A Simplified Approach to Distribution Feeder Protection for Microgrids With Inverter-Based Resources

Bryan Hosseini and Jason Eruneo
Duke Energy

Ahmed Abd-Elkader, Fred Agyekum, and Rona Vo
Schweitzer Engineering Laboratories, Inc.

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A Simplified Approach to Distribution Feeder Protection for Microgrids With Inverter-Based Resources

Bryan Hosseini and Jason Eruneo, *Duke Energy*
Ahmed Abd-Elkader, Fred Agyekum, and Rona Vo, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Duke Energy installed a 6.25 MVA distributed energy resource (DER) site to improve the power reliability for customers within an isolated portion of its operating region. The site consists of photovoltaic (PV) and battery energy storage system (BESS) generation resources and a dedicated grounding transformer that is only in service during microgrid system configuration. The DER site transitions to microgrid operation upon the loss of the upstream substation source. This process requires a break-before-make transition to isolate the feeder from the system abnormality and allows the inverters to switch from a grid-following control mode to a grid-forming control mode. This transition is performed in an automated sequence without operator intervention using an automation controller.**

The absence of the substation source severely reduces the fault current disparity along the distribution feeder when operated as a microgrid. This prevents the use of traditional protection schemes and practices. The reduction in fault current introduced challenges with the coordination of protection systems located downstream of the DER site. Using the full potential of the inverter capabilities helped in finding solutions to these protection challenges. We developed protection schemes based on the fault current responses of inverters and zero-sequence currents that are available from the zero-sequence path provided by the ground transformer.

This paper describes the unique protection and control philosophies for a distribution system used to handle the challenges of an inverter-based-resource (IBR)-dominated system. It also details the in-depth hardware-in-the-loop (HIL) validation process that provided a high degree of confidence that the engineering solution provides secure and dependable operation.

I. Introduction

The distributed energy resource (DER) site is located in a western North Carolina mountain town named after its local hot springs, which are geothermal waters emerging from the ground. Hot Springs, North Carolina, is situated approximately 35 miles from Asheville surrounded by the Pisgah National Forest and French Broad River. The town is served by a single overhead three-phase 10-mile distribution circuit that starts near the town of Marshall, North Carolina and extends northwest where it terminates at Hot Springs, as shown in Fig. 1. Due to the environmental sensitivity of the area and the more than ten miles of rough terrain limiting the options to address frequent and extended power outages, it was decided a non-wires alternative was needed to address the reliability concerns for the 550 year-round residents, as well as the tourists who frequent the area.

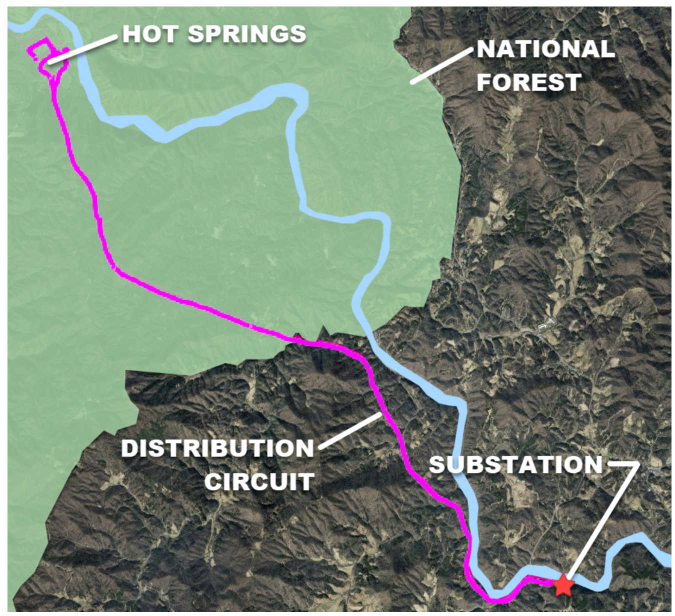

Fig. 1 Distribution Circuit

The non-wires alternative that was ultimately selected is an inverter-based solution consisting of a 4.4 MW lithium-ion battery system and a 1.85 MW solar facility, shown in Fig. 2, to provide real and reactive power support functions when the utility source is available and serve as an alternate power supply for the town during grid outages.

Fig. 2 Hot Springs Battery Energy Storage System (BESS)

This solution also allows the solar facility to provide year-round clean power to the town and improve the circuit reliability, which is important to the customers and tourists in the area.

II. System Topology

A. Distribution Circuit

The distribution circuit is fed from a single 115 kV/22.8 kV, 6.25 MVA substation transformer, which does not have an alternate source. Also due to the topology and national forest, there are no secondary circuits to provide switching points. Once the circuit leaves the substation, there are only a handful of laterals to provide service to other customers before arriving at Hot Springs. Due to the limited number of customers between the substation and the town, it was decided that the optimized design would be limited to providing microgrid service at the town of Hot Springs.

The circuit enters the town at an intentional islanding device (IID) that was installed to allow the circuit to be segmented and provide the microgrid boundary, as shown in Fig. 3. The simplified one-line diagram also shows the overhead backbone with three main branches protected by three reclosers. Beyond those three reclosers are laterals that serve various customers.

The customer peak load of 2.48 MW is an interesting blend that includes restaurants, stores, an elementary school, residences, and other lodging, as well as a small manufacturing facility. During the design process, it was determined that the largest load is a large compressor at the manufacturing facility, which is in the first zone of load.

Prior to the microgrid design, the existing line reclosers within the microgrid boundary were hydraulic-type devices, located to protect three-phase load splits in the town. During the evaluation of the loading on the inverters, two out of the three hydraulic reclosers, R1 and R2, were replaced with electronic reclosers. The reclosers were selected based on the size of the load beyond the reclosers so they could assist with black starts. The black-start sequence requires closing the load-segmenting reclosers sequentially to minimize the power quality impacts to the customers already being powered from the BESS.

B. DER-Generating Facility

The DER site consists of two battery energy storage systems (BESSs) and one photovoltaic (PV) array generation resource. The BESSs are each rated at 2.2 MVA, and the PV array is made up of 37 string inverters, each rated at 50 kW. A grounding transformer (GNDTX) was added to the site to ensure that the microgrid maintains effective system grounding when disconnected from the distribution system. The DER site is oversized relative to the amount of load along the sectionalized distribution feeder for the microgrid configuration. This was needed to provide sufficient current capability for black-start operations and fault conditions. The BESS inverters for this site can switch from a grid-following (GFL) control mode to a grid-forming (GFM) control mode. However, to perform this transition, the entire system must be shut down to give the inverter control system the time needed to make the control change, turn off anti-islanding, and charge the direct current (dc) link capacitors. Thus, we had to implement a break-before-make scheme when transitioning from a grid-parallel system configuration to a microgrid system configuration.

The PV inverters remain in GFL mode for both grid-parallel and microgrid system configurations. This is typical at all the utility installations due to the need for a stable voltage reference for the PV inverter control systems to track and synchronize with [1].

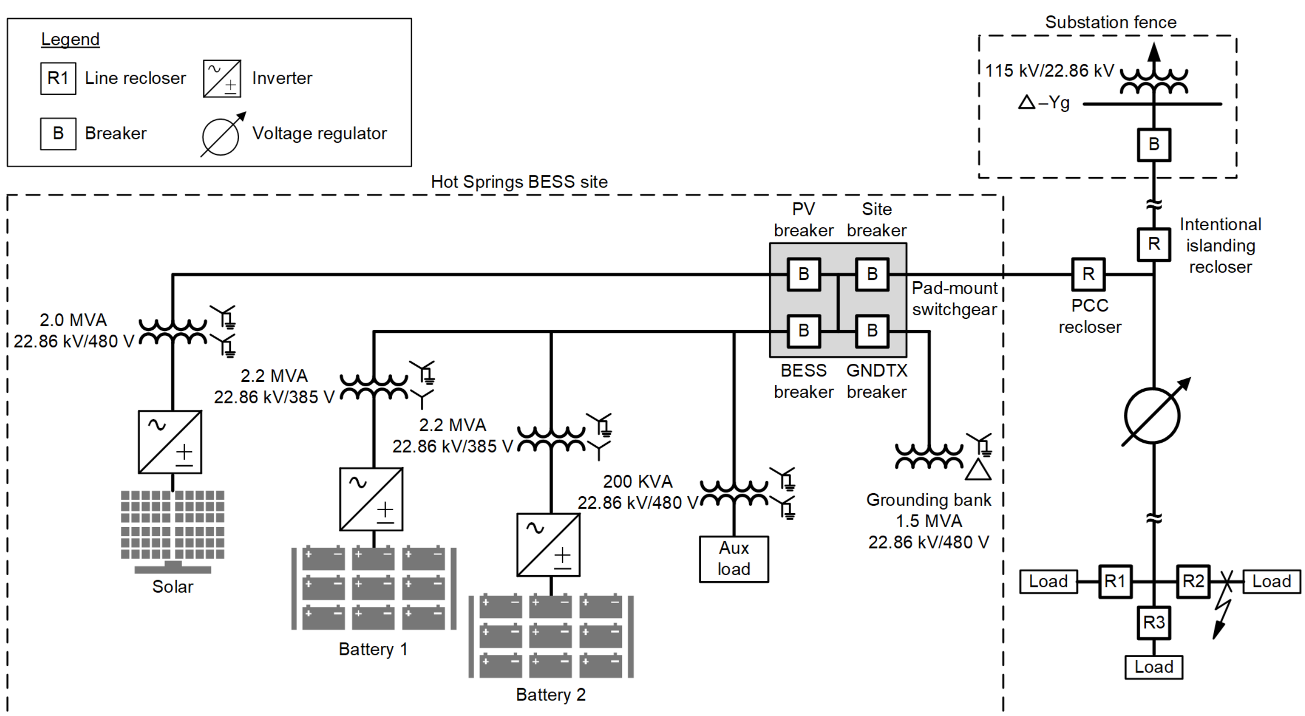

Fig. 3 Simplified One-Line Diagram

III. Inverter Control During Grid-Parallel and Islanding Operations

BESS inverters are operated in GFL or GFM mode of operation. In GFL mode, the inverters use phase-locked loops (PLLs) to track the voltage angle and frequency of a strong source like the grid [2]. The inverters inject currents relative to the voltage angle obtained from the PLLs corresponding to the desired real power and reactive power to be dispatched, thereby acting as current sources. During a fault, the inverters typically do not inject sustained fault currents, and if the strong source is lost, the inverters are tripped offline using anti-islanding schemes.

Inverters operating in GFM mode do not require a strong source to follow, but rather generate their own voltage and frequency, thereby acting as voltage sources [2]. In this mode, they can operate in parallel to a strong source, like the grid and other GFM inverters, or completely islanded. They dispatch real and reactive power using droop control. This control method is beneficial because it allows the inverters to dispatch real and reactive power based on their rating without requiring communications [3].

There are two possible inverter operating strategies when the grid source is available. Operate the inverters in GFM mode and once the grid source is lost, the inverters seamlessly island to carry the load; however, the inverters cannot provide effective grounding to the distribution circuit. Therefore, a ground path, like a grounding transformer, must be connected during grid-parallel operation to provide effective grounding for the distribution circuit upon islanding. This may result in desensitizing the ground fault protection on the distribution circuit, which may require more advanced protection schemes, like high-speed teleprotection using a protocol such as IEC 61850 Generic Object-Oriented Substation Event (GOOSE), to provide adequate protection. Alternatively, the inverters can be operated in GFL mode during grid-parallel operation, and once they are tripped offline upon loss of utility source, they can be started in GFM mode after a grounding transformer is switched in. Once this sequence is complete, the circuit can be black started to restore the load. When the grid source is restored, a similar sequence is performed in reverse. The utility chose the latter strategy because it causes no desensitization of the ground fault protection during grid-parallel operation; however, it does result in a temporary loss of load when switching from grid-parallel to islanding operation, and vice versa.

IV. Microgrid Automation

The microgrid has two main controllers located at the site that work in tandem to provide islanding functionality for the distribution circuit, as shown in Fig. 4. The BESS site has a power plant controller (PPC) that is responsible for managing the site for grid-parallel and islanding modes. The distribution system uses a separate local automation controller named the Monitoring, Information, and Control hub (MICHUB), for controlling the assets in the area electric power system (EPS). It was decided to keep the two controllers separate because the grid operations and BESS operations groups are separate at the utility. Although the controllers share data to make operating decisions, both controllers must provide a permissive signal for islanding operations to occur. Additionally, the PPC also performs grid-parallel services independently of the MICHUB functions. This increases the importance of good design and integration, in addition to comprehensive commissioning testing.

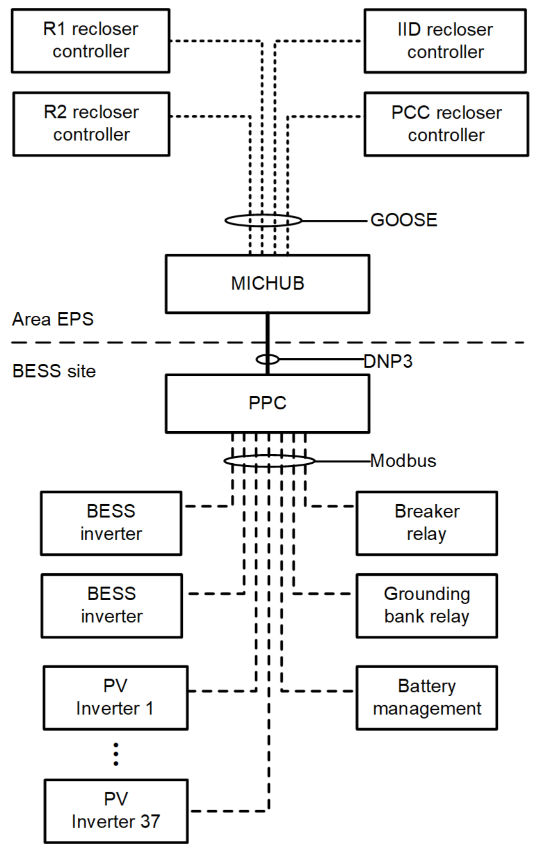

Fig. 4 BESS and Distribution Circuit Data Flow Diagram

The PPC has a rules engine that aggregates all the data from the inverters, battery management systems, and switchgear; it also manages the BESS to provide various services. The PPC primarily uses Modbus TCP for its communications channels on the site. It also has Distributed Network Protocol (DNP3) channels with the MICHUB for information and controls. The MICHUB relies primarily on IEC 61850 GOOSE protocol to interface with the recloser controllers along the feeder for controls like changing settings groups and operating the reclosers when transitioning between grid-parallel and islanding operations.

The primary function of the MICHUB is to run the microgrid rules engine. During normal conditions, the MICHUB is primarily in a standby state, monitoring system conditions and waiting for islanding initiating conditions, primarily the loss of utility source voltage. Once the controller detects initiating conditions, it sends commands to the recloser controllers and requests status feedback while transitioning to and from islanding mode, as well as during islanding operation. The MICHUB performs the following black-start sequence after the loss of source voltage:

1. Verifies the loss of system voltage.
2. Sends open commands to the IID recloser and load-segmenting reclosers, R1 and R2, to establish the microgrid boundary.
3. Puts the recloser controllers in the proper islanding settings groups.
4. Sends a request signal to the PPC to initiate islanding operations, which includes the following actions:
   i) Open Site breaker
   ii) Connect the grounding transformer
   iii) Set BESS inverters to GFM mode
   iv) Ramp inverters to rated voltage
   v) Close Site breaker
5. Waits for a signal from the PPC that the BESS site is ready to pick up load.
6. Sends a close command to the point of common coupling (PCC) recloser to energize the initial load segment from the BESS inverter.
7. Sends close commands to R1 and R2 to pick up load segments sequentially, not overload inverters, and maintain power quality to customers.

After the microgrid is established and running in islanded mode, the MICHUB continues to monitor system conditions and waits for the grid source voltage to return or the BESS to deplete its energy. After either condition is met, the MICHUB performs the following system restoration sequence:

1. Sends open commands to reclosers in the microgrid boundary (PCC, R1, and R2).
2. Removes islanding signal from the PPC to initiate the transition to grid-connected configuration, which includes the following actions:
   i) Commands inverters to idle state
   ii) Opens Site breaker
   iii) Disconnects the grounding transformer
   iv) Sets BESS inverters to GFL mode
3. Puts the recloser controllers in the proper grid-connected settings groups.
4. Sends a close command to the IID recloser to re-energize the initial load segment from the utility source.
5. Sends close commands to R1 and R2 to pick up each load segment sequentially to maintain power quality to customers. (Note: close commands may not be sent depending on the recloser configurations prior to islanding operations.)
6. After the PPC has completed its transition to grid-connected configuration, it sends a signal allowing the PCC recloser to be closed.

V. Grounding Transformer Selection and Design

The bulk power system (BPS) provides the distribution system with effective system grounding during a normal grid-parallel operating configuration. When the DER site disconnects from the BPS, the system may lose its effective grounding. The loss of effective system grounding leaves the microgrid susceptible to temporary overvoltages during ground faults. This creates the need for a dedicated grounding transformer at the BESS site to provide adequate ground fault current during ground faults and to prevent equipment damage from ground fault transient overvoltage (GFTOV).

To reduce GFTOV, the microgrid system must be effectively grounded. An effective grounding system is determined based on the system coefficient of grounding (COG) of less than 0.8 [4]. In other words, the maximum phase-to-neutral voltage of 138 percent ($0.8\times\sqrt{3}\times100\%$) or less must be experienced on the unfaulted phases during a line-to-ground (LG) fault. The microgrid system uses a grounding transformer for this purpose because the inverters cannot provide effective grounding during islanding operation.

Specifying a grounding transformer for 100 percent IBR distribution systems requires one to consider load connection types and system operation requirements and needs. Since this islanding transition is designed as a break-before-make event, the grounding transformer is intended to be connected during island operation only. Thus, the desensitization of ground overcurrent relaying during grid-parallel operation is not a concern. The grounding transformer is switched in during islanding operation as part of the black-start sequence after the loss of the grid source. To avoid significant inrush current caused by the grounding and generator step-up (GSU) transformers during microgrid startup, the PPC ramps up the inverter voltages to gradually magnetize the GSU and grounding transformer cores. In this case, the grounding transformer also provides effective grounding and ground fault sensitivity during startup. There are a few design criteria when specifying a grounding transformer for island operation:

- COG less than or equal to 0.8 throughout the microgrid system.
- Total ground fault current larger than the total rated current of the DERs for an LG fault at the PCC. This ensures the selected grounding transformer does not restrict the system from sourcing ground fault current.
- Line-end ground fault current larger than the highest system current imbalance.
- Continuous grounding transformer rated current higher than the highest system current imbalance, considering the largest single-phase fuse operation. This helps in deriving the transformer kVA rating.
- Thermal rating sustaining the highest ground fault current of the microgrid system.

A preliminary zero-sequence impedance can be preselected for the dedicated grounding transformer with no external connected resistance as 20–40 percent prior to performing transient simulations [5] [6].

Although the previous methodology may result in a system that has optimized ground fault characteristics, it may not be practical with manufacturing lead times for transformers continuing to extend and the utility’s plans to increase the scale of circuit microgrids they deploy. Furthermore, trying to maintain spares with site-specific impedances and configurations becomes difficult and costly. Therefore, standardizing on several off-the-shelf transformer designs is a better practice for preliminary and final impedance selection. Thus, the transient overvoltage (TOV) analysis should be performed based on the closest of the off-the-shelf zero-sequence impedance values to the ones obtained from [5] or [6].

Fig. 5 illustrates a simplified circuit followed by the simplified sequence networks that illustrate the role of the grounding transformer.

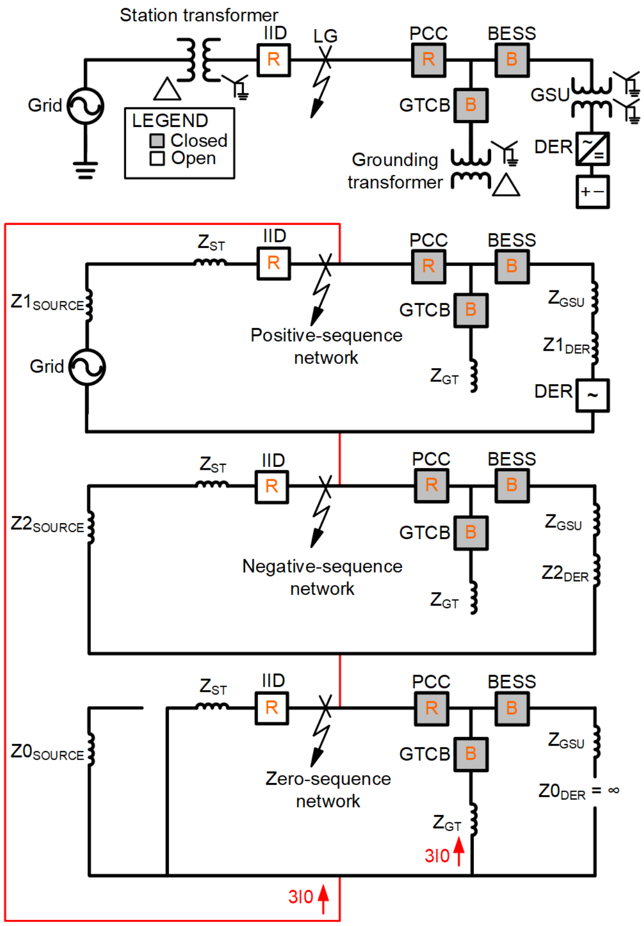

Fig. 5 Simplified Circuit With Sequence Networks for a Generic Microgrid

Based on the figure, there are a few key points to consider:

- Desensitization of the ground overcurrent protection on the grid side is not a concern because the IID recloser and grounding transformer circuit breaker (GTCB) cannot be closed simultaneously, per the break-before-make islanding strategy adopted by the utility.
- The ground fault current (3I0) is dependent on the zero-sequence impedance of the grounding transformer (Z_{GT}), the positive-sequence impedance of the inverter ($Z1_{DER}$), the negative-sequence impedance of the inverter ($Z2_{DER}$), and the line impedance to the fault (not shown).
- The zero-sequence impedance of the inverter is very large, effectively acting as an open circuit.

To verify the effectiveness of the grounding transformer and its impact on the microgrid system, an Electromagnetic Transients (EMT) software model must include the grounding transformer with the preliminary impedance. Additionally, a minimum loading condition should be used for validating the grounding transformer impedance. The EMT software with the original equipment manufacturer (OEM) inverter model provides a more accurate validation as compared to a phasor domain (PD) platform because the OEM inverter model provides the true characteristics for positive- and negative-sequence impedances of the inverter that directly affect the ground fault current and TOV results. In addition, the EMT model also provides load rejection overvoltage simulation while a PD platform cannot. Based on simulation results, the impedance of the grounding transformer can be adjusted to satisfy the microgrid system design criteria and accommodate any protection requirements for fault sensitivity.

VI. Protection Scheme

A. *Grid-Parallel Configuration Protection Scheme*

The protection philosophy in this configuration relies on the transmission-connected synchronous generation, the transmission system, and the protection requirements of IEEE 1547. We cannot rely on the inverter when the control system is in grid-parallel operating mode to provide the electrical output needed for reliable protection operation.

We use overcurrent elements to detect faults within the DER site. These elements rely on the fault current provided from synchronous generation through the transmission system to operate in a secure and dependable manner. The symmetrical component quantities available from a synchronous-based generation system allow us to design reliable protection schemes for various faults within the DER site.

System-level faults are detected using voltage-based protection schemes. These protection schemes operate based on voltage excursions that are driven by the transmission system and are used to isolate the DERs during system faults.

B. *Microgrid Configuration Protection Scheme*

Developing a protection scheme for a distribution circuit sourced solely from IBRs presented many challenges. It required a revalidation of the assumptions and engineering reasoning used in developing the grid-parallel configuration protection scheme.

In grid-parallel configuration, we are dependent on synchronous generation and the transmission system to provide adequate protection. In a microgrid configuration, we cannot rely on these concepts. Hence, we attempted to use the full capabilities of the inverters that source the microgrid.

The biggest challenge to developing the protection schemes for this system was determining how the inverter would react during faults. This centered around the fault current magnitude and the sequence current components that the inverter outputs. Oversizing the inverters to maintain better sensitivity margins between the fault current and the protective device pickup is not always financially feasible. However, the inverters can source their specified fault currents at different fault locations throughout the microgrid without significant changes in the faulted phase(s) current magnitude. Through multiple working sessions with the inverter manufacturer and EMT simulations, as discussed in Section VII.A, we were able to determine that the inverter would output 1.2 pu fault current on the faulted phase(s) for an extended period suitable for the protective relays and electronic recloser controllers to clear the fault. We were also able to obtain factory test records for an actual line-to-line (LL) fault that showed the project-specified inverter capable of outputting a high magnitude of negative-sequence current that can be relied upon in developing the protection scheme, which is not necessarily the case for all inverter manufacturers.

The speed of protection schemes is typically dictated by the needs of the system. The fault current magnitudes from the inverters were low enough that they did not pose a risk to equipment or system stability. Hence, high-speed protection was not required for the microgrid, and we used time-delayed definite-time overcurrent elements with a coordination time interval (CTI) of 0.3 seconds to achieve coordination between the protective devices included in the microgrid boundary.

C. DER Site Protection

We treated the DER site like a traditional generation facility from a protection perspective. The protection schemes are designed to isolate faults within the site and provide backup protection for uncleared system faults.

We applied hybrid methodology to our protection scheme to use as much of the inverter current capability as possible. This methodology was based on the inverter fault current capability and the North American Electric Reliability Corporation (NERC) PRC-025 reliability standard [7]. This standard ensures that the generation resource is not artificially restrained by an overcurrent protection function. It requires overcurrent elements to be set high enough to account for the apparent current (real and reactive) that a generation resource can provide to support the grid. We wanted to ensure that we allowed enough margin in this pickup setting for the inverters to support the system during black starts and system-level abnormalities.

We used a definite-time phase overcurrent element (50PT) as the primary protection for three-line-to-ground (3LG) faults. Because the BESS inverter fault currents are limited to 1.2 pu of the rated inverter current, the phase element pickup in the BESS breaker relay is set to 1 pu of the rated inverter current. The 50PT element is torque controlled by an undervoltage element set to 0.8 pu of the nominal system voltage to ensure it does not pick up on load current. Furthermore, the 50PT element is torque controlled by second harmonic blocking for better security during cold load pickup. To achieve better sensitivity for LL faults, we used a definite-time negative-sequence overcurrent element (50QT). It is important to analyze the negative-sequence current the inverter can source for each application because many inverter manufacturers actively try to limit the negative-sequence current contribution. In our case, the inverter can source enough negative-sequence current to detect LL faults. The pickup is set to 0.5 pu of the minimum observed negative-sequence current seen for LL faults at the electrically farthest lateral in the microgrid, and at least twice the maximum steady-state negative-sequence load current imbalance. The BESS breaker relay will only see positive- and negative-sequence currents for faults on the distribution circuit, as illustrated in Fig. 5 and Fig. 8. Thus, the 50PT and 50QT elements use a CTI of 0.3 seconds to coordinate with the site main breaker relay. The BESS breaker relay will only see zero-sequence currents for ground faults between the BESS breaker and the inverter GSU. To achieve better sensitivity for LG faults, we used a zero-sequence definite-time overcurrent element (50GT). The pickup is set to 0.3 pu of the minimum observed zero-sequence current for LG and line-to-line-to-ground (LLG) faults between the BESS breaker and the inverter GSU with a time delay of 0.3 seconds.

The project-specified PV plant inverters do not source sustained fault currents. Thus, the PV breaker relay will only see fault currents from the BESS inverters for faults between the PV breaker and its inverters. We used a 50PT element torque controlled by second harmonic blocking for 3LG faults protection. The pickup is set at 0.5 pu of the minimum phase fault current for 3LG faults downstream of the PV breaker and above 1.2 pu of the maximum PV plant output with a time delay of 0.3 seconds. We used a 50QT element for LL fault protection. The pickup is at 0.5 pu of the minimum observed negative-sequence current seen for LL faults downstream of the PV breaker with a time delay of 0.3 seconds. We used a 50GT element for LG and LLG fault protection. The pickup is at 0.3 pu of the minimum observed zero-sequence current seen for ground faults downstream of the PV breaker with a time delay of 0.3 seconds.

The grounding transformer (GNDTX) relay will only see zero-sequence currents for LG and LLG faults and no fault currents for LL and 3LG faults on the distribution circuit. Thus, the GNDTX relay uses a 50GT element for ground fault protection. The pickup is set to 0.3 pu of the minimum observed zero-sequence current seen for LG and LLG faults at the electrically farthest lateral in the microgrid, and at least twice the maximum steady-state zero-sequence load current imbalance. The 50GT uses a CTI of 0.3 seconds with the BESS breaker relay. The GNDTX relay will see phase currents for all fault types between the GNDTX breaker and grounding transformer, so we used a 50PT element to detect these faults. The pickup is set to 0.5 pu of the minimum faulted phase current for all fault types between the GNDTX breaker and grounding transformer, and at least twice the maximum steady-state phase load current imbalance, which is the maximum zero-sequence current imbalance divided by three. This element will pick up for LG and LLG faults on the distribution circuit, so it is set with a CTI of 0.3 seconds with the BESS breaker. The GNDTX relay has the slowest time delay to ensure the microgrid does not operate ungrounded if the grounding transformer trips. Furthermore, the GNDTX relay is designed with a scheme to trip the PCC recloser and BESS breaker if the grounding transformer is tripped to avoid operating the microgrid ungrounded.

The site main breaker will see positive-, negative-, and zero-sequence currents for distribution circuit faults, depending on the fault type. The site main breaker relay uses 50PT and 50QT elements set with the same pickup criteria as the BESS breaker relay, and a 50GT element set with the same pickup criteria as the GNDTX relay. This relay maintains a CTI of 0.3 seconds with the PCC recloser controller.

D. PCC Recloser Protection Scheme

The PCC recloser protection scheme was designed to provide overcurrent protection and act as a backup for the downstream recloser zones of protection. It also provides backup protection for customer equipment if the microgrid stability collapses.

We used the hybrid methodology previously described to ensure that the overcurrent element set points were not too sensitive. The total current component generated from the DER site can include more than just the steady-state load of the system. We wanted to ensure that the inverters provided as much support as possible for the system.

Positive-, negative-, and zero-sequence currents are available to flow through the PCC recloser for system abnormalities. The inverters can provide positive- and negative-sequence currents consistently while in GFM control mode. The grounding transformer provides a path for zero-sequence current to flow through. This allowed us to use phase, negative-sequence, and ground overcurrent elements within the device. The additional symmetrical component overcurrent elements drastically improved the sensitivity and dependability of the microgrid protection schemes.

The PCC recloser controller is set with the same criteria as the site main breaker relay described in Section VI.C with a CTI margin of 0.3 seconds with the downstream R1 and R2 electronic reclosers.

We opted to implement voltage and frequency protection schemes as a last line of defense against excessive abnormalities. Ideally, the microgrid voltage or frequency deviates from nominal magnitudes if the inverter is unable to maintain system stability. These elements consider the range of allowable deviation for voltage and frequency droop control when the BESS inverters are operated in GFM mode during islanding operation. Thus, these protection schemes are implemented if the microgrid experiences drastic off-nominal voltage or frequency excursions for a predefined period. The PCC voltage and frequency set points were chosen to avoid restraining the inverter local voltage and frequency protection while also protecting the customers.

E. Feeder Protection Scheme

The downstream electronic recloser controllers improve protection scheme selectivity by adding another protection zone farther away from the DER site. Like the PCC recloser controller, the downstream electronic recloser controllers use phase, negative-sequence, and ground definite-time overcurrent protection. The 50PT pickup is set to 1.5 pu of the maximum load current fed by the recloser, and at least 0.5 pu of the minimum observed three-phase fault currents at the downstream lateral with the highest impedance. The 50PT element is torque controlled by second harmonic blocking to provide better security during cold load pickup. The 50QT pickup is set to 0.5 pu of the minimum observed negative-sequence current for LL faults at the same location, and at least twice the maximum steady-state negative-sequence load current imbalance observed by the recloser. The 50GT pickup is set to 0.3 pu of the minimum observed zero-sequence current for LG and LLG faults at the same location, and at least twice the maximum steady-state zero-sequence load current imbalance observed by the recloser. The downstream recloser controllers operate with a time delay of 0.3 seconds.

One key point that we learned through this process is the challenge associated with coordinating fuses and reclosers for suitable isolation points. The fuses were sized to operate based on higher fault current magnitudes from synchronous generation and the transmission system. The existing fuses, and in some cases the hydraulic reclosers, were ineffective in this microgrid configuration due to the low fault current magnitudes from the inverter-based resources. This may result in overreaching some of the protection zones where selectivity is achieved under grid-parallel operation.

VII. Scheme Validation Using HIL Testing

A. Model Development

Developing protection and automation schemes for microgrids sourced solely by IBRs can be challenging, depending on the inverter operating strategy during grid-parallel and islanding operations. The development and validation of these schemes may require EMT simulations that include OEM inverter models to provide realistic inverter voltage and current responses. For example, a scheme relying on directional elements or negative-sequence currents is one that is a good candidate for EMT simulations.

A representative circuit model needs to be developed in the same software version as the manufacturer-provided inverter model. This ensures the best simulation results and avoids incompatibility issues. The following procedure provides a guideline for developing simplified EMT models of an electrical power system.

1. Collect data, such as OEM DER model and configuration parameters, in an applicable EMT software and a working model of the electrical power system to be studied from PD software.
2. Reduce the original electrical network to a representative boundary equivalent that includes all sources, lines, and interrupting equipment controlled by the protective devices under study.
3. Build a representative network with the data collected from Steps 1 and 2 in the EMT software. For loads, aggregate the loads under each protective device.
4. For branch impedance, select the branches that result in the smallest line-end fault current seen by a particular protective device.
5. Verify that the responses of the simplified EMT model match the PD model by performing load flow and short circuit analyses. Ideally, the percentage error between the two models should be less than 10 percent.
6. Integrate the OEM DER model into the simplified EMT model. This may require referencing manufacturer documentation for help if the user is unfamiliar with the OEM DER model.
7. Lastly, perform dynamic load flow simulations to ensure that dispatching power from the OEM DER

model does not cause any system instability. Also, perform short circuit simulations to ensure the inverter responses match the specified behaviors of the manufacturer documentation.

B. *Inverter Modeling Using EMT*

As the share of DERs connected to the grid continues to increase, the industry has recognized the need to use EMT models and other tools to help understand the interactions of DER controls with other components of the power system, as well as their behavior during system disturbances. From a protection design perspective, a model of the inverter controls in EMT that is parameterized to match the field installation allows its performance (fault ride through, current contribution, inverter protection response, etc.) to be quantified during unbalanced and balanced faults [8]. In [9], different degrees of EMT inverter models and control details are suggested depending on the type of study to be performed. For fault analysis, the protection scheme design and the inverter data sheet can be used as a basis to decide whether to use a generic EMT inverter control model or a detailed manufacturer inverter model. For example, it is acceptable to use a generic EMT inverter model tuned to produce similar fault current magnitudes as reported in the inverter manufacturer's data sheet to test the overcurrent protection scheme of a radial distribution feeder, if a manufacturer model is not readily available. This substitution is possible because radial distribution protection is often based purely on the magnitude of the fault current. However, when directional elements (especially negative-sequence directional elements) are involved, it is recommended to use the detailed manufacturer model. This is because the time spent trying to tune a generic model's control parameters and the fact that the resultant fault characteristics may not be a true replica of the actual inverter response make it a costly endeavor to use the generic EMT model. Additionally, negative-sequence response varies among inverter manufacturers due to different control algorithms.

Most voltage-source inverter control approaches typically involve two predominant control layers [9] [10]—an inner fast current layer and an outer control layer. The inner loop controls the amount of current injected to the ac grid and thus regulates the active and reactive power output of the inverter. The controller design can be done in the dq-frame (synchronous reference frame) with proportional-integral (PI) controllers or αβ-frame (stationary reference frame) with proportional-resonant controllers [10] [11]. The dq-frame is by far the most widely used frame since it reduces the signals (I_d for active power control and I_q for reactive power control) to be controlled to constant dc quantities rather than rotating ac quantities as required in the αβ-frame.

The outer control loop provides reference quantities to the inner control loop and operates at a much slower rate compared to the inner control loop to help minimize dynamic interaction between the two loops. The mode of operation of the inverter and the support functions required of it determine how the outer control loop is designed [12].

In this project, the black box model of the inverter controls from the manufacturer was made available to us for use in the real-time digital simulator (RTDS). Fig. 6 shows the simplified block diagram of the inverter controls as integrated in the RTDS. The filtered inverter phase current (I_{PH}) and line-to-line voltage (V_{LL}) are provided as inputs to the inverter control component. The modulation waveforms from the black box control were then used as inputs in a two-level average inverter model. Since the black box model includes the inner control loops, the ac filter (resistance value of the filter [Rfilter], inductance value of the filter [Lfilter], and capacitance value of the filter [Cfilter]) and dc capacitor (C_{dc}) were modeled to help suppress higher-order harmonics, using recommended values obtained from the inverter manufacturer. The inverter control parameters, fault ride through, and protection set points, as determined from the microgrid impact studies, were configured for use by the black box model.

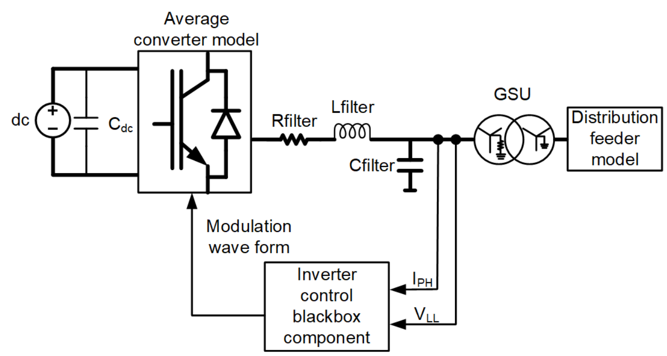

Fig. 6 Simplified Block Diagram of the Inverter Control Structure Used in RTDS

C. *Scheme Validation Using Controlled Hardware-in-the-Loop (CHIL) Testing*

CHIL testing was performed as part of a factory acceptance test to help demonstrate the microgrid control scheme and protection coordination performance among the reclosers along the feeder, PCC, and DER-site relays. The availability of the inverter black box model in the RTDS environment allowed us to use the same distribution circuit model for both the protection scheme and the microgrid control scheme, testing the transition from grid-parallel to island and vice versa. As is often the case with most CHIL protection testing, the real-time currents and voltages from the power system model were sent directly to the recloser controllers and the relay low-level analog interfaces via the RTDS giga-transceiver analog output cards, as shown in Fig. 7.

To simplify the CHIL test setup, the DER switchgear breakers and microgrid recloser open/closed statuses from the RTDS model were sent to the relays using IEC 61850 GOOSE protocol. Likewise, the trip and close signals from the recloser controllers and relays were monitored in the RTDS runtime software using GOOSE communications. The RTDS was also configured to send several analog and binary statuses to the DER-site controller via DNP3. In return, the site controller also communicates the appropriate analog and binary controls and outputs information to the RTDS to allow for the initiation of the islanding and grid connection sequence.

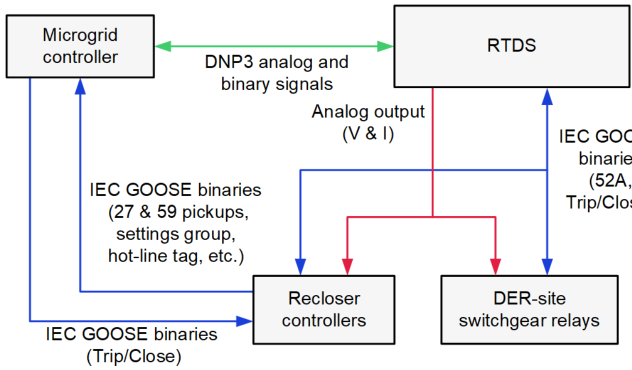

Fig. 7 RTDS CHIL Setup

D. *Testing Results*

1) Protection Scheme

Proper modeling of the inverter fault response is important in validating the protection scheme because the response can vary depending on the firmware version, even if it is for the same inverter hardware. Several fault scenarios were simulated in the RTDS test environment using the manufacturer-provided black box model. Fig. 8 shows the phase and sequence currents and corresponding digitals for the PCC recloser controller, BESS relay, and grounding transformer relay for LG, LL, LLG, and 3LG faults under a no loading scenario at the electrically farthest lateral downstream of the R2 recloser, as shown in Fig. 3. The PCC phase and sequence fault currents closely match the same analog quantities (not shown in this paper) seen by R2.

The phase elements (50P) asserted for all fault types within the microgrid boundary. However, because they are set with a lower sensitivity margin in the PCC recloser controller, BESS relay, and site main breaker relay so as not to limit the BESS plant output, negative-sequence elements (50Q) and ground overcurrent elements (50G) are used to provide better sensitivity margins for the applicable fault types. The 50Q elements asserted for LG and LL faults in the PCC and R2 recloser controllers, site main and BESS breaker relays, while the 50G elements asserted for LG and LLG faults in the PCC and R2 recloser controllers, site main relay, and grounding transformer relays.

The use of non-directional time-coordinated definite-time overcurrent elements configured with the pickup criteria, discussed in Section VI, and a CTI of 0.3 seconds between the downstream recloser controllers, PCC recloser controller, and plant relays proved to provide dependable protection for this application, given the small number of reclosers in the islanded area and the BESS plant as the only source of fault currents.

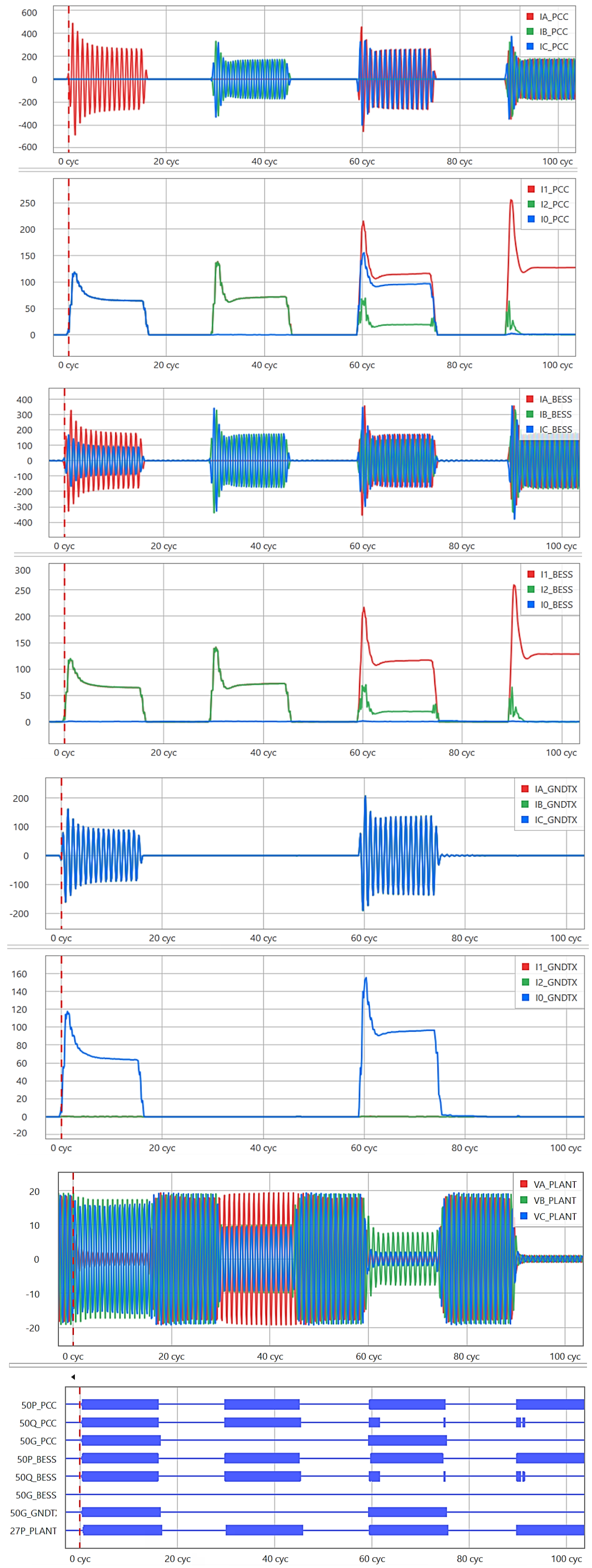

Fig. 8 Phase and Sequence Fault Currents at the PCC, BESS, and Grounding Transformer Breakers, Plant Bus Voltages, and Digitals

2) Microgrid Formation Control Scheme

Based on the sequence presented in Section IV, the microgrid island is formed when there is a loss of utility for at least 60 seconds. After this time has elapsed, the MICHUB sends open commands via IEC GOOSE communications protocol to the IID and R1 and R2 reclosers. This is followed by a settings group change to the island mode in the PCC and R1 and R2 reclosers. After a successful group change, the PCC is commanded to close to form the island, which is followed by the closing of R1 and R2 sequentially to pick up the system loads.

For testing, we opened the substation medium-voltage step-down transformer high-side breaker to simulate the permanent loss of utility for the distribution circuit. With the BESS inverter control in GFL mode, the loss of grid caused the PCC undervoltage protection (27P and 27T) to trip the recloser after 0.1 seconds, as shown in Fig. 9. Once the MICHUB had successfully performed the island group settings change (GRP1 and GRP2) for reclosers and DER-site relays, it issued a close command (CLS_CMD) to the PCC recloser, as illustrated in Fig. 10, to supply the island loads. When forming the island, the PCC recloser is allowed to close on a live voltage on the DER-source side and dead voltage on the load side of the recloser control. Although not shown in this paper, similar close commands were sent to the load segmentation reclosers during the startup process.

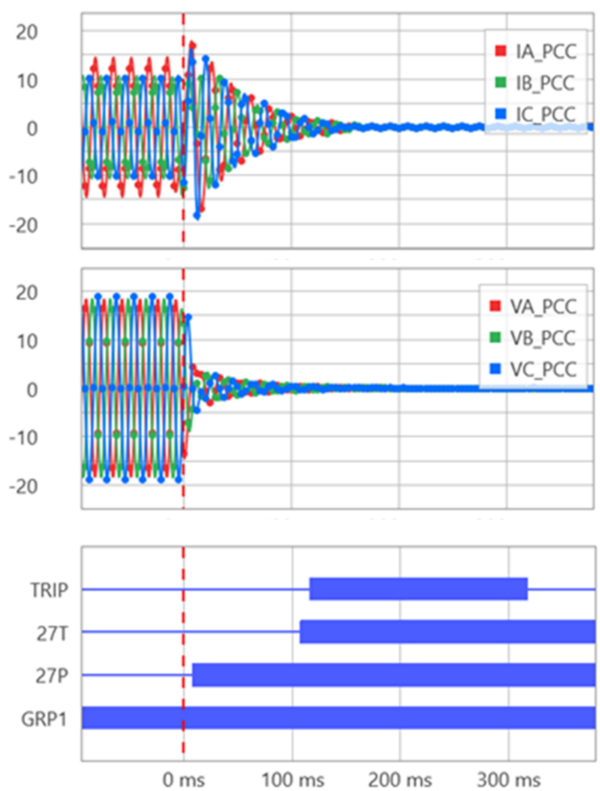

Fig. 9 PCC Recloser Undervoltage Trip Event During Loss of Grid

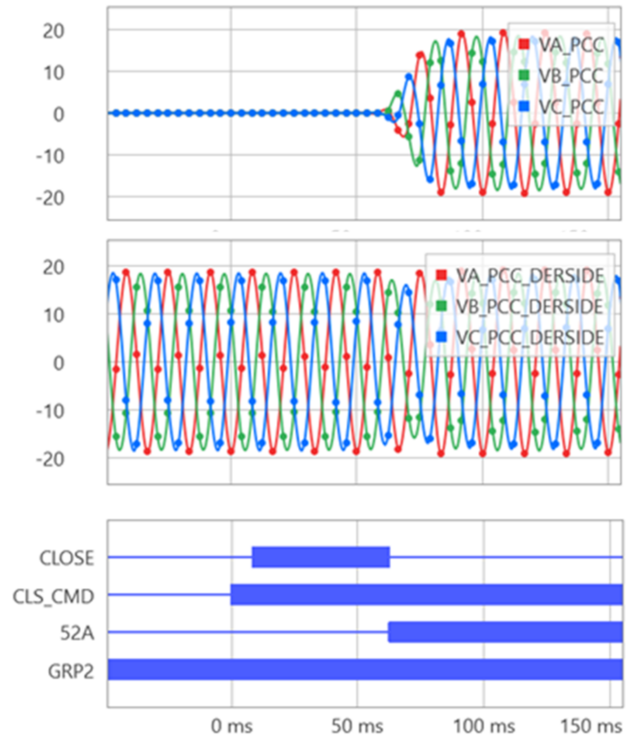

Fig. 10 MICHUB Controller Close Request to PCC

The human-machine interface (HMI) used to provide awareness of the state of the microgrid to an operator is shown in Fig. 11. The HMI allows the operator to visualize the state of the BESS inverters and reclosers, as well as whether conditions for transitioning from island to grid-parallel mode and vice versa are satisfied. With the microgrid in island state, return to grid-parallel operation is blocked if voltage on the IID recloser source side is dead. Provisions were made on the HMI for operator testing purposes to facilitate forcing transitions between island and grid-parallel modes.

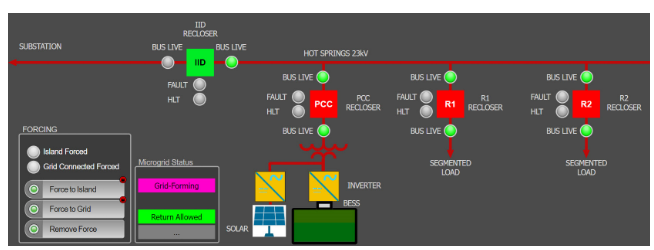

Fig. 11 Microgrid Controller HMI After Successful Island Formation

VIII. Conclusion

DERs offer a viable non-wires alternative to building new distribution feeds when evaluating options to improve power reliability for customers in remote areas. IBRs provide grid-support functions when the grid source is available and act as an alternate source when the grid source is lost. Operating a microgrid fed solely by IBRs presents many challenges to protection and control strategies. IBRs source limited fault currents of up to 1.2 pu in response to distribution circuit faults. Furthermore, IBRs cannot provide effective grounding to the distribution circuit when the grid source is lost. Thus, providing an external ground path in the form of a grounding transformer is essential to operating microgrids with IBRs. Properly sizing the grounding transformer to provide effective grounding and TOV reduction is a critical step of the engineering design process.

Duke Energy opted to switch in the grounding transformer during islanding operation only to prevent desensitization of the ground fault protection on the distribution circuit when the grid source is available. The BESS inverters need to be operated in GFL mode during grid-parallel operation. Upon loss of the grid, the inverters are tripped offline, the grounding transformer is switched in, and the inverters are reconfigured in GFM mode to black start the island load. Upon return of grid source, a similar sequence is performed in reverse. This results in temporary customer outages during the transitions between grid-parallel and islanding operations, but this approach was deemed an acceptable trade off to deploying a more intensive protection and control scheme that may require additional infrastructure to implement. To reduce the outage times during these transitions, the utility uses an RTDS to automate these sequences based on the availability of the grid source and state-of-charge of the BESS.

IBRs response to loading variations, switching transients, and system faults can vary significantly between inverter manufacturers. Thus, performing EMT simulations with manufacturer-provided inverter models is very important in assessing the impact of the DERs on the distribution circuit and developing effective protection and control strategies.

Lastly, CHIL testing using the RTDS facilitated the validation of the protection and automation schemes with representative models of the distribution circuit and IBRs. This testing subjected the protective relays, recloser controllers, and automation controllers to numerous operating scenarios and system contingencies to challenge the protection and automation schemes and fine-tune their performance for optimal deployment.

IX. References

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X. Biographies

Bryan Hosseini received his BS in electrical engineering from the University of North Carolina – Charlotte in 2004. He is principal engineer within the Customer Delivery (Distribution) Operational and Automation Standards "CD-OAS" team. He is the peer team lead for DER integration, Volt/VAR Strategy, Automation for all jurisdictions of Duke Energy. Bryan has worked for Duke Energy in several departments over the last ten years, including Customer Delivery, Generation Engineering and Major Projects. Prior to joining Duke, Bryan has nine years of experience in electrical design, protection, and commissioning of commercial, industrial, and power generation facilities for various projects throughout the Southeast United States.

Jason Eruneo received his BS in electrical engineering from University of South Florida in 2008, master's degree in engineering from University of Florida in 2017, and MBA from University of Florida in 2018. He is a registered professional engineer within the state of Florida. He has worked in the power industry for nearly 15 years in protection and control design and system protection engineering. He has contributed to the development of NERC PRC standards development and is a member of the NERC System Protection and Control (SPCS) Working Group. He is a main committee member of the IEEE PES Power System Relaying and Control (PSRC) Committee and vice chair of the Rotating Machinery Protection Subcommittee of the PSRC.

Ahmed Abd-Elkader received his BS in electrical engineering, with honors, from Ain Shams University, Cairo, Egypt, in 2008 and an MBA, with honors, from Wake Forest University in Winston-Salem, North Carolina, in 2015. He is currently pursuing a Ph.D. in electrical engineering from the University of North Carolina at Charlotte. He is a senior engineer with Schweitzer Engineering Laboratories, Inc. (SEL) with over 15 years of experience in power systems protection and control.

Fred Agyekum received his BSc in electrical/electronic engineering, with honors, from Kwame Nkrumah University of Science & Technology, Ghana, in 2008 and his MSc degree in electrical engineering from Texas A&M University in 2012. He worked as a power engineer in the Schweitzer Engineering Laboratories, Inc. (SEL) Research & Development division for over eight years and is currently a project engineer with SEL Engineering Services, Inc. (SEL ES). He has over 12 years of experience in power systems protection and control and is also a member of IEEE Power and Energy Society.

Rona Vo received his BSEE and MSEE, magna cum laude, from the University of North Carolina at Charlotte in 2014 and 2016, respectively. Upon graduating in 2014, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as an associate protection engineer in the engineering services division. In 2018, he became a professional engineer registered in North Carolina. Currently, he is protection lead engineer at SEL Engineering Services, Inc. (SEL ES) with over 9 years of experience in power systems protection and control.

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