Large Scale Integration of Micro-Generation to Low Voltage Grids

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Methodology for Quantifying Economic and Environmental Benefits of MicroGrids

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1. Introduction

The microgrid has been seen as one of the enabling technologies that can facilitate more efficiently and rapidly the integration of renewables in the form of micro generation in distribution networks. The application of this technology has many potential benefits which should be explored and quantified to enable proper assessments of cost benefit analysis on the deployment of microgrids in the system. The assessment will also bring deeper insight on the value of microgrids and micro generation technologies as well as benefits to society.

In the Work Package G Task 5 and 6, investigations were focused on the identification and development of methodologies to evaluate and quantify the environmental and economic related benefits of microgrids and micro generation. In this report, various benefits obtained from the applications of microgrids and micro generation such as (i) enabling large penetration of renewables, (ii) reduction in CO_2 emissions, (iii) increased service and power quality (iv) deferring network reinforcement (v) increased efficiency of entire system operation including loss reduction, (iv) reduced investment in system reinforcement and (v) reduced cost of energy and increased choice for end customers are demonstrated and described.

This report presents detailed descriptions of the identified benefits and various methods that have been developed to quantify the value of various services from microgrids and micro generation. The report is organised as follows.

Chapter 1 is the introduction. It sets out the context of this work and describes the main content of this report on chapter by chapter basis.

Chapter 2 describes the background of microgrids development and the required transformation of present power system structures (which rely on a number of central generating units dominated by hydrocarbon power stations supplying electricity toremote demand customers via long transmission and distribution networks) to more decentralised power systems with distributed generation which can integrate renewables more efficiently. A non exhaustive list of benefits that can be achieved through application of microgrids and micro generation are described qualitatively and important parameters that should be optimised to maximise the benefits of microgrids are explained in this chapter.

Chapter 3 illustrates (a) the impact of the cost of emissions on the cost of generating electricity, (b) the new regulation in the context of emissions from new generating plants and (c) the carbon content of various fossil fuels.

Chapter 4 addresses the methodology used to quantify the benefits of micro-CHP for domestic applications. The benefits obtained from coordination of heat and electricity production as well as utilisation are demonstrated and quantified. The results demonstrate that the application of micro-CHP significantly reduces the amount of electrical energy imported by the households from the distribution network. This application is very relevant especially in central and northern Europe where high correlation between the heat and electricity demand in winter would make such schemes particularly efficient. The investigation indicates that on the European scale this could lead to the reduction of more than 65 million tonnes of CO_2 per annum.

Chapter 5 describes a number of case studies that were conducted to quantify the benefits of micrograms in terms of system losses reduction, increase in network spare capacity, deferral of new network reinforcement required to accommodate demand growth. The studies also evaluate the value of services such as power factor correction that can be offered by microgrids to distribution networks and the impact on the reduction of reactive power that needs to be withdrawn from transmission systems. Impacts of micro CHP and PV on the distribution network losses and their contribution on reducing network critical capacity are also described and assessed. Applications of micro CHP and PV can be found in the central/northern and southern parts of Europe respectively.

Chapter 6 describes a methodology to quantify the permissible expenditure to enable islanding operation. This methodology also allows network developers to quantify the cost and benefits of islanding operation. It is perceived that islanding has the potential to improve the quality of service by alleviating the impact of network outages. However, islanding operation of distribution network areas must be practicable and profitable. This chapter presents a worth of supply assessment that quantified the benefits of islanding as savings from reduced customer outage costs. Based on the established benefits the maximum permissible expenditure on islanding schemes was appraised.

At the end of this report, main conclusions obtained in this research are summarised.

2. Benefits of MicroGrids in Power System (general overview)

2.1. *Structure of power systems with microgrids*

Traditionally, power systems have been structured to facilitate secure transportation of electricity generated remotely in bulk by a number of large central generation plants via transmission and distribution systems to reach demand customers in an efficient manner. The development of this structure has been driven by the benefits obtained from economies of scales in building large generation plants. Transmission and interconnected system have also been designed not only to transport electricity but also to enable sharing of electricity resources across various systems to increase the overall efficiency in the operation and investment of the systems.

On the other hand, the development of microgrids has been driven by other factors such as increased demand of integrating distributed renewable resources and ability to provide higher reliability and quality of supply. Thus, microgrids have been designed to enable control coordination of a large number of distributed micro generators connected close to loads in Low Voltage (LV) networks. By providing its own decentralised system control capability, a microgrid is similar to a traditional power system only much smaller in scale. Thus, a microgrid is capable of operating in islanding mode or grid connected mode. The latter requires a certain level of control coordination with the control systems of public grid. The structure of power system with microgrids is shown in Figure 2-1.

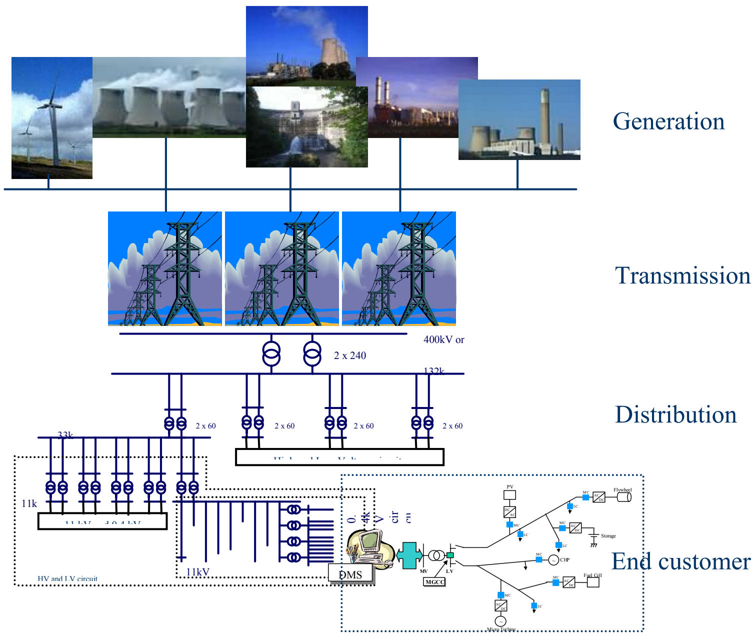


Figure 2-1 Structure of power system with microgrids

2.2. *Benefits of microgrids*

With the efficient integration of small scale distributed generation into LV system and ability of supplying its own local demand customers, exporting energy to neighbours' systems and providing ancillary services (flow management, voltage and frequency control capabilities) to the public systems, the development of microgrids has potential to bring a number of benefits into the system in terms of:

1. Enabling development of sustainable and green electricity

Renewable sources such as wind and solar are spread across wide geographical areas. The inability to accumulate and redistribute these energy sources is a key driver of the installation of a large number of small/medium sizes of power plants across the areas where the sources are available. Due to economic reasons, these types of plants are typically connected to distribution networks. However, large penetration of Distributed Generation (DG) has faced major barriers such as large connection charges due to reinforcement needed in the network to accommodate the generation and also, in the context of renewables, problems of controlling intermittent types of generation.

With the active network management in the microgrids, these two problems can be alleviated. Two typical network problems such as voltage rise and thermal congestion problems can be controlled more effectively in microgrids; hence it enhances the ability for absorbing larger penetration of renewables in the form of small scale distributed generation (micro generation) especially in LV systems.

Clearly, electricity generated by renewable energy sources can substitute electricity supplied initially by hydrocarbon based power plants with the following benefits:

- Carbon emission reduction
- Reducing dependency on depleting fossil sources
- Sustainable and "free" energy sources which in the long term brings lower energy prices

2. Enabling larger public participation in the investment of small scale generation

Investment in central generation plants so far has been dominated by a relatively small number of national/international power companies who have strong financial resources. The investment decision itself is driven by many complex factors such as electricity prices among other commercial incentives, saturation and volatility of electricity market, stability in electricity regulation, ability to get planning permission, connection to networks, and various market risk analyses. It is therefore unsurprising that the development of new large central power plants will take a relatively long time, i.e. a few years, not only for the installation and commissioning of the plant but also for the time used in the planning stages.

On the other hand, economic appraisal for installing micro generation will likely require less complex analysis in contrast to large generation. With much smaller magnitude in the investment, and less complexity in trading electricity, the financial risks exposed to the investors are much lower. At a domestic level, the decision to invest in such generation may be less motivated by financial gain and influenced by individual's will to contribute for clean environment. This will clearly enable larger public participation in contributing to the deployment of RES in the forms of micro generation.

3. Promote competition in generation and supply

It is envisaged that a larger number of market participants both central and smaller scale generation will emerge in the future to trade electricity in the electricity market. Although it may be impractical and inefficient for micro generation to be directly involved in electricity trading as an individual, a market aggregator can be used as one of possible solutions to enable involvement of micro generation in the electricity market. In the long term, competition will increase bringing benefits in terms of cheaper electricity prices, good quality of service through better management and innovation in producing and controlling the consumption of electricity.

4. Reduction in marginal central power plants

Besides substituting electricity from central generation, at certain level, micro generation can also displace the capacity of peak load or marginal central power plants. As these plants were installed typically to deal with peak load, they typically have high operating costs as and low capital costs and operate only for a relatively short period in a year. Consequently, the price of electricity from these generators is more expensive compared with the base load types of generation (hydro, CCGT) to compensate their low load factor and expensive fuel costs. As the demand of these plants depends on the generation capacity capable of supplying the peak load, micro generation can contribute to reduce the required capacity of peak load generation. With different output profiles of each micro generation technology, the overall reduction will depend on the composition of various micro generation technologies in the system. For example, in contrast to CHP, PV will not contribute to the reduction of peak generation for a system whose peak demand occurs during the night. However, PV can have significant contribution in systems with peak demand that occurs during the day.

5. Reduction of environmental resources used by central generation

Related to the previous point, the reduction of large power stations will also bring benefits in terms of reducing the land and other associated environmental resources such as water, which is required by the power stations as thermal power stations require a significant amount of water for producing steam or for cooling purposes. Furthermore, the heat from power stations is also dissipated to the environment through the water hence it may deteriorate ecological systems surrounding the power stations.

6. Improved security of supply

With a considerable large number of installed micro generation, the total generation margin increases. This will also directly increase the available capacity of supplying peak load condition. With a large number of generators, failure in a number of small generators will not have a considerable impact on the capability of supplying the demand. This is in contrast to systems which rely on a relatively small number of big generators. A failure of one large generator may cause significant generation deficit and may lead to load shedding.

Micro generation technologies also bring more diversity in the types of fuel that can be used to generate electricity. This is likely to increase the security of supply and reduce the dependency on a particular type of fuel. However, renewable sources have some degree of uncertainty and unpredictability; hence the mix of generation technologies has to be balanced.

7. Deferral of transmission and distribution network investment

For a remote area, e.g. in an isolated location, transportation of electricity from the central systems will require significant capital expenditure in building new transmission or distribution networks. In this case, the microgrid concept offers an alternative cheaper solution reducing the overall costs required to provide electricity. Micro or medium scale of generation can be installed and operated in the framework of microgrid to supply the demand. Hence, it mitigates the need for building costly transmission and distribution networks. Once the public grids have been developed closer to the area, a connection to the main system can then be realized to obtain benefits of connecting to main systems.

Once a microgrid is connected to the public distribution network, it can start contributing to the reduction of critical flows across the network during the peak loading of the transmission/distribution network. This will allow additional load to be connected to the network without any significant network reinforcement. It is worth to note that the ability of micro generation to displace transmission or distribution networks is limited by the availability and nature of output profiles of the micro generation. For example, PV generators will have a small and relatively negligible contribution to reducing critical flows in a system which has peak load during the winter evening; while micro CHPs can have potentially bigger merit in this context.

Another merit is related to the ability of tailoring the reliability of supply to network customers. At present, transmission and distribution networks are designed to include a certain level of redundancies to deal with unplanned outages in the context of specified security standards. It is likely that more redundancy is required to achieve higher standards. As the value of reliable electricity and quality of supply is tending to increase, the amount of redundancies may also increase. However, different customers may attach different values to reliability of electricity and quality of supply and building the networks to fulfil the security for the highest demand for reliability will be very expensive. Using the microgrids concept, the reliability of supply which is initially provided by network can be replaced by the ability of microgrids to control output of micro generation to supply loads locally and to enhance the quality of supply in the microgrids. Hence, it lessens the requirement of redundancy in building the public grids.

8. Reduction of losses

Currently, losses in a system which primarily relies on central generation are typically around 7% – 10% of total electricity consumption per year. The magnitude of losses is influenced by many factors such as the proximity of generation to loads, circuit impedances, loads, and profiles of loading in each circuit among others. Bearing in mind that losses are a quadratic function of the current, the largest losses occur during peak loading conditions of the circuit.

As a microgrid is able to supply its loads locally, it reduces the amount of power transferred from remote generation via transmission and distribution circuits. Hence, it will reduce system losses. This also leads to the reduction of total energy produced by central generation which is primarily composed of hydrocarbon power plants. Thus, it will also reduce pollutants (carbon, NO_x and SO_2 emissions) from these plants. According to our calculation, 1% reduction in losses in the UK system will save around 2 million tones of CO_2 emissions per year.

9. Enabling better network congestion management and control for improving power quality

Unlike in transmission where the system is actively controlled by dispatching output of generators and other power flow controllers, distribution networks were designed with passive operation philosophy. This leads to the over-sizing of distribution circuits to solve all network problems (thermal, voltage and losses) during the design stage. Although this approach might be valid in the past since there were a very limited number of distributed generators, it is not certainly the case now due to the present with increasing penetration of distributed generation. The introduction of micro generation in the LV networks will provide better capability of controlling power flows from the LV systems to the upper voltage networks. Hence, it may avoid the need for reinforcing the networks due to network congestion or voltage problems. The challenges of controlling a large number of micro generation have also been solved by using decentralised control approach as proposed in MicroGrids.

10. Enabling higher reliability

At present, most of operating standards disallow distributed generation to remain connected to the part of a network which becomes isolated from the main system due to a fault. This is clearly understood and necessary for safety reasons as the system was not designed to operate in islanding mode. However, this is also clearly a waste of power resources since the generators will not be able to provide supply to the loads in the isolated system although the capacity is available.

With the increasing demand for reliable electricity supply, customers who value highly the reliability of electricity supply such as hospitals, banks, airports, and industries will be able to benefit from the microgrid concept. A microgrid will allow micro generation to continue supplying loads while the microgrid is disconnected from the main system. During the design of microgrids, all issues related to the protection, control system and communication will be addressed to ensure the smooth and safe operation of the microgrids.

11. Better coordination of thermal and electricity generation and utilization (increased overall energy efficiency)

Location of generation close to loads also enables coordination of electricity generation and utilisation with other forms of energy especially heat. This concept is demonstrated by the use of Combined Heat and Power generation. By utilising the heat dissipated from the process of generating electricity, the efficiency of using the fuel sources increases significantly. As a comparison, the efficiency of conventional plants is around 30% - 55% while the efficiency of domestic CHP is around 90% - 95%. This clearly reduces the consumption of fossil fuels and the associated costs and also increases the overall efficiency of producing energy.

2.3. *Maximising the benefits*

In order to maximise the benefits, microgrids should be designed so as to optimise the following parameters:

- Distribution of micro generation and proximity to loads

- Local demand supply balance
  The ability to be self sufficient is critical especially in the islanding mode to prevent any load shedding; however, the use of remote generation should be considered for economic reasons.

- Matching generation-demand pattern
  The higher the correlation between the output profiles of micro generation and the load profiles, the smaller the energy imbalance between local generation and loads in the microgrid. In this case, Demand Side Management can contribute to easing the imbalance by trying to match the demand profiles with the output profiles of micro generation.

- Balanced mixture of generation technology
  This balance is critical for minimising the energy imbalance in a microgrid. The output of some micro generation technologies such as PV, wind generators and small hydro is less controllable and less predictable because these generators are driven by the availability of renewable sources while the output of domestic CHP is driven by heat load rather than electricity load. However, conventional types of generators such as diesel are controllable and can be dispatched to alleviate energy imbalance in a microgrid. Application of energy storage should also be considered to enable generation – demand matching profile in the microgrid.

- Optimum sizing of generation

- Efficiency in generation and storage

- Controllability
  In order to maintain the reliability and quality of supply, a microgrid system operator should have full control of the system by using either network control devices or network control services from controllable loads or micro generation.

- Efficient integration with public grids
  Exchange of resources and services with external systems outside the microgrids require control integration between the microgrid central controller (MGCC) and distribution management system (DMS) responsible for controlling flows in distribution networks.

- Ability to provide ancillary services
  Voltage control, frequency control, black start capability and fast reserve can be provided and should be able to be traded to increase revenue streams of micro generation or microgrid operators as the aggregator of these services to the external system.

- Market support mechanism

Ability to trade energy and services on a level of playing field is crucial to facilitate fair competition not only in energy but also in the provision of ancillary services. However, the cost of participating in such a market should not exceed the benefits obtained from it. Hence, the cost should be minimised for example by automation.

- Regulatory support
  The regulatory framework should provide an attractive and conducive commercial environment to allow development and rapid growth of microgrids in the system. A standardised procedure for applications and terms specified in the connection agreement will reduce administrative barriers.

3. Impact of emission costs on the energy prices

One of the major barriers in the deployment of Renewable Energy Resources is the relatively low electricity prices offered by hydrocarbon power plants. Although the energy sources for renewables are free, the electricity prices from these generators are still more expensive compared with the hydrocarbon power plants as shown in Figure 3-1 due to various reasons. The first reason is the high capital expenditure. However, it is envisaged that in the future this cost can be significantly reduced. For example, PV generation will cost around £2000/kW while the CCGT costs only around £ 350 - 400/kW. Secondly, renewables have a relatively low load factor and for some technologies such as PV, the lifetime of the solar panel is much shorter compared with the average lifetime of conventional generators. This leads to higher electricity prices of these generators.

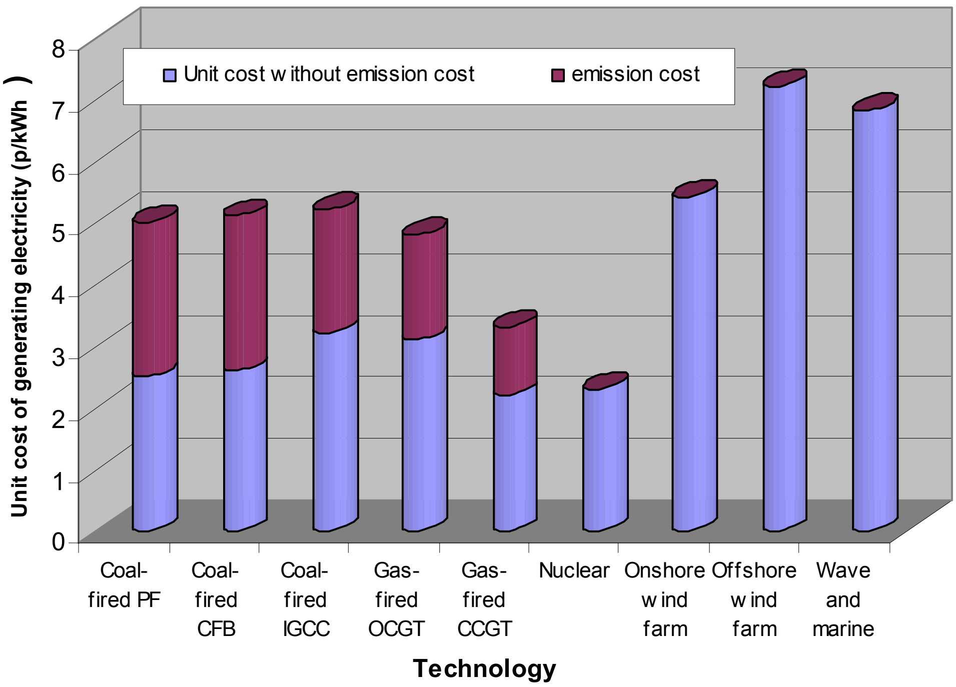


Figure 3-1 Cost for generating electricity for various power plant technologies

In the past, the impact of fossil fuel based power plants on the environment was either not properly evaluated or at worst even ignored. It was only after the issues of global warming due to the emission of green house gases (GHG) emerged and became important that the environmental cost incurred by using coal, oil and gas started to be quantified in monetary terms. In the past few years, electricity regulation started to introduce an additional cost component to the plants which emit pollutants to the environment. In the future, the emission of power plants must be below the given quota. However, to encourage further reduction of emissions, the remaining quota can be sold to the parties who fail to achieve their target.

After including this cost component, the cost for generating electricity from hydrocarbon based power plants increases significantly as shown in Figure 3-1. Data is taken from [1]. The cost increases from 2.2 p/kWh to 4.8 p/kWh for a coal fired pulverised fuel with the assumption that the cost of CO_2 per ton is £ 30. This will bring electricity prices from renewables closer to the hydrocarbon based plants. With the emission cost tending to increase as opposed to the capital cost of renewables that are likely to decrease, it is likely that in the future renewables will become more competitive compared to fossil fuel plants .

Regulation across Europe in the context of GHG emissions has also been tightened. For example, in the directive 2001/80/EC, known as the large combustion plant directive (LCPD), the EU sets limits for the reduction of emissions to air for oxides of nitrogen (NOx), sulphur dioxide (SO2) and particulates (dust) from combustion plants with a thermal input greater, or equal to, 50 megawatts (MW). This replaces the previous directive 88/609/EEC. The limits are shown in Figure 3-2 and Figure 3-3 below.

The LCPD applies to 'existing', 'new' and 'new-new' plants whereby:

- existing plants are defined as those consented before 1 July 1987 and exempt from 88/609/EEC;
- new plants are defined as those having been built between 1 July 1987 and 31 October 2001, which are obliged to meet the criteria outlined in 88/609/EEC; and
- new-new plants are defined as those commissioned after 31 October 2001 that are obliged to meet the criteria outlined in the LCPD.

Fuel type	50-100 MW	100-300 MW	> 300 MW
Biomass fuels	200	200	200
Other solid fuels	850	200	200
Liquid fuels	850	200-400	200

Figure 3-2 SO2 emissions permitted by "new-new" plant (mg/m3 normal [Nm3])

Fuel type	50-100 MW	100-300 MW	> 300 MW
Solid fuels	400	300	200
Liquid fuels	400	200	200
Natural gas	150	150	100
Other gas	200	200	200

Figure 3-3 NOx emissions permitted by "new-new" plant (mg/m3 normal)

Fuel type	Carbon content (kg/GJ)
Natural Gas	14.2
Fuel Oil	19.6
Coal	22.5

Figure 3-4 Carbon content of different fuel

In Figure 3-4, carbon content of various hydrocarbon fuels (gas, oil and coal) are shown. Coal has the largest carbon content while natural gas is the cleanest among these three fuel types. As coal was used extensively in the past as a base load energy source, various technologies to reduce carbon emissions for coal power plants have been developed. It is envisaged that the emissions from coal, gas and oil will become progressively smaller in the future. This is illustrated by the expected lower emission costs of these plants in the future as shown in Figure 3-5 below.

	Carbon emission costs (pence/kWh)	
Technology	Current	Future
Coal fired PF	0.82	0.78
Coal-fired CFB	0.82	0.78
Coal-fired IGCC	0.67	0.64
Gas-fired OCGT	0.54	0.49
Gas-fired CCGT	0.37	0.35
Oil	1.12	1.06

Figure 3-5 Carbon emission cost for various hydrocarbon generation technologies

As discussed previously in this report, the reduction of electricity output from hydrocarbon plants due to increase in renewables output, reduction in losses, increase in thermal efficiency enabled by the use of microgrids technology will contribute to the reduction of the GHG emission to the environment. As an estimate, by reducing 1 GWh output of hydrocarbon power stations per year, the CO_2 emission can be reduced up to 400 kT per year. The calculation used an average mixture of oil, coal and gas power plants equipped with the technology to reduce the pollutions. Without these technologies, the amount of pollution can be doubled.

4. Benefits of co-ordinating domestic thermal and electricity generation and utilisation

4.1. Benefits of domestic CHP generation

Among other micro-sources, domestic CHP is poised to become one of the popular choices especially for customers who typically use electricity and heat at same time. By utilising the heat generated concurrently with electricity, the thermal efficiency of using the fuel sources can reach up to 90%-95% compared with 65% for an ordinary boiler or 30% - 55% for conventional power stations. Clearly, with this level of energy efficiency, the option to use a domestic CHP to displace the conventional low efficiency central generation plants is very attractive [2],[3]. The benefits are clear: the overall consumption of non-renewable natural resources such as gas, oil can be reduced significantly by up to 30-40% if the average thermal efficiency for generating heat and electricity from conventional plants is about 50%-60%. The associated operation and environmental related costs will also be significantly lower.

With a significant saving offered, affordable capital investment and maintenance cost, the use of CHP is very attractive. The economic benefit can be obtained from the reduction in gas and electricity bills and the income from selling electricity. Thus, it is unsurprising that many manufacturers that require heat in their manufacturing process have used this technology for many years. CHP technology has recently emerged for domestic use driven by environmental concerns and the need for energy saving. Stirling engine and micro turbines are the mature technology selected to be used in the domestic CHP.

Unlike other types of generation, the scheduling of CHP is typically driven by heat requirement rather than by electricity requirement. For a domestic CHP, there are two main heat loads namely; room (space) and water heating. The heat is used to control and maintain the room and water temperature within a convenient range. Like electricity load, heat load also varies daily and seasonally. As the heat and electricity load are linked to human activities, there is correlation between both types of loads.

In order to control the temperature for various thermal loads, various factors such as: the thermal coefficient of loads, the outside temperature and the rate of thermal loss from indoor environment to outdoor need to be taken into account. For example, during the winter (cold) condition, as demand for heat is higher, CHP will be committed more often than in summer. In order to reduce the thermal loss, some thermal insulation is commonly installed. This insulation enables larger efficiency of storing heat, which should be taken into account in optimal scheduling of CHP.

4.2. Optimising schedule of domestic CHP: problem formulation

The objective is to minimise the total cost of gas fuel and electricity bill while optimising heat and electricity supply to loads subject to various thermal and electrical energy balance constraints. The problem can be formulated in a standard Linear Programming form as follows:

$$\text{Minimise } \psi = \sum_{\mathrm{i}=1}^{8760} (\mathrm{C}_\mathrm{i}^\mathrm{I} \cdot P_{\mathrm{di}} - \mathrm{C}_\mathrm{i}^\mathrm{E} \cdot P_{\mathrm{gi}} + \mathrm{C}_\mathrm{i}^\mathrm{G} \cdot \alpha \cdot Q_i) \tag{4.1}$$

Where index i refers to an utilisation period

$\mathrm{C}_\mathrm{i}^\mathrm{I}, \mathrm{C}_\mathrm{i}^\mathrm{E}$ are the price of importing and exporting electricity at period i in (p/kWh) respectively

$\mathrm{C}_\mathrm{i}^\mathrm{G}$ is the price of gas at period i in (p/kWh)

P_{di}, P_{gi} are the electricity load and generation at period i in kWh respectively

$\alpha \cdot Q_i$ is the energy content of gas fuel used in period i after conversion to kWh

Subject to:

1. Electrical energy balance constraints

$$P_\mathrm{i} + P_{\mathrm{gi}} - P_{\mathrm{di}} = 0 \tag{4.2}$$

Where P_i is the electricity imported or exported to the grids

2. Heat constraints

$$H_{\mathrm{gi}} - H_{\mathrm{di}} - H_{\mathrm{loss,i}} = 0 \tag{4.3}$$

$$H_{\mathrm{di}} = H_\mathrm{r}(T_{\mathrm{r,i}} - T_{\mathrm{r,i-1}}) + H_\mathrm{w}(T_{\mathrm{w,i}} - T_{\mathrm{w,i-1}}) \tag{4.4}$$

Where H_{gi}, H_{di}, $H_{\mathrm{loss,i}}$ are the thermal generation, thermal load and thermal losses at period i in kWh

H_r and H_w are the thermal capacity of room and water in kWh/K

$T_{\mathrm{r,i}}, T_{\mathrm{w,i}}$ are the temperature of room and hot water at period i in K respectively

3. Heat and electricity generation constraints

$$P_{\mathrm{gi}} = \eta_e \cdot Q_i \tag{4.5}$$

$$H_{\mathrm{gi}} = \eta_h \cdot Q_i \tag{4.6}$$

Where η_e is the thermal efficiency of CHP to generate electricity in p.u.

η_h is the thermal efficiency of CHP to generate heat in p.u.

Bounds:

1. Temperature constraints

$$T_{\min} \le T \le T_{\max} \tag{4.7}$$

2. Capacity constraint

$$Q_i \le Q_{\max} \tag{4.8}$$

for all $i \in \{1..8760\}$.

The problem can be solved using any LP solvers such as XPress from Dash Optimization [4].

4.3. Explanation of case studies

Several case studies were conducted to illustrate the benefits of domestic CHP application as opposed to ordinary domestic boiler for houses with different thermal insulations. Three categories of thermal insulation were used, i.e: poor, average and good to demonstrate the impact of different thermal losses in the scheduling of domestic CHP. The studies quantified the total annual cost of electricity including the revenue obtained from selling electricity and the cost of gas as described in the problem formulation.

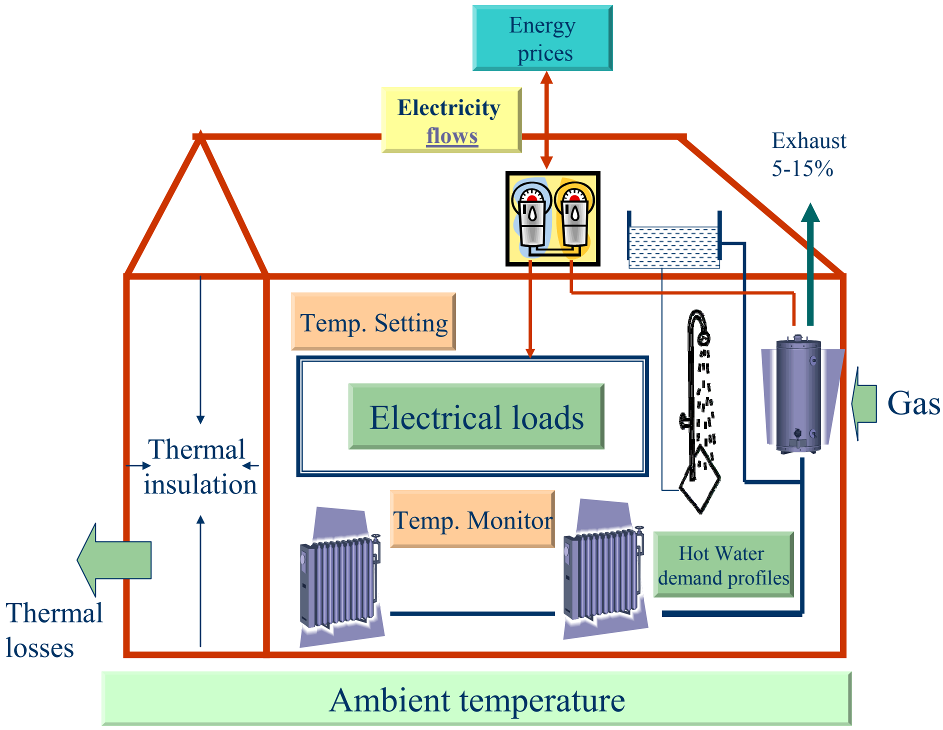
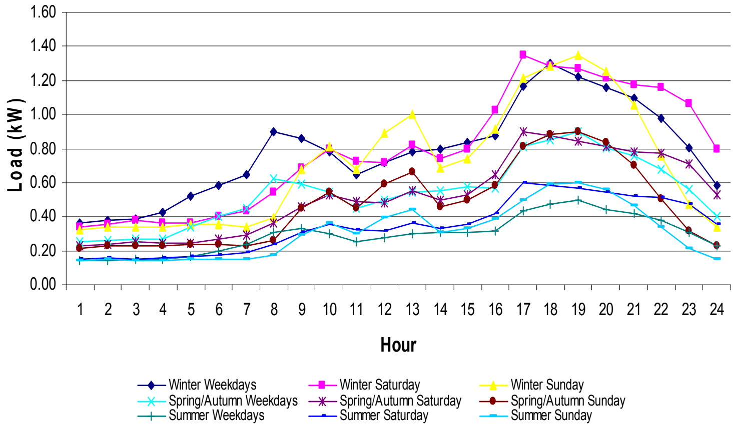


Figure 4-1 A schematic energy flows in a house equipped with a domestic CHP

In Figure 4-1, a typical application of domestic CHP is illustrated. A 10 kW CHP unit was installed and is used to heat rooms and water in the house. The heat for rooms is distributed via a gas central heating system to increase thermal efficiency. The house has a certain degree of thermal insulation installed in walls, floor and ceiling to reduce thermal losses. The application of double glazed windows or special types of windows which have low thermal conductivity are also used to reduce thermal losses. Besides depending on thermal characteristics of the insulation, losses are also influenced by many factors such as temperature differential between ambient temperature and the indoor temperature. The CHP is also used to heat water which is used for washing and showering. Hot water is stored in the hot water tank typically installed at the upper level of the house. The tank is covered with thermal insulation to maintain hot water temperature. Once the hot water is used, cold water will be pumped into the tank causing temperature drop. As and when necessary, CHP will heat the water to maintain the temperature of hot water in the tank.

The analysis takes into account different electrical and heat load profiles across a year time horizon. Since it seems to be impractical to model the fluctuation of loads in great detail, daily typical electricity residential load profiles with 1 hour resolution were developed for various characteristic days. The characteristic days were classified according to the seasonal (winter, summer, autumn/spring), weekly (weekdays, Saturday, and Sunday) and hourly. The electricity load profiles for each combination are shown in Figure 4-2 below. The Table next to the graphs shows the number of occurrence for each characteristic day in a year.



Description	Number of occurrence in a year (days)
Winter Weekdays	70
Winter Saturday	14
Winter Sunday	14
Spring/Autumn Weekdays	141
Spring/Autumn Saturday	28
Spring/Autumn Sunday	28
Summer Weekdays	50
Summer Saturday	10
Summer Sunday	10
Total	365

Figure 4-2 Load profiles

In this example, peak demands occur in winter and the lowest loading conditions occur in summer. For the hourly variation during a day, the graphs show similar patterns. The loading during the night and early morning is relatively small. The loads start to pick up during 7 – 8 a.m. in the morning and increase until 9-10 a.m. before falling slightly. It is followed by fluctuation in loads especially during the lunch time. Peak loads typically occur during the evening (5 – 7 p.m.).

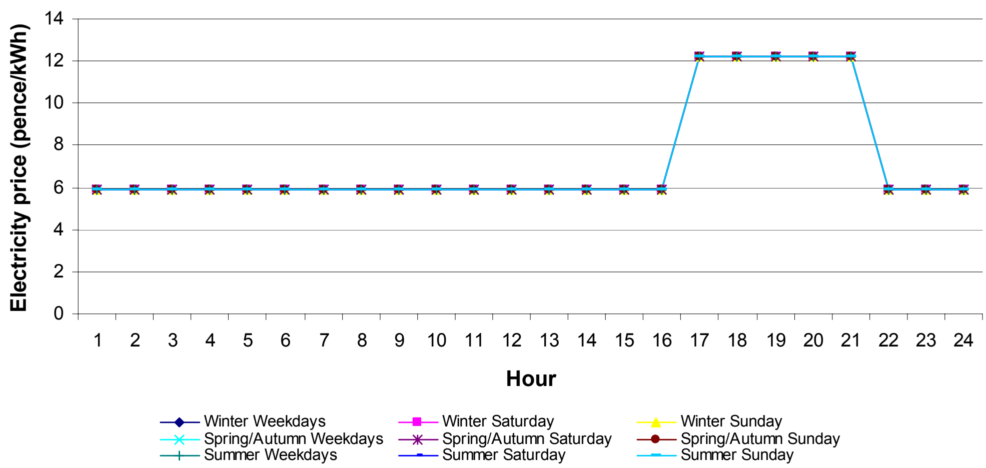


Figure 4-3 Time of use electricity prices (import)

Figure 4-3 shows two different electricity prices in a day for importing electricity from the grid. The electricity price is around 12 p/kWh during the time where typically peak load occurs, i.e., 5 to 9 p.m. while the price falls to around 6 p/kWh for other periods. By using these profiles, the total electricity consumption is 4,816 kWh. This will cost around 383 £/year. This figure is of a similar order of magnitude as the average annual cost of electricity for a residential customer in the UK. Note that the price for generating electricity was fixed at 5 p/kWh . It was assumed that a separate meter was used to record electricity generation and loads.

With similar approaches, variations in ambient temperature were also modelled for the 9 characteristic days as shown in Figure 4-4. In winter, average temperature varies between -3 °C to almost 5 °C. While in summer, the temperature increases significantly and varies between 8°C to 25°C. In a day, the lowest temperature occurs during the night while peak temperature occurs around mid-day. In this example, the profiles for weekdays are the same as the profiles for Saturday and Sunday.

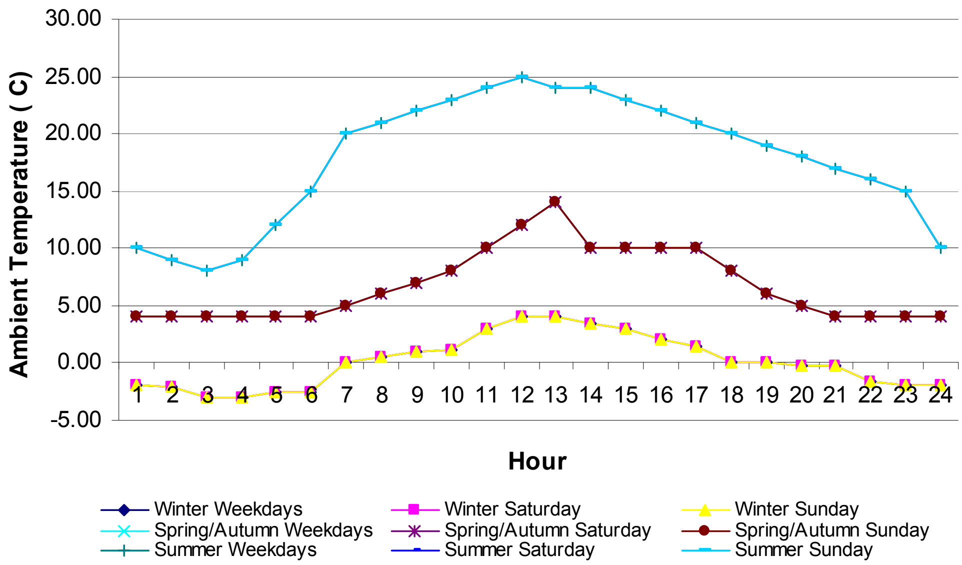


Figure 4-4 Ambient temperature

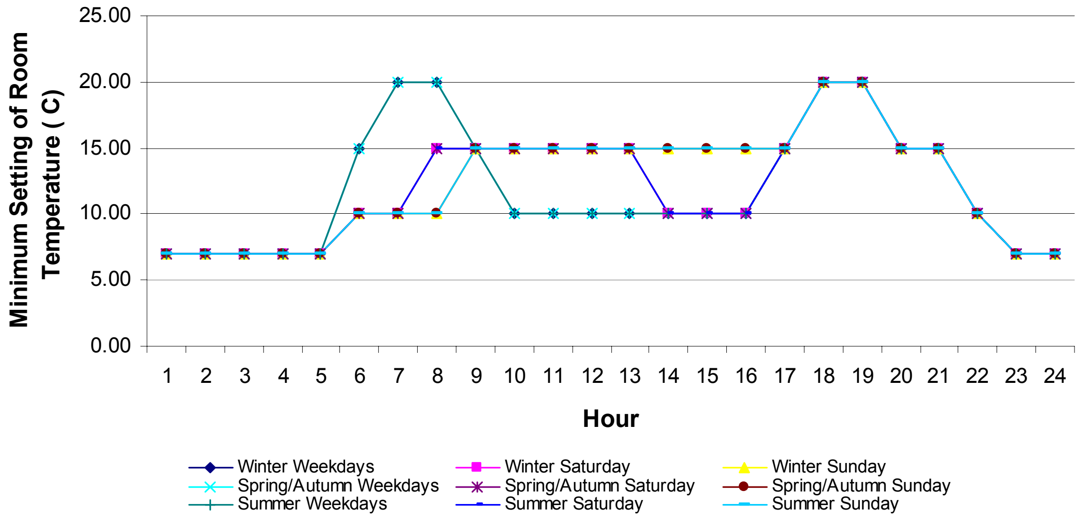


Figure 4-5 Minimum setting of room temperature

In Figure 4-5, profiles to determine the allowed minimum room temperature were developed. Although the profiles were set arbitrarily they do take into account the need for comfortable room temperature especially during 6 – 9 a.m and 5 – 9 p.m. when most of activities occur in residences. During the night, when occupants of the house go to bed, temperature is allowed to drop down to 8°C, if necessary. Bearing in mind that the higher the temperature setting is, the larger the amount of heat that needs to be produced. Hence, the cost will be higher. On the other hand, the maximum room temperature was set to 25°C.

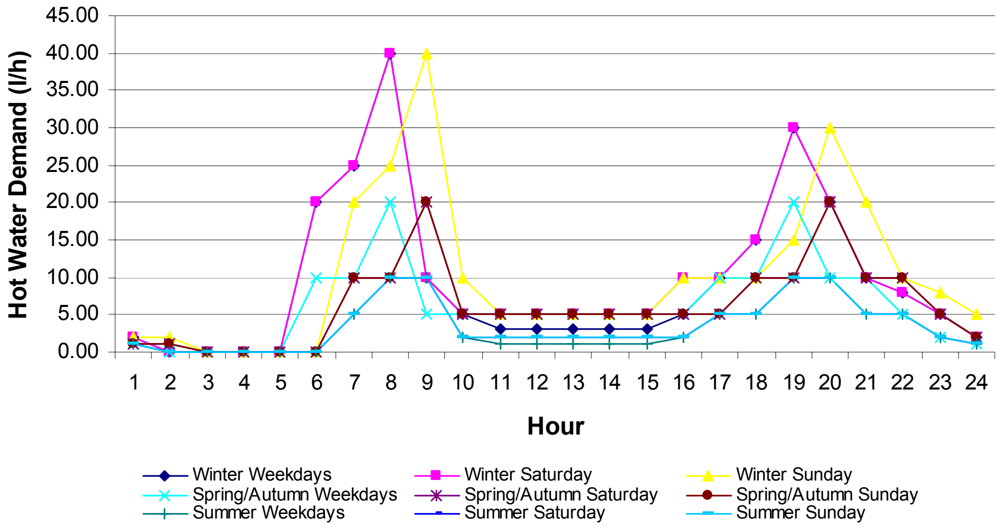


Figure 4-6 Hot water demand profiles

Hot water demand profiles as shown in Figure 4-6 were developed to illustrate the average use of hot water by 3 occupants in the house for washing (hands, dishes and clothes) and for showering. The minimum hot water temperature was set to 50 °C and the maximum at 100 °C. On average, each person uses around 50 litres of hot water per day during the cold weather (winter). The demand becomes less when the ambient temperature increases in the spring and summer.

4.4. Results of the case studies

The results of the investigation demonstrate a significant cost saving that can be obtained through the application of domestic CHP. The results are summarised in the Table 4-1.

Table 4-1 Summary of the results

Type	Insulation	Cost of buying electricity (£/year)	Revenue from selling electricity (£/year)	Gas bills (£/year)	Total cost (£/year)
Conventional Boiler	Poor	383.97	0.00	460.65	844.62
Conventional Boiler	Average	383.97	0.00	401.14	785.11
Conventional Boiler	Good	383.97	0.00	325.80	709.77
Domestic CHP	Poor	383.97	229.86	494.20	648.31
Domestic CHP	Average	383.97	195.29	419.88	608.56
Domestic CHP	Good	383.97	162.36	349.07	570.68

By having a separate meter for electrical loads and generation, the cost of importing electricity is the same for all cases. The boiler does not produce electricity; hence the revenue is always zero. The results demonstrate the impact of thermal insulation on the annual gas utilisation. Customers who have good thermal insulation pay £ 135 less per year compared with customers who have poor thermal insulation. This is a saving of almost 30%. The total energy (electricity + gas) cost of customers who use a boiler is within the range of £710 - £845 per year.

On the other hand, customers who use domestic CHP benefit from selling the electricity produced by CHP. It is noted that the amount of gas consumed by CHP is slightly larger than the annual gas consumption of the ordinary boiler. Hence, this increases slightly the gas bill. However, a relatively substantial amount of revenue is obtained from selling the electricity. It is also noted that customers with good thermal insulation use less heat and therefore receive less income from selling the electricity. The total energy (electricity + gas) cost of customers who use domestic CHP is within the range of £ 570 - £ 648 per year. Another finding is that the energy bills of the customers with domestic CHP are less sensitive to the thermal insulation that they use as opposed to the customers who use ordinary boiler.

The differences of energy bills between customers who use boilers and CHP are within the range of £ 140 - £ 197 per year. Given that the difference between the cost of CHP and boiler is known, a period when the break even point (BEP) is achieved can be calculated easily. For example, if a domestic CHP costs £ 1000 - £ 1400 more than a boiler, the BEP of the investment is around 5 – 10 years. With the expected lifetime of CHP being around 10-15 years, the customers are likely to enjoy economic benefits from installing a CHP unit.

Another benefit from the application of CHP is the reduction of electricity that needs to be imported from the grid. According to these studies, 3,250 – 4,600 kWh per year per household can be saved. This is equivalent to the saving of 1.3 T – 1.4 T CO_2 per household per year. If this number is multiplied by 1 million, a massive saving of 1.3 MT – 1.4 MT CO_2 per year will be achieved. This has not included other environmental related benefits such as reduction in SO_2, and NO_X among others.

5. Benefits of MicroGrids for Distribution Network

5.1. Case study scenarios

In this project, the studies conducted were focused on several cases to:

1. examine the impact of different micro generation technologies, i.e. CHP and PV on distribution losses and critical flows at GSP (Grid Supply Point) transformers
2. quantify the value of reactive compensation in microgrids to enhance power factor in LV networks

In order to undertake the evaluation consistently, all the case studies were performed on the developed generic distribution networks.

5.2. Generic distribution network modes

The evaluation was conducted on two generic distribution networks: urban and rural network. The circuit and transformer parameters are derived from a number of sources including use of UK DSOs long-term development statements. Although these two networks may not be considered as being necessarily representative of the UK urban and rural systems, the results are likely to be indicative of the situation obtaining in the UK. The models consist of 0.4 kV, 11kV, 33kV and 132kV subsystems to represent a distribution system connected to a Grid Supply Point (GSP). Some parts of 0.4 kV systems are modelled as microgrids. The topology of the network model is shown in Figure 5-1 below.

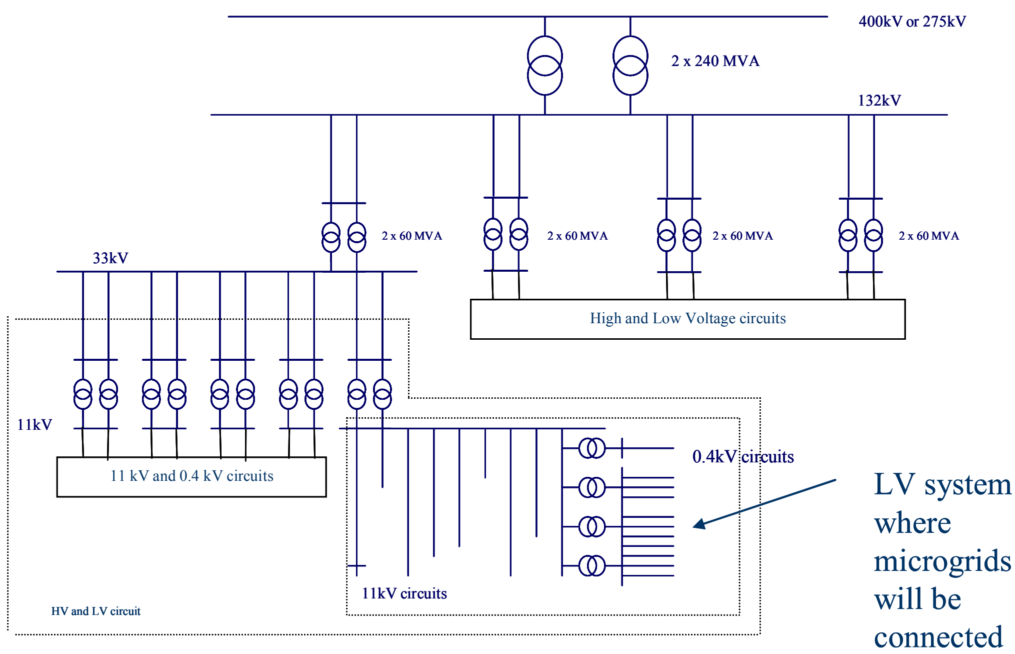


Figure 5-1 Topology of generic distribution network model

The generic urban network consists of relatively short distribution under ground (UG) cables especially at 11 kV and 0.4 kV levels. Loads are being distributed uniformly along the distribution feeders. The generic rural network consists of relatively long overhead line (OHL) at 11 kV and mixes between UG and OHL at 0.4 kV networks. Distribution of load in rural areas is a mixture between uniformly distributed and linearly increasing loads along the feeders.

The evaluation models can incorporate the impact of a number of parameters including hourly and seasonal demand profiles corresponding to various types of customers (commercial, industrial and domestic), operating at various power factors. Furthermore, various levels of penetration and concentration of distributed generation and various distributions of loads along distribution feeders can be considered in conjunction with a number of alternative voltage control strategies including use of OLTCs, reactive compensators, in-line voltage regulators and DG dispatch. The model output includes voltage, flow and losses profiles.

We assumed that the majority of load is connected to the LV network. It was assumed that 80% of the total load is domestic, 10% is commercial and remaining 10% is industrial. Nine characteristic days are used to model seasonal and daily load variations and the corresponding GSP profiles are shown in Figure 5-2.

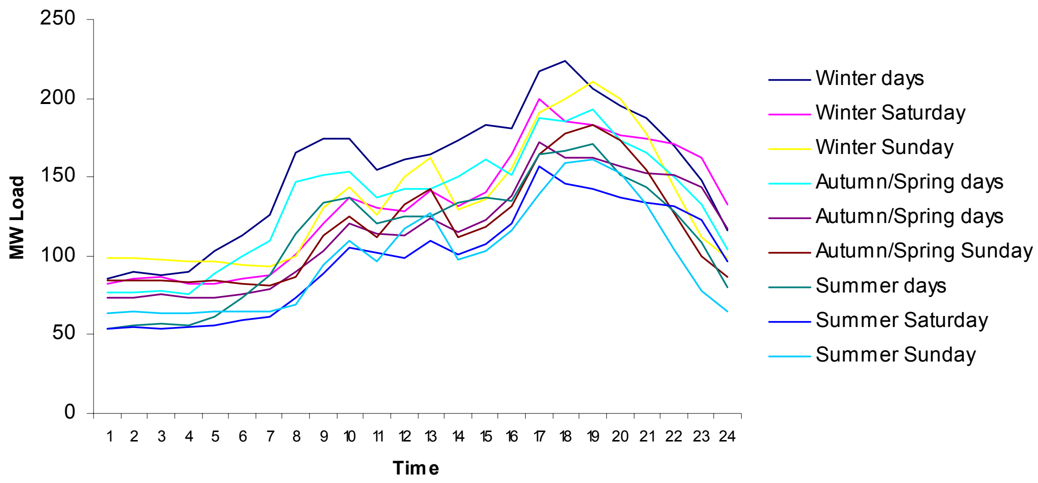


Figure 5-2 Seasonal and daily load profiles

Three different seasons, namely winter, autumn/spring and summer are used to represent seasonal variations together with three different hourly load profiles, characteristic for weekdays, Saturday and Sunday. These characteristic days are used to form the annual demand profile of the system.

5.3. The impact of different micro generation technologies, i.e. micro CHP and PV on distribution losses and critical flows at GSP transformers

5.3.1. Micro CHP

Combined Heat and Power (CHP) is the simultaneous production of electrical power and useful heat. In this 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 7-16 illustrates the normalised generation profile of micro CHP used in this study where it was assumed that the output of micro CHP is nil during the summer. Furthermore, it was assumed that 25% of the customers with micro CHP had a technology with a capacity of 3kW and 75% with a capacity of 1.1kW.

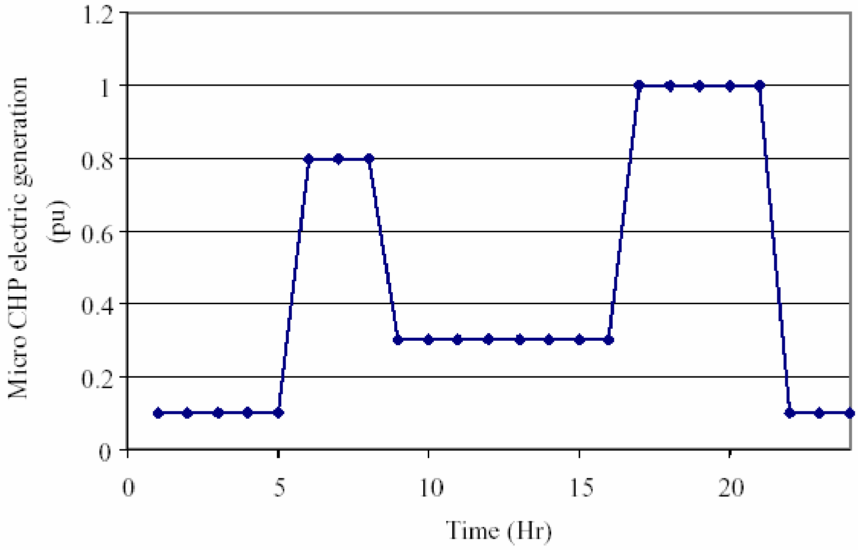


Figure 5-3 Normalised output of micro CHP

Table 5-1 Losses and maximum flow when micro CHP is allocated to 50% of GSPs in the UK

Proportion of customers	Losses in GSP with generation (%)/Losses in the entire UK network (%)			Maximum flow entering the GSP (in MVA)
	Average network	Rural network	Urban network	
0%	6.1	8.69	4.47	251.3
2.5%	5.6 / 5.85	7.92	4.12	228.7
5%	5.16 / 5.63	7.24	3.8	206.5
7.5%	4.75 / 5.42	6.63	3.52	187.9
10%	4.39 / 5.24	6.09	3.36	167.6

Table 5-2 Losses and maximum flow when micro CHP is allocated to 20% of GSPs in the UK

Proportion of customers	Losses in GSP with generation (%)/Losses in the entire UK network (%)			Maximum flow entering the GSP (in MVA)
	Average network	Rural network	Urban network	
0%	6.1	8.69	4.47	251.3
2.5%	4.93 / 5.86	6.92	3.72	195.4
5%	4.05 / 5.69	5.62	3.15	187.9
7.5%	3.48 / 5.57	4.78	2.78	187.9
10%	3.18 / 5.51	4.35	2.58	187.9

On one hand, Table 5-1 gives the annual energy losses and the maximum flow entering the distribution network for different proportion of customers with micro CHP allocated to 50% of the GSPs in the UK. The results are obtained by calculating load flows for each loading condition. On the other hand, Table 5-2 gives the same features when micro CHP is allocated amongst only 20% of the GSPs in the UK. The increase in the proportion of customers with micro CHP leads to a significant reduction in energy losses (from 6.1% to 4.39% in the average network). This reduction is important because the maximum output of micro CHP occurs at times of high customers demand hence it decreases the transfer of power in the distribution network in times of high demand.

For the same reasons the maximum flow entering the GSP network decreases as the capacity of micro CHP increases up to a point where the maximum flow entering the network occurs at a time when no electricity is produced by micro CHP (in summer for instance). Since micro CHP generation coincides with peaks of demand, adding micro CHP generation capacity at the low voltage end of the power system defers or removes the need for new capacity at upper voltage networks and reduces the utilisation of existing network. This leads therefore to benefits to DSOs.

5.3.2. PV

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 interfaced with the low-voltage distribution network. Figure 5-4 describes the normalised energy profile used in this study to model the output of PV. It is assumed that customers would have a $1m^2$ module with a capacity of 1kW.

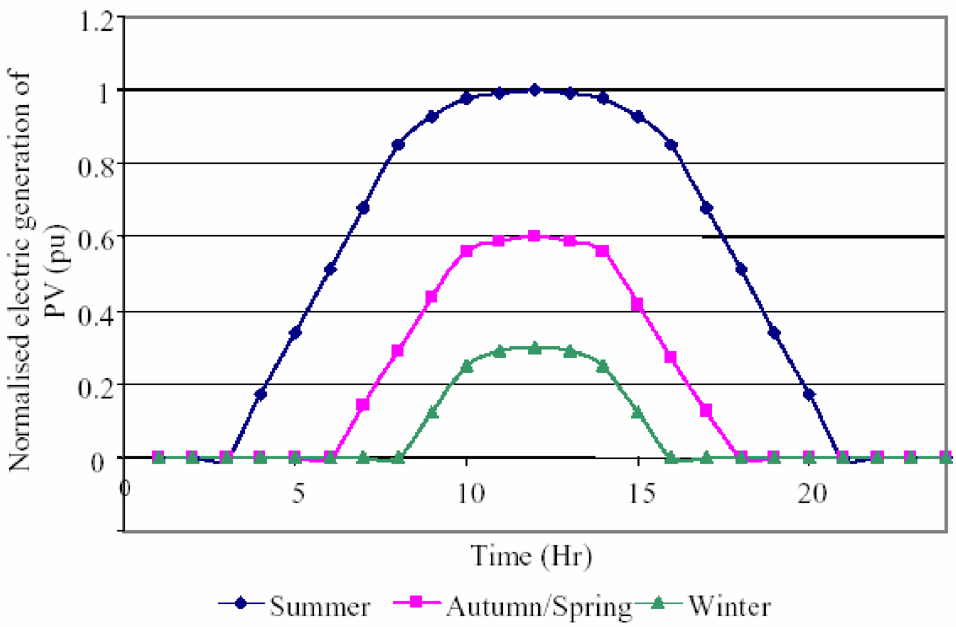


Figure 5-4 Normalised output of PV

Table 5-3 and Table 5-4 describe the distribution losses for different penetrations of PV at 0.4kV. The impact of PV on losses and on the provision of network capacity is less significant than the impact of micro CHP. Indeed, PV in the UK produce electric energy in times of low demand (during summer daytime), but not during peak demands such as the evening of winter weekdays. Therefore the maximum flow entering the distribution network is not affected by the installation of PV (251.3MVA in this example), and even if losses decrease with higher penetrations of PV, the reduction is not significant.

Table 5-3 Losses and maximum flow when micro CHP is allocated to 20% of GSPs in the UK

Proportion of customers with PV	Losses in GSP with generation (%)/Losses in the entire UK network (%)			Maximum flow entering the GSP (in MVA)
	Average network	Rural network	Urban network	
0%	6.1	8.69	4.47	251.3
2.5%	5.93 / 6	8.39	4.33	251.3
5%	5.74 / 5.92	8.12	4.2	251.3
7.5%	5.57 / 5.83	7.86	4.09	251.3
10%	5.41 / 5.75	7.62	3.98	251.3

Table 5-4 Losses and maximum flow when micro CHP is allocated to 20% of GSPs in the UK

Proportion of customers with PV	Losses in GSP with generation (%)/Losses in the entire UK network (%)			Maximum flow entering the GSP (in MVA)
	Average network	Rural network	Urban network	
0%	6.1	8.69	4.47	251.3
2.5%	5.65 / 6.01	7.98	4.15	251.3
5%	5.26 / 5.93	7.4	3.88	251.3
7.5%	4.95 / 5.87	6.93	3.65	251.3
10%	4.71 / 5.82	6.58	3.5	251.3

5.4. Value of reactive compensation in microgrids to enhance power factor of load

5.4.1. Description of the case studies

Load with 0.85, 0.9, 0.95 lagging and unity power factor were used to quantify the impact of the power factor on the annual energy losses in the urban and rural distribution networks. The proportions of active and reactive energy losses at various voltage levels were recorded. The value of installing reactive compensation at various voltage levels including in the LV microgrid systems in the context of energy losses reduction was then quantified.

We also examined the ability of microgrids to provide reactive compensation to reduce the import of reactive power from the transmission grid. TSO purchases reactive power from generators to manage the network voltage and supply reactive power demand. Using the information regarding expenditure associated with reactive power market, we assessed the value of reduced reactive power import that may be enabled by reactive compensation located in microgrids.

5.4.2. VAr compensation and losses in distribution system

The total annual energy losses in percentage of total annual energy demand in the generic urban and rural networks, for different power factors, are shown in Figure 5-5.

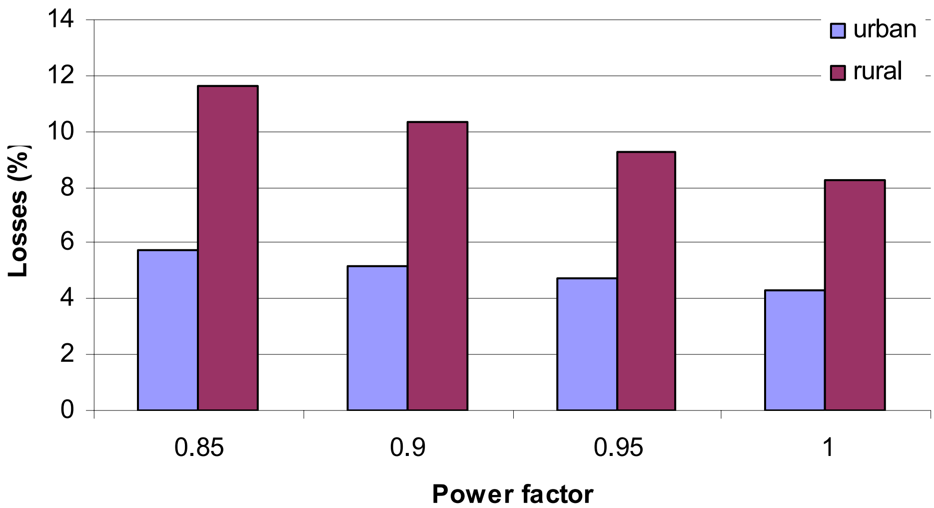


Figure 5-5 Annual energy losses in percentage of annual energy demand in the generic distribution networks

As expected, energy losses in rural networks are greater than in urban. The percentage of annual energy losses in the urban and rural networks varies between 4.4% - 5.7% and 8.2%- 11.5% respectively depending on power factor. The results have resemblance with the total losses in the UK (rural and urban) distribution networks. The average UK distribution network losses are around 7% of total electricity consumption. This coincides with the results obtained in this study for power factor 0.95 illustrated in Figure 5-5 above.

As it can be seen from the graph, power factor has a significant impact on the magnitude of losses, particularly in rural networks. Hence the benefit of improving power factor will be greater in rural networks. For example, by improving power factor from 0.85 to unity, losses reduce from 11.6% to 8.3% in the generic rural network compared with reduction from 5.7% to 4.3% in the generic urban network.

Figure 5-6 and Figure 5-7 show the annual energy losses in the generic urban and rural distribution networks at various voltage levels. Transformer and circuit losses in all parts of the network, from 0.4 kV up to 132 kV, are calculated. Around 75% of the total losses is in distribution lines (OHL and cables) while 25% is in distribution transformers.

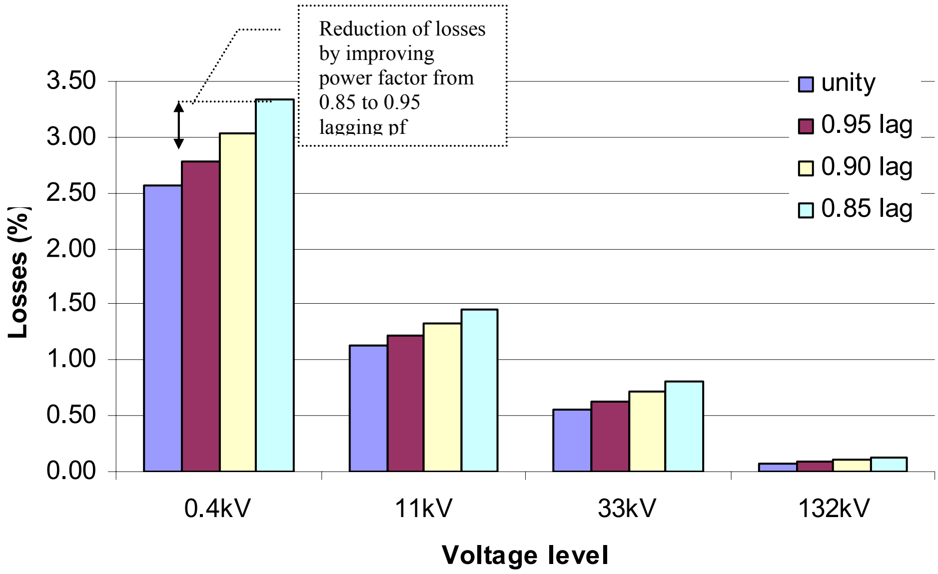


Figure 5-6 Annual energy losses in the generic urban network

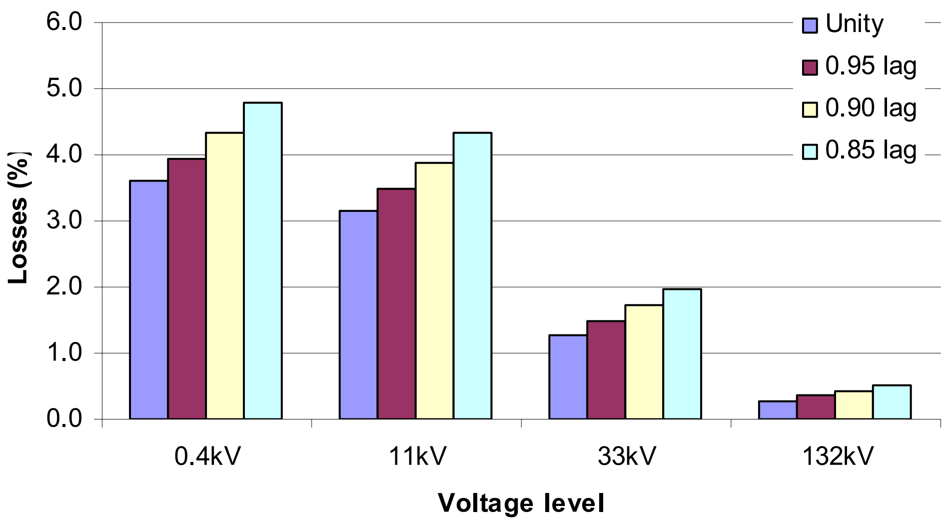


Figure 5-7 Annual energy losses in the generic rural network

Around 78%- 85% of the total energy losses is in 0.4 kV and 11 kV networks (lines/cables + transformers) for both urban and rural networks. Special attention is paid to the proportion of energy losses especially at rural 11 kV, which is significantly larger than that in urban 11 kV networks, due to longer lengths of OHL.

From Figure 5-6 and Figure 5-7, it is possible to analyse the benefits of reactive power compensation (improvements in load power factors) in terms of loss reduction, depending on the voltage level at which compensation is connected. For example, a reduction of 6.4 GWh energy losses per GSP per annum could be achieved, if the power factor is improved from 0.85 to 0.95 through installing appropriate compensation at 0.4kV, as indicated in Figure 5-6.

We have adopted a simplified approach to determine the reduction in energy losses as a function of the voltage level at which reactive compensation devices are connected. This simplification will tend to produce optimistic results as we assumed that the full benefits are obtained at the voltage level at which the compensation is connected. For example, the benefits of installing reactive compensation at 11 kV networks are in reduction of losses at 11 kV, 33 kV and 132 kV circuits while losses at 0.4 kV remain unchanged.

Figure 5-8 illustrates the total amount of reactive power compensation that needs to be installed in the generic distribution network to improve the power factor of the load. For example, if the power factor of loads is on average 0.95 lagging, there will be a need to install around 74 MVAr of reactive compensation (per GSP) to achieve a unity power factor. Assuming that there are around 220 GSPs in the UK, the amount of reactive compensation that would be needed to improve the power factor from 0.95 to 1 is 16.3 GVAr.

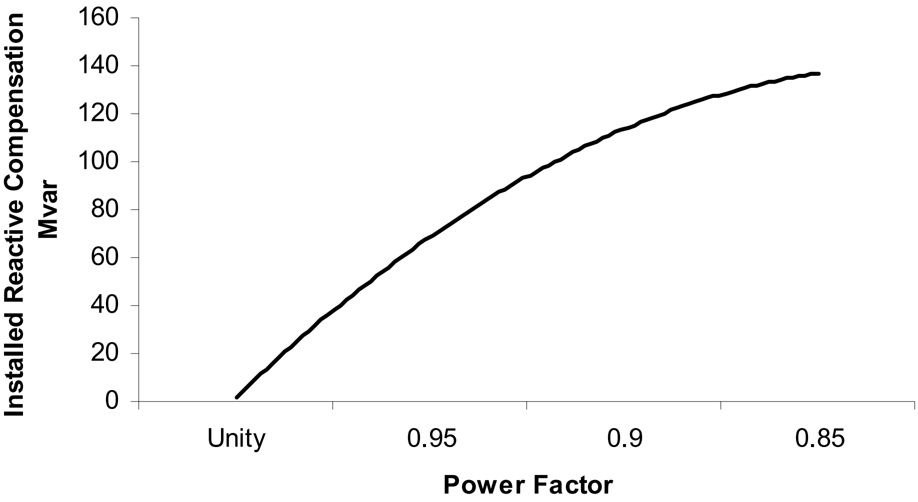


Figure 5-8 Installed reactive compensator required for power factor improvement

By quantifying the reduction of energy losses as savings due to the installation of reactive compensation, depending on the voltage level at which the compensation is connected, the associated value of compensation can be quantified.

Assuming that the average cost of energy is £30/MWh, the average lifetime of equipment is 20 years and the average rate of about 7%, the present value of capitalised saving was calculated. The results are presented in Table 5-5.

Table 5-5 Capitalised loss-reduction related benefits of reactive compensation

	Capitalised saving ('000 £/MVAr)							
	Rural network				Urban network			
Power factor improvement	0.4 kV	11 kV	33 kV	132 kV	0.4 kV	11 kV	33 kV	132 kV
0.85 lag to 1.0 pf	87.58	56.33	24.90	6.11	36.67	16.31	7.88	1.48
0.90 lag to 1.0 pf	69.25	44.80	20.41	5.10	28.96	13.04	6.49	1.25
0.95 lag to 1.0 pf	48.84	32.19	15.67	4.07	20.22	9.40	4.97	1.01

The value of reactive compensation varies significantly between £1,010/MVAr and £87,580/MVAr, depending on the network characteristics, voltage level at which the compensation is connected and the load power factor. The largest value is achieved when the compensation is installed at 0.4 kV in the rural network to improve power factor of loads from 0.85 lagging to a unity power factor. This indicates that application of micrograds in the rural 0.4 kV systems will have the largest potential benefits in this context. On the other hand, the lowest value is associated with installing reactive compensation at 132 kV in urban network when improving the power factor from 0.95 to unity[1].

5.4.3. Role of reactive compensation in reducing reactive demand in transmission system

In this section we examine the impact of installing VAr compensation in distribution networks on the reactive power imports from the transmission grid. Figure 5-9 presents the amount of annual reactive energy imported from the transmission grid into the generic urban and rural distribution networks. The import was found to vary between 0.4 – 1.2 TVArh/ GSP per year depending on the load power factor. This would amount to 88 – 264 TVArh for 220 GSPs.

The import of reactive power is required to supply reactive load at consumer premises and reactive losses in the distribution networks. Note that considerable amount of reactive power is imported form the transmission systems even if no reactive power is demanded by the loads.

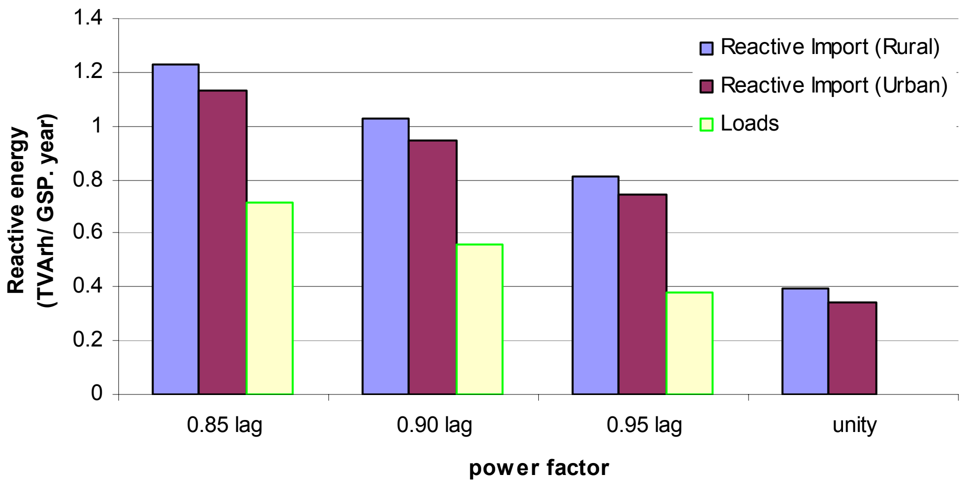


Figure 5-9 Annual reactive energy imported from the transmission network by the generic urban and rural networks

Installing reactive compensation close to the loads as proposed in microgrids, will (i) provide supply of reactive power locally, rather than reactive power being imported from the transmission network and (ii) as a consequence, reduce reactive losses in the distribution network. Both of these effects will contribute to reducing the amount of

[1] In this study, the impact of reactive compensation installed in distribution networks on transmission system real losses is not quantified.

reactive power to be imported from the transmission grid. Figure 5-9 shows a non-linear relationship between the power factor improvement and the amount of the reactive import. The largest rate of reduction is obtained when power factor is improved from 0.95 to unity.

The proportion of reactive losses in distribution networks in the overall reactive power import is significant. For example, 40% of reactive power imported from the grid is to supply reactive losses for the case with 0.85 power factor lagging. With a unity power factor, 100% of the import is due to reactive losses. The impact of the power factor on the level of reactive losses in distribution networks is illustrated in Figure 5-10.

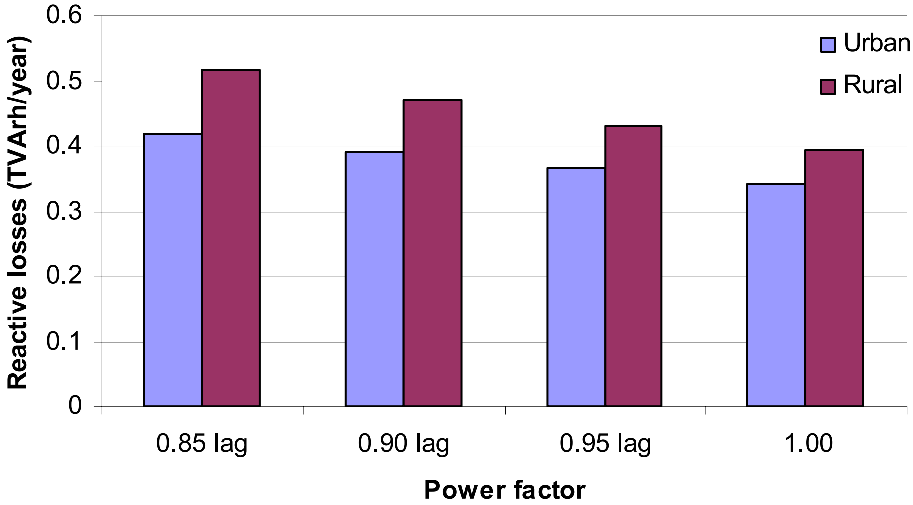
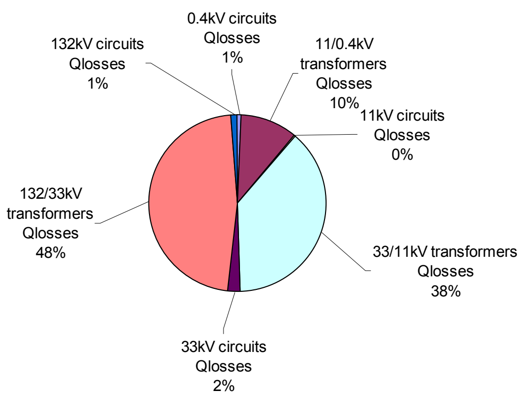
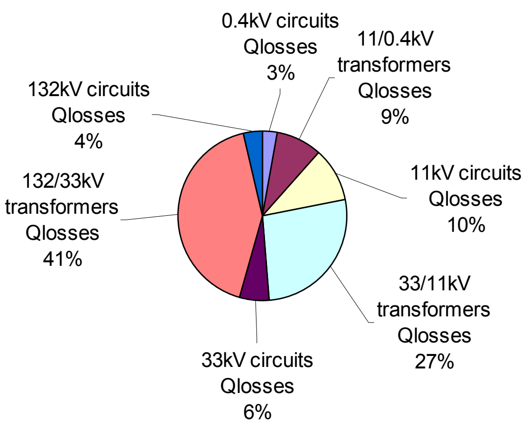


Figure 5-10 Annual reactive power energy losses in the generic urban and rural networks

This includes losses in transformers and circuits (from 0.4 kV up to 132 kV). In the urban generic network total reactive losses are found to vary between 0.34TVArh and 0.41 TVArh, while in the generic rural network this was between 0.39TVArh and 0.51TVArh, depending on the power factor. Reactive losses in rural networks are larger than in urban, as overhead circuits are longer than underground and are characterised by larger reactance.



(urban)



(rural)

Figure 5-11 Distribution of reactive losses in the generic networks

However, the absolute amounts of reactive losses in urban and rural networks are quite close. This is because the majority of reactive losses are in distribution transformers (see Figure 5-12).

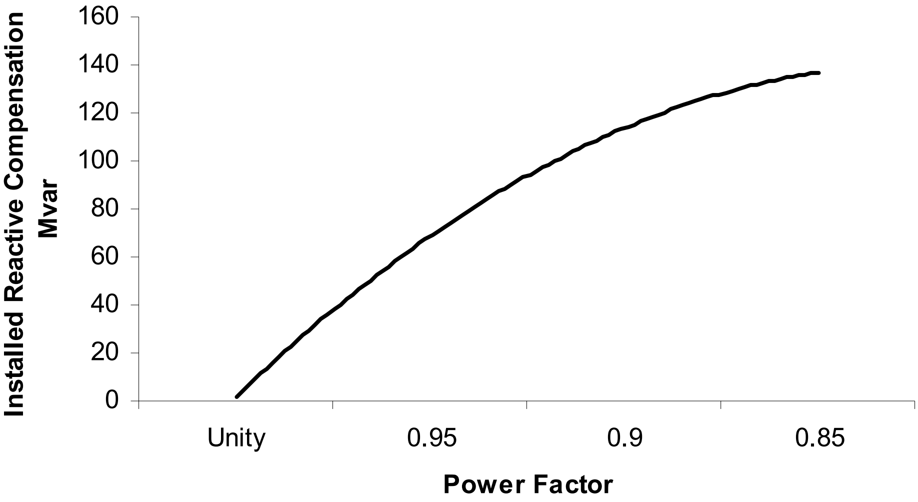


Figure 5-12 Installed reactive compensator required for power factor improvement

Figure 5-12 gives the total amount of reactive power compensation required to make the power factor equal to 1, depending on the value of the initial power factor. For example, if the initial power factor is 0.85 lagging, there will be a need to install around 140 MVAr reactive compensators to achieve a unity power factor.

By quantifying the reduction of reactive power energy imported, the associated value of VAr compensators can then also be quantified, depending on the voltage level at which the connection is actually made (similarly to approach taken in previous section). Given that the average cost of purchasing reactive energy is £1.5/MVArh[2], and assuming that the amount of reactive power that is purchased from commercial reactive power providers (generators) is 10% of total reactive load[3], the capitalised value of reactive compensation is calculated and the results presented in Table 5-6.

Table 5-6 Capitalised role of reactive compensation saving due to reactive import reduction in urban and rural network

	Capitalised saving ('000 £/MVAr)							
	Urban network				Rural network			
Power factor improvement	0.4 kV	11 kV	33 kV	132 kV	0.4 kV	11 kV	33 kV	132 kV
0.85 lag to 1.0 pf	9.04	8.94	8.68	8.19	9.58	9.44	8.97	8.28
0.90 lag to 1.0 pf	8.87	8.79	8.59	8.19	9.30	9.19	8.83	8.26
0.95 lag to 1.0 pf	8.68	8.62	8.49	8.18	9.00	8.92	8.67	8.24

[2] We assumed that TSO payment for utilising reactive power energy is £1.5/MVArh.
[3] Transmission lines and other transmission devices such as SVCs , MSC, etc. provide "free" reactive power since TSO does not include the cost of utilising reactive power from their devices into reactive power market. Our order of magnitude estimates are that TSO in the UK purchases around 25 TVArh/year.

We observe that the value of reactive compensation associated with reducing reactive imports varies in the relatively narrow range between £8,180/MVAr and £9,580/MVAr.

There is no very significant difference between the value in the urban and rural network. This is because the impact of reduction in reactive load is much larger that the impact of reduction in reactive losses. Since the characteristics of transformers in the generic rural and urban network are similar, the amount of reduction in reactive losses in the rural and urban network is not significantly different. It can also be observed that the impact of the voltage level at which the compensation is connected on the value of compensation is not very significant. The largest value (£ 9,580/MVAr) is found for the installation of reactive compensation at 0.4 kV in the rural network to improve power factor of loads from 0.85 to unity.

Clearly the most critical factor in this estimate is the assumption regarding the proportion of reactive power that is purchased from generators to provide the reactive needs of DSOs (assumed to be 10%). More work is required to make more precise estimates.

Installing reactive compensation in distribution networks will reduce reactive losses in the transmission network. This impact will also be location specific. From the transmission network perspective, connecting reactive compensation in distribution networks in the South of the country will have larger benefits (and value) than compensation connected in the North, due to North to South power flows in the UK. More work is required to quantify the impacts of these effects.

We have quantified the value of reactive power taken from the transmission network during peak load conditions using the concept of marginal costing. Assuming that generators sell reactive output at 1.5£/MVArh, we found that the marginal cost of reactive power at the GSP was around £2.25 – £ 2.5 per MVArh.

It is important to bear in mind that at present, the cost of VARs purchased from the generators is not recovered from an explicit reactive charges based mechanism and that therefore there is no (strong) incentive to manage reactive power import from the transmission network.

6. Economic evaluation of an increased quality of service due to microgrids islanded operation

6.1. Introduction

The energy policy in Europe promotes renewable and energy efficient generation technologies. A movement from power systems with a small number of large power stations to a large number of small units is anticipated. A high penetration of small and medium scale distributed generation (DG) including micro generation will require more actively managed distribution networks (DN) such as being proposed in the MicroGrids project. New operation philosophies could manage network and generation assets in an integrated manner. In some cases DG, in the context of micro generation, could be a profitable alternative to traditional network reinforcement. It could defer or reduce network reinforcement by mitigating load growth or by providing security of supply and improving the quality of supply[4].

An improved quality of service due to islanding operation could be perceived by the customer as a reduction in the number and duration of power cuts. In case of distribution networks outages, islanded operation of locally connected micro generation in microgrids could continue to power a disconnected portion of the distribution networks. The island formation through network re-configuration and the islanded operation requires additional network automation and control. In general islanding is regarded as problematic due to the complexity of technical requirements and the costs involved. However, for non-public networks, islanding is used to maintain the power supply of high value demand such as hospitals or industrial sites. DG has already a stake in the premium power market where the assigned higher value of continuous supply justifies the additional costs.

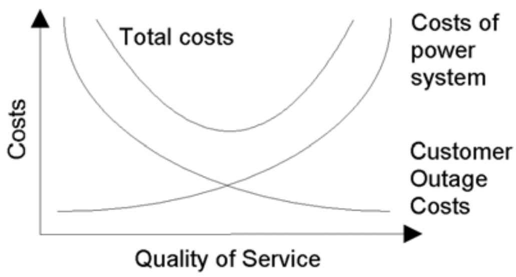


Figure 6-1: Total costs of service quality

A cost worth evaluation can determine if the value of an improved quality of service due to islanding operation outweighs the associated costs. Figure 6-1 shows that the total costs of quality of service are the sum of the customer outage costs and the costs of the power system. Ultimately, the customers will pay the costs to enable islanding operation. Hence, the value of microgrids islanding operation to the customer must be

[4] Quality of supply is defined as the level of service perceived by the customer. It includes, firstly, the quality of service that is concerned with the number and duration of customer interruptions. Secondly, there are Guaranteed and Overall Standards to be met. These comprise the investigation of voltage complaints, making and keeping appointments, the quality of telephone response and replying to correspondence [Quality of Supply, 2003, Ofgem].

established. The presented work quantifies the worth of supply and the value of intentional microgrids islanding operation during abnormal network conditions.

6.2. Worth of Supply Assessment

The reliability of the electricity supply has become a key factor for economic wealth. The costs associated with a certain level of power system reliability are well established, whereas the quantification of the resulting benefits is considered to be more difficult. The interruption costs can vary considerably depending on the demand characteristics of different electricity customer categories.

There are different approaches to quantify customer outage costs. The most common ones are: (a) case studies, (b) analysis of blackouts, (c) statistical analysis (e.g. ratio of gross economic output to energy consumption, (d) customer surveys. The presented work is based on a customer interruption cost survey and a reliability worth evaluation [5],[6]. The value of microgrids islanding is quantified as the benefit from a reduction in customer outage costs (COCs). The assessment of the COCs depends on the customer mix and the reliability of a network area. The applied methodology requires a system, a load and a cost model as input data.

6.3. System Model

6.3.1. System Design

Current power systems are designed to transmit centrally generated bulk electricity over long distances and to distribute it to load customers. A 100% reliable power system cannot be built because of technical and economic constraints as shown in Figure 6-2.

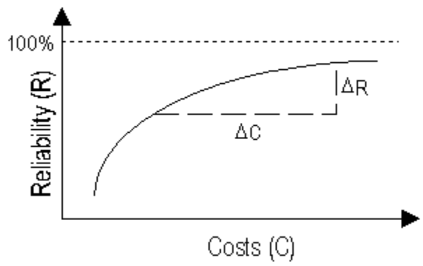


Figure 6-2: Reliability as function of costs

Therefore power systems are designed to provide a certain level of reliability. In general, higher voltage levels supply higher group demands and have higher security of supply requirements. The recommended minimum level of security is stipulated in the engineering recommendation P2/5 (ER P2/5). Table 6-1 excerpts from ER P2/5 Table 1 and gives the times after the minimum demand has to be met following a first stage outage. The allowed restoration times are higher for lower group demands.

Table 6-1: Excerpt of ER P2/5 Table 1

Class of Supply	Range of Group Demand	Minimum Demand to be met after First Circuit Outage	
A	Up to 1MW	In repair time:	Group Demand
B	Over 1MW to 12MW	Within 3h: In repair time:	Group Demand – 1MW Group Demand
C	Over 12MW to 60MW	Within 15min: Within 3h:	- For Group Demand from 12MW to 36MW: Group Demand – 12MW - For Group Demand from 36MW to 60MW: 1/3rd Group Demand Group Demand

The level of security of supply and the degree of redundancy in current power systems is simplistically depicted in the left diagram of Figure 6-3. The right diagram shows the potential contribution of microgrids islanding. The Microgrids concept has the highest potential to improve the security and quality of supply at the lower voltage levels. Interestingly, a large amount of micro generation is expected to connect to these voltage levels.

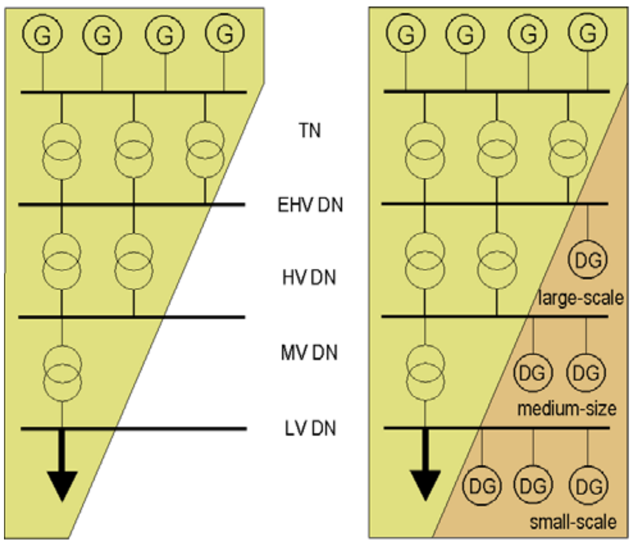


Figure 6-3: Security of supply as function voltage level: without and with DG

The impacts of network design, equipment design and different levels of security of supply are reflected in fault statistics. Figure 6-4 and Figure 6-5 summarises the distribution of customer interruption (CI) and customer minutes lost (CML) in respect to the voltage level.

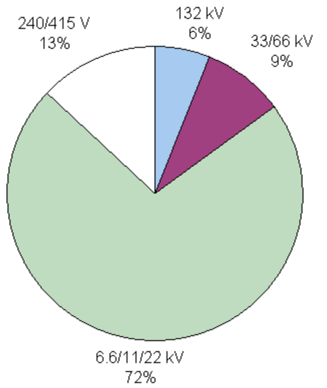


Figure 6-4: Customer interruptions

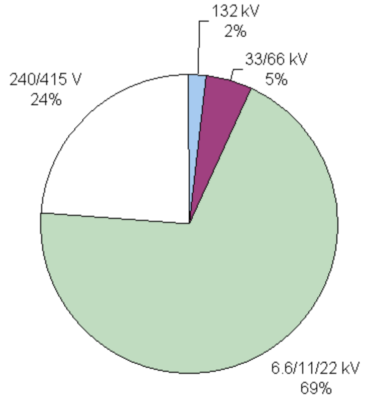


Figure 6-5: Customer minutes lost

The majority, 72 percent of the customer interruption and 69 percent of the customer minutes lost have their cause in the medium voltage distribution networks. The medium and low voltage distribution networks performance has the dominant impact on the perceived quality of service. The average number of CI and CML in Great Britain were 87.4 per 100 customers and 83.7min respectively in 2001/2002 [7]. This equals an average overall availability of around 99.98 percent, whereas the reliability of the transmission system is around 99.998 percent. Typical power systems of developed countries have reliabilities between 99.9% and 99.99%. The average availabilities of some European countries [Annual Report 2002, VDEW, Germany] are depicted in Figure 6-6. Reference availabilities and their corresponding annual times without supply are given in Figure 6-7.

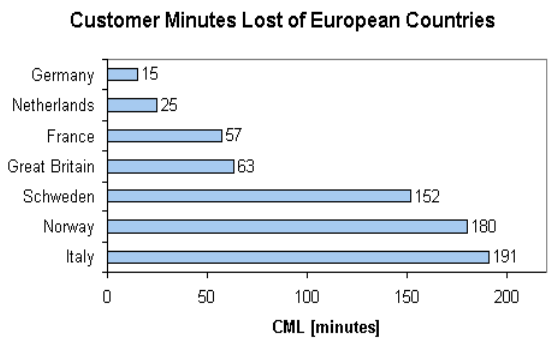


Figure 6-6: Average duration of interruptions per customer in 1999 (NB: France excludes impact of storm)

Availability	Annual time without supply
99.9%	8h 46min
99.99%	53 min
99.999%	5.3 min

Figure 6-7: Availability and corresponding annual time without supply

6.3.2. Modelling

<u>Reliability Indices</u>

The fundamental reliability indices are the average failure rate λ, the average outage duration r and the average annual unavailability U. These non-deterministic indices represent the long-run average or expected values of an underlying probability distribution function. The adjective 'average' is implicit and therefore often omitted. These indices do not reflect the severity of an outage because the number of connected or affected customers, and the characteristic of the connected load are not considered. That is why the system performance is commonly assessed by means of customer-related and energy-related interruption data. Typical customer-related indices are security and availability. They are measured as customer interruptions (CI) per 100 consumers and customer minutes lost (CML) respectively. These indices are known as SAIFI and SAIDI, as well. Other commonly used customer-related reliability indices, such as CAIFI, CAIDI, ASAI/ASUI; and the energy-orientated index AENS are described in Table 6-2 [8], [9].

Table 6-2: Definition of reliability indices

SAIFI/ CI	**System Average Interruption Frequency Index/ Customer Interruptions**: the average number of interruptions per customer per year
SAIDI/ CML	**System Average Interruption Duration Index/ Customer Minutes Lost:** the average interruption duration per customer served per year
CAIFI	**Customer Average Interruption Duration Index**: the average number of interruption per customer affected per year
CAIDI	**Customer Average Interruption Duration Index:** the average interruption duration per customer interruption
ASAI	**Average Service Availability Index:** the ratio of the total number of customer hours that service was available during a year to the total customer hours demanded
ASUI	**Average Service Unavailability Index:** the ratio of the total number of customer hours that service was unavailable during a year to the total customer hours demanded
AENS	**Average Energy Not Supplied:** the average energy not supplied per customer served per year

The applied worth of supply assessment is based on a system model that reflects the (dis-)continuity of the electricity supply. The probabilistic nature of power systems and the outage of generation and distribution plant are modelled by means of reliability indices. The outage rate λ describes how often outages are expected within a defined period of time, i.e. normally one year. The outage duration r defines the time to repair or replace the faulty component. This work neglects the impact of planned outages because most interruptions are caused by forced outages. The reliability indices r and λ can be determined based on statistics and computational methods. However, they can vary significantly at different locations due to environmental conditions and the quality of the electrical equipment.

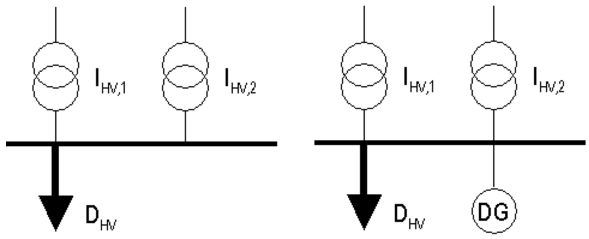


Figure 6-8: HV-system model: two independent infeed without (a) and with (b) DG

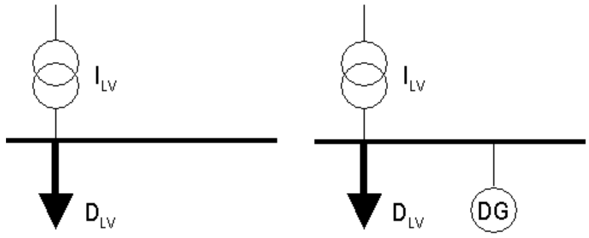


Figure 6-9: LV-system model: one infeed without (a) and with (b) DG

System models

Figure 6-8 and Figure 6-9 depict simplified HV and LV system models. The important difference between the HV and LV model is the higher level of redundancy provided by the second infeed. The system configurations in Figure 6-8 and Figure 6-9 implicitly assume that the distribution networks and the DG are operated in parallel, and that the transition into islanded mode takes place without supply interruption. Whereas the system models of Figure 6-10 imply that there is at least a short supply interruption before the load is restored by network reconfiguration or is switched over into islanded mode. Such system configuration can therefore only reduce the outage durations but not the outage rate. Hereafter, the uninterrupted and interrupted transition into islanding mode are referred to as continuous and switchover respectively. The reconnection of the lost load to a sound part of the distribution networks is referred to as load transfer.

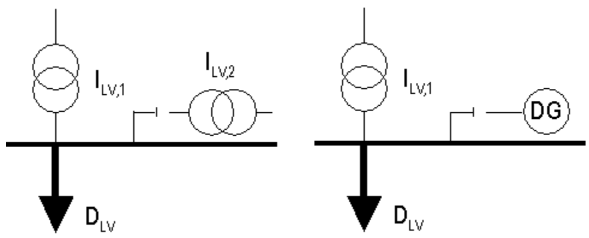


Figure 6-10: System restoration by means of load transfer (a) and switch over into DG islanding mode (b)

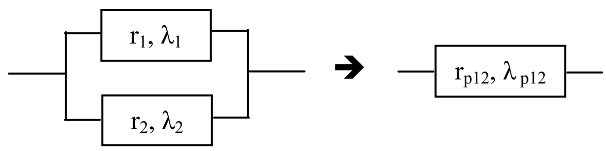
The system models consider two types of supply points: infeeds from other parts of the distribution networks and locally connected DG. The capacity rating of each infeed ILV, IHV,1, IHV,2 and DG is assumed to exceed the peak load of the aggregated demand (DLV, DHV). This implies that DG can supply the grid-disconnected portion of the distribution networks in islanded mode. The operation of an island whose demand differs from the aggregated demand under normal network conditions can be considered by means of adjustment factors.

Network Reduction Method

The applied approximate network reduction method, calculates one pair of composite outage-rate-duration indices λ and r for each system model. The method gradually combines the r and λ indices of series and parallel network components [3, 4]. The resulting pair of r_i and λ_i describes the average interruption rate and duration of the aggregated demand; this means the contemporaneous outage of all supply points.

The composite r and λ indices for two redundant network components can be calculated in accordance to equations 6-1 to 6-3. These formulae are valid under the assumption that the outage of an individual component is independent from each other. Each index represents one network component such as one infeed or DG.

Formulae for two redundant repairable network components:



$$\lambda_{p12} = \frac{\lambda_1 \lambda_2 (r_1 + r_2)}{1 + \lambda_1 r_1 + \lambda_2 r_2} \approx \lambda_1 \lambda_2 (r_1 + r_2) \qquad \text{when}^5\ \lambda_i r_i < 0.01 \tag{6-1}$$

$$r_{p12} = \frac{r_1 r_2}{r_1 + r_2} \tag{6-2}$$

$$U_{p12} \approx \lambda_1 \lambda_2 r_1 r_2 \tag{6-3}$$

where: λ: Average outage rate [units/year] p: Parallel connection
r: Average outage duration [h] U: Expected annual outage time [h/year]

Calculated and Surveyed Data

By means of the system models given in Figure 6-11, it is demonstrated how two independent infeeds (left diagram), each with the reliability indices r_1 and λ_1, can be represented by the indices r_2 and λ_2 of one composite infeed (right diagram). The calculated results are then compared to surveyed data.

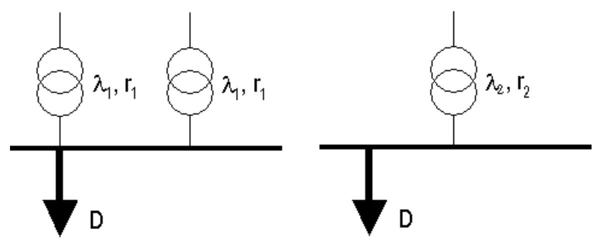


Figure 6-11: Two infeeds system model and resultant one infeed representation

The input data λ_1 and r_1 for each single infeed is shown in Figure 6-12. Three sets of input data were studied. The outage duration r_1 of each single infeed is varied from $0 < r_1 < 24$h and its outage rate is chosen as three time ($\lambda_1 = 3$) a year, once a year ($\lambda_1 = 1$) and every three years ($\lambda_1 = 0.33$). The resultant outage rates λ_2 and durations r_2 of the combination of two infeeds are depicted in Figure 6-13. It can be seen that the outage durations halved ($0 < r_2 < 12$h) in accordance to Equation 6-2 since the input data

[5] $r*\lambda < 0.01$ implies that the downtime of a component is much smaller than the uptime. In this case the downtime would be less than 87.6h (=8760h * 0.01) per year.

consists of two identical single infeeds. The outage rates reduced in accordance to Equations 6-1 and are significantly smaller than the outage rates of one single infeed. The example shows that redundant network design can reduce the number and duration of outages.

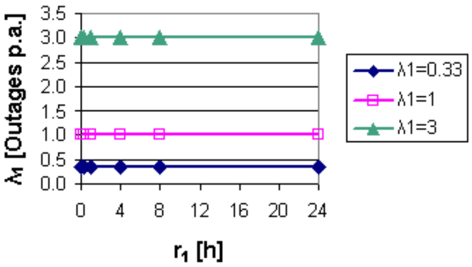


Figure 6-12: Input data r_1 and λ_1 of each single infeed

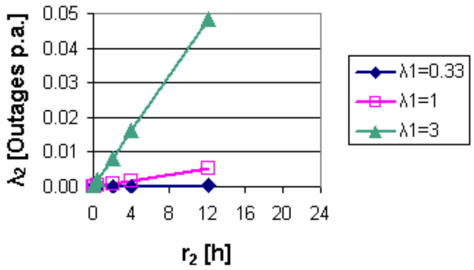


Figure 6-13: Resulting combined r_2 and λ_2 of two infeeds

However, in reality, it must be noted that distribution networks double-circuits often cannot be considered as two independent infeeds since they are connected to the same transmission system. Table 6-3 compares surveyed and calculated reliability data [10]. The outage of a double-circuit is defined as the loss of both infeeds. It can be seen that the outage rate of the surveyed case is significantly higher than the calculated outage rate that considers completely independent supply points.

Table 6-3: Comparison of surveyed versus calculated reliability data

Distribution network circuits:	Outage rate λ	Outage duration r
Surveyed single-circuit	1.956 p.a.	1.32 h
Surveyed double-circuit	0.312 p.a.	0.52 h
Calculated double-circuit data (assuming that the surveyed single-circuit λ and r are independent	0.0012 p.a.	0.66 h

It can be concluded that the calculated data must be used with caution and the assumption of independent supply points must not be forgotten. In general, it is expected that the power supply of the distribution networks and DG are more independent than of two distribution networks infeeds. Typical DG reliability data is given in Table 6-4 [4].

Table 6-4: Reliability data of DG (less than 2MW)

Distributed generation:	Outage rate λ	Outage duration r
Continuous-duty diesel	3.9 – 4.3 p.a.	2.9 – 6.4 h
Standby diesel	0.9 – 1.2 p.a.	2.8 – 3.9 h
Continuous-duty gas turbine	4.5 p.a.	7.2 h
Standby gas turbine	0.3	111.6 h

6.4. Load Model

The load model comprises information on the customer mix, peak demand and annual energy consumption. It also defines customer sectors and subsectors. Figure 6-14 shows the distribution of the UK electricity demand by sector in 2001 [Digest UK Energy Statistics 2002, DTI]. However, the UK electricity demand data cannot be directly used as a generic load mix because it does not consider the impacts of the voltage level and location on the customer mix.

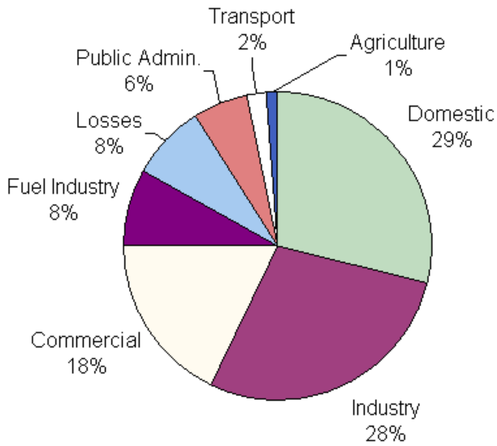


Figure 6-14: Electricity demand by sector in 2001

This work considers four main customer sectors: (a) residential, (b) commercial, (c) industrial, (d) large users. Table 6-5 gives an example for a load model of a network area with three customer sectors [11]. The given load factors are used throughout all case studies in this work. The customer sectors are defined in Table 6-6 and are consistent with the sector definitions of the customer interruption cost survey.

Table 6-5: Load model

Load model		Customer Sectors			Demand	
		Residential	Commercial	Industrial	Combined	Average Combined
E_y	(MWh pa)	8700	14600	9800	33100	
L_y	(MW)	2.43	3.97	2.00	8.40	3.78
LF_y	(%)	40.9	42	55.9	45.0	

where E_y: Annual energy consumed by sector y LF_y: Load factor of sector y
L_y: Peak demand of sector y

6.5. Cost Model

The cost model quantifies the costs of supply outages in monetary terms. The valuation takes into account the rate and duration of interruptions as well as the associated cost characteristics of the customer mix. The cost model consists of three parts: (a) the derivation of the composite customer damage function of the customer mix, (b) the calculation of customer outage costs, (c) the adjustment for load transfer.

6.5.1. Composite Customer Damage Function

The composite customer damage function (CCDF) $C(r_i)$ expresses the normalised costs of supply interruptions for a given customer mix and interruption duration r. Typically, the costs are normalised in £/kW of peak demand or £/kWh of annual energy consumption. The CCDF is composed out of sector customer damage functions (SCDF). Each SCDF reflects the average costs that incur to a specific customer sector for different interruption durations. Table 6-6 summarises the customer sectors surveyed by UMIST [5, 6, 7]. The corresponding SCDF CL,y(r_i) values are given in Table 6-7.

Table 6-6: Customer sector and subsector definitions

Sector:	Residential	Commercial	Industrial	Large User
Subsector:	- Small - Medium - Large - Economy 7	- Retail - Others	< 100kW > 100kW	> 8MW

Table 6-7: $C_{L,y}(r_i)$ - £/kW for sectors surveyed (* extrapolated values)

Interruption Durations: r_i [min]	Sector (y): Residential	Commercial	Industrial	Large User
<1	-	0.99	6.15	6.74
1	-	1.02	6.47	6.74
20	0.15	3.89	14.27	6.86
60	0.54	10.65	25.26	7.18
240	3.72	39.04	72.22	8.86
480	7.96*	78.65	120.11	9.71
1440	24.92*	99.98	150.38	13.35

The cost data should represent the consumer characteristics of the concerned network area and should ideally come from a recent survey. The cost data depicted in Table 6-7 was surveyed in 1992/93 and therefore it was inflated to the year 2003. A mathematical update of the costs to present level was carried out based on the assumption that the customer interruption costs have changed in accordance to the retail price index (RPI). For the last 10 years the RPI increased around 29% and therefore the costs, given in Table 6-7, were multiplied by an inflation adjustment factor Iy of 1.29 in Equation 6-4. We are aware that the progression of the RPI is not concordant with change of the SCDFs, and that the cost model does not reflect power quality issues and very short supply interruptions. However, it is assumed that the cost model used provides an estimate of the order of magnitude of the customer interruption costs.

The CCDF is the weighted sum of SCDFs. The weighting factors are calculated in accordance to the customer mix of the network area that is specified by the load model in Section 6.4.

$$C(r_i) = \sum_{y}^{ny} \frac{I_y \times C_{L,y}(r_i)}{LF_y \times 8.76} \times \left(\frac{E_y}{\sum_{y}^{ny} E_Y} \right) \quad \text{in £/MWh} \tag{6-4}$$

where:

$C(r_i)$:	Composite customer damage function	I_y:	Inflation adjustment factor by sector
$C_{L,y}(r_i)$:	Sector customer damage function for sector y	n:	Number of customer sectors
LF_y:	Load factor of sector	r_i:	Duration of interruption
E_y:	Annual energy consumed by sector y	y:	Index of sector

6.5.2. Customer Outage Cost Formulae

Customer Interruption Costs (CICs) are the costs of an electricity supply interruption perceived by an individual customer or an average electricity consumer within a customer sector. CICs are the costs stated in customer survey responses, therefore CICs are considered to be system independent. Whereas, the system dependent customer outage costs (COCs) reflect the customer mix and consider loading information as well as network performance data. COCs are defined as the total expected costs incurred by all the customers connected to a network area. They are calculated for each load point i in accordance to Equation 6-5.

$$COC_i = \left(\sum_{y}^{ny} E_{iy} \right) \times C_i(r_i) \times \lambda_i \quad \text{in £} \tag{6-5}$$

The load model provides the annual energy consumption E_{iy} for all ny customer sectors and the customer mix information for the cost model. Hence, different load models result in different CCDFs $C_i(r_i)$. The system model provides the average annual outage duration r_i and the average annual outage rate λ_i, whereas the CICs were surveyed per interruption. Therefore, the usage of annual averages as inputs of CCDF results in lower COCs than the average of COCs calculated per interruption.

$$COC_j = \left[\left(\frac{L_{T1}}{L_j} \right) C_j(r_{T1}) + \left(\frac{L_j - L_{T1}}{L_j} \right) C_j(r_j) \right] \lambda_j E_j \tag{6-6}$$

$$COC_j = \left[\left(\frac{L_{T1}}{L_j} \right) C_j(r_{T1}) + \left(\frac{L_{T1} - L_{T2}}{L_j} \right) C_j(r_{T2}) + \left(\frac{L_j - L_{T2}}{L_j} \right) C_j(r_j) \right] \lambda_j E_j \tag{6-7}$$

where:
- L_j: Average demand (MW) for load point j
- L_{Ti}: Average load transfer capacity (MW) available after effecting the i-th restoration stage
- r_{Ti}: Average time to effect the i-th restoration stage

The COCs calculated in accordance to Equation 6-5 consider that the total lost load is restored in the average interruption duration time. Equation 6-5 can be expanded to consider that some portion of the lost load is restored faster. Load transfer is a means of restoring a portion of the lost load by system re-configuration. The disconnected loads are reconnected to a sound part of the distribution network or are reenergized by DG in islanded mode (referred to as switchover in Section 6.3.2) while the faulty network components are being repaired or replaced. Equations 6-6 and 6-7 consider load transfer and calculate the customer outage costs for a one-stage restoration process and a two-stage restoration process respectively. The formula for a n-stage restoration process can be developed accordingly.

6.5.3. Sector Customer Outage Cost Functions

Figure 6-16 to Figure 6-18 illustrate the COCs of the SCDFs of Table 6-7. It can be seen that the COCs of different customer sectors vary significantly. The COCs are normalised per peak demand. The attribute 'peak demand' is implicit and is omitted hereafter.

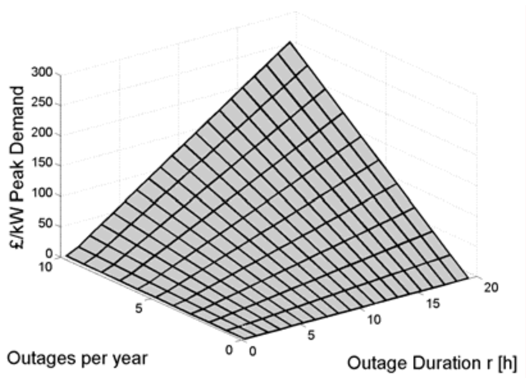


Figure 6-15: COCs of residential customers

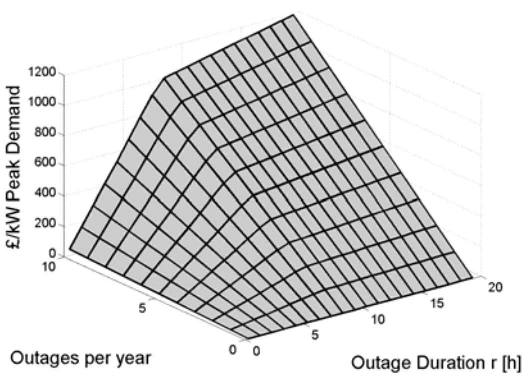


Figure 6-16: COCs of commercial customers

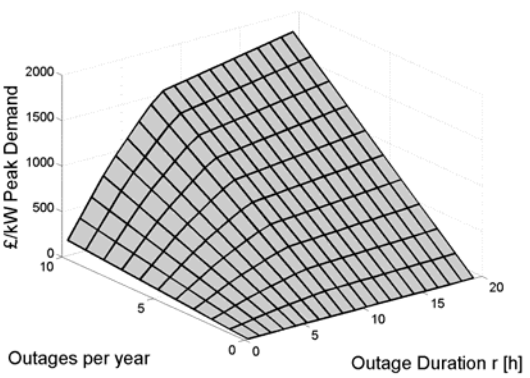


Figure 6-17: COCs of industrial customers

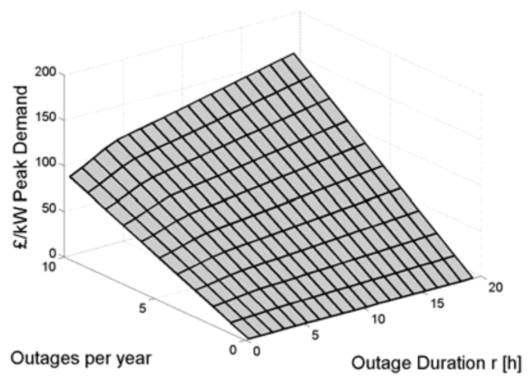


Figure 6-18: COCs of large users

Figure 6-19 depicts the COCs of residential and commercial customers; and the average outage rate λGB ≈ 0.9 and duration rGB ≈ 1.6h of British distribution networks marked as the vertical line [1]. The interception points between the COC surfaces and the British average line indicates the region of the expected average COCs for commercial (upper surface with white gird lines) and residential (lower surface with black grid lines) network areas. The line connecting the two points of interception indicates the average COCs of mixed residential and commercial network areas. The intercept points of the average rGB and λGB values with the COC surfaces for residential and commercial customers result in COCs of around 1 £/kW and 20£/kW respectively.

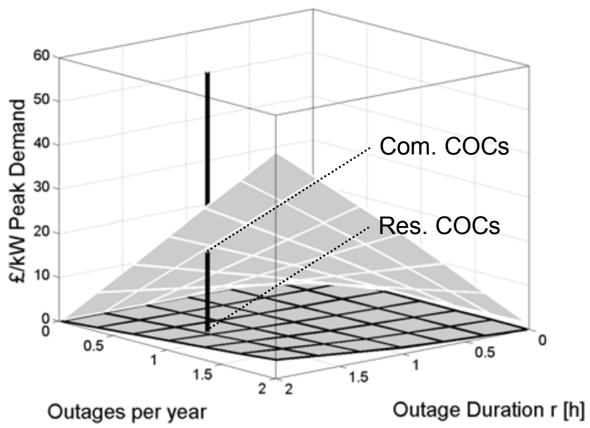


Figure 6-19: COCs of residential (black grid lines) and commercial (white grid lines) customers

6.6. Case Studies

The case studies were conducted to investigate the potential benefits of intentional islanding as corrective measure to network outages. The case studies focus on distribution network areas supplied by one single-circuit utility infeed and of DG. It assumes that technology, and engineering guidelines enables microgrids islanding. The applied methodology assesses the COCs of network areas with and without microgrids islanding. Figure 6-20 illustrates how the benefit of islanding is quantified as the reduction in COCs. The solid circle indicates the COCs of the distribution networks without islanding. The triangle marks the parallel distribution networks and microgrids operation during normal and islanding operation during abnormal network conditions.

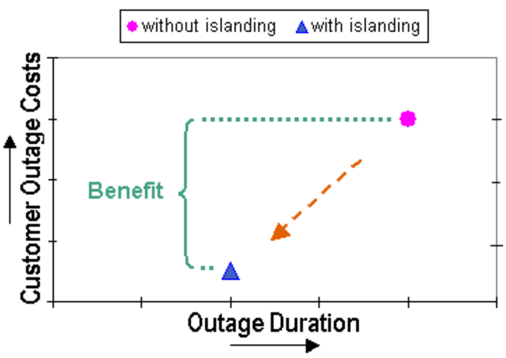


Figure 6-20: Customer Outage Cost Assessment

Figure 6-21 shows qualitatively that the continuous and switchover transition into islanded mode must be evaluated separately. The continuous transition into islanding mode sustains the supply so that customers do not experience an interruption. Hence, it reduces the outage duration r and outage rate λ. The COCs are calculated in accordance to Equation 6-5 by using the composite r and λ. The switchover into islanding mode results in reduced interruption durations only, and does not avoid a short interruption. In this study the switchover time is assumed to be negligible. Therefore, the unchanged outage rate of the distribution networks without islanding and the composite outage duration as calculated by Equation 6-2 are used for the COC calculation. The COCs are determined in accordance to Equation 6-6 considering that the total load is switched over to the DG.

Figure 6-21 illustrates that the reduction in COCs compared to the base case without islanding (o), is higher if both the outage rate and duration are reduced (x) compared to a sole reduction of the outage duration (+). The corresponding benefits are marked in Figure 6-22.

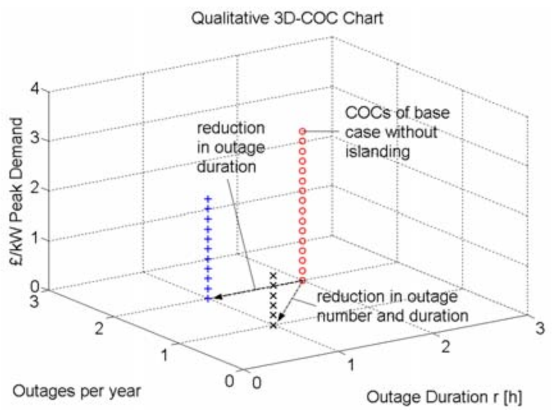


Figure 6-21: 3D-COC chart

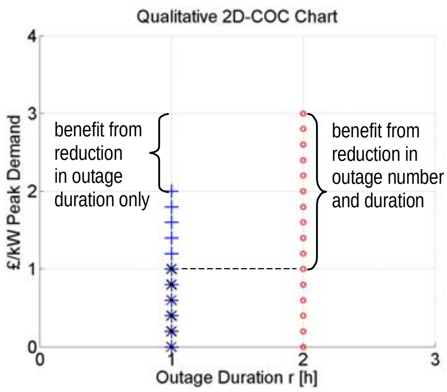


Figure 6-22: 2D-COC chart

6.7. Basic Example

The example investigates the benefits from islanding of distribution networks areas supplied by a single-circuit infeed and DG. The reliability data of the infeed and DG are given in Table 6-8 [10], the studied system models are illustrated in Figure 6-9.

Table 6-8: Distribution Networks (DN) and DG reliability data

	DN only:	DG only:	DN & DG:
Outage Duration r:	1.32 h	7.19 h	1.12 h
Outage Rate λ:	1.96 p.a.	4.50 p.a.	0.01 p.a.
Availability:	99.97 %	99.6 %	99.99 %
CML:	155 min	1941 min	0.7 min

Figure 6-23 and Figure 6-24 shows the resulting COCs of residential and commercial electricity consumers for four cases that were studied: (1) DN without islanding (2) DG islanding as normal operating conditions, (3) Parallel operation of DN and DG under normal operation condition and the continuous transfer into islanded mode during DN outages, (4) Islanded operation through switchover during distribution networks outages. The abscissa represents the outage duration r and the dashed lines indicate the outage rates λ = 3, λ = 1, λ = 0.33. The resulting COCs can be read in £/kW from the ordinate.

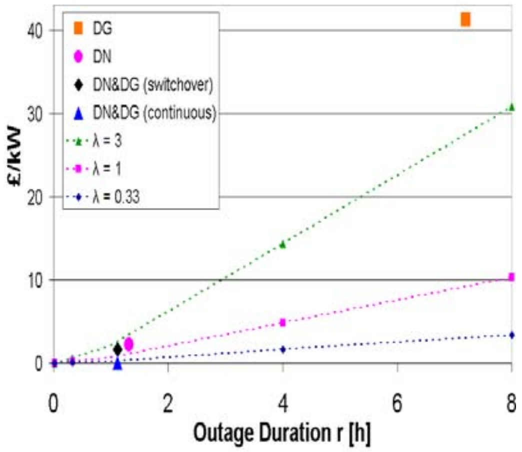


Figure 6-23: COCs of residential customers

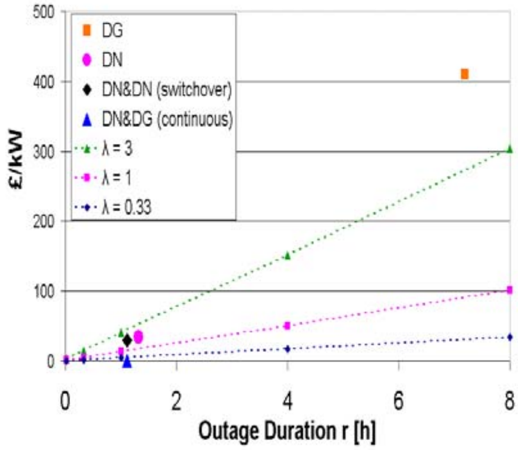


Figure 6-24:COCs of commercial customers

Figure 6-25 and Figure 6-26 show that the benefits of the switchover case is around £0.5/kW for residential and £5/kW for commercial customers, while Figure 6-27 and Figure 6-28 depict the benefits of the continuous transition into islanding as £2.2/kW and £35/kW respectively. The results suggest that there is substantial benefit in the avoidance of interruptions and therefore a continuous transition into islanding mode. However, present guidelines require the disconnection of DG during network disturbances.

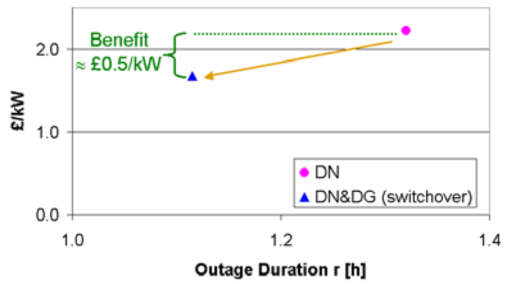


Figure 6-25: COCs of residential customers considering switchover into islanding mode

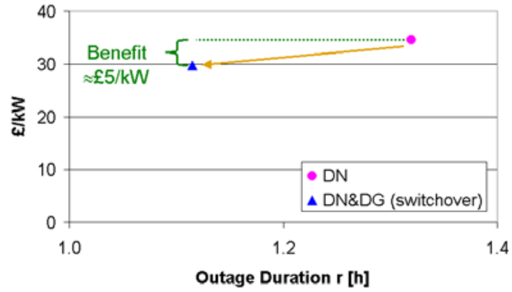


Figure 6-26: COCs of commercial customers considering switchover into islanding mode

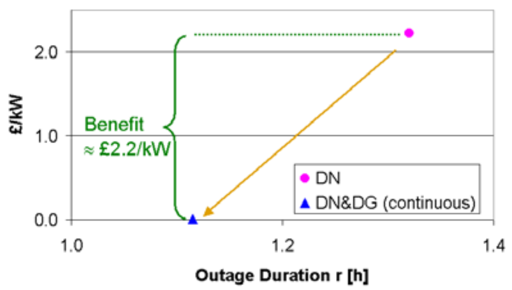


Figure 6-27: COCs of residential customers

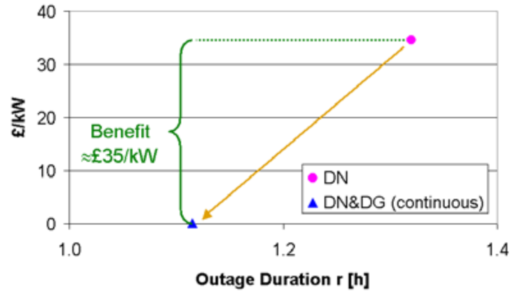


Figure 6-28: COCs of commercial customers

considering continuous transition into islanding mode

considering continuous transition into islanding mode

6.8. Sensitivity Study

The sensitivity study aims to identify the impact of varying input data. It assesses the benefits of different reliable DG connected to different reliable distribution networks. The input data, as summarised in Table 6-9, comprises a high and low reliability case for the distribution networks and DG. The distribution networks data considers outage durations between 20 minutes and 24 hours. The outage rate of the distribution networks infeed is given as once every three years as best case (DN+) and three times a year as worst case (DN-). The DG best case (DG+) assumes one four-hour outage per year. The DG worst case (DG-) considers that the DG fails on average for two days per month. It is anticipated that such a product is not marketable, despite its availability of 93%. In addition, the average British interruption duration and rate are given as a benchmark (GB).

Table 6-9: Outage-rate-duration input data

	DN+:	DN-:	DG+:	DG-:	GB:
Duration r:	20 min – 24 h	20 min – 24 h	4 h	48 h	1.6 h
Rate λ:	0.33 p.a.	3 p.a.	1 p.a.	12 p.a.	0.9 p.a.
Availability:	-	-	99.95%	93.4%	99.98%

The input data is illustrated in Figure 6-29 and the outage durations r and rates λ of the resulting DN-DG-combinations are shown in Figure 6-30. The GB average lies within the band of the DN input data but has a higher outage rate as the resulting DN-DG-combinations. This is in line with the assumption that network areas that can sustain their supply by islanded operation during distribution network outages have lower outage rates and durations.

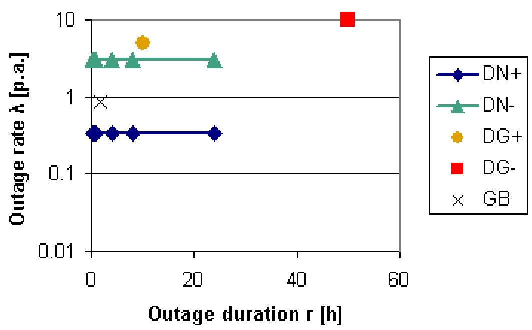


Figure 6-29: Input data λ, r of the DN and DG

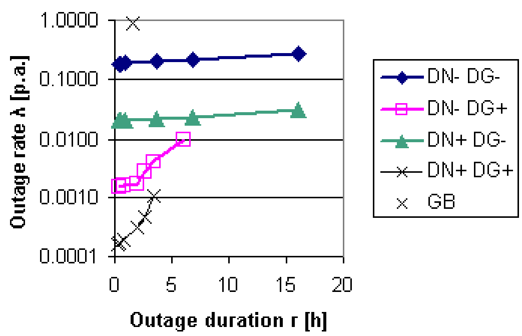


Figure 6-30: Resulting λ, r of the DN-DG-combinations

The resultant benefits for each DN-DG-combination are derived as the difference in COCs between the base cases DN-, DN+ and the corresponding DN-DG-combinations.

The abscissa is the outage duration of the distribution networks. The ordinate gives the potential benefit in £/kW that could be obtained from islanding during grid outages.

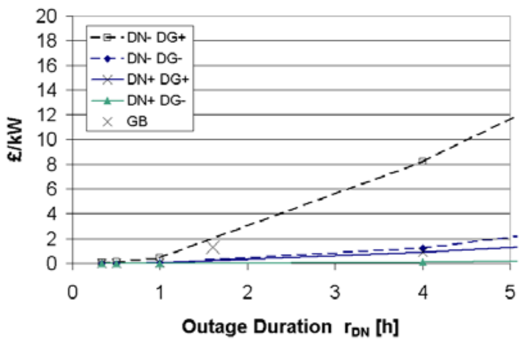


Figure 6-31: Benefit for residential customers considering switchover into islanding mode

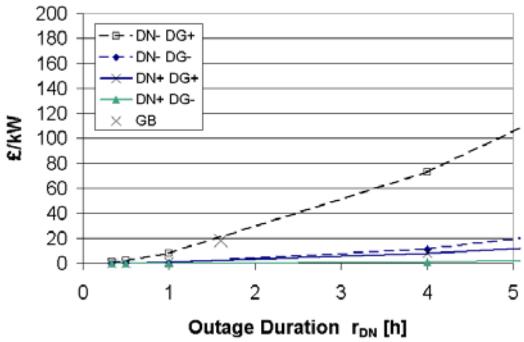


Figure 6-32: Benefit for commercial customers considering switchover into islanding mode

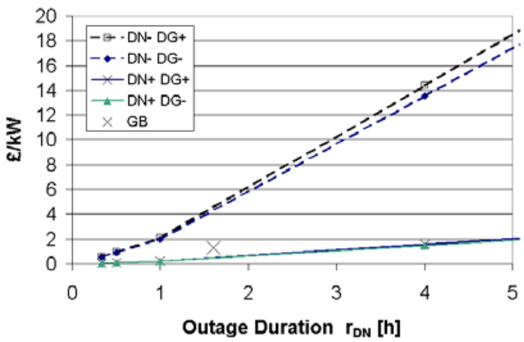


Figure 6-33: Benefit for residential customers considering an uninterrupted transition into islanding mode

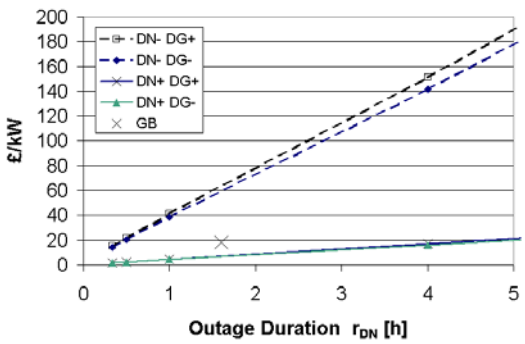


Figure 6-34: Benefit for commercial customers considering an uninterrupted transition into islanding mode

The resulting potential benefits for the switchover transition into islanding mode are depicted in Figure 6-31 and Figure 6-32. It can be seen that the average annual outage duration of the DG has a strong effect. Whereas the impact of the outage duration is secondary considering the continuous transition into islanding mode, as shown in Figure 6-33 and Figure 6-34. It can be seen that the difference between the DG+ and DG- case for the same distribution networks data is significantly smaller as is the benefit. The impact of different reliable DG on a network with the lower reliability (DN-) is depicted as a small gap between the two dashed lines (DN-DG-, DN-DG+). While the impact on the highly reliable network (DN+) is marginal and no gap is visible between the lines (DN+DG-, DN+DG+). In Figure 6-33, the difference between the DN-DG+ and DN-DG- cases is less than 1 £/kW for $\lambda = 3$ (DN-) and rDN = 5h while the benefit is around 18 £/kW. Therefore, less than 5 percent of the benefit was attributed to DG reliability in the continuous transition case. However, for the switchover cases the impact of the outage duration on the benefit was around 80 percent. It can be concluded that the DG's reliability has greater impact on the potential benefit considering the switchover transition into islanding mode.

The potential benefit of islanding lies between the top (DN-DG-) and the bottom line (DN+DG+). In Figure 6-34, the benefit ranges from almost zero up to around 200 £/kW depending on DN and DG data. The maximum benefit is limited by the COCs of the base case distribution networks area without islanding. If the network performance without DG is assumed to commensurate with the average British distribution networks then the potential benefit has the order of magnitude of the corresponding COCs. The COCs of the average British distribution networks (GB) are estimated to be around 1£/kW and 20£/kW for residential and commercial customers. However, the transition mode can have a significant impact on the fraction of potential benefits that can be exploited, as shown in Figure 6-31 to Figure 6-34.

6.9. Maximum Expenditure on DG Islanding

DG islanding operation during abnormal network conditions is only economic if associated costs do not exceed the benefit. The maximum expenditure on equipment to enable DG islanding is therefore limited by the associated benefit. In the previous section, the maximum annual benefit of continuous transition into islanding mode was quantified as 1£/kW and 20£/kW for the average residential and commercial customers.

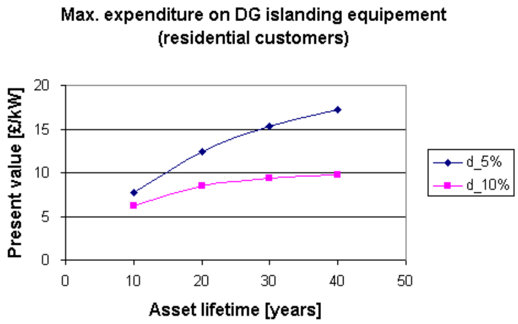


Figure 6-35: Permissible expenditure for residential customers

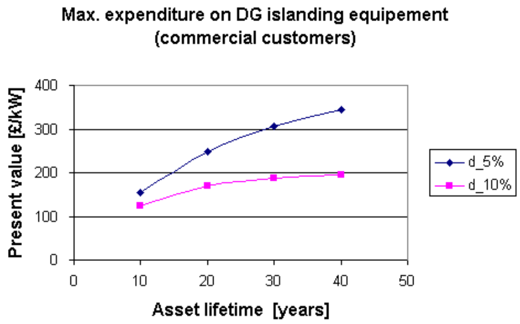


Figure 6-36: Permissible expenditure for commercial customers

Based on these values the resultant permissible expenditure is given as present values in Figure 6-35 and Figure 6-36. Different asset lifetimes from 10 to 40 years and discount rates d from 5% to 10% were studied. Considering an asset lifetime of 20 years the present values of the islanding benefits are around 10£/kW and 200£/kW for residential and commercial consumers respectively. Therefore islanding operation of small-scale DG, such as 2kW DG supplying one household, would permit an expenditure of around £20 to upgrade for islanding operation. On the other hand, a 1MW network area of commercial customers would support an investment of around £20,000 to enable islanding. Above examples are based on average values. The permissible expenditure can be higher in network areas with a lower quality of service and reliable DG. Furthermore, the number of customers connected to a service area and their load characteristics must be considered. For instance, the lower distribution networks service quality of rural network areas increase the potential benefit but the lower customer densities limit the benefit.

For most DG energy sales are the main source of income. Therefore islanding would be a secondary income source that would be profitable if the additional income outweighs the associated additional costs. In present networks, islanding operation is expensive since the costs for the generation plant and additional system automation must be incurred. In future, a large number of DG could already be connected to the distribution networks. Hence, the costs to exploit the benefits of islanding mode will be much lower since only the costs of additional automation and control will have to be met.

7. Conclusions

A list of benefits that can be envisaged from the development of microgrids are presented and described in Chapter 2. The benefits are related to the development of sustainable energy sources, environmental friendly and highly efficient power generation, more competitive electricity market and finally more reliable and higher quality of electricity supply. This can be achieved by enabling smooth integration of small scale renewables and highly thermal efficient generation such as micro CHP into present power systems and also by enabling self-controllable systems that can be operated in a decentralised manner. Among other parameters, a balance of mix micro generation portfolio altogether with network support services from responsive loads should be carefully considered during the design of microgrids to achieve optimum benefits by providing adequate capability of supplying electrical loads and controllability in microgrids.

In Chapter 3, the impact of the cost of emissions on the cost of generating electricity, the new EU regulation in the context of emissions from new generating plants, and carbon content of various fossil fuels are described. The latter is used to estimate carbon emissions for generating electricity from mix hydrocarbon based power stations.

A methodology to quantify the benefits of micro-CHP for domestic applications has been described in Chapter 4. The results of case studies demonstrate that the application of micro-CHP significantly reduces the amount of electrical energy imported by the households from the distribution network. Our findings indicate that 20% - 23% saving in energy bills can be realised if micro-CHP is used as an alternative to ordinary boiler. The saving is obtained from higher thermal efficiency of coordinating heat and electricity production. Furthermore, the studies indicate that the reduction of electricity imported from grid may potentially reduce the CO_2 emissions by 1.3 T- 1.4 T per household per year assuming that the output of micro CHP reduces the electricity supplied by hydrocarbon based power stations. On the European scale this could lead to the reduction of more than 65 million tonnes of CO_2 per annum given that 50M houses use micro CHP.

In Chapter 5, a methodology to quantify the impact of micro generation on distribution networks is described. The case studies demonstrate that lower density of micro CHP/ PV distribution in the network will have a larger reduction of losses as compared with the higher density given the total installed capacities for both cases are the same. This can be explained as the rate of decrement in losses is a function of rate of decrement in the circuit loading. The studies also indicate that different micro generation technology, depending on their power output profiles, has different capability for displacing network capacity. For example, until certain level of penetration, a micro CHP can reduce the critical loading of Grid Supply Transformer during the peak load as opposed to PV; given that the peak load occurs during evening time when power output of PV is zero.

The ability of microgrids to be a “good citizen” and to provide reactive compensation also benefits distribution system in terms of reduction in losses and reactive power required to be imported from the system. Our findings indicate that the value of this service due to reduction in energy losses is between 20 – 80 £/kVAr. In these case studies, the ancillary service from microgrids located in the rural area will have higher value compared to the service provided in the urban area. As the rural distribution networks typically comprise long overhead line, the losses in this area are higher than the losses in urban distribution networks. This explains the results of the case studies.

In Chapter 6, a methodology has been presented that determines the value of intentional islanding operation during distribution network outages. The order of magnitude of the benefits from an increased quality of service due to DG islanding operation was quantified as the saving from reduced customer outage costs. Case studies evaluated different load customer mixes as well as different reliable distribution networks and DG plant.

The results show that the potential benefits are higher in network areas with a lower reliability, but they are lower in areas with a lower load density. Interestingly, a significant number of DG is expected to connect to rural networks with a low reliability and low load density. The fraction of the potential benefits that can be exploited depends on the DG reliability and the mode of transition into islanding. Continuous transition into islanding mode results in lower customer outage cost than the switchover into islanding after a short supply interruption. The maximum economic expenditure on DG islanding was assessed based on the identified average benefits. DG islanding may be feasible at lower cost in future distribution networks with a high penetration of DG because the DG capacity is already existent and active managed distribution networks provide a higher degree of automation.

The methodology applied can be refined by considering actual outage rates and durations instead of annual averages. The accuracy of the results can be increased if location specific reliability, load/generation and cost data of the concerning network area is used. The determination of the percentage of load that can be supplied in islanding mode requires an evaluation of the DG islanding resources. The local distribution of DG, its type and availability as well as topological network and load information are crucial to assess the potential to form islands. Moreover, the probability and the extent that DG islanding could support the network under different outage conditions must be evaluated.

The necessary equipment to enable islanding must be determined and its cost quantified so that a cost benefit analysis can be performed. Further benefits such as additional energy sale, mitigation of load growth and reinforcement deferral as well as environmental benefits could be considered in the cost benefit analysis.

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N.T.U.A.

Large Scale Integration of Micro-Generation to Low Voltage Grids

Contract No: ENK5-CT-2002-00610

WORK PACKAGE G

Report

Impact of Distributed Generation on the Reliability Performance of Power Distribution Systems

June 2005

Access: Restricted to project members

Table of Contents

1. Introduction

In recent years, electrical power systems have changed their structure by increasing the competition in order to achieve better performance and efficiency in the electricity production, transmission and distribution [1, 2]. One of the most important aspects of the competitive electrical energy market is the operation of independent power producers that can be connected at any system voltage level. This fact together with the additional financial incentives being applied in many countries worldwide has increased considerably the number of power generating units using renewable energy sources and more advanced technologies. This new environment concerns distributed generation where the customers own their generating units becoming both producers and consumers of electricity [3, 4].

Distributed generation sources are adopting advanced technologies of electrical power generation and have introduced significant changes in the structure of the systems to which they are connected. It is evident that the reliability performance of these power systems is seriously affected by the operation of the distributed generating units. Therefore, improved computational methods must be developed which can model the additional operating features of the systems. The system reliability performance is mainly quantified by calculating appropriate reliability indices which must take into account all the system features. For this purpose, the improved methods must calculate an extended set of reliability and operational indices for each system under study in order to quantify the effect of each system parameter on the system reliability performance.

The present report is concentrated in power distribution networks which is the area of application for microgrids. Its major objective is to assess the impact of distributed generation on the reliability performance of power distribution systems which operate applying the principles of competitive electrical energy market. These systems are assumed to be connected to transmission systems through appropriate substations while additional power generating units are assumed to be connected to their nodes. These units mainly use renewable energy sources (photovoltaic and wind generating units) and a broad range of new technologies, such as fuel cells and microturbines. Another very important system feature that is taken into account is the operation of distributed generation in parallel with the high-voltage transmission supply system and its performance during abnormal conditions such as power supply outages.

An improved and efficient computational methodology was developed for calculating the reliability and operational indices of distribution systems incorporating distributed generation. The Monte-Carlo sequential simulation approach is used for simulating the system operation while appropriate models were developed and incorporated into the developed methodology for modelling the particular features of distributed generating units and system customer categories.

This report presents the characteristics of the developed computational methodology together with the analysis being conducted for a typical low voltage distribution network with multiple feeders supplying different categories of customers (industrial, commercial and residential) in alternative system planning schemes. These schemes include different operating conditions of power generating units, such as the different penetration levels of the renewable sources, and different capacity levels of the system supply source.

2. Main Features of Distribution Systems and Distributed Generation Sources

The reliability assessment of power distribution systems requires appropriate modelling of their features which affect their operation and, especially, the features of distributed generation. The most important issues that require a further investigation is the system topology, the customers' profiles and operational characteristics of the distributed generation sources.

In a generic representation of a distribution system with distributed generation, one or more feeders are connected to a MV/LV substation, which is the normal supply source of the system load demand. Each feeder has a radial topology and power is supplied by the electric utility through the MV/LV substation. Under normal conditions, the system supply source is capable of supplying a certain percentage of the total load demand of system customers (70%-100% of peak load demand) due to existing limitations of the MV/LV substation. The system supply source is considered to have an operating cost function (in Eurocent/kWh), which is assumed to vary in each hour of the day, and this variation mainly depends on the particular supply and load demand requirements of the system (competitive electrical energy market).

The nodes of the distribution network can either be simple nodes or customer nodes. Each customer node supplies customers of certain categories, which can be industrial, commercial, agricultural and residential customers. Table 1 presents the major areas of activities for each of these four categories of customers. The system load demand requirements are determined by the peak load demand of each system customer node and its customer categories and the annual chronological load demand curve of each customer category (8760 points). Figures 1, 2 and 3 present typical daily load demand curves of residential, commercial and industrial of customers.

Table 1: Major areas of activities for customer categories

Industrial	***Commercial***	***Agricultural***
Mining	Construction, Wholesale	Organisations in Irrigation Activities
Textile	Commercial Shops	Drainage Activities
Metal Fabrication	Hotels, Restaurants, Bars, etc.,	Cultivation Activities
Non Metal Fabrication	Organisations in Transportation, Communications, Information, Research	Cattle Breeding Activities
Food	Civil Services, Hospitals, Banks, etc.,	
Chemical		

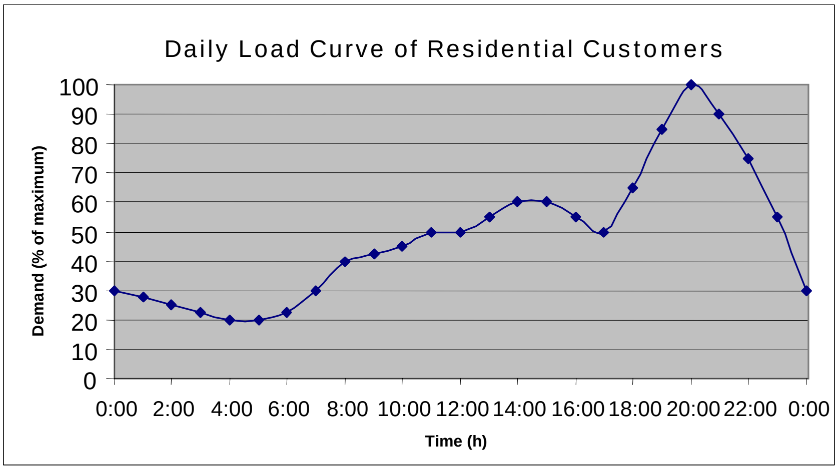

Figure 1: Daily load demand curve of residential customers

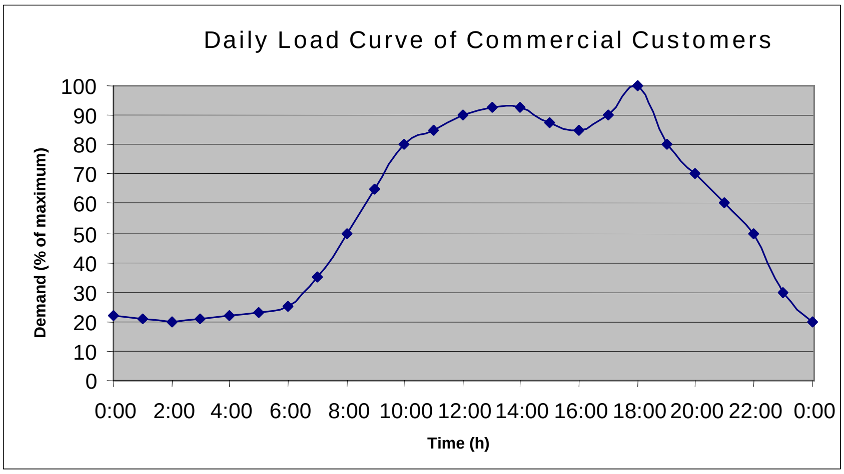

Figure 2: Daily load demand curve of commercial customers

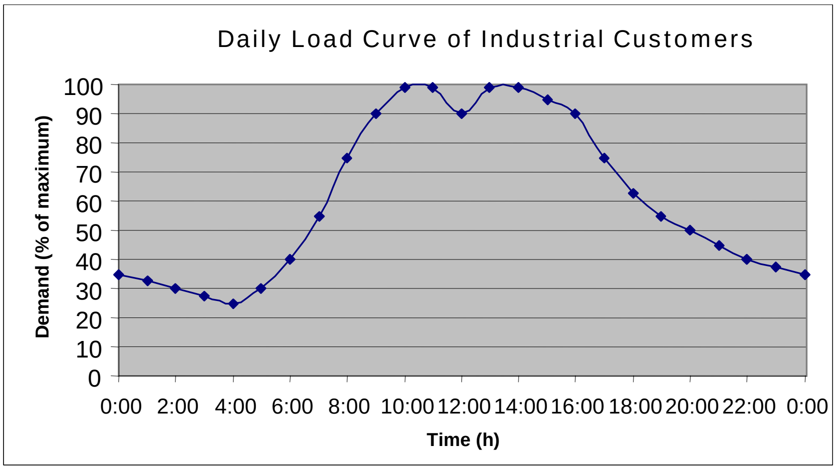

Figure 3: Daily load demand curve of industrial customers

In the modern competitive electrical energy market, various distributed generation sources may exist with different technological and operational characteristics. They can be located anywhere within the distribution system and they are connected either to a simple node or a customer node. Distributed generation covers a broad range of technologies, including many renewable energy technologies supplying small-scale power at sites close to users. Highly efficient combined heat and power (CHP) plants, back-up and peak load systems are providing increasing capacity. The present reliability assessment study considers four different technologies (wind generating units, microturbines, fuel cells and photovoltaics) and their impact on the power distribution reliability performance is calculated.

Wind generating units are based on wind turbines, which captures the wind' s kinetic energy in a rotor consisting of two or more blades mechanically coupled to an electrical generator. The turbine is mounted on a tall tower to enhance the energy capture. Several wind turbines can be installed at one site to build a wind farm of the desired power production capacity. Obviously, sites with steady high wind speed produce more energy over the year. The main push has been in large wind farms where wind turbines from 700kW to 1.5MW are available and in use. Several smaller wind turbines (<250kW) are available for use in Microgrids. When the wind turbine is operating in a stand-alone mode, any power requirement in excess of the wind energy must be supplied by storage systems or other type of generation. Because they commonly use induction generators, small wind systems are not easily adapted to Microgrid operation unless other sources supply voltage and frequency control.

Microturbines are composed of a generator and small gas turbine mounted on a single shaft. The turbine technology is based on a refinement of automotive turbo chargers and military engines. Microturbines rotate at high speeds, some at nearly 100,000 rpm. A permanent magnet generator spinning at this high shaft speed produces the power in the form of high frequency AC, which is converted DC and then to standard 50-Hz AC using an inverter. Most microturbines are fueled by natural gas but can also use liquid fuels such as diesel or jet fuel. These units currently range in size from 30 to about 100kW, while larger units are under development. Most microturbines also have a recuperator to recycle some exhaust heat back to the combustor. Because the combustion process is closely controlled and relies on relatively clean burning fuels, microturbines typically produce few emissions.

Fuel cells are an attractive power generation technology because of their potential for highly effective conversion to electrical power (35 to 55 percent without heat recovery). The only technology in general use today is the phosphoric acid fuel cell, which is available in the 200kW size range. A number of other fuel cell technologies are being developed such as proton exchange membrane (low temperature, hydrogen fueled), molten carbonate (high temperature), and solid oxide (high temperature). All fuel cell technologies operate in a similar manner electrically although they differ in operating temperature, charge carrier (H^+,O^{-2}, CO_3^{-2}, or OH^-), electrode, electrolyte, catalyst, and current collector / flow field materials. Introduction of a fuel (generally hydrogen) to the fuel cell stack where catalyst material is impregnated in the electrodes and an ion conducting electrolyte is present causes the separation of ions and electrons and results in electron movement. This movement generates a DC voltage on the stack terminals that is proportional to the number of cells in the stack. The DC voltage is sent to an inverter where it is converted to 50-Hz power. The ability of a fuel cell to change load levels is dictated by its ability to produce more voltage through consumption of additional fuel.

Photovoltaics rely on sunlight to produce DC voltage at cell terminals. The amounts of voltage and current that PV cells can produce depend on the intensity of sunlight and the design of the cell. PV systems use cell arrays that are either fixed or track the sun to capture additional energy. Because solar energy is a diffuse resource, it takes a large area of PV cells to produce significant power. A typical cell conversion efficiency of 10 percent, about 10 m^2 of panels are needed to provide a peak power of 1kW. To reduce the number of costly PV devices used, mirrors or lenses can be used to concentrate sunlight on to the cells. This increases the PV cell output but requires tracking devices to ensure that the array is aligned with the sun. Photovoltaics, like microturbines and fuel cells, generate DC voltage that must pass through an inverter to produce 50-Hz alternating current for distribution on the utility grid. A PV system’ s capability to track load changes is limited by available sunlight. Storage is required for stand - alone systems if power requirements exceed available sunlight.

By taking into account the above described main characteristics of the distributed generation sources, it can be assumed that they have the following main operating features which depend on their specific technical characteristics:

- Maximum and Minimum Capacity (in kW).
- Start Up Time (zero or certain minutes).
- Operating Cost Function (in Euro): $Ax^2 + Bx + C$ where x is the energy being produced during the time period of one hour and A, B, C are appropriate parameters.
- Start Up Cost (in Euro).

Under normal system operating conditions, distributed generation sources are assumed to operate in the relevant time periods according to their specific technical characteristics:

- Wind turbines operate when the respective wind speed of the geographical location at which they are installed is greater than their respective wind speed characteristics while they also determine their power output.
- Photovoltaics operate when there is solar radiation while their technical characteristics and the characteristics of the geographical location at which they are installed determine their power output.
- Microturbines and fuel cells operate when their operating cost is lower than the respective operating cost of the system supply source.

Under system emergency conditions, when the system sources being in operation (normal system supply source, distributed generation sources) can not supply the respective system load demand, microturbines and fuel cells may be called on to operate according to their increased operating cost in order to supply the additional system load demand which can not be supplied.

3. Monte-Carlo Sequential Simulation Method

The Monte–Carlo sequential simulation approach is a stochastic simulation procedure and can be used for calculating the operational and reliability indices of a power system by simulating its actual behaviour [5 – 7]. The problem is treated as a series of real experiments conducted in simulated time steps of one hour, which is considered adequate for a power system reliability analysis since the number of system changes within that time period is generally small. A series of system scenarios is obtained by hourly random drawings on the status of each system component and determining the hourly load demand. The operational and reliability indices are calculated for each hour with the process repeated for the remaining hours in the year (8760 hours). The annual reliability indices are calculated from the year's accumulation of data generated by the simulation process. The year continues to be simulated with new sets of random events until obtaining statistical convergence of the indices. The sequential simulation approach steps through time chronologically, by recognising that the status of a system component is not independent of its status in adjacent hours. Any event occurring within a particular time step is considered to occur at the end of the time step and the system state and statistical counters are updated accordingly. This approach can model any issues of concern that involve time correlations and can be used to calculate frequency and duration reliability indices. One very important advantage of the sequential simulation is the simplification of a particular system state simulation by considering information obtained from the analysis of the previous system states. This can only be applied when the system states change very little from one time step to the next. Such an assumption can be made for the power transmission and distribution systems that do not suffer large changes very often.

A computational method has been developed at NTUA for the reliability assessment of power systems applying the above principles of the Monte - Carlo sequential simulation approach [7]. This method is used as the basic method for developing the improved and efficient methodology being described in this report. The following main features were incorporated in the improved methodology:

1) The pseudo-random numbers are generated applying the multiplicative congruent method. The antithetic sampling technique is also used for variance reduction.

2) The classical two-state Markovian model is generally used to represent the system component operation while actual or equivalent generating units may be represented by a multiple state model in order to recognise their derated states. Common-cause transmission and distribution line outages may be also considered.

3) The generation system includes a number of plants while each plant consists of a number of single generating units.

4) The generating units are considered to be taken out for scheduled maintenance during certain time periods of the year and their appropriate data are specified.

5) A generation rescheduling technique is applied after the occurrence of a generating unit outage for modifying the output of appropriate generating units in order to compensate for loss of generation.

6) Overloading of system branches is alleviated by scheduling the output of system generating units and/or load curtailment at appropriate system load-points. For this purpose, two appropriate algorithms may be used applying different criteria for load curtailment.

7) The network branch flows are obtained for any given hour of the simulation period using a DC load flow algorithm.

8) The production cost of the generation system is calculated by using the respective fuel consumption functions with regard to the power output of the appropriate generating units.

The prime objective of the above computational method is to calculate appropriate indices that quantify the operational and reliability performance of a power system. Two sets of reliability indices are calculated that refer to system adequacy. The first set forms load-point and system indices that reflect their respective adequacy. The second set forms load-point and system interruption indices that reflect the characteristics of the interruptions occurred. The following indices are considered to be the most important system and load-point indices while they have the corresponding units and acronyms in parentheses:

- Loss of load expectation (LOLE) in hours/year
- Loss of energy expectation (LOEE) in MWh/year
- Expected demand not supplied (EDNS) in MW/year
- Frequency of loss of load (FLOL) in occ./year..
- Average duration of interruptions (DINT) in hours/occ.

It must be noticed that the above units of the reliability indices have been adopted appropriately in order to apply for low voltage distribution networks where microgrids are used

4. Interruption Cost Functions of Power System Customers

Power system reliability is defined as its ability to provide an adequate and secure supply of electrical power at any point in time [5, 8]. Supply interruptions, regardless of their cause or duration, deteriorate power system reliability and quality. Therefore, the analysis of the interruption cost for the different categories of customers is an important issue associated closely with justifying new facilities, quality and reliability of electrical power systems. The impact of supply interruptions on the global cost and the quality of supply for a power system is shown in Figure 4.

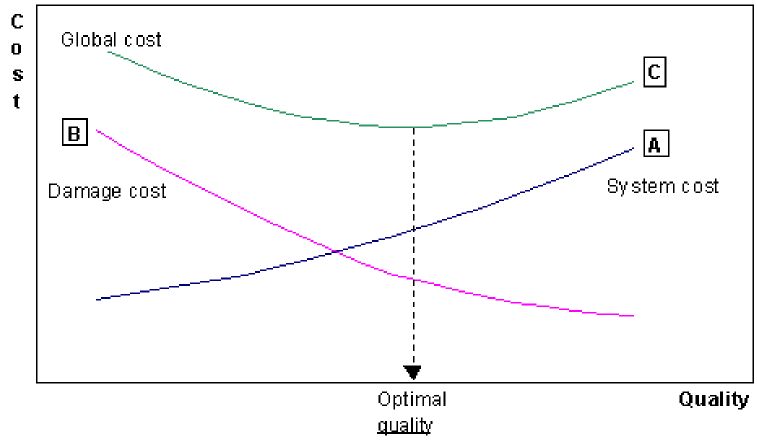

Figure 4: Impact of supply interruptions on the global cost of a power system

The ability to assess the power supply reliability has been well established [5, 8, 9, 10] while the ability to assess interruption cost (the worth of reliability) has been a subject of an increased number of publications during the last twenty years [11 - 15]. This assessment is a very difficult task to conduct directly and, alternatively, the costs and losses incurred by the customers as a result of a power supply interruption can be quantified more easily. These unreliability costs are not identical to the reliability worth but they can be considered as their representative and realistic measures since they constitute a lower bound.

The effects resulting directly from power supply interruptions are generally considered to be short-term effects as compared with the indirect effects, which tend to be considered as long term ones. The magnitude of all the direct effects is highly dependant on the characteristics of the customers (type of customer, energy dependency, size of operation, etc.) and on the characteristics of the interruption events (duration, frequency, time of occurrence, etc.). The customer survey approach has been utilized as the basic approach to investigate the direct short-term impacts and costs incurred by the electric power utility customers as a result of random supply interruptions [16]. The basis of this approach is that customers are in the best position to understand and assess how the costs due to supply interruptions impact their activities that depend upon electricity. During the last twenty years, interruption cost studies were conducted successfully in various countries and appropriate cost data were obtained for different categories of customers such as industrial, commercial, residential and agricultural [12, 13, 14, 15].

A customer survey approach was designed, carried out and utilised by the Energy Systems Laboratory of the National Technical University of Athens (NTUA) in order to conduct an interruption cost assessment study of all the different sectors of power customers in Greece [14, 15]. This study presents the results that were obtained for the industrial and commercial sectors during the last three years. These results mainly include the interruption cost data and their variation according to the various characteristics of the interruption events and the power customers.

Two types of interruption costs are reported and they are known as the average cost per interruption (€/int) and the cost normalised by annual peak demand (€/kW) which is known as ‘aggregated averages’. The aggregated average interruption cost is calculated as the ratio of the sum of interruption costs and the sum of the respective peak load demand for all customers. The approach of aggregated averages is used to offset the impact of small numbers for large or small customers, and the impact of small number of respondents who reported large or small costs. The estimates of the interruption cost are obtained from the direct cost assessment of the information being included in the respective cost questions of the questionnaires for each interruption being assumed. Therefore, interruption cost functions are determined for each customer category in a discrete form. Such functions have been reported assuming seven interruption durations (momentary, 3 minutes, 20 minutes, 1 hour, 2 hours, 4 hours, 1 day).

Appropriate interruption cost functions are available for all the major areas of activities for customers as it is shown in Table 1. As a small example, Figure 5 presents the overall Interruption Cost Functions for the three major categories of customers (industrial, commercial, agricultural) in Greece. Furthermore, Figure 6 presents the Interruption Cost Functions of the residential and certain types of agricultural customers in Greece.

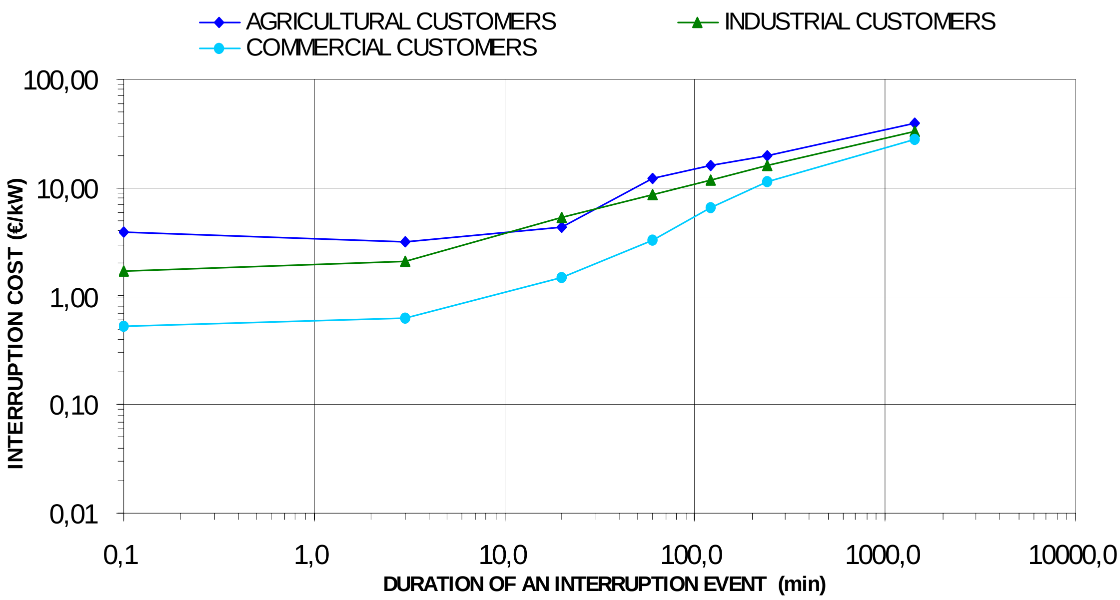

Figure 5: Overall Interruption Cost Functions for industrial, commercial and agricultural customers in Greece

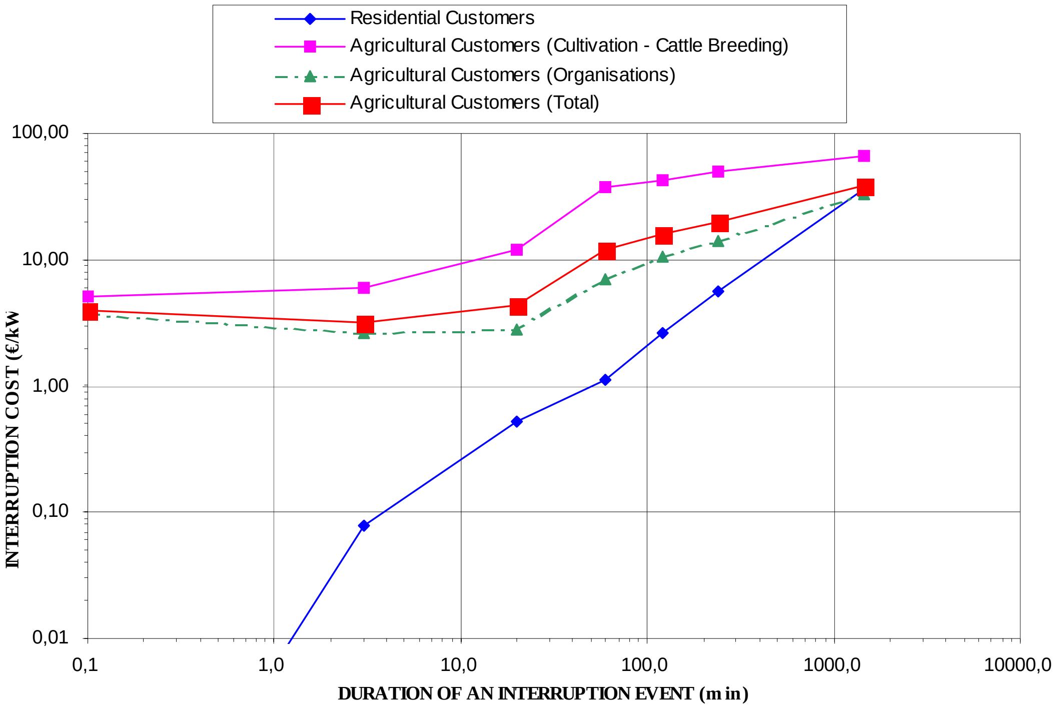

Figure 6: Interruption Cost Functions of residential and various types of agricultural customers in Greece

5. Reliability Modelling and Evaluation of Power Distribution Systems with Distributed Generation

An improved and efficient computational methodology was developed for the reliability and cost assessment of power distribution systems that integrate distributed generation (DG) sources of various technologies. The operation of DG sources is simulated by the classical two-state Markovian model while their operational performance is quantified by taking into account the events which occur when they fail to produce their available output capacity due to their existing limitations (failure events, maintenance). Failure events on the components of the distribution network are not considered since the respective feeder is disconnected from the system causing the loss of supply to all respective customers and the disconnection of all relevant DG sources.

A number of wind parks are assumed to be installed at various geographical sites and each wind park consists of a certain number of groups of identical wind generating units. These wind parks are connected to the appropriate system nodes applying the existing connection rules. The average hourly wind speed of a geographical site is represented by an appropriate normal distribution which means that the values of the mean and standard deviation need to be given as input data for each hour of the year (8760 points). For simplicity reasons, the standard deviation may be assumed constant (e.g. 5%). The actual wind speed value for a particular simulated time period is determined using appropriate random numbers. The available power output of a wind generating unit at any time period is calculated by using its appropriate curve expressing the power output in respect with the wind speed of the respective geographical site. The curve of output power for a wind turbine generating unit is shown in Figure 7. Wind turbine generating units are designed to start generating at the cut-in wind speed, (V_{ci}). As it is shown in Figure 11, the power output increases nonlinearly (or linearly for simplicity reasons) as the wind speed increases from V_{ci} to the rated wind speed V_r. The rated power P_r is produced when the wind speed varies from V_r to the cut out wind speed V_{co} at which the wind turbine generator will be shut down for safety reasons.

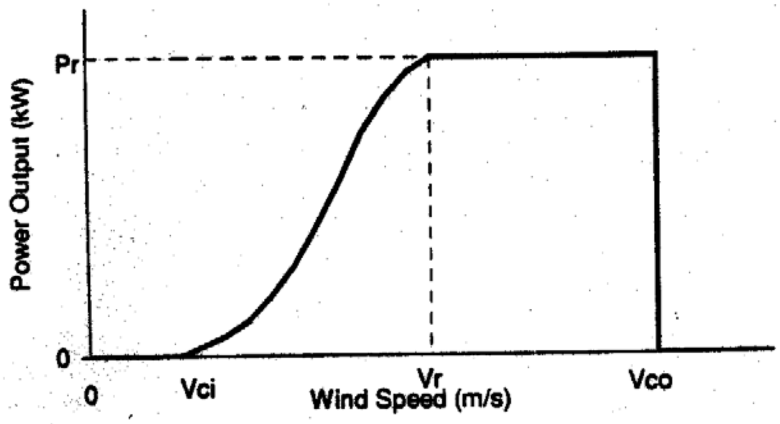

Figure 7: Curve for output power for wind turbine generating units

The total wind power generation of the system at any simulation time period of the year is not allowed to exceed a certain fraction of the respective system load demand. This fraction expresses the wind penetration constraint (margin) being assumed in order to retain acceptable service reliability, security and efficient operation of the system supply source. If the total wind power generation of the system is higher than the limiting value, this generation level is necessary to be reduced. In this case, it is considered that an appropriate order will be given by the system control centre to each wind park to reduce its total power output by a certain amount so that the wind penetration margin is satisfied. This amount of power output is calculated assuming that the same percentage of the total power output is applied for each park. As a result, a certain number of wind generating units in each wind park are assumed to be either disconnected from the system or decrease their power output using appropriate procedures that take into account the technical characteristics of the respective units.

A number of photovoltaic systems are assumed to be installed at different geographical sites and are connected to appropriate system nodes applying the existing connection rules. Each photovoltaic system consists of a certain number of groups of identical photovoltaic units. The average hourly solar radiation in a geographical site is represented by the normal distribution (or other more suitable distribution) while its actual value for a particular simulated time period is determined by using appropriate random numbers. Additional appropriate models have been developed and incorporated for modeling all necessary characteristics (slope, ground reflectance, temperature modification factor, soiling factor, etc.) for calculating the power output of each photovoltaic unit applying the solar radiation data of the respective geographical site.

The available power of the system supply source at any simulated time period is represented by an appropriate normal distribution which means that the values of the mean and standard deviation need to be given as input data. Its actual value for a certain time period is determined using appropriate random numbers.

An appropriate algorithm was developed for simulating the dispatch procedures of system supply source and DG units in order to supply the respective load demand in each simulation time period. The available DG units (not being in a repair or maintenance state) are only taken into account. The available power output of photovoltaic systems and wind generating units (applying the existing penetration margin) are assumed to supply the system load demand as a first priority since it is assumed that their operating cost is zero. The remaining load demand is usually allocated to the system supply source since its operating cost is expected to be lower than that of the microturbines and fuel cells. However, when its operational cost is greater than the respective cost of the available microturbines or fuel cells, these units are called on to operate first during the respective time periods. Finally, when the system supply source is inadequate to supply the remaining load demand and additional power generation is required due to failures being occurred, microturbines and fuel cells are called on to operate in order to supply the remaining load demand according to their operating cost.

The available spinning reserve of the system for each simulation time period is calculated by taking into account the operational features of system generation during the previous time period. For this purpose two criteria are used. Criterion 1 assumes that the spinning reserve is equal to a certain percentage of the total wind power generation in order to compensate sudden losses of this output in case of very fast wind speed changes. Criterion 2 assumes that the spinning reserve is equal to a certain percentage of total system load demand in order to compensate for a sudden loss of system supply source (reliability criterion). The actual value for the spinning reserve is calculated as the greatest value being obtained by using the two criteria.

The system reliability worth is quantified by calculating a set of appropriate indices that take into account the interruption cost function of the various customers categories of the system. An efficient algorithm is incorporated into the developed methodology having the following main steps:

- For each contingency that leads to a load curtailment at each system node the magnitude of load curtailment and the duration of contingency are calculated.

- The expected interruption cost to customers ECOST (in €/yr) that are connected at each system node can be obtained using its composite interruption cost function. This function is determined by taking into account the respective functions of all the customer categories being connected to the node.
- The expected system interruption cost IC (in €/yr) can be calculated by adding the respective indices ECOST for all system nodes.
- The interrupted energy assessment rate IEARN in Euro/kWh at each node can be calculated as the ratio of indices ECOST and LOEE for the node.
- The system index of IEARS (in Euro/kWh) can be obtained by adding the products of index IEARN of each node and its fraction odf system load being taken.

Using the above described computational methodology, the following additional system indices are calculated which have the corresponding units and acronyms in parentheses:

a) Six indices quantifying the system generation capability:

- Expected total energy supplied by the system supply source (EGSM) in MWh/year
- Expected total energy supplied by the generating units of various DG sources (EGWS) in MWh/year
- Expected energy supplied by wind generating units (EGWT) in MWh/year
- Expected energy supplied by photovoltaic generating units (EGPV) in MWh/year
- Expected energy supplied by fuel cells (EGFC) in MWh/year
- Expected energy supplied by microturbines (EGMT) in MWh/year.

b) Five indices quantifying the operational performance of the overall generation capability of DG sources, each type of DG sources and each individual DG source site by taking into account the events that may occur (failures, maintenanace). These indices have the respective acronyms (WT – wind, PV – photovoltaics, FC – fuel cells, MT – microturbines, DG - overall):

- Expected energy not supplied during the events being occurred (ENSWS, ENSWM) in kWh/year
- Expected annual duration of the events being occurred (DNSWS) in hours/year
- Expected load demand not supplied during the events being occurred (PNSWS) in kW/occ
- Frequency of events being occurred (FNSWS) in occ./year.

c) Three indices quantifying the available spinning reserve by applying the respective criterion:

- Available spinning reserve (AVSPRES) as a percentage of the respective load demand
- Percentage of applying Criterion 1 for evaluating spinning reserve (FWIND)
- Percentage of applying Criterion 2 for evaluating spinning reserve (FLOAD).

It must be noticed that the above units of the reliability indices have been adopted appropriately in order to apply for low voltage distribution networks where microgrids are used

d) Two indices for system reliability worth

- Interruption Cost (IC) in Euro/kWh
- Interrupted energy assessment rate of the system (IEARS) in Euro/kWh.

6. Assessment Studies

The developed computational methodology was applied for conducting reliability assessment studies on the typical power distribution system which has the single line diagram shown in Figure 8. The system peak load demand is equal to 190 kW. There are three feeders supplying commercial, residential and industrial customers. A certain number of DG sources exists using various technologies. One wind turbine exists with generating capacity equal to 15 kW and two photovoltaic parks are installed at two different system sites with five generating units having various power output capacities and total generating capacity being equal to 13 kW. Additionally, there are one microturbine and one fuel cell with generating capacity equal to 30 kW each. The operating cost function of the system source is shown in Figure 13 for one typical day of the year. These hourly values represent the respective average values for all the year. The coefficient for the operating cost for the microturbines and fuel cells are assumed to be equal A=0.01, B=5.16, C=46.1 for microturbines and A=0.01, B=3.04, C=130 for fuel cells.

This system provides a good example for illustrating the different operating features of DG sources. Base case study (Case 1) assumes that the capacity of the system supply source follows a normal distribution with an average value equal to 100% of the system peak load demand and a standard deviation equal to 5%. No wind penetration margin and no criteria for spinning reserve are applied. The full set of system indices was evaluated for the following nine alternative case studies:

:

Case 2: As in case 1 but the average value of the capacity of the system supply source is decreased to 90% of the system peak load demand .

Case 3: As in case 1 but the average value of the capacity of the system supply source is decreased to 80% of the system peak load demand.

Case 4: As in case 1 but the average value of the capacity of the system supply source is decreased to 70% of the system peak load demand.

Case 5: As in case 3 but the power output of wind generating units is increased by 15 kW (100%).

Case 6: As in case 3 but the power output of photovoltaic systems is increased by 13 kW (100%).

Case 7: As in case 3 but the power output of microturbines is increased by 15 kW (50%).

Case 8: As in case 3 but the power output of fuel cells is increased by 15 kW (50%).

Case 9: As in case 1 but the output of wind generating units is increased by 30 kW (200%) and a wind penetration margin equal to 15% is applied. The available spinning reserve is calculated assuming a percentage equal to 100% of total wind power generation according to Criterion 1 and a percentage equal to 10% of the system load demand according to Criterion 2.

The results being obtained for the above nine case studies are presented in Table 2. A considerable number of comments can be drawn from these results but the most important ones are the following:

- The decrease of the average value of the system supply source capacity decreases the system reliability performance as indicated by the respective results for cases 1, 2, 3 and 4. Additionally, the expected energy produced by microturbines and fuel cells increases. The expected energy produced by renewable energy sources remains the same since it depends only on their technical features and the characteristics of the respective geographical sites at which they are installed.
- The addition of wind generating units always improves the system reliability indices since there is more available power generation to supply the load demand. Furthermore, the energy supplied by wind generating units increases while the energy supplied by the system supply source decreases significantly.

- The addition of photovoltaic units, microturbines and fuel cells improves the system reliability indices, since there is more available power generation to supply the load demand and increases the system generation indices due to the respective sources.
- When a wind penetration margin is applied and as its respective level decreases the system reliability performance and the expected energy produced by wind generating units also decrease while the energy supplied by the system supply source increases significantly.
- When the power output capacity of installed system wind generating units is assumed to increase significantly (case study 9), Criterion 1 mainly determines the available level of spinning reserve.

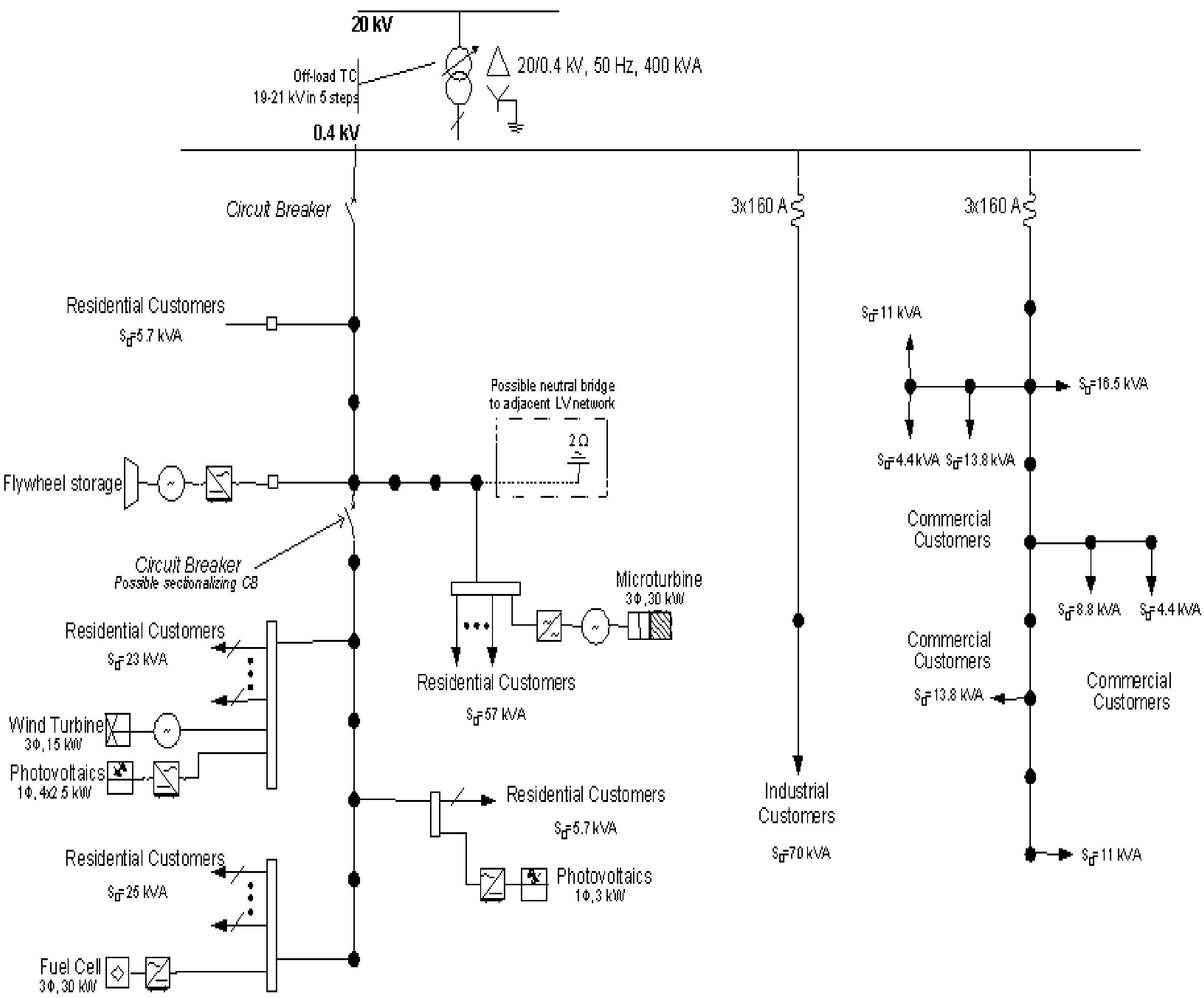

Figure 8: Single line diagram of the typical power distribution system with distributed generation

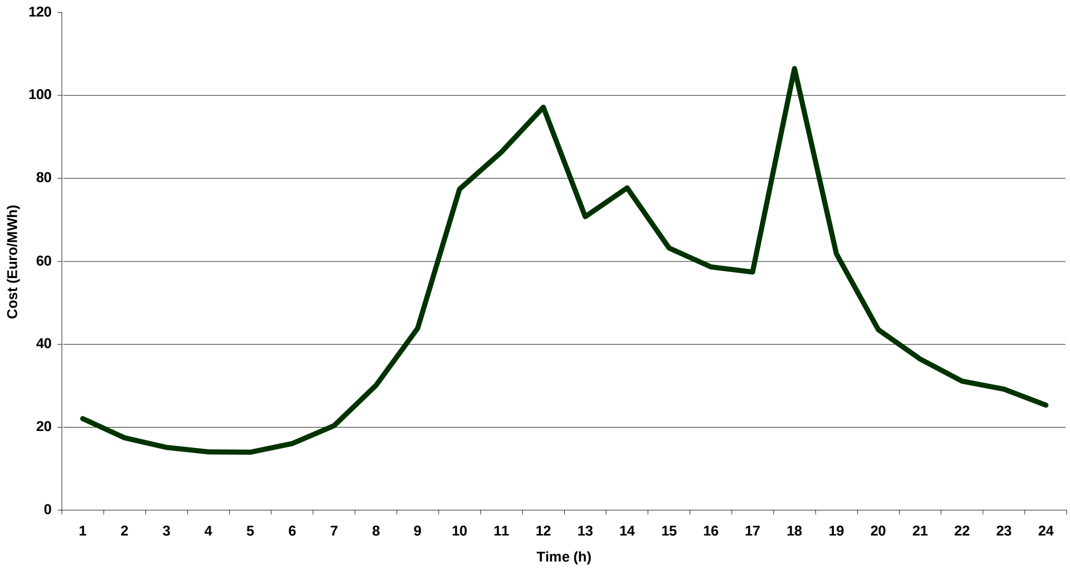

Figure 9: Operating cost function of the system source is shown in Figure 9 for one typical day of the year

Table 2: System Reliability Indices

Case Study / Index	1	2	3	4	5	6	7	8	9
LOLE	16.160	16.165	16.255	17.974	14.971	16.042	14.593	14.582	16.497
LOEE	745.436	745.453	746.042	756.799	558.013	681.338	523.804	531.617	653.657
EDNS	36.18	36.17	36.06	33.59	28.80	33.11	27.18	27.42	31.05
FLOL	2.277	2.281	2.341	3.499	2.202	2.324	2.179	2.162	2.267
D	7.097	7.087	6.944	5.137	6.717	6.903	6.697	6.745	7.277
EGSM	660.778	660.755	660.319	657.177	553.576	638.615	650.371	653.709	643.038
EGWS	177.878	177.901	178.335	181.467	285.267	200.105	188.506	185.161	195.710
EGWT	107.418	107.418	107.418	107.418	214.997	107.424	107.116	107.376	124.823
EGPV	20.952	20.952	20.952	20.952	20.952	42.804	20.950	20.949	20.949
EGFC	23.061	23.061	23.078	23.251	22.824	23.077	23.022	30.405	23.271
EGMT	26.446	26.468	26.886	29.845	26.493	26.798	37.417	26.430	26.670
ENSWS-WT	6673.85	6673.85	6673.85	6673.85	13178.88	6673.85	6673.85	6673.85	12022.5
ENSWM-WT	4698.42	4698.42	4698.42	4698.42	9394.52	4698.42	4698.42	4698.42	7618.65
DNSWS-WT	491.642	491.642	491.642	491.642	941.906	491.642	491.642	491.642	1427.33
PNSWS-WT	13.587	13.587	13.587	13.587	13.754	13.587	13.587	13.587	7.975
FNSWS-WT	5.037	5.037	5.037	5.037	9.267	5.037	5.037	5.037	13.487
ENSWS-PV	852.65	852.65	852.65	852.65	852.65	860.786	852.65	852.65	852.65
ENSWM-PV	46.81	46.81	46.81	46.81	46.81	46.79	46.81	46.81	46.81
DNSWS-PV	1573.68	1573.686	1573.686	1573.686	1573.686	1581.40	1573.686	1573.68	1573.68
PNSWS-PV	0.517	0.517	0.517	0.517	0.517	0.518	0.517	0.517	0.517
FNSWS-PV	18.699	18.699	18.699	18.699	18.699	18.589	18.699	18.699	18.699
ENSWS-FC	9161.73	9161.73	9161.73	9161.73	8966.88	9122.40	9008.37	13234.3	8850.75
ENSWM-FC	2155.68	2155.68	2155.68	2155.68	2153.52	2160.0	2157.84	3237.84	2157.84
DNSWS-FC	305.391	305.391	305.391	305.391	298.896	304.080	300.279	581.312	292.05
PNSWS-FC	30.0	30.0	30.0	30.0	30.0	30.0	30.0	22.63	30.0
FNSWS-FC	5.615	5.615	5.615	5.615	5.424	5.555	5.478	10.491	5.587
ENSWS-MT	9292.92	9292.92	9292.92	9292.92	8381.19	8934.99	13373.78	9097.89	8761.5
ENSWM-MT	2157.84	2157.84	2157.84	2157.84	2160.0	2155.68	3234.6	2157.84	2160.0
DNSWS-MT	309.764	309.764	309.764	309.764	279.373	297.833	528.16	303.263	292.05
PNSWS-MT	30.0	30.0	30.0	30.0	30.0	30.0	22.7	30.0	30.0
FNSWS-MT	5.549	5.549	5.549	5.549	5.242	5.475	10.418	5.466	5.373
ENSWS-DG	25981.1	25981.15	25981.15	25981.15	31379.51	25580.28	30212.39	29909.0	30494.5
ENSWM-DG	9058.74	9058.749	9058.749	9058.749	13754.9	9059.256	10125.94	10133.0	11983.3
DNSWS-DG	2445.01	2445.014	2445.014	2445.014	2771.774	2440.424	2657.977	2654.75	3148.5
PNSWS-DG	10.693	10.693	10.693	10.693	11.314	10.516	11.382	11.284	9.608
FNSWS-DG	28.550	28.550	28.550	28.550	30.358	28.402	31.152	31.220	31.907
AVSPRES	-	-	-	-	-	-	-	-	14.88
FWIND	-	-	-	-	-	-	-	-	99.35
FLOAD	-	-	-	-	-	-	-	-	0.65
IC	1401.31	1401.33	1402.08	1415.95	1042.70	1273.67	965.64	979.39	1203.06
IEAR	1.880	1.880	1.879	1.871	1.869	1.899	1.844	1.842	1.841

7. Conclusions

One of the most important aspects of the competitive electrical energy market is the operation of independent power producers that can be connected at any system voltage level. The increased use of renewable sources and more advanced technologies may significantly affect the operational characteristics and inevitably the reliability performance of power systems. This report describes the main concepts and features of an improved computational methodology that is based on the sequential Monte – Carlo simulation approach and simulates efficiently and realistically all the features of DG sources that can be connected to a distribution system (microgrids). It also presents the results that were obtained from the reliability assessment studies conducted for a power distribution system which is based on a typical power system with multiple feeders. It is shown that the system adequacy is critically dependent on the reliability performance of the system supply source. In addition, a sufficiently large generation capacity of DG sources can improve the system reliability indices in emergency conditions when additional power generation is required to supply the load demand. Finally, the obtained results demonstrate clearly the increased information being gained.

8. References

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