DISTRIBUTION SYSTEMS PERFORMANCE EVALUATION CONSIDERING ISLANDED OPERATION

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Abstract - This paper presents a performance evaluation approach for electric power distribution systems considering aspects related with service adequacy and security, as well as islanded operation. In this approach, a Sequential Monte Carlo Simulation based procedure is applied to emulate the distribution system operation, as well as to calculate system and load point performance indices. Steady-state aspects are evaluated using AC power flow computations. Furthermore, frequency stability is assessed using dynamic simulation aiming at verifying the feasibility of islanded operation. Simulation results are presented for modified versions of the RBTS-Bus2-F1 test system. The results highlight the importance of including steady-state and dynamic analysis into the system performance evaluation, mainly in what regards the impact assessment of distributed generation on the distribution system operation.

Keywords - Distribution systems reliability, adequacy, security, distributed generation, islanded operation.

1 INTRODUCTION

ELECTRIC power distribution systems operation and control have been changing with the ongoing integration of distributed energy resources (DERs). Such changes demand reconsidering distribution systems performance evaluation, particularly in what concerns the assessment of service adequacy and security. Distributed generation (DG) is deemed to enhance power quality and provide ancillary services (such as active/reacive power reserve, load following, restoration, etc.). Nevertheless, current practices and recommendations adopt anti-islanding procedures, where DG units are automatically disconnected from the system in case of a utility fault. Such procedures impose a barrier to DER integration as well as limit considerably the potential benefits DERs can provide to the distribution systems. On the other hand, there are several open challenges in assessing the actual impact that islanded operation can have on the distribution system operation.

Distribution system performance assessment usually relies on reliability index mean value computations to evaluate system operation. Hence, important aspects from system operation such as voltage profiles, line/transformer overloadings, and DG islanding frequency regulation, are normally assessed for specific (worst-case) scenarios. Recently, some researchers have focused on improving distribution system performance assessment. For instance, in [1] the probability distributions from the distribution system reliability indices are evaluated using a Sequential Monte Carlo Simulation (SMCS) approach from the service adequacy perspective. In [2], DG peaking and standby modes are represented in an analytical approach for distribution system reliability assessment. In [3], an analytical technique for distribution system reliability is developed, where the probability of successful islanding is taken into account. In [4], the stochastic nature of the system operation with parallel-connected customer-controlled DG units is evaluated from the adequacy point of view.

Different from these cited works, this paper presents a distribution systems performance evaluation approach considering, at the same time, aspects from service adequacy and security, as well as islanded operation. The proposed approach applies a SMCS based procedure to represent the up/down cycles of network components and DG units in the distribution systems operation. Steady-state aspects are evaluated using AC power flow computations and islanding feasibility is verified through dynamic simulation, when necessary. The SMCS is coded and implemented using object-oriented modeling. System (SAIFI, SAIDI, CAIDI, ASAI, ASUI, ENS, AENS) and load point performance indices are computed as well as their distributional aspects are investigated. Furthermore, non-standardized performance indices are derived to aggregate information regarding steady-state undervoltages and overvoltages. Finally, simulation results for modified versions of the RBTS-Bus2-F1 [5] test system are presented and discussed. The results show the importance of considering steady-state and dynamic analysis in the performance evaluations, namely for the assessment of DG integration on distribution systems.

The paper is organized as follows. Section 2 presents discussions about distribution systems performance assessment, focusing on adequacy and security issues, islanded operation as well as reliability assessment. Section 3 describes the developed distribution systems simulation and evaluation approach. Numerical results are introduced and discussed in section 4. At last, in section 5, final remarks conclude the document.

2 DISTRIBUTION SYSTEMS PERFORMANCE EVALUATION ASPECTS

Recently, distribution systems have received more attention in what regards DG impact assessment. Due to their complexity, distribution systems must be evaluated over several perspectives, considering aspects related with service adequacy and security as well as techniques for steady-state, dynamic and reliability analysis. Some of these aspects are discussed in the following subsections.

2.1 Adequacy and security issues

Electrical power systems are required to provide an adequate and secure service. Adequacy is the ability of a system to supply the demand regarding operation constraints, and taking into account planned and unplanned component outages (adapted from [6]). Security is defined as the ability of a system to withstand disturbances. When a system disturbance occurs, protection and control actions are required to stop the system degradation, restore the system to a steady-state, and minimize the impact of the disturbance. In addition, protection and control actions should pursue the improvement of the operating conditions adequacy.

The operating conditions can be encoded into states according with the degree in which adequacy and security are achieved. For instance, operation states can be categorized as healthy, marginal or at risk depending on some deterministic criteria. Similarly, operation states are classified as normal, alert, emergency, and restorative for security assessment purposes. Power system performance evaluations can be then categorized as follows (adapted from [7]).

1. Adequacy evaluation: assessing the ability of the generation capacity to serve the system total load.
2. Security-constrained adequacy evaluation: assessing the ability of generation and transmission systems to avoid load curtailments under failure events.
3. Security evaluation: assessing the ability of the system to operate under stable conditions when a major change in the system occurs.

Such categorization, nevertheless, is clearly tuned for bulk power systems applications. As a matter of fact, distribution systems are usually meshed structured and radially operated. Therefore, feeders without alternative supply (either from other feeders or DGs) are always prone to service unavailability caused by a permanent fault. As consequence, some common bulk power systems deterministic criteria (such as $N-1$ or fault in the largest generating unit) lose their meaning for distribution systems applications. Hence, distribution systems are usually assessed from a service customer-based point of view, rather than operation state classifications. Customer-based load point information is then further aggregated to provide systemic knowledge about the system service. Moreover, the proximity with the end-customer usually leads the assessment towards the continuity of supply.

Despite of this reasoning, concepts from service adequacy and security can provide important information regarding the assessment of distribution systems operation, mainly with the ongoing integration of DGs and islanded operation possibilities. As a matter of fact, from the definition of adequacy, the continuity of supply must be evaluated along with operation constraints, such as bus voltage limits. On the other hand, from the definition of security, steady-state and dynamic aspects from islanded operation must be considered in order to assess operation decisions as well as the performance of protection and control rules. Clearly, DG can improve and/or jeopardize system operation over several dimensions. By means of evaluation methodologies which consider service adequacy and security aspects, the actual impact of DG integration on the distribution system operation can be properly assessed.

2.2 Distribution systems islanded operation

Distribution systems islanded operation can be obtained through planned and unplanned network separation from the utility system. In case of unplanned network separation, islanding protection must detect Loss-Of-Grid (LOG) and trip the inter-tie breaker between the utility and the islanded subsystem. LOG detection can be achieved by combining protection schemes such as reactive power export error and/or system fault level monitoring, underfrequency/overfrequency and/or undervoltage/overvoltage relaying, rate of change of frequency and/or rate of change of generation power output relaying, voltage vector shifting, intertripping, etc. The low fault level in the islanded subsystem requires short-circuit backup protection coordination as well. The tripping time is designed to avoid that both systems are separated before any out-of-synchronism automatic reclosure trial. In addition, the islanding process requires voltage and frequency control schemes to assure both voltage and frequency stabilization are achieved. Therefore, DERs interfaced with synchronous machines or inverters capable of emulating synchronous generator units are necessary to guarantee an adequate and secure operation.

2.3 Distribution systems assessment approaches

Distribution systems operation can be assessed using analytical and Monte Carlo techniques. Analytical techniques are usually applied to compute mean values of the failure rate λ_i, average outage duration r_i and average annual outage time U_i, for each load point i of a distribution system. The load point information is further utilized to compute the mean values of system reliability indices such as SAIFI, SAIDI, CAIDI, ASAI, ASUI, ENS, AENS, using the following equalities.

$$\text{SAIFI} = \frac{\sum_i \lambda_i N_i}{\sum_i N_i} \qquad \text{SAIDI} = \frac{\sum_i U_i N_i}{\sum_i N_i} \tag{1a}$$

$$\text{ASAI} = 1 - \frac{\text{SAIDI}}{T_y} \qquad \text{ASUI} = 1 - \text{ASAI} \tag{1b}$$

$$\text{ENS} = \sum_i P_i U_i \qquad \text{AENS} = \frac{\text{ENS}}{\sum_i N_i} \tag{1c}$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} \tag{1d}$$

where N_i stands for the number of customers at load point i, P_i denotes the average active load at load point i, and T_y is the number of hours of a year.

However, these performance index mean values usually provide limited information to evaluate the distribution systems operation. Hence, distributional aspects from the system and load point indices can be investigated through SMCS. The Monte Carlo approaches are divided in non-sequential, sequential, and pseudo-sequential. Among those three approaches, the SMCS stands out as the most flexible in modeling chronological aspects from the distribution systems operation.

2.3.1 Sequential Monte Carlo simulation approach

In the SMCS approach, the up/down cycles of system elements are combined to form a synthetic operating cycle of system states. These system states are selected chronologically as well as evaluated until performance index estimates are accurately obtained. The indices are estimated using the expected value expression

$$\tilde{E}\left[\mathbf{G}\right] = \frac{1}{N_y}\sum_{r=1}^{N_y} G(y_r) \tag{2}$$

where N_y denotes the number of simulated years, y_r represents the sequence of system states in year r, $G(y_r)$ is the annual reliability test function evaluated in y_r, and $\mathbf{G}$ stands for a continuous random variable which maps $G(y_r)$ values.

The uncertainty around the estimated indices is given by the variance of the estimative

$$V(\tilde{E}\left[\mathbf{G}\right]) = \frac{E\left[(\mathbf{G} - \tilde{E}\left[\mathbf{G}\right])^2\right]}{N_y} \tag{3}$$

and the stochastic process convergence is tested using the coefficient of variation [8]

$$\beta = \frac{\sqrt{V(\tilde{E}\left[\mathbf{G}\right])}}{\tilde{E}\left[\mathbf{G}\right]} \times 100\% \tag{4}$$

For instance, the system distribution reliability indices in (1a)–(1c) can be estimated using the following equations.

$$G_{\text{SAIFI}}(y_r) \triangleq \frac{\text{n}^{\text{o}} \text{ of customer interruptions in } y_r}{\text{n}^{\text{o}} \text{ of system customers}} \tag{5a}$$

$$G_{\text{SAIDI}}(y_r) \triangleq \frac{\text{total customer interruption duration in } y_r}{\text{n}^{\text{o}} \text{ of system customer}} \tag{5b}$$

$$G_{\text{ASAI}}(y_r) \triangleq 1 - \frac{G_{\text{SAIDI}}(y_r)}{\text{n}^{\text{o}} \text{ of hours in } y_r} \tag{5c}$$

$$G_{\text{ASUI}}(y_r) \triangleq 1 - G_{\text{ASAI}}(y_r) \tag{5d}$$

$$G_{\text{ENS}}(y_r) \triangleq \text{Energy not supplied by the system in } y_r \tag{5e}$$

$$G_{\text{AENS}}(y_r) \triangleq \frac{G_{\text{ENS}}(y_r)}{\text{n}^{\text{o}} \text{ of system customers}} \tag{5f}$$

Although one can compute a CAIDI value for each year using (1d), the CAIDI is an interruption based index estimated by the total customer interruption duration up to y_r, over the number of interruptions up to y_r.

3 DISTRIBUTION SYSTEMS SIMULATION AND EVALUATION APPROACH

Simulation models can be classified over three dimensions: static vs dynamic, deterministic vs stochastic and continuous vs discrete. Regarding simulating distribution systems operation, the complexities around operation decisions and events require a rigorous representation of the dynamic and stochastic nature of the system elements. In addition, the variety of possible system conditions usually demands some sort of discretization of those conditions into operation states. Under this perspective, system operation could be simulated through scheduling discrete events. Nevertheless, when modeling the dynamic behavior of power system elements, continuous aspects can influence the occurrence/schedule of discrete events. Hence, distribution system operation can be rigorously emulated through combined discrete-continuous event simulation [9] where dynamics and stochastic aspects are taken into account.

A combined discrete-continuous event simulation involves modeling the operation of a system as a chronological sequence of events, where events (either discrete events or state events) occur at specific time instants marking possible system state transitions. This copes with the operating cycles produced in the SMCS approaches. Therefore, this work emulates the system operation behavior using combined discrete-continuous event simulation as well as evaluates system states through Monte Carlo method. State modeling, selection and evaluation are described in the next subsections.

3.1 State modeling

This subsection introduces the state modeling adopted for loads, DGs and components.

3.1.1 Load modeling

A load stochastic model is a non-deterministic representation of physical and behavioral patterns of the load demand. In a state space representation, loads can be modeled by aggregate Markov models and/or multi-level non-aggregate Markov models, as shown in [10]. Usually, these models make it possible to represent chronological aspects of the power systems load curve. Since we have adopted a combined continuous-discrete event approach, a standard load model composed by 8736 observed levels (see [11]) was used, each corresponding to one hour of the year. The algorithm procedure is then responsible to transit the load levels following a chronological order.

Loads were modeled as constant active and reactive powers for steady-state analysis purposes. Hence, the hourly load levels were considered as load factors for each of the active and reactive load points. The load response to frequency variations was modeled through a load damping constant.

3.1.2 Distributed generation and component modeling

DG units might be represented according with their up/down cycle, as well as their generating power regarding the availability of natural resources, such as water inflows, wind speed, solar irradiations, and etc. A two-state Markov model was utilized to represent network component and DG unit stochastic behaviors. From the steady-state point of view, components and DG units is modeled using equivalent $\pi-$models and PQ injectors, respectively. The dynamic behavior of the DG units is simulated through dynamic models [12] for their (if any) governing systems, turbines, primary and secondary frequency control loops, and rotational inertial equation, etc.

3.2 State selection: simulating the operation

In a SMCS approach, each system state depends on the immediate previous system state. Moreover, traditional adequacy performance evaluations employ procedures in which subsequent states differ from each other by only one component, generation and/or load state. Hence, once an initial state is specified, state transitions can be performed until the obtained sequence of system states covers a year of operation. The sequence of system states is then evaluated in order to update performance index estimates. The state transitions and evaluations continue until the index estimate accuracies are acceptable.

In order to consider adequacy and security aspects into the distribution system performance evaluations, a more complex state selection is necessary. As a matter of fact, islanding control actions have impact on finding a component energized or de-energized. Hence, to determine the next system state given the current system state, the related state transition depends upon evaluating the current system state. This coupling between state selection and state evaluation introduces complexities to the simulation procedure, namely in applying parallel computation to distribute simulation tasks.

The developed approach employs an algorithm procedure in which system states are evaluated as long as they are chronologically obtained. The simulation clock is tracked based on the *next-event time advance* [9] mechanism. System states are then evaluated from a steady-state and frequency stability perspective, as presented in the following subsection.

3.3 State evaluation

The developed evaluation procedure can be summarized in the four steps as follows.

1. Topology assessment: A topology processor is utilized to separate systems in subsystems (islands). This topology processor is called every time a protection component changes its status.

2. Adequacy assessment: Subsystems are evaluated in terms of their capacity to meet the total load. System components in a subsystem which does not have enough generation capacity to meet its load are considered de-energyzed.

3. Security assessment: If a subsystem not connected to a HV/MV link has enough generation capacity to supply its demand, but there are not control loops implemented to tackle primary and secondary frequency control, the subsystem and its elements are assumed de-energized as well. Whether control loops are implemented, a dynamic simulation is performed where underfrequency and overfrequency relaying are modeled. If the subsystem does not survive the islanding process, the subsystem and its elements are assumed de-energized. Otherwise, the evaluation follows to the next step.

4. Security-constrained adequacy assessment: AC power flows are computed using the generating output power obtained in the previous step.

During the evaluations, statistical information about load point service is stored. In the end of each simulated year, load point indices are updated including failure rate λ_i, unavailability U_i, mean time to repair r_i for each load point i. Thereafter, the load point indices are aggregated to compose the system indices. Since the AC power flow computations can provide steady-state conditions for each system state, the frequency λ_{v_i}, annual duration U_{v_i}, and mean time to solve r_{v_i} inadequate delivered voltage conditions (Voltage < 0.95 p.u. or Voltage > 1.05 p.u.) are estimated as well.

3.4 Implementation

The simulation platform was entirely implemented in JAVA language using the object-oriented paradigm. Power system dynamic simulation was implemented using the Fourth-Order Runge Kutta method of the Flanagan's Java Scientific Library [13]. Steady-state and dynamic analysis were validated using EUROSTAG [14] (version 4.3). An UML abstraction was developed for system components and tools. Regarding implementation design, classes where especially created to abstracts the elements which compose the simulation. For instance, the *Monte Carlo Simulation* class is responsible for the simulation process coordination. The *Operation State*, *State Compositor* and *State Evaluator* classes must abstract, sequentialize and evaluate operation states, respectively. State evaluations, abstracted by the *State Evaluation* class, are aggregated by an instance of the *Index Computation* class, which in turn is responsible for computing the distribution system performance indices.

4 NUMERICAL RESULTS

This section presents numerical results for a series of case studies developed over the RBTS-Bus2-F1 [5], which is illustrated in Fig. 1.

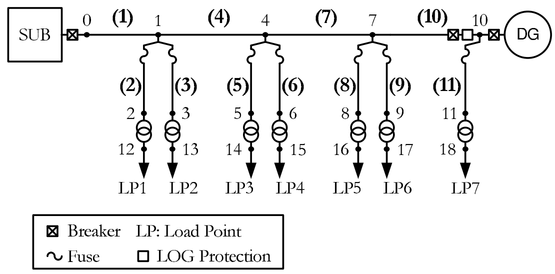

Figure 1: Modified RBTS-Bus2-F1 test feeder.

The simulation convergence was assigned when β values inferior to 5% are achieved for the system indices. It is important to highlight that such convergence criteria does not implicate the load point indices have reached the same coefficient of variation. Lines were regarded as overhead, whilst protection devices were assumed 100% reliable. Only permanent faults were considered. The case studies are organized in basic evaluation, performance evaluation with steady-state analysis, as well as performance evaluation with steady-state and dynamic analysis.

4.1 Basic evaluation

The basic set of evaluations consists of four case studies, named A, B, C and D. These cases were evaluated not only by the simulation approach, but also using an analytical technique. Cases A and B assume constant average load levels throughout the simulated years. Cases C and D applies a peak load normalized version of the load curve in [11] as load factor for each of the load points. Cases A and C assume the representation of the main breaker protection and neglect fuse operations. For the cases B and D, the main breaker and fuses are represented altogether. DG operation, control and protection were not considered in these cases.

Numerical results are shown in Table 1 and 2. As expected, the results obtained through the analytical techniques are in the confidence intervals provided by the simulation results. Since the convergence of cases B and D was achieved for the same number of simulated years, their results differ only in terms of ENS and AENS values. Cases A, B, C and D were part of a series of tests performed to validate the methodology and implementation. We emphasize these results are also representative for cases in which DG operation is considered along with anti-islanding protection.

4.2 Performance evaluation with steady-state analysis: "Optimistic view of DG integration"

This set of evaluations is composed by two case studies where steady-state analysis is performed. For this accomplishment, sections were sized as follows. Section 1 was sized with CA-XLPE-PVC (240mm^2) cable. Sections 4 and 7 were sized with 4/0 CA and 1/0 CAA cables, respectively. Other sections were sized with CA-XLPE-PVC (25mm^2) cable. Transformer impedances were assumed to be $0.1740 + j0.6512\ \Omega$ for LP4–LP5, as well as $0.1914 + j0.7163\ \Omega$, otherwise. A 500 kvar capacitor was installed at bus 10, and the load power factor was chosen to be 0.40 for all load points. The steady-state analysis was included into case D to create case E. Thereafter, DG with islanding protection was included in case E, then comprising case F. DG was modeled as a Combined Heat and Power (CHP) unit with capacity and (grid connected) production of 2.10 MW and 525 kW, respectively. CHP failure rate and mean time to repair were specified at 8.6381 interruptions/year and 77.74 hours [15], respectively.

System and load point reliability indices for case F are presented in Table 3. The results show that DG integration along with islanded operation improved the system reliability, particularly regarding the SAIFI, SAIDI and ENS indices. This implies an average customer in this system might experience less service interruptions, interruption hours and energy not supplied during a year of operation. Customers at LP7 were the ones who benefited the most with DG integration. This result was expected since LP7 is the load point covered by islanded operation.

Finally, load point inadequate voltage profile indices for cases E and F are shown in Table 3 as well. In case E, LP5–LP7 are expected to be served with inadequate voltages longer than 8.69% of the year. On the other hand, in case F, DG integration improved considerably the voltage profiles during the simulated years. As a matter of fact, the worst served load point in terms of voltage profiles (LP5) is expected to be inadequately served no longer than 0.0006% of the year. Such results, however, represent an optimistic view of DG integration where we assume islanded operation is always achieved after the occurrence of an island-outer fault.

Index	Case A			Case B			Case C			Case D		
	Analyt.	SMCS	β (%)	Analyt.	SMCS	β (%)	Analyt.	SMCS	β (%)	Analyt.	SMCS	β (%)
SAIFI	0.6250	0.6241	1.6162	0.2480	0.2455	1.9052	0.6250	0.6254	1.6085	0.2480	0.2455	1.9052
SAIDI	23.5646	22.2772	4.9982	4.1634	3.8905	4.9999	23.5646	22.6305	4.9558	4.1634	3.8905	4.9999
CAIDI	37.7034	35.6941	-	16.7886	15.8451	-	37.7034	36.1859	-	16.7886	15.8451	-
ASAI	0.9973	0.9974	0.0128	0.9995	0.9996	0.0022	0.9973	0.9974	0.0129	0.9995	0.9996	0.0022
ASUI	0.0027	0.0026	4.9982	0.0005	0.0004	4.9999	0.0027	0.0026	4.9558	0.0005	0.0004	4.9999
ENS	85.8930	81.2005	4.9982	15.1744	14.5409	3.3579	52.7759	51.0334	4.9974	9.3237	9.0016	3.3782
AENS	0.1317	0.1245	4.9982	0.0233	0.0223	3.3579	0.0809	0.0783	4.9974	0.0143	0.0138	3.3782

Table 1: System reliability indices for cases A, B, C and D. Units: SAIFI [interruptions/customer.yr], SAIDI [h/customer.yr], CAIDI [h/customer interruption], ENS [MWh], AENS [MWh/customer.yr].

Load Point	Case A			Case B			Case C			Case D		
	λ_i	U_i	r_i	λ_i	U_i	r_i	λ_i	U_i	r_i	λ_i	U_i	r_i
LP1	0.6241	22.2772	35.6941	0.2483	3.9826	16.0395	0.6254	22.6305	36.1859	0.2483	3.9826	16.0395
LP2	0.6241	22.2772	35.6941	0.2345	4.1729	17.7949	0.6254	22.6305	36.1859	0.2345	4.1729	17.7949
LP3	0.6241	22.2772	35.6941	0.2542	3.5018	13.7758	0.6254	22.6305	36.1859	0.2542	3.5018	13.7758
LP4	0.6241	22.2772	35.6941	0.2361	3.8598	16.3482	0.6254	22.6305	36.1859	0.2361	3.8598	16.3482
LP5	0.6241	22.2772	35.6941	0.2577	4.3675	16.9480	0.6254	22.6305	36.1859	0.2577	4.3675	16.9480
LP6	0.6241	22.2772	35.6941	0.2455	4.0652	16.5589	0.6254	22.6305	36.1859	0.2455	4.0652	16.5589
LP7	0.6241	22.2772	35.6941	0.2504	3.9693	15.8518	0.6254	22.6305	36.1859	0.2504	3.9693	15.8518

Table 2: Load point reliability indices using the simulation approach for cases A, B, C and D. Units: λ_i [interruptions/yr], U_i [h/yr], and r_i [h].

Index	Case F	
	SMCS	β (%)
SAIFI	0.2023	1.9788
SAIDI	4.0875	4.9995
CAIDI	20.2011	-
ASAI	0.9995	0.0023
ASUI	0.0005	4.9995
ENS	8.5897	3.4850
AENS	0.0132	3.4850

(a)

Load Point	Case F						Case E		
	λ_i	U_i	r_i	λ_{v_i}	U_{v_i}	r_{v_i}	λ_{v_i}	U_{v_i}	r_{v_i}
LP1	0.2087	4.0959	19.6258	0.0000	0.0000	-	0.0000	0.0000	-
LP2	0.1930	3.8399	19.8959	0.0000	0.0000	-	0.0000	0.0000	-
LP3	0.2106	4.3602	20.7037	0.0000	0.0000	-	0.0000	0.0000	-
LP4	0.1900	3.3149	17.4468	0.0000	0.0000	-	0.0000	0.0000	-
LP5	0.2038	3.5260	17.3013	0.0148	0.0481	3.2500	149.6010	1268.4587	8.4789
LP6	0.2031	3.9418	19.4082	0.0111	0.0360	3.2432	116.6111	761.8321	6.5331
LP7	0.1148	3.6623	31.9016	0.0000	0.0000	-	137.6010	1050.9966	7.6380

(b)

Table 3: Selected system and load point indices for cases E and F. Units: SAIFI [interruptions/customer.yr], SAIDI [h/customer.yr], CAIDI [h/customer interruption], ENS [MWh], AENS [MWh/customer.yr], λ_i [interruptions/yr], U_i [h/yr], r_i [h], λ_{v_i} [occurrence/yr], U_{v_i} [h/yr], and r_{v_i} [h].

4.3 *Performance evaluation with steady-state and dynamic analysis: "More realistic view of DG integration"*

This set of evaluations is composed by a variation of case F, named case G, which now considers the system dynamic behavior. CHP dynamics were represented using the speed governor and turbine (single reheat tandem-compound) models in [12]. Underfrequency and overfrequency relaying were set up using the thresholds 0.9850 p.u. and 1.010 p.u., respectively. If one of these thresholds is reached, the CHP unit is tripped from the islanded subsystem. Otherwise, whether steady-state rated frequency is achieved, the islanding is considered successful. Fig. 2 illustrates the frequency variation for a successful islanding process. Following the notation in [12], model parameters are: $K_G = 25$ p.u., $L_{C1} = 0.3$ p.u., $L_{C2} = -1.0$ p.u., $T_{SM} = 0.3$ s, $T_{SR} = 0.1$ s, $F_{HP} = 0.3$ p.u., $T_{CH} = 0.3$ s, $T_{RH} = 5$ s. The secondary load-frequency control integral gain, inertia constant and load damping constant were assumed to be $K_I = 5$ p.u., $H = 4.9$ s, and $D = 2\%$, respectively.

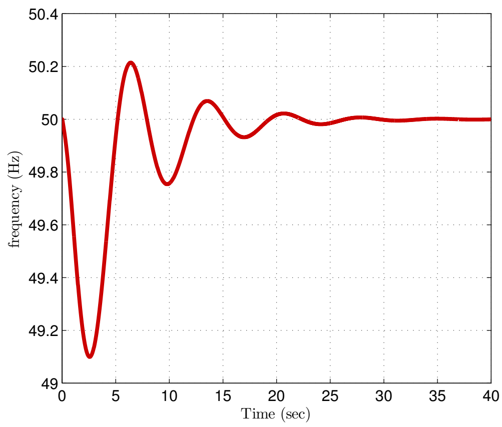

Figure 2: Frequency behavior during one of the islanding processes.

System and load point indices for case G are presented in Table 4 and 5, respectively. The results show in a more realistic way the benefits that islanded operation can provide to the distribution system operation. System indices do not differ considerably in comparison with case F since LP7 supplies only 1.53% of the system customers. Nevertheless, LP7 load point indices differ on a reasonable extend in comparison with case F results.

Index	SMCS	β (%)
SAIFI [interruptions/customer.yr]	0.2202	1.9848
SAIDI [h/customer.yr]	4.1058	4.9970
CAIDI [h/customer interruption]	18.6498	-
ASAI	0.9995	0.0023
ASUI	0.0005	4.9970
ENS [MWh]	8.6370	3.4806
AENS [MWh/customer.yr]	0.0132	3.4806

Table 4: System indices for face G.

LP	λ_i	U_i	r_i	λ_{v_i}	U_{v_i}	r_{v_i}
1	0.2257	4.1257	18.2796	0.0000	0.0000	-
2	0.2098	3.8556	18.3775	0.0000	0.0000	-
3	0.2273	4.3669	19.2121	0.0000	0.0000	-
4	0.2070	3.3405	16.1377	0.0000	0.0000	-
5	0.2207	3.5352	16.0181	0.0142	0.0424	2.9859
6	0.2202	3.973	18.0427	0.0105	0.0324	3.0857
7	0.1962	3.7256	18.9888	0.0000	0.0000	-

Table 5: Load point indices for face G. Units: λ_i [interruptions/yr], U_i [h/yr], r_i [h], λ_{v_i} [occurrence/yr], U_{v_i} [h/yr], and r_{v_i} [h].

The impact of considering islanding dynamic behavior can also be observed through load point index distributional aspects. For instance, the number of interruptions in 9968 simulated years for cases F and G is presented in Fig. 3. The coefficient of variation β is inferior to 5% for both cases.

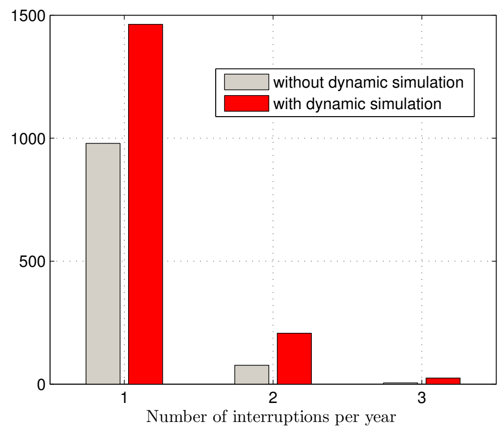

Figure 3: Histogram for the number of interruptions per year at LP7.

The number of interruptions per year is proven to be underestimated for the case in which islanding dynamics are neglected. Such result points out the need for employing more sophisticated islanding control strategies to improve quality of service.

5 CONCLUSIONS AND FINAL REMARKS

This paper presented a performance evaluation approach for distribution systems considering aspects related with service adequacy and security, as well as islanded operation. A combined discrete-continuous event simulation approach is developed to emulate the distribution system operation. Using the next-event time advance mechanism, the simulation approach produces sequences of operation states in a chronological order. Over the resultant operating cycle, distributional aspects from performance evaluation indices are assessed. These indices comprise standard reliability indices, as well as figures of merit which aggregate information regarding inadequate delivered voltage conditions. For this accomplishment, AC power flow computations were included in the evaluations. Furthermore, DG integration along with islanded operation is evaluated using dynamic simulation.

Case studies were performed using modified versions of the RBTS-Bus2-F1 test system. The numerical results show that DG units along with islanded operation had improved system operation. The results also highlighted the importance of considering steady-state and dynamic analysis into the performance evaluation, mainly in assessing the impact of DG integration on the distribution system operation. At last, we point out the simulation approach can be further applied to gather operation states which demand more DG integration detailed analysis from transient perspectives.

Further work will carry out the application of more sophisticated control strategies to guarantee islanded operation, a more detailed system dynamic modeling to allow the impact assessment of fault ride-through schemes, as well as the incorporation of other attributes from quality of supply into the evaluation approach.

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