Advanced Architectures and Control Concepts for
MORE MICROGRIDS

Specific Targeted Project

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

Annex H2.D.
Microgrid support to security of supply and generation adequacy

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Task Title: TH2. Quantifying the impact of Microgrids on investment and replacement strategies of future national electricity infrastructure

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1. Introduction

This Annex presents the contribution from INESC Porto to Deliverable DH2 regarding the evaluation of Security of Supply and Capacity Adequacy in the presence of microgeneration and Microgrids. The work was originally scheduled as a contribution within WPG, but then it has been agreed that its relevance was more specific to WPH and TH2.

The security of supply is defined as the ability of a power system to serve the forecasted load, with a specified reliability level. It is a primary objective of any power system, because of the important costs (security, economical, social and political) that result from an inadequate security of supply. There are two main components affecting the security of supply:

- The generation adequacy, which has to do with the ability of the generation assets to cover the expected values of load, including the system losses.
- The transmission adequacy, which is related to the ability of the transmission system to ensure the needed power flows between the generation and the load points.

Because of its location in the electrical system (LV networks), the μGen (and the μGrids) contributes to improve both components of the security of supply. Moreover, that contribution tends to increase when the transmission adequacy decreases. This is an opposite situation to the one occurring for the conventional generation, where the limitations of the transmission system influence negatively the contribution to the satisfaction of the system load. However, once the transmission networks present a high reliability, their influence on the security of supply tends to be low. On the other hand, the reliability of the distribution networks, to which the μGen is connected, may influence negatively that contribution. Therefore, in this work it is assumed that the contribution of the μGen to the security of supply is limited to the improvements on the generation adequacy (traditional HL1 reliability assessment).

Before the restructuring process of the power systems, the investment on new generating capacity and transmission assets was mainly decided by reasons of security of supply. However, that restructuring has been changing the decision-making process, namely concerning the traditional centralized long term planning of the generating system. This planning process is being replaced by market mechanisms. Therefore, the investment on new generating capacity tends to be decided by the investors, taking into consideration their economic judgements. This means that the generation adequacy (as well as the security of supply) is no longer the main force driving the investment [1]. The most obvious result of that situation is the gradual erosion of some excessive capacity that industrialized countries had in the period prior to the restructuring of the power systems [1-2]. The reluctance of the economic agents to invest in new generating capacity, specifically in large power plants, is the main reason for that erosion. Several facts contribute for that reluctance, namely:

- The uncertainty about the recovery of the investment;
- The lack of integration between the planning of the transmission system and the generating units;
- The tendency of investors not to reveal their investment plans;
- The possible double accounting of some generation capacity;
- The uncertainty about the future aptitude of the consumers to respond to prices;

Despite the changes on the decision-making process about the construction of new capacity, the security of supply remains as a fundamental objective of the European power systems. This is confirmed by the Directive 2003/54/EC, which requires that each Member State ensures a suitable generation adequacy. Note that, according the mentioned directive, setting up new generation capacity should be a task of the economic agents (investors). However each State must monitor the security of supply and, when appropriate, ensure the installation of new capacity through the launching of a tendering procedure (or an equivalent procedure).

The factors contributing for the reluctance to the investment on conventional power plants tends not to exist in the μGen case. Therefore, the expected dissemination of those systems may result on a valuable contribution to the security of supply. In order to evaluate that contribution, a probabilistic approach based on a non-chronological Monte-Carlo Simulation (MCS) process is presented here. To account for the potential dependencies between the seasonal and daily load and generation profiles of the μGen units (function of weather conditions) several scenarios were defined. Those scenarios make it acceptable to consider that the random variables (load level and capacity factor of the µGen units) present an independent behaviour in each scenario.

The developed methodology was applied to a system that has the size of the Portuguese one, namely concerning the load level. The adequacy indices of a base case, without µGen, were compared with the indices associated to various penetrations of different µGen technologies (CHP, PV, micro-wind) and the existence of µGrids. Moreover, the contribution of those entities to the generating adequacy of the Portuguese power system was measured by using the concept of capacity credit (CC). This concept is defined as the conventional generation that may be removed from the system, after adding the µGen and µGrids, while maintaining the initial reliability of the system unchanged.

2. Generation adequacy assessment

Historically, the assessment of the generation adequacy in electrical systems was first carried out using deterministic criteria. However, the use of such criteria does not reflect the stochastic nature that characterizes this problem [3]. As a consequence, the reserve levels may be over or underestimated. The overestimation occurs if the deterministic criterion is very severe, imposing the existence of reserves to accommodate situations of capacity scarcity with low probability of occurrence. Conversely, the underestimation will occur when the criterion is more relaxed, allowing the existence of situations of insufficient capacity whose probability of occurrence is considerable.

The inclusion of the stochastic behaviour of the variables that influence the security of supply can be achieved through the use of probabilistic approaches [3-14]. In this way, it is possible to take into consideration the severity of a particular event (e.g. the magnitude of the load not supplied) as well as their probability of occurrence. Moreover, the probabilistic methods provide a set of reliability indices that characterize the ability of the power system to cover the load. Those indices can be compared to reference values (based on the existent experience related to the operation of electrical systems) in order to assess the acceptability of the risk of a system (and therefore assess the generation adequacy). The reliability indices most often used are:

The LOLP (“Loss of Load Probability”), which measures the risk of the load of the system surpass the available generation:

$$LOLP = \sum_{i \in S} p_i \qquad (1)$$

where: p_i is the probability of occurrence of the state i of the system; and S is the set of states where there is insufficient generation capacity.

The LOLE (“Loss of Load Expectation”) is the average number of hours in a given period T (usually one year) in which the load is expected to exceed the available generating capacity:

$$LOLE = T.\sum_{i \in S} p_i \qquad (2)$$

Note that, when T corresponds to one year and the analysis is performed with hourly resolution, the value of LOLE is expressed in h/year. Despite the LOLE does not provide any indication about the severity of the loss of load, nor about the frequency and duration of those events, it is the reliability index most widely used when assessing the generation adequacy of the power systems [3].

The EPNS (“Expected Power Not Supplied”) provides the average power interrupted (in MW), and may be determined by:

$$EPNS = \sum_{i \in S} C_i p_i \qquad (3)$$

where: C_i is the average load not supplied in the state i of the system.

The EENS (“Expected Energy Not Supplied”) provides the average value of the energy not supplied (in MWh):

$$EENS = T.\sum_{i \in S} C_i p_i \qquad (4)$$

The probabilistic techniques can be divided into two groups: those based on analytical methods [4-8] and those based on simulation processes [9-14]. The analytical techniques tend to be used when complex operating conditions are not considered and when the system is very reliable. On such circumstances the analytical methods are more efficient because they use mathematical equations to evaluate the reliability indices [3]. However, the analytical techniques are unable to provide satisfactory solutions (without excessive approximations) when complex operating conditions are involved, namely when there is a relatively large number of random variables. On such circumstances, the use of Monte Carlo Simulation based methods is preferable, being the reliability indices estimated by simulating the random behaviour of the system. Furthermore, when there are chronological aspects to consider or when it is desirable to obtain probability distributions for the reliability indices, the use of simulation techniques is also preferable [3].

Independently of the approach, the assessment of the generating adequacy involves the development of appropriate generation and load models and its combination to create a risk model containing the required adequacy indices. Concerning the load, the models should represent the expected value (generally in terms of active power) for a given time period (day, month, year). These models can be derived by using information about the historic behaviour of the load and its expected growth for the following years. The models of the generating capacity should contain information about the total installed capacity and about the reliability of the different generating units. The reliability of those units should account for the availability of the generators and for the availability of primary resources needed for their operation (e.g., the reliability of a wind turbine depends on the availability of the turbine as well as on the availability of wind).

3. Impact of μGen and μGrids on the security of supply

Traditionally, the generation adequacy of the power systems has been mainly provided by the addition of new generating capacity. However, the contribution of the demand side to the performance of the system may be as useful as the one of the generation capacity [15-16]. Actually, the importance of that contribution has been growing in the recent years, namely concerning the demand management programs and the use of interruptible load contracts [16]. The demand management programs transform the load curve of the electrical systems, namely promoting the temporal displacement of the electricity consumption [17-19]. Therefore they may be understood as a preventive measure that contributes for the decrease of the system load on critical periods, impacting positively on the security of supply (due to increased reserves during the most critical periods).

The addition of µGen to a power system tends to improve the security of supply, once it increases the available generation capacity. Those improvements are influenced by the characteristics of the µGen technologies, namely regarding their generation profiles and the correlations between those profiles and the behaviour of the system load. On the other hand, the generation profiles are influenced by natural conditions, namely: the solar irradiance for photovoltaic systems (PV); the wind velocity for micro-wind turbines; and the ambient temperature for micro-CHP systems. Therefore, the contribution of a µGen technology for the generating adequacy tends to present seasonal and daily variations. Consequently, the contribution to the security of supply of a microgenerator with a low annual capacity factor (CF) may surpass the one of a microgenerator with a higher CF, but whose generation is less correlated to the load. Another issue that may influence the contribution of the µGen to the generating adequacy is the reliability of the microgenerators.

The specific contribution of a µGrid to the security of supply is a result of the ability of those structures to manage (or partially manage) their internal load and generation. Thus, the contribution of a µGrid is influenced by the characteristics of controllability of their internal µGen systems and loads. Concerning µGen, only micro-CHP systems with ability to store the thermal energy may be assumed as controllable. In fact, only those units may respond to the needs of the electrical system without wasting the thermal energy (preserving the principle of combined heat and power generation). As a consequence of such control, those microgenerators tend to be always available to respond to capacity scarcity situations. Regarding PV and micro-wind systems it is important to stress that those units are not controllable, since their generation is influenced by the availability of the primary resources.

Concerning the load, it is important to emphasise that the contribution of the µGrids to the generating adequacy comes from the ability of those entities to interrupt part of it when a situation of generation scarcity exists. The µGrids are in excellent position to participate in mechanisms of active load management, namely through their ability to interrupt internal load. Once those structures may be used to interrupt the less important loads (heat load, cooling, etc...), the interruption may be done, sometimes, without noticeable effects on consumers (reducing the potential economic cost that results from the load interruption).

4. Capacity Credit

In broad terms, the concept of CC is a measure of how a specific entity contributes to the generating adequacy of a power system (i.e., the availability of generation capacity to serve the forecasted load - HL1 reliability study). Therefore this concept may be used to measure the contribution of the μGen and μGrids to the security of supply.

In practice, several alternatives for calculating the CC have been described along the years. The main differences between those alternatives have to do with the methodologies used to obtain the CC and with the definition of the concept, which varies widely in different sources. The more simplistic approaches use "rule-of-thumb" models [20]-[22], where the CC is determined without the execution of reliability studies. However, the majority of the methodologies are based on probabilistic approaches, in order to account for the stochastic nature of the intermittent generation.

Concerning the CC concept, a number of definitions has been presented namely: the load carrying capability (LCC); the guaranteed capacity (GC); the equivalent firm capacity (EFC); and the equivalent conventional power plant (ECC).

Regarding LCC, the CC is defined as the amount by which the system load may be increased, after adding the capacity whose CC is to be determined, while the original reliability of the system is maintained [20][24-24].

The GC concept defines the CC without considering the load of the system [24], [25]. In this case, the CC corresponds to the difference between the "guaranteed capacity" that exists with and without the capacity whose CC is to be determined. In that context, the concept of "guaranteed capacity" corresponds to the capacity that can be expected to be available with a given probability ρ. It is important to stress that the probability ρ is an arbitrarily chosen parameter that should not be confused with the LOLP of the system [24].

Concerning EFC and ECC, two different approaches to define the CC concept appear in the literature. Some authors assume that the CC corresponds to the capacity of a reference generator that should be added to the system in order to obtain the same reliability level as the one resulting from the addition of the capacity whose CC is to be determined [24][27]. A different approach consists in defining the CC as the amount by which the conventional capacity of the system may be decreased, while maintaining the same reliability [20], [28-29]. On both cases, the fundamental difference between EFC and ECC has to do with the nature of the reference generator. This generator is assumed as a 100% reliability unit on the EFC, whereas on the ECC it is a “conventional” unit (with a specific forced outage rate).

A comparison between the EFC, LCC, ECC and GC approaches was made in [23]. The results show that the choice of the definition can have significant impact on the obtained CC. Moreover, the EFC and the LCC provide consistent results. As well, it can be concluded that the ECC approach provides CC values that follow the same trends as EFC and LCC, despite the higher values obtained (due to the consideration of a not 100% reliable reference generator). The results when using GC approach are not correlated to the results of the other three methods. In fact, the authors of [24] found that the CC depends on ρ in an unpredictable manner. Moreover, this approach does not take into account whether or not the available capacity is needed (once the load is not included in the model).

5. Methodology

5.1 Overall process

In this work the ECC concept is used in order to define the CC of the μGen and μGrids. Therefore, the CC values correspond to the value of conventional generation capacity that can be removed from the system, while maintaining the initial reliability, after adding the μGen and the μGrids. The algorithm used to evaluate the CC values is presented in Figure 1. The reliability index used in the process to determine the CC is the LOLE. This index was adopted because it is the most commonly used when assessing the CC (however, a different index could be used).

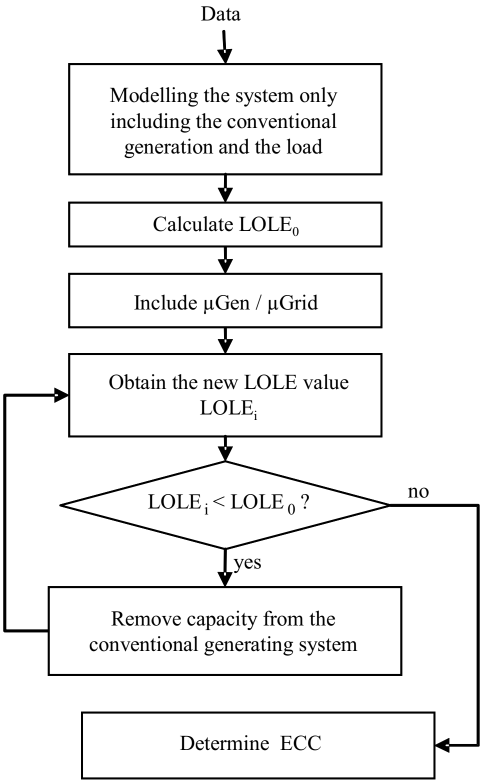

Fig. 1 – Flowchart for CC computation

As shown in figure 1, the CC evaluation implies successive computation of the system LOLE, which may be obtained by using a reliability model based on probabilistic techniques. The use of a probabilistic model allows accounting for the seasonal and daily correlations between the system load and the generation profiles of the microgenerators on the system reliability indices. The large number of random variables involved makes the use of analytical techniques unpractical, as mentioned before. Therefore, the use of MCS based methods to evaluate the system LOLE on each iteration of the algorithm presented in figure 1 is preferable.

The non-chronological MCS procedure is often used in order to assess the generation adequacy, namely when the analysis only includes conventional generators. In this case, the independence between the involved variables (load and available capacity), needed to implement this kind of approach, is ensured. Indeed, the available capacity provided by those generators is not correlated to the system load, being only a function of the unavailability of the generators (*FOR* – Forced Outage Rate). Figure 2 shows the flowchart of that MCS process where: N is the number of trials; F the number of loss of load occurrences; and PNS the power not supplied due to loss of load situations.

In every single trial of the MCS process, the state of each generator is obtained by sampling a random number with uniform distribution in the range [0,1]. This value is then compared to the FOR of the unit so that:

$$F_{Gi} = \begin{cases} 0 \quad \text{se } U < FOR_i & \text{(Generator not available)} \\ 1 \quad \text{se } U \geq FOR_i & \text{(Generator available)} \end{cases} \qquad (5)$$

where: U is a random number with uniform distribution in the range [0,1]; FOR_i is the forced outage rate of the generator G_i.

The total available generation capacity of a system, C_{GC}, will then be obtained by:

$$C_{GC} = \sum_{i=1}^{NG} F_{Gi} \times C_{Gi} \qquad (6)$$

where: N_G is the number of conventional generators, and C_{Gi} is the individual capacity of the generator G_i.

This model assumes that the unavailability of the generators includes the effects related to the non planned outages (failures) and the unavailability of the primary resource. If more detail is needed, new states to describe the operation of the generators may be added.

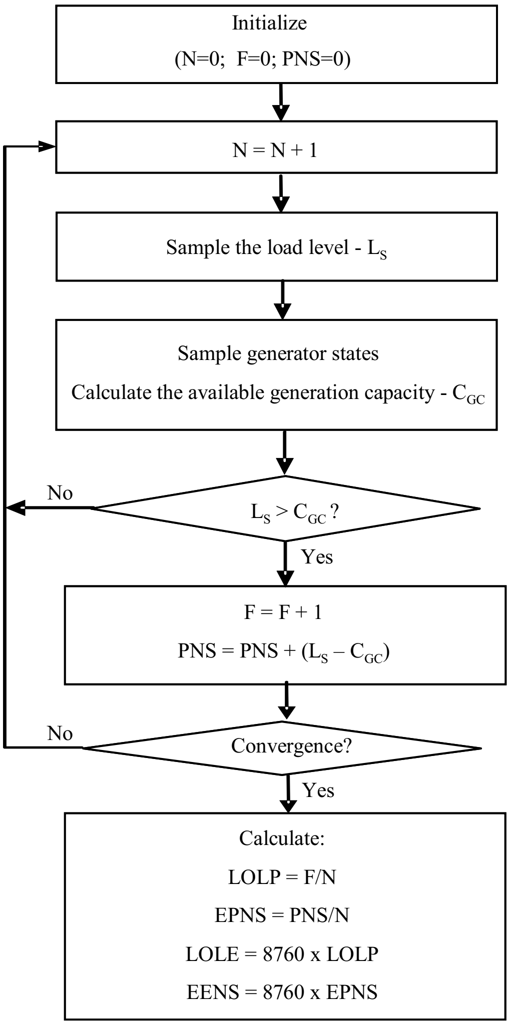

Fig. 2 – Algorithm for a non chronological Monte-Carlo Simulation process

The load level to be used in each trial of the simulation process also has to be sampled. The sampling process may be achieved by using the inverse transform method [3] and a cumulative distribution function (CDF) suitable to represent the system load behaviour. That CDF may be obtained by using the information contained on chronological load diagrams as the ones shown in figure 3.

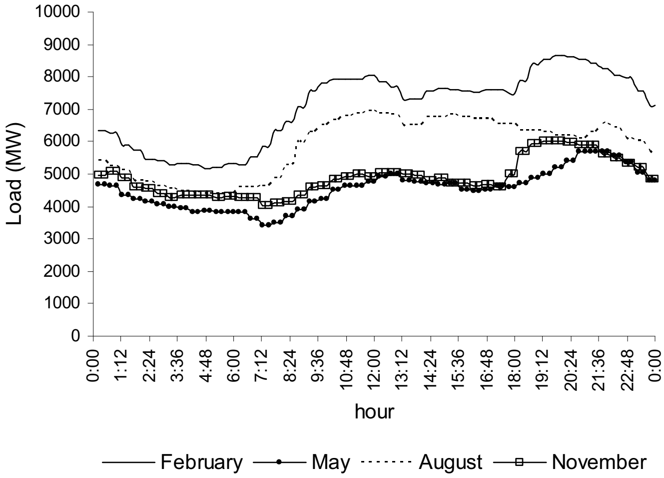

Fig. 3 – Example of chronological load diagrams

Those diagrams represent the load behaviour of the Portuguese system in four days of four months of the year 2007 [29]. This information was collected from the system operator, which makes available the chronological load diagram for all the past days.

Figure 4 shows the CDF that represent the load behaviour of the Portuguese electrical system for the year of 2007. Note that this CDF carries exactly the same information as the (more frequently seen) cumulative load curve.

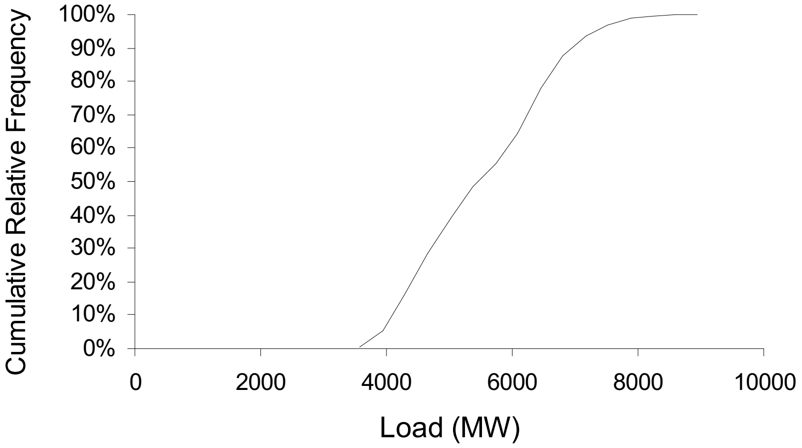

Fig. 4 – Cumulative distribution function of the system load

After sampling the available generation capacity and the load level, those values are compared in order to assess the generation adequacy. The system state is assumed as a failure state when the load level is equal or greater than the available generation (when load is equal to available generation the state represents a failure situation with no loss of load) [3]. The system state must be sampled until a convergence criterion is achieved, as shown in figure 2. This convergence criterion may be assumed as a maximum value for the coefficient of variation of the EENS index:

$$\beta = \frac{\frac{\sigma(EENS)}{\sqrt{N}}}{EENS} \qquad (7)$$

where

$$EENS = \frac{\sum_{i=1}^{N} EENS_i}{N}$$

A different reliability index may be used to control the convergence. However the EENS is the one that gives the best results, once its convergence tends to be more difficult [3]):

The non-chronological MCS process may also be used with the purpose of assess the reliability indices of a power system that includes µGen and µGrids. In order to account for the behaviour of the generating profiles of the µGen systems the year may be split in several periods (scenarios). The scenarios also allow us to account for the dependencies between different variables, namely the system load and the generation profiles. Those dependencies result from the influence of the climacteric (solar radiation, wind speed and ambient temperature) and temporal (time of day, day of the year and season) aspects on the system load and on the generating profiles. Therefore, the use of daily and annual periods (scenarios), defined so that the different variables may be assumed as independent, make it possible to include the potential dependencies on the analysis.

So, the non chronological MCS is performed in each period (scenario) and the global results are obtained by aggregating the indices, as shown in figure 5. This approach allows us to maintain the advantages of the non-chronological simulation relatively to the chronological one (the non-chronological simulation is simpler to be implemented and requires less data).

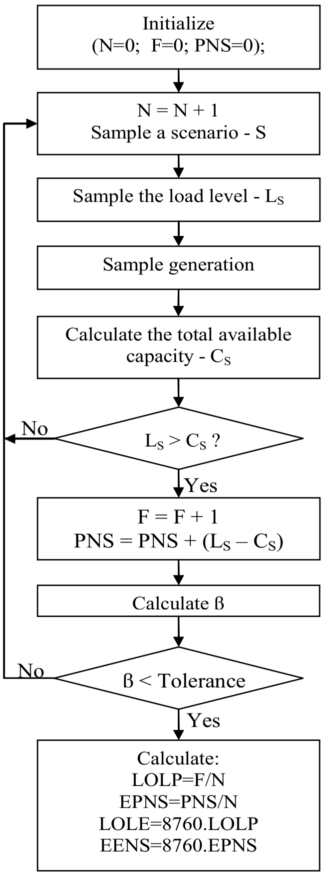

Fig. 5 – Algorithm for non chronological Monte-Carlo with scenarios

The number of scenarios to be set should be sufficient to ensure the independency between the different random variables involved. On the other hand, that number must be as low as possible in order to prevent its excessive proliferation, which may result in long periods of simulation.

Each trial of the adjusted algorithm involves sampling a scenario, performed considering the relative duration of the defined scenarios. Then, the system load and the CF of the μGen technologies are sampled taking into consideration the behaviour of those variables on the previous sampled scenario. The behaviour of the variables on each scenario may be modelled through the use of appropriate CDF. On such circumstances, the load level at each trial of the MCS (L_S) is sampled using the inverse transform method and the CDF that characterizes the load behaviour on the sampled scenario. The available generation capacity in each MCS trial (C_S) results from the sum of the available capacity in centralized generators and the one of the μGen:

$$C_S = \sum_{i=1}^{NG} F_{Gi} \times C_{Gi} + \sum_{j} F_{j,S} \times C_j \times CF_{j,S} \qquad (8)$$

where: NG is the number of centralized thermal units; C_{Gi} is the capacity of the generator i; $F_{j,S}$ is the number of microgenerators of technology j without failure on scenario S, C_j is the individual capacity of microgenerators, $CF_{j,S}$ is the capacity factor of the microgenerators of technology j on scenario S; and F_{Gi} is given by expression (5).

Note that the contribution of the µGen to the available capacity is influenced by the capacity factor (CF) and by the number of µGen systems that are available. The next sections show how those parameters are included in the analysis.

5.2 Available µGen systems

Assuming the same forced outage rate (f) for all the µGen systems of the technology j, the number of units that are available on scenario S follows a binomial distribution:

$$F_{\mu G} \sim b(n, 1 - f) \qquad (9)$$

where: n is the number of microgenerators; and f is the unavailability of each generator (forced outage rate).

For a relatively high number of µGen systems, the binomial distribution may be approximated by a normal distribution:

$$F_{j,S} \sim N\left(n(1-f); \sqrt{n(1-f)f}\right) \qquad (10)$$

Figure 6 shows the approximation obtained for a case where 300 µGen systems with *f = 20%* were assumed. Note that this approximation tends to be more suitable as the number of µGen units increases and the forced outage rate decreases. Therefore, the number of available µGen systems on each trial of the MCS process may be obtained by:

$$F_{\mu G} = n(1-f) + \sqrt{n(1-f)f} \times U_n \qquad (11)$$

where: Un is a normal distributed random number with average 0 and variance 1.

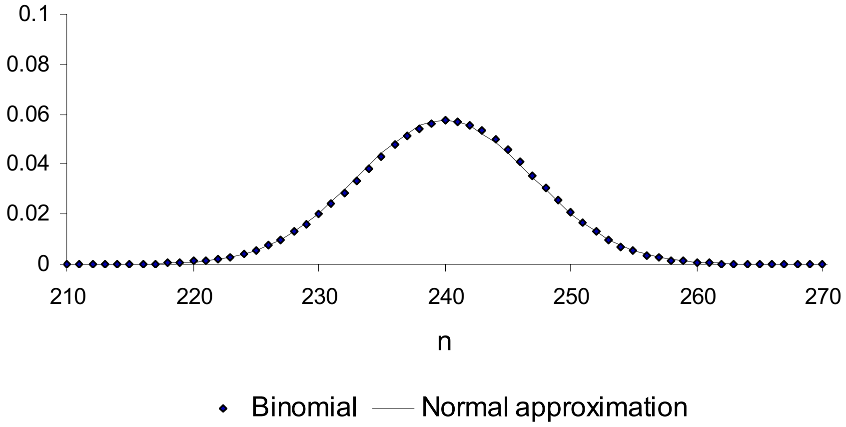

Fig. 6 – Normal approximation to the binomial distribution

5.3 Scenarios and capacity factors of µGen systems

As mentioned above, the scenarios to be used on the MCS process should be sufficient to properly represent the behaviour of the CF of the µGen systems, as well as, their correlations with the behaviour of the system load. Furthermore, the scenarios must be defined taking into consideration the requirement of independency between the involved variables. Therefore, the definition of the scenarios is constrained by the temporal behaviour of the CF of each µGen technology, which is influenced by several aspects, namely:

- The availability of primary resources (wind speed, solar radiation) in the case of micro-wind and PV systems;
- The needs for heat in the case of micro-CHP systems;
- The characteristics and the operation mode of the different µGen technologies (efficiency, control strategies, etc.);

Once defined the scenarios, the CDF suitable to describe the behaviour of the CF of each µGen technology and of the load must be done. Concerning the CF of the µGen units, the different characteristics of the µGen systems make unpractical the definition of individual CDF. This occurs even for systems belonging to the same technology, once the CF behaviour is influenced by aspects as the efficiency, the installation mode and the ways the systems are explored. Therefore, typical CDF must be used to represent the behaviour of all microgenerators of a specific technology.

The next sections show, for the case of the Portuguese power system, the approach used to define the scenarios and the CDF. Naturally, the analysis may be adapted to other power systems.

5.3.1 Micro-CHP Systems

The behaviour of the CF of a micro-CHP unit is influenced by the strategy adopted to control it. The most common strategy is the one corresponding to a heat driven regime of the micro-CHP units. In this case, the electricity generation is determined by the thermal energy needs. A different approach consists of using a micro-CHP system to follow the energy consumption of the electrical installation to which it belongs. This strategy may be appropriate when the electricity prices are high, possibly using a traditional heating boiler to produce heat when the electricity prices are low. However, this type of control may result in waste of thermal energy, contradicting the basic principle of combined heat and power production. A strategy of "minimum cost" may also be established based on the two previous ones. In this case, the control of micro-CHP systems is made in order to minimize the energy cost. Other control (more complex) strategies were proposed, namely involving the application of Fuzzy Logic [30-31].

In this work, the most common control strategy is adopted (heat driven regime of the micro-CHP). Therefore, the behaviour of the CF of the micro-CHP systems is influenced by the season of the year and by the time of the day. In fact, the micro-CHP systems tend to be used more intensely in cold months (winter) and, within these, in the early hours of the day and in the initial period of the night (due to the higher needs of hot water and of space heating) [33]. Obviously, different families tend to have different behaviours, which impact on the individual profile of use of their micro-CHP systems. Moreover, the behaviour of the CF of the micro-CHP systems is also influenced by their technology (Stirling engine, fuel cells, reciprocal engine, etc.), efficiency and rated power. Actually, providing a certain amount of thermal energy using units of different rated powers and efficiencies necessarily implies different CF [33]. However, the expected large number of those units allows defining typical profiles, overcoming those difficulties.

The available information to establish typical values for the CF of micro-CHP systems is practically nonexistent. In [32], typical generation profiles for units with rated electrical power of 1.1 kW and for the case of the UK are presented. In [34] the authors present generation profiles for the Portuguese case. These profiles were, according to the authors, obtained taking into account the typical use of a micro-CHP unit, and are only applicable to summer and winter months. Figure 7 shows the profiles defined in [32] and [34].

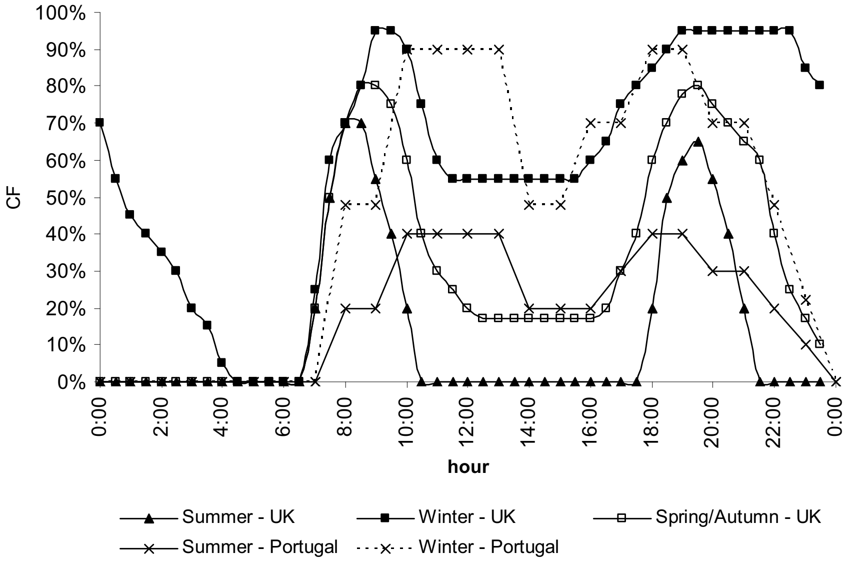

Fig. 7 – Profiles for micro-CHP systems in Portugal and in the UK

The comparison of the profiles shows the existence of important differences between them, namely regarding the summer profiles, which is natural taking into account the climactic differences between UK and Portugal. Despite those differences it is possible to conclude that, for a typical day of each season, there are periods where the CF assumes higher values, periods where the CF is low, and periods where an intermediate value applies. Therefore, the daily variation on the CF behaviour may be captured through the definition of 3 daily periods. Moreover, the seasonality of the CF behaviour may be captured through the use of 3 annual periods (summer, winter, and spring/autumn), which reflect the different needs of thermal energy throughout the year (and, as a consequence, its effect on the CF factor of micro-CHP units). Consequently, it seems reasonable to define 9 scenarios to characterize the impact of micro-CHP systems on the generation adequacy of the Portuguese electrical system. However, those scenarios must be confronted with the system load behaviour. This is particularly important in the Portuguese system case, once the system load is shaped by the behaviour of the consumers belonging to the domestic sector. Note that the presence of people at their homes not only leads to increased consumption of electricity but also of heat. As a result, the micro-CHP systems tend to present higher CF in periods that match the periods of highest load of the electrical system. Figure 8 shows the defined scenarios as well as the load behaviour on a typical day of each annual season. Note that the load behaviour is expressed in percentage of the annual peak power of the Portuguese system.

Tables 1 and 2 show, respectively, the defined periods and the applicable values of CF. Those values were defined, in the absence of better information, based on the profiles presented in [32] and [34]. Note that the CF applicable to each scenario is a constant value. However, CDF representing the behaviour of the CF on each scenario may be defined (as shown below for cases of PV and micro-wind systems), namely when more information on micro-CHP systems behaviour exists.

Table 1 - Scenarios for micro-CHP systems

		Daily period		
		High CF	Intermediate CF	Low CF
		09,30h - 13,30h 17,00h - 20,00h	07,30h - 09,30h 13,30h - 17,00h 20,00h - 23,00h	23,00h - 24,00 h 00,00h - 07,30 h
Annual period	Summer	Summer - P1	Summer - P2	Summer - P3
	Winter	Winter - P1	Winter - P2	Winter - P3
	Spring / Autumn	Spring/Autumn - P1	Spring/Autumn - P2	Spring/Autumn - P3

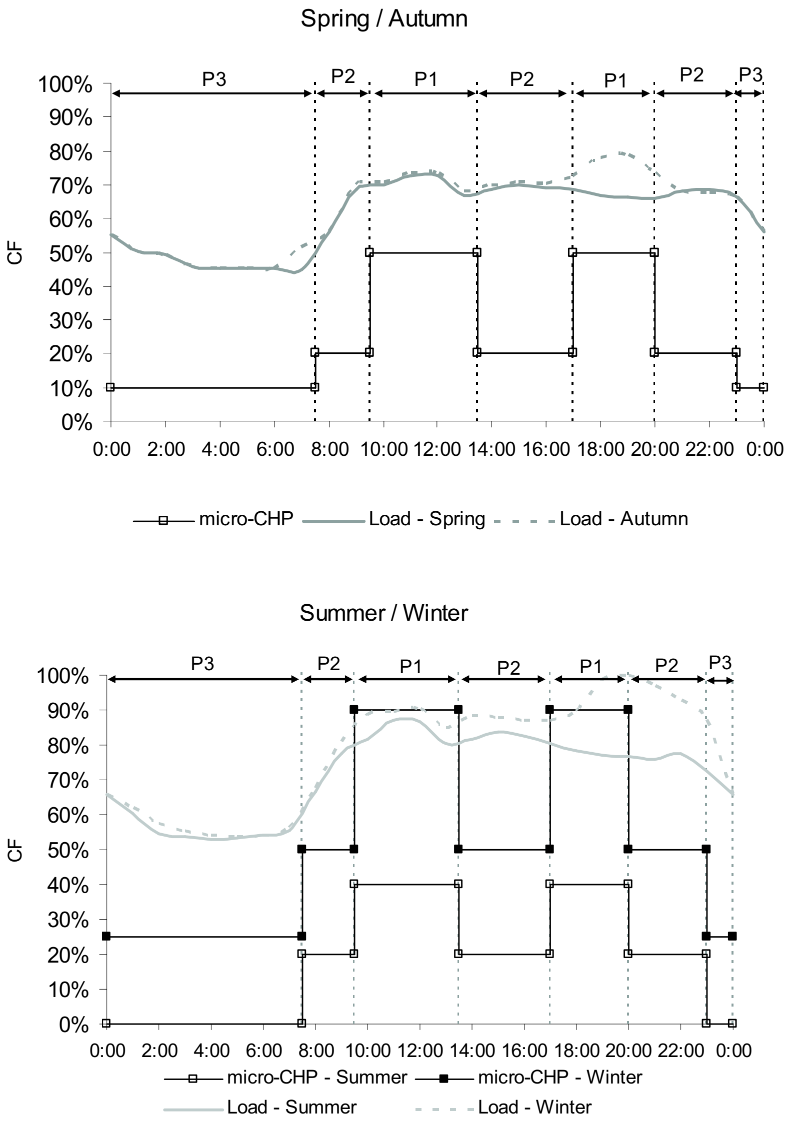

Fig. 8 – Scenarios for micro-CHP systems and load behaviour

Table 2 – CF values for the defined scenarios

		Daily period		
		P1	P2	P3
Annual period	Spring/Autumn	50%	20%	10%
	Summer	40%	20%	0%
	Winter	90%	50%	25%

5.3.2 PV Systems

The CF of a PV generator is influenced by several factors, namely:

- The availability of the primary resource (solar irradiance), which has spatial (due to the geographical location of the generator) and temporal variations (due to the season of the year and the time of the day);
- The characteristics of the generator (technology, efficiency of the panels and of the interface used to connect the panels to the network, etc.);
- The way the generator is installed, namely concerning the inclination with the horizontal (tilt angle) and the orientation of the PV panels.

The CF of a PV system may be obtained by:

$$CF_{PV} = \frac{P_{PV}}{P_p} = \frac{I \times A \times \eta}{P_p} = \frac{\eta \times I}{\nu} \qquad (12)$$

where: P_{PV} is the power generated by the PV unit; P_p is the peak power of the generator; I is the incident solar irradiance (W/m^2); A is the surface of the PV generator; η the efficiency of the PV system (including the interfaces); and ν the ratio between the peak power and the surface of the generator (W/m^2).

By using typical values for the parameters η and ν, the expression (13) becomes:

$$CF_{PV} = \frac{P_{PV}}{P_p} = k \times I \qquad (13)$$

where: k = η/ν is a constant value, defined by the typical characteristics of the PV generator.

Therefore, the CF of the typical PV generator becomes a function of the incident irradiance on the PV panels, which is influenced by factors such as:

- The geometry of the earth and its movements of rotation and translation;
- The location and characteristics of the terrain (elevation, shadows, etc.);
- The geographical location of the PV unit,
- The tilt and orientation of the PV panels;

- The irradiance attenuation produced by the particular atmosphere due to gases (air molecules, ozone, CO2 and O2), solid particles and liquids (such as aerosols) and the clouds.

Information about the solar irradiance for several locations in Europe and Africa may be found at the web site of the Photovoltaic Geographical Information System (PVGIS) project [35]. The values presented on the PVGIS site are estimated for periods of 15 minutes of a typical day of each month. The irradiance values may be obtained for surfaces at multiple locations, with different tilt angles and with different orientations (North, South, East, West, etc.).

Typical profiles of solar irradiance may be used in order to avoid the use of irradiance values for all geographical locations of a country and for all possible installation forms of the PV panels. Those profiles have to be constructed taking into consideration the influence of the installation conditions (namely concerning the orientation and the tilt angle) of the PV panels. Moreover, the geographical variation of the irradiance must be considered. This may be achieved by using irradiance profiles of a set of locations, assumed as appropriate to model the mentioned geographical variation. Figure 9 shows the eight locations assumed as suitable for the Portuguese situation.

Fig. 9 – Locations to determine the typical profiles of solar irradiance

Concerning the typical orientation and tilt angle of the panels, it is reasonable to assume that the PV generators will be installed to maximize the electricity generation. Regarding the Portuguese situation, this implies that the PV panels will be facing south. The optimal value of the tilt angle varies along the year as shown in table 3, for the eight previously mentioned locations. Based on such information, it is possible to conclude that the average value for the optimum tilt angle is 35º (assuming a static PV generator).

Table 3 – Optimum tilt angle, in degrees, for PV panels facing south (source: [35])

	Bragança	Porto	Viseu	Coimbra	Portalegre	Lisboa	Beja	Faro
January	64	65	64	64	63	63	63	62
February	56	57	56	56	55	54	55	54
March	45	45	44	44	43	42	42	41
April	28	28	27	27	26	26	25	24
May	14	16	13	15	12	14	13	12
June	8	7	7	6	4	5	4	3
July	12	11	11	10	9	9	8	7
August	24	23	22	22	21	21	20	19
September	39	39	38	38	37	37	36	35
October	51	52	51	51	51	50	50	50
November	62	63	61	62	61	61	61	60
December	66	67	66	66	65	65	65	64
Year	35	37	34	36	35	35	34	34

Figure 10 shows the profiles of irradiance obtained for the eight locations and for the months of January, April, July and November (taking into consideration the tilt angle of 35º and the south orientation of the panels). As expected, the profiles show that the irradiance has a seasonal behaviour, namely concerning the irradiance intensity and the daily hours of sunlight. Moreover, the irradiance varies over the hours of the day and, to a lesser extent, with the geographical location. Therefore, the CF of a typical PV generator also presents seasonal, daily and geographic variations, once it follows the solar irradiance behaviour.

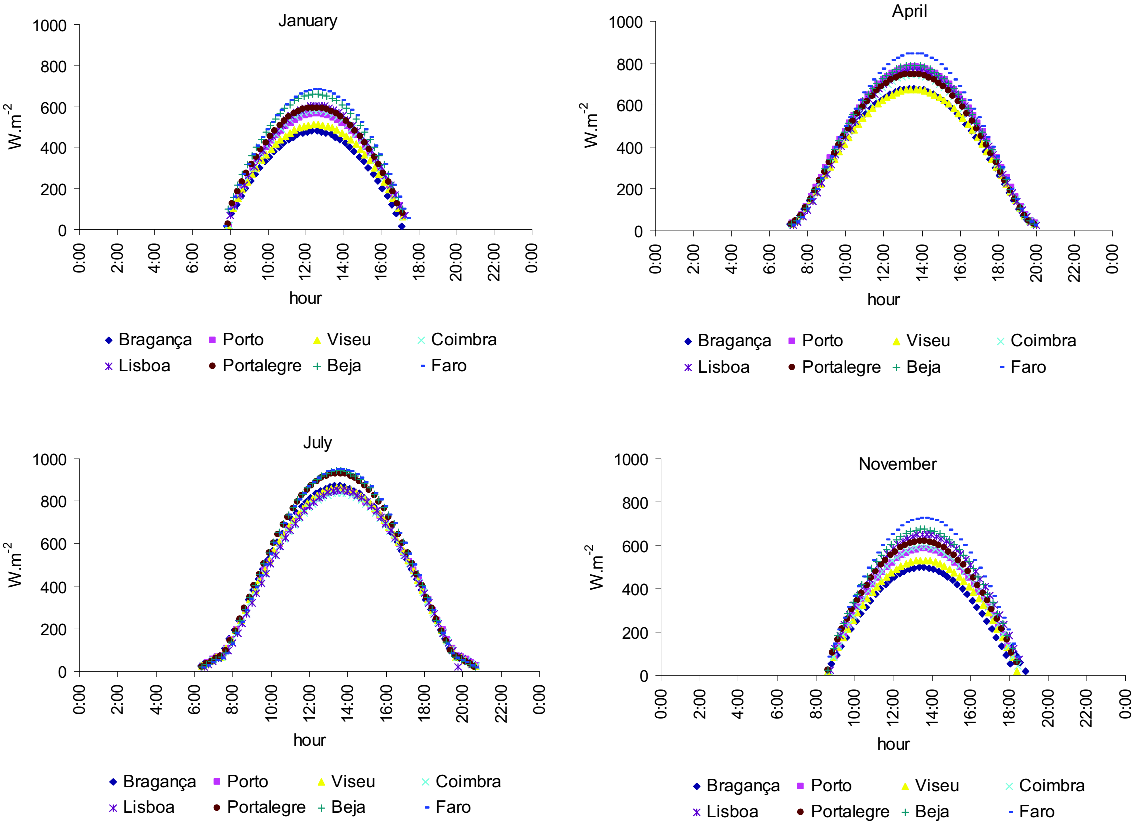

Fig. 10 – Solar irradiance profiles

As in the case of micro-CHP systems, scenarios must be defined in order to capture the behaviour of the CF of PV systems and its correlation with the system load. Ideally, the scenarios should coincide with those determined for the case of micro-CHP systems. This would allow us to avoid the multiplication of the scenarios and the inherent difficulties, namely related to the time of simulation. However, the daily periods defined for the micro-CHP case are not adequate to be directly applied to PV situation. Figure 11 shows that inadequacy, taking as a reference the irradiance profiles for Viseu (Portugal) in four mouths of the year.

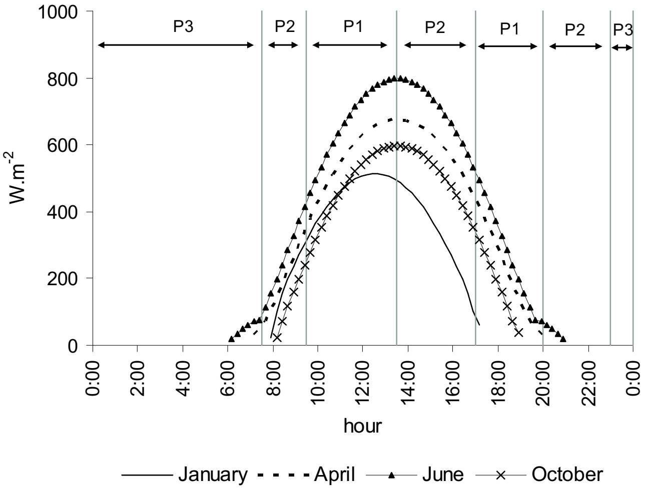

Fig. 11 – Inadequacy of the daily periods defined for the micro-CHP systems

This difficulty may be overcome by redefining the daily periods set for micro-CHP systems, namely subdividing the periods P1 and P2. Therefore, for the PV case, 24 scenarios are defined, corresponding to four annual and six daily periods, as illustrated in figure 12 and table 4. Note that the spring/autumn annual period set for the case of micro-CHP systems was also subdivided into two periods. This division is intended to reflect the different solar irradiance values that take place on those seasons. Table 5 shows the conversion of the 9 scenarios previously set for the micro-CHP case in all the 24 scenarios defined for the PV generators.

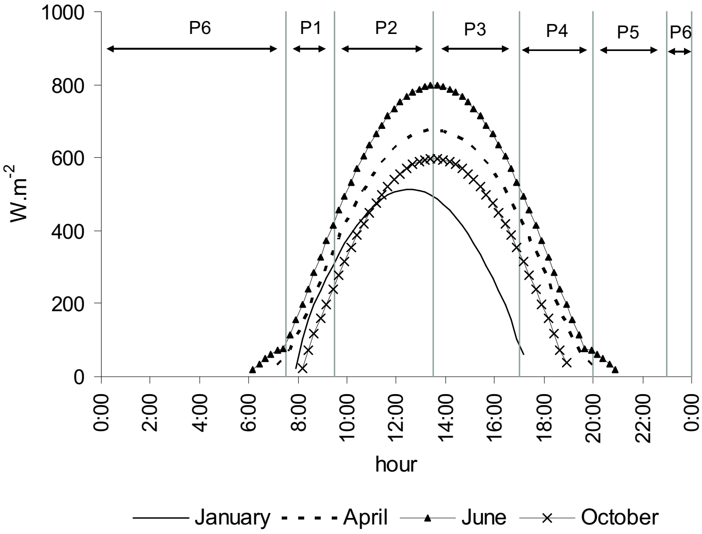

Fig. 12 – Daily periods to be applied to PV systems

Table 4 – Scenarios for the PV systems

		Daily period					
		07,30h - 09,30h	09,30h - 13,30h	13,30h - 17,00h	17,00h - 20,00h	20,00h - 23,00h	23,00h - 24,00 00:00h - 07:30h
Annual period	Spring	Spring - P1	Spring - P2	Spring - P3	Spring - P4	Spring - P5	Spring - P6
	Summer	Summer - P1	Summer - P2	Summer - P3	Summer - P4	Summer - P5	Summer - P6
	Autumn	Autumn - P1	Autumn - P2	Autumn - P3	Autumn - P4	Autumn - P5	Autumn - P6
	Winter	Winter - P1	Winter - P2	Winter - P3	Winter - P4	Winter - P5	Winter - P6

Table 5 – Conversion of the scenarios defined for the micro-CHP systems

		Daily period					
		P1	P2	P3	P4	P5	P6
Annual period	Spring	Spring - P2	Spring - P1	Spring - P2	Spring - P1	Spring - P2	Spring - P3
	Summer	Summer - P2	Summer - P1	Summer - P2	Summer - P1	Summer - P2	Summer - P3
	Autumn	Autumn - P2	Autumn - P1	Autumn - P2	Autumn - P1	Autumn - P2	Autumn - P3
	Winter	Winter - P2	Winter - P1	Winter - P2	Winter - P1	Winter - P2	Winter - P3

Once defined the scenarios, the next step is to define the CDF that represent the behaviour of the CF of the PV systems on each one. Those CDF may be obtained by using the procedure described in figure 13. Note that the information about the solar irradiance of the eight locations previously mentioned should be used in order to account for the influence of the geographical location of the PV generators (it is assumed that the PV generators are uniformly distributed throughout the Portuguese territory). Moreover, typical values of η and v were used, namely $\eta = 10\%$ and v = 100 W/m^2.

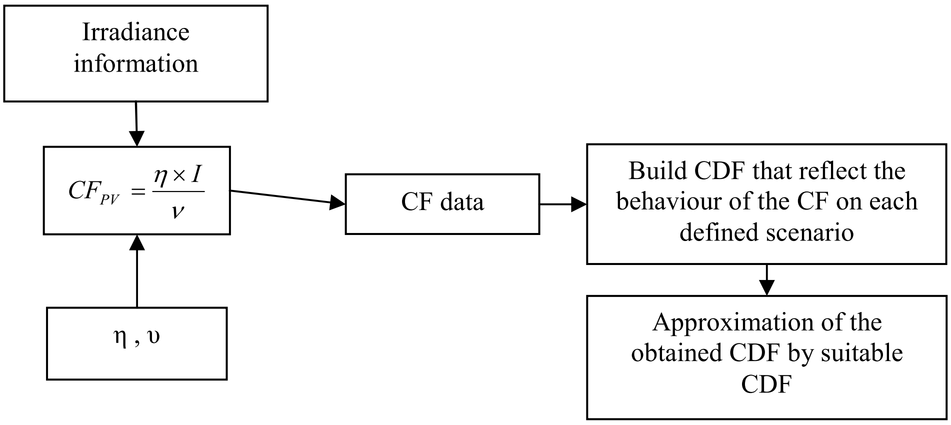

Fig. 13 – Procedure to obtain the CDF that characterize the CF behaviour of the PV systems in each scenario

Figure 14 shows, for two of the previously defined scenarios, the CDF that characterize the behaviour of the CF of the PV generators. Note that the real CDF obtained were approximated by uniform distributions. The sampling process is achieved by using the inverse transform theorem as shown in expression (14).

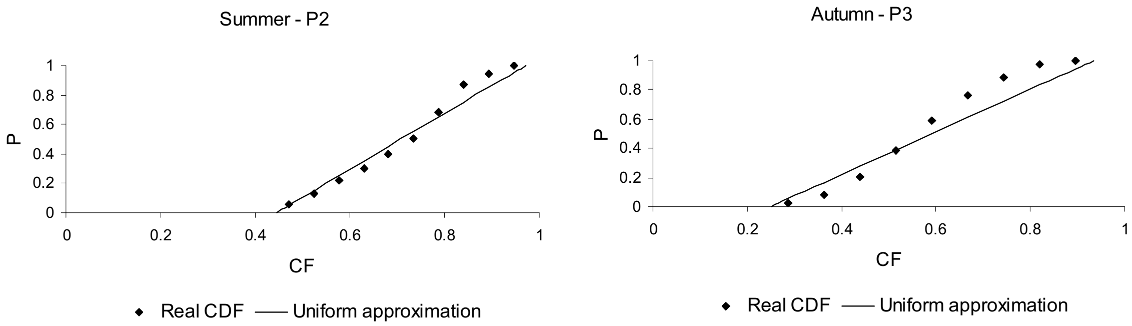

Fig. 14 – Examples of obtained CDF (two scenarios) for PV systems

$$CF_{PV} = \frac{U-b}{m} \qquad (14)$$

where: m and b are the coefficients of the line used on the approximation and U is a random number between 0 and 1 with a uniform distribution.

5.3.3 Micro-wind Systems

The definition of scenarios and CDF for use in assessing the contribution of micro-wind generators to the security of supply involves information about:

- the wind regime (wind speed) to which the generators may be subject;
- the characteristics of the generators, namely concerning the conversion of wind energy into electrical power.

Wind speed is a random variable with stochastic variation in time and space (geographical regions). This is shown in figure 15, for three locations in Portugal (Porto, Lisbon and Faro). Those series of hourly wind velocity were obtained along the year of 2007 at an altitude of 10 meters [36].

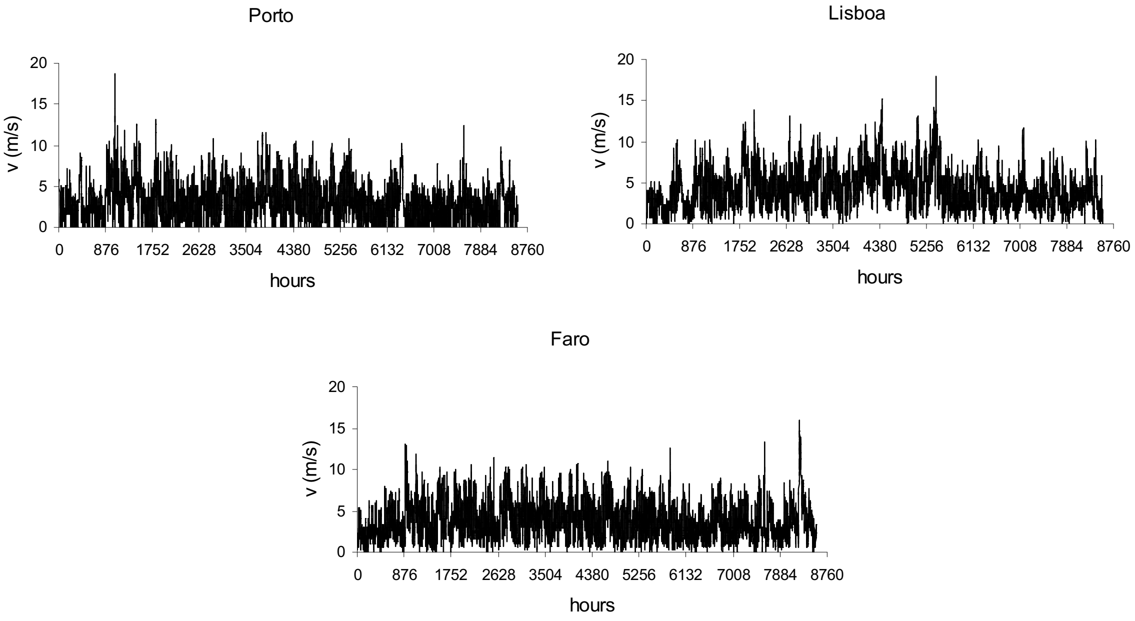

Fig. 15 – Wind series for Porto, Lisboa, and Faro (source: [36])

Since the micro-wind systems tend to be spread throughout the national territory, the overall contribution of these generators to the security of supply will be influenced by the wind regime at various locations. In this study it is assumed that the three wind series presented in figure 15 are representative of the northern, central and southern regions of Portugal. As well, it is assumed that there is no significant correlation between wind speeds of those locations.

The electrical power produced by a micro-wind system is a function of the wind velocity and of the characteristics of the generator, namely its power curve and the efficiency of the system used to connect the wind turbine to the network. The power curve establishes the relationship between the wind speed and the generated power. As shown in figure 16, different turbines tend to present diverse power curves. P and P_n (in the ordinate axis) represent respectively the power generated by the turbines and their rated powers. Therefore, figure 16 shows the CF behaviour of several wind turbines as a function of the wind speed. The assessment of the contribution of each specific micro-wind generator to the security of supply is not practical. An approach to surpass that difficulty is to adopt a typical power curve (suitable to represent the behaviour of all micro-wind systems that may be connected to the network). In this work the curve of the 7.5 kW Bergey turbine was adopted and analytically approximated as shown in figure 17 and in expression (15).

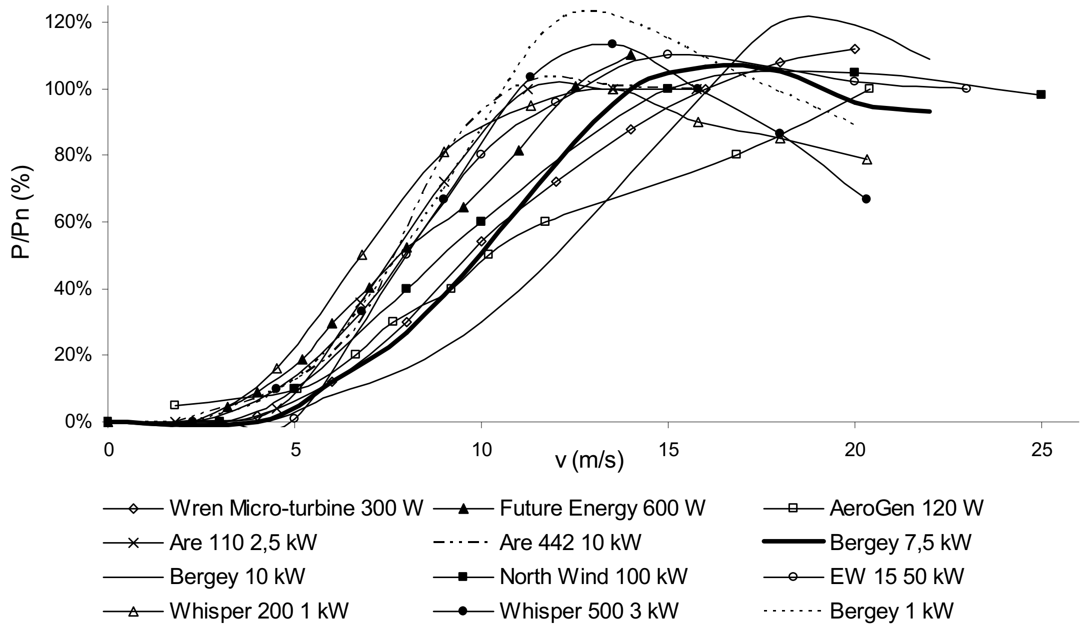

Fig. 16 – Power curves of several micro-wind turbines

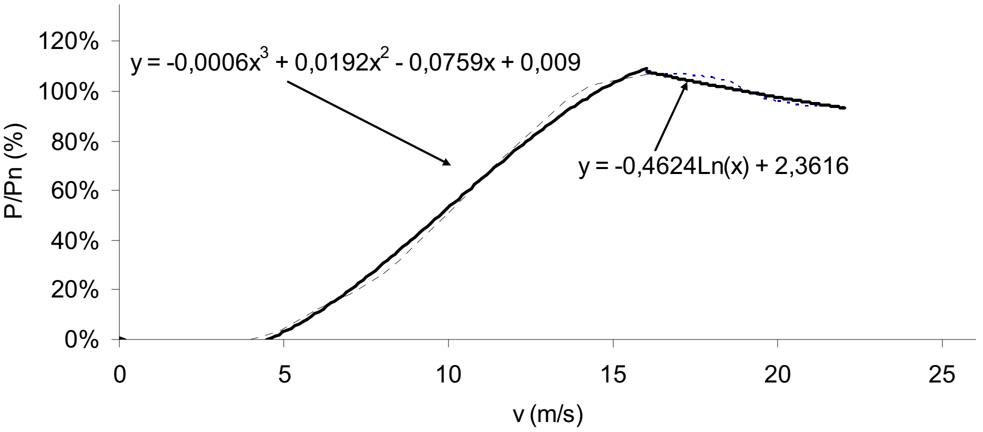

Fig. 17 – Typical power curve

$$\frac{P}{P_n}(\%) = \begin{cases} 0 & \text{se} \quad \mathrm{v} \le 4{,}5 \ m/s \\ -0{,}0006v^3 + 0{,}0192v^2 - 0{,}0759v + 0{,}009 & \text{se} \quad 4{,}5 < \mathrm{v} \le 14 \ m/s \\ -0{,}4624\ln(v) + 2{,}3616 & \text{se} \quad 14 < \mathrm{v} \le 22 \ m/s \end{cases} \qquad (15)$$

Expression (15) and the wind series presented in figure 15 allow determining series of CF applicable to each of the geographic regions defined above. A global series of CF may be obtained if the micro-wind systems are assumed as uniformly distributed throughout the geographical area. On such circumstances, the global series corresponds to the arithmetic mean of the values of the individual series.

The global CF series is then used to define CDF that represent the behaviour of the micro-wind systems for each of the 24 scenarios previously defined. Those CDF (obtained by using statistical techniques) are then approximated by standard CDF. Figure 18 shows the results for two scenarios as well as the approximations through the use of exponential distributions.

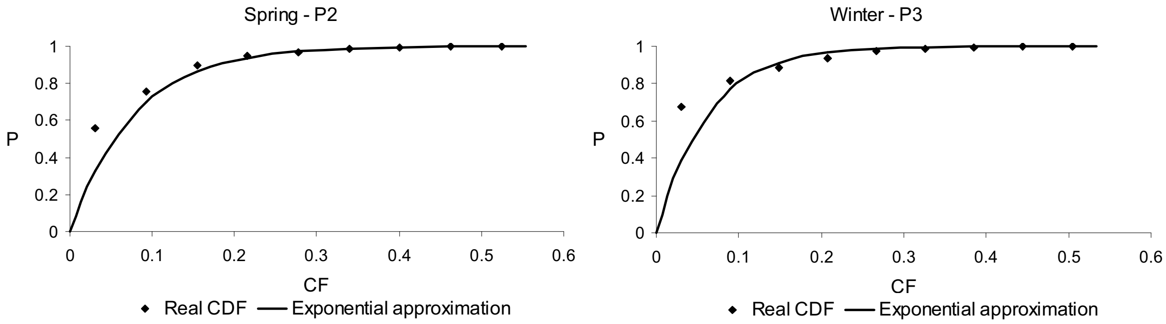

Fig. 18 – Examples of obtained CDF (two scenarios) for wind systems

As for the case of PV systems, in each trial of the MCS process the CF of micro-wind systems is sampled by using the inverse transform theorem [3]:

$$CF_{\mu Wind} = -\lambda \times \ln(U) \qquad (16)$$

where: λ is the mean value of the exponential distribution; and U is a random value with uniform distribution in the range [0,1].

5.3.4 Load

The load behaviour in each scenario must also be characterized by using CDF. Those CDF may be defined by using statistical techniques and the information of the previously mentioned chronological daily load diagrams. Figure 19 shows the CDF obtained for two scenarios and taking into consideration the load diagrams of the Portuguese electrical system. Moreover, it shows the approximation of the real CDF by using uniform distributions. A procedure similar to the one defined to sample the CF of the PV generators is used to sample the load level.

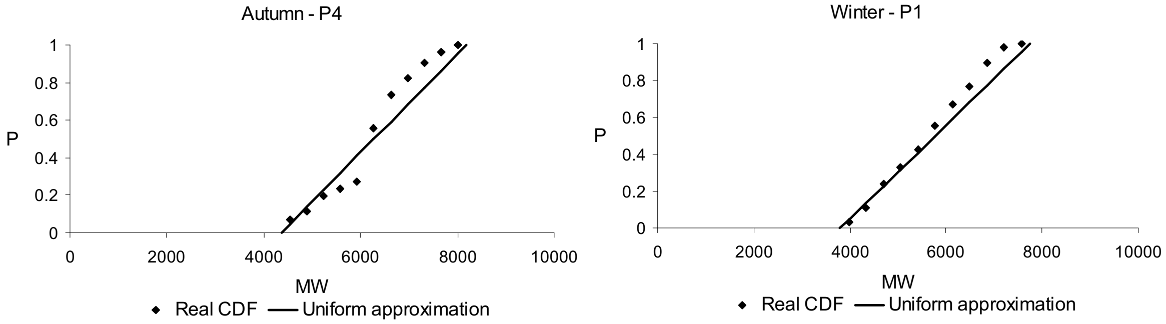

Fig. 19 – Examples of obtained CDF (two scenarios) for system load

6. Results

The presented methodology was applied to a test system adapted from the Portuguese one (peak load = 9110 MW), in order to obtain qualitative and quantitative conclusions regarding the influence of µGen and µGrids on the generation adequacy. Some simplifications to the real system were made, namely regarding the centralized generating system. This system was assumed as being constituted by 24 thermal power plants with rated power of 400 MW and FOR = 5%.

The initial LOLE of the system (in the absence of the µGen) is 27.8 h/year. Note that this LOLE does not represent a typical value of the Portuguese system. However, it was used in order to obtain a sufficient range of the reliability improvements resulting from the addition of µGen and µGrids to the system. Additional studies were made in order to assess the influence of the initial system reliability on the achieved improvements.

The scenarios (table 4) and the CDF that represent the behaviour of the load and of the CF of µGen technologies were obtained as explained above. All Monte Carlo simulations were stopped after 20 million trials, and a β value lower than 5% was ensured.

The influence of µGen and µGrids on the generation adequacy was evaluated by comparing the adequacy indices of a base case (without µGen) to the indices associated to various penetrations of different technologies of µGen (CHP, PV, wind, etc) and the existence of µGrids. A number of possible typical situations was analyzed, namely to conclude about the sensitivity of the results to parameters like the initial reliability of the system, the technology, number, size and the forced outage rate of the µGen units.

In order to facilitate the perception of the impact on generation adequacy produced by µGen alone, the analysis was separated into two parts: the first only considers the existence of µGen; the second determines the additional contribution of the µGrids.

6.1 µGen results

Adding µGen to a system, while preserving the previously existent capacity, increases the total available capacity. Therefore, the generation adequacy of the system is improved. In order to estimate the magnitude of the improvements, studies have been conducted considering increasing amounts of installed power of each µGen technology (1%, 5%, 10%, 15% and 20% of the installed power in the conventional generating system (9600 MW)).

Three rated power values for the µGen units (1 kW, 3 kW and 10 kW) were also assumed in the simulation process in order to evaluate the influence of that parameter on the contribution of the µGen to the security of supply. The influence of the unavailability of the microgenerators was evaluated using three values of forced outage rate (f=5%, f=10% and f=25%).

The results show that, regardless of µGen technology, the reliability of the system is improved as the µGen installed power increases. This is not surprising, once the centralized generation system remains with the initial installed power. Figure 20 shows the LOLE and EENS evolution when µGen units with f = 10% and rated power of 1 kW, 3 kW and 10 kW were assumed. An important conclusion that may be extracted from the results is that, regardless of the µGen technology, the individual rated power of the µGen units has a small impact on the system reliability improvements (for the same total amount of power). Moreover, the improvements tend to be less significant with the increasing penetration of µGen systems. A further conclusion is that different µGen technologies have different impacts on the reliability indices, as highlighted in figure 21. Naturally, this is mainly the effect of the capacity factor, but also of the correlation CF/load.

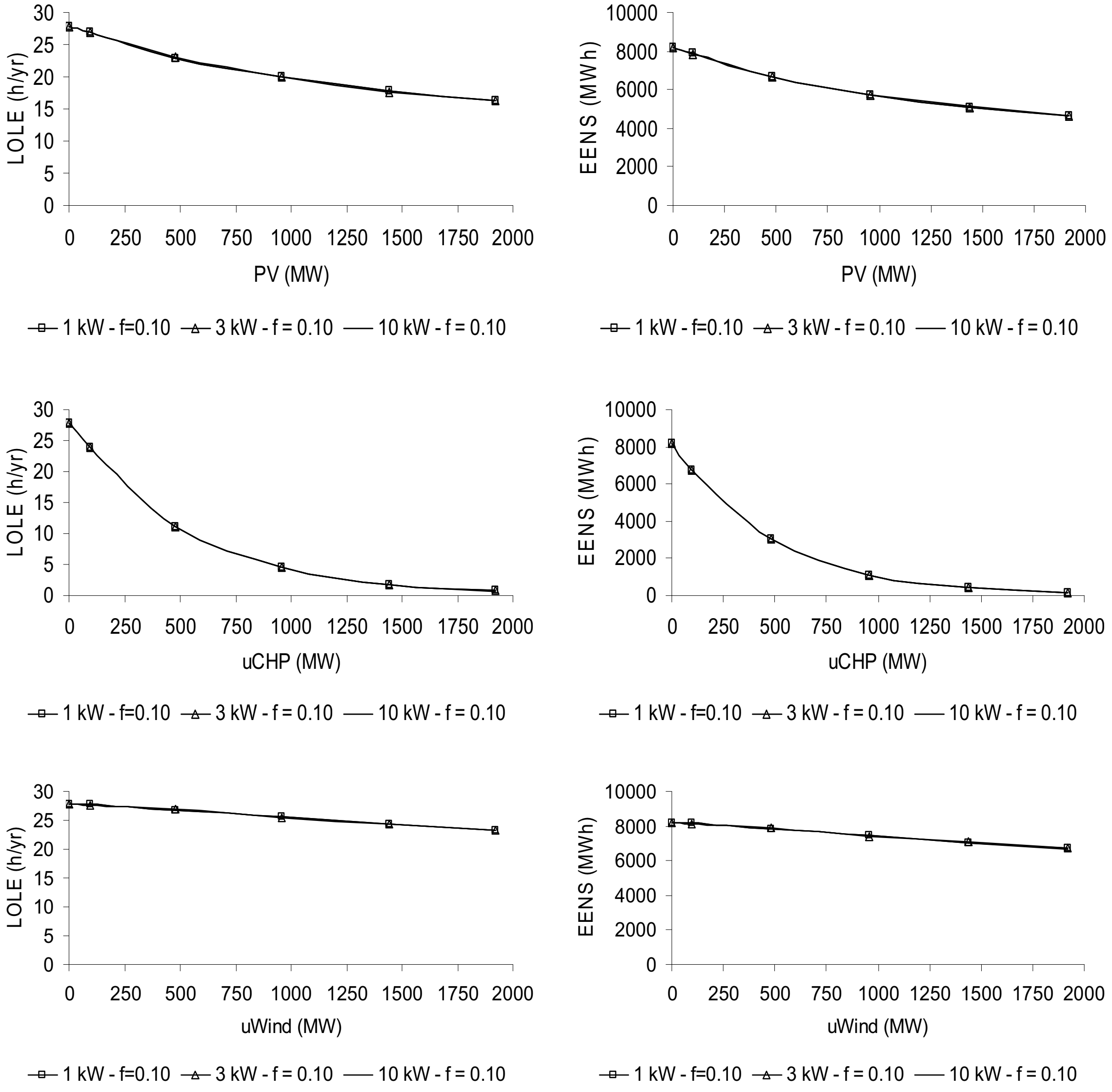

Fig. 20 – Impact of µGen on LOLE and EENS

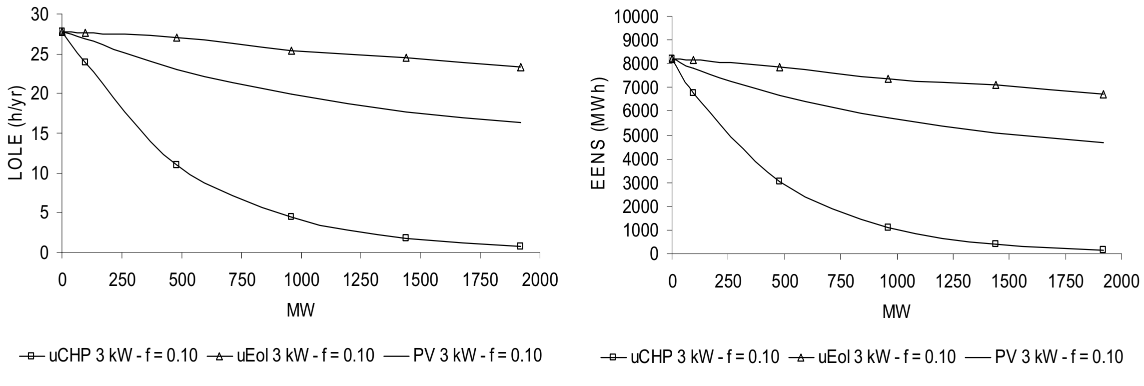

Fig. 21 – Comparison of the impact of different µGen technologies on LOLE and EENS

Figure 22 shows the influence of the unavailability of the µGen units on the system reliability improvements (the results presented refer to µGen units with a rated power of 3 kW). It can be concluded that the influence of the unavailability of the µGen units is limited, particularly considering the unavailability values assumed to the microgenerators. Here, the favourable influence of a large number of generators turns the individual unavailability less important.

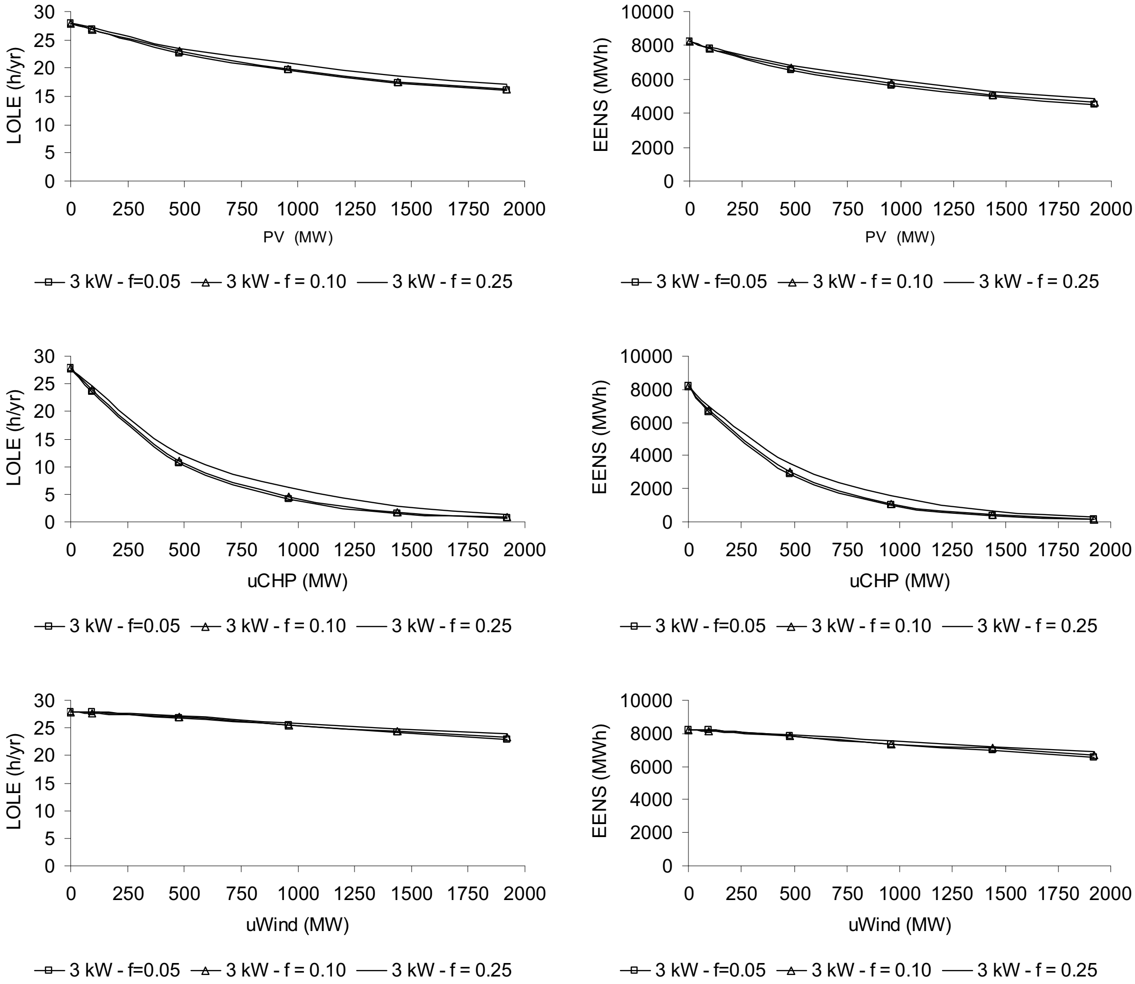

Fig. 22 – Influence of the unavailability of the µGen systems on LOLE and EENS

Figure 23 shows the CC obtained for the different µGen technologies, assuming f=10%. The CC values expressed in MW correspond to the amount of conventional generation that can be removed, after the addition of the µGen capacity, while maintaining the initial reliability of the system. The percentage values of the CC correspond to the ratio between the CC in MW and the total µGen installed capacity.

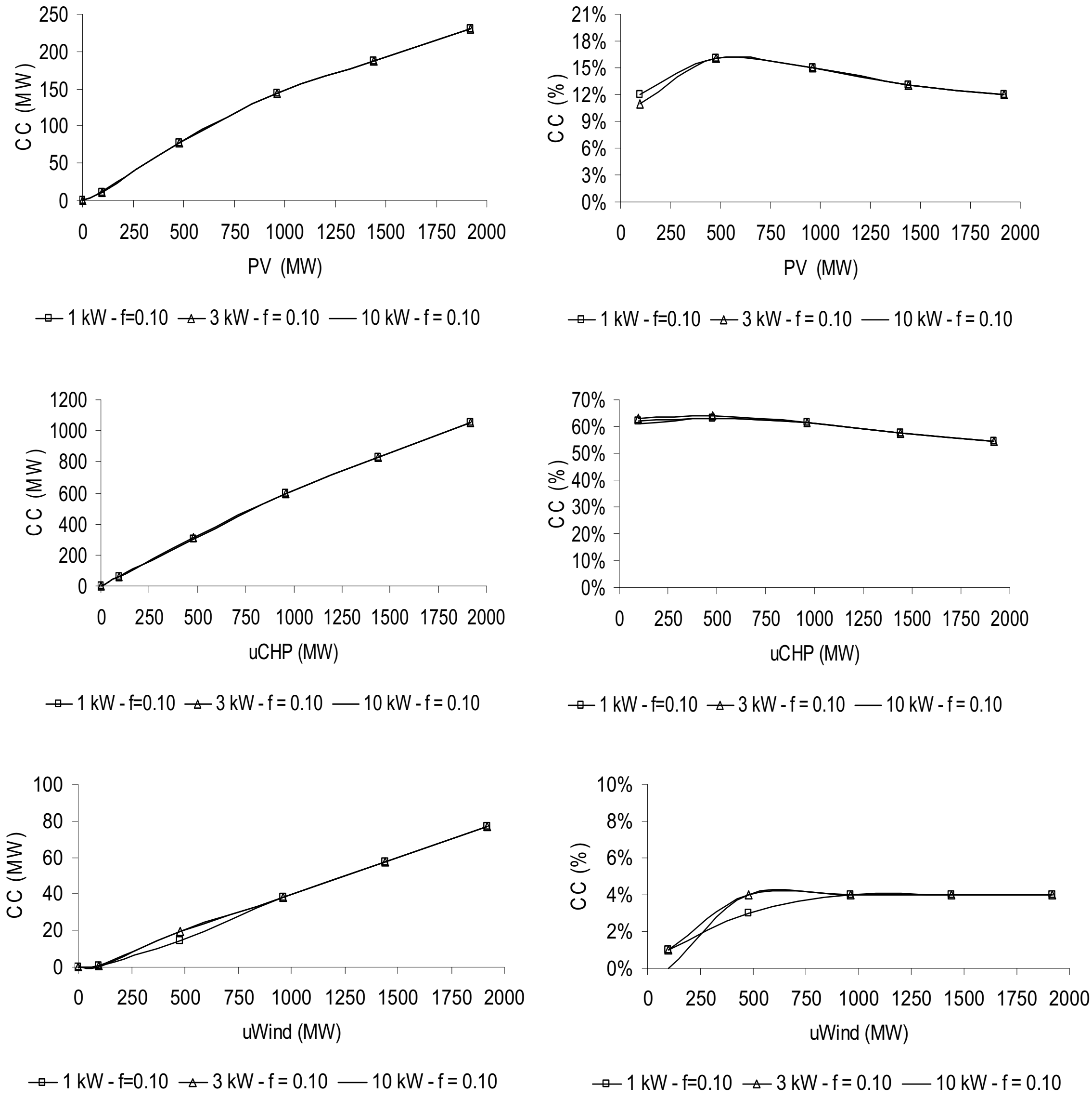

Fig. 23 – CC of different μGen technologies

The results presented allow concluding that the rated power of the μGen units does not influence significantly the CC to be allocated to those units. Another important conclusion that may be extracted from the results has to do with the behaviour of the percentage value of the CC. At the initial stage (up to approximately 500 MW), the CC increases with the increase of the μGen installed power, declining afterwards.

The influence of the μGen unavailability on the CC is illustrated in figure 24. This influence is more significant than the one of the rated power of the μGen units, however still limited.

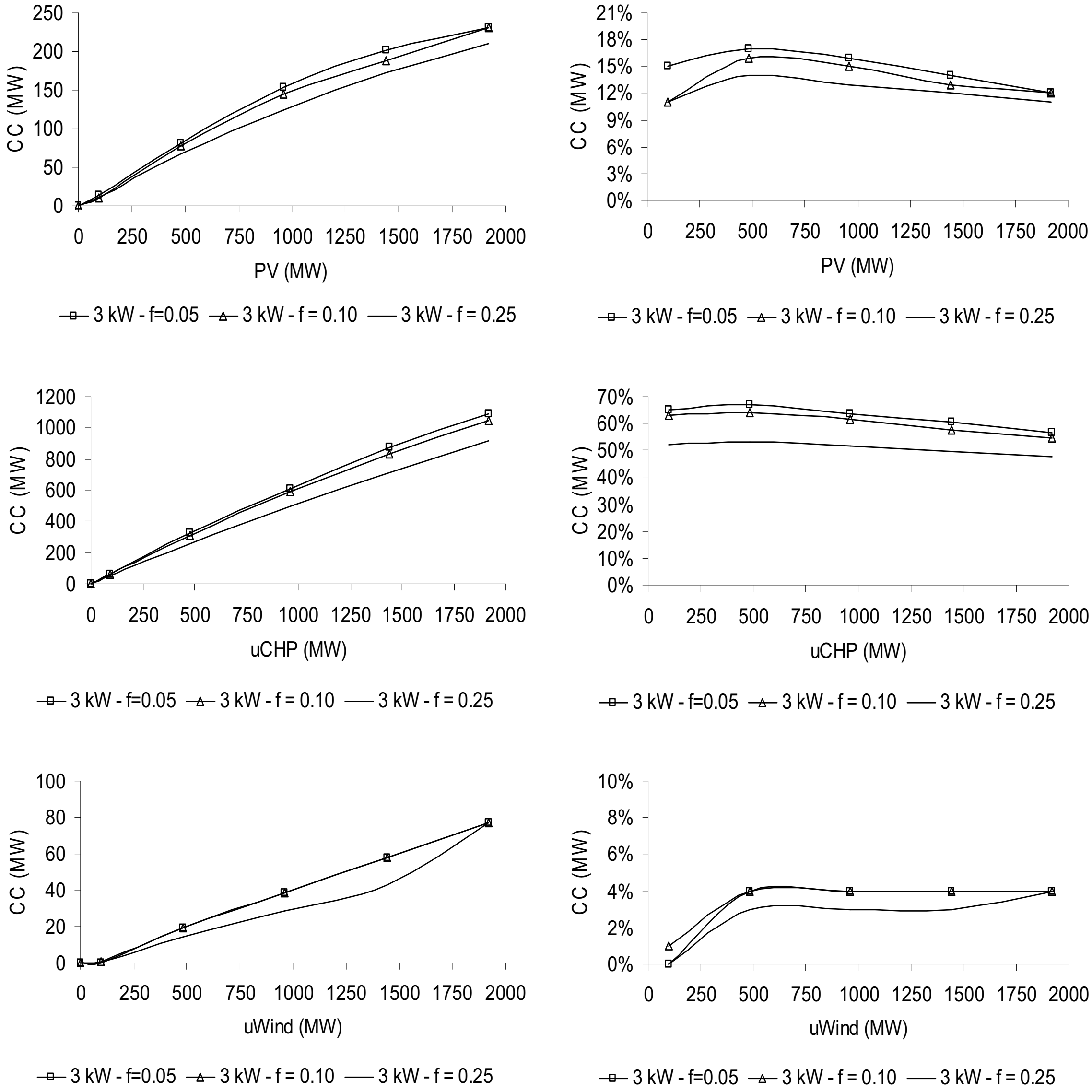

Fig. 24 – Influence of the unavailability of μGen technologies on the CC

Figure 25 allows comparing the CC to be allocated to each of the μGen technologies considered. An important conclusion that can be drawn from this figure is that the influence of the μGen penetration level on the CC tends to be limited. This is an important feature, namely from the regulation point of view (once it allows establishing CC values that are not significantly affected by the uncertainty on the μGen penetration level).

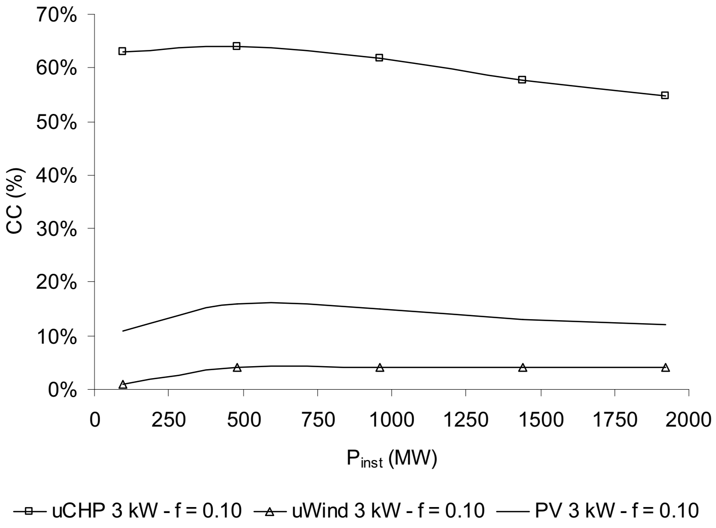

Fig. 25 – Comparison of the CC values for different µGen technologies

The CC of each µGen technology is influenced by the amount of energy it generates and by the periods where this generation takes place. Dividing the CC of each µGen technology by its average annual CF we eliminate the first influence, highlighting the second one. Figure 26 shows the CC adjusted to energy (assuming that all technologies generate the same energy). This figure confirms the tendency of the micro-CHP systems to inject power into the grid when it is more needed (from the point of view of the security of supply).

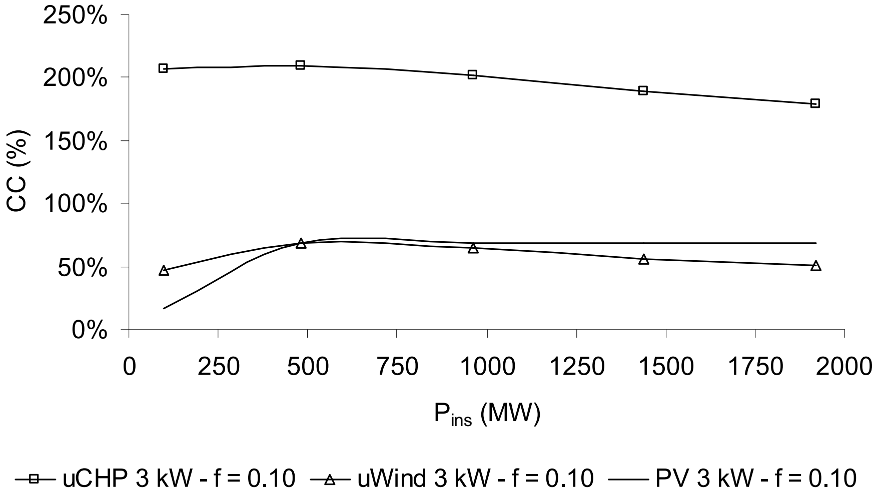

Fig. 26 – CC values adjusted to energy

In order to assess the impact of the initial reliability of the electrical system on the CC to be allocated to the μGen technologies, additional simulations were made. Figure 27 shows the results for μGen systems with rated power of 3 kW and f = 10% when different initial values of the system LOLE are assumed. The results allow us to conclude that the initial reliability of the electrical system influences, in a dissimilar way, the CC of the μGen units. The CC value of micro-CHP units tends to increase when the initial system reliability is higher. The opposite situation occurs for PV and micro-wind systems.

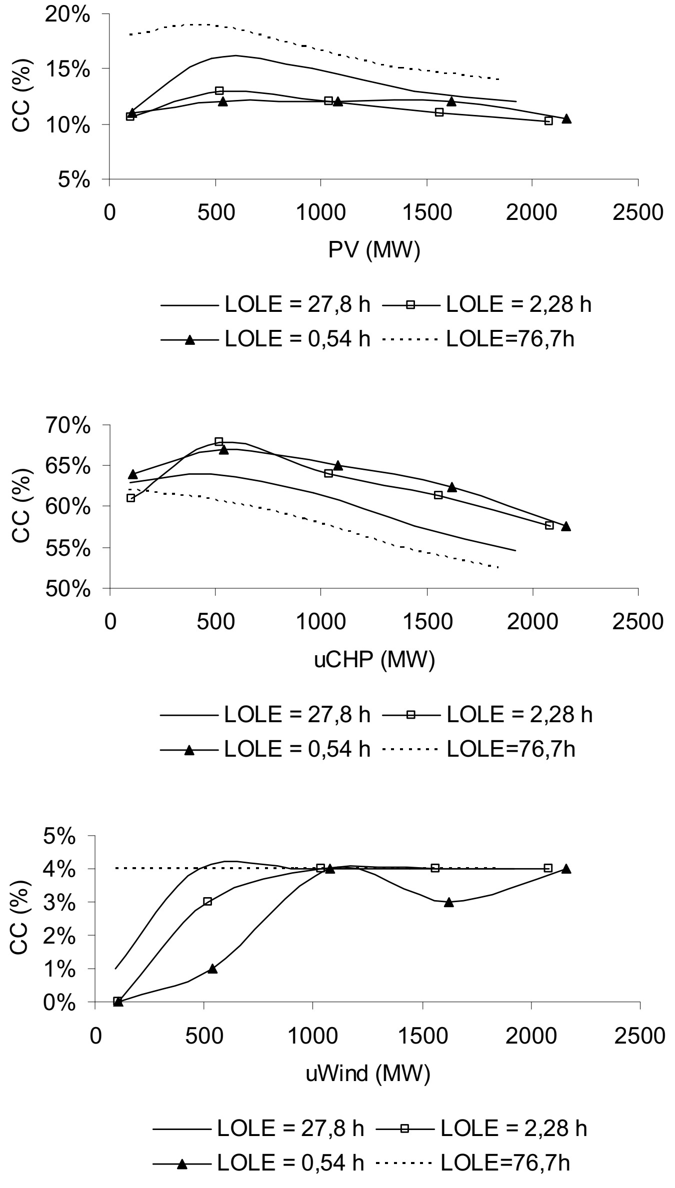

Fig. 27 – Influence of the initial reliability of the system on the CC values

6.2 µGrids results

As mentioned above, the characteristics of the µGrids, namely its ability to control internal loads and generators, also allows them to contribute to the generation adequacy. That contribution depends on the magnitude of load and of µGen that can be actively managed by the central controller of the µGrids. Concerning µGen it is important to stress that only the micro-CHP systems may be effectively controllable, once the generation of PV and micro-wind systems is imposed by the availability of the primary resources. Even for micro-CHP systems, not all of those units can be easily controlled without the waste of the thermal energy. As a consequence, only the systems with aptitude to store thermal energy should be accounted for when assessing the generation adequacy. Regarding the load management, the benefits depend on the share of the internal load that may be shed or shift from the peak period to non peak periods.

Figure 27 shows the influence of the µGrids on the CC of micro-CHP systems when different percentages of such systems are assumed as controllable (for a system with an initial LOLE of 0.54h).

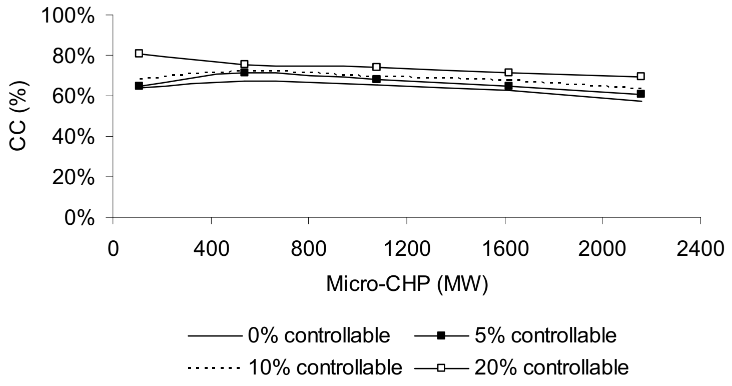

Fig. 28 – Influence of µGrid on the CC of micro-CHP systems

Concerning load control, figure 28 shows the CC to be attributed to µGrids when assuming increasing quantities of the total system load as controllable load by µGrid's action. Note that the CC refers to the total capacity of the conventional generation system (10800 MW is this case).

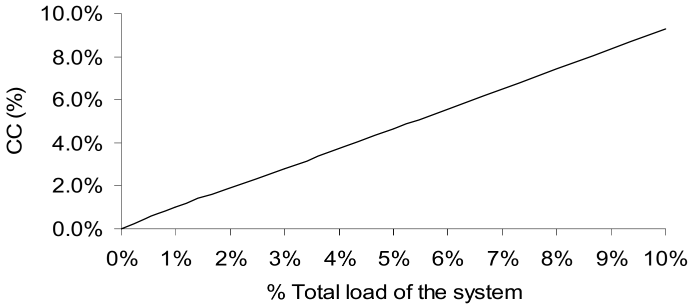

Fig. 29 – CC of μGrid due to load control

7. Conclusion

In this Annex, a methodology to evaluate the CC of μGen systems and of μGrids was described. The methodology was applied to the Portuguese system (with some simplifications) and the results were shown and discussed. First, the results show that different μGen technologies contribute differently to the security of supply. For instance, a CC = 64% was obtained by a set of 160,000 micro-CHP systems with rated power of 3 kW and f = 10%. Therefore, the addition of 480 MW of micro-CHP to the Portuguese system allows to remove 307.2 MW of conventional generation, keeping the initial reliability of the system (in this case the corresponding LOLE = 27.8h). In the same conditions, the CC values of the PV and micro-wind systems are, respectively 16% and 4%. The performance of micro-CHP systems is justified by the fact that these generators have propensity to inject power in periods of higher system load.

Another important conclusion that can be drawn from the results has to do with the limited influence that the rated power and unavailability of the microgenerators has on the CC. For example the CC of the 160,000 micro-CHP systems mentioned above increases to 67% if an availability of 5% is assumed to the generators. Therefore, halving the unavailability of the generators only increases the CC in 4.7%. If the unavailability is increased in 500% (f = 25%) the CC decreases in 17%, to a value of 53%. Similar results can be obtained for the other μGen technologies studied. From the regulatory point of view, this is an important feature, once the regulator may adopt reasonable values for those parameters without incurring in significant errors when assessing the CC.

The initial reliability of the electrical system also influences the CC of the μGen technologies. In fact, the CC of the micro-CHP units tends to increase when the system has higher initial reliability. The opposite situation occurs in the case of PV and micro-wind systems. Summarizing the previous example, corresponding to 160,000 micro-CHP systems of 3 kW and f = 10%, the CC increases 4.7% when the initial reliability of the system changes from a LOLE = 27.8 h to a LOLE = 0.54 h, assuming a value of CC = 67%. Concerning the PV and micro-wind systems, the CC decreases, respectively, in 25% (CC = 12%) and 75% (CC = 1%). So, the CC of the micro-wind and PV technologies appears as more sensitive to the initial reliability of the system then the one of the micro-CHP systems.

Regarding µGrids, the results show that the integration of controllable micro-CHP systems on these structures increases their CC. For example, assuming an initial system LOLE = 0.54 h, the CC obtained by a set of 160,000 micro-CHP systems with rated power of 3 kW and f = 10% is CC = 69%. However, if 20% of these generators may be controlled by the action of µGrids, the CC increases 9%, assuming the value CC = 75%. Concerning the load control ability of the µGrids, significant CC may be obtained by those structures. For instance, assuming an initial reliability of LOLE = 0.54 h, the control of 5% of the total system load allows to remove 500 MW of conventional generation.

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