

Challenges of Developing Situational Awareness in Active Distribution Systems^{*}

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Abstract: The increasing penetration of distributed generation poses significant challenges for the ideal and safe operation of distribution systems, adding variability and uncertainty to modern networks. New methodologies need to be developed to reduce the negative impacts of distributed generation on the distribution system and to improve operators' situational awareness in the control center. Hence, this paper presents a critical review of the main challenges that operators face in developing situational awareness in the operation of active distribution systems. Besides technological limitations, the bibliography review shows that the lack of standard features regarding operational requirements for security, quality, and performance cause inadequate situational awareness of the network. In this context, the performance of eight indexes representing the system's operational criteria is analyzed in the IEEE 34-bus test system through the variation of the penetration level of distributed generation, changes in system loading, and network reconfiguration. The results highlight the importance of a complete picture of the system for situational awareness to help the operator's decision-making during the dynamic network operation.

Keywords: Distributed energy resources, distribution system, situational awareness.

1. INTRODUCTION

The electrical distribution system has been undergone significant changes in recent years due to the growing presence of Distributed Energy Resources (DERs). The DERs are mainly characterized by modifying the power flow direction, and some of them present intermittent nature, such as the renewable generation. This type of energy resource add up considerable level of uncertainty and variability in the operation of distribution networks. In order to reduce the negative impacts of DERs on the distribution system, the distribution utilities must accurately monitor and coordinate their network devices.

In this context, the traditional distribution system presents limitations to integrating DERs when only the unidirectional power from the substation to consumers is considered. Hence, the system's modernization through improving the real-time supervision, network analysis, forecasting, operation, and planning to consider a large number of small power injections and enhance the monitoring and control of the network is urgent (Vasudevan et al., 2015).

The modernization from traditional to active distribution system has become one of the major challenges for distribution companies. Situational Awareness (SA) is one of the concepts that must be taken into account. SA is about knowing and understanding the current state of a

system and then designing the system's future conditions properly (Endsley, 1995). An adequate SA can maintain safety and ensure the availability of the basic functions that support operation plans and identify potential risks. On the other hand, inadequate SA results in operators' delayed, incorrect, or faulty responses, placing the system's stability at risk (Panteli et al., 2013a). Therefore, it is important to comprehend the factors that rule the SA in control centers to improve it during emergencies and prevent it from severe events.

Several papers discuss the main challenges of developing SA in power systems from the perspective of the control center operator (Connors et al., 2007; Endsley and Connors, 2008; Lenox et al., 2011). Panteli and Kirschen (2015) discuss about the main challenges and technologies needed to enhance SA and proposes a platform to minimize human errors. However, these papers do not distinguish the challenges found in transmission and distribution systems and do not address the influence of DERs operation on SA. The distribution system has different structure, technology, practices, and operational objectives when compared with the transmission system. Thus, the challenges of developing SA in active distribution systems are different and must be analyzed separately.

Therefore, in this study, we investigate the concept of SA in the distribution systems and how the increasing integration of DERs influences the comprehension of the system's operation. A bibliographic review has been carried out considering recent studies to clarify this concept to distribution systems and identify the challenges in this

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research field. The review shows that data acquisition, communication limitations, and the lack of integration of operational criteria of security, quality, and performance are the main issues to developing adequate SA. Thus, simulations are performed to demonstrate the importance of obtaining information representing these operational criteria to accurately identify the system's operating state in its dynamic operation.

This paper is divided as follows: Section 2 presents the concept of SA, in addition to the requirements of SA in power systems and the challenges of developing SA in active distribution systems. Section 3 shows the study methodology, including the operational indices proposed to analyze SA and the computational method. Section 4 shows the analysis of the proposed indices, and, lastly, Section 5 concludes the study.

2. SITUATIONAL AWARENESS

SA is a concept widely used to assist the decision-making process of dynamic and complex systems. Endsley (1995) describes SA as the perception of environmental elements within a defined time-space, the comprehension of its meaning, and the projection of its near-future state. Hence, SA can be divided into three hierarchical phases: perception, comprehension, and projection. Fig. 1 presents the SA decisions levels described below (Endsley, 1995):

- (1) Perception: the first level of SA is the perception of the system's relevant states, attributes, and dynamics. This level is responsible for collecting different data types, which separately may have no relation to the problem but together provide the system state.
- (2) Comprehension: the large amount of information collected at the first level is synthesized, and the most critical ones are prioritized according to the operation's objectives. The selected information helps understanding the system's current state, assisting in the decision-making process and identifying the immediate impact of components malfunction or that specific data does not correspond with the expected values.
- (3) Projection: the ability to project the system's future behavior based on the comprehension of its current state constitutes the third level of SA. Operators with a high level of SA can develop strategies and responses to events, avoiding undesirable situations. The level of SA determines the system's future performance, but it is highly dependent on perception and comprehension. Any misinformation leads to a wrong decision and, consequently, to system collapse.

Acquiring high level of SA is more than simply collecting a large number of data. The authors of Endsley and Connors (2008); Connors et al. (2007) discuss the challenges in developing SA due to the interaction between human capabilities of information processing and the software's design. These challenges, called as "SA demons" are workload, data overload, operator memory, and increased system complexity. Therefore, even if the correct data is provided at the right time, the SA demons can jeopardize the system operator's cognitive ability to develop adequate SA.

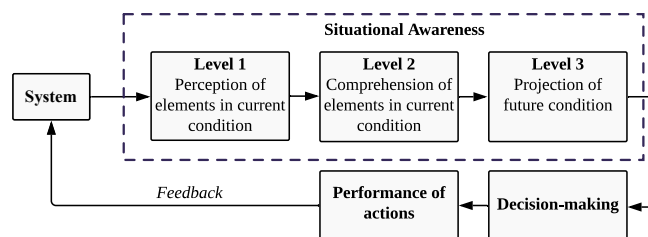


Fig. 1. The three levels of situational awareness employed in complex systems to assist in the decision-making process (Panteli et al., 2013a).

2.1 Situational Awareness in the Power Systems Operation

SA in control centers is the basis for the decision-making process to ensure the safe performance of the electrical power system. Maintaining a high level of SA is essential for effective control actions, considering that the operator's mistakes can initiate an electrical disturbance or contribute to its development. The impact of inadequate or insufficient SA is analyzed in Panteli et al. (2013a) by simulating contingencies in an electrical power system. SA is insufficient if, after an initial electrical disturbance, the response to the event is ineffective and the system begins a cascading electrical failure. This study shows the importance of operators' SA by simulating how a single element failure can increase the probability of a blackout when a bad decision is executed. A well-known example is the 2003 blackout in the United States (U.S.– Canada Power System Outage Task Force, 2004), in which "inadequate SA" was identified as the main cause of the system's state deterioration. Multiple data system failures and the lack of information exchange among system operators have led to inadequate SA and to a delayed response to the initial failure, resulting in the spread of the disturbance.

Fig. 2 presents the information required by the operator at each level of SA. This method has a hierarchical information structure in which each stage helps the operator to develop a complete view of the control area and consequently predicts the future system condition. The data at the perception level is often provided to operators in parts and must be combined mentally from different systems and sources. Usually, operators must sort data manually from six to ten software applications spread across multiple computer monitors to make a single decision (Connors et al., 2007). Thus, several data tables from the Supervisory and Data Acquisition Systems (SCADA) are examined, in addition to system diagrams that use various screens with component data, including bus voltages, currents, and powers. Moreover, operators must search for meteorological data, alarms, state estimators, and contingency analysis to comprehend the system condition. Connors et al. (2007) identified that the biggest challenge to developing SA is the lack of data integration that presents a real challenge for operators by giving space for misinterpretation. The accuracy of the information and the moment it is available are crucial aspects of the operator's decision process since outdated data can lead to incorrect reactions, as in the 2003 blackout.

Besides the lack of data integration, other factors lead to inadequate SA. The main challenges found in control

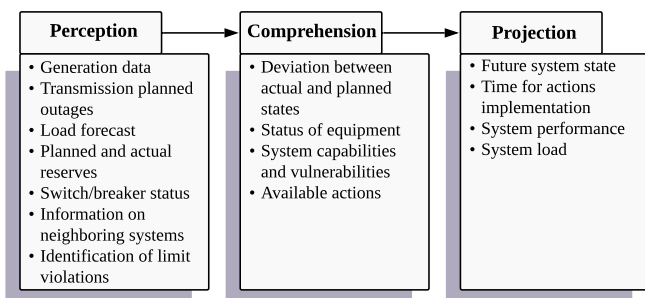


Fig. 2. Required data at each level to obtain adequate situational awareness (Sobajic, 2011).

centers are described by Panteli and Kirschen (2015), such as:

- **Hardware and software applications:** the failure of any tool, such as the state estimator or contingency analyzer, neglects considerable information necessary to establish effective responses.
- **Real-time measurements:** missing or inconsistent data due to failure in measurement devices or communication systems can result in insufficient SA. Moreover, the use of asynchronous data can provide a false sense of security and prevent the implementation of appropriate corrective or preventive control actions.
- **Automation:** despite reducing operators' workload, highly automated systems can leave operators unaware of the real state of the network's operation. Also, operators may fail to detect automation malfunctions or problems that require manual actions.
- **Human factors:** the lack of experience and training of operators with specific technologies results in an incorrect interpretation of the information, thus compromising the effective response of operators in critical situations. Moreover, the inability of operators to follow procedures risks system reliability.
- **Data and information exchange:** insufficient communication between operators in one or more control rooms reduces awareness of the key elements that affect the system's stability;
- **Graphical User Interface (GUI):** each software uses a different color scheme, screen font, and alarms that deflect the operator's focus. The lack of application standardization confuses the user, requiring more effort to maintain concentration on screen changes;
- **Amount of data:** while improving SA, real-time measurements generate a large amount of data for analysis. Without a mechanism to synthesize and classify it, important information can be lost.

Therefore, SA depends on several factors that affect the development of an accurate and complete image of the operator's control area. To enhance SA in control centers, Panteli et al. (2013b) proposes the following practices:

- To use state estimation to detect inconsistencies in acquired data by eliminating bad data and errors in the system topology. These problems are caused when failures in the communication devices do not measure the status of a circuit breaker or switch correctly.
- Improve the GUI with 3D visualization of system information and colors to represent the line loading.

- Only use automation on functionalities that human operators cannot perform on time.
- Frequently teach operators how to use new technologies and tools for monitoring and security and deal with various situations, from routine procedures under normal conditions to catastrophic contingencies.
- Guarantee the Energy Management System (EMS) functionality by verifying hardware applications for damaged components and software that usually fails after updates.

Several key technologies are already being studied or applied to address the SA challenges and assess system security. Phasor Measurement Units (PMUs) are modern devices that provide real-time system measurements responsible for advancing the system state estimation and accurately forecasted load data. Generally, system monitoring is performed by SCADA, which provides active and reactive voltage, frequency, and power measurements every 4-10 seconds. Then, the state estimator provides in approximately 30 seconds the steady-state of the network with low resolution, unsynchronized and incomplete measurements. However, PMUs can provide up to 60 samples per cycle of operation parameters improving the network observability that helps assist system stability analysis, state estimation, reliability, and protection.

Real-time measurements build up the SA perception by increasing the monitoring and security level of the system's operation. Thus, it is possible to relate the state estimation with the synchronized measurements from PMUs to provide dynamic monitoring of the network and develop the comprehension level. Diao et al. (2010) make use of PMUs information to assess security indices, including voltage stability, transient stability, thermal violations, and voltage magnitude violation, to plan preventive and corrective control actions to avoid system collapse. In addition, the comprehension stage is improved by developing the user interface by allowing changes in the graphics, maps, specific event alarms, color variations in the network single-line diagram from logical conditions, such as power grid areas that present overvoltage.

The growing penetration of renewable energy sources increases the necessity to improve the operator's SA. Unlike conventional energy sources, renewable sources do not generate energy on demand due to their intermittent nature. Wind generation tends to increase at night when the system load is lower and can vary in time and intensity. Photovoltaic generators present the same variability challenges. Although there are generation forecasting tools for renewable sources, low reliability is still a concern for power grid operation. Operators attempt to include the variable characteristics of renewable sources in the daily operating schedule, but the increase in uncertainties in the system impairs the development of SA (Jones, 2017). Thus, recent studies on the development of SA started to include renewable sources in operational security analysis (Zhang et al., 2019; Ge et al., 2021). These methodologies focus on overcoming the uncertainties of renewable sources, but their insertion carries security, quality, and efficiency problems to the system operation. Besides, although SA in transmission systems is a widespread issue, it is a new concept with different challenges in active distribution systems.

2.2 Challenges to Developing Situational Awareness in Active Distribution Systems

The reliable operation of the distribution system cannot be performed effectively without high levels of SA. Operators must have the correct information at the right time, which must be provided efficiently to allow the complete understanding of the state of the complex dynamic system, allowing the projection of the future network behavior and on-time response (Jones, 2017). However, the distribution network has challenges, such as numerous buses that complicate its observability, inconsistencies in the parameters of the evolving network, high penetration of DERs that results in unpredictable power flow patterns, and complex stability problems.

Current solutions in distribution control and data acquisition are generally unable to meet the new technology requirements of SA (Lin et al., 2016). Existing applications provide only the substation data, such as voltage and nominal power of the substation HV/MV transformers and the current flow of the feeder. Nevertheless, these data do not help estimate an accurate picture of the dynamic network due to the DERs' peak loads and temperature changes.

State estimation has been an essential part of monitoring transmission systems' operations to verify vulnerability areas, diagnose the cause of critical events and make corrective decisions. The most significant challenge of state estimation in active distribution systems is the lack of monitoring and communication infrastructure to obtain dynamic measurements in real-time. Thus, several methodologies are developed to optimize meters allocation to reduce the high cost of digital measurement instrumentation and improve the state estimator reliability (Vasudevan et al., 2015).

Besides the necessity for methods to forecast renewable sources generation accurately, the operator must also adapt to new system conditions and react to failures and emergencies. Comprehending complex information and making correct decisions depends on maintaining SA in this new, highly complex, unpredictable system. Endsley and Connors (2008) suggest implementing the Global Situational Awareness Assessment Technique (SAGAT) to measure SA in new interface technologies, display concepts, sensor sets, and training programs. Lenox et al. (2011) apply this technique in a survey with nine network operators. Although operators could identify and understand the system's current state, this study demonstrates their difficulty in predicting the future network state due to the lack of tools to facilitate the forecast analysis.

The active distribution network has become the main alternative for managing DERs due to its high capacity to integrate different resources economically and safely. Zhang et al. (2018) implement a SA method to predict the risks of voltage instability in an active distribution system by analyzing wind generation data, environmental factors and the state of power flow. Lin et al. (2016) propose a SA structure for controlling and supervising active distribution networks divided into two main subsystems: SA and operation management. The SA subsystem provides information collected in the perception stage, such

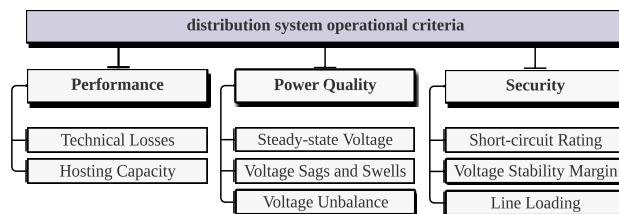


Fig. 3. Indices selected to represent operational criteria for security, power quality and performance.

as the system parameters and operation status. Then, the comprehension level includes DG uncertainties, potential network risks, and recommendations for action. Lastly, the projection stage presents the highest risk scenarios to the active network operators and recommendations for control responses. The operation manager's role is to receive information, synthesize it and schedule operation actions to return them to the SA subsystem. The SA system performs tasks such as mitigating overvoltages caused by the sudden increase of DG power, reducing line congestion, and verifying the network's security considering different action strategies.

3. METHODOLOGY

In this section a methodology to analyze the influences of dynamic operation of the network on the security, quality, and system performance areas is proposed. Different levels of loading and penetration of DG were simulated in the modified 34-node IEEE test system (IEEE Distribution System Analysis Subcommittee, 2010) using OpenDSS software (Dugan, 2018). Also, a network reconfiguration proposed by Gangwar et al. (2019) to reduce technical losses is simulated to analyze how a control action taken to improve system performance can affect operating requirements such as security and power quality.

3.1 Operational Indices

Improving SA requires determining what information the operator must obtain to ensure the secure, efficient system operation. Eight indices were selected to represent the system performance regarding different metrics. These indices have been evaluated considering different operating conditions, such as changes in demand, topology, and control actions. Some DG parameters, such as generation type, penetration level, connection point, and control mode, may also affect the performance of these indices, shown in Fig. 3. They are briefly described next, with its mathematical definition:

- **Technical Losses (TL):** is one of the main metrics to evaluate the distribution system's performance. In this paper, the TL index is calculated from Eq. 1, where P_{losses} and P_{co} represent the system losses and load, respectively, in the current operating condition.

$$TL = \frac{P_{losses}}{P_{co}} \times 100[\%] \quad (1)$$

- **Hosting Capacity (HC):** is the determination of the maximum amount of DG output power allowed in the system without violating operational limits. The

HC has become essential information among distributors for operational planning as system performance can improve or deteriorate with the connection of DG. This paper determines the HC by increasing DG penetration until the upper voltage limit is reached. Then, the HC is calculated from Eq. 2, where P_{rated} is the rated load of the system and P_{DG} is the generators' output power.

$$HC = \frac{P_{rated} - P_{DG}}{P_{DG}} \times 100[\%] \quad (2)$$

- **Steady-state Voltage Violation (VV):** is an essential indicator for assessing power quality since voltage-related disturbances are the most common issues associated with the operation of the distribution system. With the increasing penetration of DG to the network, the steady-state voltage that used to decrease along the radial topology feeder may rise due to the bidirectional power flow. Therefore, the VV index indicates the number of buses that violated the adequate voltage limits defined by ANEEL (2018) between the range of 0.93 and 1.05 p.u. In this study, the VV index is calculated from Eq. 3, where n_{VV} represents the number of buses that violate the established range and n_b is the number of the system's buses.

$$VV = \frac{n_{VV}}{n_b} \times 100[\%] \quad (3)$$

- **Voltage Sags and Swells (VSS):** is characterized by deviations in the voltage amplitude during a time interval of fewer than three minutes, mainly caused by short circuits. According to ANEEL (2018), voltage swells are determined by the increase in voltage amplitude by 1.1 p.u., while voltage sag is the decrease between 0.1 p.u. and 0.9 p.u. of the reference voltage. This paper uses VSS as a quality index due to the impact of DG on voltage amplitude during short circuits. The VSS index is calculated by Eq. 4 where n_{VSS} indicates the number of buses with VSS and n_b is the number of the system's buses.

$$VSS = \frac{n_{VSS}}{n_b} \times 100[\%] \quad (4)$$

- **Voltage Unbalance Factor (VUF):** is an indicator of power quality, affected by system operating conditions and the location, capacity, and connection of DG. The VUF index is calculated according to Eq. 5, where V_+ and V_- correspond to the magnitude of the positive and negative sequence voltage, respectively.

$$VUF = \frac{V_-}{V_+} \times 100[\%] \quad (5)$$

- **Short Circuit Rating (SCR):** is used as an operating security index due to the contribution of DG to the fault current that affects the system's protection. This paper analyzes the contribution of the system dynamic operation in the magnitude of three-phase, two-phase, and single-phase faults. The index is calculated by Eq. 6, where $I_{cc_{co}}$ is the SCR in the current scenario and I_{cc_b} is the SCR in the original 34-node IEEE test system, without the DG connection.

$$SCR = \frac{I_{cc_{co}}}{I_{cc_b}} \times 100[\%] \quad (6)$$

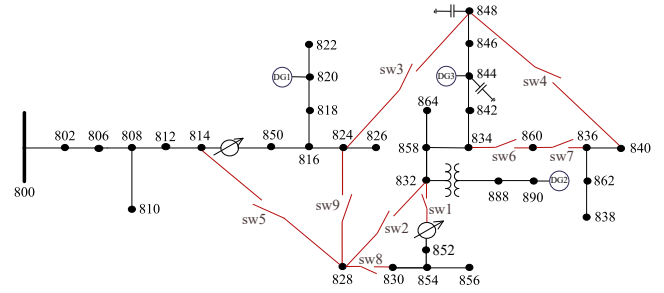


Fig. 4. Modified IEEE 34-node test system.

- **Voltage Stability Margin (VSM):** is responsible for measuring the proximity of the system to voltage instability, that is, how close the current operating condition is from the critical point of voltage stability. The VSM is an important security index because the system can collapse if a single bus operates close to its voltage stability limit. This paper determines the maximum load point when the bus voltage level is below the critical limit of 0.90 p.u. Thus, the VSM is calculated according to Eq. 7, where λ_{co} is the load level in the current operating condition and λ_{mlp} is the load at the maximum load point.

$$VSM = \frac{\lambda_{co}}{\lambda_{mlp}} \times 100[\%] \quad (7)$$

- **Lines Loading (LL):** is used as a security index since DG connection may increase the line loading close to its operational limit. The LL index is calculated from Eq. 8, where I_{co} is the value of the current flow in the conductor and I_{max} is the maximum current allowed for the cable specification.

$$LL = \frac{I_{co}}{I_{max}} \times 100[\%] \quad (8)$$

3.2 Computational Method

In this study, the modified IEEE-34 Bus system has been analyzed with OpenDSS software (Dugan, 2018). The network is radial and unbalanced, operating with nominal voltage of 24.9 kV and rated load of 1769 kW and 1044 kvar. Fig. 4 illustrates the test system with the modifications implemented by Gangwar et al. (2019), in which nine switches are added to enable network reconfiguration. In addition, two three-phase synchronous generators are connected to buses 844 and 890 and a single-phase synchronous generator to bus 820.

The proposed indices are evaluated for 18 operational scenarios in which the load level, the power injection level of the DG, and the network configuration vary. Fig. 5 presents the proposed computational method that uses OpenDSS to run the power flow controlled via Python. Thus, two network configurations were implemented:

- **Configuration 1:** it is the original configuration of the system, where only the switches sw9, sw8, sw7, sw6, and sw1 are closed.
- **Configuration 2:** according to Gangwar et al. (2019), it is the system configuration that presents the lowest value of TL during the normal operating condition of the network, with the DG penetration level equal to 20% of the rated system load. Only

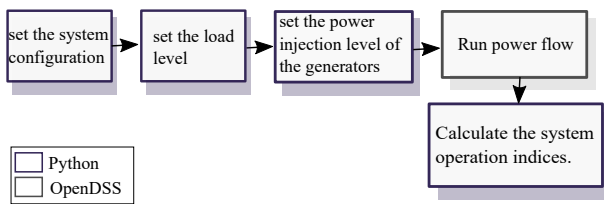


Fig. 5. Flowchart of the proposed computational method.

switches sw8, sw6, sw5, sw4, and sw3 are closed in this situation.

Thus, three load levels were simulated for each configuration: low, rated, and high, as shown in Table 1. The low load level represents 50% of the rated demand, while the high load level equals 150%. Finally, for each load level, three cases of DG penetration were simulated: 0%, 20%, and 50% of the system rated power. The power of DG in each case is shown in Table 2.

4. ANALYSIS AND RESULTS

In this section the analysis of the proposed indices considering each operational scenario is presented. The scenarios are elaborated to verify the impacts on the indexes. Thus, the network reconfiguration proposed by Gangwar et al. (2019) is applied to reduce TL based on a given operating scenario: rated load level and 20% penetration of DG. The implications of the topological reconfiguration to other performance indexes related to security and quality considering changes on the DG penetration and load are described.

Fig. 6 presents the results obtained for the eight proposed indices. Fig. 6a presents the behavior of the TL index. It is noted that for any level of load and DG penetration, the network reconfiguration is able to reduce the TL due to the change in the system topology, responsible for reducing the power flow in the feeder and, consequently, the active power losses. However, during the low load level and 50% DG penetration, TL increase due to the reverse power from the DG. It is interesting to observe that the TL in the low load condition is the highest in the rated load level and 50% DG penetration scenario due to the reverse power flow. Furthermore, the DG and the new network topology significantly maximize network performance, reducing the TL from 20.48% to 5.71% during the high load level.

Fig. 6b shows the HC, another performance index. The HC suffered a minimal change with the new network topology, presenting a difference of 1% at all load levels. This low difference is due to the overvoltage criterion used

Table 1. Simulated load levels.

Low (kW)	Rated (kW)	High (kW)
884.5	1769	2653.5

Table 2. Simulated distributed generation penetration levels.

DG Penetration Level	DG output power (kW)			
	DG1	DG2	DG3	Total
0%	0	0	0	0
20%	96	146	144	386
50%	220	336	350	888.5

to determine the HC that is primarily seen at the point of connection of the DG with the distribution system. Finally, it is noted that the limiting factor of the HC is the system load level. During the low load condition, it is equal to 24.06% and 23.59% but increases to 65.75% and 66.40% during high load, given that now more power injection from the generators is required to exceed the upper limit of adequate voltage.

Regarding the power quality indices, Fig. 6c shows that the network reconfiguration reduced the number of buses with voltage violations during low and high load levels conditions. It is also noted that in the low load scenario, there is only voltage violation when the DG penetration is equal to 50%. These violations can be explained by the HC index, which indicates that the network will operate with overvoltages for power injections above 23.59% and 24.06%. Ultimately, it is observed that in the high load condition, the voltage violation index increases by the appearance of undervoltage in several system buses.

Fig. 6d shows the highest values of the VUF found in the system in each scenario. The index increases with the load level and violates the 2% limit in only one scenario: high load, configuration 1, without DG. In this case, after the network reconfiguration, the index decreases from 2.7349% to 1.8039%. Increasing the DG penetration level can reduce or increase the VUF. It is noted that the index increases with the penetration level during the low load level, but during high load, the index decreases. The difference is due to the single-phase generator connected to bus 820. During the low load period, the generator raises the voltage more than necessary, increasing the unbalance between phases. During the high load, the penetration level of 50% helps reduce system loading, which is the main source of voltage unbalance.

Fig. 6e shows the last power quality index. The index was obtained during a single-phase fault applied to phase A of bus 890. This index decreases with the increasing DG penetration level during high load due to voltage support of generators during the fault. However, this support eliminates voltage sags during rated load on the faulted phase but introduces voltage swells in the unaffected phases. Hence, the index value remains unchanged. Also, although network reconfiguration changes the voltage profile of the system, it is not enough to eliminate VSS.

The security index SCR, obtained by applying faults at bus 890 represents the difference between the current and base fault levels obtained without DG in the original system configuration. Thus, Fig. 6f shows an increase in the index in low-load scenarios due to the gain in the pre-fault voltage. The SCR increases significantly with the network reconfiguration due to the new system impedance between the substation and the fault location. Hence, the SCR is considerably elevated in configuration 2, intensifying the short circuit's negative impacts.

Fig. 6g shows the system's most critical VSM in each scenario. The network reconfiguration tends to increase the index, leaving the system closer to its maximum load of 100% when it presents voltages below 0.9 p.u. In the scenario of rated load and 0% DG penetration, the VSM increases from 87.63% to 100%. Thus, network reconfiguration to minimize losses without DG connection has the

potential to cause voltage instability. That is an interesting result because it demonstrates that the optimization developed by Gangwar et al. (2019) to achieve the best network operation performance is mainly suitable for the rated load and 20% DG operation scenario. Therefore, the operation of the system is not being considered, leaving the state of the system vulnerable considering the Voltage Stability Margin. Configuration 2 was developed for the rated load condition and 20% DG penetration. Therefore, although the system operates without stability violations in this scenario, the maximum VSM of 81.56%. Hence, the loss of DG would endanger the system operation.

Fig. 6h presents the LL security index. It can be noted that the reduction of the index with the network reconfiguration also leads to TL reduction. Also, the DG penetration is also responsible for decreasing this index by supplying loads close to its connection point. However, there is a small increase in the index during the low load scenario when the DG penetration varies from 20% to 50% due to reverse power flow.

By analyzing the simulation of operational scenarios, it is possible to verify that although the network reconfiguration has improved system performance, it has also introduced negative impacts on the security and quality of the operation. The increase in SCR due to reconfiguration and the connection of DG can compromise the correct performance of the protection system and damage the network components. The DG connection reduced the voltage sags produced by the single-phase fault close to the synchronous generator but also caused voltage swells in the non-faulting phases. In addition, the VSM growth changes the operating state of the insurance system to an alert or even an emergency due to the violation of adequate safety limits. Therefore, when changing the system topology, the operator must be aware of the importance of DG to adapt the security and quality indices, otherwise, the operating state is compromised.

Finally, the insertion of DG improves the performance of the indices to a certain extent and then begins to deteriorate the network operation mode, as seen in the case of low-load scenarios. Therefore, it is challenging to define an ideal operating scenario since the same scenario allows the improvement and deterioration of different indices. In this way, the SA assessment helps to verify several operational possibilities to assist in decision-making and answer questions such as: how to define the best operating scenario, what is the priority of the obtained indices, how to decide if a control action should be implemented and how to quantify the improvement or deterioration of the operation in general.

5. CONCLUSION

This paper presents an analysis of SA in the distribution system and how the growing presence of DERs influences the comprehension of the system's operation. This discussion was based on the bibliographic review of the recently published scientific papers. Through this analysis, it was possible to identify the main challenges and opportunities in this matter. The system observability, inconsistencies in the parameters, the comprehension of the system state and the events responsible for the current state signifi-

cantly impact the distribution operator's SA. Eight indices to represent operational criteria of quality, security, and performance were analyzed in different operational scenarios to demonstrate the importance of SA of current active distribution networks. The results demonstrated the vulnerability of the indices in the face of changes in the level of load and penetration of DG and the control actions implemented by operators. With this paper, the authors expected to incentive the discussion of SA in active distribution systems and also to serve as a reference for future studies.

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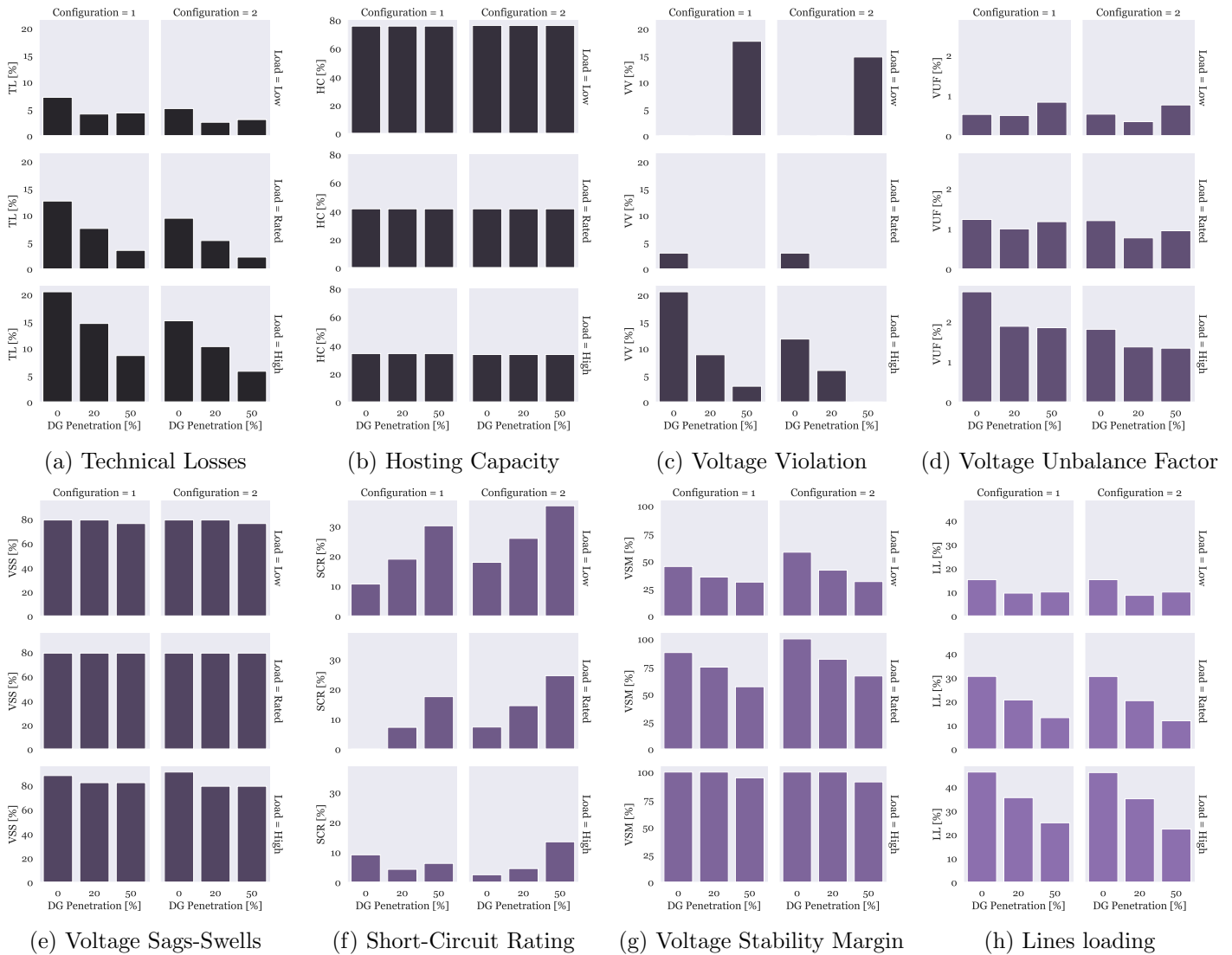


Fig. 6. Results of the eight proposed indices in each operational scenario.

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