

Integration of Dispersed Power Generation

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Abstract Current paper deals with three main issues, regarding the operation of the electric power systems in the presence of distributed generation. The first issue regards the assessment of the main continuity of supply parameters, such as frequency of interruptions, duration of interruption, power not served and energy not served. These issues are the base guidelines for the network system operators' decision of building new distributed generation capacities which might be able to mitigate the electric network loss of operation. The second issue addressed was the consume variability of the various low-voltage consumers. This particularity, in conjunction with the sheer number of consumers leads to the creation of serious unbalance for the daily curve. This means that if the network system operator cannot contain the load variability, it must buy energy from intraday energy market, with a price decisively higher than the one of the reserved capacity. This issue leads to a two-fold necessity: implementing a better know-how system in order to better contain the customers load fluctuation and the necessity of distributed generation implementation, in order to help load shedding. The third issue regards general technical aspects with respect to the electrical distribution systems operation in the presence of distributed generation.

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1 Introduction

Current transition of the current electric power system to the future smart grid is generating a turmoil of changes in the electric systems. These changes range from the electric network design, construction, analysis, operation and maintenance. The main driver of change is the ever-growing presence of distributed generation in the electric distribution systems. This situation lead to some unexpected results, such as increasing pressure on distribution systems operators to improve their services by assessing their interruption indexes, buying energy from intraday electricity markets to cover losses and turning their operation to a more business-orientated one. These three main topics were addressed in this analysis as a single framework, due to the fact that they are the causes that affects as a whole the electric distribution systems performance.

The first section is addressing the electricity distribution systems reliability indices such as frequency and duration of interruptions, power and energy not supplied. This was performed by evaluating the probability density functions (PDFs) of the of a set reliability indices. By considering the number of occurrences and duration of the interruptions as random variables (RVs), the indices become RVs and were evaluated through analytical expressions for computing their expected values and variances and with the Monte Carlo method in order to obtain the PDFs.

The second section deals with the evolution of the DSOs on the electricity market realm, where electricity suppliers need to have information on their customers' electricity consumption evolution in order to buy sufficient energy from the wholesale market to cover the hourly consumption at negotiated prices and average periods. This part proves to be particular sensitive, due to the fact that DSOs networks behaviour changes drastically, in terms of technical losses, proportionally with the presence of dispersed generation capacity into traditional electricity grid.

In the absence of such information, the service provider will be obliged to purchase the electricity wholesale market. The quantities of purchased energy may be smaller than its customer's needs—in which case, the deficit will be covered by purchasing the missing quantities in the market for next day or balancing market at higher prices. Where the supplier will buy power on the wholesale market more energy than is necessary for the customer, will be forced to sell the surplus, balancing market at a price lower than that with which the energy was purchased. Therefore, this material contains an analysis of three different customers for which DSO must refine its analysis, in order to supply with the exact amount of energy, in order to mitigate the eventual energy-level mismatches and subsequent financial losses.

The last part of the current framework shows small and medium-scale distribution generation systems as profitable solutions emerging for supplying the customers' loads in a de-centralized way. The necessity of reducing the high pollution produced by classical generation systems, the raising level of technological

solutions available and, especially, an explicit trend—in several countries—towards strong incentives for using renewable sources are among the main reasons explaining the success of the so-called distributed or dispersed generation.

2 Evaluation of the Probability Distributions of Reliability Indices in Electricity Distribution Systems Using Monte Carlo Simulation

For a distribution system with K load points, the reliability analysis takes into account two types of indices (local and global) [1]:

Local indices: are defined for each load point $k = 1, \dots, K$, and are calculated considering the frequency and duration of the states in which the point k is not supplied. Assuming the power P_k to be delivered to the point k during normal operation, the following local indices [2] are defined:

1. f_k —frequency of the interruptions;
2. d_k —duration of the interruptions;
3. $P_kNS = f_k P_k$ —power not supplied;
4. $E_kNS = d_k P_k$ —energy not supplied;
5. $dkNS = d_k/f_k$ —average duration of the interruptions.

Global indices: are defined for the whole electrical network, representing the overall system reliability [2]:

$$\text{System Average Interruption Frequency Index SAIFI} = \quad (1)$$

$$\text{System Average Interruption Duration Index SAIDI} = \quad (2)$$

$$\text{Customer Average Interruption Duration Index CAIDI} = \quad (3)$$

The aim of this section is to introduce methods for calculating the analytical expressions of expected value and variance of the reliability indices, their PDFs and Cumulative Distribution Functions (CDFs).

For a better understanding of the purpose of the system analysis, we consider several parameters some of which are constant and deterministic (load power), or constant but associated to an exponential distribution (failure rate) or probabilistic, as RVs, as shown in Table 1.

Table 1 Nature of the distribution system variables

	Constant	Probabilistic
Load power (P)	×	
Failure rate (λ)	×	
Restoration time (τ)		×
Number of occurrences of fault (n)		×

Also, we consider the distribution system with K load points during a given time interval $[0, T]$. We introduce a set Θ of the faults occurring in the distribution system and the sets Φ_k of the faults for which load point k is not supplied, for $k = 1, \dots, K$. A fault $f \in \Theta$ may require different phases of fault diagnosis and system restoration. Three types of faults are considered:

1. faults at the supply nodes, concerning the high voltage (HV) system, with a single restoration phase, due to the operations occurring on the HV system;
2. temporary faults in the distribution system, with trip of the circuit breaker, successful re-closure and final normal operation, again with single restoration phase;
3. permanent faults, requiring three different restoration phases after the trip of the circuit breaker:
 - (a) remote—controlled operations, driven from the control center, to isolate the fault and restore the operation in the non-faulted part of the system;
 - (b) additional manual operations, performed by the maintenance operators to isolate the fault and restore the operation in the non-faulted part of the system;
 - (c) on-site repair of the fault and final service restoration.

We assume that faults are independent random events, with negligible probability of simultaneous faults.

1. The number of occurrences of a fault in a specified time interval is represented by the random value (RV) n , with Poisson distribution:

$$\Pr\{n_f = N_f\} = \frac{(\lambda_f T)^{N_f}}{N_f!} e^{-\lambda_f T} \quad (4)$$

where:

- λ_f is the failure rate;
 - T is the length of the period of analysis;
 - N_f represents a deterministic number of occurrences of fault f .
2. The multi-phase service restoration is assumed to have a random restoration time for each phase, independent of the fault and of the restoration phase of the same fault. The RV τ is used to represent the restoration time.

Normally, we don't know a priori which is the type of distribution that emulates the behaviour of this RV. Generally speaking, there is a multitude of distribution functions which are used in calculation of τ . They are divided into two parts: one-parameter distribution functions and two-parameters distribution functions. Some other examples are shown in Table 2. The exponential PDF is sometimes used for its simplicity, but the Gamma distribution has been proven to be better to represent the real behaviour of the restoration times.

Table 2 Array of most utilized PDFs for calculating τ

	Function	Formula	Notes	Advantages
One parameter distribution functions	<i>Exponential</i>	$f(x) = \lambda e^{-\lambda x}$	Have limits for reality representation, due to its single parameter	Easy to calculate
	<i>Rayleigh</i>	$f(x) = \frac{2t}{x^2} e^{(-t^2/x^2)}$	Must pay attention to negative values when the variable makes sense only for positive values	
	<i>Normal (Gaussian)</i>	$f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-(x-\eta)^2/2\sigma^2}$	The calculation of the parameters is iterative (assuming that mean value and variance are known)	
Two parameters distribution functions	<i>Weibull</i>	$f(x) = \frac{\beta t^{\beta-1}}{x^\beta} e^{-(t/x)^\beta}$	Very flexible	They characterize exhaustively the real representation
	<i>Gamma</i>	$f(x) = \frac{c^b x^{b-1} e^{-cx}}{\Gamma(b)}$	It is very easy to calculate (from known mean value and variance)	
	<i>Lognormal</i>	$f(x) = \frac{1}{x} e^{-\ln^2 x/2}$	Very flexible	

2.1 Reliability Indices

For calculating the reliability indices, it is essential to know the PDF of τ , because we must utilize the convolution without constraints. This boundary restrains the freedom of choosing PDFs, in particularly at Normal (Gaussian) and Gamma (only if they have the same scale factor).

2.1.1 Definition of the Reliability Indices

In this work, we consider the following reliability indices, defined for the time interval $[0, T]$ [3]:

- The **total duration of the interruptions**, represented by the RVs $\mathbf{d}_k$ at load point k and $\mathbf{d}$ for the whole system;

- The **total energy not supplied**, represented by the RVs $\mathbf{w}_k$ at load point k and $\mathbf{w}$ for the whole system;
- **The Frequency of fault occurrence** f_k ;
- **The Power not supplied** (P^{NS}).

We also assume that the power delivered to load point k to be P_k during normal operation. For $k = 1, \dots, K$, the classical reliability indices are then expressed in terms of the expected values of the RVs $\mathbf{d}_k$ and $\mathbf{w}_k$. For the *local indices*, we consider the expected value $E\{\mathbf{d}_k\}$ of the duration of the interruptions and the expected value $E\{\mathbf{w}_k\} = C_k E\{\mathbf{d}_k\}$ of the energy not supplied to load point k . The probability of the event “load point k is not supplied at a generic instant” is given by $E\{\mathbf{d}_k\}/T$. Global indices, which depend on the whole network can be build by computing a weighted average of the load point indices, using as weights the numbers of customers or the power supplied to the load points in normal conditions.

2.1.2 Expected Value of the Interruption Duration at Load Point K

The occurrence of a fault leads to a sequence of mutually exclusive fault states. Each fault state corresponds to a restoration phase, with remote-controlled or manual operations performed for restoring the service. By neglecting the simultaneous faults, it is possible to compute the duration of the service interruption during the restoration phases for any load point. We assume the service restoration after a fault $f \in \Theta$ to include a number ϕ_f of independent restoration phases.

The expected value $E\{\mathbf{d}_k\}$ of the duration of the service interruption during the restoration phases at load point k is computed by considering all the restoration phases in which load point k is not supplied. We introduce the binary variable $\delta_{kf}^{(m)} = 1$ if load point k is not supplied in the phase m of service restoration after the fault $f \in \Theta$, otherwise $\delta_{kf}^{(m)} = 0$ [3]. Assuming a negligible probability of simultaneous faults, in the restoration phase $m = 1, \dots, \phi_f$ after fault $f \in \Theta$ with failure rate λ_f , corresponding to the restoration time $\tau_f^{(m)}$, the expected value of the duration of the interruption is

$$E\{\mathbf{d}_k\} = \sum_{f \in \Theta} \sum_{m=1}^{\phi_f} \lambda_f E\{\tau_f^{(m)}\} \delta_{kf}^{(m)} \quad (5)$$

In the presence of permanent faults with multi-phase restoration, it is convenient to evaluate, for each fault $f \in \Theta$ and for all the load points $k = 1, \dots, K$, the binary variable $\delta_{kf}^{(m)}$ introduced by the fault, for $m = 1, \dots, \phi_f$. For each fault at a supply node, with a single restoration phase ($\phi_f = 1$), the variable $\delta_{kf}^{(1)}$ is equal to unity for the load points fed by the faulted supply node, zero otherwise. For each *temporary fault*, the trip of the circuit breaker isolates all the load points fed by the faulted

branch, there is again a single restoration phase ($\varphi_f = 1$) and the variable $\delta_{kf}^{(1)}$ is equal to unity for the load point fed by the faulted branch, zero otherwise. For each permanent fault, with three restoration phases ($m = 1, 2, 3$), the value of $\delta_{kf}^{(m)}$ depends on the restoration phase:

- in the first phase, $\delta_{kf}^{(1)} = 1$ if load point k is not supplied after the trip of the circuit breaker, otherwise $\delta_{kf}^{(1)} = 0$;
- in the second phase, $\delta_{kf}^{(2)} = 1$ if load point k is not supplied after the remote-controlled operations, otherwise $\delta_{kf}^{(2)} = 0$;
- in the third phase, $\delta_{kf}^{(3)} = 1$ if load point k is not supplied after the manual operations, otherwise $\delta_{kf}^{(3)} = 0$.

For any permanent fault, the evaluation of $\delta_{kf}^{(m)}$ for $m = 2, 3$ requires the detailed simulation of the operators performed to isolate the fault and to restore service. For this reason, we choose the backward/forward sweep analysis method (which will be presented in the next section).

2.2 Distribution System Structure and Analysis

For performing calculations as close as possible to the reality, we thought to generate a radial electrical distribution network which includes all the elements existing in a real electrical distribution network:

- Circuit breakers;
- Disconnects:
- Remotely commanded;
- Manually commanded
- Loads
- Branches (lines or transformers)

The design of the network structure was thought to be stratified into layers to simplify its numerical treatment and to facilitate the application of various calculation iterations.

2.2.1 Network Structure and Definitions

Let us consider a radial network with $n + 1$ nodes fed at constant voltage at the root node (node 0) as in Fig. 1. For each i -th node, let us define $\text{path}(i)$ as the ordered list of the nodes encountered starting from the root (not included in the list) and moving

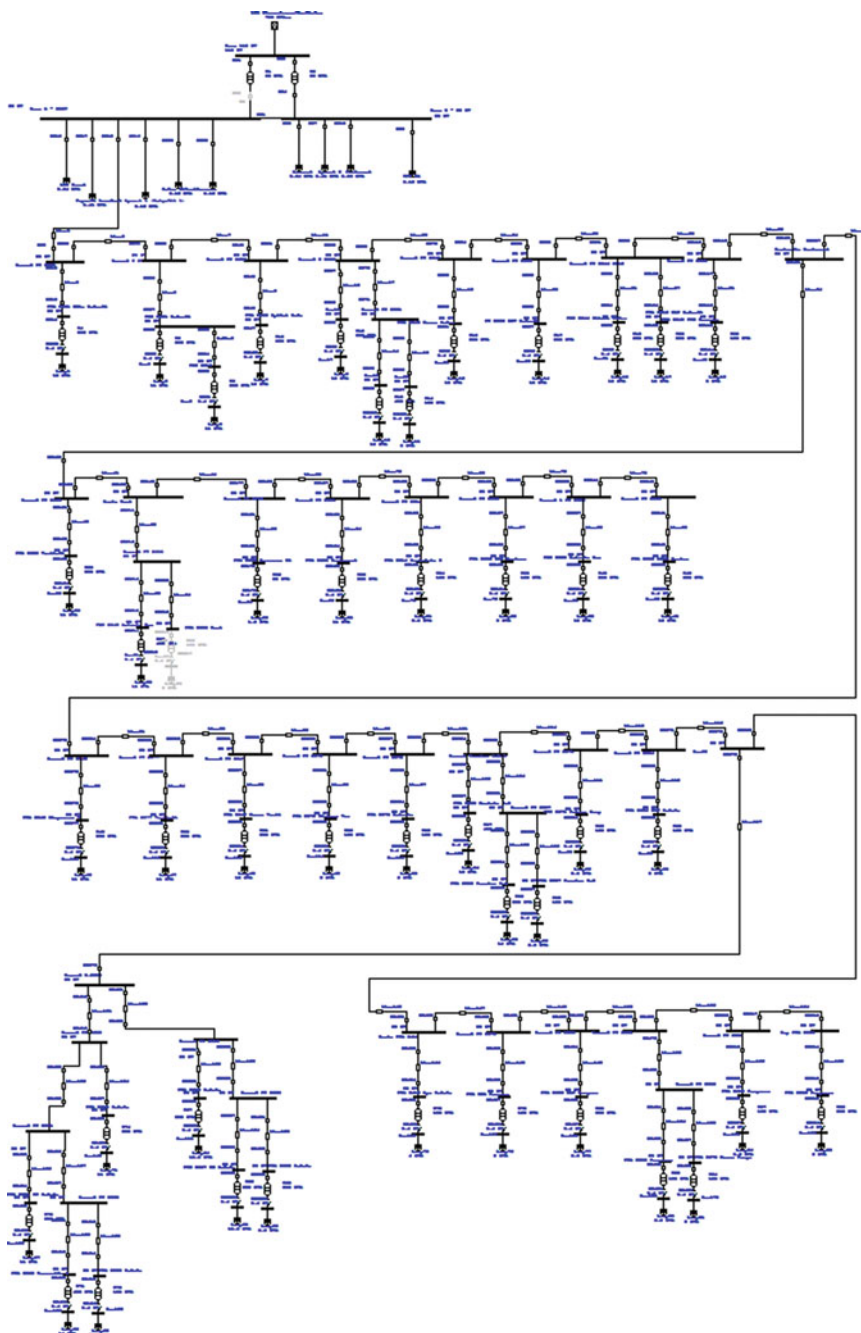


Fig. 1 The representation of the tested electrical network (ETAP 12.5)

to its i -th node [4]. Furthermore, each node belongs to a layer [5], which represents the position of the node in the network.

The following criterion is assumed for node and line numbering:

- The nodes are numbered sequentially in ascending order proceeding from layer to layer (Fig. 1), in such a way that any path from the root node to a terminal node encounters node numbers in ascending order;
- Each branch starts from the sending bus (at the root side) and is identified by the number of its (unique) ending bus.

2.2.2 Extracting $\mathbf{L}$ and $\mathbf{\Gamma}$ Matrices Out of the Test-Network

The above numbering leads to a particularly convenient system representation, in which both the node-to-branch incidence matrix $\mathbf{L} \in \mathbb{N}^{n,n}$ (root node not included) and its inverse $\mathbf{\Gamma} = \mathbf{L}^{-1} \in \mathbb{N}^{n,n}$ are lower triangular. Assuming for each branch a conventional value +1 for the sending bus and -1 for the ending bus, the generic component l_{ij} of the matrix $\mathbf{L}$ is

$$l_{ij} = \begin{cases} -1 & \text{if } i = j \\ 1 & \text{if } j = \text{sending bus}(\text{branch } i) \\ 0 & \text{otherwise} \end{cases} \quad (6)$$

while the generic component γ_{ij} of the matrix $\mathbf{\Gamma}$ is

$$\gamma_{ij} = \begin{cases} -1 & \text{if } j \text{ path}(i) \\ 0 & \text{otherwise} \end{cases} \quad (7)$$

In the j -th column of the matrix $\mathbf{L}$, the rows with non-zero terms correspond to the branches having the j -th node as sending bus. In the j -th column of the matrix $\mathbf{\Gamma}$, the rows with non-zero terms correspond to the nodes belonging to the branches derived from the j -th node. In the absence of mutual coupling between branches, it is possible to build the matrix $\mathbf{\Gamma}$ directly by visual inspection, without inverting the matrix $\mathbf{L}$. The present calculation technique used largely Matlab's mathematical power. It was intended to develop a program which could include a complete view over an electrical network and calculate its different reliability indices.

So, it was implemented an algorithm which identifies a network and its mutually coupling between branches ($\mathbf{L}$ matrix) and further on, identifies the $\mathbf{\Gamma}$ matrix [4]. Its next attribute is to compute the power not supplied for temporary faults at each branch by varying m from $\delta_{kf}^{(m)}$ (see Table 3). So, for $m = 2$ the program calculates the P^{NS} after completing all the remote-controlled operations to restore the network; for $m = 3$, the program calculates the P^{NS} after completing all the remote and manual operations due to restore the network.

Table 3 Evaluation of possible fault types and corresponding load point indices

Type of fault	φ_f	m	$\delta_{kf}^{(m)}$		Explanation
Supply point	1	1	$\delta_{kf}^{(1)}$	1	Fed by the faulted branch
				0	Otherwise
Temporary	1	1	$\delta_{kf}^{(1)}$	1	Fed by the faulted branch
				0	Otherwise
	3	1	$\delta_{kf}^{(1)}$	1	Load point k is not supplied after the trip of the circuit breaker
				0	Otherwise
Permanent		2		1	Load point k is not supplied after the remote-controlled operations
				0	Otherwise
		3		1	Load point k is not supplied after the manual operations
				0	Otherwise

The results of these two iterations are used afterwards to compute the w_k for the branches affected by the fault. The advantage of this approach of the electrical network is that it gives a greater elasticity in formulating different scenarios of faulted branches.

2.3 Application of the Monte Carlo Method

2.3.1 General Hypotheses

Monte Carlo Methods (MCM) consist in experimental simulation of mathematical problems for which random numbers are used for discovering the solution.

In reliability calculations of electrical distribution networks, both analytical and simulation techniques are used. The analytical techniques are mathematical rigorous and are used to find expected value and variance. These are valuable indices for the system, but they are insufficient into give a complete view of the resulting PDF.

In our test network, the point of interest is constituted by reliability indices. It is well known the fact that MCM is a so called “blind method”, which means that it has no “a priori” instrument to guide itself through the iterations for reaching an outcome. The most effective approach is to generate a random variable using a suitable probability density function that could emulate the development of the process.

So, for realizing our tests, we considered that the best type of distribution for our random numbers should be Poisson, due to the fact that its domain of definition covers the “rare event probability”, and in our case (reliability indices analysis) the events (interruptions) are rare. Another motivation for our choice was that a convolution made with many discrete Poisson probability distribution functions (PDFs) has the propriety of keeping a Poisson profile.

2.3.2 The Sequential Monte Carlo Method

The sequential MCM [6–10] has been used to address the reliability indices computation. Typically, the number of faults involving a single load point is not very high, so that the load points indices exhibit unusual forms with possible multi-modal shapes. In these cases, the MCM is particularly used. Therefore, some load point indices have been computed. Global indices are less interesting for the MCM method application, since the presence at several load points make these indices very close to the Normal form.

The program is structured to run in steps, facilitating the interventions required for any modifications, also providing a better level of understanding of the algorithm.

- Step 1: Read data of the electrical network matrix, composed of sending nodes, receiving nodes, type of each node (0-rigid; 1-circuit breaker; 2-remote controlled disconnect; 3-manual controlled disconnect), failure rate (λ) for each node for temporary faults, λ for each node for permanent faults, restoration time (τ) for temporary faults and τ for permanent faults; also the restoration times for Gamma-distributed temporary and permanent faults (min/year) (shape factor and scale factor) are established; the step concludes with the initialization of the indices (as permanent failure rate and temporary failure rate), and the number of years for the analysis (in our case, 10 years).
- Step 2: Initialization of the parameters required for Monte Carlo (MC) simulations. There are the boundary values which delimit the acceptable values of MC simulation. Also there are the range of the classes utilized to realize MC histograms, whose limits are also determined in function of Power Not Supplied (PNS), for which two a priori values for each level were chosen and the number of classes inside the range min-max
- Step 3: For a single load point a series of routines are executed to calculate:
 - The Power Not Supplied (PNS),
 - The Outage Time,
 - Number of Interruptions,
 - The Energy Not Supplied (ENS)
- Step 4: Extraction of the incidence matrix Gamma out of the test-network

Step 5: An external cycle for MC calculation is generated, composed of the following subroutines:

- Creation of the random temporary fault profile;
- Creation of the random permanent fault profile;
- Another cycle is initialized for computing the reliability indices:
 - Location of the temporary faults;
 - Computation of PNS, TotalInterrTime, NumberInterr, ENS for temporary faults at each branch;
 - Location of the permanent faults;
 - Computation of the PNS, TotalInterrTime, NumberInterr, ENS for permanent faults at each branch,
 - Computation of MC histograms for PNS, TotalInterrTime, NumberInterr and ENS.

The data used in the program was structured, for more convenience, into a two-dimension array, having number of rows equal with number of nodes of the test-network and number of columns equal with the number of indices needed for our iterations. In our case, the columns were formed by: *ending nodes* (of the test-network), *receiving nodes*, *type of receiving node* (0-rigid; 1-circuit breaker; 2-remote controlled disconnect; 3-manual controlled disconnect), *load* (in p.u.), *failure rate for each node for temporary faults* and *failure rate for each node for permanent faults*.

The output of the program looks as a series of histograms as indicated in Figs. 2, 3, 4, 5, 6, 7, 8 and 9.

Fig. 2 Histogram of PNS

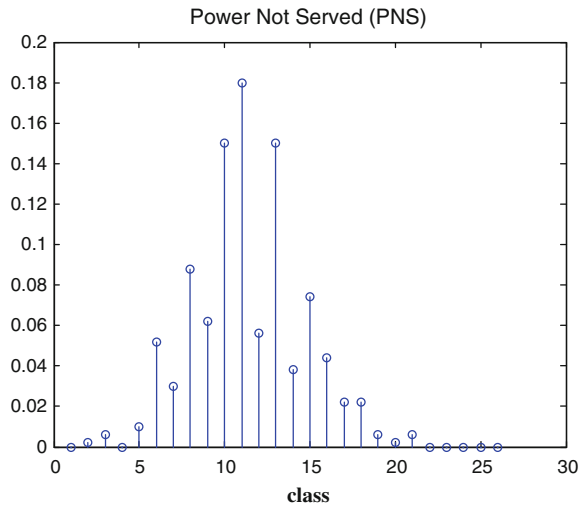


Fig. 3 Histogram of number of interruptions

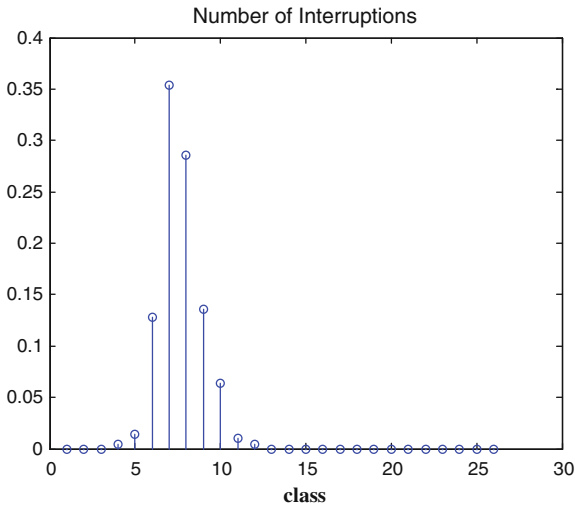
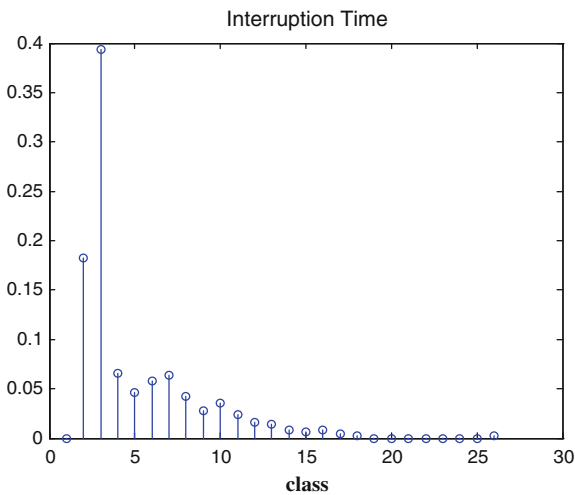


Fig. 4 Histogram of interruption time



In order to further clarify the program output, a table containing principal indices of the network has been realized. It shows the variables (PNS, Interrupted Time, Number of Interruptions and ENS), differentiated upon the left (*L*) and right (*R*) part of the test-network (Tables 4, 5 and 6).

- (calculated in 500000 iterations)
- (calculated in 500000 iterations)

Fig. 5 Histogram of ENS

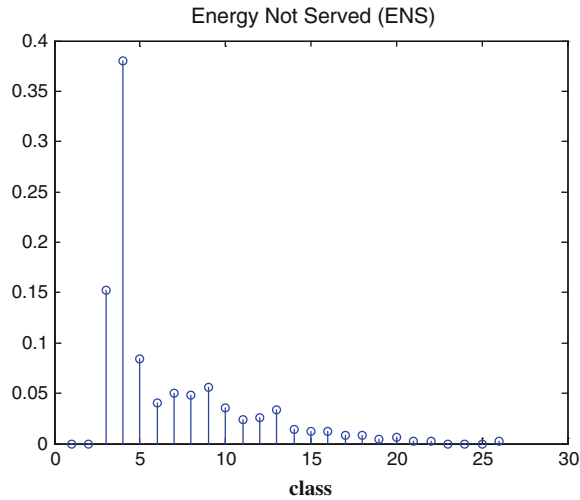
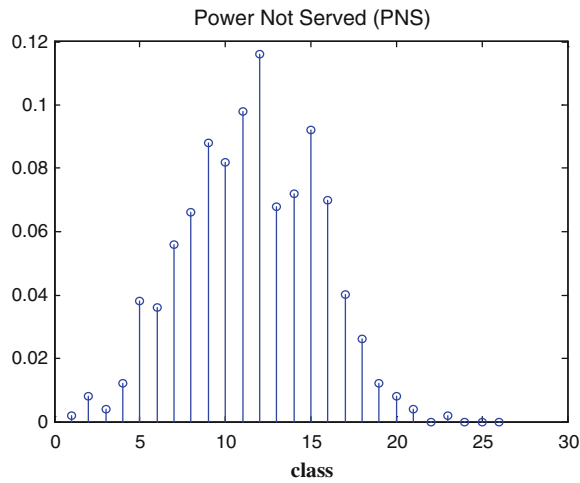


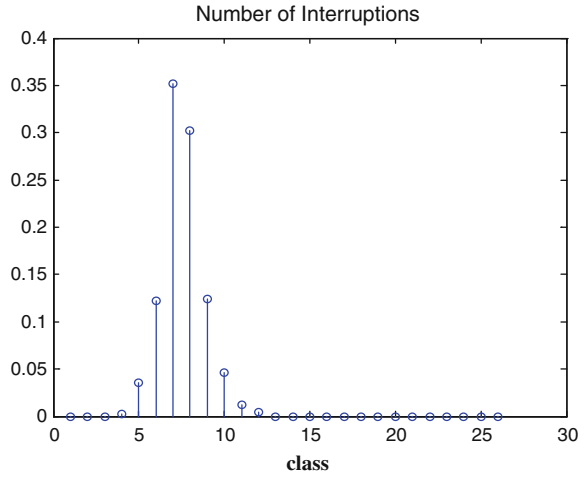
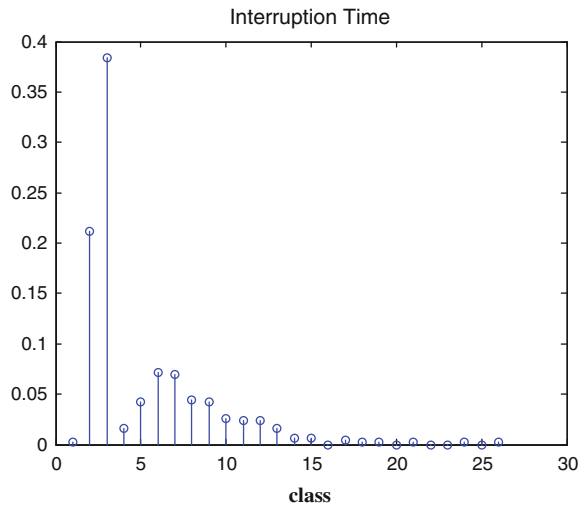
Fig. 6 Histogram of PNS



2.4 Mean Value Calculated with Analytical Methods

2.4.1 Number of Interruptions N

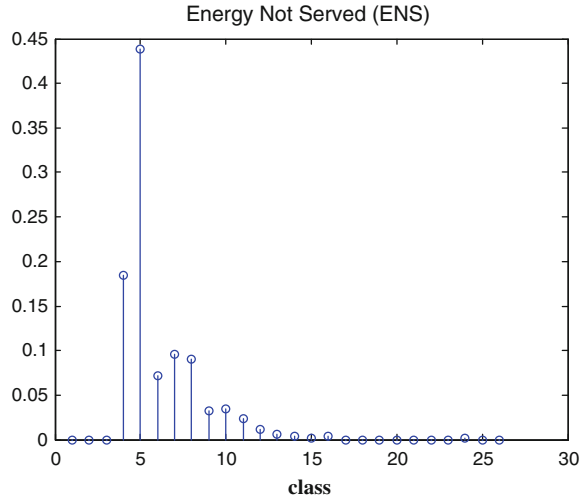
Represents the number of times the load point is interrupted, depending on the interruption occurred in every load point belonging to the side of the network under the same circuit breaker.

Fig. 7 Histogram of number of interruptions**Fig. 8** Histogram of PNS

$$E\{\mathbf{n}\} = \lambda T n_{\text{branches}} \quad (8)$$

2.4.2 Power not Supplied PNS

Represents the amount of MW not supplied for every interruption at the load point in the time period under study.

Fig. 9 Histogram of number of interruptions**Table 4** Values for program variables, depending on the positioning on the network (L = Left; R = Right)

Variable	Network side	Min	Step	No of steps
PNS	L	10	1.6	25
	R	50	2	25
Interruption time	L	100	130.2	25
	R	100	130.2	25
Number of interruptions	L	0	4.18	25
	R	0	4.18	25
ENS	L	0	110	25
	R	0	220	25

$$E\{PNS\} = \lambda T P n_{\text{branches}} \quad (9)$$

2.4.3 Interruption Time d

Represents the total duration of interruption of the load point in the time period under study.

$$E\{\mathbf{d}\} = \lambda T n_{\text{branches}} E\{\tau_t\} \quad (10)$$

$$E\{\mathbf{d}\} = \lambda T n_{\text{branches}} E\{\tau_p\} \quad (11)$$

Table 5 Results of Monte Carlo simulation of the test-network with Matlab program

Variable	Network side	5000 iterations			500 iterations		
		Expected Value	Variance	Standard deviation	Expected Value	Variance	Standard deviation
Number of interruptions	L	27.7	630	25.1	23.3	437	20.9
	R	77.1	4941	70.3	72.8	4563	67.5
Interruption time (min)	L	664.9	664910	815.4	741.9	769965	877.4
	R	1136.1	1389866	1178.9	1131.5	1312599	1145.6
PNS (p.u.MW)	L	25.6	629	25.1	27.1	712	26.7
	R	71.1	4770	69.1	126.8	4268	65.3
ENS (p.u.MW h)	L	575.1	472067	687.1	569.5	7916910	2813.7
	R	1169.3	1525242	1235.1	1316.7	2480102	1574.8

where $E\{\tau_p\} = \alpha_p \beta_p$ and $E\{\tau_t\} = \alpha_t \beta_t$ due to the fact that we used a Gamma distribution with parameters (α_p, β_t) for the restoration time after temporary interruptions and (α_p, β_p) for the restoration time after permanent interruptions.

2.4.4 Interruption Time d

$$E\{ENS\} = \lambda T n_{\text{branches}} E\{\tau_t\} \quad (12)$$

$$E\{ENS\} = \lambda T n_{\text{branches}} E\{\tau_p\} \quad (13)$$

Table 7 shows that for the analysis performed upon the test-system, some discrepancies occur between the values obtained with 50000 extractions and 500000 extractions. These differences depend on the number of permanent faults occurred during the reliability simulation in the time period under study. Bolded parameters correspond to the biggest values for each parameter (column).

3 Role of Statistical Profiling for Energy Markets. Load Profiles Definition for Electricity Market

3.1 Operational and Functional Requirements for Accurate Load Profiling—Analytical Assessment

Average daily consumption which is scheduled by using weights specified in a table which contains data relating to consumer profile (differentiated for working day and non-working day) is defined from the following relations:

Table 6 Histograms of the simulated parameters PDFs’

No of extractions	P_{sel}	P_{swU}	P_{swD}	Upstream network	Downstream network
500000	0.95	0.9	0.05		
	0.05	0.05	0.05		

(continued)

Table 6 (continued)

No of extractions 50000	P _{sel} 0.95	P _{swU} 0.9	P _{swD} 0.9	Upstream network				Downstream network			

(continued)

Table 6 (continued)

No of extractions	P_{sel}	P_{swU}	P_{swD}	Upstream network	Downstream network
	0.05	0.05	0.05		

Table 7 Values for program variables, depending on the positioning on the network

Extractions	P _{sel}	P _{swU}	P _{swD}	P _{NS}	N _{IN}	T _{INT}	E _{NS}
50000	0.95	0.9	0.9	9	3	10.248	40.160
				6	6	17.250	50.716
	0.05	0.9	0.9	6	6	95.884	0.038
				10.5	3	8.004	0.002
	0.95	0.05	0.9	4	6	19.390	75.985
				14	4	14.264	75.985
	0.95	0.9	0.05	12	6	99.096	0.039
				4.5	3	15.302	0.004
	0.95	0.05	0.05	10	5	48.672	190.731
				7.5	5	56.240	165.292
	0.05	0.05	0.9	0	3	22.797	89.336
				10.5	3	22.797	67.002
	0.05	0.05	0.05	12	11	67.679	0.027
				17.5	5	48.690	0.014
500000	0.95	0.05	0.9	16	8	38.011	148.954
				3	2	4.829	14.193
	0.05	0.9	0.9	0	1	3.939	15.436
				3.5	1	3.939	11.577
	0.95	0.05	0.9	10	5	16.717	21.403
				6	4	10.924	32.105
	0.95	0.9	0.05	4	2	5.076	19.891
				4.5	3	14.178	19.891
	0.95	0.05	0.05	10	5	18.512	82.185
				0	0	0.000	0.000
	0.05	0.05	0.9	0	5	15.769	61.793
				17.5	5	15.769	46.344
	0.05	0.05	0.05	14	7	19.755	77.415
				7.5	5	62.623	184.051

3.1.1 Monthly Energy Aggregation

For an average month, some using the data presented in a table that contains the results of the measurements of energy for all hourly intervals (curves, as the average consumer used to establish the data measured consumer profile):

$$\bar{Q}_{WD} = q_{WD} * N_{ZD} \quad (14)$$

$$\bar{Q}_{NWD} = q_{NWD} * N_{NWD} \quad (15)$$

$$\bar{Q}_{WD} = Q_{WD} + Q_{NWD} \quad (16)$$

where:

$\bar{Q}_{WD}$ = amount of energy distributed on working days for a month, according to the measured values;

$\bar{Q}_{NWD}$ = amount of energy distributed in non-working days for a month, according to the measured values;

q_{WD} = average daily consumption associated with any working days for a month, according to the values given in the table containing the results of the measurements of energy for all hourly intervals;

q_{NWD} = average daily consumption associated with any non-working days for a month, according to the values given in the table containing the results of the measurements of energy for all hourly intervals;

Q = energy distributed within one month according to measured values

N_{WD} = number of working days in the month;

N_{NWD} = number of non-working days in the month.

3.1.2 Evaluation of Energy Weights

$$P_{WD} = \frac{\bar{Q}_{WD}}{\bar{Q}} \quad (17)$$

$$P_{ZNL} = \frac{\bar{Q}_{NWD}}{\bar{Q}} \quad (18)$$

where:

P_{WD} , P_{NWD} is the weight of the energy distributed for one month with respect to working days/holidays, determined accordingly to the measured values which underline the consumer profile, according to the table that contains the results of the measurements of energy for all hourly intervals.

3.1.3 Monthly Energy Calculation

Energy distributed in the settlement month, differentiated according to type of day (working/nonworking) shall be established according to the following relationship:

$$\bar{Q}_{monthWD} = Q_{month} * P_{WD} \quad (19)$$

$$\bar{Q}_{monthNWD} = Q_{month} * P_{NWD} \quad (20)$$

$$\bar{Q}_{monthWD} + \bar{Q}_{monthNWDZNL} = Q_{month} \quad (21)$$

where:

Q_{month} = the amount of energy distributed in the settlement,

3.1.4 Monthly Calculation of Energy Weights

Daily quantities of energy distributed in paying month must be approved according to profile schedule (using the weights shown in a table containing data relating to consumer profile) is determined according to the relationship presented in sequel:

$$Q_{WD} = \frac{Q_{monthWD}}{N_{WD}} \quad (22)$$

$$Q_{NWD} = \frac{Q_{monthNWD}}{N_{NWD}} \quad (23)$$

3.1.5 Daily/Hourly Energy Calculation

Monthly representation of quantities of energy will be distributed on the basis of the approved profile on differentiated working days/non-working days, according to the following relationship:

working day

$$Q_{hourWD} = Q_{WD} * \gamma \quad (24)$$

where:

Q_{hourWD} = energy distributed according to a time interval for a working day;
 γ = represents the percentage determined for the characteristic profile of working days, for a given time interval (according to the table containing data relating to consumer profile)

non-working day

$$Q_{hourNWD} = Q_{NWD} * \eta \quad (25)$$

where:

$Q_{hourNWD}$ = energy distributed according with a time interval for a working day;
 η = is the percentage determined for the characteristic profile of working day, for a given time interval (according to the table containing the data relating to consumer profile)

Hourly quantities are expressed in, MWh with 3 decimals, so that the difference between the amount of energy distributed monthly and the sum of hourly energies to be less than 1 kWh.

3.2 System Application

The question of determining the load curve profile is very economically-efficient for small users and for users. Under these circumstances, the establishment of hourly values of energy associated with a supplier can realize, for each point of consumption for providing hourly consumption by spreading recorded on a calculation based on a consumer profile (Table 8).

3.2.1 Daily/Hourly Energy Calculation

This illustrates loading profile contributions such as lighting, cooling, ventilation and other tasks performed throughout the day. Evaluation of total energy consumption in energy will show a rapid increase during the morning because of the transitional arrangements of the receivers. Once the systems are started, the demand is relatively constant throughout the day (Fig. 10 and Tables 9 and 10).

Table 8 Types of end-users

No	User
1	Fuel stations
2	Small businesses without cooling
3	Small businesses with cooling

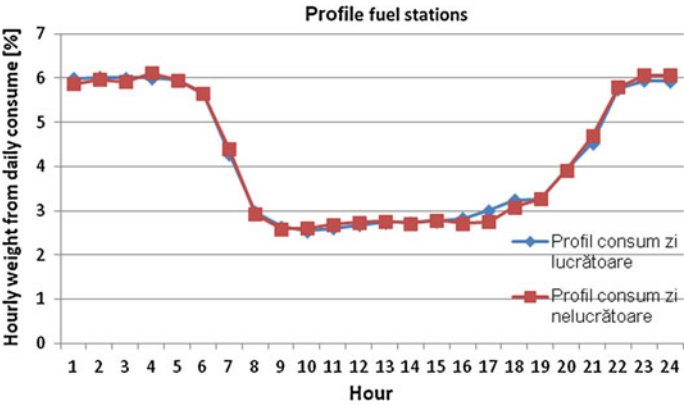


Fig. 10 Load curves for fuel stations

Table 9 Measurements results

Average consume curve (MWh)		
Interval	Interval	Interval
00:00:00	0.022172	0.0216
01:00:00	0.022233	0.021959
02:00:00	0.022206	0.021763
03:00:00	0.022228	0.022517
04:00:00	0.02201	0.021892
05:00:00	0.020953	0.020771
06:00:00	0.015875	0.016159
07:00:00	0.010996	0.010746
08:00:00	0.009761	0.00953
09:00:00	0.009384	0.009575
10:00:00	0.009638	0.009875
11:00:00	0.009911	0.010075
12:00:00	0.010116	0.010171
13:00:00	0.01013	0.009992
14:00:00	0.01024	0.010242
15:00:00	0.010442	0.01
16:00:00	0.011121	0.010105
17:00:00	0.011998	0.011334
18:00:00	0.012086	0.011996
19:00:00	0.014503	0.01443
20:00:00	0.016751	0.017271
21:00:00	0.02131	0.021321
22:00:00	0.021964	0.022321
23:00:00	0.021949	0.022325
QWD	0.369977	
QNWD		0.367971

3.2.2 Small Businesses Without Cooling

This illustrates loading profile contributions such as lighting, cooling, ventilation and other tasks performed throughout the day. Evaluation of total energy consumption in energy will show a rapid increase during the morning because of the transitional arrangements of the receivers. Once the systems are started, the demand is relatively constant throughout the day (Fig. 11).

3.2.3 Small Businesses with Cooling

Minimum and maximum limits presents a limited variation of about 2 %, which indicates the uniformity of type SBC users consumption. The load curve flattening

Table 10 Data for fuel stations (hourly weights of energy consume)

	Consume profile	
	Mean WD (%)	Mean NWD (%)
00:00:00	5.992922	5.87012
01:00:00	6.009401	5.967501
02:00:00	6.002037	5.914281
03:00:00	6.007807	6.119338
04:00:00	5.948917	5.949384
05:00:00	5.663411	5.644785
06:00:00	4.290759	4.391289
07:00:00	2.972176	2.920385
08:00:00	2.638239	2.589743
09:00:00	2.536494	2.602199
10:00:00	2.605032	2.683727
11:00:00	2.678725	2.738079
12:00:00	2.734215	2.764123
13:00:00	2.737945	2.715432
14:00:00	2.767672	2.783372
15:00:00	2.822449	2.717697
16:00:00	3.005845	2.746005
17:00:00	3.24298	3.080044
18:00:00	3.266598	3.260086
19:00:00	3.91999	3.92137
20:00:00	4.527673	4.693623
21:00:00	5.759701	5.794254
22:00:00	5.936602	6.066014
23:00:00	5.932409	6.067147

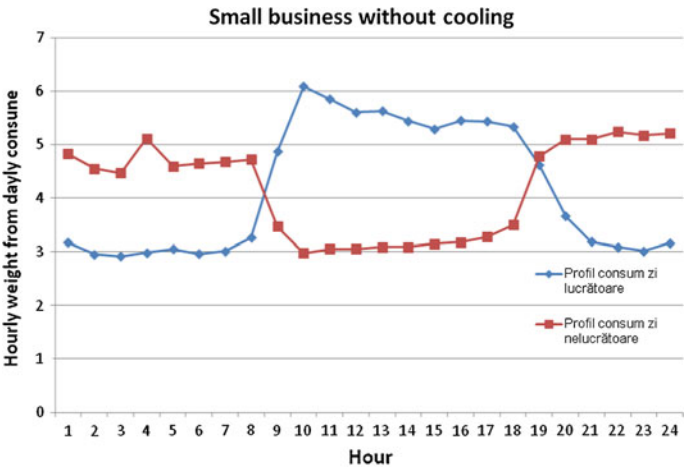


Fig. 11 Load curves for SBwC (WD and NWD)

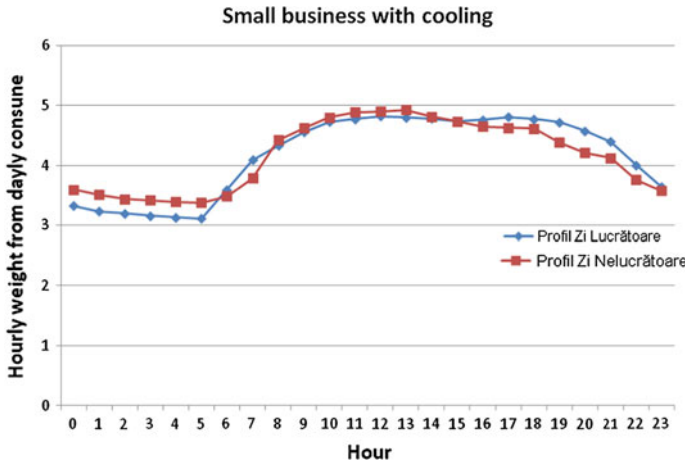


Fig. 12 Load curves for SBC (WD and NWD)

we can say that it has a high value which indicates that in the case of SBC have a flat load curve (Fig. 12).

4 Operation of Distribution Systems with Dispersed Generation

4.1 Operational Aspects of Voltage Control

An evident effect of the introduction of DG sources in the distribution system is to increase the voltage profile along the feeders. If the total power provided by the local generators does not exceed the local load, the effect is limited to reducing the currents injected in the local nodes by the distribution systems, with the beneficial effects of reduce losses and increase the voltage profile, without leading to unacceptable voltage values. In this case, the possible contribution of switchable nodal capacitors located in the distribution systems should be coordinated with the real needs of reactive power support for voltage profile improvement.

For the customers that have implemented smart metering devices [11–46] (which can record consumption at different time intervals, memorize the values and remotely transmit the information), this consumption variation is known [47–52]. For customers that have not installed such intelligent devices, it requires a method by which the total electricity consumption over a period of time to be assigned to time slots [53–56].

Typically, the issue of the load curve profile determination is posed for small users and for users. In their case, the installation of meters with registration of hourly electricity consumption is economically unjustified [57, 58].

The integration and development of local resources, owned and managed by different subjects, requires a strong effort for revising the current operation practices of the distribution systems [59–61]. In fact, well-known properties of traditional distribution systems, such as operation with radial configuration with a single generator in the root node, and the subsequent unidirectionality of real power flows and typical decreasing voltage profiles along the feeders, are no longer ensured in the presence of a non-negligible amount of distributed generation. The differences affecting the system operation are extended to the need for using new or dedicated algorithms to solve traditionally studied problems such as power flow, voltage control, fault calculation, reliability and power quality aspects, and so on.

Analyzing the DG impact on the distribution systems requires specifying the type of network used (Low Voltage—LV, or Medium Voltage—MV, in urban suburban or rural areas) and the DG technology considered, depending on the location of the system and on the voltage level. Aggregations of loads and sources used at a certain voltage level are required to analyze higher voltage levels. A key aspect is the type of interface between the DG and the network. This can be either a voltage-controllable synchronous machine/transformer group or an inverter-type connection or, considering the possibility of operating a portion of the system as a micro-grid [60], a suitable separation device allowing for re-synchronization between the separated micro-grid and the distribution system. The impact of the introduction of DG sources in the distribution system is typically analyzed by using a parameter called *penetration level*, expressed as $\chi = \gamma P_{DG} / P_L^{\max}$, where P_{DG} is the total generation installed for the local sources, $P_L^{\max}$ is the peak power demand and γ is the capacity factor, depending on the characteristics of the technologies used [61].

The last section of the paper provides a detailed discussion of the key aspects concerning the integration of local generations into the distribution systems. The focus is on voltage control and its impact on voltage profile and distribution system losses. Faults, dynamics and power quality issues are not included due to space limitations, while network islanding and reliability issues are addressed in [62]. Results showing the impact of the local generation on voltage control and losses are shown for examples on the real MV distribution system, operating in a rural area. In particular, cogeneration sources were positioned in the nodes requiring a relatively large amount of power, while groups of photovoltaic generators were located in every node.

When the amount of local generation exceeds the local load, the local sources supply part of the distribution system load. In this case, there are branches in which the current flow is inverted, leading to a voltage increase at the branch terminal far from the HV/MV substation (the root node). The subsequent increase of the voltage profile may lead to unacceptable voltages at some nodes [59, 60, 63]. The above problem is related to voltage-uncontrollable local sources. In some cases, voltage-controllable DG sources are used, typically consisting in synchronous machines interfaced with the distribution system with a local transformer. These sources can give a contribution to the overall voltage control of the distribution

system, by imposing a proper set-up voltage. However, this contribution is limited to the range in which the reactive power of the generator lies within its lower and upper bounds.

The voltage set point of the local generators interacts with the centralized voltage control at the HV/MV substation [64, 65]. Traditional methods for supporting the voltage profile in radial distribution systems include the use of under-load tap changers (ULTCs) in the HV/MV substation transformer, driven by line drop compensation (LDC), switchable capacitors at the MV node of the HV/MV substation or at some nodes of the distribution system. The recent introduction of local DG sources, generally owned and operated independently of the centralized voltage control, is leading to an increasing difficulty in performing voltage control, since the local sources are out of the control of the centralized control. Studies have been carried out for evaluating suitable techniques to modify the existing centralized voltage regulation at the HV/MV substation transformer [66–70]. The results obtained indicate that voltage monitoring at various nodes of the distribution system is required in order to take into account the variability of the voltage profile along the feeders. However, in the presence of a large penetration of DG sources, monitoring should be extended to a large number of nodes, in order to represent the effect of several scattered local sources on the voltage profile variation.

In urban distribution systems, the possibility of voltage control through DG sources is almost negligible, since distribution lines are relatively short and the contribution of the HV/MV substations prevails over the one of the local DG sources. For extra-urban or rural systems, some voltage control may be given by voltage-controllable local generators, depending on their size and reactive power limits.

In order to study the possible voltage control provided by the local generator, the Q - V characteristics of the generator (including the reactive power limits) and of the external system (including the local transformer) are compared. Let's consider an operating condition in which the specified real power of the local generator is P_G . The local transformer has transformation ratio t_T and the series impedance $Z_T = R_T + j X_T$ located at the local generator side, as shown in Fig. 3. Assuming the voltage magnitude V_L at the network side as a parameter, the reactive power output Q_G of the generator depends on voltage magnitude V_G at the generator terminals according to the nearly linear external characteristic

$$Q_G = \frac{X_T V_G^2}{Z_T^2} - \sqrt{\frac{V_G^2 V_L^2}{t_T^2 Z_T^2} - P_G^2 - \frac{V_G^4 R_T^2}{Z_T^4} + 2 \frac{V_G^2 R_T}{Z_T^2} P_G} \quad (26)$$

The external characteristics correspond to the dashed lines in Fig. 14. In order to identify the possible operating points for the generator, the reactive power/voltage curve of the generator is superposed to the external characteristic. Figure 14 shows that the generator is able to operate in the voltage support mode (PV node model) until its reactive power limits are reached. This corresponds to guarantee voltage support for a limited range of voltage magnitude values at the network side, while

Fig. 13 Model of the local generator and transformer

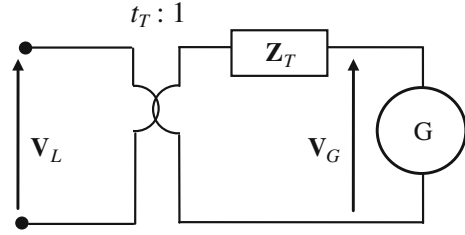
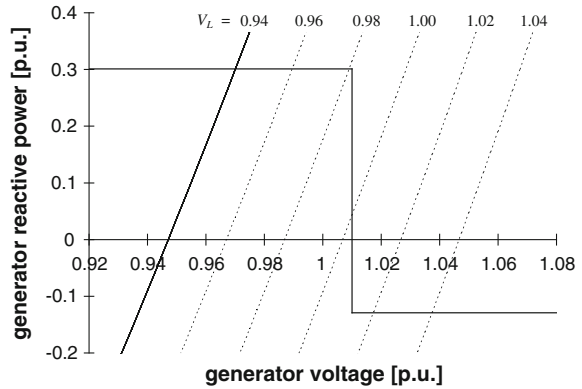


Fig. 14 Local generator and external system Q - V characteristics



in the other operating conditions the generator operates with reactive power generation fixed at the maximum (or minimum) value and as such is no longer able to provide voltage support to the network (Fig. 13).

5 Conclusions

The increasing penetration of dispersed generation into the electricity distribution systems calls for revisiting the operation practices and the related analysis tools. In this framework, some key aspects have been analyzed, concerning voltage control, voltage profiles and losses. These topics showed a particular interest from the point of view of electricity grid evolution towards smart grid.

The approach of this section was to gather and analyze a collection of topics and phenomena, which are depicting apparent eclectic parameters of electric distribution systems, but which are among the most sensitive issues for the utilities and customers alike, due to their high impact on reliability, continuity of operation and prices.

For addressing the continuity of supply issue, a sequential MCM has been implemented to deal with the calculation of the reliability indices. The MCM method is effective to give not only the expected value and variance, but the whole

PDF of different reliability indices. The interest for the PDF is due to the possibility of computing particular information such as the tail probability, which could be useful for defining additional indicators such as the probability of exceeding a given value, important for the regulation of competitive electricity markets.

Results obtained on a test distribution system have been successfully compared to the analytical values of the reliability indices. The permanent faults have a very long restoration time, failure rate and relatively long restoration time, so that the values obtained by the MCM method vary according to the number of permanent faults occurred in the time period under study. This causes the discrepancies between analytical and simulated mean values.

Also, throughout the whole section, the authors have sought to create frameworks that can be used later by the beneficiary for mathematical models. In sequel are listed the obstacles in the face of improving energy distribution activity and the action required to be taken with a view to the removal of obstacles. The second part of the material contains a study of the power consumption curves of the electricity customers in general, with a special focus on three different customers. These customers are important, and the DSO must refine its analysis in order to supply with the exact amount of energy, in order to mitigate the eventual energy-level mismatches and subsequent financial losses.

The electricity prices and operation costs issues were addressed in the second part of this section, some key objectives were completed, such as definition of the mathematical model for calculating the hourly energy specific, identification of the three target groups for users who have developed consumer profiles, definition of the two types of significant load and assessment of the impact of using consumer profiles on users.

The analysis performed showed both the possibility of developing an exact summary of the hourly consumption, and the possible volatility of the customers' consumption profile, weighted by a set of very volatile state parameters.

The main perils for smart grids development are the lack of investment in facilities for LV, a significant proportion of the consumers having old installations with access to conductors. Also, other pitfalls are poor status of the DSO infrastructure, namely network areas with great lengths, LV overload, with inadequate insulation and ageing hardware. Another difficulty is the action to raise awareness of the extent of the economic agents who work with very low loads.

The action required in order to ease the translation from the current electric systems to smart grid is the continuance of control actions for faulty consumers of electrical energy, recovery and restoration system compulsory in secure system.

The objectives of the distributor and of the owner or manager of the local generator-transformer group are generally different. The distributor aims at maintaining an acceptable voltage profile, while the local manager is primarily interested in reducing the internal losses of the local group. Besides being antagonist, these characteristics are complementary for the electric system operation.

The three issues addressed in this section deserve to be further analysed, in order to deepen the understanding the overall impact of the DG into the existing

distribution systems, in order to develop innovative tools for assisting the distribution operators in performing efficient voltage control, suitable loss allocation and profitable use of DG resources in competitive electricity markets.

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