Inverter-Based Radial Distribution System and Associated Protective Relaying

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Presented at the
58th Annual Minnesota Power Systems Conference
Saint Paul, Minnesota
November 8–10, 2022

Previously revised edition released October 2021

Originally presented at the
48th Annual Western Protective Relay Conference, October 2021

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***Abstract*—Battery energy storage systems (BESSs) and solar-photovoltaic (PV) inverter sources installed in distribution systems are often designed to improve system resilience. These sources can complement the bulk electric system by increasing and maintaining the continuity of service while offering peak-shaving capabilities during high-demand periods. A BESS can be designed to function as a dispatchable energy source when configured for grid-forming with droop (GFMD) characteristics to support a seamless transition to and from an island condition without changing modes and without outages.**

Traditional protection schemes deployed by distribution utilities use inverse-time overcurrent elements (51) to coordinate the protective devices in the network, such as fuses, reclosers, and circuit breakers. In an islanded system with inverter-based sources, there is a need to modify this protection scheme due to the limited amount of available fault current. Inverters (BESSs and PV) are limited in their short-circuit capabilities due to the thermal considerations of their switching devices, effectively making the inverters current-limiting sources for system faults. The result is that the inverter does not behave as a traditional source, and the protective relaying scheme must accommodate the limited fault- current contribution.

The authors evaluated the islanded operation of a distribution substation with BESSs as an energy supply. The results of real-time digital simulations and hardware-in-the-loop (HIL) testing yielded a simple definite-time overcurrent coordination method with standard protective relaying elements to protect the distribution feeders. For successful operation during both grid and islanded operation, the relays need to differentiate between time overcurrent coordination while the system is grid-tied and definite-time overcurrent coordination while the system is islanded.

Protective relaying elements are enabled based on an innovative frequency-shift methodology to avoid the need for a protection-grade communication channel. A load-shedding scheme during islanded conditions provides additional resiliency and stability for the system while improving continuity of service for the connected loads.

This paper discusses the use of inverter-based energy resources in distribution systems, the fault current contribution from these sources, the protective relaying solution during islanded operation, the load-shedding scheme during islanded conditions, and the detection of open-source conditions (upstream of the point of common coupling [PCC]). All discussion points are illustrated with examples.

I. Introduction

The electric power industry is in transition, moving away from fossil-fueled generation and toward the integration of renewable resources. As traditional capacity is retired, several forms of distributed energy resources (DERs) are being developed to serve as alternatives to the traditional (centrally located generation) system configuration [1].

Photovoltaic (PV) is currently the most widespread form of renewable generation technology. It is easily scalable and installed in a variety of configurations, from small residential rooftop systems, connected at secondary distribution voltage, to large solar farm facilities, connected at transmission voltage. This paper focuses on intermediate PV plants, connected at subtransmission (also known as bulk distribution) voltage.

Regardless of scale, PV generation exhibits one challenging characteristic—intermittency. Since it requires solar irradiance to produce power, PV generation does not operate at night. Even during daylight hours, variations in solar irradiance due to cloud cover can reduce or interrupt power output [2].

Reliance on intermittent power sources invariably requires the implementation of responsive online energy storage technologies. This paper considers the deployment of battery energy storage system (BESS) capacity in conjunction with PV generation to form hybrid solar-plus-storage facilities.

Strategically locating solar-plus-storage facilities within the distribution system can provide voltage support and peak load shaving on supply circuits. Furthermore, designing facilities to operate as microgrids and locating them near distribution substations at the ends of radial circuits can improve service resiliency for the associated electric customers.

This paper discusses several challenges associated with designing microgrids that have only inverter sources:

- Automatic transfer to islanded operation.
- Grid-following (GFL) versus grid-forming (GFM) inverter operation.
- Power dispatch versus frequency droop control.
- Inverter output current magnitude limitations.
- Balanced and unbalanced output current considerations.
- Grid-tied versus islanded system overcurrent protection.
- Frequency shift versus high-speed communications.
- Upstream (supply circuit) anti-islanding detection.
- Automatic retransfer to grid-tied operation.

II. Background

Ameren Missouri has explored several scenarios for meeting the requirements of the state's Renewable Energy Standard. One approach involves constructing combined PV and BESS facilities at key locations within the 34.5 kV subtransmission system. Under normal operating conditions, future facilities would provide the benefits of renewable generation, voltage support, and peak load shaving on supply circuits. Locating the facilities near smaller distribution substations at the ends of radial circuits and designing them to operate as microgrids can also improve service resiliency for the associated electric customers. Such nonwire alternative (NWA) projects are seen as initial steps along the road to a decentralized distribution system of the future.

To reduce costs associated with project design and ongoing maintenance, solar-plus-storage projects standardize on single-axis-tracking solar arrays with plant ratings of 10 MW. BESS installations standardize on 1 MW modules, with the overall plant capacity able to serve the peak load of the neighboring distribution substation. Battery-system energy ratings are tailored to serve the needs of the neighboring substation for the duration of expected planned or forced outages (minimum of four hours).

Fig. 1 provides a single-line diagram of a typical solar-plus-storage facility and adjoining distribution substation.

Solar-plus-storage facilities are designed to automatically function in one of two general modes of operation:

- **Grid-tied** operation is the normal state. PV inverters operate in GFL mode at maximum power output and a fixed power factor, within solar irradiance and system dispatch constraints. BESS inverters also synchronize with the grid, but real and reactive power output are subject to voltage control, system dispatch, and battery management system constraints. In this example, the BESSs operate only in grid-forming with droop (GFMD) mode.
- **Islanded** operation may be initiated by remote control dispatch or by an automatic response to faltering utility supply voltage. BESS inverters operating in GFMD mode enable the microgrid to seamlessly decouple from the grid and enter islanded operation. PV inverters remain in GFL mode, following the BESS output voltage waveform.

While the system is grid-tied, the operating frequency is controlled by the upstream utility grid. BESS power inverters follow the grid and may be programmed to produce or absorb reactive power to support local voltage conditions. Until Ameren implements a system-wide distributed energy resource management system (DERMS) to coordinate the operation of smart inverters, PV inverters will operate in GFL mode at a fixed (leading) power factor to limit voltage flicker under contingency conditions.

BESS power inverters operate in GFMD mode in both islanded and grid-connected states. GFMD mimics the performance of traditional rotating-generation sources. While the system is islanded, PV inverters continue to operate in GFL mode at a fixed output power factor, but power output is limited by solar irradiance and microgrid dispatch (curtailment) controls.

Whether the system is grid-tied or islanded, reliable interruption of fault currents and selective isolation of faulted circuits is critically important to the safe operation of the microgrid [3]. Protection is provided via 34.5 and 12.47 kV reclosers and fuses. Traditional inverse-time overcurrent relay coordination provides secure, reliable, and selective protection while the system is grid-tied [4] [5], but the situation becomes complicated under islanded conditions.

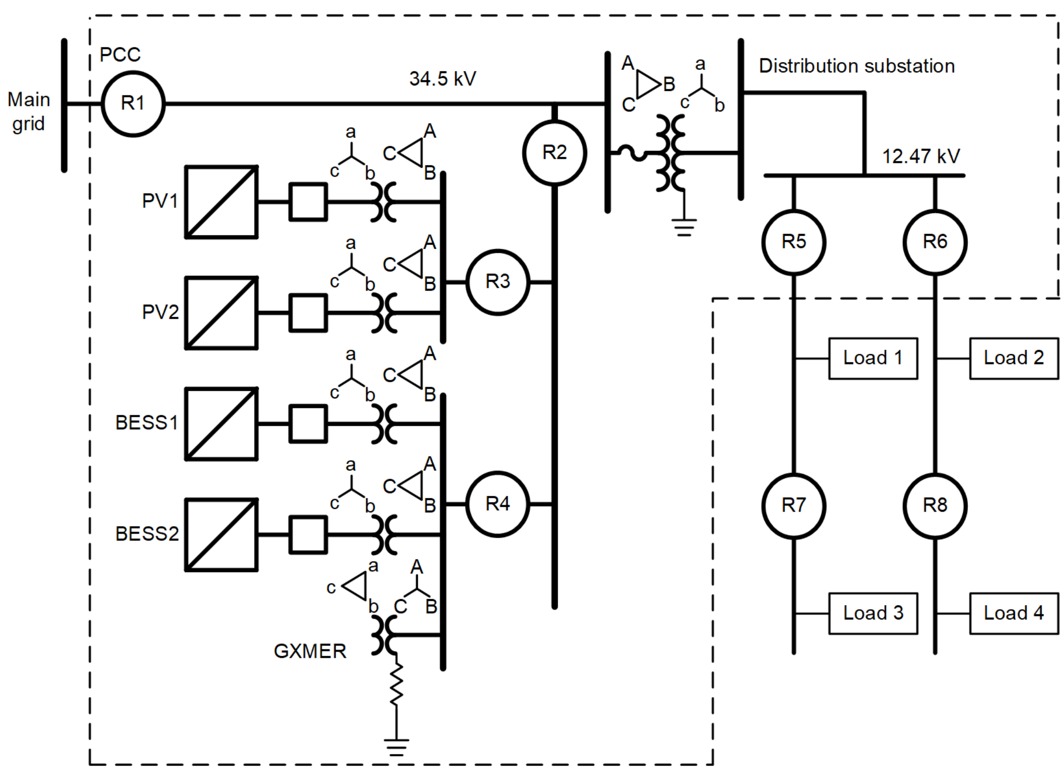

Fig. 1. Solar-plus-storage project configuration

Regardless of operating mode, solid-state inverters are thermally limited devices and are programmed to limit their output currents within their thermal ratings. Achieving higher fault current magnitudes to meet fuse-clearing and overcurrent relaying concerns typically requires oversizing the BESS—an expensive proposition. Rather than using oversized BESSs, inverter specifications for solar-plus-storage projects require momentary current capability of 2.0 pu for 2 seconds, followed by 1.2 pu for the remainder of 5 seconds [6]. Even with these ratings, the available fault current under islanded conditions is insufficient to activate the traditional time overcurrent relay protection noted above. Simple overcurrent protection is not enough, so additional relay functions are required to detect and clear faulted circuits. Voltage-controlled definite-time overcurrent relay elements perform well under these conditions.

In addition to fault current magnitude, the nature of unbalanced fault currents requires special attention when using inverter-based power sources. Inverters are generally designed to optimize positive-sequence current production. Although unbalanced loads or faults might draw negative-sequence current, most inverters are programmed to attenuate imbalance currents to reduce internal heating.

The majority of short-circuit faults in distribution systems are line-to-ground and line-to-line in the 12.47 kV circuits. Due to the distribution substation transformer winding configuration, both of these types of faults appear as line-to-line faults at 34.5 kV. To support backup protection for 12.47 kV faults, the BESS inverter specifications for solar-plus-storage projects require equal positive- and negative-sequence current capabilities under all unbalanced load and fault conditions [6].

Zero-sequence current is another matter of concern with inverter-based power sources. The majority of three-phase power inverters are three-wire devices with no neutral connection, so supplemental system grounding via transformer connections is often required. The 34.5 and 12.47 kV substation transformers associated with solar-plus-storage projects use solidly grounded neutral connections, so traditional ground fault protection considerations apply during grid-tied operation. When the point of common coupling (PCC) recloser opens to commence islanded operation, the connection to the upstream substation is broken and the 34.5 kV portion of the microgrid becomes ungrounded. To avoid this condition, the 34.5 kV bus associated with the BESS is equipped with a resistance-grounding package. High-resistance grounding (30 to 50 A) is employed, so the grounding package can be continuously energized without adversely affecting the performance of upstream ground fault protection equipment while in grid-tied operation [7].

As briefly described above, protective relays associated with 34.5 and 12.47 kV reclosers need to employ traditional protective functions while the system is grid-tied and enable supplemental functionality under islanded conditions [4]. Multifunction relays are capable of doing so, but informing them when to enable supplemental functions can be problematic. Using supervisory control and data acquisition (SCADA) communication is often too slow, while direct communication via radio or fiber-optic cable introduces additional equipment and possible points of failure. This paper discusses a novel approach of shifting the microgrid operating frequency to indicate operation under islanded conditions. Reclosers sense the system frequency change and alter their protective relay characteristics accordingly. Aspects of frequency offset, droop control, and underfrequency load shedding are discussed later in this paper.

Although solar-plus-storage projects are designed to operate as islands, it is not acceptable for those islands to include upstream portions of the supply system. While the PCC recloser is closed, microgrid controls monitor grid-tied status by periodically modulating the BESS inverter's output frequency. This can happen when the PCC measurements are not good indicators; for example, during low power flow conditions with the PCC breaker closed. If the system frequency shifts, upstream island conditions are identified and the PCC recloser is tripped. This common form of anti-islanding protection is disabled when the PCC recloser is open.

Solar-plus-storage project microgrids automatically synchronize and retransfer to grid-tied operation following restoration of 34.5 kV supply voltage or in response to remote control dispatch signals.

This paper discusses desired BESS characteristics for solar-plus-storage projects, the integration of these into microgrid functionality, and the seamless transition between grid-tied and islanded operation. Microgrid electrical design issues and challenges will be described, as well as specific protection challenges resulting from the nature of current-limiting solid-state inverters. Specific issues include the need for voltage-controlled overcurrent relay protection and load shedding when the system is islanded. To validate the design, a real-time digital simulation model of the distribution substation has been created, and the results will be described.

One aspect of solar-plus-storage project operation that is not discussed in this paper is energizing power transformers via current-limited BESS inverters following a complete collapse of supply voltage, commonly described as a black start, which is a challenging process. This issue will be the subject of a future paper.

III. BESS

The BESS is included in the solar-plus-storage project to improve voltage control, peak load shaving during grid-tied operation, and resilience during islanded operation. Adding a BESS alongside a PV inverter source greatly increases the dispatchability of the available energy. Moreover, having a BESS source allows for the deployment of microgrids, which increase the resiliency and reliability of the grid. Microgrids can be deployed easily when the inverter is configured to run on GFMD, which was defined earlier as grid-forming with droop, control at all times.

A. GFMD

GFL inverter designs employ phase-locked-loop (PLL) technology to maintain synchronism with the system voltage reference. GFMD inverter designs provides a frequency and voltage reference for the operation of the microgrid [8].

Inverters configured in GFL mode, like PV inverters, are only able to dispatch active and reactive power when paralleled to a stiff frequency and voltage. GFL inverters are easy to synchronize to the grid but are less stable and more likely to disconnect from the power system during faults [9]. They cannot operate on an island without a strong voltage source used by the PLL algorithm as a reference, as shown in Fig. 2.

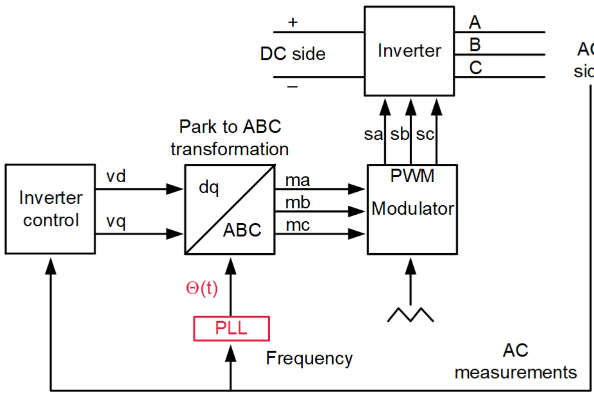

Fig. 2. GFL-PLL-based inverter requires strong voltage source

Rotating generators operate with frequency and voltage droop. These characteristics support the paralleling of generators, proportional load sharing, and stable operation of power systems [10]. Frequency droop is also important for the protection of power systems, facilitating underfrequency load-shedding schemes during extreme conditions. Fig. 3 illustrates a four percent frequency droop curve. For a 1.0 change in per-unit output power, there is a proportional (0.04) change in per-unit frequency. Real power (P) and frequency are related, as are reactive power (Q) and voltage.

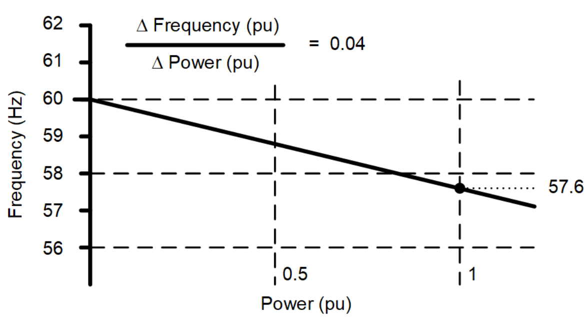

Fig. 3. Four percent frequency droop curve

The no-load frequency intersection of the droop curve depends on the bias or set point. Assuming a stiff power system, Fig. 4 shows that when P_{set} = 0.5 pu, the power output of the machine is 0.5 pu at rated speed (60 Hz). Power output varies along the droop curve, increasing or decreasing as frequency falls or rises. The upper and lower curves in the figure illustrate machine output when P_{set} = 1.0 pu and P_{set} = 0 pu, respectively.

If the frequency is variable and the load is fixed, inverter frequency (instead of power output) varies along the droop line. If there is a single strong source in the system (or microgrid), it sets the frequency of the system, and other units share load according to their droop curves. Generation dispatch controls send the P_{set} to each inverter (DER) to balance generation with load and maintain system frequency. The overall plant controller (also known as a microgrid controller) fills this role in a microgrid, whereas the automatic generation control (AGC) does so in a large utility power system [10].

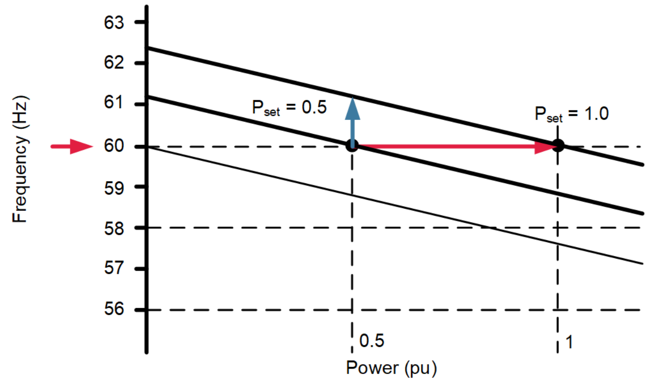

Fig. 4. Increase of the set point from 50 percent to 100 percent

There are many benefits to operating generating assets with droop characteristics, including ease of paralleling generating sources, simple load-sharing schemes and load shedding based on frequency, increased operational stability for microgrids with resistance to overtripping as compared to PLL-type inverters, higher asset resiliency that does not require a strong source to operate, and autonomous DER operation [11] [12] [13].

It is important to select the appropriate BESS inverter with GFMD functionality. The inverter should be configured to run as a voltage source with voltage and frequency droop characteristics for both grid-tied and islanded operation scenarios (GFMD). The generating asset does not need to change modes of operation for grid-tied and islanded conditions. This decreases the complexity of the microgrid controls, prevents unnecessary momentary outages and complex black-start challenges, and also provides negative- and zero-sequence-current production in some advanced GFMD inverters. The GFMD is a simpler system that is usually more reliable and more dependable [12] [13].

There is a key difference between a GFMD and a GFL inverter. In a GFMD inverter, there is an active control system that controls the voltage and frequency of the inverter in the output terminals, while a GFL inverter uses a PLL to measure the angle of the grid voltage and regulate its power output, which makes GFL inverters unsuitable for microgrid systems unless there is an adequately sized anchor source available [11] [12] [13].

When a GFMD inverter is configured to behave as a voltage source, it provides many benefits to the system's functionality and operations capabilities. During islanded conditions, the GFMD inverter can be used as the anchor point for any GFL inverter. This allows for easier operation and paralleling of any source that requires a reference voltage. Moreover, configuring the BESS inverter with a single type of control strategy reduces the complexity of the controls. It allows for better integration of protection because fewer conditions need to be considered. At the same time, it is a more robust source that does not tripoff or misbehave as a GFL inverter would, like PV or Type 4 wind inverters [8]. It also allows for simpler and faster seamless islanding because the inverter does not have to change between control strategies depending on system conditions. Furthermore, this type of inverter control strategy is similar to the operation of a traditional source, such as that of a conventional synchronous generator. Protection and control systems with generators have been developed over and operated for many decades, and it is beneficial for the overall system to run the inverters in such a manner as well.

B. Hardware Limitations

The BESS inverter behaves as a voltage source during normal conditions but exhibits current-limiting behavior during short-circuit faults and overload conditions. These limits are imposed by the inverter's hardware design and are needed to protect the inverter's switching components from thermal damage.

Most solid-state inverters use pulse-width-modulation (PWM) control methods to produce sinusoidal output from dc battery voltage. Four-quadrant operation facilitates the import or export of real and reactive power. When the system is islanded, the inverter establishes the microgrid frequency and voltage according to the programmed droop characteristic.

The inverter's power electronic devices are mounted on heat sinks and cooled via chilled water, air, or combined systems. Sudden increases in output current result in higher losses and increased heat sink temperatures [14]. Thermal time constants are factors in determining transient temperatures and current capabilities.

To support the operation of downstream distribution system protective equipment, it is desirable for inverters to afford certain elevated short-term current capabilities. Increased capability comes at a price, so many commercially available inverters do not provide elevated capabilities. BESS inverter specifications for solar-plus-storage projects require short-term current capability, as shown in Fig. 5.

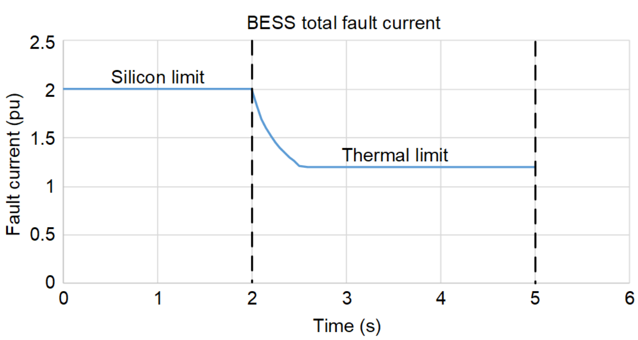

Fig. 5. Specified BESS current capability curve

Four items are of special note to the current limits illustrated in Fig. 5:

- Silicon limit (surge limit) [6]—there is a transient period right after the inception of a fault when the inverter is able to provide a short burst of current. This is on the order of 1.4 to 2.0 pu current output. The availability of this surge current is based on the inverter's filter capacitor, firmware design, and the insulated gate bipolar transistors' (IGBTs) short-circuit withstand time [14]. For some lower end inverters, this current is available for less than 100 ms. Thus, it is very challenging to design a reliable protection scheme using this current limit. Silicon limits are extended on some inverters to assist in relay coordination and grid resilience.
- Thermal limit [6] [14]—this current limit is usually dictated by the design of the cooling system for the inverter's power modules. The current level usually ranges from 1.0 to 1.4 pu and is available for a longer time interval than the surge current. It is possible to not only design a reliable protection scheme using this current limit but to increase the magnitude and duration of the limit by increasing the cooling capacity of the inverter.
- DC battery limits—this is of similar current magnitude to the thermal limits of the inverter and is based on the sizing of the batteries. The battery pack system supplies the power-producing currents associated with faults. Faults at the lower voltages of microgrids have larger components of real power, whereas higher-voltage faults are considered to be dominantly reactive current. The inverter bridge is the limit for reactive currents associated with a power system fault. Batteries that are cold (or out of service) can produce fewer currents for some types of faults.
- Software limitations—the inverter has built-in hardcoded protection limitations in the firmware. These limits have to be configured according to the design limitations to avoid operating the inverter outside the specifications of its components.

The nature of unbalanced phase currents is also a matter of concern for three-phase power inverters. Inverters are generally designed to optimize positive-sequence current production, since that is the component that produces power. Although unbalanced loads or faults might draw negative-sequence current, all GFL and most GFM inverters are programmed to attenuate negative-sequence current so inverter switching components do not overheat [7] [11].

Most GFL inverters have difficulty producing a good (expected) negative-sequence current profile during a fault. On the other hand, some GFMD inverters can produce full I_2 and I_0 components.

The authors have simulated and tested a GFMD inverter using a simple and robust control strategy that allows for $I_1 = I_2$, thus supporting both unbalanced loads and faults. Real GFMD inverters were characterized by field tests and then modeled in the real-time digital simulator environment to match.

IV. Solar-Plus-Storage Project Configuration

A typical solar-plus-storage project configuration is shown in Fig. 6. The number of BESS and PV modules can be adjusted to meet the requirements of a specific project.

To reduce costs associated with project design and ongoing maintenance, solar-plus-storage projects employ standardized single-axis tracking solar arrays with plant ratings of 10 MW. The BESS installation employs standardized modules that are able to serve the peak load of the neighboring distribution substation. Battery-system energy ratings are tailored to serve the needs of the neighboring substation for the duration of expected planned or forced outages (minimum of four hours).

Solar-plus-storage facilities are connected at 34.5 kV, upstream of the small (1.5 to 5.0 MVA) distribution substations, to avoid overloading substation transformers by back-feeding during grid-tied operation. A plant's microgrid controller (MC) curtails PV output to follow load during islanded operation.

Fig. 6 shows the protection and control (PAC) devices associated with the key components. PAC functions are distributed, similar to an installation with rotating machinery. Seamless islanding and retransferring to the utility supply circuit is controlled by the PCC PAC.

A. *BESS and PV Integration*

Solar-plus-storage facilities normally function in grid-tied mode. PV (GFL) inverters follow the utility supply voltage and produce maximum output power at a fixed (leading) power factor within solar irradiance and system dispatch constraints. BESS inverters (GFMD) also follow the supply voltage, but real and reactive output power are subject to voltage control, system dispatch, and battery management system constraints. In accordance with Public Service Commission requirements, the BESS' batteries must be charged using PV output power at least 75 percent of the time.

During islanded operation, GFMD BESS inverters control microgrid voltage and frequency without changing mode. This approach results in a seamless transfer to GFMD operation on loss of supply voltage, resulting in an automatic transfer to an islanded condition without loss of load. PV inverters remain in GFL mode, synchronizing with the BESS output voltage waveform.

All PV, BESS, and microgrid control functions are configured for automatic operation, but remote control overrides from Distribution Control Office (DCO) personnel are accommodated.

B. *System Grounding Considerations*

Fig. 6 illustrates the locations of system grounding provisions for solar-plus-storage projects.

Power transformers in 34.5 kV supply substations and 12.47 kV distribution substations employ solid neutral grounding connections, so traditional time overcurrent ground fault protection considerations apply during grid-tied operation. When the PCC recloser opens to commence islanded operation, the connection to the upstream supply substation is broken and the 34.5 kV solidly grounded source is lost.

To control possibly damaging voltage conditions, the BESS 34.5 kV bus is equipped with a resistive grounding package. High-resistance grounding (30 to 50 A) is employed so the grounding package can be continually energized without adversely affecting the performance of upstream ground fault protection equipment while in grid-tied operation.

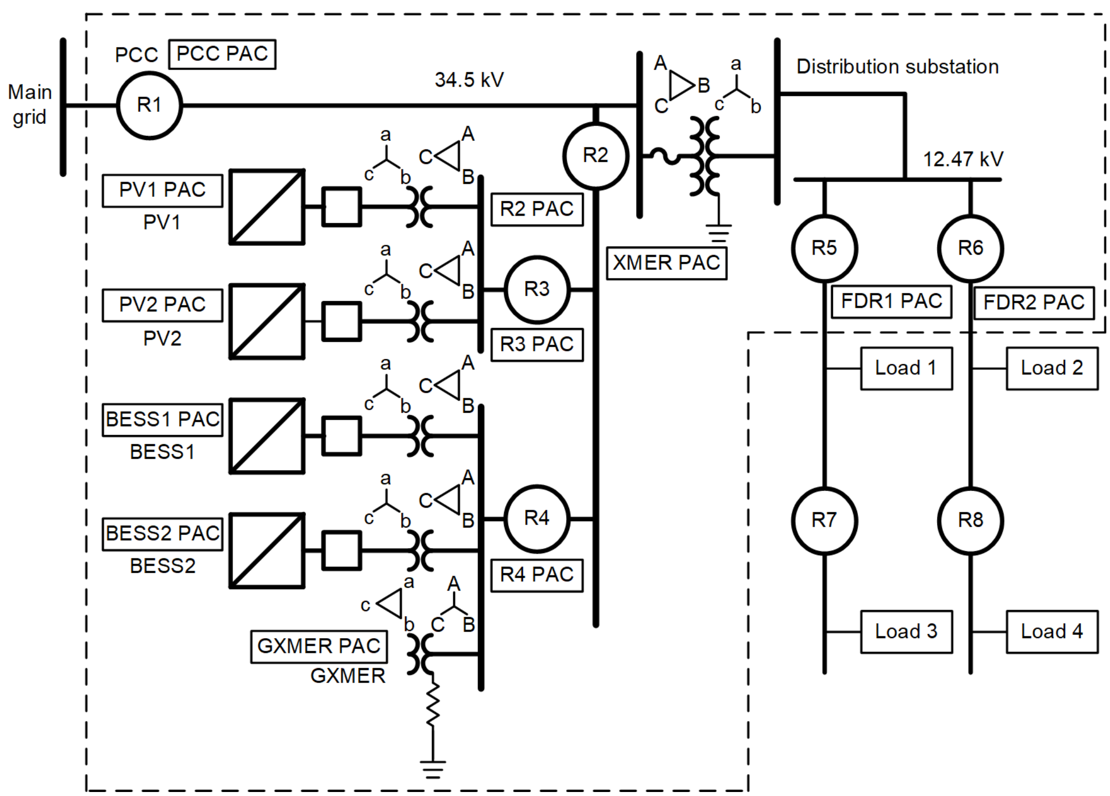

Fig. 6. Solar-plus-storage project configuration

High-resistance grounding produces neutral-to-ground voltage of 19,920 V during single-line-to-ground faults when the microgrid is in islanded operation. This results in phase-to-ground voltage of 34.5 kV, exceeding the maximum continuous operating voltage (MCOV) rating (and perhaps the temporary overvoltage [TOV] rating) of surge arresters applied on the 34.5 kV system. Insulation coordination studies are required to evaluate overvoltage duties and select appropriate surge arresters for each solar-plus-storage project. Grounding resistors are thereby selected in coordination with metal oxide surge arresters and protective relaying schemes.

C. Substation Relays and Available Communications

Fig. 6 shows the PAC devices used in the proposed scheme. Traditional time overcurrent protective relay coordination can be employed for fault clearing while in grid-tied operation; however, a modified scheme is required when the system is islanded to compensate for the limited fault current available from solid-state inverters [4].

The distributed nature of the microgrid control scheme requires communication between the associated intelligent PAC devices. A proposed architecture for this communication network is IEC 61850 Generic Object-Oriented Substation Event (GOOSE) on single or multiple software-defined networking (SDN) switches for increased cybersecurity [15]. The detailed description of the substation network is beyond the scope of this paper, but general requirements and functionality of the network include:

- Time latency adequate for protection and control (in the range of 4 ms).
- PAC to PAC transfer of control messages (GOOSE messages).
- Cybersecurity (provided by SDN).

Establishing a communications network within the solar-plus-storage facility is relatively easy, since the devices are close to each other, but extending protection class communications to downstream 12.47 kV reclosers can be problematic.

As discussed in Section V, this paper introduces a novel approach of shifting the microgrid operating frequency to indicate operation under islanded conditions. Reclosers measure the system frequency and modify their overcurrent settings accordingly.

D. Microgrid PAC Functions

The intelligent electronic devices (IEDs) identified in Fig. 6 provide the PAC functionalities required for grid-tied and islanded operation of the substation.

1) PCC PAC

This PAC controls the link to the main grid. It provides the necessary protective functions to island the substation, when necessary, and rides through external faults in the main grid. The PCC PAC is the device that determines and acts when the substation is islanded. It must be able to provide the automatic synchronization (A25A function) to reconnect the islanded distribution substation with the main grid.

The PCC PAC also monitors the PCC breaker status. When the PCC breaker opens, the breaker status is communicated to other IEDs through the network. The PCC PAC is fundamental to implement the frequency-shift scheme. Additionally, metering and monitoring data are available from this IED. The PCC PAC provides a local interface for the user to initiate the synchronizing process and control the PCC breaker.

2) PV PAC

PV inverters require control and monitoring as well. The PV PAC provides the protection, control, and monitoring functions to the PV inverter. It implements the necessary protocol gateway functions and control sequences required by the inverter controller. The PV PAC talks to the PV inverter via the "Modbus TCP/IP" communication protocol.

3) BESS PAC

The dispatchable BESS gets its set points as well as necessary protective relaying functions from this IED. The BESS PAC provides the interface that allows users to locally dispatch the BESS. When an island is detected, the BESS PAC receives status detection from the PCC PAC and commands the BESS to shift frequency, to denote islanded operating mode.

Inverters usually have a Modbus TCP/IP communications interface. The BESS PAC communicates to the BESS inverter via Modbus TCP/IP and communicates to a protective relay via IEC 61850.

Metering and monitoring data are available from this IED. State of charge (SOC) and state of health (SOH) monitoring can also be implemented in the BESS PAC.

4) GXMER PAC

This PAC provides protection, control, and monitoring for the 34.5 kV high-resistance bus grounding transformer. Its neutral-to-ground overvoltage function is critical to detect 34.5 kV ground faults and immediately trip the BESS and solar PV modules while operating in islanded mode.

5) R PAC

Solar-plus-storage facility relays provide bus protection as well as backup neutral-to-ground overvoltage protection.

6) XMER PAC

This IED provides the PAC functions required by the distribution substation transformer.

7) FDR PAC

These IEDs protect, control, and monitor 12.47 kV feeders and coordinate with downstream reclosers and tap fuses. The FDR PAC requires voltage inputs to measure frequency, which is necessary to detect islanded operation and implement load-shedding schemes, even when the system is islanded. The FDR PAC enables traditional overcurrent coordination curves when the microgrid is grid-tied and uses definite-time overcurrent coordination when the substation is islanded. If load-shedding is implemented, the feeder reclosers implement the appropriate frequency thresholds and the automatic restoration of power.

E. Distribution Feeder

Feeders of 12.47 kV predominantly serve single-phase loads that are connected line-to-neutral. These loads are geographically dispersed, and significant unbalance may occur on tap circuits or along the feeder backbone. Many BESS inverters can have difficulty serving imbalanced load conditions. The installation of downstream sectionalizing reclosers can support load-shedding and cold (or hot) load pickup schemes.

Feeder taps are often fuse-protected, exhibiting adequate selectivity under grid-tied operation. Larger fuses may be ineffective for islanded operation due to the reduced fault current available from BESS inverters.

F. Central Controller

When operating in islanded mode, a solar-plus-storage facility and the neighboring distribution system effectively become a microgrid. For efficiency, frequency, and voltage control, and to comply with operational requirements, microgrids typically require a central controller to properly dispatch the sources [16].

The protection devices are used in tandem with control devices at each DER and PCC. A more complex control scheme can be implemented in a centralized controller (MC). The controller can communicate with BESS and PV inverters to dispatch these and maintain proper frequency and voltage.

With a central controller, the main objectives of the system—peak shaving during grid-connected operation and resiliency during islanded operation—can be achieved in a more flexible manner. PV smoothing may also be achieved with the BESS when the system is islanded. If required, a central controller can implement complex BESS dispatching when the system is grid-connected.

When the dispatch is complex or the inverter operation requires decision-making based on measurements (SOC, for example), a central controller may be needed to coordinate the operation of the distribution substation. Moreover, a centralized controller can provide a protocol gateway to the company's SCADA.

V. ISLANDED MICROGRID PROTECTIVE RELAYING

A. Short-Circuit Protection

Short-circuit faults in distribution feeders are common. The purpose of protective relays in distribution feeders and the reclosers in the feeder is to selectively isolate the faults. The goal of the protection scheme is to selectively trip the in-zone devices and disturb the fewest number of loads when issuing a protective trip command. Given the transient nature of most distribution feeder faults, once the recloser or breaker contacts have been open for a predetermined time, reclose logic is implemented in a protective relay to maintain continuity of service.

When connected to the main grid (with the PCC breaker closed) there is adequate fault current magnitude, for both phase and ground faults, for relays to coordinate with inverse-time overcurrent elements. Fig. 7 illustrates the inverse-time overcurrent (51) coordination normally used in feeder protection. The coordination time interval (CTI) is traditionally in the range of 0.2 to 0.3 seconds, which includes the breaker opening time and a safety factor.

When the system is connected to the main grid, the BESS contributes a smaller portion to the feeder fault. Fig. 7 illustrates that the coordination does not depend on the BESS, but on the main grid. When the system is islanded, the BESS may be the sole source of current.

The small difference between full load current and the fault magnitude contribution of inverters does not allow the use of inverse-time overcurrent (51) elements. Inverters behave like current sources [4], and, to a certain extent, the fault current magnitude is the same regardless of the location of the fault along the feeder.

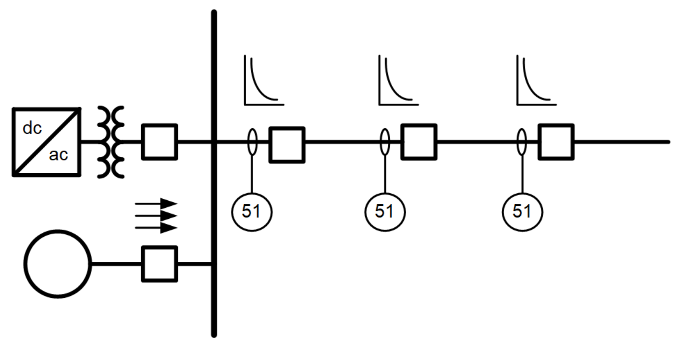

Fig. 7. Grid-connected overcurrent coordination

Current BESS inverters do not contribute significantly more than the rated current to power system faults. Some inverter designs can handle unbalanced faults and contribute negative-sequence currents. The substation transformer secondary has its neutral grounded, allowing for ground return current ($3I_0$). For unbalanced faults, the use of I_2 (50Q) and I_0 (50G) is appropriate to detect them. Voltage magnitude is also an indicator of a fault. To add security to the detection process, the overcurrent elements are supervised by voltage. Fig. 8 shows the fault detection criteria. Voltage controls the trip of the overcurrent elements. The unbalanced faults are detected by the 50Q or 50P elements, which can be above the maximum unbalance of the feeder. The three-phase faults require that the three phases be low, allowing the phase overcurrent (50P) to be set below load.

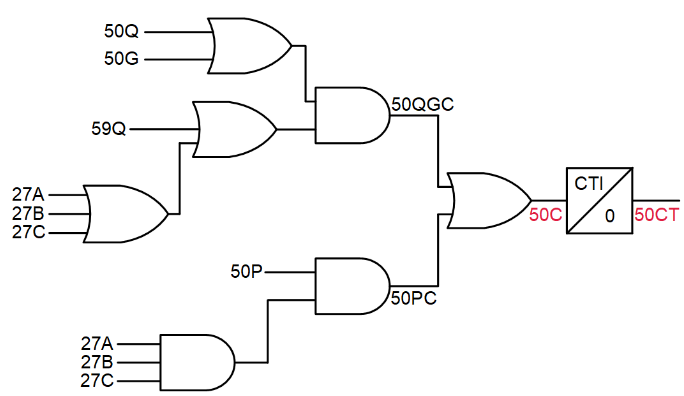

Fig. 8. 50C—voltage-controlled overcurrent

Definite-time coordination of the 50C (voltage-controlled overcurrent, shown in Fig. 8) can be used to provide selectivity.

The CTI that is used for grid-connected coordination (0.2 to 0.3 seconds) can also be used for islanded conditions.

Fig. 9, which illustrates the definite-time overcurrent coordination when the substation is islanded, can be contrasted with Fig. 7, which illustrates the traditional inverse-time overcurrent coordination when connected to the grid.

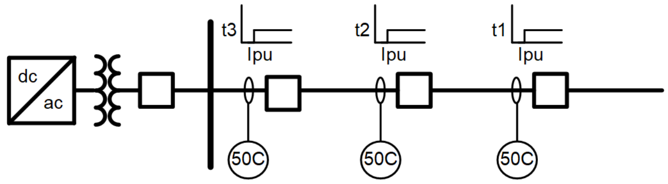

Fig. 9. 50C—definite-time coordination

B. Overcurrent Coordination Mode Switching

For the relays in the substation, switching modes from grid-connected to and from an islanded substation can be communicated using the substation network. Feeder reclosers do not have the link needed, and the scheme requires a way for the reclosers to determine when the distribution substation is islanded.

One solution is to use the system frequency to communicate an islanded condition. BESS inverters can easily switch operating frequency. The frequency bias to the inverters is set such that the underfrequency load-shedding schemes are not disturbed. When the PCC breaker is opened, the BESS PAC sets the inverter droop line set point to 61 Hz, effectively operating the distribution system at a higher frequency than nominal (60 Hz). Fig. 10 shows the droop curves for zero bias when the system is grid-connected (60 Hz at zero power) and when the system is islanded. The choice of a 0.7 percent droop line is explained in the next section.

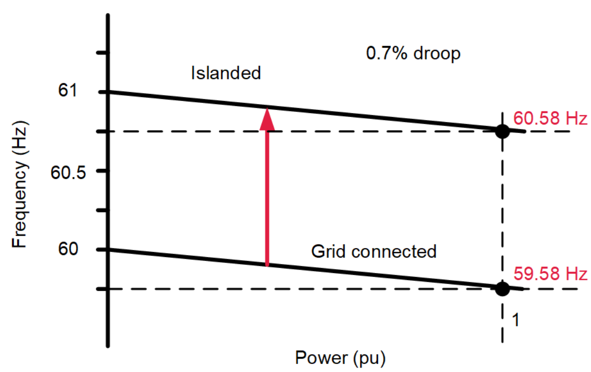

Fig. 10. BESS droop characteristic

The frequency shift signals the downstream reclosers in the feeder to identify grid-connected or islanded operation. A frequency threshold of 60.35 Hz signals the recloser protection to enable the voltage-controlled definite-time overcurrent elements.

The islanded detection is determined by the PCC PAC monitoring the breaker status of the PCC breaker. Once the breaker opens, the PCC PAC sends a signal to the BESS IEDs to shift the inverter bias to the 61 Hz line, as shown in Fig. 10.

Voltage schemes can be used during islanded conditions as a last-resort protective method if the unbalance in the system remains and the overcurrent elements do not detect a fault. For a time, a three-phase undervoltage condition is the indication that the islanded distribution system is de-energized. Before a black start, all circuit breakers and reclosers are opened. A black start is accomplished in distributed PACs closing after observing good voltage for a selected pickup time.

Distribution systems generally use multiple-shot reclosing. However, when a substation is islanded, users should consider implementing single-shot reclosing to lower the impact of fault current on the BESS and PV inverters.

C. Frequency Thresholds and Islanded Operation

BESS inverters are operated in GFMD (both in frequency and voltage) for a seamless transition between grid-connected and islanded operation. The frequency droop allows for the implementation of load-shedding schemes, which are described in a later section.

Traditionally, distribution feeder recloser and feeder relays implement load-shedding schemes based on frequencies below nominal (60 Hz). These thresholds, determined by the utility, are used to disconnect load when the frequency measurement drops below them. These underfrequency load-shed set points are usually set by a utility standard and do not promote microgrid functionality. The traditional frequency thresholds will be below the nominal 60 Hz.

Shifting the operating frequency to 61 Hz avoids encroaching on traditional load-shedding thresholds and allows for the definition of appropriate thresholds (see Table I) when the system is islanded. The operating frequency shift to 61 Hz is within the range allowed in IEEE 1547-2018 (Table 18 in [3]) and does not impact the loads in the feeders. For motors and transformers, the increased operating frequency decreases the flux in their iron cores as the V/Hz ratio decreases. Operating at 61 Hz increases the direct-connected motor speeds by a maximum of 2 percent, which is acceptable for most residential and industrial loads.

D. Load Shedding During Islanded Operation

When the system is islanded, frequency load-shedding thresholds are applied based on the 61 Hz operating frequency and the droop line shown in Fig. 10. The feeder recloser can implement a stepped frequency scheme to shed load in blocks (time-coordinated). The base frequency thresholds and times selected are shown in Table I.

TABLE I
ISLANDED LOAD-SHEDDING THRESHOLDS

L	Freq (Hz)	T	P_{out} (pu)	Comments
I	60.6	2 s	0.95	Marginally overloading the inverter in P, accounting for loading in Q
II	60.5	0.3 s	1.19	First level for time coordination
III	60.3	80 ms	1.67	Severe overload
IV	60.1	32 ms	2.14	Disable load-shedding scheme

The above frequency scheme assumes that the inverters can provide the power and follow the droop line. For example, Level III may not be possible if the maximum overload is 1.2 pu, causing the BESS to stop commutation.

The feeder reclosers will enable the load-shedding scheme at 60.35 Hz. The scenario of the parallel operation of the BESS, the main grid (grid-connected), and the opening of the PCC breaker can lead to overloads to the inverters. There is a limit to the amount of overload that the inverters can tolerate. During islanded conditions, the PCC PAC raises the frequency above 60.35 Hz, the load-shedding scheme is enabled, and Level II or even Level III can allow load shedding.

E. Synchronizing to the Grid

The synchronization and reconnection back to the main grid is handled by the PCC PAC. This device monitors both sides of the PCC circuit breaker. When the synchronization is requested, the PCC PAC implements an internal algorithm similar to the one used to synchronize a generator. Signals to raise or lower the frequency and voltage level are sent from the PCC PAC to the BESS PAC for the control of the inverters, using the local network. When the synchronism is within margins, a sync-check function (A25A) automatically closes the PCC breaker. The combined effort of a dispatch and sync element is commonly called A25A (advanced auto sync).

SCADA operators initiate the A25A scheme remotely by sending commands to the PCC PAC. An operator, requesting local control, can also initiate the synchronism from the PCC PAC human-machine interface (HMI).

When the A25A process starts, the frequency is dropped back down to 60 Hz. The downstream reclosers are provided with a delay time before disabling the sensitive protection elements. The A25A schemes usually close the breaker in a fraction of a second, owing to the zero inertia inverter system.

F. Opening of the Upstream Source

The PCC PAC monitors the PCC breaker status. When the breaker is open, it sends the islanded detection signal to the BESS IED, and the operating frequency shifts to 61 Hz. This detection of an open PCC is secured by ensuring that there is no measured current as well. If the breaker status is closed and there is no measurable current, the PCC PAC cannot determine if the distribution substation is islanded.

Power may be allowed to feed loads upstream of the PCC by exiting by exiting the substation to the subtransmission network. It is therefore not clear in the case of nearly zero power flow, or a negative-rated value (power out of the substation into the main grid within the capabilities of the BESS and PV inverters), whether the substation is islanded or not.

To detect open conditions upstream of the PCC, two schemes are used: 1) the I_2/I_1 ratio to detect up to two poles open and 2) a pulse technique for three-pole open condition.

For three-pole open condition detection, the BESS PAC periodically pulses the frequency bias of the inverters (once every minute, for example). Upon detecting a measurable frequency change or power change, the PCC PAC opens the PCC breaker and the BESS shifts the operating frequency to 61 Hz.

VI. Hardware-in-the-loop (HIL) Testing

The concepts described in the previous sections will be implemented. To ensure their feasibility, a real-time digital simulator was used [17] and HIL simulations were performed with real relays and controllers (PACs). A sample microgrid (like Fig. 6) has been modeled. The control hardware is substation devices, such as relays, sending and receiving messages using IEC 61850 GOOSE control messages to the modeled breakers, BESS, and PV inverters. As mentioned in previous sections, the BESS inverters in the model can support unbalances and source negative-sequence components. The main grid is a strong source, and the feeders are modeled with typical impedances and loads.

Two results of simulations for representative faults in the distribution feeders are shown in Fig. 11 and Fig. 12. The two figures represent simulation-captured quantities for faults in the distribution feeder. Refer to Fig. 6.

The key points to interpret from the figures are:

- The load in the feeder is unbalanced. The inverters are sourcing the unbalance, satisfying the negative-sequence-current requirements.
- The faulted feeder currents (b) and voltages (c) have negative- (from the inverter) and zero- (from the neutral of the station transformer) sequence components. The components (I_2 and I_0) allow for the operation of the definite-time overcurrent elements. I_0 is not shown in the figures; it has a similar behavior to I_2.
- The inverter currents in per unit (d) illustrate that for the BESS inverter model, the combination of I_1 and I_2 is below 2 $\sqrt{(I_1^2 + I_2^2)}$ pu.
- The two faults illustrate the typical behavior of faults in the feeders.
- The proposed relaying scheme with voltage-controlled definite-time overcurrent relays tested effective for fault detection.

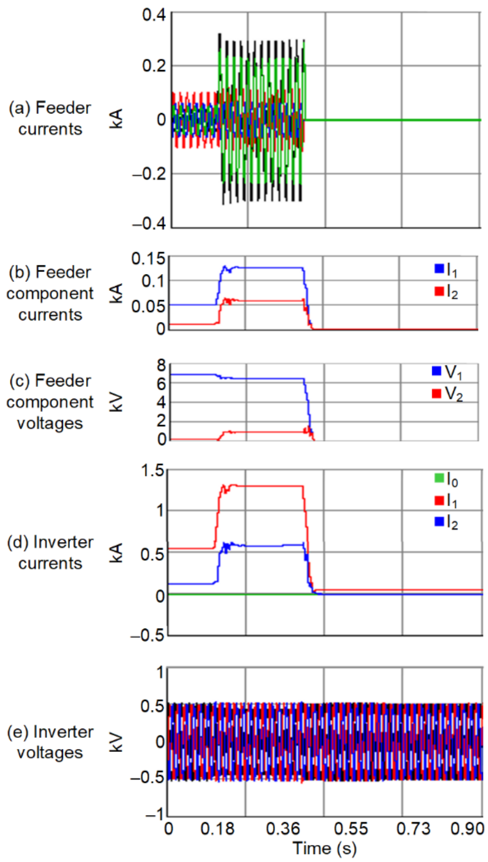

Fig. 11. Distribution feeder Phase-A-to-ground fault (islanded operation)

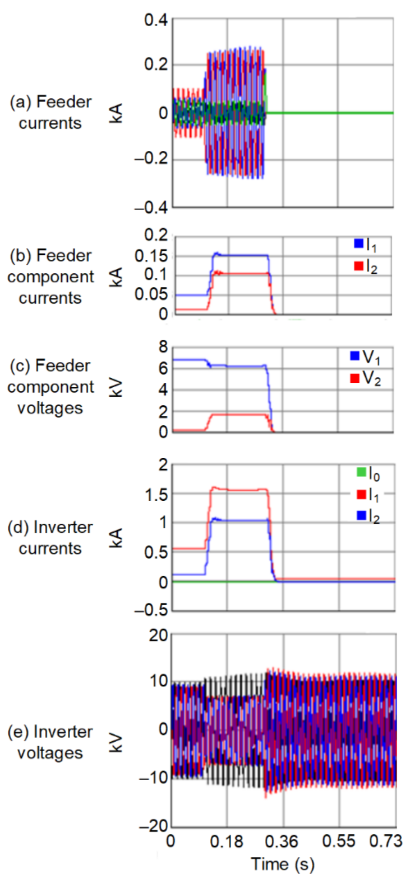

Fig. 12. Distribution feeder Phase-B-to-C fault (islanded operation)

Fig. 13 illustrates the case of a sudden loss of the PCC breaker and the link to the main grid. The distribution system has the inverters online, but their capability is below the load. Load shedding, therefore, takes place and is illustrated in the figure.

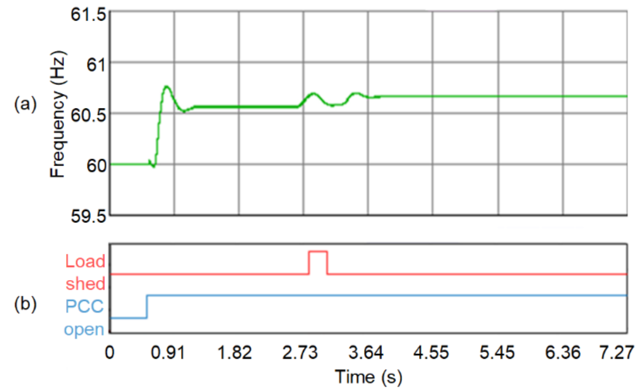

Fig. 13. Loss of the PCC (utility) and load shedding

In Fig. 13, the distribution system frequency is shown. Notice that when the PCC breaker opens, the frequency tries to climb to the 61 Hz programmed for an islanded condition. The overload and the droop behavior of the inverter only allow the frequency to climb to 60.55 Hz. Two seconds later, the underfrequency LI threshold proposed in Table 1, allows for load to be shed, and the islanded frequency can recover to 60.65 Hz (Fig. 13).

Fig. 14 illustrates the three phase open condition of the upstream breaker feeding the PCC. Fig. 14a shows the frequency of the system, which is near the nominal 60 Hz before and after the upstream breaker opens. The frequency at low power flows will not change drastically. Fig. 14b shows the frequency bias sent to the inverter in percentage, which is small according to the inverter output. When the PCC breaker power measurement, Fig. 14c, is very small (near zero), the frequency bias is stepped up (Fig. 14b). The microgrid is islanded from the grid, and the frequency ramp bias used as an islanding detection method raises the frequency, which is sensed by the PCC_PAC that detects and declares that the upstream breaker is opened (Fig. 14d). After the PCC breaker is opened, the frequency bias to the inverter is shifted to the 61 Hz set point.

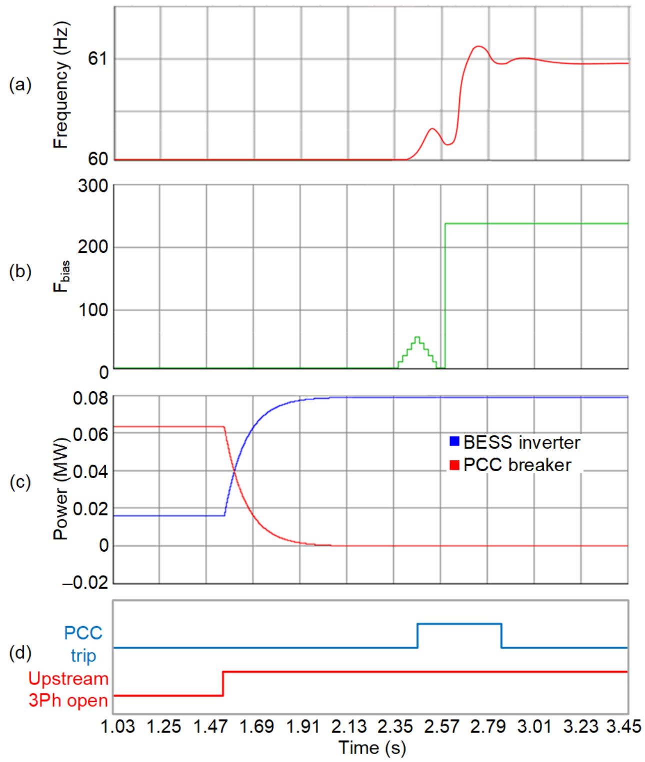

Fig. 14. Islanded detection

VII. Conclusion

PV and BESS facilities can be implemented to improve resiliency for remote load centers.

Configuring the BESS as GFMD allows the microgrid to seamlessly transition (without control reconfiguration) between grid-tied and islanded operation.

Some GFMD inverters can produce fully unbalanced currents unlike GFL inverters, which cannot (without undue sophistry). Frequency droop supports the use of load-shedding schemes when the system is islanded to remain within BESS dynamic ratings.

Microgrids with inverter sources must be designed for safe operation in the presence of limited fault current. An adaptive protective system is required to accommodate different fault levels during grid-tied or islanded operation.

Conventional inverse-time overcurrent elements are applicable when the system is grid-tied, and voltage-controlled definite-time overcurrent elements are enabled when the system is islanded. Frequency shifting (within allowable limits) can be a cost-effective means for communicating grid-tied or islanded status to downstream protective devices and deciding when to enable the voltage-controlled elements.

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IX. Biographies

Richard Ruppert is supervising engineer of the Ameren Missouri system protection group. He received a BSEE from Missouri S&T in 2010 and began his career with Ameren that same year. He received an MSEE degree at Southern Illinois University Edwardsville in 2014. He obtained his Missouri PE license in 2015. In his career at Ameren, he has been in several engineering departments including system protection, substation maintenance, and distribution operating.

Randall Schlake is a principal engineer of Ameren Missouri—Customer and Power Operations. He received a BSEE degree from Southern Illinois University Carbondale (1978) and an MSEE degree from University of Missouri–Rolla (1979). He obtained his PE license in Kentucky (1985) and has instructed the electrical portion of a PE License Review Course (sponsored by Missouri Society of Professional Engineers) since 2006. He has worked in turbine-generator development (Westinghouse), power transformer development (Kuhlman), power system application engineering (GECo), data center power systems (Emerson), and distribution system planning and protection (Ameren). He is currently focused on distribution system planning and operations, distributed energy resource integration, distributed energy resource management system development, and Electric Power Research Institute program liaison activities.

Scott Manson received his MSEE from the University of Wisconsin–Madison and his BSEE from Washington State University. Scott is the engineering services technology director at Schweitzer Engineering Laboratories, Inc. (SEL). Scott is a registered professional engineer in five states and holds 17 patents.

Fernando Calero is a principal engineer at Schweitzer Engineering Laboratories, Inc. (SEL). He started his professional career with the ABB relay division in Coral Springs, Florida, where he participated in product development and technical support for protective relays. He also worked for Florida Power & Light Company in the energy management system group and Siemens in the energy automation group. From 2000 to 2019, he was an application engineer in the SEL international organization. His responsibilities included the application support of SEL products, training and technical support for customers, and internal training and mentoring of engineers. In 2020, he transferred to the research and development division and is currently working on projects related to renewable sources and control. He holds eight patents and has written technical papers on protective relaying, remedial action schemes, and other protection and control (PAC) applications. He is a registered PE in the state of Florida.

Angelos Kokkinis received his BS in Electrical Engineering from the University of Missouri–St. Louis in 2019. He is employed with Schweitzer Engineering Laboratories, Inc. (SEL) as a protection engineer in the engineering services division.

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