Adequacy and Security Evaluation of Distribution Systems With Distributed Generation

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***Abstract*—This paper presents an adequacy and security evaluation of electric power distribution systems with distributed generation. For this accomplishment, bulk power system adequacy and security evaluation concepts are adapted to distribution system applications. The evaluation is supported by a combined discrete-continuous simulation model which emulates the distribution system operation. This model generates a sequence of operation states which are evaluated from a steady-state perspective using AC power flow computations. Frequency and voltage stability are also assessed using dynamic simulation in order to verify the feasibility of islanded operation. Simulation results are presented for the RBTS-BUS2-F1 as well as an actual feeder from the South of Brazil. The results emphasize the need to consider adequacy and security aspects in the distribution system assessments, mainly due to the ongoing integration of distributed energy resources.**

***Index Terms*—Adequacy and security evaluation, distributed power generation, power distribution, power distribution reliability, sequential Monte Carlo simulation.**

I. Introduction

DISTRIBUTION system operation models are mandatory to evaluate and support the establishment of local protection/control actions as well as centralized distribution management system decisions. This necessity becomes even more pertinent with the gradual introduction of concepts aggregated by the smart grid paradigm. Power distribution systems can become increasingly complex due to the integration of distributed energy resources (DERs). Consequently, protection and control systems have been gradually moving towards a more sophisticated distributed architecture, which considers information technology and advanced software design as the major requirements for development.

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If distributed generation (DG) is appropriately operated, it can provide benefits for distribution systems through reductions in losses and capacity requirements, improvements on reliability, voltage control, and so on. However, there is a lack of evaluation methodologies to assess the actual impact the DGs can have on the distribution system operation. In fact, distribution system performance assessment normally relies on interruption-based index mean value calculations to assess the system's performance, generally disregarding the steady-state and dynamic effects that come from the DGs. Therefore, critical issues linked to steady-state and dynamic evaluations such as voltage profiles, as well as frequency and voltage stability are usually assessed separately through (worst-case) scenarios.

More recently, some researchers have made efforts to improve the distribution system assessment methodologies. As examples, in [1], a comprehensive set of nonsequential Monte Carlo simulation-based results are presented for the feeders associated with the Roy Billinton Test System (RBTS) buses [2], [3]. In [4], the probability distributions from the distribution system reliability indices are evaluated using a sequential Monte Carlo simulation (SMCS) approach from a service adequacy perspective. In [5], DG peaking and standby modes are represented in an analytical approach for distribution system reliability assessment. In [6], an analytical technique for distribution system reliability is developed, where the probability of successful islanding is taken into account. In [7], the stochastic nature of the system operation with parallel-connected customer-controlled DG units is evaluated from the adequacy point of view. Adequacy evaluation is also approached for distribution systems with wind-based DG units in [8], as well as with wind/solar DG units in [9].

This paper presents an adequacy and security evaluation of distribution systems considering DG islanded operation. The approach applies a combined discrete-continuous simulation model where steady-state aspects are assessed through AC power flow computations. Islanding feasibility is also verified, when necessary, through dynamic simulation. System and load point reliability indices along with their distributional aspects are investigated. In addition, undervoltage/overvoltage information is aggregated in terms of performance indices. Simulation results for a modified version of the RBTS-BUS2-F1 [2] as well as a real Brazilian distribution feeder are presented and discussed.

The paper is structured as follows. Section II introduces the representation of adequacy and security aspects into the assessment of distribution systems. Section III presents the

proposed combined discrete-continuous simulation approach which is applied to emulate the distribution systems operation. In Section IV, validation and case studies are discussed. Finally, Section V outlines conclusions and final remarks.

II. Adequacy and Security Aspects for Power Distribution Systems

Adequacy and security concerns are interdependent and part of the same problem. However, power engineers often decouple adequacy and security aspects to facilitate the power system analysis. The main implication of this decoupling is to adopt certain assumptions in what, for instance, system dynamics might not affect the adequacy performance. This is the case of, for instance, bulk power system adequacy evaluations [10], where only the generation capacity to serve the total load is taken into consideration. In distribution systems, where the presence of generators was limited in the past, the assumptions applied to adequacy studies are generally considered sufficient to providing satisfactory input to the decision-making processes [2], [3]. Nevertheless, when a considerable number of generators of different technologies are connected to distribution networks, aspects related with system dynamics might be of great importance to evaluate the distribution system operation.

From an evaluation perspective, a power system is deemed adequate according with its ability to meet the demand regarding operation constraints, and taking into account planned and unplanned component outages (adapted from [11]). On the other hand, a power system is deemed secure according with its ability to withstand disturbances. Power systems are designed to provide an adequate and secure service. Therefore, protection and control must guarantee service adequacy under normal operation conditions. In case of disturbances, protection and control must stabilize the system and minimize the impact of the disturbance.

Unfortunately, the definitions commonly used to bulk generation and transmission system evaluation [3], [10] cannot be directly applied to distribution system assessment. For instance, since distribution systems are usually meshed structured and radially operated, feeders without alternative supply (either from other feeders or DGs) are always prone to service unavailability caused by a permanent fault. Consequently, some common bulk power systems deterministic criteria (such as $N-1$ or the loss of the largest generating unit) lose their meaning on distribution systems analysis. Hence, distribution systems are usually assessed from a customer service point of view, rather than operation state classifications. Customer service information is then further aggregated to provide systemic knowledge on the system service. Moreover, the proximity with the end-customer usually leads the assessment towards the continuity of supply.

Following a customer service perspective, it is possible to classify the load point service as *adequate* according with the voltage waveform at the point of consumption, taking into account planned and unplanned component outages. By extension, any system composed of adequately served load points would provide an adequate service. If the voltage waveform is nonexistent, the load point is not energized characterizing a service interruption. On the other hand, load point service would then be classified as *secure* according with its ability to withstand a set of disturbances. Analogously, any (sub-)system composed of securely served load points would provide a secure service.

Therefore, the following definitions can be derived from the classifications above:

1) Distribution system adequacy evaluation (classical): assessing the ability of the system to provide a continuous service in terms of interruptions in its points of consumption.
2) Distribution system adequacy evaluation (alternative): assessing the ability of the system to provide an adequate service in terms of voltage waveform in its points of consumption, taking into account planned and unplanned component outages.
3) Distribution system security evaluation: assessing the ability of the system to operate under stable conditions when a major change in the system occurs, taking into account planned and unplanned component outages.

Following these suggested definitions, distribution system adequacy evaluation (alternative) covers the standard reliability assessments where failure rates, average annual outage times, and average outage durations are estimated for the points of consumption. This evaluation also deals with voltage waveform aspects when the load points are energized. Finally, the distribution system security evaluation covers topics such as system frequency and voltage stability, taking into account the possibility of DG islanded operation.

Clearly, the ongoing integration of DGs requires evaluation models which deal with adequacy and security aspects in an integrated way. The developed combined discrete-continuous simulation model focuses on customer interruption evaluations, undervoltage/overvoltage aspects through AC power flow computations, as well as DG islanding frequency and voltage stability evaluations through dynamic simulation.

III. Combined Discrete-Continuous Simulation Approach

Simulation models can be categorized as discrete-event, continuous-time, or the combination of both. A pure discrete-event simulation model concerns the representation of a system by scheduling and/or sampling a sequence of events, which are assigned to specific time instants making possible discrete state transitions. The SMCS approaches cope with this definition, where the operating cycles of the system components are combined to compose operation states, which in turn are subjected to evaluation. Conversely, in a pure continuous-time simulation model, state transitions are never abrupt but continually evolve over time. Typically, continuous simulation models involve differential equations to represent state variable rates of change with time. Power system dynamic simulation usually applies this concept by solving a set of differential equations through numerical integration, although some event scheduling is common in terms of, for instance, machine setpoint changes, switch opening/closing, relay-based protection/control actions, etc. A combined discrete-continuous simulation model utilizes both discrete-event and continuous-time representations. The challenge in developing such a model is to couple these representations in a unique simulation process.

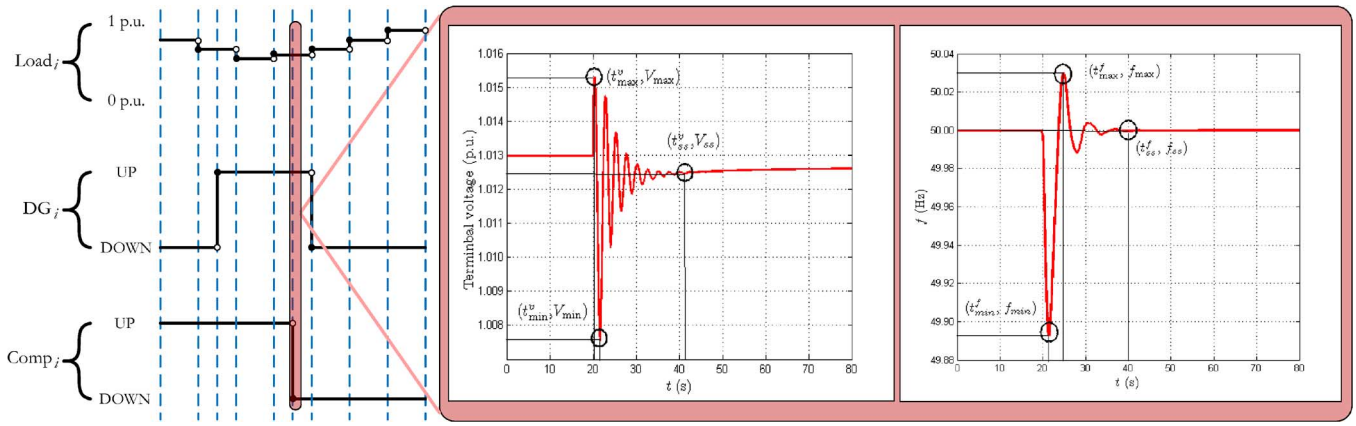

Fig. 1. Operating cycle in the combined discrete-continuous simulation approach.

The complexity of modeling the distribution systems operation naturally leads to a combined discrete-continuous simulation approach. In fact, the three fundamental types of interaction between discretely changing and continuously changing state variables are inherent to the system operation (adapted from [12]):

1) A discrete event may cause a discrete change in the value of a continuous state variable (e.g., a component transition to the down state may cause breaker actions, which in turn may lead to a sudden change in a node voltages).
2) A discrete event may cause the relationship governing a continuous state variable to change at a particular time (e.g., the DG transition to a down state causes the abrupt uncoupling between the DG continuous state variables and the remaining system state variables).
3) A continuous state variable achieving a threshold value may cause a discrete event to occur or to be scheduled (e.g., underfrequency relay-based load shedding).

Such interactions influence the simulation modeling. Indeed, since the transition from current to new system states is dependent on the evaluation of the current state, traditional procedures of generating subsequent system states covering a year of operation followed by their post-evaluation are not possible. This leads to a coupling between state selection and state evaluation introducing complexities to the simulation procedure, namely in the application of parallel computation to distribute simulation tasks. Furthermore, these interactions require synchronizing events that were scheduled during state evaluation as well as state selection.

Hence, the developed approach employs a combined discrete-continuous simulation model in which system states are evaluated as long as they are obtained. Similarly to the SMCS, the up/down cycles of the system components are merged to create a synthetic operating cycle of system states (see Fig. 1). Discrete and continuous state variables are then updated over time and the evaluation proceeds until the performance index estimates are accurately obtained. The clock of the combined discrete-continuous simulation procedure is tracked using the *next-event time advance* [12] mechanism. More details about the simulation modeling are presented in the following subsections.

A. Stochastic and Deterministic Modeling

DG units may be represented according with their failure/repair cycle, as well as their generating power regarding the availability of natural resources, such as water inflows, wind speed, solar irradiations, and so on. In this approach, the simple two-state Markov model [3] was used to represent network components and DG unit stochastic behavior. DG and network components state residence times are assumed to be exponentially distributed, and are sampled using the following equation [13]:

$$T \leftarrow -\frac{1}{\lambda} \ln U \tag{1}$$

where T is the residence time of the component/unit, λ is the transition rate out from the current state, and U is a uniformly distributed random number which is sampled at [0, 1].

Loads patterns can also be modeled by aggregated and/or multi-level non-aggregated Markov models, as shown in [14]. Nevertheless, since a combined discrete-continuous simulation approach which follows chronology has been adopted, a deterministic load model consisting on 8736 peak load percentage levels [15] was utilized, each associated to one hour of the year. These load levels are then applied during simulation following a chronological order.

B. Electrical and Electromechanical Modeling

The power systems conditions can be described by a set of differential equations $\dot{\mathbf{x}} = \mathbf{f}(\mathbf{x})$, algebraic equations $\mathbf{g}(\mathbf{x}) = \mathbf{0}$, and algebraic inequations $\mathbf{h}(\mathbf{x}) \leq \mathbf{0}$. These equations and inequations represent the dynamic models of generators and loads (including the prime movers, control loops, rotational inertia equation, excitation systems, etc.), as well as the network model. In the formulation, the high voltage (HV) systems are modeled by infinite nodes with constant voltage and frequency, while network components are represented by their equivalent π-models. For steady-state analysis, the load demands and DG unit's productions are modeled using constant complex powers $S_l = P_l + jQ_l$ and $S_g = P_g + jQ_g$, respectively. If dynamic simulation is required, loads are then represented by their equivalent admittance $(y_l = (S_l^*/\|V_l\|^2))$ which is computed using

the pre-fault voltage V_l at the connection node. These admittances are added to the main diagonal of the network admittance matrix to create the network model

$$\begin{bmatrix} \mathbf{I_g} \\ \mathbf{\Delta I_r} \end{bmatrix} = \begin{bmatrix} \mathbf{Y_{gg}} & \mathbf{Y_{gr}} \\ \mathbf{Y_{rg}} & \mathbf{Y_{rr}} \end{bmatrix} \begin{bmatrix} \mathbf{V_g} \\ \mathbf{V_r} \end{bmatrix} \tag{2}$$

where $\mathbf{I_g}$ denotes a vector of injected currents at the generation nodes; $\mathbf{\Delta I_r}$ represents a vector of variations in the injected currents at the other nodes; $\mathbf{V_g}$ and $\mathbf{V_r}$ are vectors of voltages associated with generation and other nodes, respectively; as well as $\mathbf{Y_{gg}}$, $\mathbf{Y_{gr}}$, $\mathbf{Y_{rg}}$, and $\mathbf{Y_{rr}}$ are network admittance sub-matrices associating nodes with each other.

By manipulating the matrix equation in (2), we have

$$\mathbf{I_g} = \underbrace{\left(\mathbf{Y_{gg}} - \mathbf{Y_{gr}}\mathbf{Y_{rr}^{-1}}\mathbf{Y_{rg}}\right)}_{\mathbf{Y_h}} \mathbf{V_g} + \underbrace{\mathbf{Y_{gr}}\mathbf{Y_{rr}^{-1}}}_{\mathbf{K_h}} \mathbf{\Delta I_r}. \tag{3}$$

Note now that (3) can be represented in the dq system reference frame as follows:

$$\mathbf{I_g^{dq}} = \mathbf{Y_h^{dq}}\mathbf{V_g^{dq}} + \mathbf{K_h^{dq}}\mathbf{\Delta I_r^{dq}} \tag{4}$$

where

$$\begin{aligned}
\mathbf{I_g^{dq}} &= [\Re\{\mathbf{I_g}\}_1, \Im\{\mathbf{I_g}\}_1, \ldots, \Re\{\mathbf{I_g}\}_n, \Im\{\mathbf{I_g}\}_n]^T \\
\mathbf{V_g^{dq}} &= [\Re\{\mathbf{I_g}\}_1, \Im\{\mathbf{I_g}\}_1, \ldots, \Re\{\mathbf{I_g}\}_n, \Im\{\mathbf{I_g}\}_n]^T \\
\mathbf{\Delta I_r^{dq}} &= [\Re\{\mathbf{\Delta I_r}\}_1, \Im\{\mathbf{\Delta I_r}\}_1, \ldots, \Re\{\mathbf{\Delta I_r}\}_s, \Im\{\mathbf{\Delta I_r}\}_s]^T \\
\mathbf{Y_h^{dq}} &= \begin{bmatrix} \{\mathbf{G_h}\}_{11} & -\{\mathbf{B_h}\}_{11} & \ldots & \{\mathbf{G_h}\}_{1n} & -\{\mathbf{B_h}\}_{1n} \\ \{\mathbf{B_h}\}_{11} & \{\mathbf{G_h}\}_{11} & \ldots & \{\mathbf{B_h}\}_{1n} & \{\mathbf{G_h}\}_{1n} \\ \vdots & \vdots & \ddots & \vdots & \vdots \\ \{\mathbf{G_h}\}_{n1} & -\{\mathbf{B_h}\}_{n1} & \ldots & \{\mathbf{G_h}\}_{nn} & -\{\mathbf{B_h}\}_{nn} \\ \{\mathbf{B_h}\}_{n1} & \{\mathbf{G_h}\}_{n1} & \ldots & \{\mathbf{B_h}\}_{nn} & \{\mathbf{G_h}\}_{nn} \end{bmatrix} \\
\mathbf{K_h^{dq}} &= \begin{bmatrix} \{\mathbf{\Theta_h}\}_{11} & -\{\mathbf{\Psi_h}\}_{11} & \ldots & \{\mathbf{\Theta_h}\}_{1s} & -\{\mathbf{\Psi_h}\}_{1s} \\ \{\mathbf{\Psi_h}\}_{11} & \{\mathbf{\Theta_h}\}_{11} & \ldots & \{\mathbf{\Psi_h}\}_{1s} & \{\mathbf{\Theta_h}\}_{1s} \\ \vdots & \vdots & \ddots & \vdots & \vdots \\ \{\mathbf{\Theta_h}\}_{n1} & -\{\mathbf{\Psi_h}\}_{n1} & \ldots & \{\mathbf{\Theta_h}\}_{ns} & -\{\mathbf{\Psi_h}\}_{ns} \\ \{\mathbf{\Psi_h}\}_{n1} & \{\mathbf{\Theta_h}\}_{n1} & \ldots & \{\mathbf{\Psi_h}\}_{ns} & \{\mathbf{\Theta_h}\}_{ns} \end{bmatrix} \\
\mathbf{G_h} &= \Re\{\mathbf{Y_h}\}, \quad \mathbf{B_h} = \Im\{\mathbf{Y_h}\} \\
\mathbf{\Theta_h} &= \Re\{\mathbf{K_h}\}, \quad \mathbf{\Psi_h} = \Im\{\mathbf{K_h}\}
\end{aligned}$$

in which n is the number of generation nodes and s is the number of other nodes.

The dynamic model of each unit is initialized using the voltage, current and frequency obtained through a previous saved state. For synchronous and asynchronous machines, a stator electric model is built for each unit according with the following equation:

$$V_{unit}^{dq} = E_{unit}^{dq} - Z_M^{unit} I_{unit}^{dq} \tag{5}$$

where V_{unit}^{dq}, E_{unit}^{dq}, and I_{unit}^{dq} are 2×1 vectors with the connection node voltage, transient internal voltage, and terminal (injected) current, respectively, at the dq unit reference frame. The variable Z_M^{unit} denotes a 2×2 matrix with entries given by stator impedance parameters.

The expressions in (4) and (5) can be combined as follows:

$$\mathbf{I_g^{dq}} = \left(\mathbf{\Upsilon} + \mathbf{Y_h^{dq}}\mathbf{Z_M}\right)^{-1} \left(\mathbf{Y_h^{dq}}\mathbf{E^{dq}} + \mathbf{K_h^{dq}}\mathbf{\Delta I_r^{dq}}\right) \tag{6}$$

where $\mathbf{\Upsilon}$ is the unit (identity) matrix, $\mathbf{Z_M}$ is a block diagonal matrix with elements Z_M^{unit} converted to the dq system reference frame, and $\mathbf{E_{dq}}$ is a vector with entries E_{dq}^{unit} converted to the dq system reference frame.

The dynamic simulation is then performed using a partitioned approach which alternates between the solution of the differential equations and the algebraic equations, and was successfully applied in works specifically related with dynamic analysis [16], [17]. In summary, according with a numerical integration rule: 1) the continuous state variables are estimated and the variables E_{dq}^{unit} and Z_M^{unit} are updated; 2) the terminal node currents are updated using (6); and 3) terminal voltages are updated using (5). These steps are repeated until a new steady-state is achieved or other disturbance is assigned. In case the network configuration changes or a generation unit is disconnected, the matrix variables in (6) are updated. If necessary, the dynamics of other components can be added, involving the change of $\mathbf{\Delta I_r^{dq}}$ depending on, for instance, terminal voltage and/or system frequency information.

C. Evaluation Procedures

As previously described, the combined discrete-continuous simulation approach produces operation states which are subjected to evaluation. The state evaluation then varies according with the transition which produced the operation state. In case of a network component state transition, the following steps summarize the evaluation.

1) Protection actions are performed by changing the status of the protection devices (breaker, switch, or fuse) depending on the component under state transition. For instance, a component state transition to the down state may trigger a breaker action at the substation bus.
2) A topology processor is applied to verify possible network unifications or separations in subsystems (islands). Subsystems composed of at least one HV link are considered energized and a power flow is computed to assess its steady-state. Otherwise, the evaluation goes to the next step.
3) The subsystems capability to operate in islanded mode is assessed. For this accomplishment, the generation capacity to meet the load is verified. Furthermore, islanded operation is assigned only for subsystems with DERs interfaced with synchronous machines or inverters capable of emulating a synchronous generator. If one of these conditions is not met, the subsystem and its elements are assumed de-energized. Otherwise, the evaluation continues to the next step.
4) Dynamic simulation is performed following the modeling introduced in Section III-B. Only if frequency and voltage stabilization are achieved, the subsystem is considered energized. State discrete and continuous variables are updated at the end of the dynamic simulation.

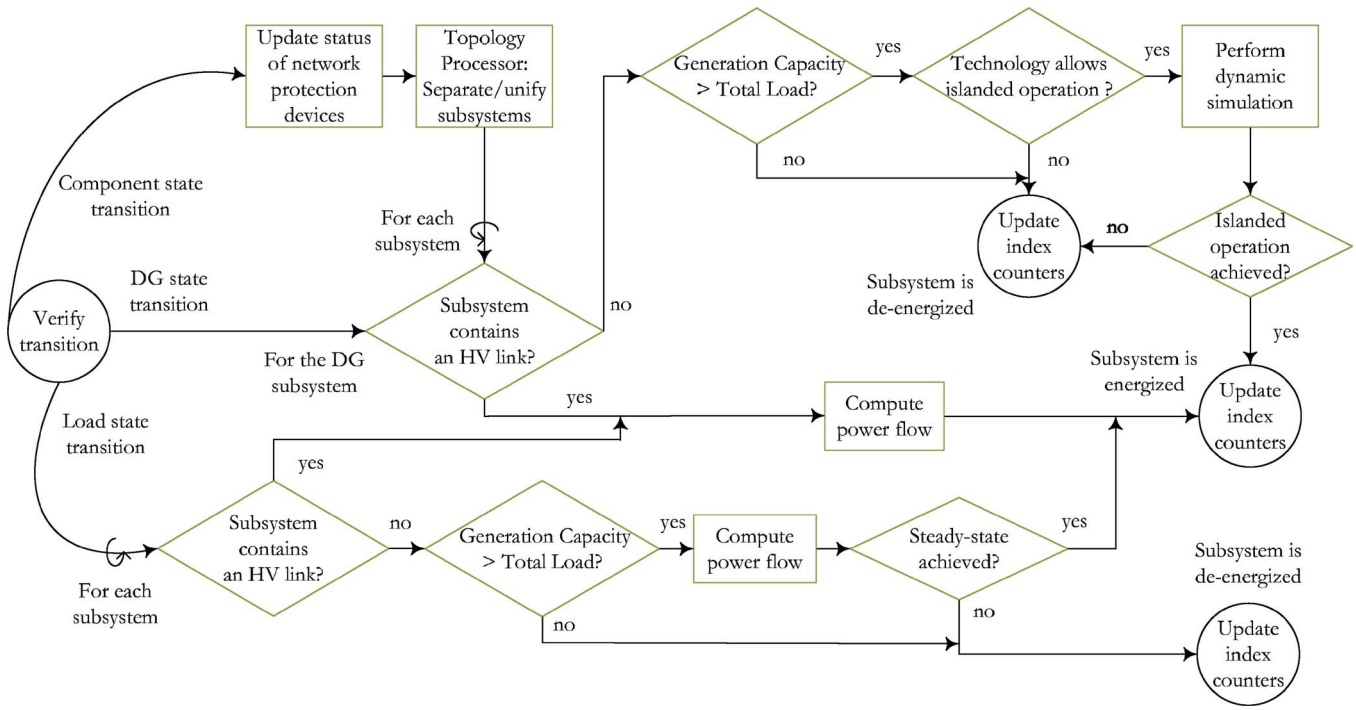

Fig. 2. Evaluation procedures in the combined discrete-continuous simulation approach.

In case of a load transition, if the subsystem contains an HV link, then a power flow is computed and the subsystem is considered energized. If the subsystem does not contain an HV link, a power flow is computed for the islanded subsystem only if there is enough generation capacity to supply the load. As an approximation, in order to meet the load in islanded mode, DG unit's productions are increased/decreased from the previous operation state following a merit order. Losses are then compensated by the unit at a chosen reference node. In case the subsystem does not have capacity to supply its load demand and network losses and, therefore, steady-state is not achieved, then the subsystem and its elements are considered de-energized. Otherwise, they are considered energized. Finally, in case of a DG state transition, if the subsystem contains at least one HV link, a power flow is computed to assess the subsystem steady-state. Otherwise, steps 3) and 4) are considered. Fig. 2 summarizes the evaluation procedures.

Note that dynamic simulation is not performed in case of load transitions. Hence, it is assumed the subsystems in islanded mode are able to perform load-following perfectly.

D. Index Computation

The actual impact DG integration can have on the distribution system operation can be measured using the uprising/downrising of performance indices. Similarly to the SMCS approach, the performance indices are estimated using the expected value equation

$$\tilde{E}[\mathbf{G}] = \frac{1}{N}\sum_{u=1}^{N} G(y_u) \tag{7}$$

in which y_u stands for the sequence of system states in year u, $G(y_u)$ is the reliability test function evaluated at y_u, N represents the number of simulated years, and $\mathbf{G}$ is a continuous random variable which maps $G(y_u)$ values.

The uncertainty around the estimated indices is given by the variance of the estimative [18]

$$V\left(\tilde{E}[\mathbf{G}]\right) = \frac{E\left[\left(\mathbf{G} - \tilde{E}[\mathbf{G}]\right)^2\right]}{N} \tag{8}$$

and the stochastic process convergence is tested using the coefficient of variation [18]

$$\beta = \frac{\sqrt{V\left(\tilde{E}[\mathbf{G}]\right)}}{\tilde{E}[\mathbf{G}]} \times 100\%. \tag{9}$$

Following these definitions, the conventional system reliability indices can be estimated using equations introduced in [19]. These indices are the SAIFI [interruptions/customer/yr], SAIDI [h/customer/yr], CAIDI [h/customer interruption], ASAI, ASUI, ENS [MWh], AENS [MWh/customer/yr]. In the proposed approach, the impact of DG integration is directly attained through the variation in the performance indices according with the following equations:

$$\Delta G_{\mathrm{SAIFI}}(y_u) \triangleq -\frac{\text{n}^{\text{o}} \text{ of avoided customer interruptions in } y_u}{\text{n}^{\text{o}} \text{ of system customers}} \tag{10a}$$

$$\Delta G_{\mathrm{SAIDI}}(y_u) \triangleq -\frac{\text{avoided customer interruption duration in } y_u}{\text{n}^{\text{o}} \text{ of system customer}} \tag{10b}$$

$$\Delta G_{\mathrm{CAIDI}}(y_u) \triangleq \frac{G_{\mathrm{SAIFI}}(y_u)\Delta G_{\mathrm{SAIDI}}(y_u) - G_{\mathrm{SAIDI}}\Delta G_{\mathrm{SAIFI}}(y_u)}{G_{\mathrm{SAIFI}}(y_u)\left(G_{\mathrm{SAIFI}}(y_u) + \Delta G_{\mathrm{SAIFI}}(y_u)\right)} \tag{10c}$$

$$\Delta G_{\mathrm{ASAI}}(y_u) \triangleq -\frac{\Delta G_{\mathrm{SAIDI}}(y_r)}{\text{n}^{\text{o}} \text{ of hours in } y_u} \tag{10d}$$

$$\Delta G_{\mathrm{ASUI}}(y_u) \triangleq -\Delta G_{\mathrm{ASAI}}(y_u) \tag{10e}$$

$$\Delta G_{\mathrm{ENS}}(y_u) \triangleq -\text{avoided energy not supplied in } y_u \tag{10f}$$

$$\Delta G_{\mathrm{AENS}}(y_u) \triangleq \frac{\Delta G_{\mathrm{ENS}}(y_u)}{\text{n}^{\text{o}} \text{ of system customers}}. \tag{10g}$$

Statistical information on load point service is acquired. At the end of each simulated year, load point indices are updated including failure rate λ [interruptions/yr], unavailability U [h/yr], mean time to repair r [h]. Frequency λ_v [occ./yr], annual duration U_v [h/yr], and mean time to solve r_v [h] inadequate delivered voltage conditions ($\mathrm{Voltage} < 0.95$ p.u. or $\mathrm{Voltage} > 1.05$ p.u.) are estimated as well. Following a security perspective, other indices (related with frequencies, annual durations, mean times) are accounted, for instance, regarding the interruptions which are avoided by DG islanded operation. Hence, frequency $(t^f_{\min}, t^f_{\max}, t^f_{ss}, f_{\min}, f_{\max}, f_{ss})$ and voltage $(t^v_{\min}, t^v_{\max}, t^v_{ss}, V_{\min}, V_{\max}, V_{ss})$ stability issues associated with islanding dynamics (see Fig. 1) are observed.

E. Implementation

The simulation platform was coded in JAVA language using, as a consequence, the object-oriented paradigm. Power system dynamic simulation was implemented using the fourth-order Runge-Kutta method from the Flanagan's Java Scientific Library [20]. Steady-state and dynamic analysis were validated using EUROSTAG [21] (version 4.3).

IV. Numerical Results

This section introduces a series of performance evaluations for the RBTS-BUS2-F1 [2] and for an actual distribution feeder from the South of Brazil. Underfrequency/overfrequency and undervoltage/overvoltage relays were set off in order to support the discussions. Furthermore, although the DG impact on the index histograms can be derived from (10a)–(10g), comparative numerical results for base cases and for cases with DG islanded operation are presented separately for didactic purposes. Finally, the simulations for cases with DG integration cover the complete set of evaluations presented in Section II.

A. RBTS-BUS2-F1

The RBTS-BUS2-F1 [2] was chosen for validation purposes. Several cases were evaluated not only by the combined discrete-continuous simulation (CDCS) approach, but also using an analytical technique [19]. Two of them, named here Case A and B, refer to scenarios where breaker and breaker-fuse protection are employed. Results for these cases from a customer-interruption point of view are presented in Tables I and II.

As expected, the results attained by the CDCS approach were very acceptable when compared with the results provided by the analytical technique. Further discussions about these (and other) results are presented in [19].

TABLE I
System Reliability Indices Using the Analytical and CDCS Approaches

Index	Case A			Case B		
	Analyt.	CDCS	β (%)	Analyt.	CDCS	β (%)
SAIFI	0.6250	0.6254	1.6085	0.2480	0.2455	1.9052
SAIDI	23.5646	22.6305	4.9558	4.1634	3.8905	4.9999
CAIDI	37.7034	36.1859	-	16.7886	15.8451	-
ASAI	0.9973	0.9974	0.0129	0.9995	0.9996	0.0022
ASUI	0.0027	0.0026	4.9558	0.0005	0.0004	4.9999
ENS	52.7759	51.0334	4.9974	9.3237	9.0016	3.3782
AENS	0.0809	0.0783	4.9974	0.0143	0.0138	3.3782

TABLE II
Load Point Reliability Indices for the CDCS Approach

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

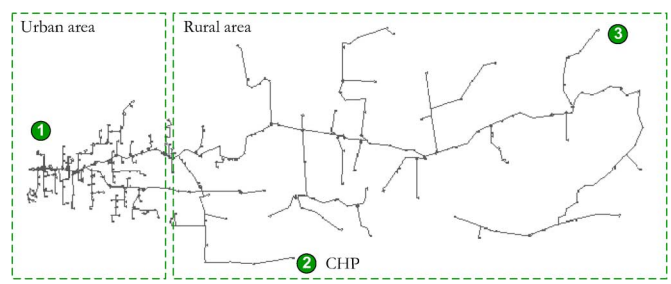

Fig. 3. Actual distribution feeder from the South of Brazil.

B. Actual Distribution Feeder

The proposed approach was applied to a real case related with a distribution feeder from the South of Brazil, illustrated in Fig. 3. The feeder covers the wide area of 166.33 km^2 providing electricity for 9780 registered clients ($5.36 + j1.84$ MVA peak). The service area is split into an urban area (on the left-hand side of the figure) and a rural area (on the right-hand side of the figure). Most of the clients dwell at the urban area which is small, reliable, and well-serviced. In contrast, the rural area supplies only 1865 registered clients ($1.03 + j0.34$ MVA peak) and is characterized by its large extension and low quality of service in certain periods of the year.

Network protection is composed of a substation breaker, a tie-breaker in between both areas, 10 sectionalizers and 41 lateral fuses. The case includes the connection of a CHP unit (1.2 MVA) in the rural area. Hence, the possibility of improving the service at the rural area through DG islanded operation is evaluated. For this accomplishment, the tie-breaker was set up to clear faults at the main trunk of the urban area as well. The CHP unit was modeled using a governor-steam turbine, IEEE DC1A exciter, and synchronous generator-forth order model (parameters are presented in the Appendix).

System reliability index mean values for a base case and for a case with DG islanded operation are presented in Table III. In addition, load point (LP) reliability indices are shown in

TABLE III
SYSTEM INDICES FOR THE ACTUAL DISTRIBUTION FEEDER

Index	Base case		with DG integration	
	CDCS	β (%)	CDCS	β (%)
SAIFI [occ./customer/yr]	1.1477	3.3002	0.9023	3.4604
SAIDI [h/customer/yr]	4.5423	4.6462	3.5695	4.9150
CAIDI [h/customer occ.]	3.9578	-	3.9558	-
ASAI	0.9995	0.0024	0.9996	0.0020
ASUI	0.0005	4.6462	0.0004	4.9150
ENS [MWh]	14.8319	4.7263	11.6390	4.9909
AENS [MWh/customer/yr]	0.0015	4.7263	0.0012	4.9909

TABLE IV
LOAD POINT INDICES FOR THE BASE CASE

LP	λ_i	U_i	r_i	λ_{v_i}	U_{v_i}	r_{v_i}
1	0.8381	3.2764	2.178	0.0000	0.0000	-
2	1.5666	6.1485	3.0631	0.0000	0.0000	-
3	2.7993	11.3534	3.7542	0.5379	0.5477	0.3912

TABLE V
LOAD POINT INDICES FOR THE CASE WITH DG ISLANDED OPERATION

LP	λ_i	U_i	r_i	λ_{v_i}	U_{v_i}	r_{v_i}
1	0.8381	3.2764	2.178	0.0000	0.0000	-
2	0.2782	1.0463	0.8894	0.0000	0.0000	-
3	1.511	6.2512	3.1342	0.0236	0.0843	0.0811

Tables IV and V for three particular nodes depicted in Fig. 3. These indices were obtained for 593 simulated years, attaining the same sequence of events ruled by (1) in both cases.

The results indicate that DG islanded operation can improve the performance index mean values and the quality of service provided by the utility. As expected, from a customer interruption point of view, the urban area was unaffected by DG integration. However, it must be noted that voltage profiles in this area improved considerably with the DG local production. On the other hand, the rural area benefited the most both from customer interruption and voltage profile points of view. The number of undervoltage occurrences at the end nodes reduced at the rural area as well. As a matter of fact, the frequency and duration of undervoltage events diminished 0.5143 occ./yr and 0.4634 h/yr, respectively, for the load point 3. The frequency and duration of inadequate service for the whole system improved from 3.6307 occ./yr and 2.0239 h/yr to 0.1855 occ./yr and 0.0978 h/yr, respectively.

Despite the narrow view provided by the performance index mean values, the approach make it possible to survey histograms related with these indices, and see how they are affected by DG islanded operation. This provides valuable information regarding the actual impact DG islanded operation can have on the system operation performance. For example, Figs. 4–6 exhibit the $\Delta G_{\mathrm{SAIFI}}(y_u)$, $\Delta G_{\mathrm{SAIDI}}(y_u)$, and $\Delta G_{\mathrm{ENS}}(y_u)$ values obtained through simulation. In the set of simulated years, the SAIFI highest reduction caused by DG islanded operation was 0.9535 occ./customer/yr, as indicated in Fig. 4. Similarly, DG islanded operation improved the SAIDI and ENS indices at most by 5.8126 h/customer/yr and 20.6134 MWh, respectively, as shown in Figs. 5 and 6. The simulations highlighted 1.4147 islanding attempts per year, from which only 8.03% were unsuccessful. This implies that the rural area became 91.97% more secure from faults in the main trunk of the urban area.

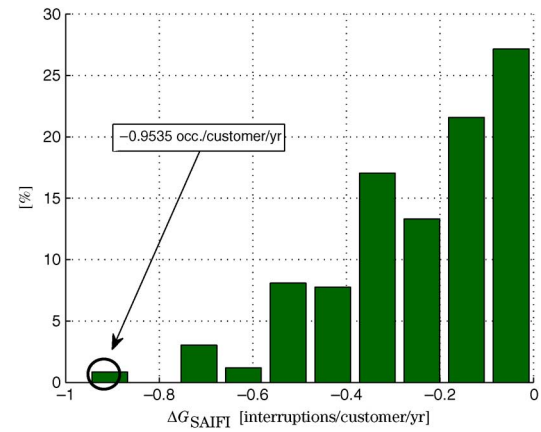

Fig. 4. Impact of DG islanded operation on the SAIFI.

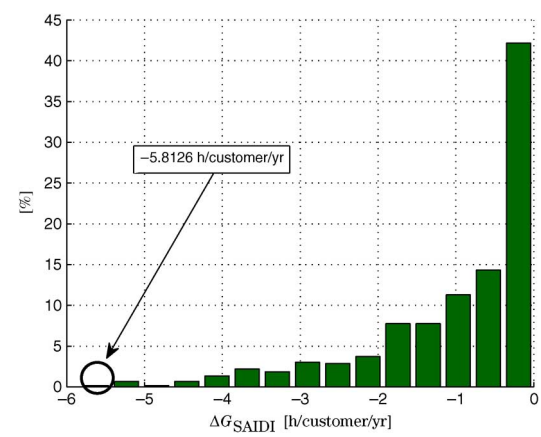

Fig. 5. Impact of DG islanded operation on the SAIDI.

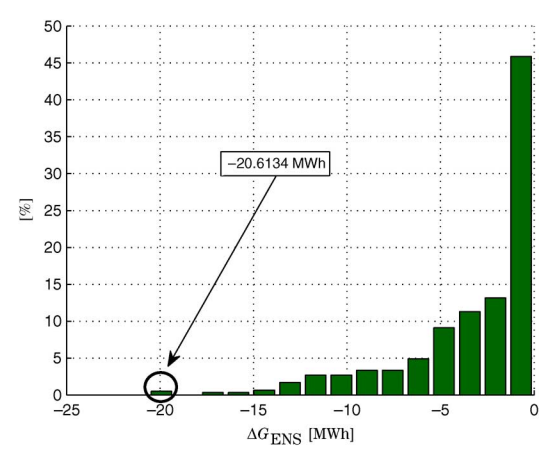

Fig. 6. Impact of DG islanded operation on the ENS index.

It must be emphasized that the improvements shown in Figs. 4–6 may not be completely achieved depending on relay operations. In fact, the more restricted the relay settings are the less successful the islandings are and, therefore, the fewer are the improvements attained by DG islanded operation. For instance, Fig. 7 illustrates the histograms for the minimum and maximum frequency excursions during successful islandings. In case an underfrequency relay is set to disconnect the DG on frequency values less than 0.98 p.u, only 61.64% of the

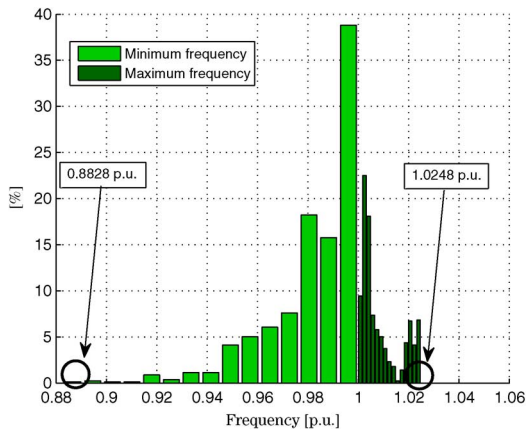

Fig. 7. Frequency excursions during successful islandings.

islandings would be successfully achieved, thus reducing the improvements on the performance indices. Therefore, using information on the islanding dynamics, the tie-breaker position and relay settings can be devised according to equipment constraints and possible/desired improvements on the performance indices. This seems an interesting approach when compared with tie-breaker allocation and relay settings that are only devised by scenario evaluations.

At last, it can be verified that most of the lowest values for minimum frequencies were obtained at time periods in which the rural area is importing power from the urban area. On the other hand, some of the highest values of maximum frequency as well as large voltage excursions are related with double contingencies as follows: 1) transition to the down state by a component in the urban area main trunk; 2) islanded operation is attained with frequency and voltage stabilization; 3) a component in an islanded branch transit to the down state, then causing fuse operation. These analyzes are possible due to the representation of adequacy and security aspects from the distribution system operation, where the object-oriented modeling allowed saving operation states of interest for further assessments.

V. Conclusions and Discussions

The ongoing integration of DERs has created several challenges for power distribution systems planning and operation. These challenges brought up the need to include aspects from adequacy and security, in an integrated way, on the distribution system assessments. However, differently from bulk power systems, distribution systems are mainly assessed from a customer-interruption perspective. Hence, this paper introduced the performance evaluation of distribution systems operation where adequacy and security aspects are taken into consideration and the actual impact of DG integration can be evaluated. For this accomplishment, a combined discrete-continuous simulation model was devised, using steady-state and dynamic analysis to assess the system operation. Local protection/control actions and centralized distribution/outage management system decisions can be evaluated using the simulation model as well.

A case study considering an actual distribution network revealed several insights about DG connection. With regards to the utility, DG integration provides an opportunity to improve the system service over several dimensions, as highlighted during a result analysis for a rural area of the case study. With regards to the DG's owner, the integration must be profitable. For both of these aspects, whether the DG is connected to weak points of the network, potential profit and technical benefits can be lost due to local high levels of interruption per year. Clearly, the utility should account for DG outages to identify in which extend DG can improve adequacy and security performance. Furthermore, the utility and DG's owner must be aware of the DG impact on system operation in order to establish a fair relationship between both parts according with the local regulation.

The integrated adequacy and security evaluation had shown to be an interesting way of obtaining synthetic information to devise protection/control settings, and assess their impact on the distribution system performance. As stated, through the simulation platform developed under an object-oriented paradigm, it is possible to save synthetic operation states in order to separately study critical operational conditions. Therefore, protection/control rules and remedial actions can be identified aiming at improving the operational procedures. The platform opens the way to evaluate the interdependencies between adequacy and security aspects of the distribution system performance, and to analyze smart grid solutions considering DER integration.

Appendix
DG Unit Parameters

The governor-steam turbine and IEEE DC1A exciter parameters are given in [22]. The synchronous generator-forth order model parameters are presented as follows: rated power: 1.2 MVA, rated voltage: 13.8 kV, inertia constant: 4.9 s, mechanical damping coefficient: 0%, stator resistance: 0 p.u., d-axis synchronous reactance: 2.73 p.u., q-axis synchronous reactance: 2.73 p.u., d-axis transient reactance: 0.27 p.u., q-axis transient reactance: 0.31 p.u., d-axis open-circuit time constant: 4.47 s, q-axis open-circuit time constant: 1.50 s.

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