Reliability Evaluation of Active Distribution Networks Including Islanding Dynamics

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***Abstract*—This paper presents a model that incorporates the impact of islanding dynamics in reliability evaluation of active distribution networks. In order to do that, the effects of the islanding process in terms of voltage and frequency variations, as well as the impact of component failures, are taken into consideration in the reliability assessment. The proposed model is based on a combination of probabilistic reliability evaluation with the dynamic simulation of the islanding process. The reliability evaluation is performed by Non-Sequential Monte Carlo simulation, while the islanding process is evaluated by a transient stability simulation with complete models of synchronous machine and its voltage and speed regulators. Results are obtained for a MV distribution test system, where the influence of dynamics in the survivability rate of islanding is incorporated into the calculation of traditional reliability indices, leading to more realistic results.**

***Index Terms*—Distributed generation, dynamic simulation, islanding, probabilistic reliability evaluation.**

I. Introduction

DISTRIBUTED Generation (DG) units, in the distribution network, can cause positive and negative impacts, especially when associated with sources of intermittent nature. The concept of Active Distribution Networks (ADN) has been introduced to maximize the benefits of DG. ADN are defined as self-managing distribution systems, where small and mid-sized generators are integrated into the distribution control centers, in order to provide an efficient, safe and reliable way to enable the operation of the so-called microgrids [1]. Microgrids, in turn, can be characterized as distribution networks containing distributed generators that can operate interconnected to the distribution network or, in cases of emergency, isolated, fed by their own resources.

The islanding of a portion of the distribution network can be considered one of the greatest present challenges in reliability studies of these systems. In practice, traditional reliability assessments address the impacts of failures of network components or DG in the system operation without exploiting the islanding process. In fact, the inclusion of these aspects in reliability studies is directly related to the dynamic characteristics of the system, given that in ADN, the presence of generating units imposes new restrictions on the islanding processes. The complexity involved can be compared with the islanding phenomena of bulk transmission systems. However, the degree of complexity and the stochastic data necessary to incorporate dynamic analysis into reliability studies are extremely high and, thus, it is necessary to explore alternative approaches.

Some papers have dealt with these issues. In [2], a study is presented on the reliability of transmission systems, including the probabilistic assessment associated with system security through the use of transient stability analysis. Two sets of indexes (static and dynamic) are presented to evaluate the consequences of dynamic phenomena. Reference [3] further develops the idea presented in [2]. In this case, the methodology uses traditional transmission reliability indices to present assessment calculations based on aspects of adequacy and security. Reference [4] evaluates the benefits, in terms of reliability, of ADN considering the intentional islanding, through an algorithm for optimal allocation of automatic isolator switches, in order to fully exploit the formation of islands. In [5], the idea of a survival index (SI) for the distribution system associated with the islanded operation is developed, but does not take dynamic aspects into account. The reference is based on a deterministic evaluation that incorporates analysis of bus voltages by means of a linear power flow and load-generation balance. Ref. [6] presents an approach for assessing the reliability of distribution systems related with adequacy and safety aspects, including islanded operations. The evaluation of the islanding dynamics includes issues related to frequency control. The two-state Markov model is used for the DG in Sequential Monte Carlo simulation (MCS). Finally, in [7], a study is presented where reliability analyses and assessments of the islanding dynamics are handled in a decoupled way. The survival of the island is assessed based on the occurrence of a default event in a predetermined point for different operating conditions. For cases in which the island survives, an assessment of reliability is made.

This paper presents a model for probabilistic reliability evaluation that incorporates the islanding process dynamics when evaluating if the islanded network will reach a new stable point of operation. It combines two studies within a joint approach by using the Non-Sequential MCS and transient stability simulation with representation of complete models of synchronous machines and their voltage and speed regulators. This approach provides more precise information on the compliance of available generation with loads after the separation of the systems. The conventional reliability indices are used to determine the

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severity of system failures, which now include the effect of the SI of the islanded network, obtained from the dynamic simulation. The proposed model is evaluated on a medium voltage distribution test system [8], with the addition of a Small Hydro Power Plant (SHPP) and different protection schemes. The results are compared with those obtained by the traditional approach to highlight the importance of considering islanding dynamics aspects in reliability evaluation.

II. Simulation of Islanding Dynamics

The main benefit associated with the adoption of islanded operation based on DG is reliability improvement. However, the increase in the number of generating units in distribution networks may degrade protection coordination, power quality, causes control mal functioning and eventually system instability, especially during the islanded operation.

Therefore, the challenge is to be able to change from the grid-connected mode of operation to the islanded mode without negatively impacting the voltage regulation, the frequency stability and the system reliability. This transition may require generating units or loads to be shed, for balancing purpose. After finishing the process of islanding, the island should be able to follow the load changes and regulate voltage and frequency, until the time to reconnect to the main grid. Reconnection can be done either manually or automatically, after the synchronizing conditions are met at the coupling circuit breaker. Once reconnected to the grid, generating units or loads could be restored.

After disturbances, the automatic separation of the distribution network into small islands with generators assuming partial or total loads requires an assessment whether the available resources are able to maintain adequate control of voltage and frequency in the island. The survivability of this network transition will depend on how large is the disturbance, how much is the power flowing through the decoupling circuit-breaker, and how fast the voltage and speed regulators are. The regulators play an important role in determining the dynamic performance of the network [9].

Two situations may occur when an island is formed: an island with insufficient generation or island with generation surplus. If the generation capacity is lower than the load, in the former situation, the frequency will drop. If there is not possibility of increasing the generation, the frequency will reach values that violate the levels established, e.g., in [10], and under frequency protection schemes will trip generating units, further worsening the problem. In this case, to avoid a total collapse of the island, under frequency load shedding schemes should be employed to stabilize the system frequency. On the other hand, in the latter situation the frequency will increase, forcing the speed regulator to decrease the mechanical power input. Normally, speed regulators are rate-of-change limited, what could imply the adoption of a generation unit trip scheme.

As previously mentioned, the system performance may be influenced also by the availability of reactive power sources in the island. Therefore, variations in reactive power may violate voltage limits that could lead the island also to a complete blackout. For these reasons, according to [9], the problem under study requires an analysis that is able to capture the effects of the fast dynamics of the generating units and their regulators during the transitional period, to be more realistic. In this work, the transitional period is analyzed by conventional electromechanical transient stability simulation considering full models of synchronous machines, automatic voltage regulators and governors. In other words, the idea is to identify if the frequency and voltage behaviors are transiently appropriate.

TABLE I
Distribution Network Reliability Indices

System Average Interruption Frequency	$SAIFI = \frac{\sum \lambda_L N_L}{\sum N_L}$
System Average Interruption Duration	$SAIDI = \frac{\sum U_L N_L}{\sum N_L}$
Expected Energy Not Supplied	$EENS = \sum CM_L U_L$

Although various non-conventional inverter-based generating technologies are used as DG nowadays, this paper only investigates the dynamic aspects of islanding considering synchronous machines (e.g., small hydros and small thermal plants). It is important to emphasize that the regulation mode of the generators must change from the grid-connected to the islanded operation mode when the system is islanded. The voltage regulation must change from the power factor control to the voltage control mode, and the speed regulation must change from the active power control to the speed control mode.

III. Reliability Evaluation Including Islanding Dynamics

There are currently more uncertainties related to the planning and operation of distribution systems with islanded operation than in the past, especially in relation to the survivability of the islanded system and also due to the use of generating units based on intermittent energy sources. Therefore, for this type of reliability assessment, it is necessary to make an analysis that takes into account the probabilistic nature of power systems, the influence of the intermittent nature of some alternative energy sources, the location and type of protection equipment and the short and mid-term dynamics associated with the formation of islands, as well as the load and generation shedding schemes to help, during transient periods, the system stability. Thus, to assess the reliability of the distribution network with islanded operation, it is important to assess the dynamic behavior of the system for failures that lead to islanding, in order to estimate the level of associated risks. In other words, the survival of the island necessarily implies that transient performance criteria have been met during the islanding process. The reliability indices chosen to capture the severity and importance of failures in the distribution system are shown in Table I, where λ_L is the failure rate, N_L is the number of consumers, $\mathrm{U_L}$ is the unavailability and CM_L is the demand of load point *L*.

The influence of islanding is incorporated into the reliability indices, which now includes the effects of the dynamic simulation associated with the switch from the connected to the islanded operation mode. These consequences are related to the network SI, calculated according to Equation (1).

$$SI = \frac{\text{Number of successful islandings}}{\text{Total number of islandings}} \quad (1)$$

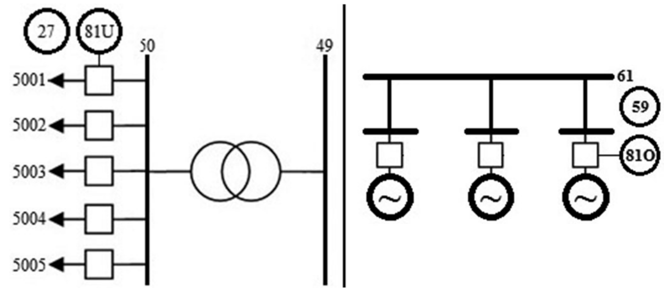

Fig. 1. Load and generation shedding schemes.

A successful islanding occurs when both voltage and frequency do not surpass their transient limits and the load-generation control is able to enforce the generation/load balance. It is noteworthy that the number of successful islandings can be associated or not with partial load and generation shedding, depending on the existence of load shedding schemes. Thus, the values of partial or total shedding occurred during the transient period, per load point, are incorporated into the indices calculation.

The algorithm used to assess the reliability of distribution systems, including the dynamics of the islanding process, consists of the following steps:

1) Sample the system states using Non-Sequential MCS. Generating units are modeled by multiple states stochastic models and network components by two-state models.
2) If during the states sampling process, failures in network components entail the islanding of part of the system, go to step 4. Otherwise, go to step 3.
3) Solve an AC power flow for the sampled state, in order to identify whether the system is able to meet the demand without violating operating constraints. The values of load shedding are stored. Go to step 5.
4) Run a transient stability simulation. Upon the detection of the islanded operation, DG control modes change from power factor control to voltage control mode in the voltage regulation loop, and from active power control to frequency control mode in the speed regulation loop, causing regulators to operate in the "islanded mode". If the island survives, the load shedding is then determined by the load-generation adjustment of the dynamic simulation. Otherwise, the whole load of the island is shed.
5) Calculate the annualized reliability indices based on the load shedding calculated for each sampled state.

The reliability indices are calculated based on the load shedding value calculated in step 4. If the island does not survive, the total load of the island is shed. If it survives, the load shedding value is the result of the load-generation adjustment strategy, which cuts the load and/or the generation gradually according to voltage and/or frequency variation during the transient simulation. Fig. 1 shows an example where the load is divided into five parts and the generation is composed of three units. The load shedding is implemented by modeling the relays 81U and 27, whereas the generation curtailment is implemented by relays 59 and 81O.

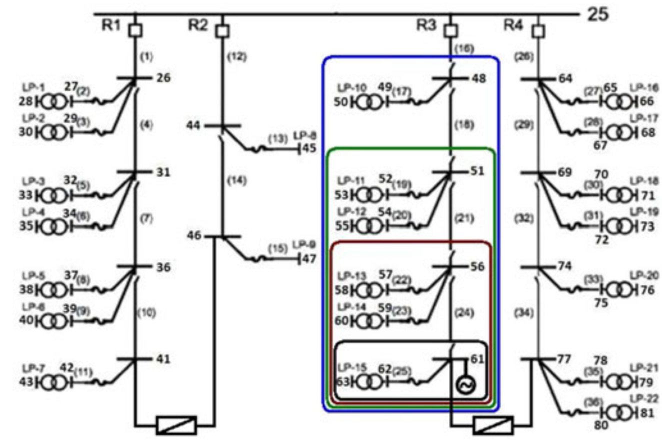

Fig. 2. RBTS-Bus2.

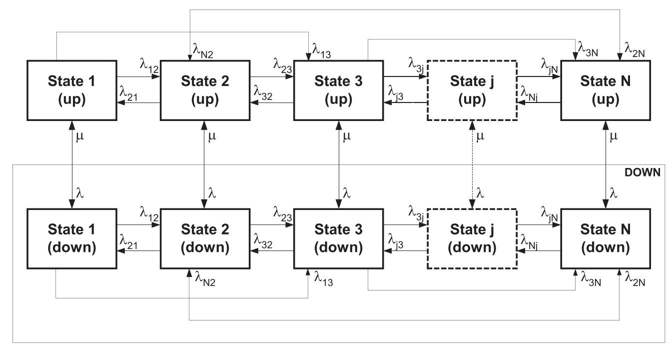

Fig. 3. SHPP Model.

IV. Results

The simulations of the proposed approach were made using the RBTS Bus2 system [8], shown in Fig. 2. The RBTS - Bus2 has four radial feeders and 20 MW of load. Feeder 3 has a load of 5.046 MW and will also be evaluated considering the possibility of islanded operation. The DG is a SHPP of 5.5 MW connected to Bus 61.

The SHPP is represented by a multiple state Markov model, with transition rates and average durations as shown in Fig. 3. This model combines the river inflow with the generator model [11], in order to incorporate the effects of inflow variation in power generation availability.

The river inflow is modeled as a stochastic process, where each state represents a different value taken from the inflow time series, and the transition rate from state *i* to state *j* is calculated by the transition rate λ_{ij} by (2):

$$\lambda_{ij} = \frac{N_{ij}}{D_i} \tag{2}$$

where N_{ij} is the number of transitions between states *i* and *j* and D_i is the duration of residence in state *i*, given by the sum of the *n* time intervals in which this state occurs, as (3):

$$D_i = \sum_{i=1}^{n} t_i \tag{3}$$

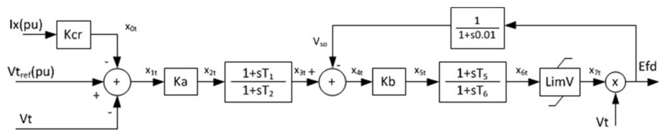

Fig. 4. Voltage regulator.

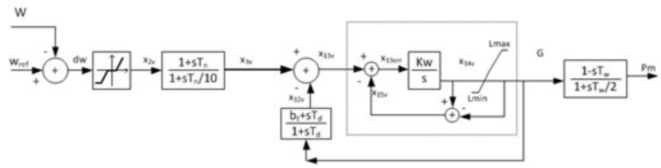

Fig. 5. Speed regulator.

TABLE II
LOAD POINT INDICES—WITHOUT DG

Protec. Scheme	λ [occurrences/year] LP10	LP11-12	LP13-14	LP15	U [h/year] LP10	LP11-12	LP13-14	LP15
SP	0.0563	0.1064	0.1501	0.2064	0.2815	0.3065	0.3253	0.4317
DP	0.0563	0.1064	0.1501	0.2064	0.0563	0.1064	0.1501	0.2064

TABLE III
SYSTEM INDICES—WITHOUT DG

Scheme	SAIFI [occ./year]	SAIDI [h/year]	EENS [kWh/year]
SP	0.0914	0.3003	1653.68
DP	0.0914	0.0914	648.75

The generator is modeled by the two states Markov model (up and down), as usually done for hydro generators [12].

Therefore, in Fig. 3, the inflow states are represented by states 1 to N and the transitions between them are represented by the rates λ_{ij}, while the transitions between the generator up and down states are represented by λ and μ. The down states can be aggregated into just one, producing a SHPP model with $N + 1$ different states: N up and one down.

To evaluate the dynamic performance of the islanding process, it was considered that the fault responsible for the islanding part of Feeder 3 is caused by a three-phase short-circuit, followed by the opening of the associated protection devices. Islanding may occur in case of failures in branches 16, 18, 21 or 24.

Regarding the protection devices, it was considered that, besides the R3 circuit-breaker, each branch of the main feeder is protected by automatic switches in two different configurations: single protection SP, corresponding to one automatic switch upstream each branch, and dual protection DP, corresponding to one automatic switch upstream and one downstream each branch.

Each load of Feeder 3 was divided into five parts, as shown in Fig. 1. The goal is to allow that, during the dynamic simulation, percentages of the load are shed according to frequency and voltage variations.

The reliability evaluation was performed using the *RelSim* computational model [13], which evaluates power systems reliability using either Sequential MCS or Non-Sequential MCS. The model can perform composite, generation and distribution systems reliability evaluations. The dynamic simulations were performed using the computational model *Simulight* [14]. Both models were integrated in a higher level framework to enable evaluating the dynamic influence on reliability evaluation.

Generators are represented by the complete subtransient models of synchronous machines, including their voltage and speed regulators. Figs. 4 and 5 show the block diagrams of the voltage and speed regulators considered in the simulations, respectively.

The hydro turbines of the SHPP are linearly modeled with its typical non-minimum phase characteristic and the excitation system is represented with a standard rotating brushless model [9]. As observed in [15], grid-connected DG typically operates in a voltage following mode, as their contracts do not accounts for voltage or reactive power support. Usually, the DG operates with a constant unitary power factor, giving no support to the system voltage. Grid-connected DG also operates in constant active power output, giving no support to frequency regulation. Therefore, in islanded operation the generators must change their control modes in order to give voltage and frequency regulation to the electrical island. If for some reason the islanded control modes are not present in the synchronous machine regulators, islanded operation is not possible, and it would be innocuous the consideration of dynamic models.

A. *Influence of Network Protection Configuration*

Table II shows the load point indices prior to considering DG, for network protection configurations SP and DP.

The DP scheme does not modify the λ values, because faults in any branch of Feeder 3 are eliminated by the actuation of R3 circuit-breaker, independently to single (SP) or double (DP) protection scheme adopted. However, the benefits of DP are observed in the U values. Since in the DP scheme the faulted branch can be completely isolated, no loads in the island depend on the branch repair time, but only on the restoration switching time. As a result, the reliability index U improves between 52% (LP15) and 80% (LP10), possibly justifying the economic impact of doubling the protection switchgear. Table III shows the system reliability indices for both protection schemes.

B. *Influence of Dynamic Effects of Islanding*

The influence of the dynamic effects of islanding in the reliability evaluation is quantified considering a 5.5 MW SHPP, the DP scheme, and considering the alternatives of having, 1, 2 or 3 generating units.

Table IV presents the results obtained by the traditional adequacy analysis, disregarding the dynamic effects of islanding, for the locations of faults that cause islanding.

From the results shown in Table IV, one can note that all states evaluated based on traditional studies of reliability resulted in

TABLE IV
ISLANDING OPERATION STATES—ADEQUACY ANALYSIS

Faulted Branch	Island Load (MW)	State	Sampled Generation (MW)	Load Shedding (%)	Island Survival
16	5.046	1	2.88	43	Partial
		2	3.24	36	Partial
		3	3.63	28	Partial
		4	4.16	18	Partial
		5	4.72	6	Partial
18	4.179	6	0.00	100	No
		7	1.59	62	Partial
		8	2.44	42	Partial
		9	3.47	17	Partial
		10	3.63	13	Partial
		11	4.72	0	Total
21	2.583	12	2.44	6	Partial
		13	3.24	0	Total
		14	3.84	0	Total
24	0.750	15	2.44	0	Total
		16	2.88	0	Total
		17	3.47	0	Total
		18	3.84	0	Total
		19	4.16	0	Total

TABLE V
ISLANDING OPERATION STATES—DYNAMIC SIMULATION

			SHPP number of generating units								
			1 UNIT			2 UNITS			3 UNITS		
Faulted Branch	State	Gener. (MW)	IS	Load Shed (%)	DG cutoff	IS	Load Shed (%)	DG cutoff	IS	Load Shed (%)	DG cutoff
16	1	2.88	N	100	1UN	N	100	2UN	N	100	3UN
	2	3.24	P	40	-	P	40	-	P	40	-
	3	3.63	P	40	-	P	40	-	P	40	-
	4	4.16	P	20	-	P	20	-	P	20	-
	5	4.72	P	20	-	P	20	-	P	20	-
18	6	0.00	N	100	-	N	100	2UN	N	100	3UN
	7	1.59	N	100	1UN	N	100	2UN	N	100	3UN
	8	2.44	N	100	1UN	N	100	2UN	N	100	3UN
	9	3.47	P	20	-	P	20	-	P	20	-
	10	3.63	P	20	-	P	20	-	P	20	-
	11	4.72	T	0	-	T	0	-	T	0	-
21	12	2.44	P	20	-	P	20	-	P	20	-
	13	3.24	N	100	1UN	P	40	1UN	P	20	1UN
	14	3.84	N	100	1UN	N	100	2UN	P	60	2UN
24	15	2.44	N	100	1UN	N	100	2UN	T	0	2UN
	16	2.88	N	100	1UN	N	100	2UN	N	100	3UN
	17	3.47	N	100	1UN	N	100	2UN	N	100	3UN
	18	3.84	N	100	1UN	N	100	2UN	N	100	3UN
	19	4.16	N	100	1UN	N	100	2UN	N	100	3UN

survival of the island, with the exception of state 6 (SHPP failed). The difference among the states is the amount of load shed that is calculated by the analysis of adequacy.

When the influence of the dynamic aspects is included in the analysis, the SI of the islands significantly reduces. Table V presents the results obtained including the dynamic effects of islanding, considering both load shedding and generator disconnection schemes, aimed at trying to increase the number of islanding success. With regard to the column IS ("Islanded Survival"), the initials N, P and T stand for No, Partial and Total, respectively.

TABLE VI
SURVIVABILITY INDEX PER FAULTED BRANCH

Case	16		18		21		24	
	SI_P	SI_T	SI_P	SI_T	SI_P	SI_T	SI_P	SI_T
Adequacy	100.0	0.0	66.6	16.6	33.3	66.6	0.0	100.0
Dynamic -1UN.	80.	0.0	33.3	16.6	33.3	0.0	0.0	0.0
Dynamic - 2UN.	80.	0.0	33.3	16.6	66.6	0.0	0.0	0.0
Dynamic - 3UN.	80.	0.0	33.3	16.6	100.0	0.0	0.0	20.

Table VI summarizes the SI index per faulted branch, $SI = SI_P + SI_T$, where SI_P and SI_T mean partial survivability index and total survivability index, representing the proportions of the island survivals where there is partial and no load shedding, respectively.

As one can notice, the consideration of the islanding dynamics decreases SI, even with partial load shedding scheme in operation. For example, for faults on branch 16, the successful islanded operation considering the dynamics is achieved in 4 out of 5 states regardless the number of generating units ($SI = 80\%$), while in traditional adequacy evaluation the island survives for 100% of the states. In state 1 (2.88 MW of generation and fault on branch 16) all load in the island is shed because the automatic load and generation shedding schemes are not able to guarantee the island formation.

Figs. 6 (frequency) and 7 (DG terminal voltage) show a sequence of events along the time simulation, where it can be noted the actuations of the underfrequency (81U) and overvoltage (59) relays. In this simulation, performed with 2 generating units, 60% of the load is shed by relay 81U, bringing the frequency to the permissible range established by the Brazilian regulating agency [10]. However, this causes the voltage to be over 1.1 p.u. for more than 1 s, making relay 59 to trip 1 generating unit. After unit tripping, the frequency sags again and relay 81U sheds an extra 20% of the load. Another overvoltage follows making relay 59 to trip the remaining generating unit, and the island undergoes a complete blackout.

For faults on branch 18, with the exception of state 11 where the generation is 4.72 MW, all states are associated with the generation level being lower than the load. Therefore, an automatic underfrequency load shedding scheme is needed. Consequently, differences up to 50% in SI_P can be observed between the adequacy and the dynamic analysis.

The adequacy evaluation also underestimates the effects of faults on branch 21. The dynamic simulations for faults on this branch show that the SHPP is able to feed the load, fully or partially, when it is generating 2.44 MW (state 12). In the other states, the islanding non survival yields a full shedding of loads LP13, LP14 and LP15, which confronts with the adequacy analysis, where there is no load shed at all. This is reflected in the reduction of SI_T from 66.6% to 0%. It is worth noting that for the generation surplus states with 3.24 and 3.84 MW (states 13 and 14, respectively), the automatic unit generation tripping

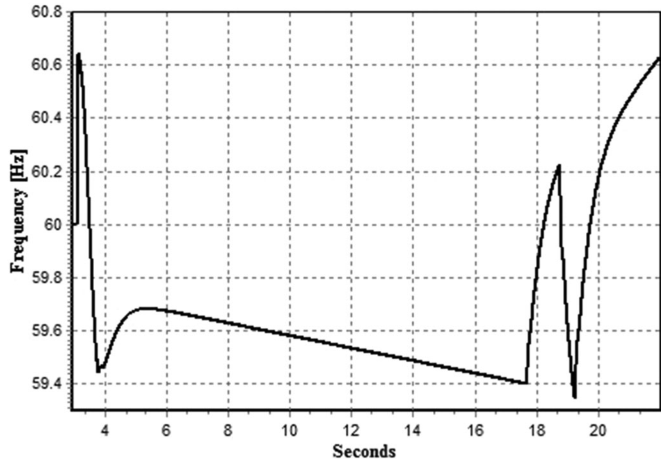

Fig. 6. Frequency–Fault on Branch 16 – 2 units – 2.88 MW.

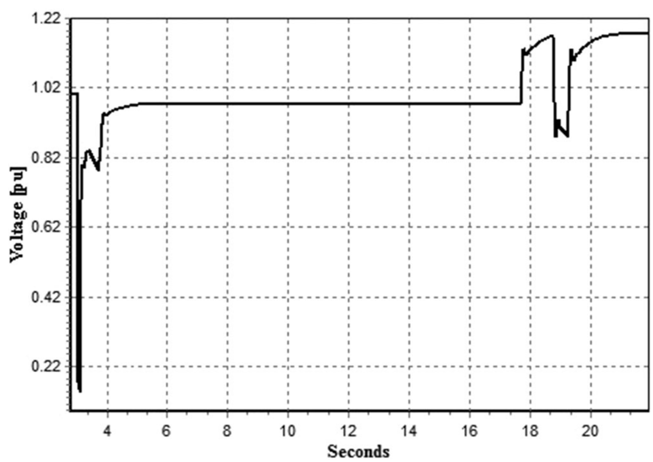

Fig. 7. Voltage–Fault on Branch 16 – 2 units – 2.88 MW.

scheme permits a partial islanding survival. For example, in the 3.84 MW-generation state, islanding is not possible in configurations with 1 or 2 generating units in operation. Whereas, in the configuration with 3 units islanding is possible with a 60% load shed and 2 generating units trip.

Finally, for faults on branch 24, the differences between the adequacy and the dynamic analysis are even more evident. Since the generation is considerably higher than the load, in the adequacy analysis islanding is always possible. On the other hand, in the dynamic simulation analysis, due to the large pre-fault mismatches between generation and load, the generation trip scheme and the rate-of-change-limited speed regulators are not able to timely reduce generation in order to guarantee frequency stability. Exception is made in state 15, where generation is 2.44 MW and 3 generating units are in service. For this successful case, Figs. 8 and 9 show the frequency and the terminal voltage, respectively. Note that both frequency and voltage accommodate in acceptable values in reasonable time, guaranteeing the islanding formation without load shedding. Frequency stability is achieved with 2 generating units trip by relay 59.

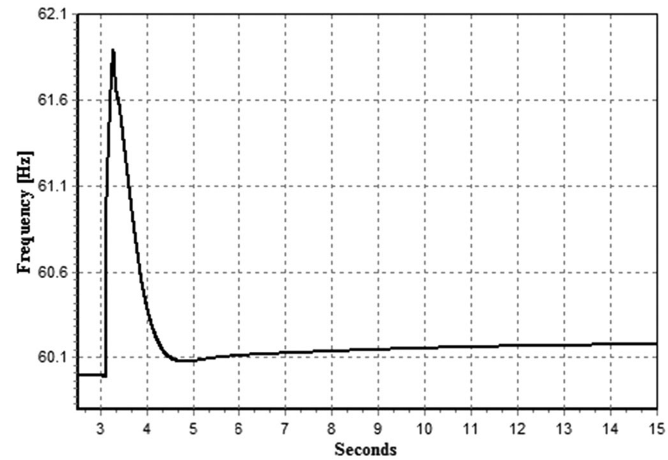

Fig. 8. Frequency–Fault on Branch 24 – 3 units – 2.44 MW.

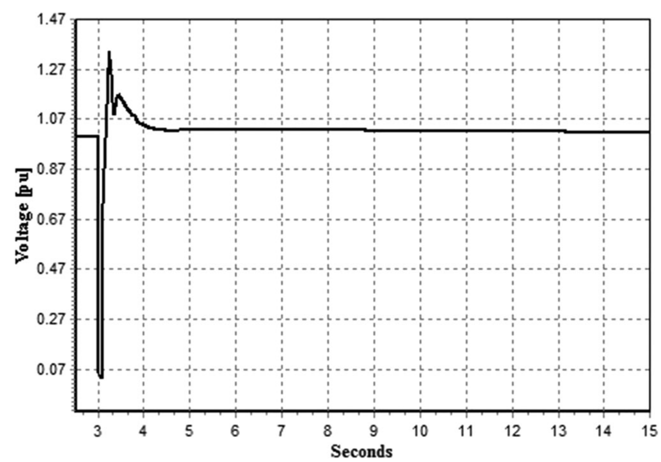

Fig. 9. Voltage–Fault on Branch 24 – 3 units – 2.44 MW.

TABLE VII
LOAD POINTS RELIABILITY INDICES

	λ [occurrences/year]				EENS [kWh/year]				
	LP10	LP11/12	LP13/14	LP15	LP10	LP11	LP12	LP13/14	LP15
Ad-1UN	0.056	0.093	0.100	0.100	13.3	29.3	24.7	31.3	25.6
Ad-2UN	0.056	0.093	0.100	0.100	13.3	27.2	22.9	29.1	23.8
Ad-3UN	0.056	0.093	0.100	0.100	13.3	26.5	22.3	28.4	23.2
Dy-1UN	0.056	0.093	0.137	0.193	21.7	45.6	38.3	83.8	110.7
Dy-2UN	0.056	0.093	0.137	0.193	21.7	45.6	38.3	70.0	99.5
Dy-3UN	0.056	0.093	0.137	0.187	21.7	45.6	38.3	60.8	87.3

C. Influence on Reliability Indices

The reliability indices per load point of feeder 3 incorporating the dynamic aspects of islanding are shown in Table VII.

The λ values for load points LP10 and LP11/12 are the same in both adequacy and dynamics analysis, remaining 0.0563 and 0.0938 occurrences/year, respectively. Since load LP10 benefits from islanded operation only for faults on branch 16 and the associated $\mathrm{SI_T}$ is null, the failure rate does not alter, in both

TABLE VIII
SYSTEM RELIABILITY INDICES

	SAIFI [occ./year]	SAIDI [h/year]	EENS [kWh/year]
Dyn-1UN.	0.0831	0.0831	383.80
Dyn-2UN.	0.0831	0.0831	345.00
Dyn-3UN.	0.0830	0.0830	314.50

TABLE IX
SYSTEM RELIABILITY INDICES—SHPP 9 MW

	SAIFI [occ./year]	SAIDI [h/year]	EENS [kWh/year]
Dyn-1UN.	0.0727	0.0727	451.2
Dyn-2UN.	0.0722	0.0722	240.9
Dyn-3UN.	0.0643	0.0643	233.7

adequacy and dynamic analysis. With respect to loads LP11/12, a successful island occurs in the sampled states where the generation is higher than the load, and there is no load shedding. For those cases, the results of the adequacy analysis are identical to the ones from the dynamic analysis, which justifies the same values for λ.

With respect to loads LP13/14 and LP15, there are differences between the failure rates from the adequacy and dynamic analysis, due to the islanding survival aspects already explained. It can be observed that the obtained failure rate when considering the dynamic analysis is more sensitive to the generating units in operation.

For the EENS evaluation, besides the $\mathrm{SI_T}$, it is also important to observe the $\mathrm{SI_P}$, since the partial load shed has a direct impact in the index. Faults occurring towards the feeder end are associated with a higher probability of having generation significantly higher than load. The islanding formation in those circumstances, even considering the automatic generation trip scheme, may fail because the machine regulators are not able to regulate frequency or voltage in due time. This is reflected in a higher value for the EENS when compared to the value of the index obtained from the adequacy analysis only. For example, in the case with 3 generating units in operation, the increase of the EENS for the load point LP15 from 23.2 kWh (adequacy) to 87.3 kWh (dynamic) is a consequence of the low SI for faults on branches 18 and 21 when the dynamic analysis is considered.

Table VIII shows the system reliability indices considering the dynamic analysis. The objective is to quantify the systemic impact of the islanded operation in the reliability of feeder 3.

The presence of the SHPP is responsible for a reduction in the indices, not only considering the SP scheme, but also when considering the DP scheme, shown in Table III. This betterment is directly associated with the islanded operation. However, it is worth noting that replacing the SP scheme with the DP scheme yields a reduction of 69% in SAIDI and 61% in the EENS. The possibility of considering the SHPP in islanded operation, yields additional reductions of 9% in SAIFI, 9% in SAIDI and 51% in EENS, e.g., for the case of 3 generating units in operation. Therefore, the replacement of the protection scheme is more significant than the islanding to improve SAIDI. On the other hand, for EENS, the islanding has a positive impact in the reliability as significant as the protection scheme enhancement.

For the frequency and duration indices (SAIFI and SAIDI), the consideration of 2 generating units does not guarantee better results when compared with only 1 unit. The consideration of 3 units provides a small reduction in the indices. The availability of more generation units in operation allows progressive reduction in EENS, owing the more possibilities of generation tripping.

D. *Influence of DG Capacity*

The impact of DG islanding dynamics in the probabilistic reliability evaluation of distribution networks is directly related to the pre-fault system operating condition. For this reason, to better quantify the influence of the mismatch between generation and load during the island formation and the consequences reflected in the reliability indices, a new set of simulations was performed by considering a SHPP with a larger capacity of 9.0 MW. The new reliability indices considering the dynamic analysis are given in Table IX.

In this case, the benefits obtained by having a larger number of generating units can be observed in all indices. It should be noted that in comparing the indices obtained with the 9 MW-capacity SHPP and the 5.5 MW-capacity SHPP, the EENS is better when considering the latter, contrary to expected with traditional reliability analysis. The reason for this outcome is explained by the better balancing conditions sampled in the non-sequential MSG for the 5.5 MW-capacity SHPP case, where the curtailment schemes are more effective resulting in less load shedding. Since the mismatches between generation and load for the 5.5 MW case are smaller, the regulating systems are also more effective in responding fast enough to avoid load shedding in the cases where the generation level is higher than the load.

Even though for the other cases the indices are reduced, these reductions are less than 10% even for a 63.6% increase in generation capacity. Therefore, the investment in higher generation capacity does not reflect proportionally in a better reliability, since the island survival can be impaired due to larger generation/load unbalances in the pre-fault operating condition. This result, once again, reinforces the importance of the proposed model for reliability analysis when associated with islanded operation of distribution networks.

E. *Influence of Load Level*

In order to evaluate the influence of the load level on the success of the islanding process, a final set of simulations was performed by considering the total load of Feeder 3 as 3.106 MW (61.55% of the regular load). The light load reliability indices considering the dynamic analysis are given in Table X.

For the light load evaluation, the best results for the SAIFI and SAIDI indices are obtained with the 9 MW-capacity SHPP with 2 generating units. However, for 1 or 3 units, these indices are better for the 5.5 MW-capacity SHPP than for the 9 MW-capacity SHPP.

As for the EENS index, the best value is obtained for the islanded operation with the 5.5 MW-capacity SHPP with 2

TABLE X
SYSTEM RELIABILITY INDICES—LIGHT LOAD

DG Capacity		SAIFI [occ./year]	SAIDI [h/year]	EENS [kWh/year]
5.5 MW	Dyn-1UN.	0.0727	0.0727	277.0
	Dyn-2UN.	0.0722	0.0722	147.7
	Dyn-3UN.	0.0727	0.0727	154.9
9 MW	Dyn-1UN.	0.0831	0.0831	366.4
	Dyn-2UN.	0.0602	0.0602	276.6
	Dyn-3UN.	0.0832	0.0832	324.0

generating units. Indeed, the EENS indices obtained with the 9 MW-capacity SHPP are always worse than those obtained for the 5.5 MW-capacity SHPP, what again contradicts the results that would be expected by using the adequacy-based reliability evaluation.

V. Conclusion

This paper presented a model that incorporates the effect of the dynamics of islanding in assessing the reliability of distribution systems with islanded operation. The effects of the islanding process in the voltage and frequency of the islanded system were presented. The results show that, in some cases, the island cannot survive the process and, therefore, the conventional reliability evaluation is not sufficient for a proper assessment. Additionally, it is observed that, depending on the case, the island may be subject to wide variations in voltage and frequency. Thus, protection and control schemes are really important to ensure the quality of supply. The use of models that adequately address the intermittent energy sources within the probabilistic assessment is of great importance for capturing the states of distributed generation, since these units do not have the same availability as conventional generators.

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