Comparative Analysis Between Synchronous and Induction Machines for Distributed Generation Applications

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***Abstract*—This paper presents a detailed comparative analysis between synchronous and induction machines for distributed generation applications. The impacts of these generators on the distribution network performance are determined and compared by using computational simulations. The technical factors analyzed are steady-state voltage profile, electrical power losses, voltage stability, transient stability, voltage sags during unbalanced faults, and short-circuit currents. The results showed that the best technical choice depends on the network characteristics, i.e., the main factors that may limit the penetration level of distributed generation.**

***Index Terms*—Distributed generation, induction generator, short-circuit currents, steady-state voltage profile, synchronous generator, transient stability, voltage sag, voltage stability.**

I. Introduction

RECENTLY, the interest in distributed generation has considerably increased due to market deregulation, technological advances, governmental incentives, and environment impact concerns [1]–[3]. At present, most distributed generation installations employ induction and synchronous machines, which can be used in thermal, hydro, and wind generation plants [3]. Although such technologies are well known, there is no consensus on what is the best choice under a wide technical perspective.

Based on these facts, it is important to understand the different impacts provoked by this choice on several technical factors. This paper presents research results considering distinct scenarios and technical factors. The factors analyzed are steady-state voltage profile, electrical power losses, voltage stability, transient stability, voltage sags during unbalanced faults, and short-circuit currents. These factors were investigated by using different kinds of power system analysis programs, e.g., load flow programs, transient stability programs, and electromagnetic transient programs. Simulation results showed that the choice should be done considering the main factors that may limit the amount of distributed generation in a given system. The results can be a useful technical guide for utility engineers, and energy producers decide which machine is more suitable, taking into account the main characteristics of their network.

This paper is organized as follows. Section II describes the network component models employed in this paper. The impacts on the steady-state voltage profile are addressed in Section III. Section IV discusses the electrical power losses. The impacts on the system voltage stability margin are determined in Section V. Section VI presents the results considering transient stability. Voltage sags during unbalanced faults are analyzed in Section VII. The short-circuit currents supplied by the generators during faults are investigated in Section VIII. Finally, Section IX summarizes the main conclusions.

II. Network Component Models

In this paper, all network components were represented by three-phase models. In the studies about steady-state voltage profiles, power losses, and stability, the network variables were represented by phasors. Such analyses were conducted by using a load flow and a transient stability program. On the other hand, in the studies about voltage sags and short-circuit currents, the network variables were represented by instantaneous values. These cases were analyzed by using an electromagnetic transient program. The simulation package adopted was the SimPowerSystems for use with Matlab/Simulink, version 2.3 [4].

In all cases, the distribution network feeders were represented by a series *RL* impedance, because they can be considered short-lines, and the transformers were modeled by employing the T circuit. In the steady-state studies, the loads were represented by constant power models, as is usual in load flow programs, whereas in the dynamic studies, active power loads were represented by constant current models and reactive power loads were represented by constant impedance models, as recommended in [5].

A. Induction Generators

Although most induction generators in operation are employed in wind power plants [3], [6], such machines have also been used in medium-size hydro and thermal plants [3], [7]–[9]. Therefore, in order to keep the results as generic as possible, the mechanical torque was considered constant, i.e., the regulator and prime mover dynamics were neglected. The squirrel-cage rotor induction generator was represented by

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a sixth-order model in the electromagnetic transient studies, which was reduced for a fourth-order model in the transient stability simulations [10]. In all cases simulated, part of the reactive power consumed by the generator was locally supplied by capacitors installed at the terminal of the machine, whose compensation capacity was adopted equal to $1/3$ of the machine capability, as is usual in this case [3].

B. Synchronous Generators

At present, most distributed generation systems employ synchronous generators, which can be used in thermal, hydro, or wind power plants. In the electromagnetic transient simulations, the synchronous generators were represented by an eight-order model, which was reduced to a sixth-order model in the transient stability simulations [10]. Usually, synchronous generators connected to distribution networks are operated as constant active power sources, so that they do no take part in the system frequency control. Therefore, in this paper, the mechanical power was considered constant, i.e., the regulator and prime mover dynamics were neglected. Similar to the induction generator case, this option also leads to results that are more generic. In addition, typically, there are two different modes of controlling the excitation system of distributed synchronous generators. One aims to maintain constant the terminal voltage (voltage control mode), and the other one aims to maintain constant the power factor (power factor control mode) [3], [11]. Power factor control mode is usually adopted by independent producers to maximize the active power production [3]. In consequence, unitary power factor operation is adopted. Thus, both forms of control are employed in this paper. In the voltage regulator cases, the controller set point was fixed at 1 p.u., whereas in the power factor regulator cases, the controller set point was fixed at 1 (unitary power factor). A functional description of excitation systems acting as a voltage or power factor regulator is provided in [11].

III. Steady-State Voltage Profile

Voltage violations due to presence of distributed generators can considerably limit the amount of power supplied by these generators in distribution networks [3], [12]. Before installing (or allowing the installation of) a distributed generator, utility engineers must analyze the worst operating scenarios to guarantee that the network voltages will not be adversely affected by the generators. These scenarios are characterized by [12] the following:

- no generation and maximum demand;
- maximum generation and maximum demand;
- maximum generation and minimum demand.

In this paper, it was considered that the minimum demand corresponds to 10% of the maximum demand. Moreover, the allowable steady-state voltage variation was adopted equal to $\pm 5\%$ ($0.95/1.05$ p.u.). The single-line diagram of the system used in this section is shown in Fig. 1. Such network consists of a 132-kV, 60-Hz subtransmission system with short-circuit level of 1000 MVA, represented by a Thevenin equivalent (Sub), which feeds a 33-kV distribution system through one 132/33-kV, Δ/Yg transformer. The feeder X/R ratio is 4.3. The

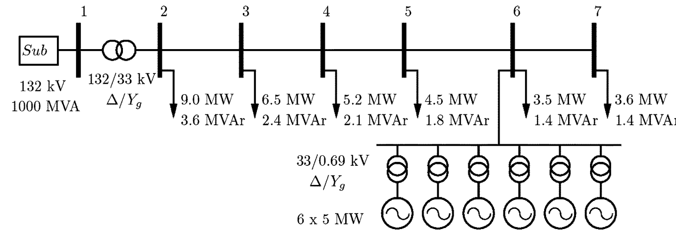


Fig. 1. Single-line diagram of system 1.

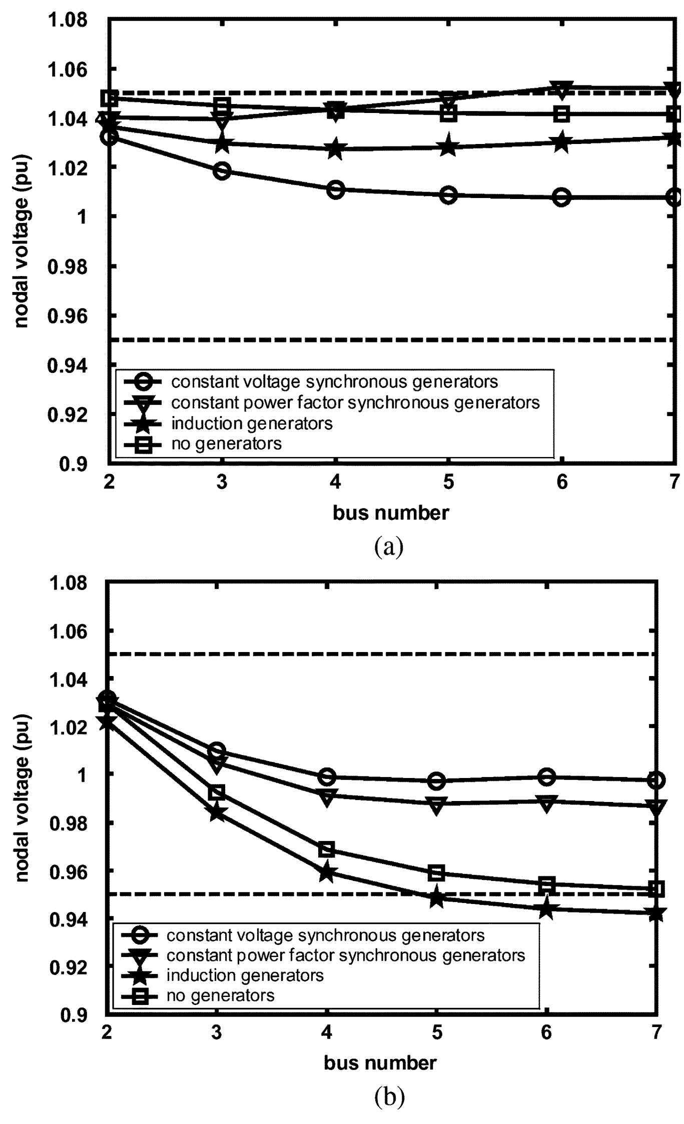


Fig. 2. Steady-state voltage profile for different generators. (a) Minimum demand (10%). (b) Maximum demand (100%).

substation transformer tap was adjusted to maintain the nodal voltage in all buses within the allowable range for minimum and maximum demand considering the case without generator ($\text{tap} = 1.05\%$). Assume that an independent producer wishes to install six 5-MW distributed generators at bus 8 through dedicated transformers. For this situation, simulation studies were carried out to verify what kind of generator allows such installation under a steady-state voltage profile viewpoint.

The network voltage profile considering maximum and minimum demand and different generators is presented in Fig. 2.

TABLE I
GENERATOR TERMINAL VOLTAGES

generator type	minimum demand terminal voltage (pu)	maximum demand terminal voltage (pu)
constant voltage synchronous generator	1.0000	1.0000
constant power factor synchronous generator	1.0514	0.9876
induction generator	1.0286	0.9359

TABLE II
MAXIMUM ALLOWABLE NUMBER OF AC GENERATORS CONSIDERING STEADY-STATE VOLTAGE PROFILE VIOLATIONS

generator type	maximum number of generators	limiting factor
constant voltage synchronous generator	6	no problem
constant power factor synchronous generator	2	superior limit violation during minimum demand
induction generator	5	inferior limit violation during maximum demand

In this figure, the allowable values of nodal voltage (0.95/1.05 p.u.) are represented by horizontal dotted lines. In this case, it was considered that the six generators were injecting nominal active power (5 MW) into the network. It can be seen that some nodal voltages will violate the superior limit during minimum demand if a constant power factor synchronous generator is adopted, whereas, if induction generators are chosen, then some nodal voltages will be below the inferior limit during maximum demand. On the other hand, if constant voltage synchronous generators are employed, then the nodal voltages will remain within the allowable range for both demand cases. In this case, the power factor of the synchronous generator varied from 0.986 inductive to 0.990 capacitive for the minimum and maximum demand values, respectively. The generator terminal voltages are shown in Table I.

In order to determine the maximum number of ac generators that can be installed without steady-state voltage violations, the nodal voltages were calculated for each generator added in a one-by-one basis (from one to six generators). The results are presented in Table II. If the constant voltage synchronous generator is selected, it is possible to install the six generators without steady-state voltage violations. On the other hand, in the other cases, there will be voltage violations. The third column in Table II shows what will be the problem if a new generator is installed. The most restrictive case is related to the constant power factor synchronous generator.

A. Steady-State Voltage Variation Due to Generator Disconnection

One important issue related to steady-state voltage profile is to determine how much the nodal voltages will change when the distributed generators are suddenly disconnected, because the actuation time of voltage controllers in distribution systems, e.g., under load tap change transformers, is slow [3]. Thus, network operators want such variations to be as small as possible. In order to analyze this issue, the following global index

TABLE III
STEADY-STATE VOLTAGE VARIATION DUE TO GENERATOR DISCONNECTION (V_{I1})

generator type	V_{I1} (%) minimum demand	V_{I1} (%) maximum demand
constant voltage synchronous generator	2.79	3.08
constant power factor synchronous generator	0.61	2.29
induction generator	1.23	0.97

TABLE IV
VOLTAGE REGULATION (V_{I2})

generator type	V_{I2} (%)
constant voltage synchronous generator	0.88
constant power factor synchronous generator	4.77
induction generator	6.40
without generators	6.74

can be utilized to quantify the impact provoked by generator disconnections:

$$V_{I1} = \frac{1}{\mathrm{nb}} \frac{\sum_{i=1}^{\mathrm{nb}} \|V_i^g - V_i^n\| \times 100}{\sum_{i=1}^{\mathrm{nb}} V_i^n} \tag{1}$$

where nb is the total number of buses, $V_i{}^g$ is the magnitude of the nodal voltage of bus i in the presence of distributed generators, and V_i^n is the magnitude of the nodal voltage of bus i without distributed generators.

The results are summarized in Table III considering that the six generators are tripped off during maximum and minimum demand. It can be observed that the cases with induction generators or constant power factor synchronous generators lead to the smallest variations of the voltage. In the case of constant power factor synchronous generators, the generators do not supply or consume reactive power. Therefore, the difference of the distribution of reactive current between this case and the case without generators is small. Thus, when the generators are disconnected, the steady-state operating point do not change considerably. Similarly, in the case of induction generators, the generators practically do not inject or consume reactive power as well, remembering that part of the reactive power consumed by the induction generator is locally supplied by capacitors. On the other hand, in the case of constant voltage synchronous generators, the voltage variation is larger. In this situation, the amount of reactive power injected/supplied by the generators is significant. Thus, the steady-state operating point changes considerably after the disconnection of the generators.

B. Steady-State Voltage Regulation

Another important issue related to steady-state voltage is the regulation characteristic of the network, i.e., how much the nodal voltages change between maximum and minimum demand cases. It is desirable that the nodal voltages change as little as possible during load variations. The following global index can be employed to analyze this question:

$$V_{I2} = \frac{1}{\mathrm{nb}} \sum_{i=1}^{\mathrm{nb}} \left\| V_i^{\max} - V_i^{\min} \right\| \times 100 \tag{2}$$

TABLE V
ACTIVE POWER LOSSES (IN MEGAWATTS)

maximum demand (losses without generation = 0.7608 MW)			
number of generators	constant voltage synchronous generator	constant power factor synchronous generator	induction generator
1	0.5016	0.5453	0.5666
2	0.3774	0.4190	0.4557
3	0.3389	0.3758	0.4258
4	0.3784	0.4119	0.4770
5	0.4928	0.5254	0.6119
6	0.6798	0.7161	1.0132
minimum demand (losses without generation = 0.2107 MW)			
number of generators	constant voltage synchronous generator	constant power factor synchronous generator	induction generator
1	0.2524	0.2348	0.2343
2	0.3663	0.3262	0.3229
3	0.5499	0.4839	0.4763
4	0.8032	0.7080	0.6959
5	1.1265	0.9998	0.9845
6	1.5189	1.3619	1.4963

where $V_i^{\max}$ is the magnitude of the nodal voltage of bus i during maximum demand, and $V_i^{\min}$ is the magnitude of the nodal voltage of bus i during minimum demand.

The results are shown in Table IV. It can be seen that the usage of constant voltage synchronous generators leads to the best characteristic of voltage regulation (minimal variation). Such a fact occurs because the generators' reactive power output changes according to the load variation, resulting in a good voltage regulation. On the other hand, the usage of constant power factor synchronous generators or induction generators implies the worst voltage regulations (maximal variation), because these machines are not voltage self-regulated.

IV. ACTIVE POWER LOSSES

Although active power losses are not a technical factor that can limit the amount of distributed generation, it is an important economical factor [13], [14]. Therefore, in this section, the electrical losses of the system shown in Fig. 1 are determined for different scenarios of generation and load. The losses were calculated by using the following equation:

$$P_{\text{losses}} = P_{\text{substation}} + P_{\text{generator}} - \sum P_{\text{loads}} \tag{3}$$

where P_{losses} is the total active power losses of the system, $P_{\text{substation}}$ is the active power supplied by the substation, $P_{\text{generator}}$ is the active power supplied by the generators, and $\sum P_{\text{loads}}$ is the total active power consumed by the loads. The results are presented in Table V. The values of the active power losses for the case without distributed generators are also shown. The following facts can be observed.

1) Maximum Demand: It can be verified that during heavy load, typically, the installation of distributed generators leads to a decrease of the electrical losses. Initially, each generator added implies a reduction of the losses. However, after the third generator is installed, then, if a new generator is connected to the network, the losses start to increase. This fact indicates that the loss improvement saturation point has been reached. This characteristic has already been reported in other works [15]. The adoption of constant voltage synchronous generators leads to the largest reduction of the losses because this generator supplies the active and reactive loads locally, decreasing the magnitude of the current in the feeders. On the other hand, the usage of induction generators does not cause a great reduction in the active power losses; indeed, when the six generators are operating, the system losses increase. In this case, the generators consume reactive power from the network, rising the magnitude of the currents circulating in the feeders. The losses behavior in the presence of constant power factor synchronous generators is situated between the other two cases, because these generators supply locally active power but do not provide or consume reactive power.

2) Minimum Demand: In this case, typically, the presence of the generators increases the active power losses, independent of the generator employed. In this situation, a large amount of active power generated is exported to the subtransmission system, influencing adversely the distribution system losses. The usage of the constant voltage synchronous generators can be related to the worst case under losses viewpoint because, in order to keep the terminal voltage at 1 p.u., the generator consumes a large amount of reactive power.

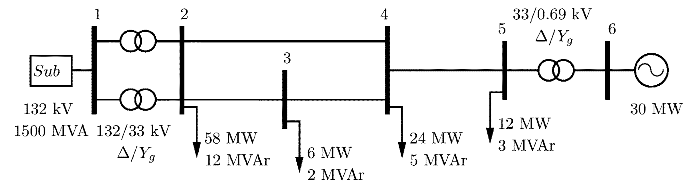


Fig. 3. Single-line diagram of system 2.

V. VOLTAGE STABILITY

Normally, it is expected that the installation of generators close to the loads leads to a gain in the system voltage stability margin. However, the impact on the margin depends on the reactive power exchanged between the generator and the network, which is different from distinct technologies. Therefore, in this section, the PV curves of the system shown in Fig. 3, which is derived from [3], are analyzed. Such network comprises a 132-kV, 60-Hz subtransmission system with short-circuit level of 1500 MVA, represented by a Thevenin equivalent (Sub), which feeds a 33-kV distribution system through two 132/33-kV, Δ/Yg transformers. An ac generator with capacity of 30 MVA is connected at bus 6, which is connected to the network through a 33/0.69-kV, Δ/Yg transformer. This machine can represent one generator in a thermal generation plant as well as an equivalent of various generators in a wind or small-hydro generation plant. In some cases, such a machine was simulated as an induction generator and in other ones as a synchronous generator. The PV curves were obtained by varying the active and reactive loads and keeping the active power injected by the ac generator at the nominal level (30 MW). The active power supplied by the generator was kept constant because, usually, such generators are not rescheduled by the system operator. In addition, simulation results showed that the extreme cases (i.e., the smallest/largest stability margin) are obtained when the generator is supplying nominal power.

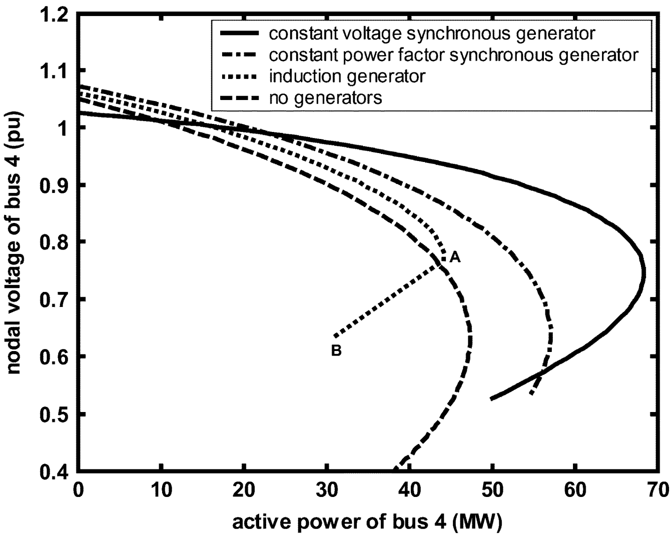


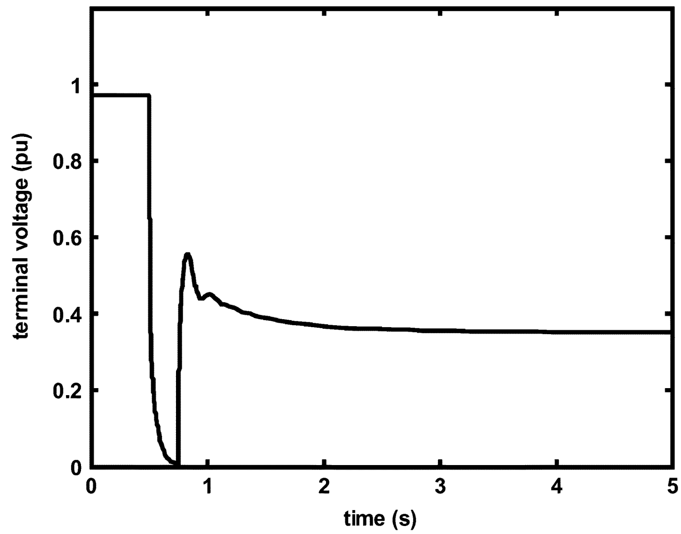
Fig. 4. PV curves of bus 4.

The PV curve of bus 4 is shown in Fig. 4. It can be verified that the presence of the synchronous generators augments the system stability margin, independent of the excitation system control mode. In addition, the usage of the constant voltage synchronous generator leads to the largest gains, because this machine provides active and reactive power to local loads. On the other hand, in the case with an induction generator, the system stability margin is reduced. In this case, the operating point of the system goes from point A to B on the curve after only one step in the load increment. It can be verified, by using dynamic simulation, that the point A on the PV curve represents the steady-state stability limit of the induction generator. If the load augments further, the machine rotor speed increases monotonically. This fact occurs because when the loads increase, the generator terminal voltage decreases. As the electrical torque is proportional to the terminal voltage, it also decreases; in consequence, the rotor speed increases to compensate the electrical torque reduction. From a determined point, the rotor speed increases unlimitedly, leading the system to a voltage collapse. Of course, at this point, the generator would be disconnected by the protection system and the system would return to the PV curve for the case without generators, if there are no dynamic loads.

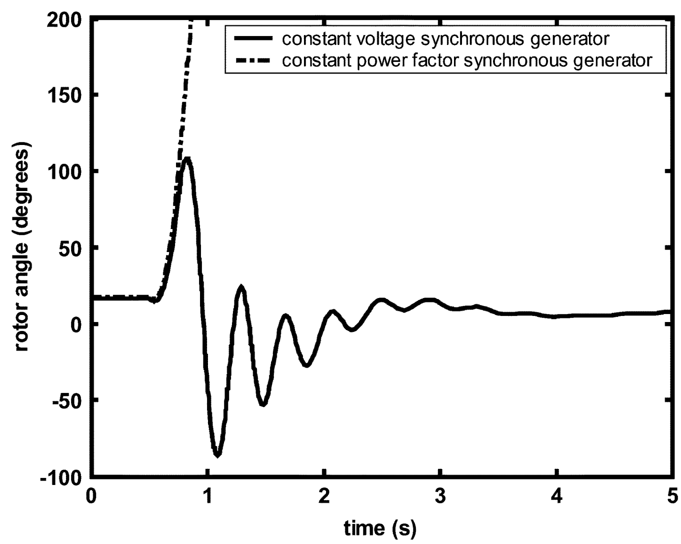
VI. Transient Stability

Typically, the actuation time of the protection system of distribution network is rather slow [3]. In addition, the value of the inertia constant of ac-distributed generators is low; usually it is smaller than 2 s. Therefore, transient stability issues can limit the amount of active power exported by distributed generators to the system. Thus, in this section, the dynamic behavior of the generators during three-phase-to-ground faults is analyzed. The system employed for this investigation is the same as presented in Fig. 3.

During short circuits, usually, synchronous generators accelerate, so that they may become unstable due to loss of synchronism. The stability of synchronous generators can be determined by analyzing the dynamic response of the rotor angle [10]. Alternatively, in the case of induction generators, these generators also accelerate during short circuits, and as a result, the reactive power consumed by the generators increase considerably, which may lead the system to a voltage collapse. Thus, in this case, the stability phenomena can be verified by analyzing the dynamic response of the rotor speed or the terminal voltage [16].



(a)



(b)

Fig. 5. Dynamic responses of the generators for a three-phase short circuit. (a) Terminal voltage of the induction generator. (b) Rotor angle of the synchronous generator.

Fig. 5 presents the dynamic responses of the different generators for a three-phase-to-ground short circuit applied at bus 4 at $t = 0.5$ s, which is eliminated at 15 cycles by tripping branch 2–4, when the generator is injecting 25 MW into the network. It can be seen that only the case with the constant voltage synchronous generator is stable.

The different behavior of each generator can be explained by analyzing the response of the reactive power exchanged between the generator and the network for each situation, which is shown in Fig. 6. In the case of the induction generator, the reactive power exchanged takes into account the reactive power supplied by the capacitors. It can be verified that the reactive power injected by the constant voltage synchronous generator

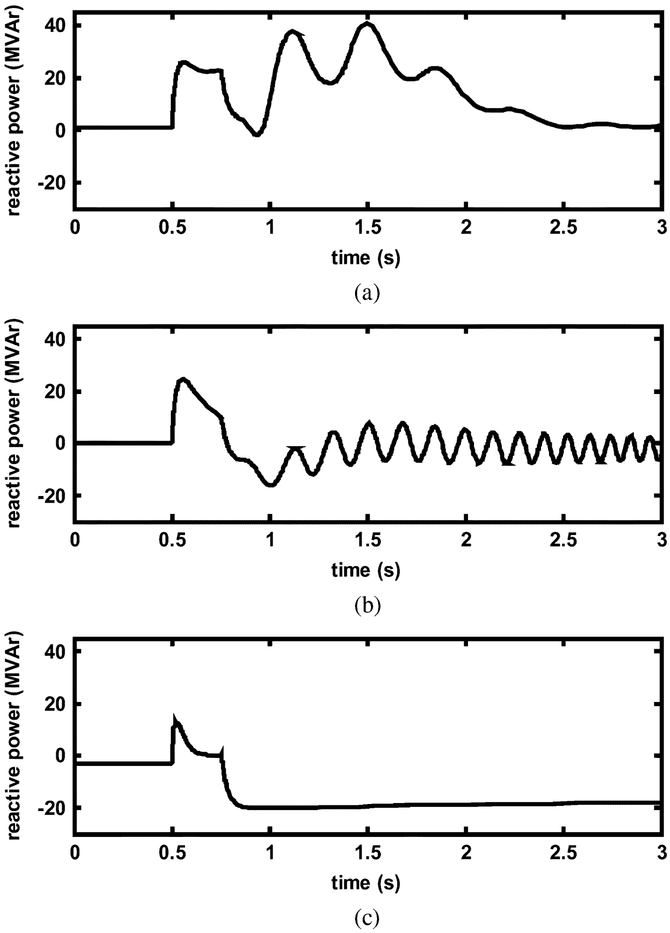


Fig. 6. Dynamic behavior of the reactive power exchanged between the generator and the network during a three-phase short circuit. (a) Constant voltage synchronous generator. (b) Constant power factor synchronous generator. (c) Induction generator.

increases during and after the fault. This fact has a positive impact on the transient stability response of the generator. In the case of the constant power factor synchronous generators, it can be noted that the reactive power injected by the generator increases during the fault due to the delayed response of the excitation system. However, soon after the fault clearance, the excitation system acts to keep unitary power factor operation. This fact reduces the reactive power injected, affecting adversely the transient stability performance of the system. On the other hand, in the case of the induction generator, although during a fault the generator injects reactive power into the network due to self-excitation phenomenon [3], soon after the fault clearance, the generator consumes a large amount of reactive power, which can lead the system to a voltage collapse if the generator was not disconnected quickly.

One important aspect related to the transient stability issue is to determine the critical active power, i.e., the maximum active power that the generator can inject exhibiting a stable response for a determined actuation time of the protection system. In order to evaluate this question, repeated transient stability simulations were conducted for different fault clearance times. The same contingency previously described was simulated, i.e., a three-phase-to-ground short circuit at bus 4, which is eliminated by tripping branch 2–4. The results are summarized in

TABLE VI
CRITICAL POWER INJECTED BY THE GENERATORS FOR DIFFERENT FAULT CLEARANCE TIME (IN MEGAWATTS)

	critical power (MW)			
	fault clearance time (cycles)			
generator type	9	12	15	18
constant voltage synchronous generator	30.0	29.8	26.5	24.1
constant power factor synchronous generator	30.0	25.5	21.3	18.3
induction generator	24.9	22.8	21.2	19.8

Table VI. It can be verified that the usage of the constant voltage synchronous generator permits that the critical power assumes the highest values. On the other hand, in the case of induction generator or constant power factor synchronous generator, the values of critical power are smaller.

VII. Voltage Sags

The incidence of unbalanced short-circuits in distribution networks is relatively frequent. During such short circuits, voltage sags may occur in the system buses. The presence of ac generators may influence the magnitude and the duration of these voltage sags. It will depend on the impact of these generators on the system short-circuit level and the dynamic behavior of the reactive power exchanged between the generator and the network. Thus, this section presents an analysis about voltage sags due to unbalanced faults by using electromagnetic transient simulations. The network employed is the same shown in Fig. 3.

Fig. 7(a) and (b) presents the dynamic responses of the nodal voltages of buses 4 and 5, respectively, for a 400-ms phase-A-to-ground short circuit applied at bus 4 at $t = 200$ ms. In this paper, voltage sag magnitude refers to the remaining voltage, as recommended in [17]. Analyzing the voltage of bus 4, one can verify that the voltage sag magnitude (minimum value of voltage) is smaller in the presence of the generators, i.e., the voltage sag problem is aggravated by the installation of the generators. It occurs because the generators increase the system short-circuit level. On the other hand, analyzing the voltage of bus 5, one can see that in the presence of the constant voltage synchronous generator, the voltage sag magnitude is larger, i.e., the voltage sag problem is improved by the generator. In the case of the constant power factor synchronous generators, there is practically no difference between the situation with and without generator considering the voltage sag magnitude of bus 5, whereas the voltage sag of bus 5 is adversely affected by the induction generator. In all cases, the ac generator and its transformer are installed at bus 5, so that the factor that predominantly influences the voltage behavior of this bus is the response of the reactive power exchanged between the generator and the network.

In order to obtain a better understanding of the influence of each type of generation on voltage sags, many repeated simulations were carried out considering different clearance times of the fault described previously. Voltage sags can be characterized by their magnitude (minimal value of voltage) and duration (period that the voltage remains below a determined value) [17]. In this paper, the value adopted to calculate the duration voltage sag was 0.85 p.u. The results are summarized in Table VII,

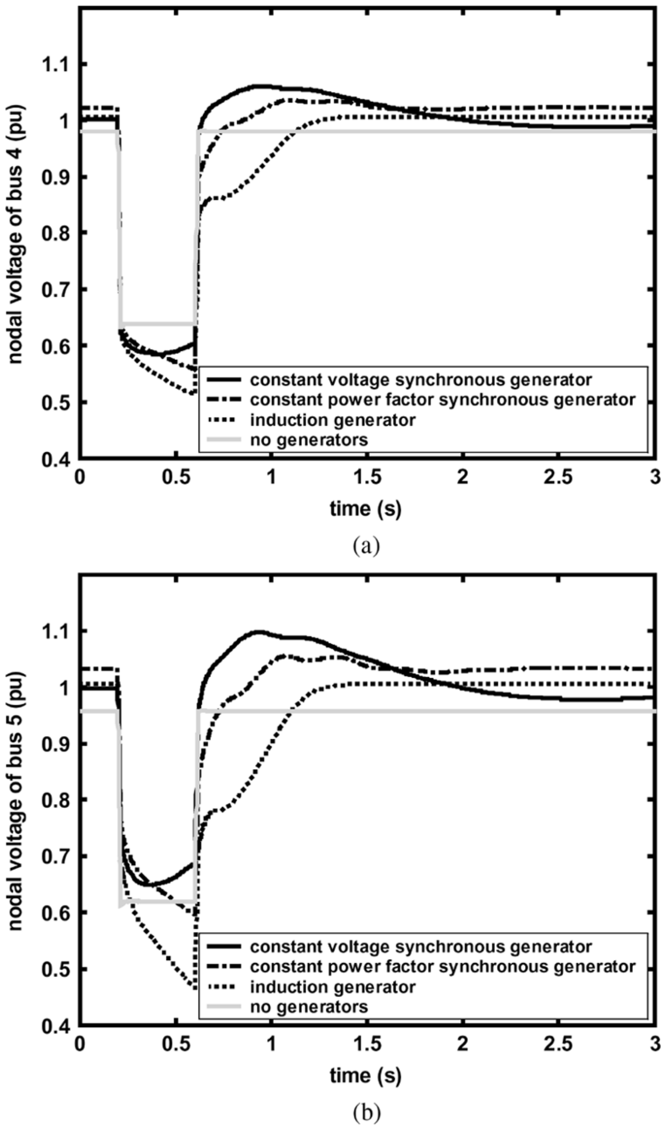


Fig. 7. Response of the nodal voltage of buses 4 and 5 for a phase-A-to-ground short circuit applied at bus 4. (a) Nodal voltage of bus 4. (b) Nodal voltage of bus 5.

where the voltage sags of buses 4 (where the fault is applied) and 5 (where the generator is installed) are shown.

Analyzing the behavior of bus 5 voltage, one can confirm that the usage of the constant voltage synchronous generator improves the voltage performance under sag magnitude viewpoint. In the case of constant power factor synchronous generator, for some situations, the voltage sag magnitude is improved. However, when the fault clearance time increases, the presence of the generator affects negatively the response of bus 5 voltage. On the other hand, in the case of the induction generator, independent of the fault clearance time, both the magnitude and the duration of the voltage sag are adversely affected when compared with the case without generators. Such differences can be explained through the dynamic behavior of the reactive power exchanged between the generators and the network, as previously discussed. In the case of bus 4 voltage, independent of the type of the generator employed, in all cases, the voltage sag is aggravated by the installation of the generators due to the increase in the system short-circuit level.

TABLE VII
VOLTAGE SAGS DUE TO A PHASE-TO-GROUND SHORT CIRCUIT

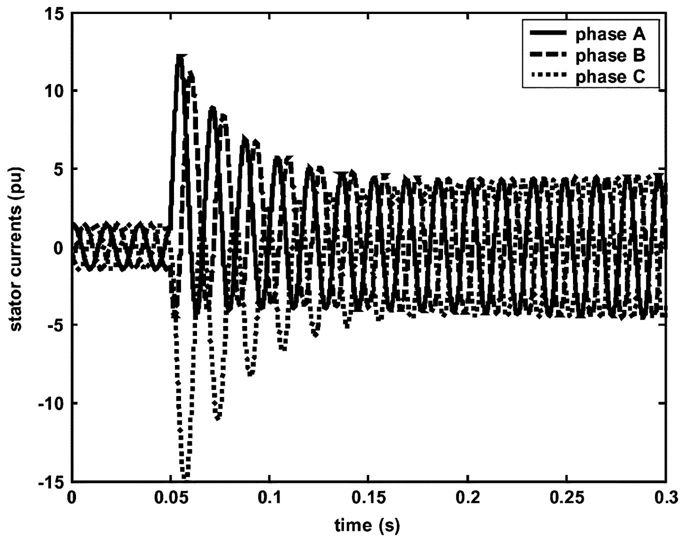
	fault duration = 200 ms			
	bus 5		bus 4	
generator type	magnitude (pu)	duration (ms)	magnitude (pu)	duration (ms)
no generators	0.623	207	0.632	206
constant voltage synchronous generator	0.640	203	0.585	207
constant power factor synchronous generator	0.644	204	0.585	207
induction generator	0.5445	236	0.550	212
	fault duration = 300 ms			
	bus 5		bus 4	
generator type	magnitude (pu)	duration (ms)	magnitude (pu)	duration (ms)
no generators	0.612	307	0.632	306
constant voltage synchronous generator	0.649	302	0.585	307
constant power factor synchronous generator	0.620	306	0.570	307
induction generator	0.503	434	0.529	315
	fault duration = 400 ms			
	bus 5		bus 4	
generator type	magnitude (pu)	duration (ms)	magnitude (pu)	duration (ms)
no generators	0.612	407	0.632	406
constant voltage synchronous generator	0.649	401	0.585	406
constant power factor synchronous generator	0.596	414	0.558	411
induction generator	0.466	705	0.512	442
	fault duration = 500 ms			
	bus 5		bus 4	
generator type	magnitude (pu)	duration (ms)	magnitude (pu)	duration (ms)
no generators	0.612	507	0.632	506
constant voltage synchronous generator	0.649	500	0.585	506
constant power factor synchronous generator	0.578	525	0.551	512
induction generator	0.438	1241	0.501	1011

Therefore, it can be verified that, typically, the installation of a generator in an industry plant can reduce the voltage sag at this bus. However, the voltage supplied to the other consumers may be adversely affected by this installation.

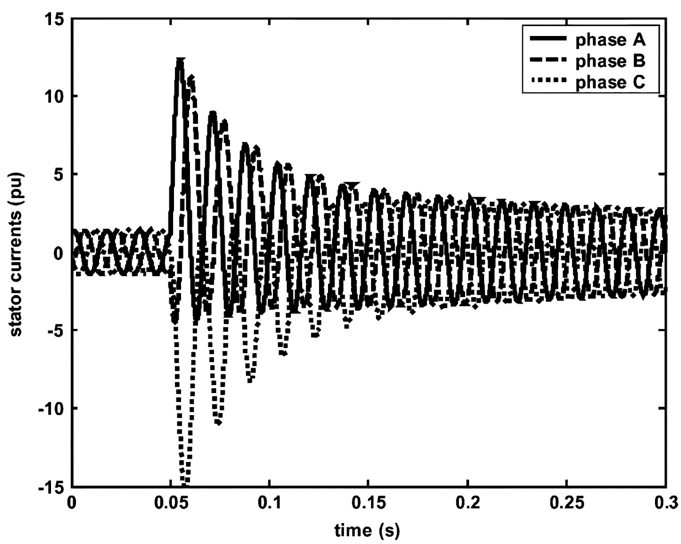
VIII. SHORT-CIRCUIT CURRENTS

The installation of ac generators may elevate the values of the short-circuit currents, becoming mandatory to update the protection and/or the network devices. Moreover, the relay settings need to be readjusted to detect faults properly. Thus, in this section, the short-circuit currents supplied by the ac generators during balanced and unbalanced faults are determined by using electromagnetic transient simulations. The fault and ground resistances were set equal to 0.001 ohm.

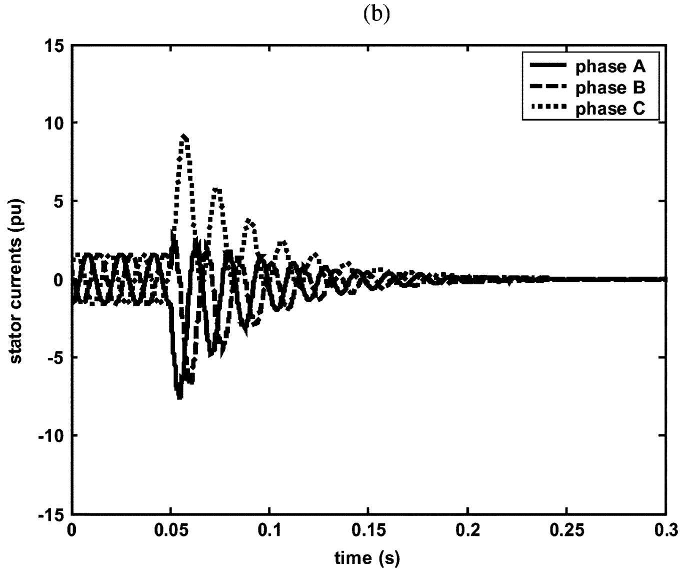
Fig. 8 presents the dynamic behavior of the currents supplied by the generators (stator current) during a three-phase-to-ground short circuit applied at bus 5 at $t = 50$ ms. The system employed is the same as presented in Fig. 3. It can be seen that the current response is different from each generator. In the case of the induction generator, although initially the magnitude of the currents is high, they decrease quickly because this machine has no capacity to provide sustained short-circuit currents



(a)

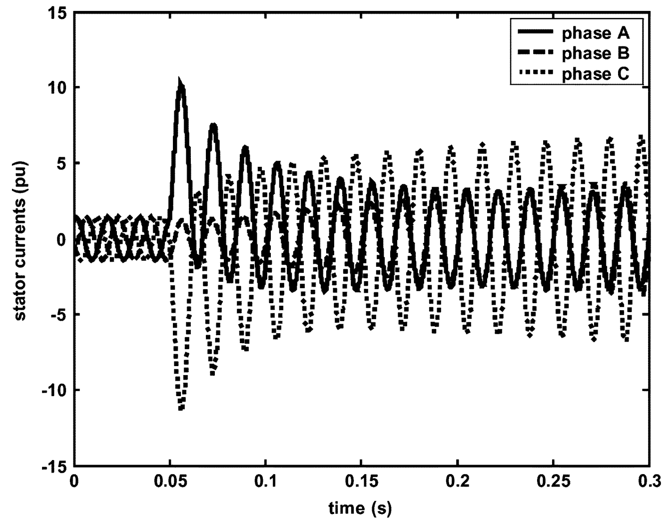


(b)

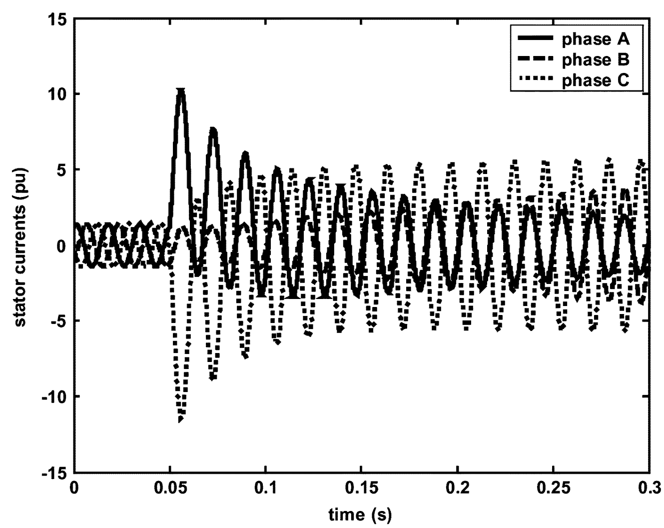


(c)

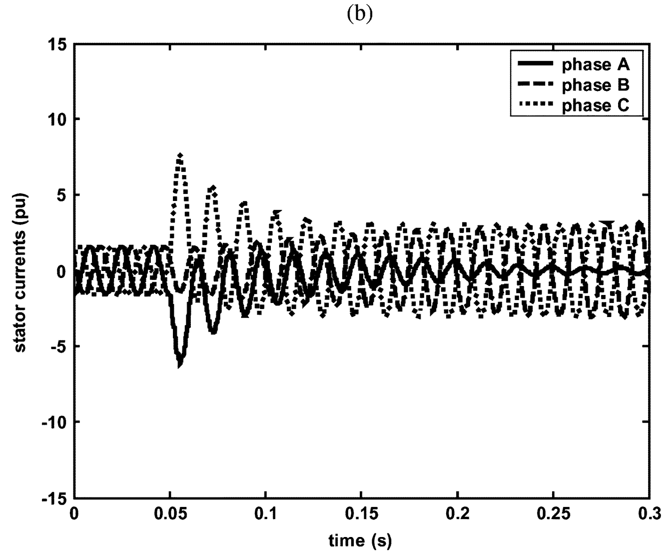
Fig. 8. Stator current during a three-phase-to-ground short circuit. (a) Constant voltage synchronous generator. (b) Constant power factor synchronous generator. (c) Induction generator.



(a)



(b)



(c)

Fig. 9. Stator current during a phase-A-to-ground short circuit. (a) Constant voltage synchronous generator. (b) Constant power factor synchronous generator. (c) Induction generator.

during three-phase faults. In this situation, the network three-phase voltages drop to zero and the capacitor bank becomes

TABLE VIII
SHORT-CIRCUIT CURRENTS SUPPLIED BY THE AC GENERATOR (IN P.U.)

	three-phase-to-ground short-circuit at bus 5											
	phase A				phase B				phase C			
generator type	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles
constant voltage synchronous generator	12.21	4.08	3.03	3.14	11.21	3.95	2.45	1.92	15.30	4.79	2.98	3.28
constant power factor synchronous generator	12.33	4.09	2.45	1.90	11.21	3.96	3.04	3.17	15.42	4.79	2.41	1.99
induction generator	7.68	1.75	0.16	0.02	6.66	1.68	0.16	0.02	9.24	2.20	0.18	0.02
	phase-A-to-ground short-circuit at bus 5											
	phase A				phase B				phase C			
generator type	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles
constant voltage synchronous generator	10.17	3.56	2.32	2.19	3.91	1.09	1.99	2.64	11.37	4.51	4.30	4.78
constant power factor synchronous generator	10.27	3.60	2.05	1.35	4.41	1.04	1.89	2.65	11.45	4.50	3.88	3.99
induction generator	6.18	1.72	0.49	0.15	3.35	1.32	1.92	2.25	7.63	2.73	2.15	2.11
	phase-A-to-phase-B short-circuit at bus 5											
	phase A				phase B				phase C			
generator type	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles
constant voltage synchronous generator	12.23	5.21	4.30	4.33	5.36	1.80	0.31	0.80	7.25	3.52	4.12	4.88
constant power factor synchronous generator	12.34	5.21	3.81	3.18	5.34	1.85	0.54	1.08	7.27	3.48	3.74	4.24
induction generator	7.70	2.72	1.52	1.12	3.91	0.92	1.17	1.48	5.10	2.40	2.44	2.55
	phase-A-to-phase-B-to-ground short-circuit at bus 5											
	phase A				phase B				phase C			
generator type	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles	max	3 cycles	9 cycles	15 cycles
constant voltage synchronous generator	12.22	4.54	3.48	3.42	6.42	2.40	1.90	3.04	10.96	3.43	3.32	4.06
constant power factor synchronous generator	12.34	4.54	2.90	2.14	6.09	2.42	1.38	2.12	11.04	3.41	2.79	2.97
induction generator	7.69	2.09	0.59	0.31	3.90	0.84	0.40	0.62	7.00	1.70	0.98	0.93

TABLE IX
PRE-FAULT TERMINAL VOLTAGE (IN P.U.)

generator type	terminal voltage (pu)
constant power factor synchronous generator	1.0061
constant voltage synchronous generator	1.0000
induction generator	0.9669

unloaded. Consequently, there is no external excitation source for the generator, and it becomes unable to produce voltage. Theoretically, this fact could become the detection of faults by protection systems based on over-current relays more difficult. However, in this case, voltage-based relays could be used. In the case of synchronous generators, it can be observed that the usage of the excitation system as a voltage regulator permits that the generator supplies sustained short-circuit current. Nevertheless, if the excitation system is used as a power factor regulator, this capability is decreased.

Fig. 9 shows the currents supplied by the generators during a phase-A-to-ground short circuit applied at bus 5 at $t = 50$ ms. In this case, the induction generator can supply sustained short-circuit currents during the fault. However, it is interesting to observe that the current of the faulted phase (phase-A) decreases quickly to zero. Only phase B and C currents present a sustained response. It occurs because these phases remain excited by the network. On the other hand, in the case of the synchronous generators, all currents present a sustained response due to the presence of the excitation system.

In order to obtain a better understanding of the short-circuit currents supplied by ac generators, many repeated simulations were conducted for different faults. The results are summarized in Table VIII. In this table, the second, sixth, and tenth columns show the maximum (peak) value of the stator current after the fault for A, B, and C phases, respectively. The other columns show the rms value of the stator currents at different instants after the fault application.

The previous discussion can be confirmed by analyzing these results. In addition, it can be verified that the largest peak values of currents are related to the synchronous generator cases, and the smallest values can be related to the induction generator cases. This fact can be partially explained by analyzing the pre-fault magnitude of the terminal voltage, which is shown in Table IX. The larger the pre-fault magnitude of the terminal voltage, the larger the peak of current. In addition, the results show that, usually, the peak of current supplied by the induction generator is lower than the current supplied by the synchronous generator. This characteristic can be useful if it is desirable to expand the distributed generation in networks with constraints related to elevation of the short-circuit level.

IX. Conclusion

This paper presented an extensive study about the impacts provoked by the connection of induction and synchronous generators to distribution networks. The objective was to determine the main technical differences between these generators. In the case of synchronous generators, we analyzed the usage of the excitation system as a voltage or a power factor regulator.

To sum up, it was verified that from the viewpoint of a steady-state voltage profile, voltage stability, and transient stability, the usage of constant voltage synchronous generators is advantageous and permits to increase the allowable penetration level of distributed generation. The usage of induction generators may be interesting in networks suffering from constraints related to the increase in the short-circuit levels. In the case of voltage sags, it was observed that the usage of constant voltage synchronous generators can improve the dynamic performance of the voltage at the installation point. However, other consumers may be adversely affected due to more intense voltage sags. According solely to the technical factors analyzed in this paper, the usage of constant power factor synchronous generators may be considered the worst option. However, other factors must be considered to decide what is the best option in global terms, for example, economical and political aspects.

Appendix

In this section, the systems data are presented. All symbols used are defined in [4].

A. Data of System 1

Substation transformer (100 MVA):

$$\mathrm{R_1 = R_2 = 0.0\ p.u.} \quad \mathrm{X_1 = X_2 = 0.01\ p.u.}$$
$$\mathrm{R_M = X_M = 500\ p.u.}$$

Generator transformers (5.1 MVA):

$$\mathrm{R_1 = R_2 = 0.0\ p.u.} \quad \mathrm{X_1 = X_2 = 0.02\ p.u.}$$
$$\mathrm{R_M = X_M = 500\ p.u.}$$

Impedances of the feeders:

$$\mathrm{Z_{23} = 0.5624 + j2.5318\ \Omega}$$
$$\mathrm{Z_{34} = 0.4999 + j2.2505\ \Omega}$$
$$\mathrm{Z_{45} = 0.3124 + j1.4066\ \Omega}$$
$$\mathrm{Z_{56} = 0.2499 + j1.1252\ \Omega}$$
$$\mathrm{Z_{67} = 0.1875 + j0.8439\ \Omega}$$

Synchronous generator (5 MVA):

$$\mathrm{X_d = 1.4000\ p.u.} \quad \mathrm{X_q = 1.3720\ p.u.}$$
$$\mathrm{X'_d = 0.2310\ p.u.} \quad X'_q = 0.8000\ \mathrm{p.u.}$$
$$\mathrm{X''_d = 0.1180\ p.u.} \quad \mathrm{X''_q = 0.1180\ p.u.}$$
$$\mathrm{X_l = 0.0500\ p.u.} \quad \mathrm{R_a = 0.0014\ p.u.}$$
$$\mathrm{T'_{d0} = 5.5000\ s} \quad \mathrm{T'_{q0} = 1.2500\ s}$$
$$\mathrm{T'_{d0} = 0.0500\ s} \quad \mathrm{T''_{q0} = 0.1900\ s}$$
$$\mathrm{H = 1.5000\ s}$$

Induction generator (5 MVA):

$$\mathrm{R_s = 0.010\ p.u.} \quad \mathrm{L_{ls} = 0.100\ p.u.}$$
$$\mathrm{R'_r = 0.014\ p.u.} \quad \mathrm{L'_{lr} = 0.098\ p.u.}$$
$$\mathrm{H = 1.500\ s} \quad \mathrm{L_m = 3.500\ p.u.}$$

B. Data of System 2

Substation transformer 1 (100 MVA):

$$\mathrm{R_1 = R_2 = 0.005\ p.u.} \quad \mathrm{X_1 = X_2 = 0.02\ p.u.}$$
$$\mathrm{R_M = X_M = 500\ p.u.}$$

Substation transformer 2 (100 MVA):

$$\mathrm{R_1 = R_2 = 0.0046\ p.u.} \quad \mathrm{X_1 = X_2 = 0.02\ p.u.}$$
$$\mathrm{R_M = X_M = 500\ p.u.}$$

Generator transformer (30.5 MVA):

$$\mathrm{R_1 = R_2 = 0.005\ p.u.} \quad \mathrm{X_1 = X_2 = 0.02\ p.u.}$$
$$\mathrm{R_M = X_M = 100\ p.u.}$$

Impedances of the feeders:

$$\mathrm{Z_{23} = 0.4860 + j2.0885\ \Omega}$$
$$\mathrm{Z_{34} = 2.6000 + j4.5239\ \Omega}$$
$$\mathrm{Z_{24} = 2.3400 + j3.7322\ \Omega}$$
$$\mathrm{Z_{45} = 1.3000 + j2.2619\ \Omega}$$

Synchronous generator (30 MVA):

$$\mathrm{X_d = 1.4000\ p.u.} \quad \mathrm{X_q = 1.3720\ p.u.}$$
$$\mathrm{X'_d = 0.2310\ p.u.} \quad \mathrm{X'_q = 0.8000\ \ p.u.}$$
$$\mathrm{X''_d = 0.1180\ p.u.} \quad \mathrm{X''_q = 0.1180\ p.u.}$$
$$\mathrm{X}_l = \mathrm{0.0500\ p.u.} \quad \mathrm{R_a = 0.0014\ p.u.}$$
$$\mathrm{T'_{d0} = 5.5000\ s} \quad \mathrm{T'_{q0} = 1.2500\ s}$$
$$\mathrm{T'_{d0} = 0.0500\ s} \quad \mathrm{T''_{q0} = 0.1900\ s} \quad \mathrm{H = 1.5000\ s}$$

Induction generator (30 MVA):

$$\mathrm{R_s = 0.010\ p.u.} \quad \mathrm{L_{ls} = 0.100\ p.u.}$$
$$\mathrm{R'_r = 0.014\ p.u.} \quad \mathrm{L'_{lr} = 0.098\ p.u.}$$
$$\mathrm{H = 1.500\ s} \quad \mathrm{L_m = 3.500\ p.u.}$$

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