Tutorial on Inverter and Battery Management Best Practices

Brian Johnson
University of Idaho

Matt Raiford
Consortium for Battery Innovation

Scott Manson and Angelos Kokkinis
Schweitzer Engineering Laboratories, Inc.

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Brian Johnson, *University of Idaho*
Matt Raiford, *Consortium for Battery Innovation*
Scott Manson and Angelos Kokkinis, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Misunderstandings about inverters and battery management systems (BMSs) limit the success of many battery energy storage system (BESS) projects. This paper fundamentally explains several common inverter control systems to help engineers specify, design, commission, and diagnose events in a BESS. It also explains the interactions between the ac grid, inverter, and battery.**

The internal controllers of several common inverter types are explained. A taxonomy of inverter control strategies is provided, contrasting the ability of each inverter control strategy to generate sequence currents during unbalanced loading and faulted circuit conditions. Protective relay event reports from multiple in-service inverters are shared to illustrate these points. The impact of inverter control strategies on several common protection elements is also discussed.

This paper provides recommendations and best practices for inverter selection, inverter configurations, battery management, system monitoring, transformer selection, system grounding, system modeling, and site testing. It also explains remote dispatch methods, limitations of batteries, limitations of inverters, transient response considerations, battery health, and operation during fault conditions. The examples are from several in-service projects ranging from microgrids to transmission interconnected systems.

I. Introduction

This paper teaches the first principles of inverters and battery management systems (BMSs). It shares performance data from several in-service battery energy storage systems (BESSs) and provides best practices for designing control and protection systems.

An inverter-based resource (IBR) plant is much more than an inverter. Per [1], an IBR is defined as any source of electric power that connects to the transmission system partially or primarily through a power electronics interface. However, an IBR plant is a system of many components, one of which is a power electronics interface called an inverter. Inverters are commonly referred to as power conversion systems. For example, a BESS IBR plant includes batteries, dc/dc converters, dc/ac inverters, plant controllers, network equipment, fire suppression, a BMS, transformers, breakers, a switchgear, and more.

AC protection and control systems interact with many of these IBR sub-control systems. A relevant example is a BMS that detects large dV/dt on the dc bus during an ac system phase-phase fault and will commonly trip off the battery and shut down the inverters if an ac protection system cannot clear the fault fast enough.

The explanations herein apply to behind-the-meter applications, microgrids, independent power producers, distribution, or transmission bulk electric power system (BEPS) connected BESS projects.

Batteries and their management systems are intimately tied to the challenges of a BESS IBR system. Inverter management systems are introduced in Section II.D. Battery and ac power systems are explained and conflicts identified in Section V.B.

Inverter control systems are explained in Section III and Section IV. Those that impact protection are identified, most notably the current control systems. Forms of negative-sequence current production of inverters are classified by type.

The paper provides a categorization of inverters to aid the reader in Section V.A. Generalizations about inverters are challenging as manufacturers, firmware, site configurations, and site conditions are unique. Every inverter has proprietary designs and the site installations vary due to settings decisions made by commissioning teams.

Field data from transmission, distribution, and microgrid IBR installations are shared in Section VI. Further modeling results are shared in Section VII. A short set of best practices for the industry follows in Section VIII.

II. System Description

Battery energy storage projects contain a great number of control systems. All together, these constitute a BESS IBR system. Fig. 1 depicts how some of the larger components of an IBR plant interact, including the:

- Power conversion system (PCS)
- Battery
- BMS
- Inverter management system (IMS)
- AC protection system (ACPS)
- DC protection system (DCPS)
- Plant logic control systems (PLCS)
- Historian
- Inverter and battery management system (IBMS)

BMSs focus on battery health, IMSs coordinate the ac and dc systems, and PLCSs manage the physical infrastructure of the plant.

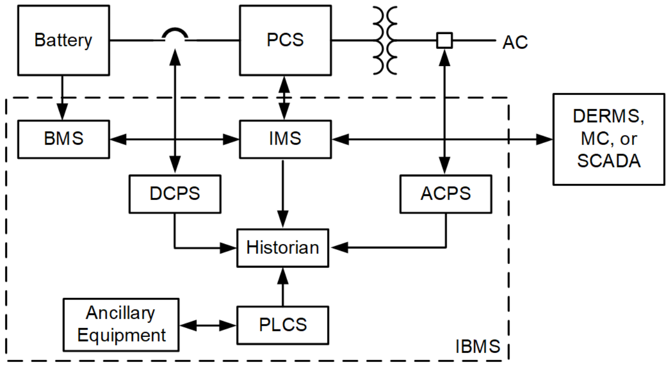

Fig. 1. BESS IBR plant sub-systems

A. Power Conversion Systems

PCSs are comprised of one or more inverters. Inverters convert ac to dc and/or vice versa. Inverters are placed in combinations of series and parallel arrangements to make a PCS.

One key to understanding inverters is commutation. Commutation occurs when power transistors are being gated on and off. Fig. 2 shows two common types of commutation methods used by inverters today: line-commutated and self-commutated (often pulse-width modulated [PWM]).

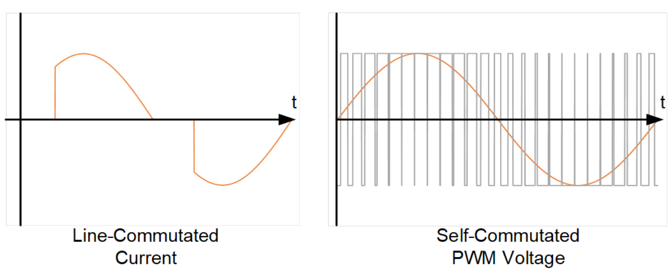

Fig. 2. Comparison of IBR commutation methods

Load commutation and line commutation are the same, just different use cases. Thyristor-based converters use line commutation where each device switches once per voltage cycle. A silicon controlled rectifier (SCR) is a four-layer solid state current controlling device with three terminals that conduct current in one direction. SCRs have anode and cathode terminals like a conventional diode and a third control terminal referred to as the gate. A thyristor is a semiconductor device that is triggered into a conducting state by a gate signal and turns off when the ac voltage reverses polarity and the current through the device falls to zero. The current does not reverse direction as the thyristor allows only one direction of current. Thyristors are commutated off when transitioning to the non-conducting (off) state.

Load- and line-commutated inverters are usually 6 pulse or 12 pulse thyristor technology. Today these are used for medium voltage motor drive technology (ac and dc), high-current applications such as smelters, and HVdc converters because of their higher energy efficiency than self-commutated technology. In this technology, the reversal of voltage waveform allows the thyristor to gate off once per cycle. Either the system (line) or load (motor) supplies the reactive power for the converter. Similar in construction, other thyristor-based inverters that forcibly commutate include resonant-pulse commutation, impulse commutation, and complementary commutation systems.

Self-commutated technology forces transistors to gate on and off, most commonly IGBT or MOSFET. Fig. 2 shows the transistors turning on and off, and the orange line shows the filtered waveform. Self-commutated PWM technology is less costly, provides more control options, and has lower harmonic distortion than thyristor technology. The remainder of this paper focuses on PWM-based self-commutated inverter technology because nearly all photovoltaic (PV), wind, and BESS designs today use it.

Inverters today are built for motor drive, uninterruptable power supply, low-voltage power supply, and energy storage and grid interaction applications. This paper focuses on the latter.

B. Battery Management Systems

BESS BMSs maximize energy throughput, maintain battery warranty conditions, and protect the battery from damage. Presently, best practices revolve around minimizing abusive duty cycles and mitigating potentially dangerous events by disconnecting the dc battery system from ac control when fault or overload conditions occur.

BMSs protect batteries from damage, creating significant interaction issues between the inverter, battery, and ac grid controller. A common example of this interaction problem is a BMS trip and lockout that cannot be cleared by a distributed energy resource management system (DERMS) or SCADA because of lack of control outside the BESS.

Total energy throughput, reliability, and cost are the major drivers for a BESS, and the design and implementation of the BMS focuses on low cost and safe control schemes to maximize energy throughput and prevent dangerous conditions for the battery. The system is typically composed of a distributed network of CPUs with built-in logic and active control. For instance, a BMS in a lithium-ion-based BESS operates at the cell level measuring dc voltage, dc current at the pack and/or string level, temperature, instantaneous battery impedance, and use metrics such as dV/dt, conductance, and internal resistance to provide information about state of health (SoH). Over the service life of the BESS, battery health is promoted by understanding state of charge (SoC) at any given moment, keeping the SoC in specific regimes, using acceptable charge and discharge rates, and mitigating overload conditions.

A BMS for the purposes of this document is defined as a battery management system, but within BESSs are battery monitoring systems that collect data from the batteries. BMSs can isolate and selectively use segments of the battery while also estimating SoC of each cell. Monitoring systems are a collection of cell and terminal sensors for I, V, and T directly connected or wirelessly connected to a controller or integrated circuit boards. Typical data sampling rates for I, V, and T are in seconds; there are, however, instances of higher sampling rates down to milliseconds [2]. DC BMS sampling rates today are several orders of magnitude slower than the rates utilized in ac protection and control operation [3] [4].

BESS overload conditions are currents that may damage the battery. For lithium-ion-based BESS operation outside of 20–90 percent, SoC is discouraged, mainly to deter dangerous thermal runaway events at high SoC and to prevent warranty damage at low SoC. According to SAE International, thermal runaway is defined as battery operation resulting in uncontrollable exothermic events.

At SoC ranges less than 20 percent, consistent operation and possible related undercharging slowly activates a battery failure mode in lithium batteries known as dendritic shorts. As the battery electrodes are consistently cycled at low SoC, a condition suitable for lithium-based crystal growth out through the solid electrolyte interphase layer and separator, and eventually to the anode, occurs [5]. Dendritic shorts result in deterioration of the cell, and the resulting short causes not only battery failure but also instigates thermal runaway, possibly leading to propagation to other cells nearby. At high SoC greater than 90 percent, charging and overcharging (charging above 100 percent rated battery capacity) in this regime is discouraged because of the buildup of heat in the battery cell. Persistent overcharging may result in thermal runaway as well.

C. *Batteries*

Lithium-ion BESS safety has been targeted by engineering and construction companies, battery manufacturers, utilities, and other stakeholders as a major problem area. UL Solutions has developed protocols for testing thermal runaway in battery systems (UL 9540A), packs and cells (UL 1973), and in specific applications like residential BESS (UL 9540B) for lithium systems [6]. Thermal runaway testing under these methods includes the BMS as a crucial regulatory system to pass the test. UL 9540A and UL 9540B are also included as necessary tests in National Fire Protection Agency (NFPA) 855 codes for BESSs and the analogous 2024 International Fire Code (IFC) for BESSs [7] [8]. The BMS for a lithium-ion BESS is specifically configured for strict safety boundaries, motivated by the iterative codes and standards cycles over the last ten years. Manufacturers of lithium-based BESSs depend on the BMS (amongst other design features) to inhibit thermal runaway. Because of these stringent controls, excursions outside of 20–90 percent SoC typically result in a BMS-related trip.

BESS IBRs at the utility scale require tactile, dynamic use of energy storage assets. As presently configured, the combination of a grid-following inverter and non-integrated BMS control strategies make the BESS a problem, not a benefit, in many cases. For BESSs to be useful in any system, BESSs need to be tolerant to faults and support system frequency stability.

As previously mentioned, there are several limitations to a lithium BESS, but the limitations are not limited to BMS-related safety boundaries affecting dispatch. For all types of batteries, the employment of an overarching controller enables control and communication between the various systems of the BESS IBR plant. Presently, the communication between the inverter and BMS is kept blind to typical utility controls. The IMS (if the system has built-in management protocols and intelligence) receives information on the entire battery and, in some cases, receives additional information at a pack level as 48 V blocks of battery cells. This information is typically SoC of the battery, SoH information like conductance and internal resistance, string and/or pack voltage, and possibly impedance measurements. However, instantaneous impedance, while useful in many different electrical systems, has yet to have clearly defined ties to SoH. Extensive research on this subject is presently underway, but impedance is also impacted by temperature, pack voltage, other electric interferences, frequency, and transient charge and discharge events [9] [10] [11].

Lithium-ion batteries are commonly used because of low-cost batteries from China, high energy density, and moderate service life. However, there are many different types of batteries to choose from that do not suffer from issues specific to a lithium-based BESS.

An alternative to lithium systems is battery chemistry with more robust fundamental processes capable of accepting power off the grid as a buffer during overload situations or phase-phase faults. Examples of battery types of this duty are lead-acid batteries and aqueous nickel-based batteries [12]. Lead-acid batteries, or lead batteries, are domestically produced in the U.S., low cost, recyclable, and a robust alternative to lithium-ion BESSs. Recently, lead batteries have been innovated to reach service life and cycle life performance similar to lithium-ion batteries [13]. However, like all electrochemical devices, there are clear disadvantages—mainly the low energy density inherent to lead-based materials [14]. New types of lead batteries possess higher energy density through the use of plastic substrates and thin lead foils [15].

In addition to battery type-specific advantages, the governing principles for lead batteries allow for lead-based BESSs to act more like generators in terms of dispatch. Lead-acid batteries are more robust under overload conditions. Thermal runaway is only possible with lead batteries under extreme conditions and, even then, it is possible to gradually walk thermal runaway down. As a direct comparison to low and high SoC conditions and resulting process with lithium, the processes for lead are:

- At high SoC and overcharge, other electrochemical processes like the electrolysis of water in the electrolyte occur. Over time, this process can be damaging to lead batteries as the electrolyte level depletion can lead to drying out of electrodes. Unlike lithium, lead-acid battery operation and technology has a very high tolerance for operation at high SoC.
- At low SoC and in undercharge conditions, lead battery electrodes suffer sulfation damage from consistent undercharge. Dendritic shorts, while possible with lead batteries, rarely occur and do not lead to thermal runaway.

A major benefit to a lead battery BESS (and some other types) is that transient loads and faults can be absorbed by the BESS with minimal impact on the battery. For example, ac load rejections result in momentary overcharge. Unbalanced faults will result in significant second-harmonic content on the battery. Neither of these common examples pose significant risk to a lead-acid battery.

Furthermore, BMSs for lead battery BESSs do not have structured design parameters from the BMS preventing overcharging or harmonics. Additionally, NFPA 855 and the IFC exempt lead-acid battery systems from SoC control and thermal runaway protection. Safety measures are used with lead battery BESSs, but these are very similar to the mature measures taken for lead battery strings used in the backup of telecommunications and nuclear power plants, ancillary services, and data centers.

D. Inverter Management Systems

IMSs de-conflict the ac and dc protection and BMS, thereby improving IBR plant system reliability. IMSs bridge the gap between BMSs and ac power systems. IMSs are now being deployed on several BESS projects for U.S. Department of Defense (DoD) microgrids, car charging, demand peak shaving, and mobile microgrid applications. The IMS features described herein fill a critical gap that is commonly missing on BESS IBR plant projects.

IBR BESSs historically exhibit erratic behavior where they do not go to dispatch set points. This commonly occurs because systems have not taken the dynamic nature of batteries and inverters into consideration. Systems dispatched beyond their limits will have unexpected system outages. Batteries near their maximum SoC will have reduced charge limits. Batteries at their minimum SoC will have reduced discharge limits. Multiple batteries and inverters in the BESS plant may be out of service. Environmental conditions may be derating the inverters. IMSs calculate the dispatch limits in real time and restrict dispatch set points to avoid outages. Limits are published to the SCADA system interface.

Batteries have warranty limitations that must be considered in the dispatch calculation as well. Reduction of charging rates, charge balancing routines, and equalization control reside in the IMS. Battery life is prolonged by controlling charge and discharge rates. Both inverter and battery charge and discharge limits are dynamic functions of temperature. Inverters must report their dynamic current limit and an IMS must consider this simultaneous to battery limit calculations. All dispatch commands are limited. All limits and actionable alarms are reported to SCADA.

Some lead battery chemistries can have their discharge and charge limits temporarily violated, providing system support during large transients. In lead-acid batteries, charging more than allowed causes dissociation of H_2O in the electrolyte. Momentary intentional dissociation allows the battery to act as a dynamic brake for conditions of large load disconnection; the prime movers may overspeed during the condition of ac load loss. Having a temporary allowance for overcharging the battery absorbs the excess kinetic energy from overspeeding gensets and prevents overfrequency outages. Temporary overcharging is especially helpful in locations where batteries run at high SoC for prolonged periods.

Fig. 3 shows an example of a 17 kW grid-forming (GFM) BESS IBR going past the IMS-calculated battery charging limit to support a large load rejection. The batteries are valve-regulated lead-acid absorbent glass mat (VRLA AGM) batteries, which are intentionally designed to recombine H_2O that has been dissociated during overcharging events. Note how this battery reaction created a gentle landing for the genset. In this case, the controls were achieved by IMS configurations that mimicked the droop line of a genset, which calculated the charge and discharge limits, and allowed for transient overcharging. Without the IMS, the generator would have tripped offline from overfrequency.

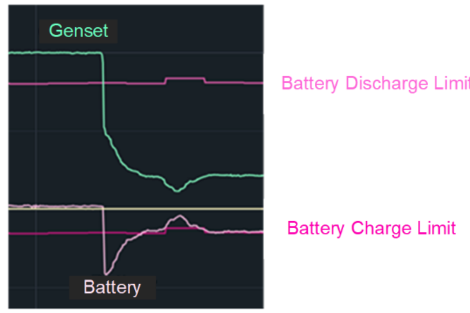

Fig. 3. Lead battery pushed past charge limit to support ac grid

IMSs sample raw dc voltage, dc current, ac voltage, and ac current at 3 kHz or faster. Faster sampling supports new advances in calculating SoC and SoH and improved root cause analysis of events surrounding the inverter. Update intervals of IMS control logic need to be on par with ac protection, meaning 4 ms is typical. This drives up CPU storage requirements considerably compared to what is presently required by a BMS or plant controllers. Because of the event storage and data collection, memory requirements of an IMS are similarly scaled to ac protection systems.

An IMS provides adaptive controls for a non-linear battery. Varying SoH, SoC, temperature, impedance, string configuration, battery failures, and inverter failures are used by the IMS to calculate charge and discharge limits, update control strategies, adapt system gains and time constants, and more.

Extending the life of a battery is accomplished by limiting charge and discharge levels, equalization when required or periodically, limiting voltages, and adapting to changes in battery SoH. Whereas a BMS has built-in intelligence that isolates, charges, or discharges on an out-of-bounds voltage, an IMS interacts with the inverter and ac protection and control systems to proactively prevent these conditions. The IMS actively manages dc voltage by providing dynamic charge and discharge limits to the ac SCADA dispatcher to prevent battery and inverter shutdown and potential damage.

The IMS provides operators with an experience similar to dispatching a conventional generation unit. Voltage and reactive power are dispatched with reference set points and response times similar to a generator automatic voltage regulator with a brushless excitation system. Frequency and real power are dispatched with reference set points and response times similar to a prime mover governor on a turbine prime mover. Dispatch is available remotely from SCADA or locally from a user interface.

IMS provides interconnection to the conventional substation protection and control equipment and utility SCADA systems. DNP3, IEC 61850, MIRRORED BITS® communications, MIL-STD-3071, and C37.118 are commonly used for this integration work. An IMS is integrated with protection schemes, local backup generation units, renewables, and more.

An IMS provides enhanced cybersecurity features through software-defined networking (SDN), local control, and more. Unexpected traffic is denied access with SDN deny-by-default configurations. Local control provides a reliable backup controls interface so strongly revered by cybersecurity experts [16].

E. AC Protection Systems

AC protection functions for IBR power plants, distribution, transmission, industrial, and microgrids are provided by protective relays. These relays protect transformers, feeders, transmission lines, load tap changers (LTCs), busbars, auxiliary supplies, and more. Protection actions such as tripping and locking out an IBR interconnection point are communicated to the IMS for safe shutdown of the IBR system.

IMSs are also used to enhance ac protection systems. The IMS can calculate ac fault current capability of a BESS IBR plant. Batteries, entire battery strings, and inverters are commonly out of service in a BESS and the effect on fault currents can be tallied and communicated to adaptive protection systems.

F. DC Protection Systems

DC protection of battery systems has historically been performed by non-intelligent devices with fast and slow time-overcurrent mechanical devices such as molded case circuit breakers (MCCBs) and fuses. Advanced dc protection methods are now practical with the IMS.

Tripped MCCBs or blown fuses on the dc are monitored by the IMS and charge/discharge limits are adaptively changed in real time. Severe dc fault events are relayed to the ac system for lockout and vice versa. Emergency stop lockouts are initiated when protection events have possibility of endangering life.

Real-time collection of status of MCCBs, fuses, inverter faults, and alarms is integrated with ac protection Sequential Events Recorder (SER) and oscillography. This greatly improves root cause analysis efforts.

IMSs are used to enhance dc protection systems. For example, an IMS provides dV/dt blocking signal under unbalance conditions to prevent nuisance BMS trips. Unbalances are measured by the ac protection relays as the level of negative-sequence current. Negative-sequence current causes second-harmonic ripple on the dc bus, which appears as dV/dt to the BMS. BMSs for lithium battery systems will trip a battery offline to protect it under large dV/dt conditions. This problem is most common with GFM lithium BESS and has not been observed with any lead-acid battery system.

G. Plant Logic Control Systems

PLCSs provide ancillary controls and monitoring systems for the IBR power plant. PLCSs provide environmental controls, fire suppression, metering, alarm management, human-machine interface, and more. PLCSs were usually performed in programmable controllers with processing update intervals of 20–100 ms.

H. Historian

All systems must provide real-time, time-synchronized data collection and archiving inclusive of SER, oscillography event records (ERs), and C37.118 data streaming data historian. The system must collect high-speed, high-fidelity data from both the ac and dc bus because inverters rarely provide sufficient fidelity, length of data recording, or time-synchronized data necessary to perform root cause analysis of events.

I. Inverter and Battery Management Systems

IBMSs are a combination of the IMS, BMS, PLCs, historian, and possibly more into a single control system. Because an IMS requires significantly larger computation power than a BMS or PLCS, these functions are commonly pulled into the IBMS.

There is some risk associated with integrating all plant control functions into a single IBMS controller. For example, fire suppression is commonly a separate control system for warranty and liability considerations. Some battery chemistries with thermal runaway dangers require an active and embedded CPU throughout the batteries; these systems require some BMS functionality be in these separate distributed controllers.

III. INVERTER CONTROLS

Fig. 4 depicts the most common control systems within an inverter, including:

- Bridge
- Modulator
- Transform
- Tracking
- Angle control
- Power control
- Voltage control
- VAR control
- Current control

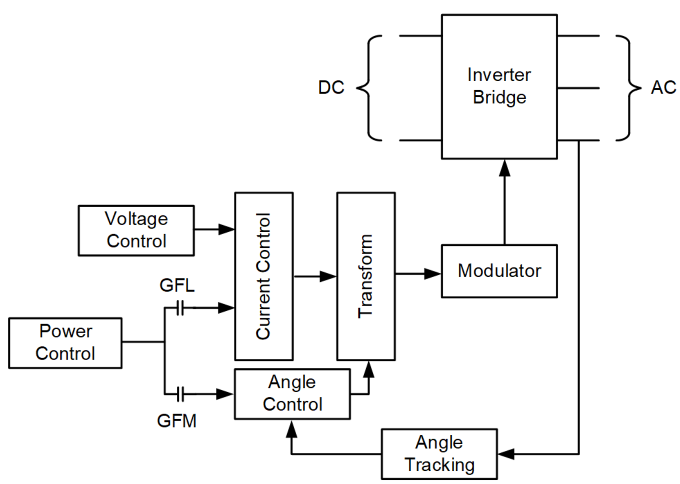

Fig. 4. A typical inverter control system

A. Bridge

Power electronic bridges carry the current from dc to ac systems. The bridges are constructed of self-commutated power electronics, primarily IGBTs or MOSFETs.

The majority of inverters today are two-level topologies with one IGBT connecting the ac to dc bus per phase. They are called two-level inverters because an ac conductor can be at two different dc voltages. Higher level PWM inverters have multiple IGBT/capacitor modules to allow higher voltages while reducing switching losses and increasing reverse voltage withstands. This allows operation at higher voltages, thereby providing more energy dense solutions. Two-level inverters are connected to the BEPS at typically 480–690 Vac and have dc buses that range from 800–1200 Vdc. Step-up transformers bring the voltage up for distribution or transmission. Multi-level inverters are required for larger voltages and higher MVA ratings per inverter. Because of cost and reliability challenges associated with higher level designs, two-level, single-stage inverters dominate the power industry for usage in PV, wind, and BESS IBR systems. For applications requiring more than 0.5 MVA (the cutoff varies by manufacturer), multiple two-level, single-stage inverters are wired in parallel. This also allows the same inverters used for microgrids to be used on distribution and transmission interconnections.

Multiple inverters combined within a system are called power converters. Power converters for PV and battery applications are classified as either single-stage or two-stage. A single-stage inverter converts dc to ac and varies the dc voltage to control power transfer from the PV array or battery. A two-stage converter system has a dc-to-dc converter stage and a second dc-to-ac inverter stage. Two-stage converters offer a larger range of operation for lower dc voltages. The midpoint dc bus of a two-stage inverter also offers isolation of 120 Hz and other harmonics from the battery or PV array. Single-stage inverters offer higher throughput efficiency and lower capital cost but lower range in dc voltage support, and they subject the batteries to ac harmonics. Inverters at transmission, distribution, and microgrid applications are dominantly single-stage, two-level designs. Some battery technologies require a two-stage design to fully extract the energy from the batteries because of low dc voltages. Many PV inverters for transmission and distribution are single-stage designs, however they have limited power extraction and curtailment. Higher performance two-stage PV inverters can extract energy at lower lumen levels but suffer lower efficiency.

Inverters come in either three- or four-wire designs. Three-wire designs dominate the industry today but four-wire designs are available for some applications. Three-wire designs are more common because they are less costly to manufacture than four-wire designs. Four-wire inverters require a fourth MOSFET/IGBT leg in the bridge to control the neutral conductor current. Three-wire designs cannot provide zero-sequence current, however four-wire designs can. Four-wire designs are more common for microgrids and data center applications where direct-connected loads may require zero-sequence current (I0) from the inverter.

Fig. 5 shows a three-wire, single-level, single-stage inverter architecture. This is the dominant design used throughout the industry today for PV, wind, and BESS applications at transmission and distribution interconnections. This inverter cannot provide zero-sequence current (I0), however the transformer configuration between the converter and BEPS allows the IBR system to provide I0 to faults on the BEPS.

The dc midpoint ground connection provides the ground reference for both ac and dc sides. The dc midpoint circuit may be resistors, capacitors, or both. It is essential to follow inverter manufacturer accepted grounding practices to prevent damage to inverters during upstream fault or switching events. Different inverter architectures have different sensitivities to grounding requirements.

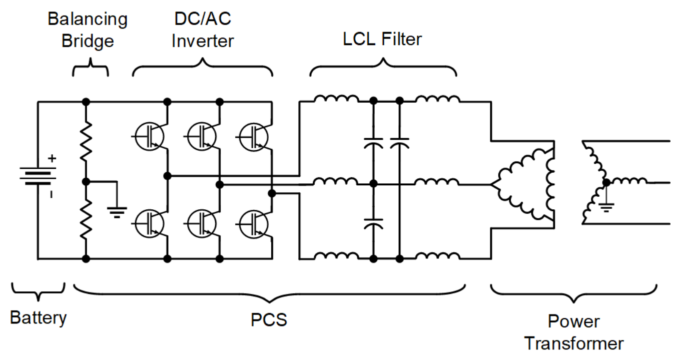

Fig. 5. Three-wire, IGBT, single-level, single-stage inverter

Fig. 6 shows a four-wire, single-level, two-stage inverter common for data center and microgrid usage. This inverter provides I0 for unbalanced loading conditions. Note there are three grounding locations of this inverter: chassis, transformer, and dc bus midpoint. DC midpoint grounding is to keep the battery centered around ground. Chassis grounding is for safety and electromagnetic interference suppression. Transformer grounding is to meet NEC separately derived ground requirements. This architecture is commonly used to power loads connected directly to the output of the inverter.

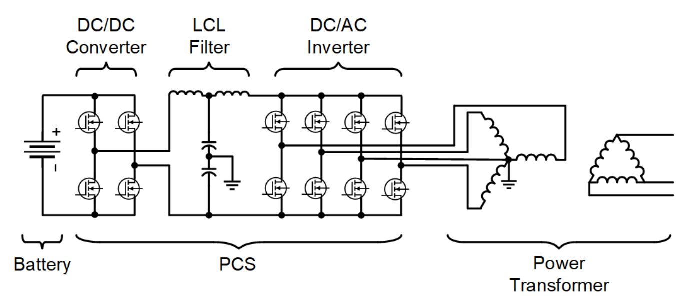

Fig. 6. Four-wire, MOSFET, single-level, two-stage inverter

Two-stage inverters can withstand lower SoC and lower voltage conditions, generally making them more reliable. Low dc voltage (low SoC conditions) can reduce current production capability of a single-stage inverter, thereby impacting protection coordination.

The choice between multi-level or single-level designs has no significant impact on ac protection systems. However, the number of stages can impact ac protection.

B. Modulator

This control system drives the gating on and off of the semiconductor switches in the power electronic bridge. Older MOSFET and IGBT bridge technology typically operated at 4–8 kHz. Modern materials such as silicon carbide MOSFETs have allowed switching frequencies of power electronics in inverters to increase to over 40 kHz.

There are a great number of different modulation control strategies, ranging from sine-triangle, harmonic elimination, harmonic injection, space-vector modulation, and many more. Because of the large inductances of the ac power system, the modulation frequency and control method have no significant impact on protection.

PWM IBRs rarely cause harmonic distortion, and when they do it can be difficult to isolate root cause. It is also challenging to predict or recreate these problems with models. When PWM IBRs inject harmonics, it is usually a tuning, signal condition, or grounding issue. In some cases, delay because of signal conditioning on voltage and current measurements can impact low-order harmonic production. For example, second-harmonic dc bus ripple from ac unbalances can propagate into larger problems. Using a power quality meter on every IBR is the first step toward finding the root cause of these problems.

The choice of modulator used in the inverter has little influence on ac protection today.

C. Transform

Three mathematical transforms are used in inverter controls: Park transform to the synchronous rotating reference frame (dq0), Clarke transform ($\alpha\beta0$), and Sequence transform (1, 2, 0). Both the Park and Clarke transforms map the three phase quantities to two axes offset from each other by 90 degrees, with an option for a 0 term for common mode (zero sequence) behavior. Park is a rotating quadrature reference frame. Clarke is a special case of the Park transform to a non-rotating, stationary reference frame. Some inverters calculate the positive- and negative-sequence values for Park (d1, d2, q1, q2, 0, δ1, δ2, δ, 0).

When designing controls in the Park or Clarke transform domain, active and reactive power are largely decoupled by mapping real power to the direct (d) or α axis and reactive power to the quadrature (q) or β axis, i.e., a change in one has minimal impact to the other. For this reason, the dq0 representation is most commonly used for inverter controls today. D-axis current is often associated with power production in most designs where it is mapped to be in phase with the phase of the reference voltage. Q-axis current is associated with reactive power production because it is 90 degrees out of phase with reference voltage.

The choice of transforms used in the inverter has little influence on ac protection today.

D. Frequency and Phase Tracking

Tracking systems are dominantly phase-locked loop (PLL) technology. Converters that use a PLL for primary angle and and frequency tracking are referred to as grid-following (GFL) converters. GFL converters track the grid response with a fast time constant on the order of milliseconds. A PLL in an inverter is a control system that generates an output signal whose phase is locked to the phase of the power system voltage and the point of interconnect for the individual IBR. The angle measurement is updated in real time to the control system and various transforms. Dual reference frame tracking PLLs are used to measure the positive-sequence and negative-sequence angles.

PLLs have a long history of poor outcomes in our power systems [17] [18]. Measuring angles of voltage waveforms is challenging because the ac voltage waveform is not an ideal 60 Hz sinusoid at all times. During faulted circuit conditions, the voltage may become too low to measure or experience a sudden phase angle jump, forcing the PLL into holdover (guessing mode). During inrush conditions, large dc offsets may result in no zero crossings to measure, again forcing the PLLs into guessing mode. Switching operations changes grid Thevenin impedances, and thus will cause sudden phase angle jumps that PLLs struggle to track. In some cases, inverter reactive current injection in response to a fault may cause a phase angle roll that causes the PLL to have an offset in its frequency, in turn causing the frequency of the voltage output by the IBR to drift.

Weak grids (high Thevenin impedance) will cause the output of the inverter to impact the phase angle of the measurement, creating something to the effect of a dog chasing its tail. These can create inter-oscillations between inverter controls referred to as sub-synchronous control interactions (SSCIs).

E. Angle Control

GFM inverters create their own phase angle whereas GFL inverters must have a PLL to measure the system phase angle and frequency. Thus, GFM inverters have some immunity to the PLL challenges described previously. Both GFM and GFL inverters depend on PLLs for synchronization prior to the commencement of switching.

GFM inverters adjust phase angle of the modulation reference to control power. There are many different ways GFM inverters are controlled to implement this. GFL inverters follow the grid phase angle and adjust d-axis current to control power. In both GFM and GFL inverters, the q-axis current is controlled for reactive power control, but GFM inverters may use different schemes to produce this current. GFM inverters use power measurement to control their phase angle. Power measurement is a more reliable measurement than angle.

GFM controls require a droop control to parallel to the BEPS. This is referred to as grid forming with droop (GFMD). Inverters with virtual machine mode (VMM) or virtual synchronous generator controls are derivatives of GFMD controllers.

F. Real Power Control

Fig. 7 shows how a GFL inverter controls power by increasing the Vid d-axis voltage. The inverter controls change the d-axis voltage to regulate power by controlling the d-axis current. In Fig. 7, the grid is Vg and the inverter voltage is Vi. Increasing Vid advances Vi and outputs power.

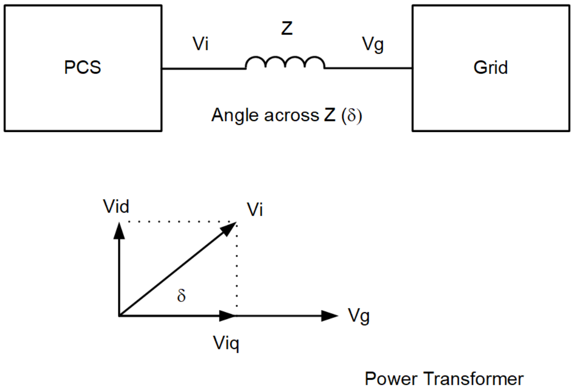

Fig. 7. GFL inverter control of power

G. Reactive Power Control

Both GFM and GFL inverters control reactive power by sending command references to the Viq q-axis voltage reference.

The amplitude and impedance of the dc bus can play a significant role in VAR production, especially for single-stage inverters.

H. Frequency Control

GFL inverters do not provide direct frequency control because they are tracking grid frequency and focusing control efforts on managing dc bus voltage, current, and/or power. However, if the converter is not trying to track peak power production from the wind or PV resource, a bias can be added to the outer power control loop to vary the power output for frequency support. This is usually implemented at the plant controller level and can override the peak power tracking when commanded. GFM inverters can provide frequency control for a microgrid and grid frequency support functions for a BEPS.

I. Voltage Control

In contrast to a synchronous generator automatic voltage regulator (AVR) that raises and lowers the flux in an air gap, an IBR produces reactive power by injecting currents out of phase with the ac voltage. IBRs therefore control reactive power significantly faster than brushless synchronous generators. Both GFM and GFL inverters control voltage by sending command references to the quadrature current reference.

Loss of generation or load can create over- or undervoltages. The loss of distributed PV solar installations, which are not pushing VAR to match watts, will commonly cause overvoltages on upstream circuits and IBRs. When disconnected, the upstream LTC and other generations that were pushing the VAR to support the 1.0 pf PV then cause an overvoltage. Assertions that this has to do with the load-to-generation ratio [19] are misleading. IEEE Std. 1547a-2014 began addressing this by allowing IBR systems to provide reactive power support, and IEEE Std. 1547-2018 then required VAR support.

Fig. 8 shows a typical voltage and reactive power control method used in IBRs of all types, acting on the q-axis component in the Park reference frame. Working from left to right, the outermost control is a reactive power (Q) PID control loop with an output driving a voltage reference. The voltage reference is limited by a voltage limit and drives a voltage PID control loop. The voltage loop drives a current reference that is current limited. The output of the current loop drives a Park transform q-axis voltage magnitude. The output of the Park transform drives a modulation reference function (m(t)*) comprised of three ac voltage waveforms that are the real-time voltage reference signals to the pulse-width modulator (modulation) control. The PWM controller drives the power semiconductor switching patterns with one of several pulse-width modulation techniques.

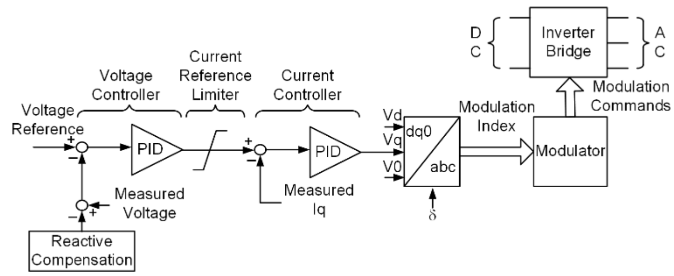

Fig. 8. Reactive power and voltage control

J. Cessation

Cessation means an abrupt stop of switching operation leading to zero output current. This commonly happens when the inverter control systems are unstable or not following command. Most common is the loss of current control or PLL tracking. Some commercial converters have a control setting to enable momentary cessation if voltage or frequency is out of tolerance.

Events leading up to cessation are usually caused by rapid changes in voltage amplitude or voltage angle that the PLL struggles to track. Loss of PLL measurement signal will commonly push an inverter into cessation. A PLL may go into cessation faster than a protective coordination scheme. Loss of a PLL synchronization to the grid may cause disturbances to current and voltage control loops, excessive current or voltage loop errors, or damaging currents.

NERC provides guidelines for PLL synchronization loss [20]. During a loss, the inverter should not go into cessation or commutation lockout. Should cessation occur, the PLL is to resynchronize to the grid and resume current injection within a few cycles. PLL methods can greatly impact I2 production. Thus, PLL controls have a large impact on ac protection.

Sudden change in grid voltage amplitude or angle may cause current loops to lose control. The results of these changes are summarized in Table I.

TABLE I
EFFECT OF AMPLITUDE AND PHASE JUMPS ON GFL CONTROL

Current Limit Priority	**Impacts of Voltage Amplitude Jumps**	**Impacts of Voltage Angle Jumps**
Voltage	Loss of control of power production	PLL tracking lost
Power	Loss of control of VAR production	PLL tracking lost

Industry standards for IBR disconnection during faulted circuit conditions are inconsistent. Per IEEE Std. 1547-2018

[21], distribution-connected inverters cannot backfeed into abnormal grid conditions in the interest of safety for linemen. Transmission-connected inverters are expected to ride through events to support protection systems per IEEE Std. 2800.2 [1].

K. Virtual Inertia

A synchronous generation will dispense current faster than an inverter because the magnetic fields driven by spinning kinetic energy can be dispensed through the stator windings at near the speed of light. However, mechanical energy (fuel valve response) of an engine prime mover is much slower than inverter power control. This distinction makes it practical for inverters to assist prime movers but not provide inertial support to a power system at the same speed as the flywheel effect of a conventional generation unit.

Virtual inertia, also known synthetic inertia, is a control system feature in some inverters. This provides power proportional to rate-of-change of frequency (ROCOF) of the grid. Equation (1) describes the power provided by virtual inertia.

$$Pv\left(t\right) = 2H\omega \frac{\partial \omega}{\partial t} \tag{1}$$

where:

ω is the power system frequency.

H is the per unit system inertia.

Pv(t) is the power provided by IBRs associated with virtual inertia.

Virtual inertia compensation in an inverter requires the ability to increase or decrease power supplied and is limited by the current limits of the bridge and battery. Virtual inertia compensations in IBRs are a known source of SSCI for lower inertia power systems like microgrids.

IV. Inverter Current Control

Current is limited in an inverter for many reasons. Silicon switching devices have damage curves much like fuses; they fail quickly at high currents and slowly at lower currents. Often, an inverter is comprised of many bridges in parallel. In this case, a failure of one bridge reduces the current limit of the inverter. Single-stage inverters with batteries at a low SoC can also affect the current production ability of an inverter. Thermal heatsinks are limited in their ability to dissipate heat from silicon switching losses. High ambient temperature, fan failures, blocked coolant water piping, and other environmental and mechanical issues also affect inverter current limits. High temperatures on the heatsink will cause the inverter to pull back current limits or go into cessation.

Fig. 9 shows an example of inverter thermal and silicon current limits that are regulated by inverter firmware [22]. Not shown on Fig. 9 is the momentary uncontrolled current spike that may happen at fault initiation. Thermal pullback from a silicon limit is often associated with a washout filter time constant. The thermal pullback is designed to prevent the silicon device from destruction. Inverters commonly can only carry up to 1.2 times the rated current for a few seconds, unlike conventional synchronous generators that will carry 5 times the rated current for extended fault conditions.

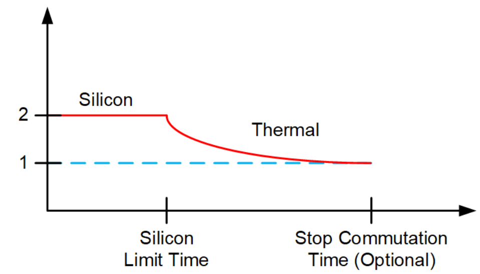

Fig. 9. Inverter current limits

Instantaneous symmetrical components calculations are performed in real time in the synchronous Park reference frame in some inverters if they have an appropriate PLL configuration and filtering [23]. Many existing IBRs do not have this capability. As noted earlier, d-axis current (I1d) is associated with active power production and I1q is associated with reactive power production. Similarly, negative-sequence I2 components are characterized by d- and q-axis components I2d and I2q with current references assigned for each axis for inverters with appropriate controls. Some early models of inverters with independent I2 controls regulated I2 to 0. Per [1], IBRs are required to produce I2 at an angle leading V2 by approximately 90 degrees. Four-wire inverters add control of I0 as I0q and I0d.

Inverters have observable transition phases including fault detection, mode switching and reconfiguration, PWM saturation, and closed-loop control convergence to inject I2. Inverters take as long as 20 ms to determine fault conditions and as long as 100 ms to regain full current control.

Low dc voltages can also affect both real and reactive current production. DC voltage and battery resistance affects the amount of voltage that can be switched on the ac side. Balanced reactive fault current does not come from the battery because there is no average energy transfer, however the inverter requires a stable dc voltage source to produce reactive current.

All inverters reduce voltage during faulted circuit conditions to maintain current within limits. Fig. 10 shows approximately how an inverter behaves like a current source for low-impedance faults by curtailing voltage. Inverter controls pull back the voltage at low fault impedances to limit the current to meet device current limits. The inverter behaves as a current-limited source for this region. At higher impedances, the voltage is limited and the current falls off. The inverter acts as a voltage source for loads and faults with higher impedances. From the perspective of steady-state power flow with the IBRs operating underneath their current limits, a GFL IBR is considered a current source while a GFM IBR is considered a voltage source until it hits a current limit. IEEE Std. 2800.2 compliant IBRs in a faulted condition are current sources. Inverters not compliant with IEEE Std. 2800-2022 are generally not predictable sources of current in terms of I1 and I2 magnitude and angle under faulted current conditions.

Table II is a first order interpretation of the inverter behaviors, where the GFL column is for IEEE Std. 2800–2022 non-compliant converters.

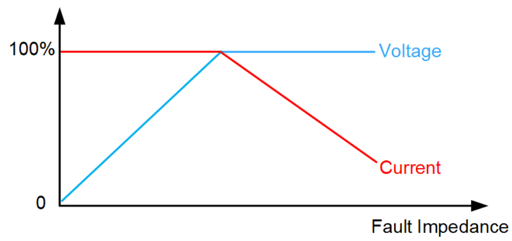

Fig. 10. Fault impedance means different demands on battery

TABLE II
CURRENT AND VOLTAGE SOURCE SIMPLIFICATION

AC Power System	GFL	GFM
Faulted	Offline if in cessation, current source if it provides ride-through	Current source
Normal	Current source	Voltage source

Both symmetrical and asymmetrical faults may require energy from a battery depending on the inductive to resistive (L/R) ratio of the faulted circuit. For example, faults are commonly highly resistive in low-voltage systems and in microgrids. These types of systems require the battery to supply most of the energy during the fault. Higher voltage distribution and transmission systems, such as transformers and long overhead lines, commonly have large inductances that limit the energy needed from batteries. Resistive faults pull dc energy from the battery. Balanced faults circulate only dc current from the dc bus. Unbalanced faults circulate dc and 120 Hz ac currents on the dc bus.

A. Impact on Protection

IBR fault response is based on control design and user settings. The currents may reach steady state within several cycles, with the state-state operating point also determined by the control design and settings chosen within the inverter. We can characterize the fault response, both in terms of transient response and the quasi-steady-state voltages and currents, using circuit models. Current control loops have time constants of less than a cycle, meaning protection elements are trying to make decisions during transient control response.

The fast control response of the IBRs presents challenges for some common protection elements. In conventional power systems, protective relays respond to faults before the control actions, such as generator excitors, capacitor switching, or transformer tap-changing, respond to the fault event. Several commonly used protection elements are negatively affected by inverter current behaviors, including:

- Large ROCOF from limited inertia in GFL converters causing protective relay frequency tracking to fail over to 60 Hz. This may cause current elements to become desensitized because the cosine filter is not at the frequency of the power system [24].
- Inverter effective impedance and voltage phasor angles change rapidly due to current control system (unlike a conventional source with inertia). Memory polarized mho circle expansion/contraction methods become unreliable. This causes fault impedance calculations to oscillate.
- Inverter current controls reduce voltage to restrain current, which makes determining V1 angle for polarization elements unreliable. This causes elements that estimate source voltage angles during faults (memory polarization) to become unreliable.
- Sufficient fault current to enable overcurrent supervision elements is unavailable. Specifically, GFL or GFM converters that are not programmed to regulate I2 will not provide sufficient I2 for relay negative-sequence supervision elements to operate. This behavior impacts elements that rely on ratios of |I2|/|I1| or |I2|/|I0|, directional elements, fault type identification logic, or negative-sequence polarized quadrilateral elements.
- Some IBRs produce inadvertent I2 where the magnitude is large enough to enable negative-sequence elements, but the angle of I2 is either incorrect or rotating. This behavior impacts negative-sequence directional elements, fault type identification logic, and negative-sequence polarized quadrilateral elements.
- Angular relationship of positive- and negative-sequence components shifts rapidly because of inverter current limiting methods. This prevents fault identification logic from operation. This will cause distant element 21 overreach and prevent identification of the faulted phase. This also prevents fault directionality detection elements (67 or 32) that rely on V2/I2 angular relationships. This also affects permissive overreaching transfer trip and zone interlocking schemes that use 67 elements.
- Even when the converter controls are programmed to provide negative-sequence currents with magnitudes and angles meeting the IEEE Std. 2800-2022 [1] recommendations, it make take four cycles or longer to reach steady-state currents. The magnitude of the negative-sequence current may oscillate during this process and the current angle may rotate through wide ranges during the transient response of the current controls. Directional elements, fault type identification logic, and distance elements may be impacted during this transient control response.
- Inverter tuning inconsistency and supplier-specific control algorithms may create unpredictable behavior.
- Inverter controls are much slower than the physics-based generator behavior prior to exciter response, so protection response will be slowed down and it may be desirable to delay Zone 1 responses to avoid false tripping.
- Unexpected cessation and re-energization of inverters foils system coordination. This is usually caused by PLLs, dc bus problems, or incorrect inverter settings. Sometimes it can be caused by active or passive anti-

islanding controls in the inverters. Cessation prior to a relay trip response may leave a fault present on the system if there is no transfer trip.

- There is a lack of transparency by inverter manufacturers. Most do not supply event or Sequence of Events reports under claims of proprietary information. Inverter memory of event recordings is commonly volatile.
- Conventional impedance-based power swing detection methods may operate correctly when GFM inverters are paralleled to weak utilities but may operate incorrectly for stiff utility connections [25]. This is because of, in large part, current-limiting schemes of inverters.

B. *GFL I2 Squelching*

Many existing GFL inverters exhibit nearly infinite effective negative-sequence impedance because of the fast current controls, which are designed to produce only I1 current. Any I2 present on the ac current is thereby squelched by the very fast current loops. GFL controls may or may not intentionally measure I2 and try to decimate it. Some GFL control strategies cancel I2 as a byproduct of their priority on dc power production and their very fast current loops [26].

Some newer converter designs use a dual reference frame control where measured voltage and current are transformed to both a positive-sequence rotating synchronous reference frame and a negative-sequence rotating reference frame [26]. Filters are used to remove double-frequency oscillations because of mapping counter rotating components. In this case, separate d- and q-axis current regulators operate for the positive- and negative-sequence currents. Early designs using this scheme regulated the negative-sequence currents to zero. Following the development of European and U.S. grid codes requiring IBRs to supply negative-sequence current in response to fault [1], negative-sequence current commands for GFL inverters are set to regulate magnitude and angle of negative-sequence current.

By eliminating I2 production, GFL inverters reduce the 120 Hz ripple on the dc bus associated with unbalanced loading. GFM inverters acting as a voltage source or any inverter injecting I2 will apply 120 Hz ripple on the dc bus. Many GFL inverters actively control the dc voltage. An example is a maximum power point tracking control used on PV systems. Fig. 11 shows a GFM inverter with Phase A disconnected and load X/R = 10. In this case, the resultant power on the dc bus is oscillating at 120 Hz.

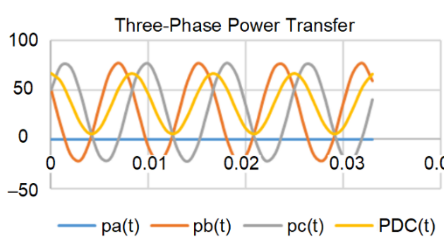

Fig. 11. I2 creates 120 Hz ripple on dc bus

C. *Accidental I2 Production*

IBRs can produce inadvertent negative-sequence current in response to a fault. There are two primary courses. The first is short-term unbalanced currents because of the dynamic response of the control loops to a short-circuit condition. These currents may only last a few cycles, but the amplitude and phase angle of the resulting negative-sequence phasors calculated by the relay may be sufficient to impact protection elements until the controls approach new steady state.

The second cause is because of the impacts of unbalanced fault-induced voltages on the response of the control loops. These impacts can be mitigated by proper signal filtering. Two possible feedback mechanisms include:

- The negative-sequence voltage from the power system maps to a double-frequency voltage component in the synchronous reference frame, leading to a double-frequency term in the current reference and subsequently mapping back to small, uncontrolled negative-sequence current from the converter. The angle of the negative-sequence current is not stable.
- The negative-sequence voltage maps to double-frequency oscillations in calculated real and reactive power applied to control loops in the converter controls, again leading to double-frequency current references for the current regulators and leading to small, unregulated negative-sequence currents.

D. *Forced I2 Production*

Because of GFL inverter squelching of I2 and the desire for directional element polarization, standards have called out the injection of I2 during fault conditions to be dependent on magnitude and angle of V2. Reference [1] requires all inverters under faulted circuit conditions to inject negative-sequence current 90 degrees, leading the negative-sequence voltage to mimic the response observed with conventional generation. The amplitude of I2 is defined by a relationship with I1 by a factor K as described by the relationship in (2). The angular relationship between I2 and V2 are defined by (3).

$$\mathrm{Mag}(\mathrm{I2}) = \mathrm{K} \bullet \mathrm{mag}(\mathrm{V2}) \tag{2}$$

$$\mathrm{Angle}(\mathrm{I2}) = \mathrm{Angle}(\mathrm{V2}) + 90 \text{ to } 100^\circ \tag{3}$$

I2 forced injection is challenging for several reasons:

- The logic determining when a faulted condition has occurred is inconsistent between inverters and undefined in standards. For example, high-impedance faults may not be detected.
- I2 injection means 120 Hz components on the dc bus, which some BMSs and renewables detect as dangerous conditions and shut down.
- PLL may go into holdover during the fault having failed at estimating the phase angle. Failed angle estimates will quickly cause a cessation.
- Changing conditions will cause inverters to move on and off their current limits. When this happens, the voltage/power priority logic causes sudden phase

angle shifts in I2 in relation to V2. This can cause oscillation in I2 angles.

- GFM inverters are not explicitly called out in IEEE Std. 2800-2022. GFM inverters in voltage mode (normal) will produce I2 naturally as a function of the circuit impedances, which may not match the standard. GFM inverters in current mode (overload) have the same challenge with current limits as GFL inverters. Some GFM controls have very slow response to a fault and may take more than four power frequency cycles to stabilize current.
- Forced I2 production circuits are often turned off in the field because the feature cannot be tested.
- Dual reference frame tracking refers to the method of two PLLs tracking the positive- and negative-sequence voltages on the inverter. I2 injection standards require the inverter to track sometimes weak V2 signals.
- Some GFM inverters intentionally suppress the I2, meaning this system cannot carry unbalanced loads.

E. Natural I2 Production

Nearly all GFM inverters in production today allow for natural I2 production while in voltage mode (i.e., below the current limit). These I2 currents are produced naturally without complexity of I2 forcing control systems. Fig. 12 depicts a GFM inverter naturally producing I2 for a phase-to-ground load on a typical BESS GFM inverter installation. In this example, the transformer winding configuration requires that the GFM inverter produce I2 to support the single-phase loading on the high-voltage side of the transformer.

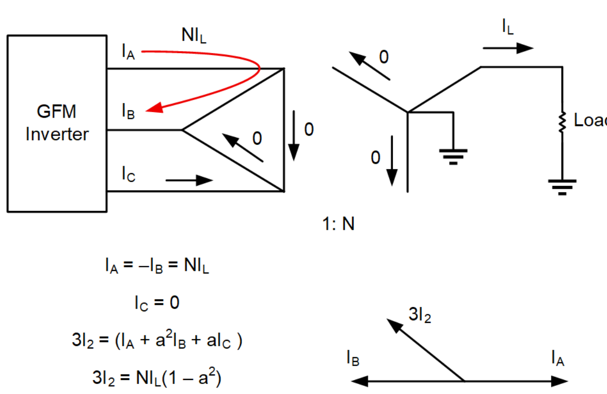

Fig. 12. Calculating natural GFM inverter I2 production

Fig. 13 shows the response of a GFM inverter to a loss-of-phase event. In this case, the inverter was islanded and carrying a three-phase delta-connected resistive and inductive load bank and the Phase A to the resistive load bank was removed. Note the GFM inverter current loops produced I2 to meet the imbalance within two cycles. Angles shown on the bottom are V2-I2 and I1-I1. V2-I2 is roughly 180 degrees and V1-I1 is 39 degrees. There was some house load on Phase B. The V1-I1 angle increased because the X/R ratio of the load increased. The current did not hit a limit.

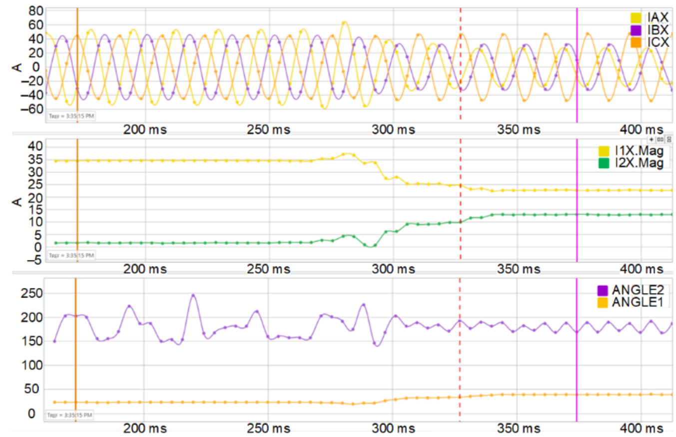

Fig. 13. GFM inverter carrying unbalanced load on island

Some GFM control schemes, notably virtual synchronous machines, have the objective of behaving as a positive-sequence voltage source behind a programmed reactance. This control scheme will naturally produce a negative-sequence current if the terminal voltages are unbalanced.

Because of the natural I2 production of most GFM inverters, they may be modeled as a variable effective negative-sequence impedance while acting as a voltage source (normal). Once in current limit (overloaded), their impedance effectively changes. The impedance is variable because GFM controls acting as voltage sources inject whatever current is required to develop a clean V1, which will necessarily include I2 for unbalanced conditions.

A great number of incorrect assumptions have been stated around I2 production, most notably that all GFM inverters intentionally reject I2. I2 rejection control schemes have been developed to prevent oscillation on the dc bus. The truth is that only a few GFM control schemes suppress I2 [27], whereas many GFM controls allow I2 to flow naturally because of the ac grid priority of the GFM inverter [28]. Any GFM inverter pushed into supporting an islanded grid must necessarily provide I2 for unbalances.

Note that a GFL inverter cannot provide the natural I2 currents of a GFM inverter and requires control loops specifically designed to regulate I2.

F. Current Limiter Impacts

Self-preservation behaviors of inverters create waveforms that a synchronous generator cannot produce. Most notably, IBR current limits have a large impact on the control of I2 magnitude and angle [29]. IBR current limits dynamically change as a function of inverter ratings, inverter heatsink temperatures, battery SoC conditions, battery health, or other [30].

Several types of current limiters are used on inverters today, including:

- Positive-sequence priority under limiting. Sometimes called quadrature current prioritization, reactive current injection, or dynamic voltage support [19]. These limiters prioritize current to either the q-axis (reactive power) or d-axis (real power priority). Either can squelch negative-sequence current.

- Negative-sequence current priority. These systems reduce positive-sequence current to supply I2.
- Proportional reduction of I1 and I2. Some of these schemes still prioritize d- or q-axes.
- Instantaneous limits of phase current (clipping). Sometimes called hardware limiting, this will create harmonic content.
- No current limit. Should the inverter exceed the current limit, the inverter stops commutation and issues a fault.

The positive-sequence priority limiter is most common today. Upon reaching a current magnitude limit, the IBR will prioritize either d (power priority) or q (voltage priority). Equation (4) depicts how this current limiter scheme functions in an inverter. Note the multiple levels of dynamic behavior of this calculation. I_{Rated} is continuously changing for site conditions and I_Q is continuously changing for power system conditions.

$$I_D^{Lim} = \sqrt{I_{Rated} - \left(I_Q^{measured}\right)^2} \tag{4}$$

Fig. 14 shows the total balanced current limit of an inverter as a circle. The low impedance of a faulted circuit is represented by the dot outside the inverter limits, forcing the inverter to pull back voltage. In voltage priority, the inverter follows Path A and produces dominantly quadrature current. In power priority, the inverter follows Path B and produces dominantly direct axis current.

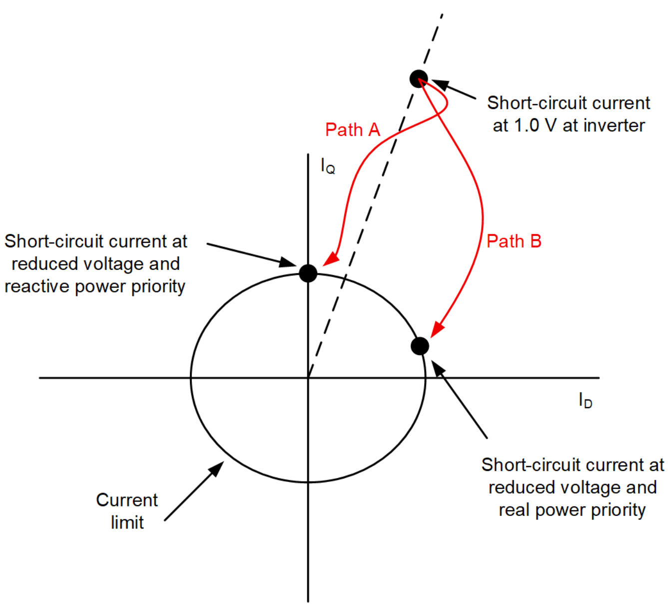

Fig. 14. Faulted circuits require inverters to pull back

Both power and voltage priority current limiting causes the current angle to suddenly shift. These sudden changes cause changes in both I1 and I2 angles. Protective relays continuously track sequence current amplitude and angles, and these sudden changes take time for the relay measurement to track. Therefore, these sudden shifts cause delays in protection systems.

These limiting schemes are different than impedance compensation. Impedance compensation in inverters and generator voltage regulators is used for either load-drop compensation or voltage control stabilization. Positive-impedance compensation increases terminal voltages to compensate for downstream impedances. Negative-impedance compensation reduces terminal voltages to add virtual impedance. Adding virtual impedance is functionally similar to VAR/Volt droop in that it improves gain margins and is thus used to commonly damp out voltage inter-oscillations between paralleled AVR and/or inverters. It is also used for steady-state VAR load sharing.

All current-limiting methods impact protection. Improving the current-limiting methods of inverters is required to improve response of traditional protection methods.

G. I0 Production

Per the previous discussion on bridge construction, there are three- and four-wire inverters. Three-wire inverters cannot provide I0, four-wire inverters can. Most commonly today, inverters connected to the BEPS are supplied three-wire with step-up transformer winding configurations that allow the flow of I0.

Transformer neutral ground bonding systems at IBR facilities must be designed to prevent equipment overvoltage and to provide the I0 required for protective relays to detect ground faults. Systems commonly experience transient overvoltage conditions because of single-phase loads, faults, switching transients, or unbalanced capacitive coupling between phases and earth ground. Overvoltage conditions cause surge arrestors, lightning arrestors, inverter damage, or insulation flashover.

V. BESS IBR Applications

This section explores BESS IBR applications by comparing inverter attributes, identifying conflicts and solutions in inverters and BESSs, and explaining a generalized taxonomy of inverters.

A. Inverter Taxonomy

GFM inverters depend on a strong dc source for their ac controls, and GFL inverters depend on a stiff ac source for their dc priority controls. GFM inverters, therefore, require energy storage on the dc bus and GFL inverters do not.

GFL inverters have a dc priority control strategy. GFL inverters reject 120 Hz oscillations from unbalance ac loading by squelching I2. GFL inverter control loops for PV systems control the dc voltage to gain control over power transfer from the PV cells. Many GFL control loops use dc power as their measurand.

Most GFM inverters have an ac priority control strategy. Their priority is to produce a perfect ac terminal voltage. GFM inverters will produce any current required to keep voltage sinusoidally perfect. During normal loading, they can be considered a voltage source. Fig. 15, Fig. 17, Fig. 18, and Fig. 20 further explain this, showing one 30 kVA generator and one 17 kVA inverter operating in parallel without load at

208 V. Both are configured with 4 percent frequency droop and 8 percent voltage droop. These pictures were taken from a time domain meter front panel.

Fig. 15 shows the generator providing 60 Hz with minor harmonic distortions because of winding imperfections (also known as slot harmonics). VB has a somewhat different distortion due to house loads. Note that generator currents were not measured in this plot because of current transformer locations. Fig. 16 shows that 32 sample event reports from a relay did not capture the voltage distortion, thus the 1 MHz meter was added. Notice how all phase voltages are distorted.

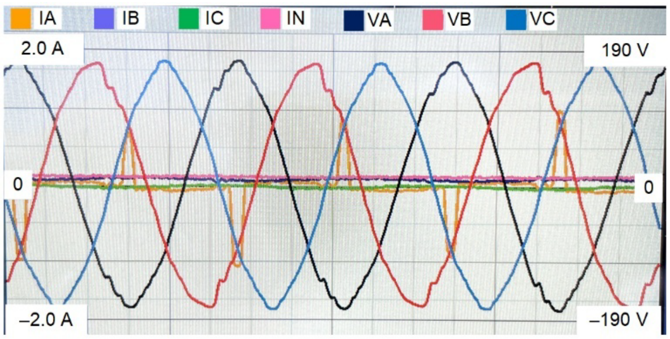

Fig. 15. MHz capture shows generator slot harmonics

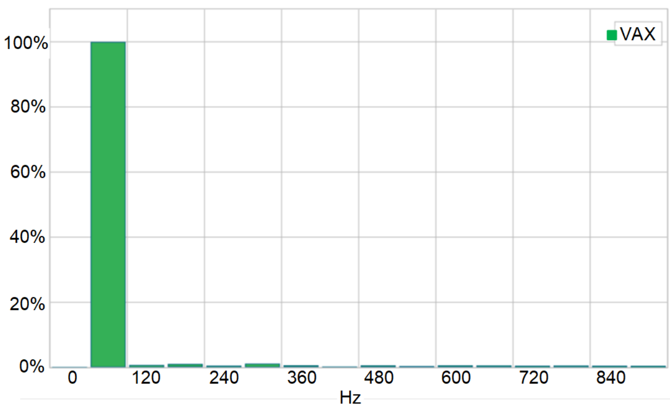

Fig. 16. Relay could not detect the generator slot harmonics

Fig. 17 shows the GFM inverter providing 60 Hz with no voltage distortion while feeding house electronics loads on Phase B. The generator was offline for this. In this case, the house load was observable in the IB currents and only Phase B voltage was distorted because of this. Note how the GFM inverter is providing a nearly perfect voltage sine wave except for Phase B.

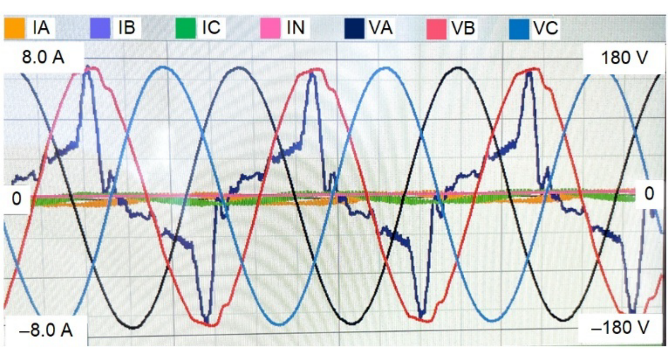

Fig. 17. 1 MHz capture of GFM inverter operating on an island

Fig. 18 shows the GFM inverter and generator paralleled. Fig. 19 shows the GFM inverter here is injecting fifth- and seventh-harmonic current to "clean up" the slot harmonics. Current loops in the GFM inverter are so fast as to easily keep up with the asymmetry in the generator stator windings. GFM inverters are excellent at cleaning up distorted voltage waveforms.

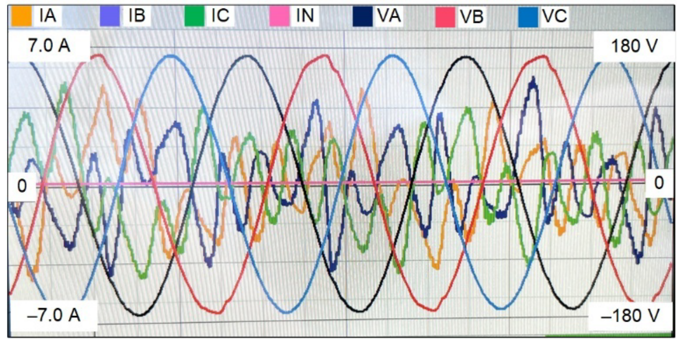

Fig. 18. MHz capture of GFM inverter operating parallel to a generator

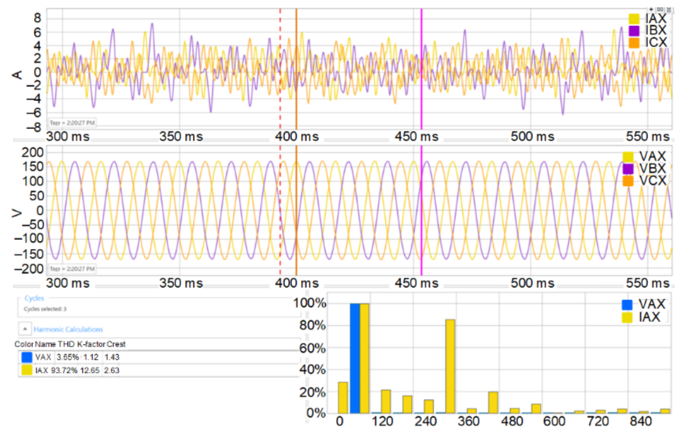

Fig. 19. Relay detected strong fifth- and seventh-harmonic currents but a clean voltage waveform

Fig. 20 shows the same inverter operating in GFL mode and paralleled to the generator. In this case, the GFL inverter is managing dc bus voltage and disregarding (worsening) the imperfection on the ac voltage waveform.

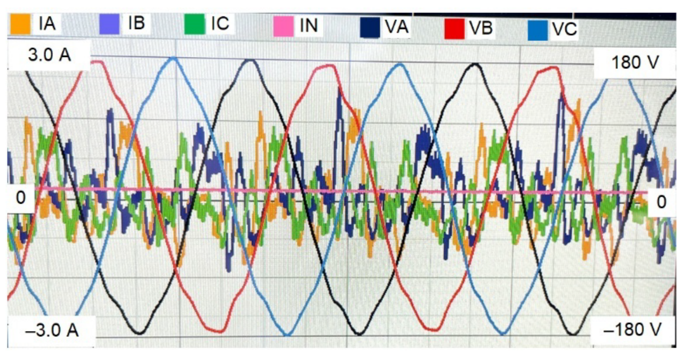

Fig. 20. 1 MHz capture of GFL inverter operating parallel to a generator

The GFM inverter has many advantages over the GFL inverter, however their impact on BESS needs further research. The primary objective of the GFM inverter is ac voltage continuity. GFM inverters have limited PLL dependence, whereas GFL inverters completely depend on their PLL phase angle tracking. GFM inverters are more reliable than GFL inverters because their primary measurand is power for phase angle control, and power is much easier to measure than phase angle. GFM inverters exhibit fewer cessation events than GFL inverters, superior ride-through, and they naturally produce I2 current production ability when not current saturated, whereas GFL inverters cannot naturally produce I2. GFM controls can be built to create the virtual machine mode with transient performance approaching that of a synchronous generator, whereas GFL controls cannot. GFM inverters will carry islanded load and transition back and forth to grid-connected operation seamlessly, whereas GFL inverters cannot. GFM inverters can be reliable for a weak grid interconnection, whereas GFL inverters will exhibit cessation in this situation.

GFL inverters have a few advantages over GFM inverters. GFL inverters expose the batteries to fewer harmonics because of I2 suppression. GFL inverters generally have more stable ac power production during non-transient conditions. The opposite is true during transient conditions. GFL inverters can be configured to follow a power set point, and GFM inverters must be in frequency droop mode for them to parallel with the power system. Some GFM inverters have problems in frequency stiff power systems, whereas GFL inverters work best with stiff grids.

There are some functions that GFM and GFL inverters perform with similar capability. Both can be configured with droop lines for grid interaction and frequency support, and in this mode both can use a BESS as a brake for overfrequency events. Both can increase output for low-frequency events. In faulted circuit conditions, both can provide I2 injection to meet code. Both can push VARs for voltage support on a voltage droop line or by remote dispatch.

Table III summarizes the two main types of IBRs in use today. Continuing to produce current during faulted circuit conditions is called ride-through. An IBR that rides through a fault must operate under reduced voltage and distorted terminal voltage conditions. During these conditions, the PLL does not have reliable measurements of ac voltage and will shift into a mode of estimating phase angle called holdover. PLL will fall out of synchronization with a power system for prolonged holdovers, at which point the GFL IBR must stop switching and ride-through is lost. IBRs must also ride through frequency and voltage transient events [21].

TABLE III
INVERTER SUMMARY

	GFL	GFM
Priority	DC bus for power production	AC bus for voltage production
PLL dependence	Always for all control	For virtual inertia and synchronizing only
Ride-through	Struggles	Yes
Operates without a grid	Never	Yes
DC bus	Controls dc bus	Requires stiff dc bus
PV	Yes	Requires a second inverter stage
BESS	Yes	Yes
I2 production for fault conditions	Forced	Undefined†
Natural I2 production for Itotal <1.0	No	Yes
Virtual generator	N/A	VMM
Simple model unfaulted	Current source	Voltage source
Simple model faulted	Current source	Current source

† I2 for GFM is being considered by the IEEE Std. 2800 team for a future revision

B. *BESS Challenges*

A deeper dive into the battery system identifies further conflicts between the ac and dc systems. The conflicts of the dc priority GFL inverter and ac power system are largely explained in Section IV.A. Section II.B explained the functions performed by the BMS. In this section, we explore conflicts between the BESS, BMS, inverters, and the ac grid.

Battery development focuses on longevity, leveraging service life and total energy throughput as a major financial driver. Researchers have issued reports characterizing a battery financially, measuring a possible energy storage system (ESS) based on a levelized cost of ownership model and serving as an example of the migration to commodity pricing occurring in ESS [31]. This focus on depreciation and capital cost has driven the battery industry toward maximizing life at the battery level, best described as cycle life.

There are two pathways to increase cycle life: new materials and battery management using state-of-the-art approaches to mitigating damage to battery electrodes. For instance, SoC management is key in preventing overcharge and undercharge events that are both damaging and potentially dangerous for lithium-based batteries. SoC window control is based around controlling current and voltage across the entire usage cycle, with predictive models used to understand the impact of current and voltage on SoC.

Financial objectives are detached from ac resiliency, with dc objectives centered on performance over the life of the system influenced heavily by the need to maximize total energy throughput (and likely minimize warranty claims). BMSs and IMSs have become key solutions to increasing longevity without significantly increasing cost.

BMS objectives are prolonging battery life, whereas inverters sourcing I2 to the ac grid can degrade battery with some chemistries. Choosing correct chemistry and sizing of batteries alleviates some of this challenge. Adding capacitance to the battery system can also assist in mitigating battery damage. Alternately, an inverter that suppresses I2 can be chosen.

IMSs are used to de-conflict ac and dc priorities. IMSs limit dc charging and discharging currents to within battery damage curves. IMSs must adapt current limits based upon SoC, SoH, dc voltage, and temperature. A doubling of battery lifetime can be achieved with a properly configured IMS [32]. IMSs must manage the dc bus voltage to prevent damage to the battery or the inverter and to prevent inverter shutdown. Unintentional islanding, power quality, V/VAR regulation, remediation of equipment overloading, and adaptive protection coordination must be coordinated with an IMS.

Balanced reactive currents amount to no net transfer of energy through the inverter, meaning these currents should not impact the battery. Balanced resistive currents result in dc currents charging or discharging the battery.

Unbalanced resistive and reactive inverter currents become 120 Hz oscillations in current on the dc bus. Missing, undersized, damaged, or deteriorated capacitors may force the current through the battery. Often, the inverter hardware and firmware design impacts the level of current ripple on the battery. AC ripple at 120 Hz can be controlled to minimize battery aging while still providing grid imbalance compensation [33].

Furthermore, the discharge processes governing lead batteries are well known to provide high pulse power performance [34]. Lead battery systems are useful in providing sudden change in voltage over a matter of milliseconds and seconds and are the go-to technology for black start of generators and engines. Similarly, lead battery systems can provide sudden power and voltage production for supporting the inrush associated with system restoration.

VI. Field Data

Herein we provide data collected on projects.

A. *Distribution Feeder BESS Case Study*

The distribution-level microgrid system consists of a point of common coupling (PCC), BESS, and feeder shown in Fig. 21. The BESS is connected to the distribution system through a 550V:12.47 kV, Yg-D step-up transformer and contains three inverters and two batteries. Two inverters are connected to a common battery bus running in GFM mode with droop while the third inverter is not connected to a battery bus and runs in GFL mode. The third inverter is acting as a static synchronous compensator and is used to increase the total fault current contribution of the BESS. Table IV summarizes inverter ratings.

TABLE IV
INVERTER RATINGS

V_{nom} Inverter	0.55 kV
Amperes Rated Per Inverter	1500 A
Total Rated Amperes	4500 A
BESS Overload Total Amperes	5400 A
S_{rated} per Inverter	1196 kVA
S_{rated} Total	3588 kVA
Total Rated Amperes at 12.47 kV	198 A

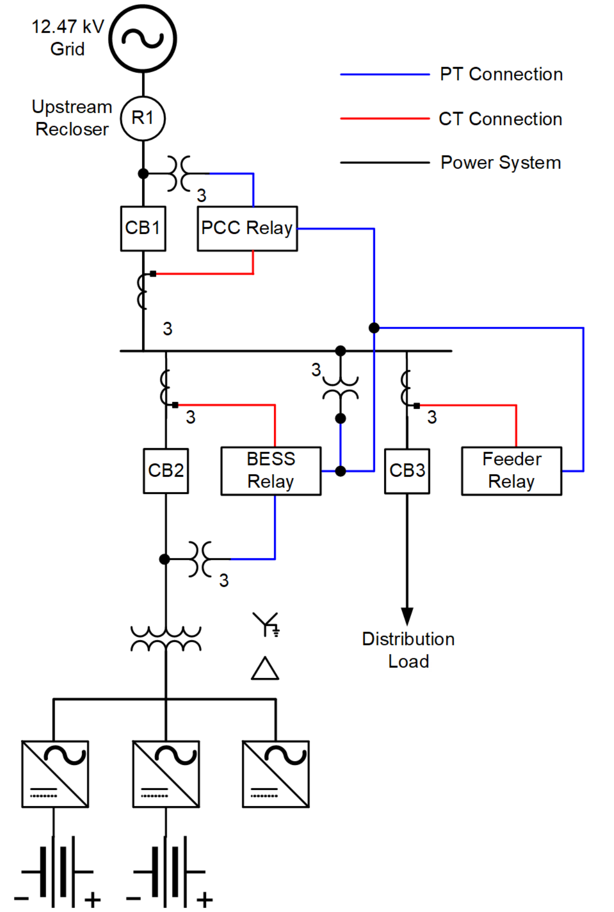

Fig. 21. Distribution system example

The main goal of the distribution microgrid is increased resiliency. The local feeder experiences frequent power interruptions.

The microgrid has been in service for two years. The inverters and the BMS could not capture oscillography data. All events were analyzed using the event report data captured by protective relays.

The PCC relay protects the downstream equipment, coordinates with BESS and distribution relays for downstream faults, and detects grid disturbances using voltage and frequency elements. The voltage elements in the BESS relay are blocked from operation when an upstream fault is detected to allow the PCC to open first.

The BESS relay protects the BESS cable and transformer and coordinates with the elements of the PCC. The feeder relay protects the downstream cable and coordinates with the PCC relay and the largest downstream fuse.

For all events in which the fault is located upstream from the PCC, the only fault current contributing sources are the inverters and the Yg-D transformer. Moreover, the event reports are unfiltered with 32 samples/cycles and raw phasors are generated in the analysis software.

As shown in Fig. 21, the BESS relay is metering at the 12.47 kV side of the BESS step-up transformer. The allowed overload factor of the inverter (previously referred in this paper as the silicon limit) is 120 percent of its rated current.

The battery manufacturer updated the dc current and voltage protection parameters to allow the battery to ride through unbalanced ac fault events long enough for the relay protection to operate. In all the events, we can see that the inverters contribute both positive- (I1) and negative- (I2) sequence current for unbalanced faults while the grounded transformer winding contributes zero (I0) sequence current for faults involving ground.

The reasons behind IBR shutdown include:

- BMS opened the dc contactor for voltage excursions during unbalanced faults.
- BMS opened the dc contactor for current excursions during unbalanced faults.
- GFL inverter went into cessation. A hardwired direct transfer trip from the GFL inverter to the GFM inverters then shut down the two GFM inverters.
- Inverters shut down for exceeding their dynamically calculated current thermal limits.
- Inverter hardware overcurrent trips.

Fig. 22 and Fig. 23 show ER 1 from the BESS relay with all three inverters online. Fig. 23 shows the positive-, negative-, and zero-sequence impedance angles of the inverters. The fault occurred downstream of the microgrid in the distribution system and involved a line-to-line (LL) fault. The fault lasted for more than 580 ms and was cleared by a miscoordinated upstream feeder relay trip. The inverters then went into shutdown incorrectly upon islanding. The inverter contributed approximately 40 percent of its rated amperes while paralleled to the utility. All three inverters contributed current to the fault in this case.

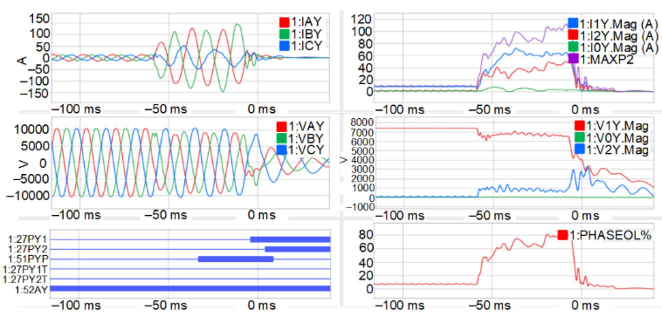

Fig. 22. ER 1 downstream LL distribution fault

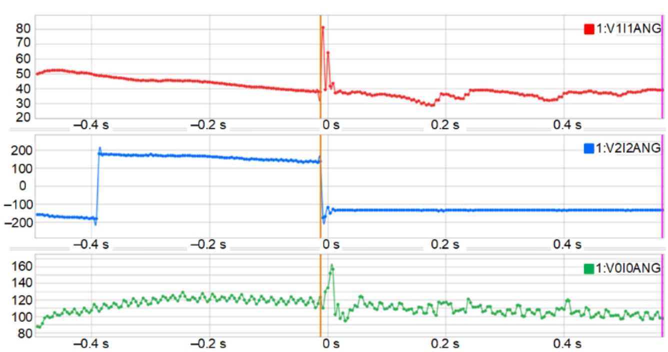

Fig. 23. ER 1 downstream LL distribution fault – V and I angle

Fig. 24 and Fig. 25 show ER 3 from the PCC relay with all three inverters online. Another upstream transmission system fault, this LL fault lasted approximately 56 ms and was cleared by an upstream transmission line relay trip after approximately 35 ms. The inverter contributed around 80 percent of the rated amperes for 20 ms.

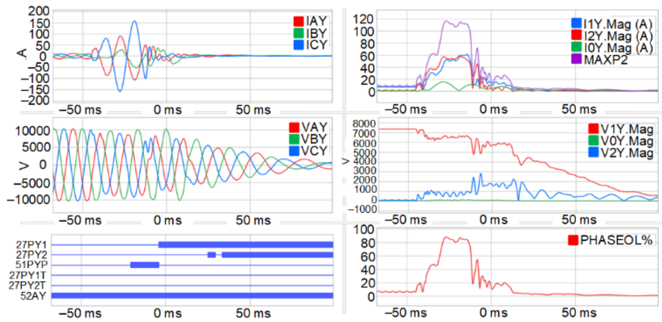

Fig. 24. ER 3 upstream LL transmission fault

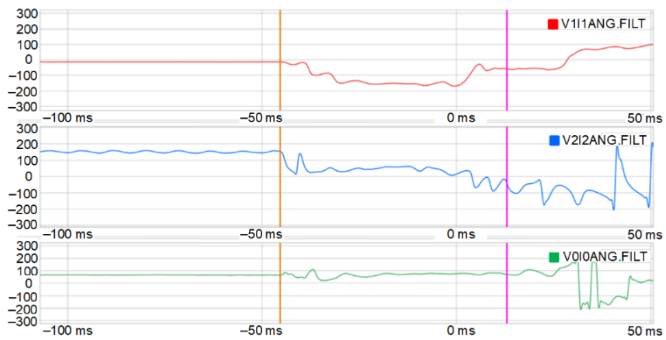

Fig. 25. ER 3 upstream LL distribution fault – V and I angle

Fig. 26 and Fig. 27 show ER 5 from the PCC relay with only the two GFM inverters online at the time. This event involved an upstream line-to-line-to-ground (LLG) fault in the distribution system, lasting approximately 276 ms. The PCC tripped on undervoltage after 39 ms. The inverters contributed about 90 percent of their rated amperes for 8 ms

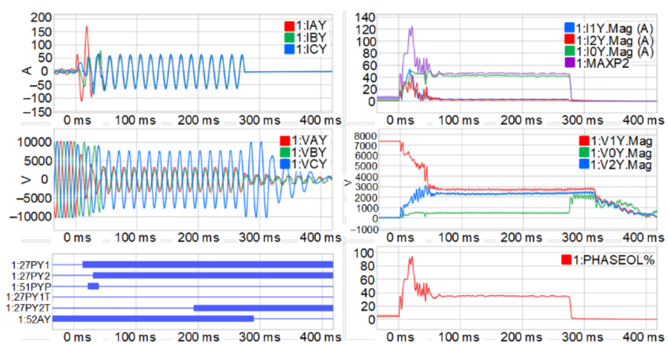

Fig. 26. ER 5 upstream LLG distribution fault

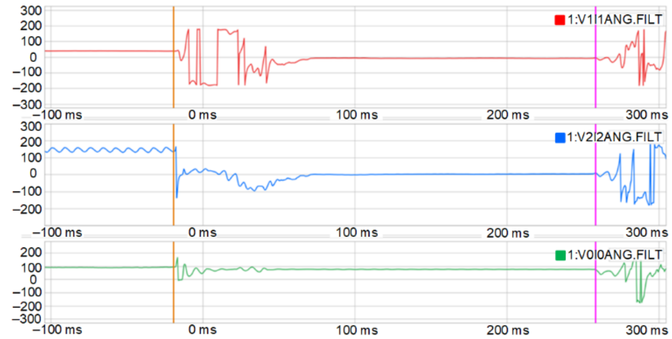

Fig. 27. ER 5 upstream LLG distribution fault – V and I angle

Fig. 28 and Fig. 29 show ER 6 from the PCC relay with all three inverters online. This upstream line-to-ground (LG) fault in the distribution lateral lasted approximately 84 ms and was cleared by an upstream lateral fuse trip after 35 ms. The transformer contributed over 100 percent rated current, however the inverter contributed less than 100 percent because much of the current was I0 and not dependent upon the inverter. A dc undervoltage trip by BMS shut down all inverters.

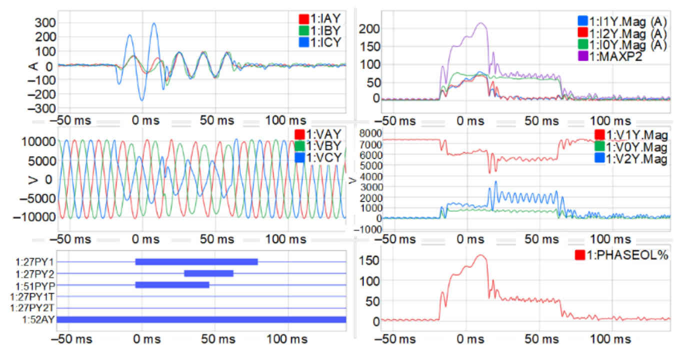

Fig. 28. ER 6 upstream LG distribution fault

Fig. 29. ER 6 upstream LG distribution fault – V and I angle

Fig. 30 and Fig. 31 show ER 8 from the PCC relay with all three inverters online. This upstream LL fault in the distribution system lasted approximately 419 ms and was cleared by the PCC tripping on undervoltage. The inverter contributed between 100 percent and 110 percent of the rated amperes for the entire fault duration. The microgrid successfully islanded from the utility.

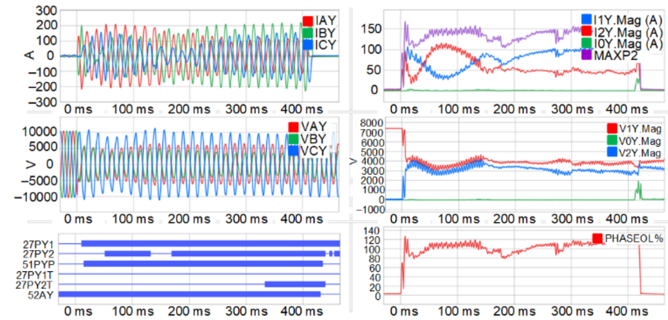

Fig. 30. ER 8 upstream LL distribution fault

Fig. 31. ER 8 upstream LL distribution fault – V and I angle

Fig. 32 and Fig. 33 show ER 10 from the PCC relay with all three inverters online. This upstream LL fault in the distribution system lasted approximately 132 ms and was cleared by an upstream recloser trip. The inverter contributed between 80 percent and 110 percent of the rated amperes for 166 ms. The microgrid successfully islanded from the utility.

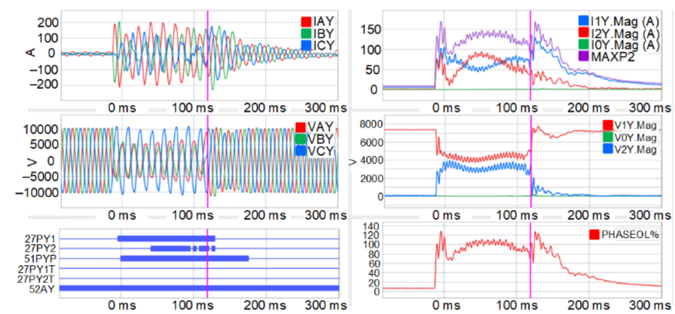

Fig. 32. ER 10 upstream LL distribution fault

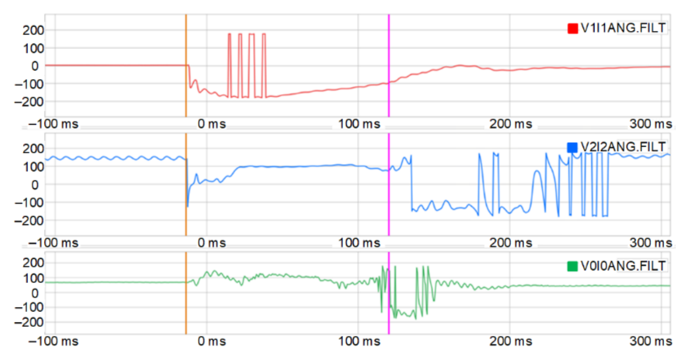

Fig. 33. ER 10 upstream LL distribution fault – V and I angle

B. *Transmission BESS Case Study*

This facility is a dc-coupled PV facility with a battery as depicted in Fig. 34. The dc/ac inverter is in GFM mode with droop and has IEEE Std. 2800-2022 I2 forced injection turned on.

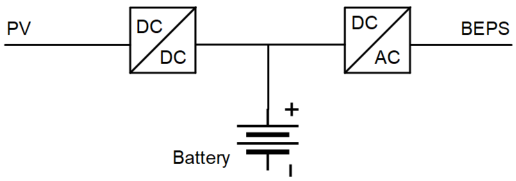

Fig. 34. BESS with dc-coupled PV facility

During a storm, foreign material was blown into conductors for transmission and distribution lines sharing the same corridor. Initially, the transmission fault had a very high resistance and there was no response. A distribution relay detected and tripped a phase-phase fault on the distribution feeder. A digital fault recorder captured the distribution fault event. The IBR was supplying no current prior to the fault because it was the middle of the night. The IBR initially supplied reactive power to the fault, but no real power. Fig. 35 shows the voltages at the IBR bus and the phase currents at the main breaker for the two IBRs at the station.

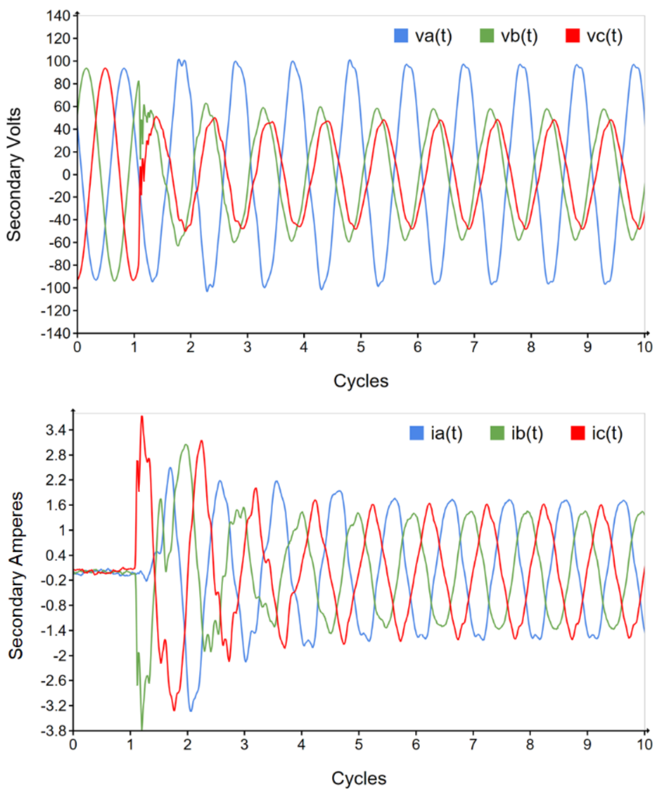

Fig. 35. Transmission-connected GFM IBR transmission substation voltage and current response to nearby distribution fault

Fig. 36 shows the sequence voltages and currents in response to the same fault. Notice the transient increase in negative-sequence current in the first two cycles that settles to a lower value. The ratio of |I2|/|I1| settles to 0.106 and remains at that level.

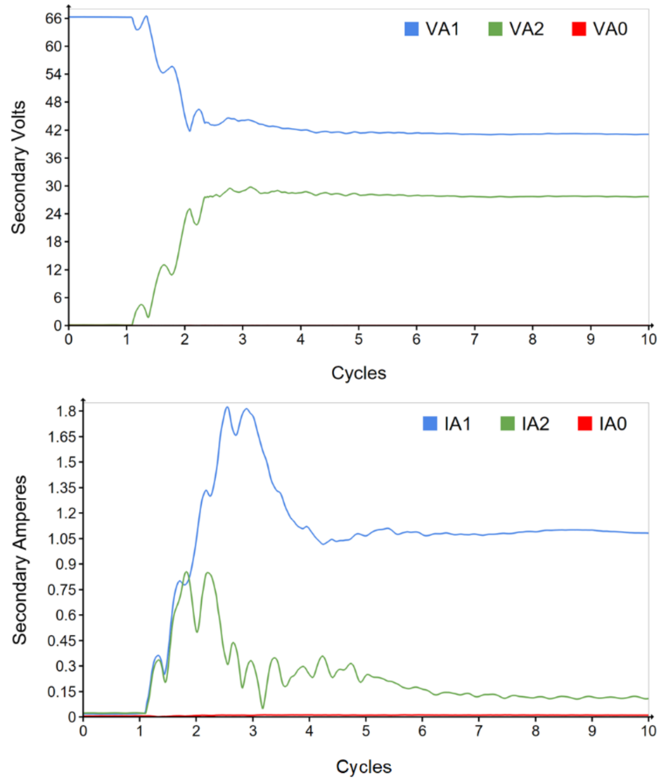

Fig. 36. Sequence voltages and currents for transmission-connected GFM IBR transmission substation voltage and current response to nearby distribution fault

C. *Microgrid BESS*

This facility is a 208 V direct-connected microgrid with a 30 kW diesel generator and 17 kW inverter paralleled. For these tests, the inverter is first run in GFM mode, then the tests are re-run in GFL mode. In these tests, a phase was removed from the resistive portion of the delta-connected load, however the inductive load remains. Fig. 37 shows the GFM inverter producing 7 A of I2 within 85 ms. The GFM inverter shared I1 loading with the generator because it was on a droop line. The V1-I1 angle jumped because the X/R ratio of the load increased.

Fig. 37. Removing Phase C with inverter in GFM mode and paralleled to generator

Fig. 38 shows the GFL inverter producing no I2 under the same scenario. Also, the GFL inverter did not have a droop line, so it shared no load with the generator. The magnitude of I2 and

I1 are so small as to make it difficult for the relay to measure angles.

Fig. 38. Removing Phase C with inverter in GFL mode and paralleled to generator

VII. Modeling Data

This section provides data collected from electromagnetic transient program simulations with black box models of IBRs connected to reduced models of power transmission systems.

A. Transmission PV-BESS Case Study

Fig. 39 is the modeled version of the prior transmission PV-BESS case study. This is a GFM dual-stage inverter with a battery at midpoint. Negative-sequence current injection is enabled.

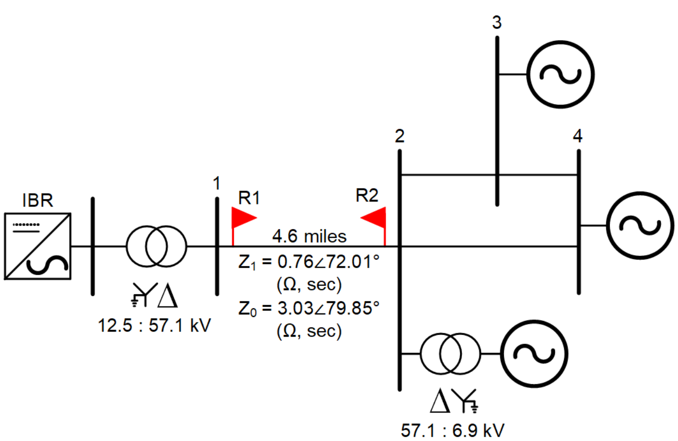

Fig. 39. PV-BESS reduced system

Fig. 40 shows the current response measured at relay R1. The fault occurs at the orange cursor. The inverter starts to inject controlled negative sequence (I2) at the pink cursor, or around 25 ms after fault inception. The interval between the orange and pink cursors consists of uncontrolled I2. At 25 ms after the fault, the inverter switches its control mode to enable I2 injection. The current response settles after 150 ms. In this case, the GFM inverter does not provide a natural I2 response.

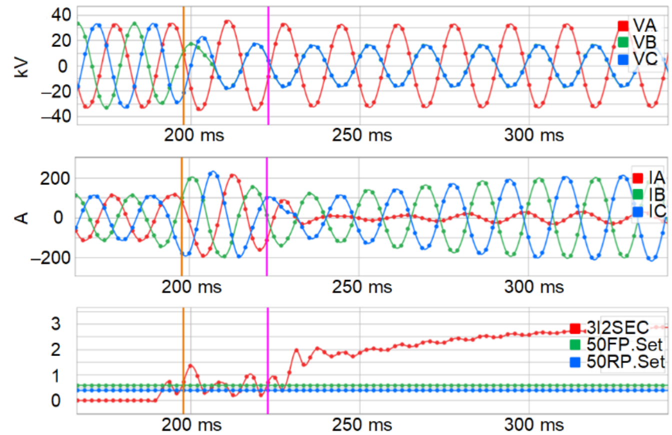

Fig. 40. 50 percent Phase B to Phase C fault measured by R1

B. Transmission Mixed DER Example

Fig. 41 shows a simplified model of a transmission system. For these results, lines 10–14 were opened. The IBR at Bus 9 includes GFL PV and BESS inverters. Neither have negative-sequence injection turned on.

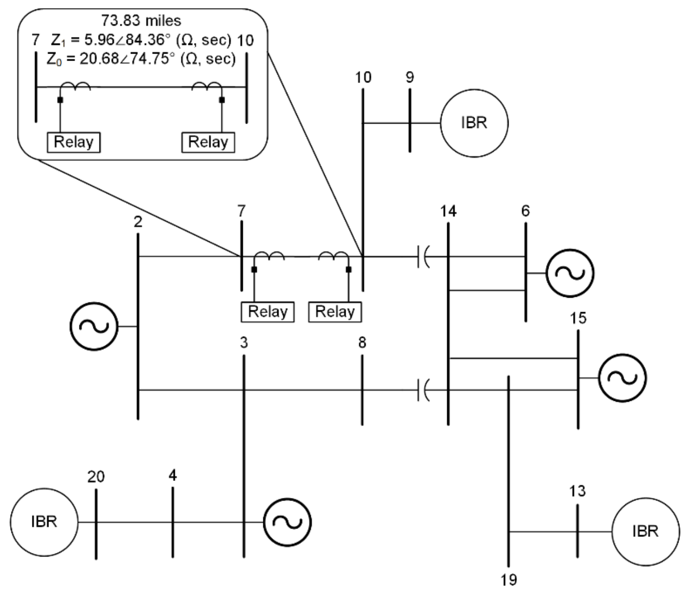

Fig. 41. Reduced system

Fig. 42 shows what the relays at Bus 10 observed for an AG fault at 50 percent. In this case, the IBR created accidental I2.

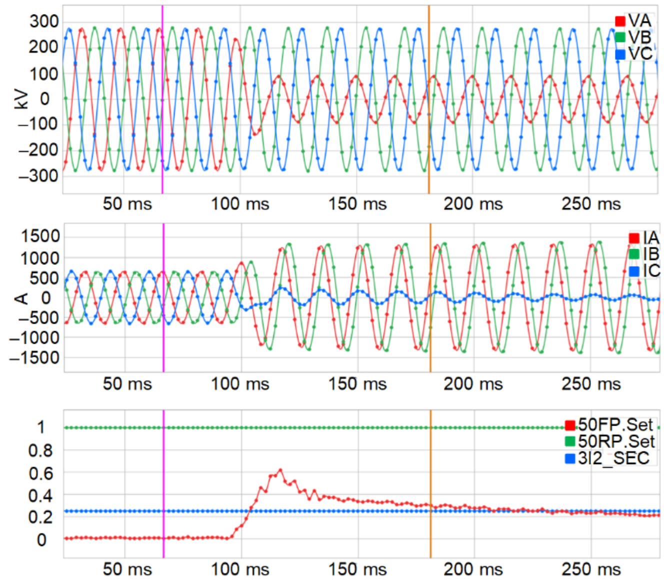

Fig. 42. Relay observations at Bus 10

VIII. Best Practices

Suggested best practices for BESS IBRs include:

- Collect high-fidelity event reports and time-synchronized C37.118 streaming data from ac protective relays at every IBR site.
- Collect high-fidelity event reports and time-synchronized C37.118 streaming data from each dc bus.
- Incorporate high-speed time domain metering at every IBR to collect data that relays cannot see.
- Inverter current limiting and inverter control schemes must be specified at procurement. Inverter current loop and current limiters are the root cause of I2 problems with protection systems. Angular control of I2 and I0 are required for transmission fault identification directional supervision logic to perform correctly.
- Battery and inverter sizing must consider all possible ac fault conditions, states of charge, number of discharge cycles, depth of discharge, dc voltage levels and battery states of health.
- Features of inverter and IBMS sub-systems must be specified at procurement.
- Inverters, BMSs, PLCSs, and any other intelligent device must provide non-volatile latching alarms specifying every reason they shut down.
- Neutral-ground bonding configurations must be designed to provide I0 for protection systems, prevent equipment damage, and meet inverter manufacturer guidelines.
- System protection coordination modeling may require electromagnetic program difference equation solvers with black box models to replicate inverter firmware and configurations. Average and switched modeling methods both work adequately to replicate inverter interactions with protection relays. All models must be validated against field data.
- Site testing must include proof of inverter current carrying capacity, including I2 production for unbalanced loads.
- Consider the advantages of GFM inverters. BESSs are required for GFM applications. PV inverters can be dc coupled to batteries to make them GFM. GFL inverters are natural companions to frequency stiff systems, whereas GFM inverters are naturally pairing with a weak frequency system.
- Dual- or single-stage inverters must be specified for the battery chemistry chosen.
- Batteries need to be tolerant to ac unbalanced fault conditions for single-stage inverters.
- Batteries must be capable of overloading momentarily without significant damage at any SoC. Alternatively, you must limit SoC.
- Inverters and batteries need to be sized appropriately to produce sufficient currents for all protection to operate correctly.
- Zero-sequence sources can be more reliable than inverter-based negative-sequence sources for polarization and memory related protection functions such as mho or quadrilateral elements.

IX. References

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X. Biographies

Angelos Kokkinis received his BS in electrical engineering from the University of Missouri–St. Louis. He is employed with Schweitzer Engineering Laboratories, Inc. (SEL) as a protection engineer in the SEL Engineering Services, Inc. (SEL ES) division. His experience includes protection design, microgrid controls, and DER integration. Angelos holds two patents. Angelos can be reached at angelos_kokkinis@selinc.com.

Brian Johnson is the Schweitzer Engineering Laboratories, Inc. (SEL) endowed chair in power engineering and university distinguished professor in the department of electrical and computer engineering at the University of Idaho. He received a Ph.D. in electrical engineering from the University of Wisconsin–Madison. His teaching and research interests include power system protection, integration of inverter-based generation, HVdc transmission, FACTS devices, cyber-physical systems security, and power system resilient control. He is a registered professional engineer in the state of Idaho.

Matt Raiford received his Ph.D. in chemistry from the University of Texas at Austin and his BS in chemistry and chemical engineering from Texas A&M University. He is employed by the Consortium for Battery Innovation (CBI) as the senior technical director. His experience includes battery design and fundamentals, materials science of batteries, battery energy storage system design and management schemes, and battery manufacturing. Matt holds seven patents and has been the author of numerous peer reviewed journal articles. Matt can be reached at matt.raiford@batteryinnovation.org.

Scott Manson received his MSEE from the University of Wisconsin–Madison and his BSEE from Washington State University. Scott is a Fellow Engineer at Schweitzer Engineering Laboratories, Inc. (SEL). Scott is a registered professional engineer in 6 states and holds 34 patents. Scott can be reached at scott_manson@selinc.com.

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