak demand [MVA]	3	166
Load density [MVA/km2]	0.5	0.3
Number of 11/0.4kV subst.	35	1925
Number of 33/11kV subst.	-	18
Network area [km2]	6	576
Network length [km]	33	625
Number of LV consumers	2,000	110,000

2.3.2 Overall value of DG per kW of peak load

As shown in Figure 2-6, the network aggregated demand profile in rural areas is dominated by domestic customer patterns, whereby the peak tends to occur in the evening when people are back home even more than in the urban case. This justifies the resulting extremely low value of PV to contribute to network design as illustrated in Figure 2-21. This is mainly due to losses reduction, which is the main driver for network cost decrease in the PV case, as discussed above for urban areas, although in this case it is even less effective than for urban networks. On the other hand, the relative impact on cost reduction from CHP is quite similar to the urban case as shown in Figure 2-22 and Figure 2-23 respectively and as summarized in Table 2-5. In addition, the relative value of CHP controllability proves to be higher for urban areas, above all for higher penetration levels, due to a better overall correlation between local generation and demand in the rural case (although the rural absolute contribution is lower, due to lower DG capacity available as from the typical customer breakdown).

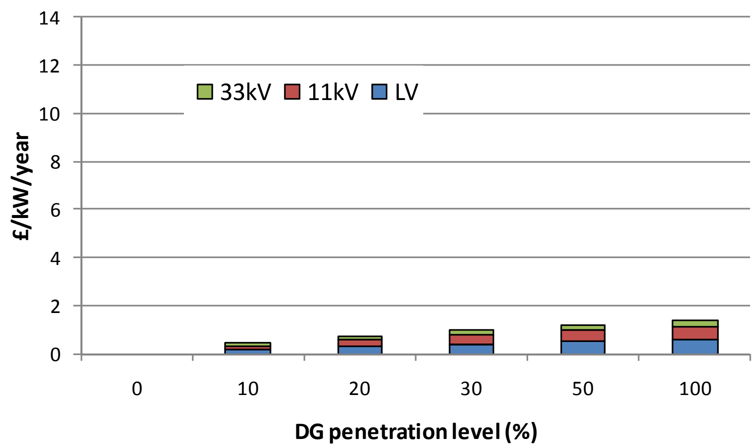


Figure 2-21: Value of DG for PV in rural system

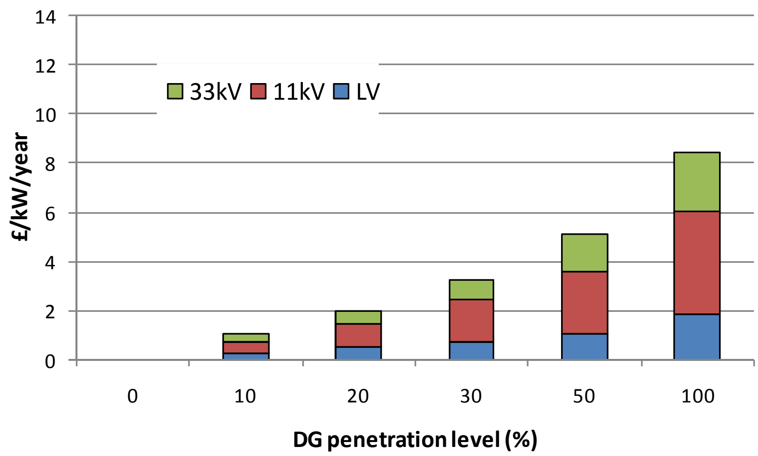


Figure 2-22: Value of DG for uncontrolled CHP in rural system

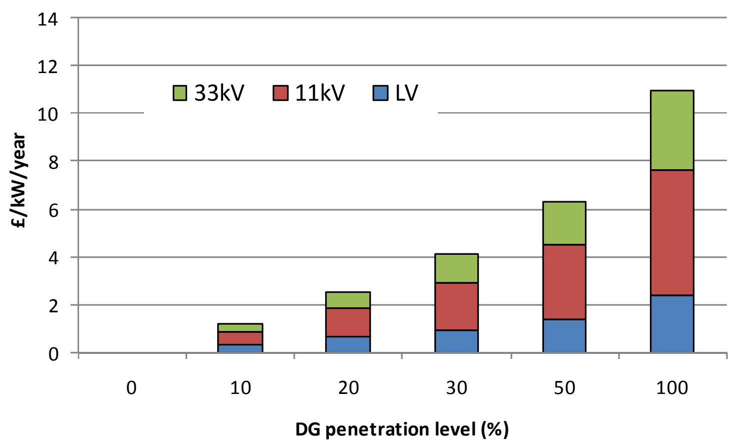


Figure 2-23: Value of DG for 100% controlled CHP in rural system

In the urban case winter working days, (as previously shown in Figure 2-9), the load profile exhibits relatively good correlation with the generation (both generation and load shapes are substantially influenced by industrial and commercial customers), which is effective in reducing the network peak. On the other hand, the aggregated demand profile used in the study for rural case is domestic customer-dominated, and the aggregated generation profile from uncontrolled CHP fails to contribute as effectively to reduce the network peak (at hour 18), as shown in Figure 2-24. This explains why in the presented analyses, the value of DG in rural case is less than in the urban case. However, it has also to be considered that the average network cost in rural areas is lower than in urban areas. Figure 2-25 finally shows the highly uncorrelated PV generation-load in the summer time, which could result in reverse power flows as well as voltage raise issues in weak rural networks.

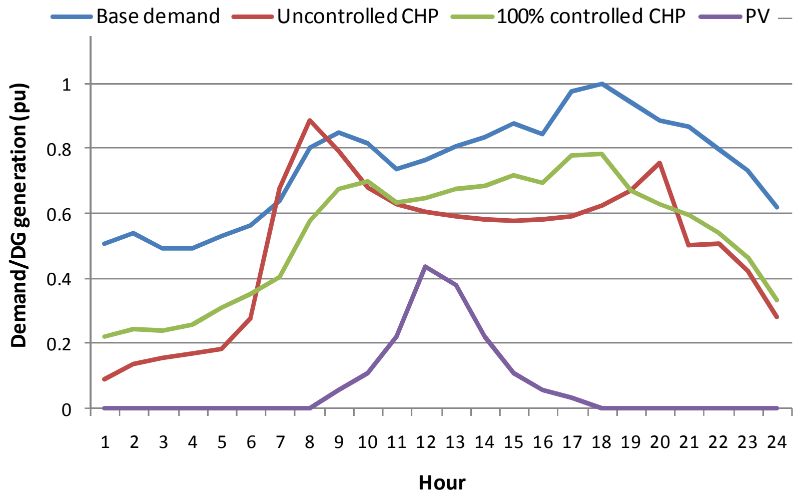


Figure 2-24: Aggregated rural winter working days customer demand versus DG generation profile.

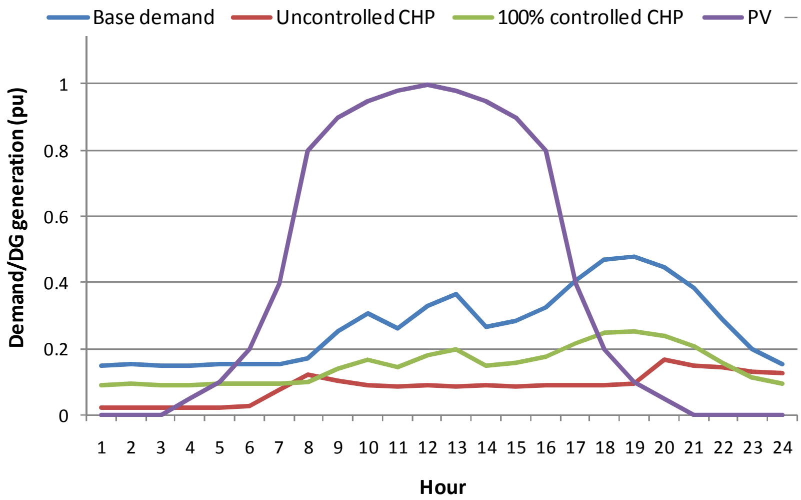


Figure 2-25: Aggregated rural summer Sundays customer demand versus DG generation profile.

Table 2-5: Percentage of value of DG with respect to total network cost (LV, MV, HV)

	DG penetration levels (%)					
Scenarios	0	10	20	30	50	100
PV	0.0	1.2	2.0	2.6	3.3	3.7
Uncontrolled CHP	0.0	3.0	5.4	8.9	14.0	23.2
100% Controlled CHP	0.0	3.3	7.0	11.3	17.4	30.1

2.3.3 Overall value of DG per kW of DG installed capacity

In terms of specific value per kW of installed DG, for CHP the trend is even more non-linear and non-monotonic than in the urban case as shown in Figure 2-26. In fact, now the maximum specific benefits are reached at the 30% penetration level for the controlled CHP case, mainly due to not significant improvement in cost contribution for higher penetration levels. On the other hand, as mentioned above, the trend of the network cost is also related to discrete availability of pieces of equipment, which may further increase the nonlinearity in the trends. The value of controllability does not change significantly with the penetration level (apart from very low penetration), and it is in the order of 30 £/kW_{DG}.

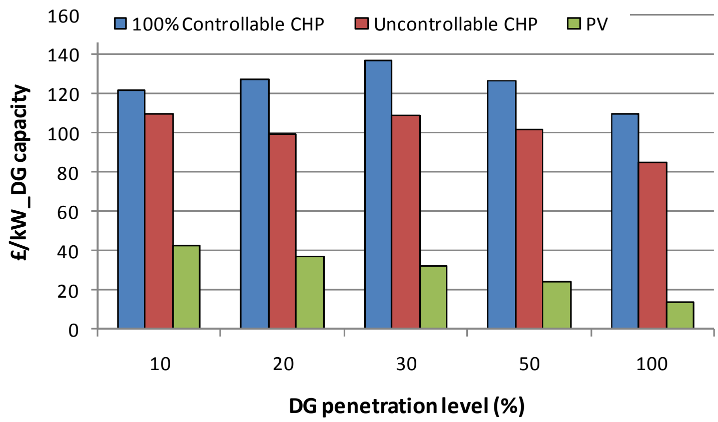


Figure 2-26: Total value of DG per installed capacity

2.3.4 Breakdown of value chains per equipment and voltage levels

In terms of cost breakdown per different voltage levels (Figure 2-27 to Figure 2-32), it is interesting to notice that the total network cost for rural systems is not so much dominated by the substation cost as in the urban system. In particular, it is interesting to see that for the MV network (Figure 2-29 and Figure 2-30) the cost of overhead lines is even higher than transformers, and transformer cost decreases faster than overhead lines for increasing penetration level of controlled CHP. In fact, at 11kV the network in the rural case needs to reach sparsely located customers (MV/LV distribution substations), with longer average feeders than in the urban case, and then higher cost. On the other hand, substation costs are generally smaller than in urban areas owing to the use of relatively cheaper pole-mounted transformers.

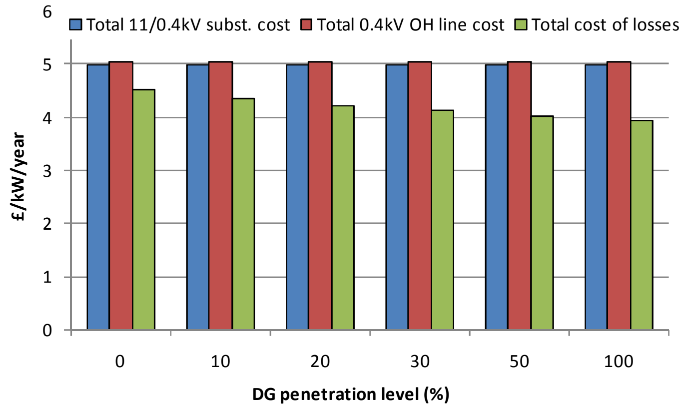


Figure 2-27: LV rural system cost breakdown for PV (excludes installation cost)

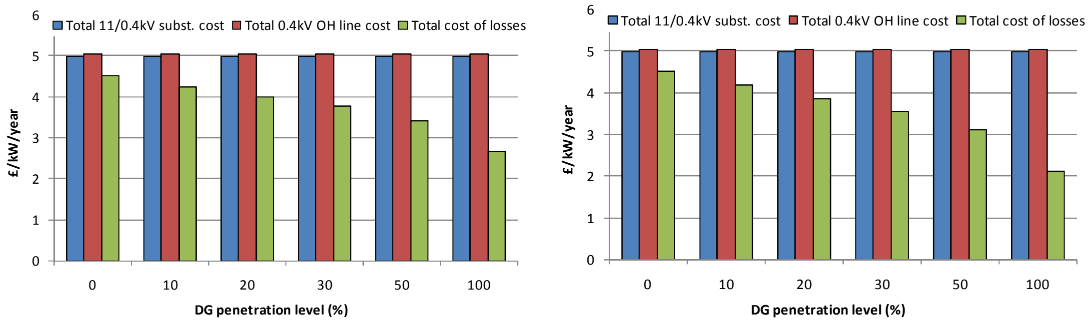


Figure 2-28. LV rural system cost breakdown for uncontrolled (left) and 100% controlled (right) CHP (excludes installation cost).

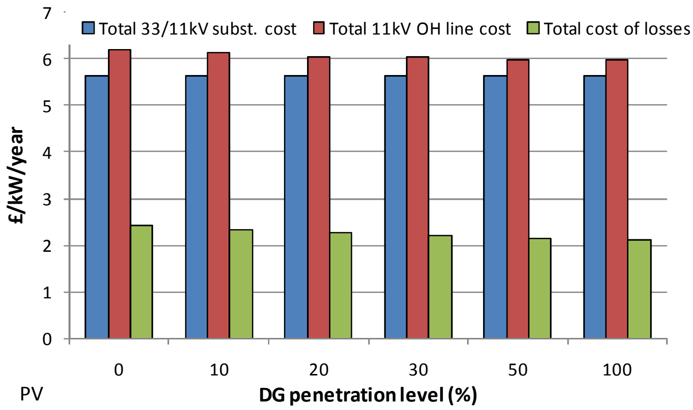


Figure 2-29: MV rural system cost breakdown for PV (excludes installation cost)

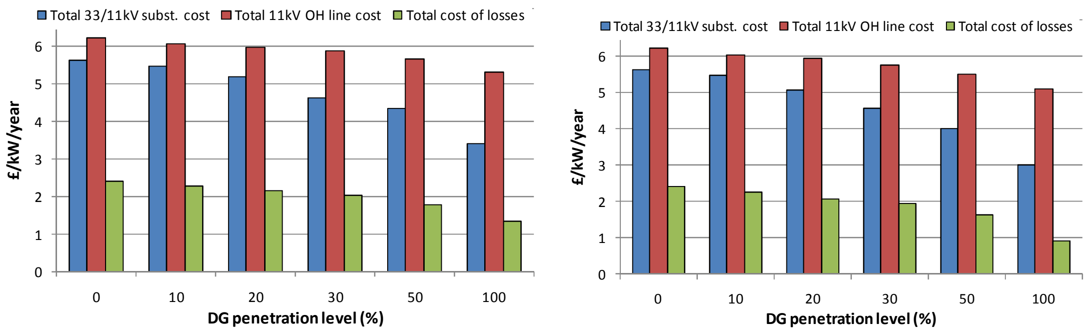


Figure 2-30: MV rural system cost breakdown for uncontrolled (left) and 100% controlled (right) CHP (excludes installation cost).

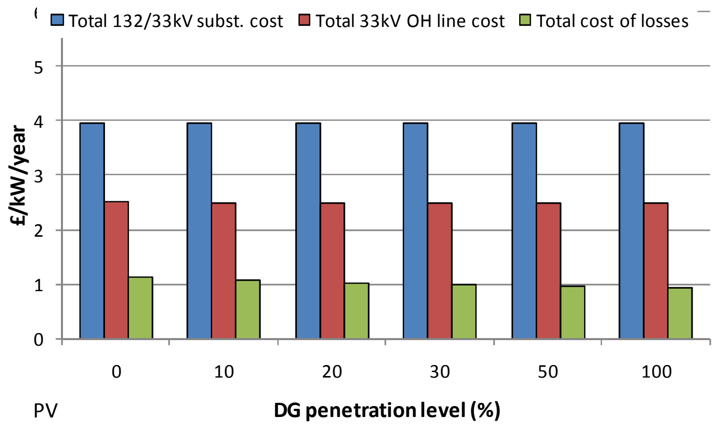


Figure 2-31: HV rural system cost breakdown for PV (excludes installation cost)

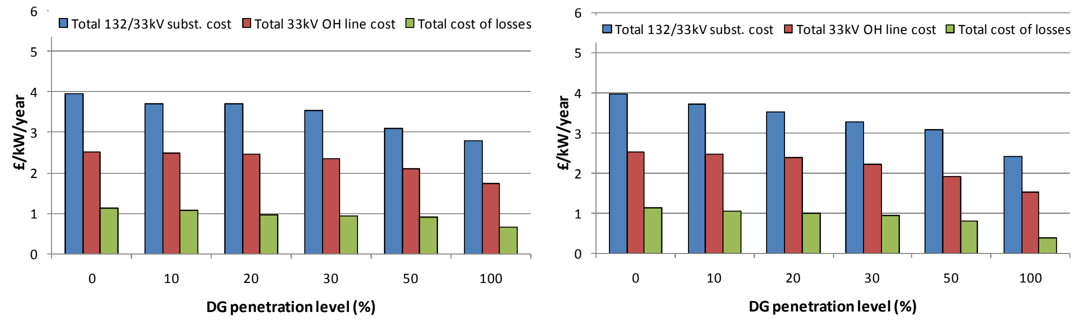


Figure 2-32: HV rural system cost breakdown for uncontrolled (left) and 100% controlled (right) CHP (excludes installation cost).

Directly connected to the topology difference between rural and urban areas, also losses differ from each other. In particular, the long feeders at 11kV lead to higher share of total network losses for this voltage level in rural areas than in urban one. The losses decrease is quite limited for PV, for the reasons discussed above, and it basically saturates after 50% penetration as shown in Figure 2-33. On the other hand, also in the rural case the contribution of CHP (both controlled and uncontrolled cases) is substantial as clearly shown in Figure 2-34 and Figure 2-35 respectively.

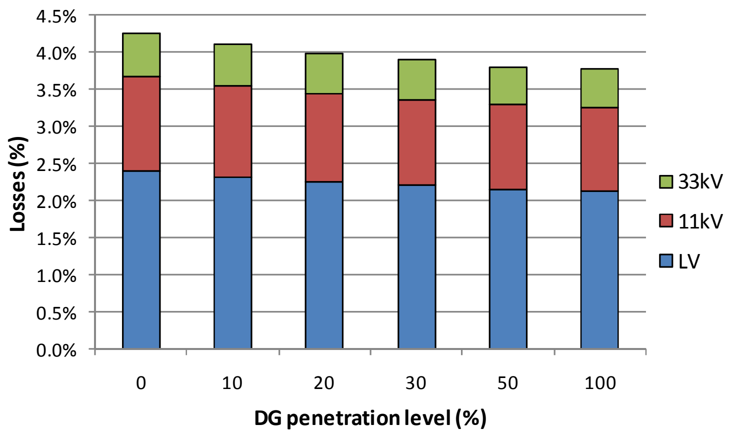


Figure 2-33: Total network losses for PV case

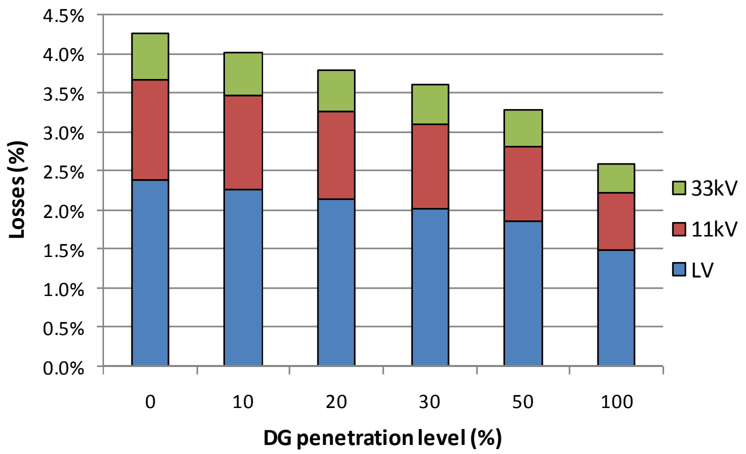


Figure 2-34: Total network losses for uncontrolled CHP

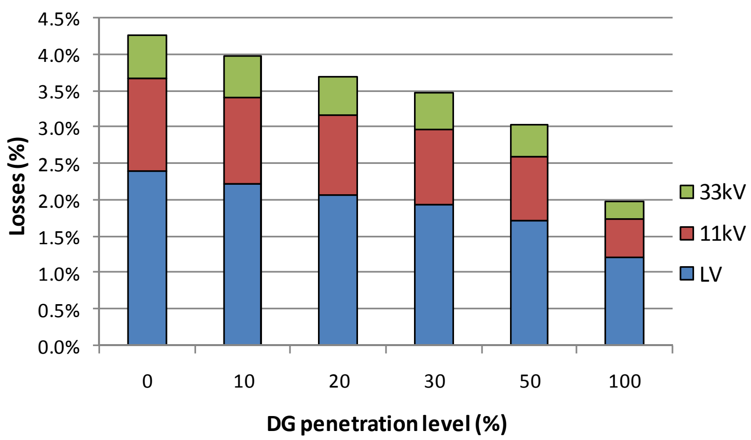


Figure 2-35: Total network cost for 100% controlled CHP

2.4 Concluding remarks on fractal network development studies

The presented studies show that correlation between load and generation is a key factor for network development contribution of DG and the relevant value of control micro-generation within Microgrids. In this light, uncontrolled CHP could potentially provide network support owing to good correlation, with a substantial value brought by DG in both urban and rural areas. Up to one-third of network cost can be avoided for 100% controllable CHP (corresponding to an annual network cost of about 11 £/kW), with the maximum value of controllability in the order of 50 £/kW_{DG} in urban areas for 100% penetration level and 30 £/kW_{DG} in rural areas for penetration higher than 30%. On the other hand, PV has poor correlation with the load in the UK systems analysed, and can only provide up to 10% of network avoided cost, mostly in terms of losses. The network infrastructure savings due to reduced power flows is substantial at MV, with prevailing influence on transformers in urban areas and overhead lines in rural areas. Equipment capacity saving is also significant at higher level, where the smaller number of pieces of equipment available may induce form of nonlinearities in the DG value for different penetration levels, though. This may make it more complex to come up with consistent policy support to the customers for the installation of micro-DG to internalise network benefits, above all in rural areas.

3. Fractal studies on the economic and environmental impact on micro-cogeneration systems in Microgrids

As widely discussed and exemplified in Deliverable DH1 [1], by recovering heat otherwise wasted, micro-cogeneration or Distributed Combined Heat and Power (DCHP) systems allow potential primary energy saving and emission reduction with respect to conventional energy systems where heat and electricity are produced separately in boilers and relatively large power plants, respectively [5]. Therefore, technologies such as the Stirling Engine (SE), the Microturbine (MT), and the Internal Combustion Engine (ICE), typically installed at the household or building level, are protagonist technologies for development of Microgrids. In this respect, as an important part of the work carried out in WPH, it is interesting to run a comprehensive analysis of network and environmental benefits for distributed CHP (DCHP) systems operated within Microgrids according to different control strategies, and of the relevant impact of controllability actions. This is fundamental to identify all the costs and benefits from DER not only in terms of electrical networks but for the overall energy system chain.

3.1 Modelling aspects

3.1.1 Network and DG modelling

Potential costs and benefits in terms of network impact from DCHP operated within Microgrids are calculated on the basis of a reference network whose topology and circuit sizing is generated through the fractal model and the LCC methodology described in the previous Section. Again, a typical UK urban network model is specifically used for the analysis, but the methodology could be applied to more general situations for system-wide assessments.
Within the network/environmental assessment framework introduced for DCHP systems, a further aspect considered here is the interaction between electrical and thermal demand and generation. In order to do so, suitable thermal load models are analysed here in addition to electrical loads, and the impact of following the thermal load as opposed to the electrical one is also assessed, also already done above. Hence, again insights on controlling DCHP generation within Microgrids can be obtained.
The energy performance of CHP prime movers are represented by their electrical efficiency and thermal efficiency. In addition, the *cogeneration ratio*, ratio of heat to electricity output as well as of thermal to electrical efficiency, is used to characterise the DG behaviour. Details on the modelling can be found in Deliverable DH1.
Different penetration levels are analysed, indicated with the index p, defined as the relative number of customers with a CHP unit out of the overall LV customers. Hence, for 100% penetration level all the consumers have their own DCHP system. The DG allocation is selected randomly, so as to reflect the situation that is likely to take place in the next years, with the DCHP users deciding about the installation. The ratio between DG installed capacity and peak load depends on the specific characteristics of the DCHP

systems, while the network load flows are also a function of the electrical and thermal consumer's load patterns and on the control strategy adopted.

3.1.2 Micro-cogeneration control strategies

For network analysis, the correlation between electrical local generation and loads plays a key role, as widely exemplified in the analyses run within the project. In addition, specific focus has been put in analyzing also electricity and heat interaction from the generation and the demand points of view. In this respect, as in the previous Section two control strategies for DCHP have been defined here, namely, *Heat Following (HF)* and *Electricity Following (EF)*. In terms of environmental benefits from cogeneration, recalling the considerations drawn in Deliverable DH1, heat following strategy is the "classic" strategy for micro-generation, which maximizes the environmental effectiveness of cogeneration with no heat waste, while positive or negative electricity local generation/load unbalances are made up for through grid connection. As mentioned above, from the electrical outlook heat following mode may be considered as *uncontrolled* or intermittent generation. On the other hand, if the CHP generator follows the local electrical load, heat is produced accordingly (regardless of the actual thermal load), as resulting from the characteristics cogeneration ratio. In this case, an auxiliary boiler is assumed to be put in operation to supply the thermal load if the thermal production is not sufficient (no storage is modelled here). On the other hand, if the heat cogenerated is higher than the actual local thermal demand, heat is wasted. Therefore, either because additional boiler production is needed, or because heat production is wasted, this strategy brings smaller environmental benefits relative to the thermal load following.

For each penetration level p of DCHP, *controllability* within microgrids is addressed by changing the number of units operated following the local electrical load rather than the thermal one (assumed to be the base case). This is indicated through the index c_p, indicating the ratio of electricity-driven CHP units with respect to overall ones (the remaining units are supposed to operate with classical thermal following). Network benefits could be maximized by formulating suitable objective functions and then resorting to optimal power flow analysis. However, this approach would be case-specific (see for instance the models developed in WPG). On the other hand, the methodology discussed here provide simple and clear trends on the impact of controlling a certain volume of electricity-oriented energy production potentially driven by a central agent in a Microgrid

3.1.3 Energy and environmental performance of cogeneration-based Microgrids

When assessing the overall energy system performance in a given network portion, cogenerated electricity and useful heat typically cover only a quota of the overall demand, while the remaining part is supplied through network connection and auxiliary boilers/burners locally installed. Therefore, for a given LV network portion the Primary Energy Saving (*PES*) due to cogeneration can be conventionally expressed as

$$PES = 1 - \frac{F}{F^{SP}} = 1 - \frac{F_y + F_Q + F_W}{\dfrac{W}{\eta^{ESP} \cdot \eta_{TD}} + \dfrac{Q_u}{\eta^{TSP}}} \quad (3\text{-}1)$$

The formula (3-1) is a generalization to network analysis of the classical *PES* cogeneration indicator referred to a single power plant and illustrated in Deliverable DH1.
In the expression, F is the total fuel burned to supply energy (heat and electricity) to the portion of network considered, and F^{SP} is the fuel thermal input to the equivalent models used as the SP references. The entry F^{SP} is typically and conventionally evaluated by means of equivalent efficiencies for separate production of electricity (with reference electrical efficiency η^{ESP}) and heat (with reference thermal efficiency η^{TSP}). In addition, in order to take into account the decentralized nature of DCHP, also avoided electrical transmission and distribution losses up to the LV level are indicatively taken into account through an equivalent network efficiency η_{TD}.
Further breakdown of the above energy balances lead to consider the following entries:

- The primary energy F_y delivered from burning fuel in DCHP.
- The primary energy F_Q delivered from auxiliary boilers.
- The equivalent primary energy F_W delivered when burning fuel to produce the electricity needed in the network on top of the local generation; this amount is addressed through the same equivalent model for electrical separate production as above, also including transmission and distribution losses.
- W is the overall electricity needed in the base case (no DCHP) by the network, which differs from the energy demand by a quota equal to the network losses (that change owing to the presence of DG).
- Q_u is the thermal energy demand. Q_u thus represents the *useful* heat produced by cogeneration and in case topped up by boilers. In particular, the useful cogenerated heat is net of a quota of heat cogenerated but potentially wasted away (in this sense, electricity is never "wasted" if network connection is available, while no heat networks or storage systems are envisaged in this work). This distinction is particularly relevant with the purpose of assessing different control strategies.

Following the same lines as for the definition of the *PES*, taking into account the environmental models discussed in Deliverable DH1, it is possible to extend to a network case the definition of the *CO2ER* (*CO_2 Emission Reduction*) indicator addressing a single CHP plant, as

$$CO2ER = \frac{m_{CO_2}^{SP} - m_{CO_2}}{m_{CO_2}^{SP}} = 1 - \frac{m_y + m_Q + m_W}{\mu_{CO_2}^{ESP} \cdot \dfrac{W}{\eta_{TD}} + \mu_{CO_2}^{TSP} \cdot Q_u} \quad (3\text{-}2)$$

The meaning of the symbols is analogous to the energy case, with emissions in the place of primary energy. In particular, the SP emissions are expressed by weighting the relevant useful energy outputs through $\mu_{CO_2}^{ESP}$ and $\mu_{CO_2}^{TSP}$, that is, the reference *emission*

factors from equivalent electricity production and heat production, respectively. Again, these references are conventionally evaluated.
In both *PES* and *CO2ER* expressions, all the relevant energy balance entries (electricity, heat and fuel) are calculated summing up the contributions of all the *N* LV networks downstream the MV/LV substations in the considered network portion considered.

3.2 Reference Network Design and DCHP Impact Metrics

Instead of analysing the impact of DG in a specific distribution network, a more general approach is followed here. More specifically, a large LV generic network is created and designed by using the fractal tool described above. This enables to address system-wide scenarios in generic conditions rather than one case specific one and enabling a more general picture to be drawn in terms of network impact.
In order to assess the network impact of DCHP for different scenarios, the performance and the characteristics of the reference network *without* DG is compared with the ones in the presence of DG. The “distance” between the two cases thus represents the “value” brought by DCHP for the considered scenario, and can be used to estimate possible compensation or tariff schemes to network or DG operators/owners. It is worth pointing out here that this kind of analysis is more relevant to network *assessment* rather than *design*, as in the previous Chapter of this Annex.
Different metrics are considered here to assess the impact of DCHP, namely:

- Losses and relevant costs, associated to losses occurring in conductors and substation transformers (load losses and no-load losses); the cost of losses is evaluated on the basis of the economic value attributed to losses from market prices.
- Substation loading level, years of investment deferral, and economic value of substation investment deferral owing to capacity release, whose appraisal methodology is illustrated below.

In addition to this, the minimum and maximum voltages within the overall LV network are recorded for the different scenarios.
In terms of estimates of network savings due to reduced flows of DG, if C_i is the cost of transformer *i*, the Net Present Value (NPV) of the network benefits brought by DCHP systems in a given scenario in terms of investment deferral for capacity release can be estimated as

$$NPV^{DCHP} = \sum_{i=1}^{N} C_i \left(\frac{1}{(1+d)^{T_i}} - \frac{1}{(1+d)^{T_i^{DCHP}}} \right) \quad (3\text{-}3)$$

where *d* is the discount rate used for economic evaluations, the sum is extended to all the *N* substations in the network, and T_i^{DCHP} is the number of years T_i before reaching the substation capacity owing to the presence of DCHP the network, estimated according to the model illustrated in [6]. The above expression highlights the economic value of capacity release from DG as related to time value of money. For the sake of simplicity, at first approximation availability of 100% is considered here for the DG units, in order to

have an estimate of the potential effects of DG for different penetration levels and control strategies.
In the case study run here, only capacity release benefits for MV/LV transformers are addressed, in order to focus on the effects of the electro-thermal interactions between supply and demand and of different controllability levels. However, the same model could be used also for upper voltage network capacity release economic estimate. Similar approaches could also be used to estimate the impact/benefits from DG in terms of voltage profile (especially in rural areas).

3.3 Numerical Applications

3.3.1 Case study description and base case

In order to exemplify the approach illustrated above for network and environmental assessment, a large UK urban network is considered here, generated adopting the fractal model developed by Imperial. The LV network (Figure 3-1) is characterised by the synthetic information shown in Table 3-1. Typical distributions of consumer types commonly found in UK networks have been considered. More specifically, electrical and thermal after-diversity hourly load pattern curves for two typical types of consumers in the UK, namely, residential flat buildings (share of 10%, thermal peak demand of 107 kWt and electric peak demand of 35 kWe) and residential terrace houses (share of 90%, thermal peak demand of 6.5 kWt and electric peak demand of 1 kWe), have been used. A constant power factor equal to 0.9 is assumed for all users. In order to speed up the calculation, for each user type nine characteristic days have been considered, namely, weekday, Saturdays and Sundays for winter, intermediate and summer seasons. As an example, the typical electrical load patterns and thermal load patterns for terraces are reported in Figure 3-2(a) and Figure 3-2(b), respectively. The substation capacities range from a minimum of 100 kVA to a maximum of 500 kVA.

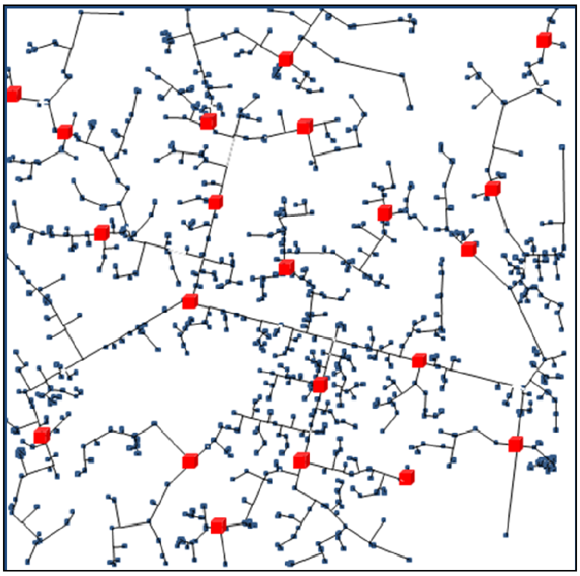
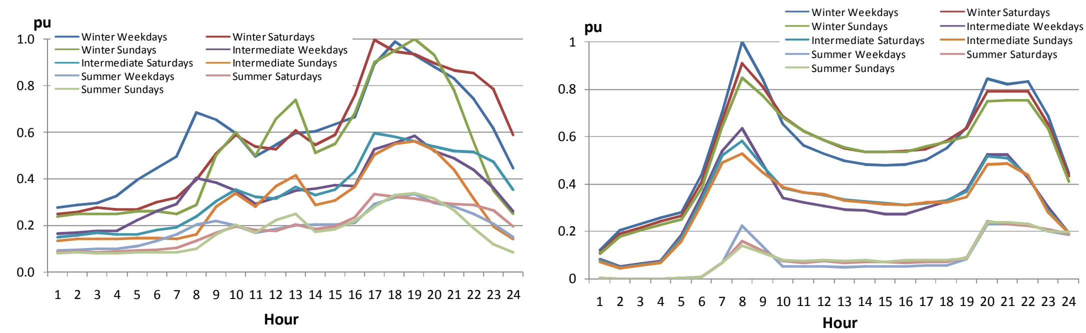


Figure 3-1. Urban network used in the case study examples (substations are indicated as "cubes").

Table 3-1. Synthetic characteristics of the LV network used in the case study example.

	Electricity	Heat
Number of consumer points	1000	1000
Peak demand [MW]	4.4	18.5
Total number of 11/0.4kV substations	21	---
Annual consumption [MWh/year]	13549	42867
Peak load density [MW/km^2]	4.4	18.5
Substation density [Nsub/km^2]	21	---
Network area [km^2]	1	---
Total network length [km]	19.3	---



a) Electrical b) Thermal

Figure 3-2. After-diversity electrical (a) and thermal (b) hourly load patterns used for terrace houses in the case study.

3.3.2 Generation scenarios and analyses

Starting from the network and demand characteristics illustrated above, two generation mixes have been considered, which lead to a number of scenarios obtained by changing the DG penetration and controllability indices. More specifically, with reference to the DCHP types and characteristics reported in Table 3-2, the following generation mix schemes have been studied:

1. Terrace houses equipped with SE, and flat buildings equipped with MT1;
2. Terrace houses equipped with ICE, and flat buildings equipped with MT2.

Table 3-2. Types and characteristics of the DCHP systems used in the case study.

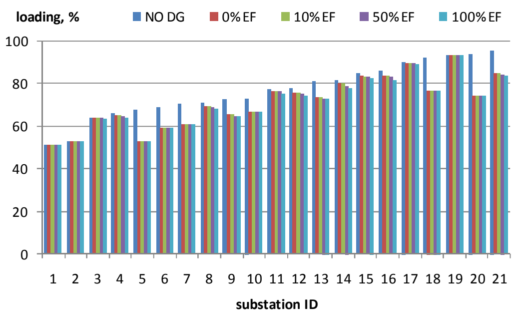
Type	**Capacity**		**Efficiency**			**Cogeneration ratio**
	Electrical	Thermal	Electrical	Thermal	Total	
SE	1	7.5	0.10	0.75	0.85	7.5
MT1	25	45	0.27	0.49	0.76	1.8
ICE	2	6.5	0.20	0.65	0.85	3.3
MT2	45	75	0.30	0.50	0.80	1.7

In all cases, it is assumed that auxiliary boilers are available for thermal back-up, with average thermal efficiency equal to 0.75 (for terrace houses) and 0.85 (for flat buildings).
For these two generation mix schemes, different values of penetration levels and controllability have been considered.
In the *generation mix 1*, the terrace houses equipped with DCHP can in principle cover both electricity and heat peak (if the two peaks occurred simultaneously); this is line with currently envisaged applications of micro-CHP systems mainly aimed at substituting residential boilers. On the other hand, regardless of the control strategy adopted, the flat buildings equipped with the MT1 in any case needs support from the grid to cover the electrical demand and from auxiliary boilers to cover the heat demand. Again, this sizing approach is in line with typical design strategies for relatively larger CHP systems aimed at covering a certain part of the electrical/thermal load to maximize the plant profitability.
In the *generation mix 2*, again the terrace houses with DCHP can potentially cover both electricity and heat peak, with a major difference relative to the previous case, namely, that electricity can be exported to the grid owing to the larger electrical capacity of the ICE unit. Similarly, the flat buildings equipped with the MT2 will be able to export electricity when following the heat demand. It is also important to highlight that the overall DG electric capacity installed in *generation mix 2* is such that all LV networks considered can in principle operate isolated from the MV network as energy autonomous Microgrids, while isolated operation for *generation mix 1* could occur only through resorting to load control actions.

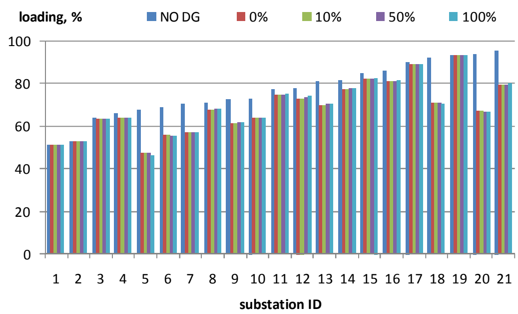
3.3.3 Investment deferral time and capacity release value for LV transformers

Figure 3-3 to Figure 3-5 show the maximum loading level for the 21 substations considered in the case study, for different penetration levels of DCHP and for different

levels of electricity controllability. For each picture, case a) refers to generation mix 1 and case b) refers to generation mix 2. In the figures, the substations are ordered according to their increasing substation loading in the base case without DG.
The maximum loading level gives a clear indication of the asset utilization, and thus of the headroom before need for upgrade. In this respect, it can be seen how for a penetration level *p*=10% (meaning that 10% of customers are equipped with CHP) (Figure 3-3) for the smaller substations (with fewer connected customers) no benefits in terms of loading decrease are obtained, due to the random allocation of DCHP. At the same time, the effects of shifting from thermal to electrical load following are not remarkable, although it can be noticed that in all cases the substation loading level slightly decreases while the share of units in electricity following mode increases. This is due to the rise in correlation between local electrical demand and generation, whose aggregated effects can be noticed at the substation level, and is particular evident for generation mix 2, owing to the larger overall installed electrical capacity.
While the DG penetration increases to 50% (Figure 3-4), the loading decrease effect becomes substantial for all substations in the case a), with also an increasing effect of control strategy shift owing to the higher number of units in operation. On the other hand, the same effect can generally be appreciated also for case b), with more remarkable role played by electricity following strategy. However, more interesting dynamics can be observed. For instance, it is interesting to point out how for substation #1 the loading level of case b) is higher than for case a) for a controllability index equal to 0% and 10%, due to counter-flows brought about by uncorrelated generation that also change the peak time. On the other hand, for instance with regard to substation #2, increasing the number of units following the local electrical load increases the substation loading level. This is due to the fact that although uncorrelated with the local load, heat-based distributed generation would inject exceeding electricity into the network. This would thus provide load support to the consumer points not equipped with DCHP and result into an overall decreased peak loading at the substation level. The peak loading profiles for the other substations can be justified accordingly.
When all the consumers are equipped with DCHP units (Figure 3-5), the effects described for 50% of DG penetration are even more exacerbated. In fact, moving from c_p=0 to c_p=100% (that is, from a situation in which all CHP units follow the thermal load to a situation in which all CHP units follow the electrical load) leads to a loading level that can potentially decrease by more than half in case a), whereas again the dynamics for case b) is more complex, in line with the discussion relevant to Figure 3-4.

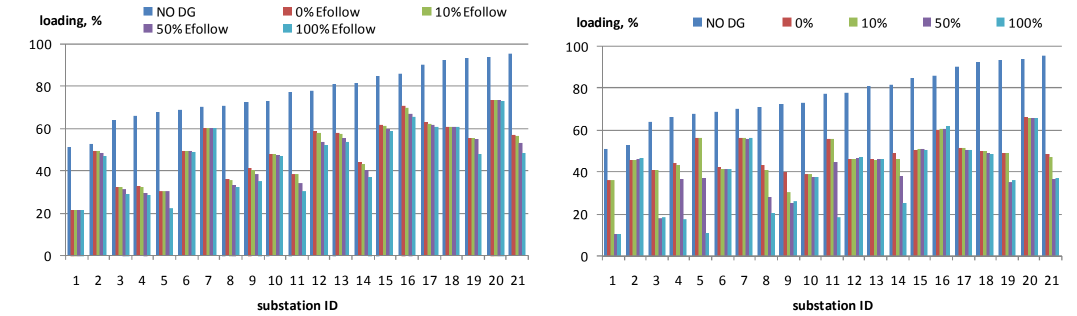


a) Generation mix 1



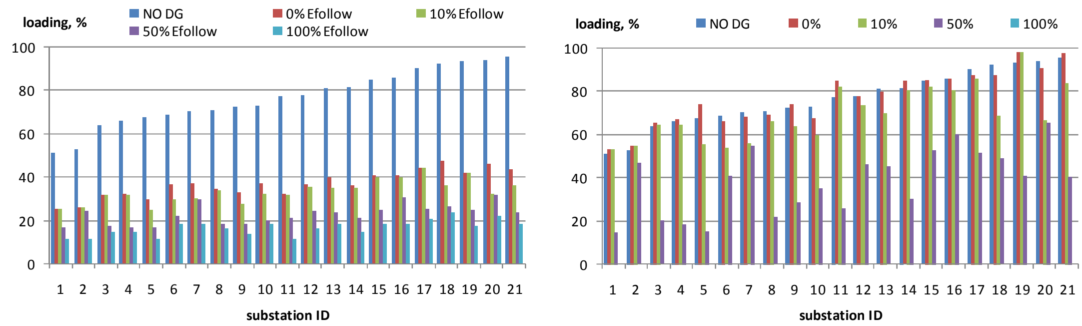
b) Generation mix 2

Figure 3-3. Substation loading, 10% penetration level.



a) Generation mix 1 b) Generation mix 2

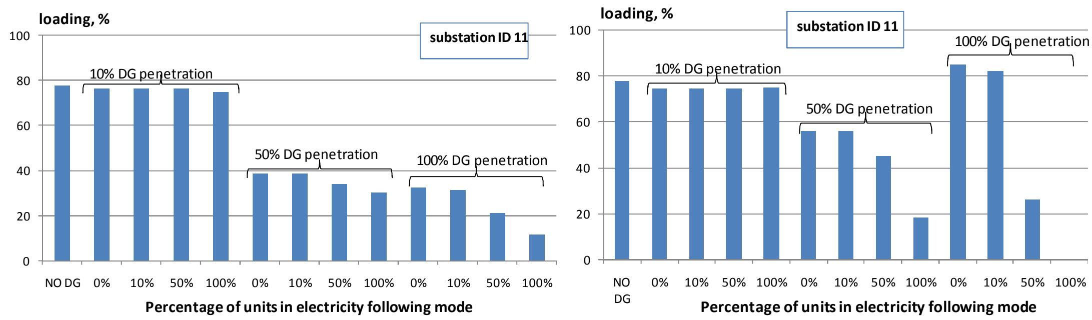
Figure 3-4. Substation loading, 50% penetration level.



a) Generation mix 1 b) Generation mix 2

Figure 3-5. Substation loading, 100% penetration level.

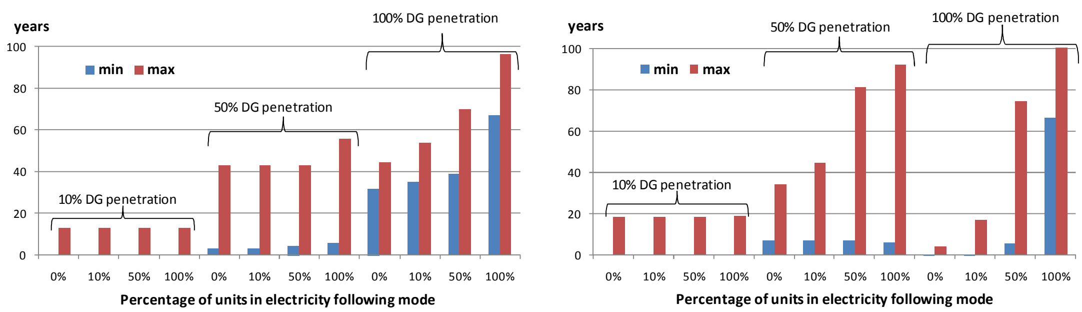
The points discussed above can be further highlighted through Figure 3-6, synthesizing the nonlinearities that may characterize the peak loading analysis for a representative case of 100 kVA transformer. In particular, it can be seen how for generation mix 1 while moving from p = 10% to p = 50% the loading level halves, with negligible impact of controllability for 10% penetration and relatively small for 50% penetration. On the other hand, increasing the penetration level to p = 100% does not change substantially the substation peak loading level, due to some sort of saturation in the correlation between generation and loads. However, the loading level further decreases when the share of generation units in electricity following mode increases. Contrarily, the higher installed electrical capacity in generation mix 2 is such that counter-flows occur for high penetration levels, leading to even higher loading level than in the base case (without DG) for p=0 and all CHP units in heat following mode. In this case, the effects of controllability to mitigate counter-flows are apparent, with the LV network that can operate isolated as an autonomous Microgrid for c_p=100% (transformer loading level equal to zero in Figure 3-6 (b)).



a) Generation mix 1 b) Generation mix 2

Figure 3-6. Zoom-out of substation maximum loading profile for a 100 kWe unit.

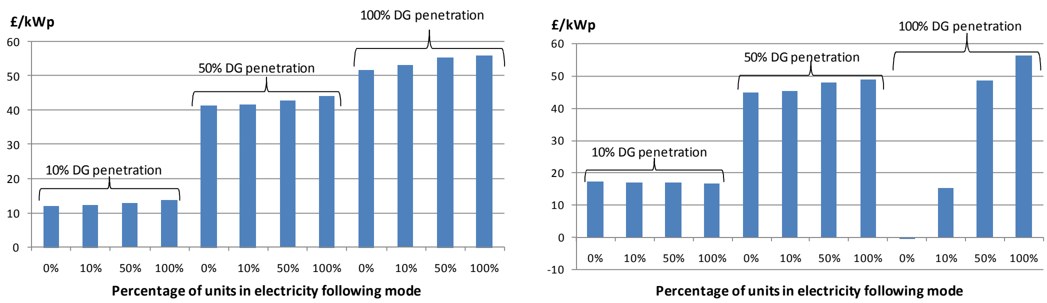
The analysis regarding the substation maximum loading level directly translates into ability of DG to defer investment, as opposed to potential negative effects of anticipating investment. This is synthesized in Figure 3-7, showing the range of years of investment deferral (maximum and minimum of the 21 substations) by assuming 2% of load growth. It can be noticed how for small penetration some substations do not benefit at all of DG (minimum substation deferral equal to zero) for both generation mixes, owing to the random allocation and to the generation/load correlation. While the penetration increases to 50% and 100%, for generation mix 1 the years of investment deferral increase as well. However, for heat following systems there is no change in the maximum deferral time, while the minimum one increases substantially, owing to the widespread effect of larger DG penetration. On the other hand, when *p*=100% electrical controllability can have a major impact, with a maximum deferral time increasing steeply. For generation mix 2, when the penetration level of DG increases to 50%, the maximum deferral time increases with respect to the 10% penetration case, and it also increases with the effect of controllability. On the other hand, the minimum deferral time decreases with controllability, owing to the local compensation effect described above. Due to uncorrelated generation, finally, for a penetration level of 100% both minimum and maximum investment deferral times are lower than for the 50% case for lower values of the controllability index, and increase when increasing the latter.



a) Generation mix 1 b) Generation mix 2

Figure 3-7. Boundary profiles of years of investment deferral due to DG.

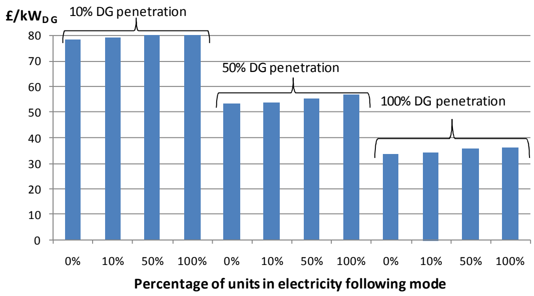
A further view on the effects of penetration and controllability levels is provided in Figure 3-8, showing the potential economic value (normalized to the network peak load) of network capacity release for the overall network, calculated as from (3-3) with $d = 7\%$ and for typical prices for UK transformers. Figure 3-8 yields somehow an average picture on the DG effects, rather than for the limit cases (maximum/minimum) of Figure 3-7. For generation mix 1, Figure 3-8 confirms that there is some sort of saturation effect in terms of network deferral value while increasing *p*, mainly due to the generation/load correlation. In all cases, controllability can increase the economic value of the network asset. Again, it is even more interesting to analyse what happens for generation mix 2. In fact, in this case for low penetration (p = 10%) the value is about 50% higher than for generation mix 1, owing to local generation/load balance. On the other hand, there are only marginal benefits from generation mix 2 relative to generation mix 1 for p = 50%, due to the increasing uncorrelated energy between generation and load. The situation is exacerbated for large DG penetration (p = 100%) of generation mix 2, for which no economic value arise at all due to uncorrelated flows as exemplified in Figure 3-8, unless DG is operated under electricity following mode. However, even in this latter case the value is less than from generation mix 1, apart from marginal benefits in the extreme case with p = 100% and c_p = 100% (isolated energy autonomous Microgrid operation).



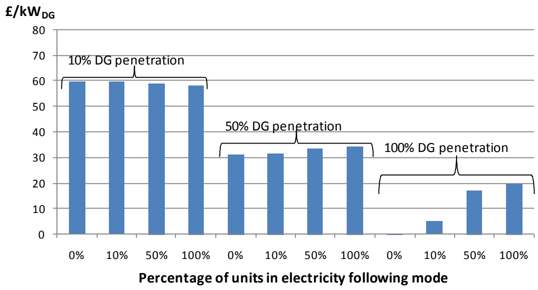
a) Generation mix 1 b) Generation mix 2

Figure 3-8. Network overall *NPV* (normalised with respect to the network peak demand) of transformer capacity release.

In terms of network value brought by DCHP normalised with respect to DG installed capacity (potentially useful to formulate rewards for the prosumers), it can be appreciated how the specific value of DG decreases with the penetration level, that is, the marginal value of DG is a negative slope function with respect to the penetration level as shown in Figure 3-9. In fact, the benefits brought by local balancing are maximised when the DG production is relatively low (all produced electricity displaces peak flows), and decreases with an increase of (in part uncorrelated) production. For the same reason, the value for generation mix 1 is higher than for generation mix 2 by about 20 £/kW_{DG} regardless of the control strategy for penetration level of 10% and 50%. The value is even higher for p = 100% when part of the units in generation mix 2 are run following the heat, for the reasons explained above.



a) Generation mix 1

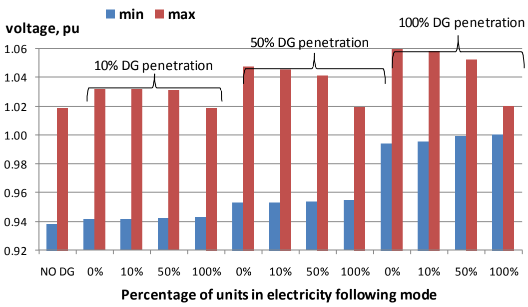


b) Generation mix 2

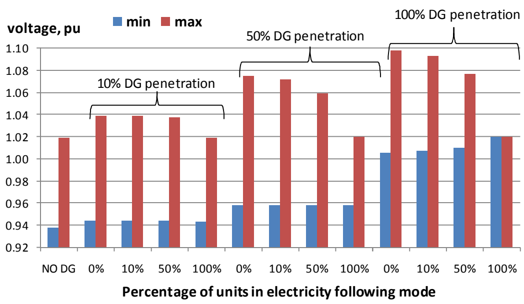
Figure 3-9. Network overall *NPV* (normalised with respect to the DG installed electrical capacity) of transformer capacity release.

3.3.4 Operational performance: losses and voltage profiles

As for the substation loading analysis, Figure 3-10 shows how the maximum and minimum voltages occurring in the overall network change with *p* and c_p. Although voltage control is not modelled here, and more effective three-phase load flow models would be needed for a detailed analysis, the results here are useful for comparison purposes to estimate how different DCHP scenarios would impact overall on the voltage network profiles. In this respect, it can be noticed how for both generation mixes the minimum voltages increase with penetration and controllability. On the other hand, the maximum voltages increase with *p* (although not dramatically), but running in electricity following mode can reduce the voltage rise impact substantially. When comparing the two mixes, the basic trends are essentially the same in the two cases, with the impact of controllability being higher for *generation mix 2*, in line with the above considerations.



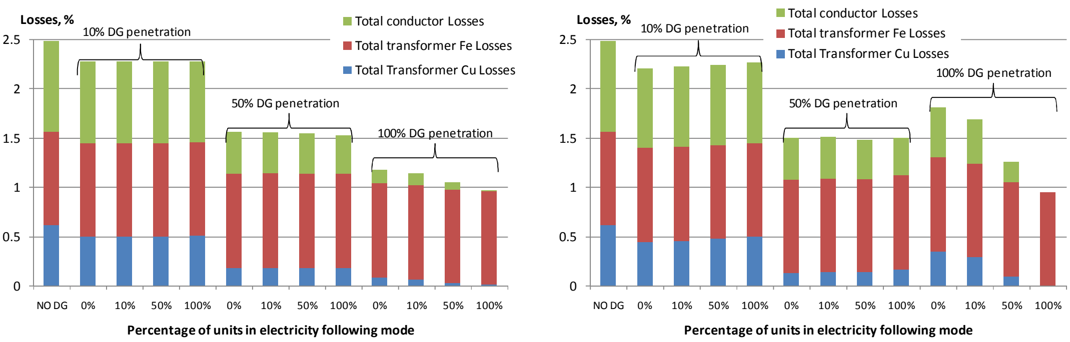
a) Generation mix 1



b) Generation mix 2

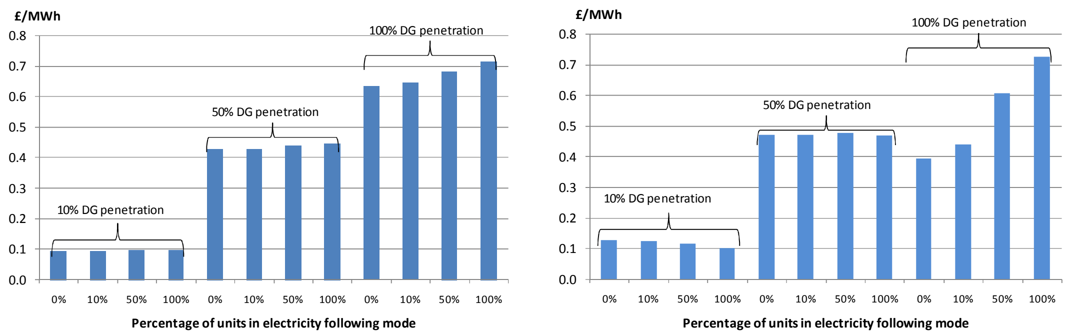
Figure 3-10. Voltage boundary profiles in the overall network.

Another key aspect for network operational assessment is represented by losses, whose percentage value with respect to the overall demand is reported in Figure 3-11, with breakdown of where losses occur. The relevant economic value (based on an average cost of losses of 48 £/MWh) is reported in Figure 3-12. As it can be appreciated, for generation mix 1, flow-dependent (in conductors and transformers) losses and cost of losses decrease substantially for increasing p and c_p, due to the lower network flows. As a limit case, for p=c_p=100% flow-related losses become negligible, and only transformer no-load losses remain. On the other hand, for generation mix 2 whereas the losses profile is roughly the same as for generation mix 1 for p = 10% and p = 50%, when all the consumers are equipped with DG losses increase with respect to p = 50%, due to the decrease in correlation between local generation and load and consequent counter-flows. Indeed, increase in the number of electricity-following DCHP units reduces the copper losses up to virtually zero in the case of isolated operation for c_p = 100%.



a) Generation mix 1 b) Generation mix 2

Figure 3-11. Breakdown of network losses.



a) Generation mix 1 b) Generation mix 2

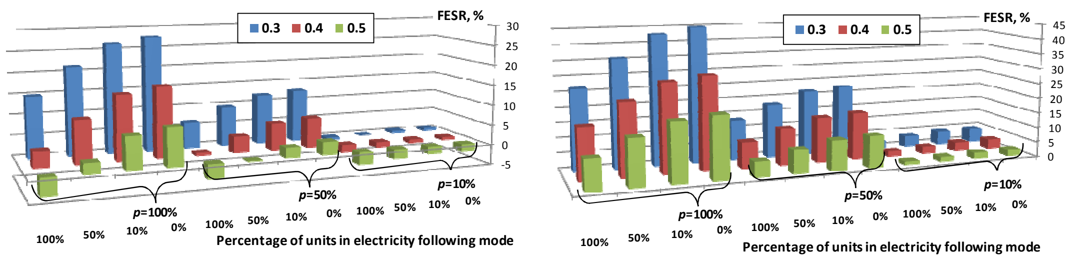
Figure 3-12. Savings in cost of losses due to DG.

3.3.5 Environmental performance

While the previous analyses have focused on network impact, Figure 3-13 and Figure 3-14 show the potential environmental benefits that DCHP systems can bring owing to cogeneration of electricity and heat. More specifically, Figure 3-13 shows the cumulative energy saving results for the overall network calculated as from (3-1), while Figure 3-14 refers to emission reduction results, as from (3-2). Besides for different values of p and c_p, also different average power system electrical generation efficiencies (η^{ESP} in (3-1) and emission factors ($\mu_{CO_2}^{ESP}$ in (3-2)) are considered as parameters, while for heat generation the base case refer to the thermal energy balances calculated in the case of no DG.

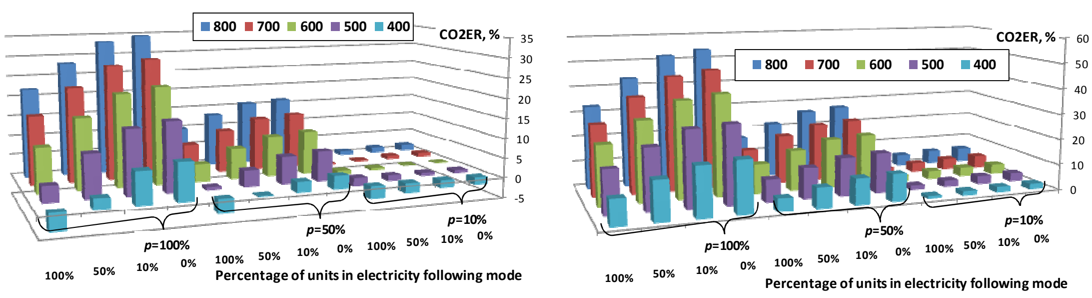
From the results, it can be seen how a multiplicity of variables are involved in the analysis. First of all, the environmental benefits increase with DG penetration, as expected since a higher share of overall generation is achieved through high efficiency combined production. This is also apparent from the comparison between generation mixes 1 and 2, with the latter bringing higher benefits in all cases owing to the higher overall electrical and thermal capacities installed. In addition, the benefits increase substantially if the comparison is carried out with respect to relatively lower efficiency and higher emission marginal plants. Typical electrical efficiency reference values for marginal plants can be in the order of 30÷35% (open cycle gas turbines and coal plants), with relevant emission factors in the order of 700÷800 g/kWh$_e$. Negative values in Figure 3-13 and Figure 3-14 correspond to energy and emission convenience of SP.

A further key point is that the environmental benefits are dramatically influenced by the control strategy, with heat following mode yielding much better performance with respect to electricity following mode. Again, this is due to the fact that the benefits of cogeneration are maximized when the heat load is followed, as the electrical network is available as a sink for excess production or as a source for covering demand in excess of generation. On the contrary, when electricity is followed, heat generation comes along and the non perfect correlation between electrical and thermal load may generate either heat in excess of the demand (to be wasted off) or insufficient to cover demand (so that auxiliary boiler production is needed). Either way, the benefits of cogeneration are decreased relative to the heat following strategy.



a) Generation mix 1 b) Generation mix 2

Figure 3-13. Cogeneration energy saving performance of the overall network (separate production parameters refer to average marginal plant electrical efficiency).



a) Generation mix 1 b) Generation mix 2

Figure 3-14. Cogeneration emission reduction performance of the overall network (separate production parameters refer to average marginal plant CO_2 emission factor, in g/kWh$_e$).

In order to get an idea of what the environmental benefits might mean in economic terms, a possible way is to transform the emission reduction into economic flows by costing the emissions, for instance based on the prevailing cost of emission trading scheme. This corresponds to internalize the external environmental effects according to the external cost framework discussed in Deliverable DH1. The results from such an exercise are reported in the Figure 3-15 with reference to *generation mix 2*, based on a carbon cost of 20 £/ton$_{CO2}$, highlighting that the environmental benefits if properly internalized lead to substantial economic savings for the society (the environmental cost savings are normalized with respect to overall electric energy demand). In particular, for the largest penetration of CHP and marginal emission factor around 700 g/kWhe, the environmental cost savings are in the order of 14 £/MWhe for heat following CHP and drop to 8 £/MWhe for completely controlled CHP units (and autonomous operation of the LV Microgrids). These benefits should be taken into account too when analyzing the overall costs and benefits for the entire energy system owing to Microgrids development.

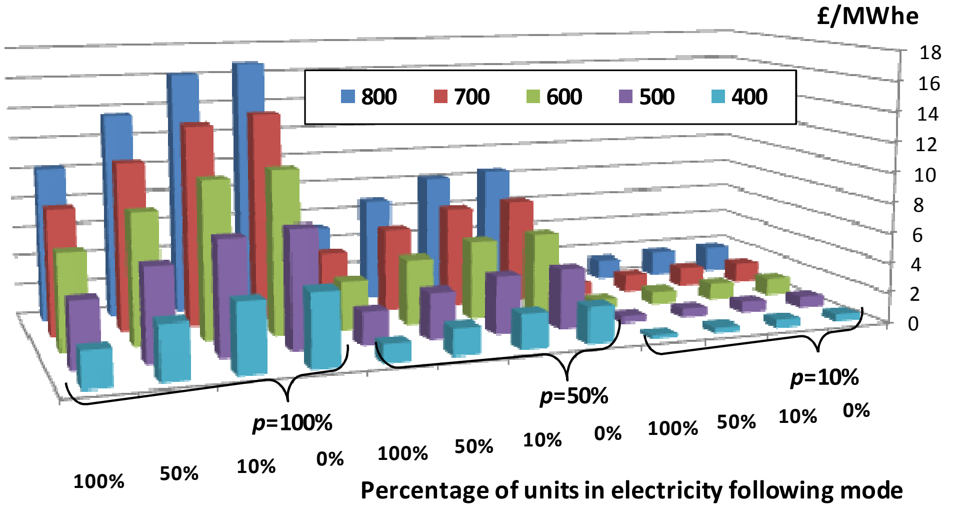


Figure 3-15. Cogeneration environmental-related potential economic savings for the overall network for *generation mix 2* (separate production parameters refer to average marginal plant electrical efficiency, cost of carbon equal to 20£/ton$_{CO2}$).

3.4 Concluding remarks on distributed cogeneration studies

The analyses run in this Chapter have illustrated a comprehensive approach and results to a combined network and environmental analysis of cogeneration systems, a key technology for sustainable development of power systems as well as Microgrids. In particular, by taking into account electricity and heat aspects at the same time, more insights on the drivers for benefits have been gained. From the analyses it has emerged that the main driver for environmental benefits is the adoption of DG technologies with high electrical efficiency and run under heat following mode. On the other hand, if these technologies are sized to satisfy the heat demand, it is likely that substantial electricity exports to the grid occur. More specifically, the grid impact from the second generation mix could be much higher than from the first one when following the thermal load. In fact, owing to the lower cogeneration ratio, for a given unit of produced heat much more electricity is now produced. On the other hand, the possibility of controlling the units according to an electricity following strategy could lead to decrease the environmental benefits due to cogeneration (which corresponds to passing from an external cost benefits of about 14 £/MWhe to 8 £/MWhe, based on a carbon cost of 20 £/ton). For the generation mix 1, owing to the better match between production and demand cogeneration ratio, a better compromise between network and environmental benefits can be expected. In general, small penetrations are not going to lead to a substantial impact in any case, and benefits for both environmental and network criteria are likely to arise. For network deferral benefits, in particular, the value is in the order of 10÷15 £/kWp for small penetration and rises to about 40÷45 £/kWp for both micro-generation scenarios and 50% penetration level, with minor impact of controllability. However, for larger penetration levels problem might arise in terms of network impact, as apparent from generation mix 2, p=100% and c_p=0, needing network reinforcement (negative *NPV*) In this case, the adoption of controllability by reducing the electricity export can help mitigate the need for network reinforcement, although this would come at the above cost of environmental benefit loss. In any case, the upper level for network investment deferral is in the order of 55 £/kWp, which reflects the value of the transformer asset at LV. This value would further rise if the network deferral for the feeders at upper voltage levels were taken into account as well.

For case specific analyses, control strategies cutting the peak only when needed (moving from classical heat following to electricity following) could be adopted, or equivalently DSM strategies could be performed. Adoption of thermal storage systems, not modeled here, could also help mitigate the environmental downsides from an electricity-driven control strategy. In particular, if environmental benefits are to be maximized within energy *autonomous* Microgrids, thermal storage represents a key enabling technology.

4. Concluding remarks

This Annex report has described the results obtained by Imperial College within Task TH2 through the fractal-based distribution network model specifically developed to run system-level analyses of the impact of DG and Microgrids.

Two basic different types of analyses have been considered, namely, based on greenfield network design and impact assessment on reference network. The results obtained with both types of analysis are consistent with the results obtained with the other network models described in Annex H2.A and Annex H2.B. In particular, apart from quantifying the value and benefits of DG in various scenarios, it has been confirmed through different approaches that for small penetration level the impact of DG on distribution network is not substantial, and network benefits normalised with respect to the installed DG capacity are the highest. On the other hand, the benefits of controllability arise for larger penetration, whether in terms of reducing the impact on existing networks or on increasing the value of DG for system design support, although this might come at the cost of decreased environmental benefits, at least if alternative means such as heat storage are not envisaged.

The tools and the methodology developed, as well as the numerical results from the analyses run, are valuable contribution to inform network operators and policy makers on the major drivers for cost and benefits of DG and controllable systems with respect to distribution networks, which sum up to the further results illustrated in the main part of Deliverable DH2.

5. REFERENCES

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