Considerations for Automatic Outage Restoration in Distribution Systems With Distributed Energy Resources

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***Abstract*—There have been many discussions about requirements and conditions for distributed energy resources to stay connected or disconnected during events. However, less concern has been given regarding their reconnection after an outage is restored and how entering service requirements may influence distribution automation schemes. Automatic power outage-restoration solutions—such as fault location, isolation and service restoration—use network reconfiguration to restore power to end users within seconds of the event. The solution's decisions are usually made based on pre-event demand levels. However, distributed energy resource reconnection after re-energization can vary from seconds to minutes, according to IEEE 1547-2018, and that generation contribution may not be available at the moment of restoration completion. This paper interprets the IEEE 1547 standard criteria and requirements with regard to distribution system power outage restoration. The intention is to explore the impact that distributed energy resources' contribution to demand levels and time for entering service and ramping up can have on automatic restoration decisions. Different scenarios are analyzed and potential solutions to mitigate and address this influence are discussed.**

***Keywords*—Distributed energy resources, distribution automation, distribution management systems, outage restoration, and IEEE 1547.**

I. Introduction

Distributed energy resources (DERs) are being increasingly employed in the interests of energy independence, sustainability, and lower energy costs. However, the large integration of DERs has been a major factor in disrupting the way distribution systems have been planned, operated, protected, and controlled for decades. While many solutions for distribution protection and operational challenges have been developed, tailored, and improved over time based on traditional assumptions, such as radiality and unidirectional power flow, the growing integration of DERs requires a reevaluation of these solutions and how they respond under these new operating conditions.

For instance, power outage restoration decisions have been automated to properly perform fault location, isolation, and service restoration (FLISR) within seconds from an unplanned outage event—improving reliability, quality, and end user satisfaction. The primary objective of FLISR schemes is to maximize the number of customers whose service is restored. To achieve that, optimal decisions are usually made based on pre-event demand levels [1].

IEEE 1547-2018, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources With Associated Electric Power Systems Interfaces* [2], establishes criteria and requirements for interconnecting DERs with electric power systems (EPSs), ensuring that the expected range of DER responses is known and standardized to support safe and efficient operation. Many studies and discussions have been performed around the behavior of DERs during events and conditions for staying connected or disconnected. However, once the event takes place and protection acts and initiates a distribution power outage, the impacted DERs are required to disconnect. With FLISR schemes in place, faults can be located and isolated. The remainder of the impacted system is then restored as much as possible, based on pre-event levels and the assumption that these levels will not significantly change over the short period of time a FLISR scheme requires to compute and deploy a solution [3].

However, with the increasing presence of DERs, the load consumption levels are masked, and demand levels have become more volatile and unpredictable. Moreover, once an outage deenergizes loads and disconnects DERs, there is a lack of visibility to these elements and uncertainty on when they will reenter service once re-energized and how they will ramp up. This brings up the need to investigate how demand levels, compounded by load and generation, may change from pre-event to postrestoration and how these effects may challenge automatic restoration decisions.

This paper interprets criteria and requirements outlined in IEEE Std 1547 that relate to distribution system power outage restoration, exploring the influence of the DER contribution and response in automatic restoration decisions. The intention is to explore the impact of changes in DER demand levels, entering service timing, and ramp-up behavior after an outage can have on a system with automatic restoration schemes. Different scenarios are analyzed and potential solutions to mitigate this influence are discussed. This paper does not provide a comprehensive review of IEEE 1547 or its substandards. Readers are encouraged to consult the full standard alongside this paper.

II. Automatic Outage Restoration

A. Outage Restoration

It is estimated that power interruptions cause U.S. electricity consumers $150 billion each year [4]. This cost has led to the creation of various regulatory organizations and reliability standards that incentivize utilities to measure power interruptions and invest in reliability improvements.

When a permanent fault occurs on the distribution system, a protective relay is expected to trip a circuit breaker or recloser to stop the flow of current to the fault. If visibility from field devices and fault locators is unavailable, operators may not be immediately aware of the event and must rely on customer reports to identify the event. Initially, only a rough estimate of the location may be available, and a crew must be dispatched to patrol the line, find the exact location of the fault, and repair any damage. They may have to travel and perform manual switching with or without coordination with an operator. This process is time-consuming and very costly for utilities, leaving customers experiencing long outages.

On the other hand, depending on the technology available and the communications network between field devices and supervisory systems, the operators may quickly become aware of the event and its rough location. They may be able to analyze statuses and reports to determine the location of the event and how much power was lost before validating neighboring feeders' voltage levels and available capacity for rerouting power and transferring load. With a solution in place, remote switching can be done to isolate the fault, restore any segments de-energized due to miscoordinations, and restore power from adjacent feeders considerably faster than through manual switching.

Outage restoration is further complicated by DERs connected to the distribution system and feeding a portion of the load on the feeder. When a fault occurs, it is possible that a DER was feeding part of the load de-energized by the outage. The DER will disconnect and may vary in its time to reconnect, as discussed in the next section. Without adequate data from the DER and an understanding of the system, its presence makes it challenging to estimate how much load a neighboring feeder will need to pick up to restore power to downstream end users. Current measurements prior to the fault may give the appearance that there was less load in areas fed by a DER than was present. With the DER disconnected, operators may end up transferring more load to the adjacent source than intended, potentially causing an overload or supplying power at an unacceptable voltage level.

B. Automatic Solutions

Automated restoration solutions, given adequate data, can do much of the outage-restoration work without operator involvement. These solutions can locate a fault, isolate it, and restore power from one or more adjacent feeders to as many end users as possible, as well as report the event. The automatic outage-restoration schemes account for the system's pre-event conditions through current and voltage measurements and ensure that adjacent feeders have enough capacity and acceptable voltage levels before computing a restoration solution. Even when accounting for communications delays, the automatic solution system is able to implement its solution in less than a few minutes. As a result, a majority of customers experience shorter outages, potentially increasing utility revenue, reducing outage costs, improving reliability metrics, and improving customers satisfaction [1].

These automated solutions include FLISR schemes. As the name suggests, when a permanent fault occurs, FLISR schemes detect and locate the fault, isolate it by opening switching devices that bound the fault zone, and restore power to as many end users as possible by switching in neighboring feeders. FLISR applications vary in complexity, scalability, and features. These schemes may be centralized and be able to account for the network topology and configuration providing a global optimal solution but require communications with field devices over a wide area. On the other end of the spectrum, such schemes can be implemented at the edge, with peer-to-peer communications between devices providing a local optimal solution.

However, these solutions can also be misled by the presence of DERs. Without adequate data or the capability to properly process it, they will suffer the same miscalculations as operators performing the restoration. For example, they may mislocate the fault or calculate loading based on radial power flow assumptions, which would be incorrect with strong DER penetration. The following sections analyze various scenarios to demonstrate and discuss the impacts of DERs on outage restoration.

III. Response From DERs

The IEEE 1547 standard was created to establish guidelines for safe and effective operation of generation in parallel with the utility distribution system [2]. Within the standard, three DER categories are defined. Category I DER has a minimum capability to support the grid, while Category II has improved capabilities to support the grid and high penetration, and Category III has extended capabilities designed to support the grid.

The standard includes a section that defines how a DER should respond to the Area EPS during abnormal conditions, such as faults and open phases. The document presents ranges of voltage levels and times that the different DER categories shall disconnect or stay connected. The standard also presents conditions and requirements for DERs to enter service. From a power outage perspective, DERs have two responses to be considered: their trip and their reentry into service.

A. Trip

Tripping requirements vary according to the DER category. Specifically, in the context of undervoltage (UV) events, the IEEE standard describes two undervoltage zones, UV1 and UV2, for each DER category. In general, the allowable clearing time for UV1 zone can range from 2 to 50 s for a voltage equal to or less than 0.88 pu, while the allowable clearing time for UV2 zone can range from 0.16 to 21 s for a voltage equal to or less than 0.5 pu.

B. Entering Service

1) General

As a general requirement the DER shall only energize the Area EPS when applicable voltage and system frequency are within specified ranges. The standard defines the range of allowable settings for a minimum voltage of 0.88–0.95 pu and for a maximum voltage of 1.05–1.06 pu.

While entering in service, the DER may need a permit, depending on the agreement with the utility. In addition, the DER may delay the entering service by 0 to 600 s from the re-energization, 300 s being the default. Once entered in service, the DER is required to increase power in a linear stepped ramp with a duration of 1 to 1000 s, 300 s being the default, where a single step increase must be less than or equal to 20 percent of the name plate. This requirement helps define the minimum ramp duration.

2) Exception

If the exception is followed, a DER with a capacity greater than 500 kVA may increase active power with no rate-of-change limitation. However, the DER must still have a delay to enter service of 0 to 600 s from the re-energization, 300 s being the default, as well as having an additional randomized time delay to enter in service. The randomized delay can range from 1 to 1,000 s, and its main purpose is to avoid synchronized inrush and oscillations that may be initiated by having large DERs reconnecting at the same time.

C. Considerations

Considering the standard requirements for tripping, the longest allowable clearing time for a voltage equal to or less than 0.5 pu is 21 s. The response time for an automatic outage-restoration scheme may vary depending on the number of reclosing shots and their open intervals, communications infrastructure, solution speed, and configurable temporizations. However, the impacted DERs will most likely have already tripped by the time a solution is computed and acted upon.

On the other hand, the time to enter service and reach the full generation can vary, not only by the DER category, but also by the agreed-upon settings. Table I shows the fastest, default, and slowest response a DER may have to enter in service and ramp up.

TABLE I
SUMMARY OF DER RESPONSES TO ENTER SERVICE

Response	Delay From Energization (s)	Ramping Time (s)	Total Time (s)
Fast	0	1	1
Default	300	300	600
Slow	600	1,000	1,600

Assuming an applicable voltage within the allowable range and by inference from the requirements, the fastest response duration to enter in service and ramp up would be 1 s, where there would be 0 s of delay from re-energization and 1 s of ramping. On the other hand, the slowest duration a DER could have to enter service and ramp is 26 min, where there is 600 s of delay from re-energization and another 1,000 s from ramping. However, the default values set a duration of 10 min, where there is 300 s of delay from re-energization and 300 s of ramping. It is important to highlight that other characteristics can be specified by mutual agreement between the Area EPS operator and DER operator. However, this paper focuses on the extreme ranges provided by the standard.

Considering that a FLISR scheme may take seconds from the last trip and lockout to achieve a restoration, the DERs may take anywhere between 1 s to 26 min to fully ramp up. Fig. 1 illustrates the range of possible DER responses during following restoration.

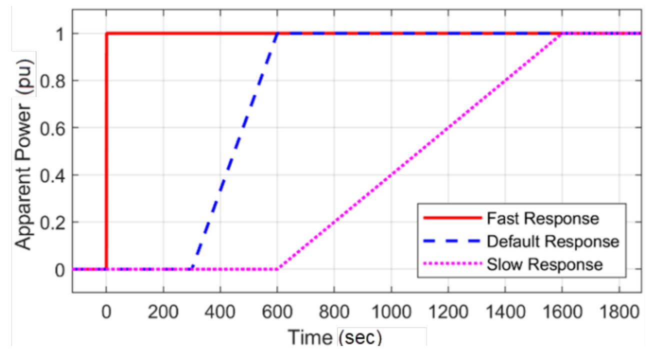

Fig. 1. DER Responses to Enter Service

From Fig. 1, the re-energization of a DER happens in 0 s and its pre-event capacity is 1 pu, which is considered available over the analyzed time window. The shown behavior assumes that the DER applicable voltage when re-energized is within its allowable range. If the restoration decision provides an operating condition where some restored DERs have an applicable voltage within their allowable range while others do not, it may happen that the ramping up of the former set of restored DERs will improve the system voltage in such a way that the DERs in the latter set may detect applicable voltage levels within their allowable range and thus enter service. Such response may increase the total time to fully ramp up the system-aggregated DERs.

IV. Challenges

As discussed in the previous sections of this paper, when an outage occurs and restoration begins there is a time delay that DERs must wait for prior to ramping up and participating in the power system again. This behavior creates several challenges in the distribution system. Most simply put, pre-fault conditions and postrestoration conditions may be significantly different for seconds to several minutes after the restoration occurs. Traditional automatic outage-restoration algorithms typically rely on the assumption that post restoration conditions will be similar to pre-fault conditions.

A major challenge of having DER generation on the distribution system when working through a restoration process is the risk of the pre-fault demand not matching the load current requirements of the postrestoration system due to the presence of DER generation. Often, automatic outage-restoration algorithms only have access to demand line current flows from breakers and reclosers. This information may not explicitly represent the system load, as DER generation influences demand levels and can mask the actual load. Because the DER may no longer be connected or producing power for up to several minutes after service is reestablished, the restoration process may need to account for actual load rather than demand levels until the DER can reenter service and, depending upon system configuration, return the restored demand to similar levels as the pre-fault conditions. The concern with not knowing the contribution of load and generation to line demand leads to increased risk that restored lines may exceed their capacity or system nodes may transgress their lower voltage level limits. Such conditions may cause additional events that can disrupt the automatic restoration process and require a distribution system operator to become involved with the restoration sequence, significantly increasing the outage time [5].

It is difficult for a restoration scheme to be DER aware and take into account the presence of DER without additional metering on the system. A majority of the DERs placed on the distribution system is intermittent in nature. Because of that, PV generation typical curves are not accurate enough to support automatic outage-restoration decisions. Battery energy storage systems (BESS) are often operated to benefit the economic considerations of an individual load. The BESS may discharge to reduce utility operating costs, leading to lower demand levels. Alternatively, the BESS may charge, operating as a load, leading to higher demand levels. However, that load may not be re-energized until the BESS reenters service from its restoration. This variability prevents simple rule additions to restoration schemes from being effective.

The most accurate solution to account for DERs on the system is to include additional demand metering information from each connection which has DERs and load. The additional metering would provide separate metering data for the load and DER generation so that the restoration scheme is able to decouple and identify load and generation from demand. Unfortunately, this solution also adds significant costs due to the need for metering devices and communications infrastructure. This creates additional complexity in accurately processing DER measurement points and information, which can significantly increase depending upon the density of metering points on the distribution system and their location relative to DERs in the system.

V. Case Study

The case study explores the impact that different DERs and their responses for entering service may have during automatic outage restoration. More specifically, the analysis aims to investigate how restoration decisions-based on demand or consumption levels, along with the delayed response of the DERs to reach full capacity—may impact restoration decisions and create unreliable system conditions, such as overloading or low voltage levels.

A. Distribution System

The MV Oberrhein (MVO) network is used as a test distribution system. This is an open-source synthetic network model available through pandapower [6]. The MVO network is comprised of four 20 kV feeders, which are serviced by two 25 MVA 110/20kV substations. There are six normally open switching devices interconnecting the four feeders and enabling a networked topology, even though the system is designed to operate in radial configuration. In total, the system has 63 MVA of installed load and 22 MVA of generation capacity from 153 DERs connected over the four feeders. The system is defined with three types of cable, 243 AL1 39 ST1A 20, NA2XS2Y 1x240 RM25 12/20 kV and NA2XS2Y 1x185 RM25 12/20 kV, which have a maximum capacity of 625, 430, and 385 A, respectively. Fig. 2 provides a spatial view of the MVO network based on its Geographic Information System data.

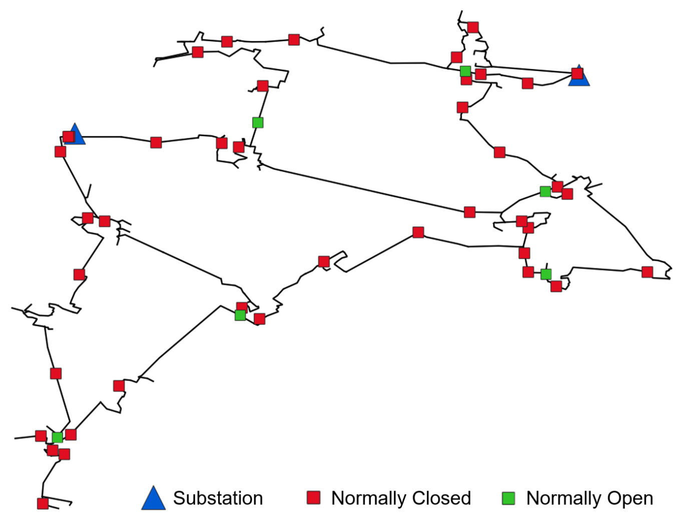

Fig. 2. Network Spatial Topology

B. Testbed

With the intention of properly simulating the network and its element response, a software-in-the-loop testbed was used for this analysis. The MVO system was modeled in Open Distribution System Simulator (OpenDSS), developed by Electric Power Research Institute. By using py-dss-interface, the network model runs within a Python environment. The pymodbus package was also used to create Modbus servers and clients so information can be exchanged between the Python environment and an external device.

In Python, DERs and switching devices are updated and OpenDSS runs power flows every 250 ms. Every 1 s the power flow results and devices statuses are organized in Modbus servers declared and hosted by pymodbus. These servers then exchange information with an external physical data concentrator. At the same time, every 1 s, commands from the data concentrator to open and close switching devices are read. The data concentrator then converts the Modbus protocol into DNP3 and integrates with an automatic power outage-restoration solution, which in turn, analyzes events and provides an outage-restoration decision based on system conditions and topology.

Fig. 3 shows the testbed architecture.

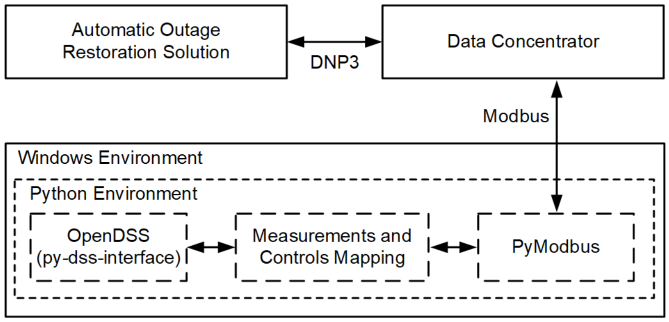

Fig. 3. Testbed Architecture

C. Scenarios

Four different scenarios were analyzed with the described testbed and distribution network. All scenarios are based on the same event type and location, but the first scenario considers that DERs are not present in the system and each of the other three scenarios considers DERs with a different response to enter in service: fast, default and slow.

In addition, each of the four scenarios was analyzed for two different variations:

- Variation A: automatic outage-restoration decisions are made based on demand levels.
- Variation B: automatic outage-restoration decisions are made based on consumption levels.

Table II provides a summary of the test cases and conditions.

TABLE II
SUMMARY OF ANALYZED SCENARIOS

Scenario	Variation	DERs		Restoration Based on
		Present	Response	
I	A	No	N/A	Demand
	B	No	N/A	Load
II	A	Yes	Fast	Demand
	B	Yes	Fast	Load
III	A	Yes	Default	Demand
	B	Yes	Default	Load
IV	A	Yes	Slow	Demand
	B	Yes	Slow	Load

D. Considerations and Assumptions

Fig. 4 shows the MVO single-line diagram and fault location used for the four scenarios and their variations, where gray and white stand for normally closed and normally open devices, respectively. In addition, all scenarios consider 1.05 pu voltage at the substation buses and consumption level of 60 percent of the installed load. Scenarios II, III, and IV consider DER presence in the system with a generation level of 100 percent of the installed capacity. All DERs are configured with a clearing time of 2 s for voltages below 0.5 pu and a required applicable minimum and maximum voltage of 0.88 and 1.05 pu, respectively. The response of the DER to entering service depends on the scenario being analyzed and follows the guidelines outlined in Table I and Table II, where no exceptions are considered. MVO is not mounted with capacitor banks, voltage regulators, or their respective controls and dynamics, so this study does not account for them.

VI. Analysis

The results for each scenario are presented as the automatic outage-restoration switching decisions to isolate and restore the event, as well as the overtime response of the total active and total reactive power demand levels of the system, the minimum voltage level and maximum line loading of the system, and the total number of connected and ramping DERs. Line loadings are computed based on power flow results and maximum current capacity of the cable type.

A. Scenario I: No DER Present

For Scenario I, both Variations A and B provide the same response as there is no generation and demand matches consumption. For a shunt fault at the proposed location, at 0 s, S047 trips and locks out. The automatic outage-restoration scheme identifies the event and opens S036 and S037 as isolation actions. In the sequence, S013, S014, S034 and S035 are also open and then S008 and S009 are closed to achieve optimal restoration. The opening actions after isolation are performed with the intention of achieving a partial restoration according to the loading conditions and the adjacent feeder capacity for picking up load. Fig. 5 provides an overtime view of the system for Scenarios I.A and I.B.

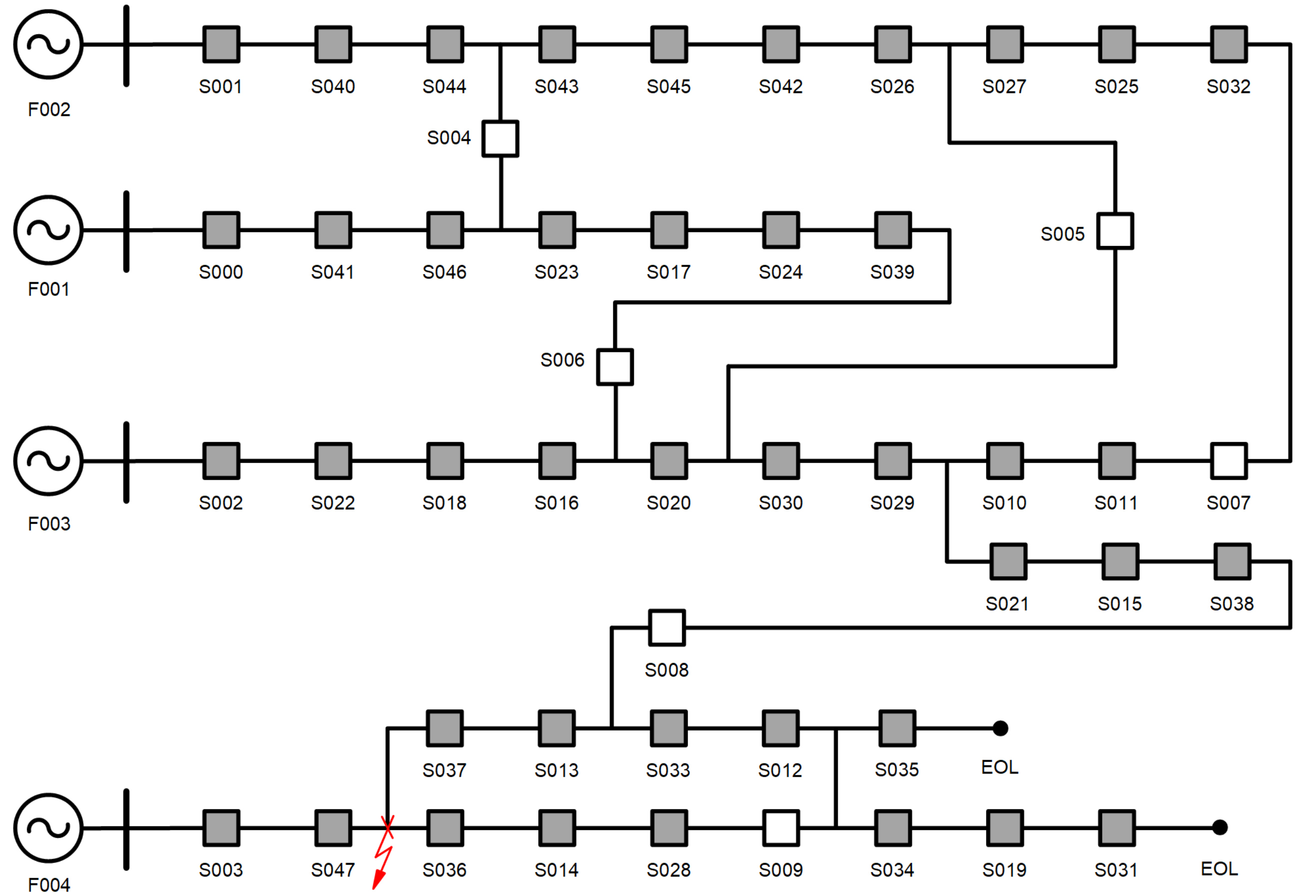

Fig. 4. Network Single-Line Diagram

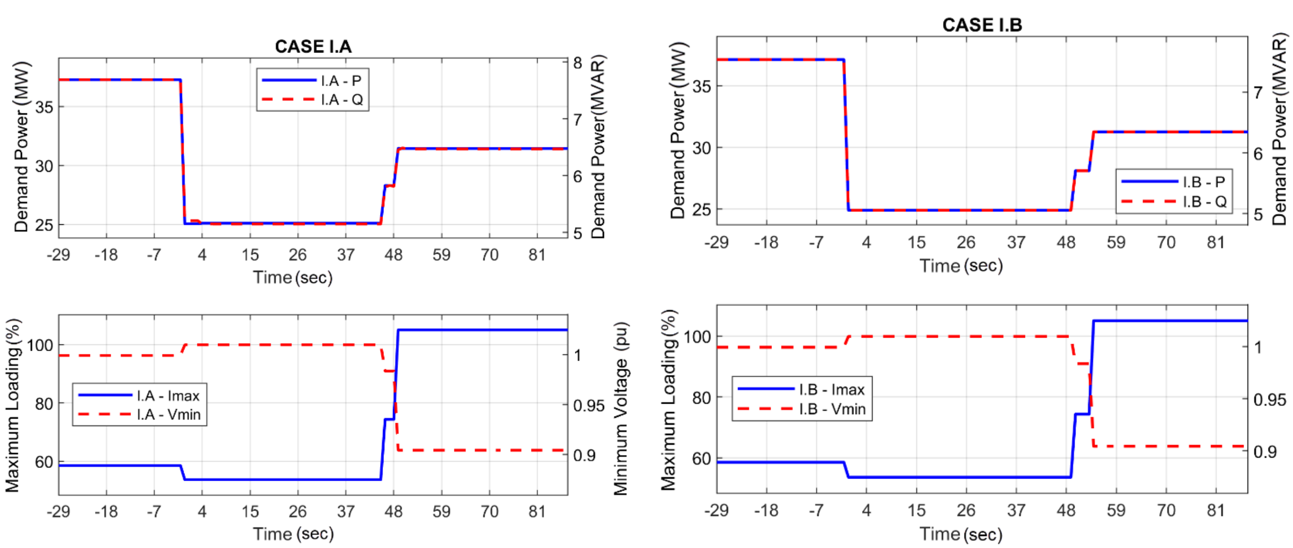

Fig. 5. Case I Results

It is possible to observe that the responses from both Variations A and B match each other with slight differences in the time response as both were run as different simulations, that the automatic outage restoration solutions may have slightly different computation times, and that the testbed may present different communications delays. System demand levels are reduced after the event takes place as part of the system is de-energized by protection actions. The restoration is partial, where further sectionalization is done only to transfer and restore load that can be picked up by the adjacent feeder. Due to the system loading and lack of DER presence, the restoration creates a maximum voltage drop close to 10 percent and a maximum loading of 105 percent, which remains the same until the end of the analyzed period.

B. Scenario II: DERs Present With Fast Response

For a trip and lockout of S047, both Variations A and B of Scenario II result in a solution where S036 and S037 are opened as isolation actions. In this case, 58 of the 153 DERs are tripped due to the outage, with 4 of the 58 DERs being within the faulted zone. However, the restoration decisions varied. For Variation A, where the outage-restoration is computed based on demand, the decision is to directly close S008 and S009, performing a full restoration. For Variation B, which is computed based on consumption, the solution is the same as the one achieved in Scenarios I.A and I.B, where S013, S014, S034 and S035 are opened and S008 and S009 are closed, performing a partial restoration.

Fig. 6 provides an overtime view of the system for Scenarios II.A and II.B.

As Variation A is computed based on demand levels, the restoration solution transfers the entire remainder of the outage to the adjacent feeder. However, as impacted DERs have tripped during the outage, the restoration transfers a large amount of unseen load to a single adjacent feeder. With a 0 s delay, DERs with applicable voltage within the predefined range are connected as soon as the restoration takes place, and then they take another 1 s to fully ramp up. The minimum captured system voltage is 0.89 pu with a maximum loading of 85 percent. Once 54 of the 58 impacted DERs are fully ramped up, the system minimum voltage is reduced to 0.92 pu and maximum loading to 72 percent.

On the other hand, when the restoration solution is computed based on actual consumption levels, such as in Variation B, the minimum captured system voltage is 0.93 pu and maximum loading is 72 percent. Because the restoration solution decided to maintain some of the impacted segments de-energized due to the adjacent feeder transfer capacity, only 30 of the initial 58 impacted DERs are re-energized and able to enter service and ramp up. Meanwhile, 24 DERs remain de-energized, and another 4 are within the faulted zone. When these 30 DERs are fully ramped up, the system maximum loading is reduced to 62 percent and voltage levels are as low as 0.95 pu.

C. *Scenario III: DERs Present With Default Response*

Similar to Scenario II, both Variations A and B of Scenario III had a solution where S036 and S037 are opened as isolation actions. In this case, 58 of the 153 DERs are tripped due to the outage, with 4 of these 58 DERs being within the faulted zone. However, the restoration decisions varied. For Variation A, the decision was to directly close S008 and S009, performing a full restoration. While for Variation B, the solution was the same as the one achieved in Scenario I.A and I.B, where S013, S014, S034 and S035 are opened and S008 and S009 are closed, performing a partial restoration. Fig. 7 provides an overtime view of the system for Scenario III.A and Scenario II.B.

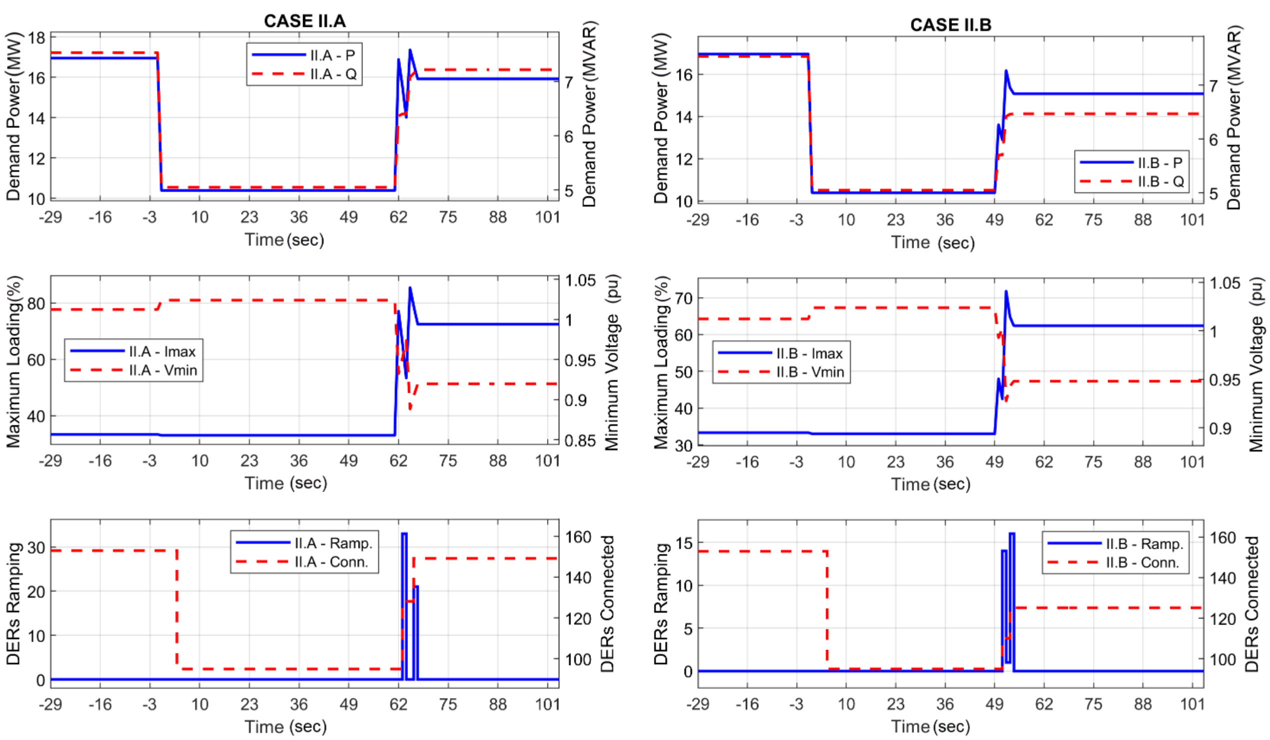

Fig. 6. Case II Results

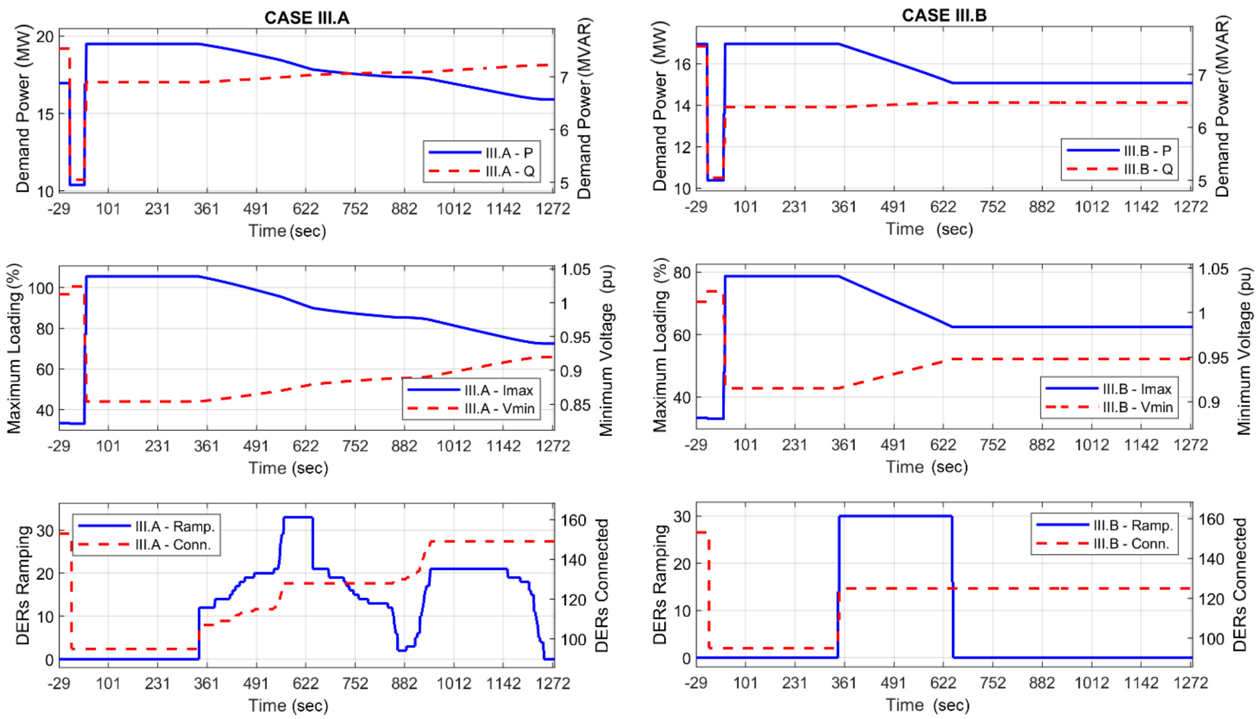

Fig. 7. Case III Results

As Variation A is computed based on demand levels, the restoration transfers a large amount of unseen load to a single adjacent feeder, loading lines to as much as 105 percent and creating voltage levels as low as 0.85 pu right after restoration. With a required applicable minimum voltage of 0.88 pu and the network minimum voltage of 0.85 pu, some impacted DERs do not have the required applicable voltage to reconnect. DERs with the required applicable voltage enter service after 300 s and start to ramp up for another 300 s. During their ramp up, system demand is reduced and voltage levels improve, allowing other impacted DERs, those that initially did not have the minimum applicable voltage of 0.88 pu, to enter service. When 54 of the 58 impacted DERs are fully ramped up, after approximately 1,249 s from the restoration, the system maximum loading is reduced to 72 percent and minimum voltage level is increased to 0.92 pu.

On the other hand, the solution decision for Variation B creates a condition of minimum voltage level of 0.91 pu and maximum line loading of 79 percent. As the network minimum voltage of 0.91 pu was greater than the required applicable minimum voltage of 0.88 pu, all 30 restored DERs are able to enter service after 300 s and ramp up for another 300 s. The remaining 24 tripped DERs were not re-energized due to the partial restoration decision and another 4 DERs are within the faulted zone. When the 30 restored DERs were fully ramped up, the system maximum loading was reduced to 62 percent and minimum voltage level was increased to 0.95 pu.

D. Scenario IV: DERs Present With Slow Response

Similar to Scenarios II and III, both Variations A and B of Scenario IV have a solution where S036 and S037 are opened as isolation actions. In this case, 58 of the 153 DERs are tripped due to the outage, with 4 of these 58 DERs being within the faulted zone. However, the restoration decision varied. For Variation A, the decision was to directly close S008 and S009, performing a full restoration. While for Variation B, the solution was the same as the one achieved in Scenario I, where S013, S014, S034 and S035 are opened and S008 and S009 are closed, performing a partial restoration.

Fig. 8 provides an overtime view of the system for Scenario IV.A and IV.B.

The dynamics of Case IV are similar to Case III, but with longer times. As Variation A is computed based on demand levels, the restoration transfers a large amount of unseen load to a single adjacent feeder loading lines to as much as 105 percent and creating voltage levels as low as 0.85 pu. With a required applicable minimum voltage of 0.88 pu and the network minimum voltage of 0.85 pu, some impacted DERs do not have the required applicable voltage to reconnect. DERs with the required applicable voltage enter service after 600 s and start to ramp up for another 1,000 s. During their ramp up, system demand is reduced and voltage levels improve, allowing other impacted DERs, those that initially did not have the applicable minimum voltage of 0.88 pu, to enter service. When 54 of the 58 impacted DERs are fully ramped up, after approximately 2,672 s from the restoration, the system maximum loading is reduced to 72 percent and the minimum voltage level is increased to 0.92 pu.

On the other hand, the solution decision for Variation B creates a condition of a minimum voltage level of 0.91 pu and maximum line loading of 79 percent. As the network minimum voltage of 0.91 pu was greater than the required applicable minimum voltage of 0.88 pu all re-energized DERs were able to enter service after 600 s and ramp up during another 1,000 s. Because the restoration solution decided for a partial restoration to respect the adjacent feeder transfer capacity, only 30 of the initial 58 impacted DERs were restored and able to enter service and ramp up.

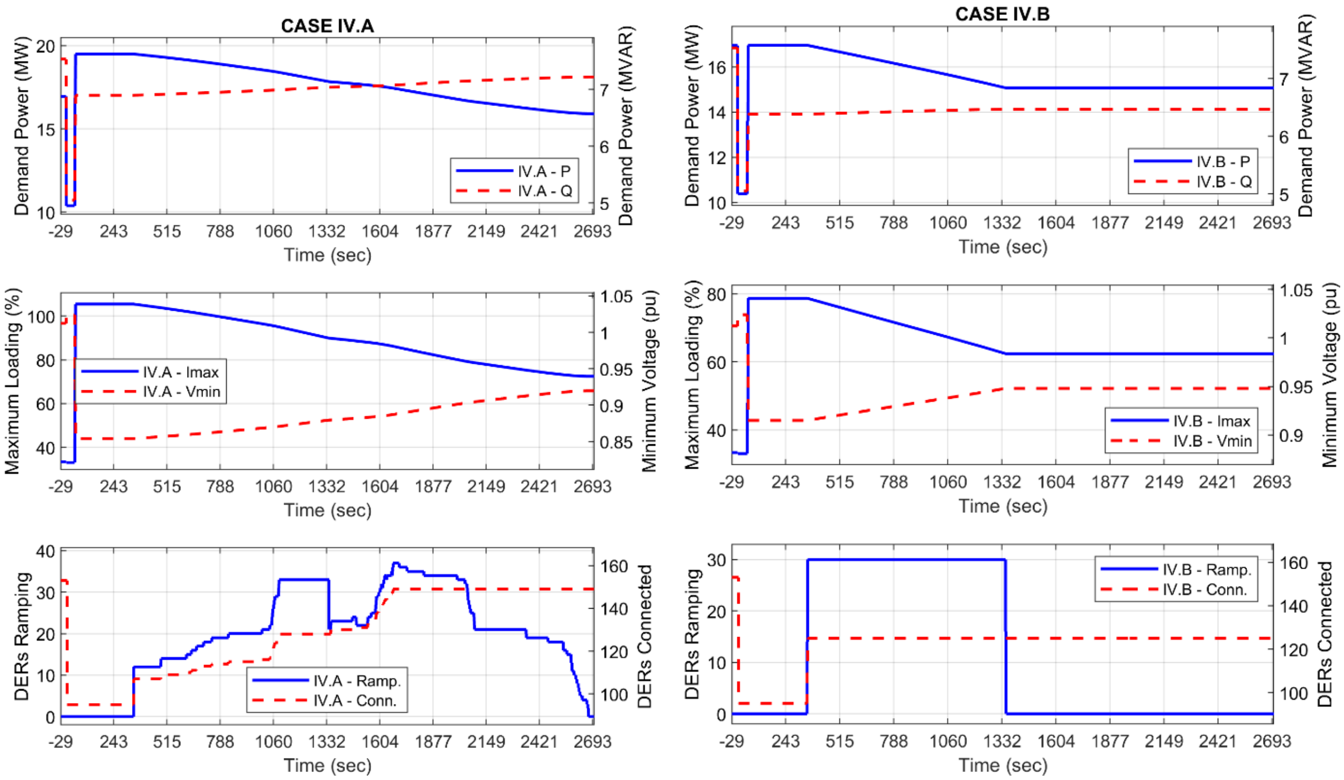

Fig. 8. Case IV Results

Meanwhile, 24 DERs remained unrestored, and 4 were within the faulted zone. When these 30 DERs are fully ramped up, the system maximum loading is reduced to 62 percent and minimum voltage level is increased to 0.95 pu.

VII. Discussions

The results obtained in the four scenarios and their variations in computation highlight the impact that DER contribution and their response may have on outage restoration. Table III provides a summary of the results for each of the four scenarios and their variations.

Restoration solutions based on demand, such as Scenarios II.A, III.A, and IV.A, created near critical voltage and loading operating conditions before DERs entered in service and ramped up, reaching up to a 15 percent voltage drop and a 105 percent loading. With a required applicable minimum voltage of 0.88 pu and the network minimum voltage of 0.85 pu, some impacted DERs did not have the required applicable voltage to reconnect. DERs with the required applicable voltage entered service and started to ramp up based on their delay and ramping time. During the ramp up, system demand is reduced and voltage levels improve, allowing other impacted DERs, those that initially did not have the applicable minimum voltage of 0.88 pu, to enter service. The full entering service and ramping up process was approximately 1,249 s instead of 600 s for Case III.A and 2,672 s instead of 1,600 s for Case IV.A. Once 54 of the initially 58 impacted DERs entered service, the systems presented a maximum voltage drop of 8 percent and maximum loading of 72 percent.

On the other hand, automatic outage-restoration solutions based on consumption, such as Scenarios II.B, III.B, and IV.B, presented a more reliable decision, where the impacted system was sectionalized and the restoration was partial based on consumption and adjacent feeder capacity, and avoided placing the system in near critical operating conditions. As part of the system was restored, only 30 of the initial 58 impacted DERs entered service, with 4 of the 58 being within the fault zone and 24 not restored. As soon as these 30 DERs fully ramped up, the system maximum voltage drop and loading were reduced from 9 percent to 5 percent and 79 percent to 62 percent, respectively.

As mentioned, this study does not account for capacitor banks and voltage regulators and their respective controls and dynamics. However, these pieces of equipment may play an important role after automatic restoration of distribution systems with DERs, especially when there is a large contribution of DERs with default and slow responses. As observed in Scenario III.A and IV.A, during the time the system was restored and some of the re-energized DERs entered service, voltage levels were improved based on the DERs ramping time and other DERs started to have voltage within applicable levels. These DERs were still entering service and ramping up based on their delay and ramping time, almost doubling the aggregated DERs time to full ramp up, which is considerably longer than the usual delay of voltage regulators and capacitor banks. This overlap in dynamics may help mitigate low-voltage level transgressions in the system and facilitate DERs entering service faster.

TABLE III
SUMMARY OF RESULTS

Scenario		Restoration Computation	Event	Decision			System					
			Trip and Lockout	Isolation	Restoration		Minimum Voltage (pu)		Maximum Loading (%)		Connected DERs	
				Open	Open	Close	Overall	Final	Overall	Final	Minimum	Final
I	A	Demand	S047	S036, S037	S013, S014, S034, S035	S008, S009	0.9044	0.9044	105.02	105.02	0	0
	B	Consumption	S047	S036, S037	S013, S014, S034, S035	S008, S009	0.9044	0.9044	105.02	105.02	0	0
II	A	Demand	S047	S036, S037	-	S008, S009	0.8884	0.9197	85.42	72.44	95	149
	B	Consumption	S047	S036, S037	S013, S014, S034, S035	S008, S009	0.9276	0.9480	71.80	62.40	95	125
III	A	Demand	S047	S036, S037	-	S008, S009	0.8541	0.9197	105.48	72.44	95	149
	B	Consumption	S047	S036, S037	S013, S014, S034, S035	S008, S009	0.9151	0.9480	78.68	62.40	95	125
IV	A	Demand	S047	S036, S037	-	S008, S009	0.8541	0.9197	105.48	72.44	95	149
	B	Consumption	S047	S036, S037	S013, S014, S034, S035	S008, S009	0.9151	0.9480	78.68	62.40	95	125

Even though it is a simple concept, the challenge to automatically restore distribution systems with DERs becomes the proper computation of consumption. While reclosers and breakers read demand levels in such systems, to separate demand into generation and consumption requires additional information and processing. Feeder or end user typical load and generation curves may help but the concern then becomes their lack of near-real-time accuracy. Another option, and more appropriate solution, may be to properly meter the point of connection (POC) of each DER in the system or at least the POC of the major ones. Such an approach would require investments in metering equipment and infrastructure to collect and process these data but could efficiently decouple demand into consumption and generation for modern distribution management solutions, not limited to automatic outage restoration.

VIII. CONCLUSION

The growing integration of DERs has been changing the way distribution systems are planned, operated, protected, and controlled. Many studies and discussions have been performed around behavior of the DERs during events and conditions for staying connected or disconnected. However, once the event takes place and protection acts and initiates a distribution power outage, the impacted DERs are required to disconnect, even though little attention has been given to how and when impacted DERs may reenter service and how this behavior may impact operating decisions following the protection, such as automatic outage-restoration decisions.

This paper interprets the criteria and requirements of the IEEE 1547 standard with regard to distribution system power outage restoration. With automatic outage-restoration schemes in place, the fault can be located and isolated, while the remainder of the impacted system is optimally restored within seconds. Often automatic outage-restoration schemes only have access to demand line current flows which are used to compute how much of the impacted system can be transferred to neighboring feeders based on their capacity. The challenge becomes that the load levels of the actual system are masked under the demand levels due to the generation of the DERs. According to IEEE 1547, a DER may take anywhere between 1 to 1,600 s to reenter service and ramp up from its re-energization, assuming that the applicable voltage of the DER when re-energized is within its allowable range. This behavior implies that pre-event demand levels may seem smaller than actual load, and once restoration is achieved, impacted DERs will not have yet entered service and ramped up, which can lead to near critical operating conditions, such as overloading and low voltage levels. In addition, the restored system may provide voltage levels outside the required applicable voltage of some DERs, thus not all of the re-energized DERs may be able to enter service initially.

By analyzing four different scenarios with two variations of possible automatic outage-restoration computations, based on demand or consumption, this paper investigated the challenges that DER behavior may add to restoration decisions. When DERs are present, the restoration decision can be made based on demand or consumption levels. The analysis shows that automatic outage-restoration solutions based on consumption offer more reliable decisions. For these variations, the impacted system is sectionalized, and the restoration is performed partially based on loading and adjacent feeder capacity, rather than placing the system in near critical operating conditions. On the other hand, restoration solutions based on demand created near critical low voltage and overload operating conditions until the DERs reentered in service and fully ramped up. It was also observed that depending on the restoration decision, only some re-energized DERs have applicable voltage levels to enter service, but as they ramp up and voltage levels are improved, other DERs may start entering service, which can almost double the total time for aggregate DERs to fully ramp up.

The challenge of automatically restoring distribution systems with DERs then becomes the proper computation of consumption. Separating demand into generation and consumption requires additional information and processing. Rather than solely relying on current flow data from breakers and reclosers, a more appropriate approach to compute generation and consumption would be by having additional metering at the POC for the DERs to support decision-making. Such an approach would require investments in metering equipment and infrastructure to collect and process these data but could efficiently decouple demand into consumption and generation for modern distribution management solutions, not limited to automatic outage restoration.

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X. Biographies

Jeffrey Hauber is a principal engineer (PE) in the Grid and Automation Technology group at Evergy. He received a BSEE from the University of Kansas in 2005. He started at Westar Energy as a Distribution Engineer with responsibilities including planning, coordination, design, power quality, and reliability. He began working in the Grid Technology group at its creation in 2013 to implement a distribution automation pilot project. The Grid Technology group has grown to now include installing and supporting smart field devices, SCADA and remote engineering communications, distribution management system support, and security support. He is a professional engineer in Kansas and a member of IEEE.

Daniel Wachter is the manager of long-term distribution planning at Evergy, where he oversees the modeling and evaluation of system-wide impacts to the electric grid resulting from industry trends, such as increasing electric vehicle and distribution generation adoption. With over 17 years of experience in utility distribution systems, Daniel has the background necessary to navigate the fast-changing distribution landscape. He holds a master's in electrical engineering from Kansas State University, has completed an MBA, and is a registered professional engineer.

Konrad Schmitt received the PhD degree in electrical engineering from Texas Tech University, USA, in 2023, and the BSc degree in electrical engineering from the Federal University of Santa Maria, Brazil, in 2019. Konrad is a power engineer at Schweitzer Engineering Laboratories, Inc. (SEL), in Pullman, USA, where he supports the design, development, and validation of Distribution Management System (DMS) applications that improve reliability, continuity, quality, and safety of power delivery. Konrad's technical expertise is in the field of power distribution systems, where has various technical publications and a book chapter related to network reconfiguration, self-healing, outage restoration and management, renewable energy integration, voltage control, and hardware-in-the-loop simulation. Since 2017, Konrad has been an active IEEE Power & Energy Society (PES) member and volunteer, where he has held local and global leadership positions, besides contributing to IEEE Technical Committees. He is a certified Project Management Professional (PMP) and member of IEEE Eta Kappa Nu (HKN), Tau Beta Pi (TBP), and Phi Kappa Phi (PKP) Honor Societies.

Mike Jones received a Master of Engineering in Mechanical Engineering from the University of Idaho, USA, in 2016, and B.Sc. degrees in Mathematics and Physics from the University of Idaho, USA, in 2013. He is currently a development lead software engineer working on Distribution Management Systems (DMS) solutions on the Blueframe platform at Schweitzer Engineering Laboratories, Inc. (SEL).

Brian Waldron is a senior automation engineer with Schweitzer Engineering Laboratories, Inc. (SEL). He has over a decade of experience in designing and troubleshooting automation systems, communications networks, and distributed energy resource (DER) control systems. He has authored several technical papers, application guides, and teaching presentations focusing on integrating automation products. Brian graduated from Gonzaga University with a BS degree in electrical engineering.

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