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Enmanuel Revi, George Wegh, and Stuart Hollis
Eversource Energy

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

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Enmanuel Revi, George Wegh, and Stuart Hollis, *Eversource Energy*
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***Abstract*—Eversource Energy deployed a 38 MWh battery energy storage system (BESS) in Provincetown, MA to improve the power reliability on the outer Cape Cod region. The BESS plant is located nearly 13 miles from the distribution substation, eliminating the need to build a second distribution feeder that could pose pricing, environmental, and regulatory challenges. This project required seamless islanding of the BESS plant and automatic circuit reconfiguration, via distribution automation, in response to system faults to minimize customer interruptions and improve restoration intervals. This requires the inverters to be operated in Grid-Forming (GFM) mode during grid-parallel and islanding operations. To provide effective grounding upon seamless islanding, the grounding transformers must be connected during grid-parallel operation. The integrated protection and automation schemes consist of 17 recloser control units using IEC 61850 Generic Object-Oriented Substation Event (GOOSE) for peer-to-peer communication, redundant microgrid controllers, BESS controllers, and inverter controllers interconnected via a fiber backbone. This paper explores the challenges of interfacing a large-scale BESS plant with the grid. It details the advanced protection and control schemes implemented to address these challenges and explains how these schemes were validated using hardware-in-the-loop (HIL) testing.**

I. Introduction

The outer Cape Cod region extends into the Atlantic Ocean from the southeastern corner of mainland Massachusetts, serving approximately 11,000 customers in the towns from Wellfleet to Provincetown. Customers on the outer cape are served by a single 13-mile overhead three-phase distribution line that starts at the Wellfleet substation and extends westward to Provincetown, as shown in Fig. 1.

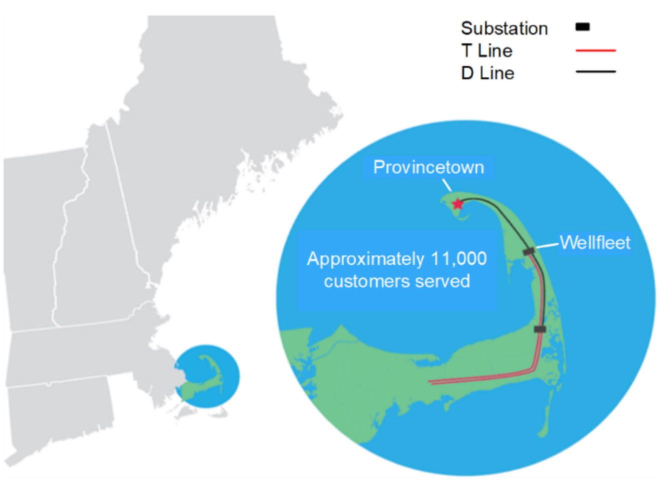

Fig. 1. Outer Cape Cod region of Massachusetts

As a popular summer destination, peak load can reach 22 MW compared to a yearly average of 8 MW. The proximity to harsh Atlantic winds and year-round weather conditions creates repeated reliability challenges for this geographically unique region.

Faced with the need to provide a backup supply to the area, the traditional solution for Eversource Energy was to build an additional 13-mile distribution line from Wellfleet to Provincetown. This would require construction through a substantial portion of the Cape Cod National Seashore with potential environmental impacts and significant cost for customers. As a non-wire alternative, Eversource constructed a 57.6 MVA/38 MWh lithium-ion battery system, shown in Fig. 2, as the sole supply source for a microgrid back to the Wellfleet substation.

Fig. 2. Provincetown BESS plant

The microgrid design includes 17 pole-mounted recloser controllers that provide fast fault isolation and dynamic distribution circuit automation in response to temporary and permanent faults to minimize customer outages.

In addition to its microgrid capability, the BESS plant can be used for grid-support functions such as peak shaving and local voltage support when connected to the grid.

The challenges associated with deploying a protection and control scheme capable of providing acceptable detection and isolation of ground faults, in both a strong and weak source configuration, required Eversource to work across multiple disciplines to identify technical solutions not traditionally used on the distribution system. The result is a state-of-the-art protection design using high-speed communications to enable the battery to transition seamlessly to a flexible and dynamic microgrid configuration.

This innovative project is expected to improve reliability for approximately 11,000 customers with automatic restoration in less than one minute. Based on an analysis on the six largest reportable outages from 2019 to 2021, Eversource determined that if the BESS was in service at the time of these events, total customer outage hours would have been reduced by 86 percent and total customers affected by 84 percent for all three years. This reduction considers the automatic restoration of customers in less than one minute via the extensive microgrid distribution automation system. The stored capacity of the BESS would have been adequate to sustain all non-faulted section customers until repairs were completed by line crews.

II. Distribution Circuit

The distribution circuit shown in Fig. 3 is fed from either Line 1 (115 kV) or Line 2 (23 kV). Line 1 feeds the circuit under normal operating conditions. If Line 1 is out-of-service for maintenance or a transmission level fault, Line 2 is switched in to feed the distribution circuit as an alternate source.

The substation has two distribution transformers: T1, which feeds the distribution circuit through BKR1, and T2, which feeds a smaller distribution circuit through BKR2. Each transformer is rated for the combined load of both circuits. Line 2 can feed the circuit through the substation via BKR1, BKR2, and a bus tie breaker, or external to the substation via a circuit tie recloser, RCL2, if Line 1 is out-of-service.

Eversource upgraded the feeder breaker relays controlling BKR1 and BKR2 at the substation and the controllers for 17 reclosers on the distribution circuit, RCL1–RCL17, to meet the protection and control requirement specified for this project. RCL1–RCL11 are backbone reclosers and RCL12–RCL15 are lateral reclosers. RCL8 is designated as the point-of-common-coupling (PCC) recloser and is used to island Provincetown from the grid, whereas RCL16 and RCL17 are designated as the point-of-interconnect (POI) reclosers and are used to connect the BESS plant to the distribution circuit. The substation breaker relays, backbone recloser controllers, and POI recloser controllers have voltage sensing on both sides of the device they control and can synchronize the BESS plant to the grid along the distribution circuit.

The circuit has six automatic sectionalizing units, ASU1–ASU6, that are designed to isolate the fault after an upstream recloser operation. The substation breaker relays, recloser controllers, and automatic sectionalizer controllers are tied through a fiber network to facilitate fast protection using peer-to-peer IEC 61850 Generic Object-Oriented Substation Event (GOOSE) communication, multi-point synchronization, fault isolation, and automatic circuit reconfiguration. The circuit has a three-phase voltage regulator configured for bi-directional voltage control.

III. BESS Plant

The BESS plant has 16 ac/dc inverters as shown in Fig. 3. It is divided into BESS1 and BESS2, with inverters 1–8 associated with BESS1 and inverters 9–16 associated with BESS2. The BESS also includes a battery rack associated with each inverter and a battery management system for each rack. Each inverter has a rating of 3.6 MVA for a total system rating of 57.6 MVA. This allows the BESS plant to source sufficient fault current even if some inverters are offline. The inverters are each connected to a 0.63 kV/22.8 kV delta ungrounded-wye generation step-up (GSU) transformer fused on the high side. The combination of battery, inverter, and GSU transformer is called a power block. A switchgear breaker connects a group of four power blocks to a common bus. Each BESS has a zig-zag transformer to provide a ground reference for the microgrid upon islanding from the grid. Two main switchgear breakers, MB1 and MB2, and a normally open tie breaker, TB, connect BESS1 and BESS2 to the distribution circuit via the two POIs. Eversource chose this configuration to maximize operational flexibility of the plant in case of a permanent fault in the distribution circuit section where each POI is connected.

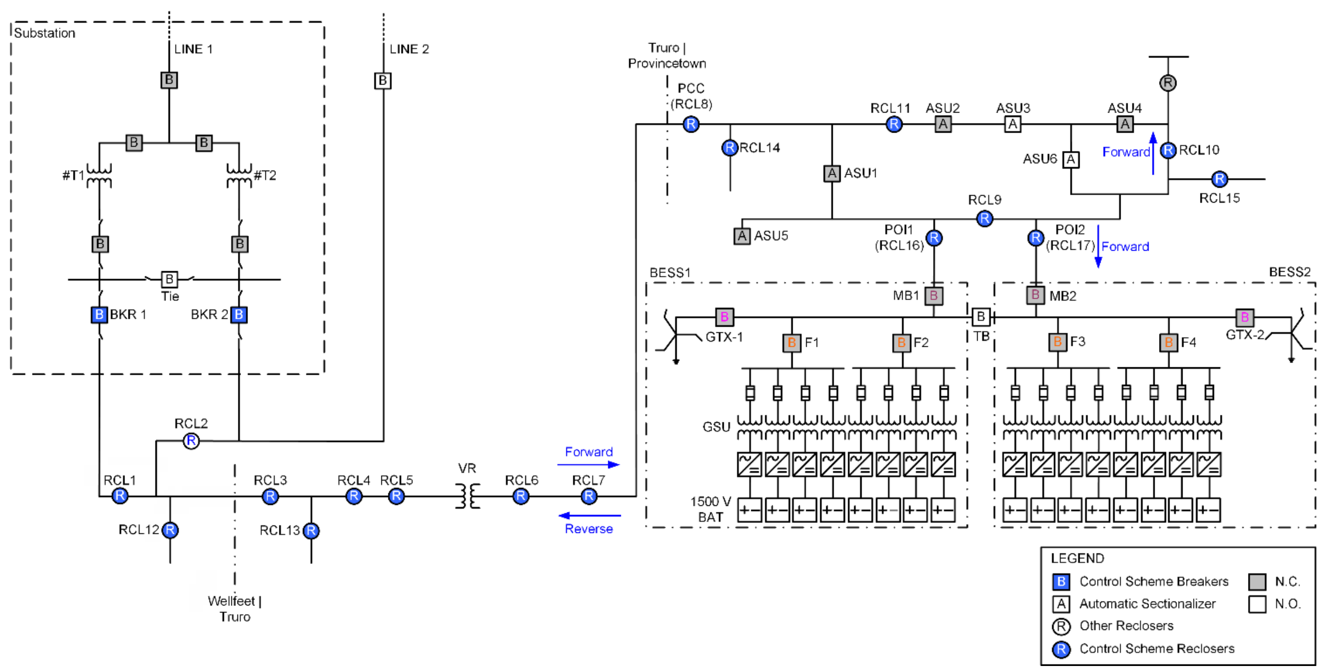

Fig. 3. Simplified one-line diagram

The microgrid controllers used for this project are designated as Microgrid Distribution Automation Controllers (MDACs). Fig. 4 shows the two MDACs at the BESS plant: MDAC-A and MDAC-B. The MDACs are configured in a redundant hot-standby function where each MDAC can dispatch BESS1 and BESS2 if the other fails without disruptions to the plant. The MDACs communicate with the following devices:

- Recloser controllers and breaker relays using IEC 61850 GOOSE.
- Six automatic sectionalizer units using DNP3.
- Centralized controllers for BESS1 and BESS2 using DNP3.
- SCADA using DNP3.

Each battery rack at the BESS plant has a battery management system responsible for monitoring and reporting various parameters of the battery cells, including their voltages, temperatures, and current flow [1]. The data collected from these parameters are used to manage the balancing of cell circuits and minimize discrepancies among the lithium-ion cells that are connected in series [1]. The battery management systems are crucial for ensuring the safe functioning of the BESS battery racks, estimating the state of charge (SOC) and health of the batteries, determining the remaining time, and facilitating intercell charge balancing [2].

The battery management system for each battery rack communicates with a centralized BESS controller that provides the control interface for all inverters via Modbus. The MDACs communicate with each BESS centralized controller for inverter control to support grid-parallel and islanded configurations via DNP3.

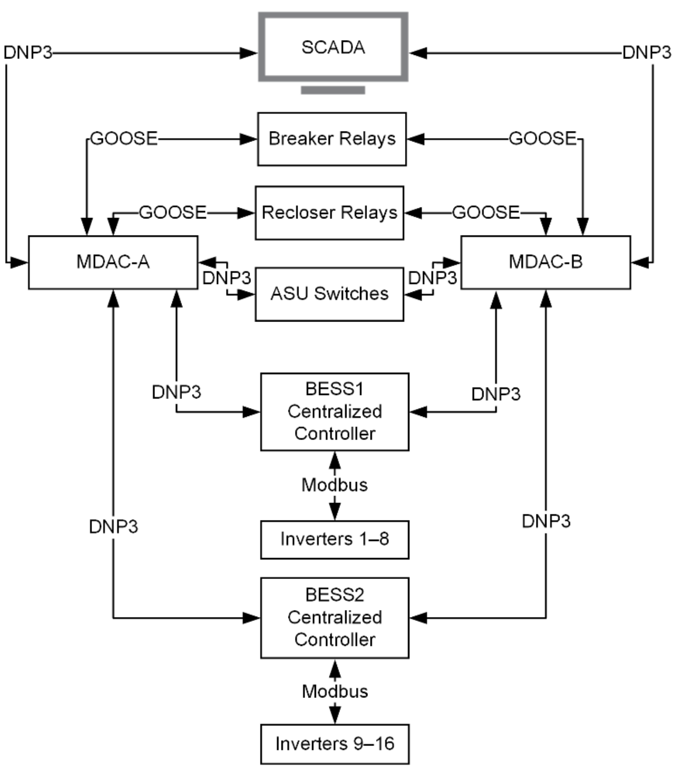

Fig. 4. BESS and distribution circuit data flow diagram

IV. Grid-Parallel Operation With Grid-Forming Inverters

Inverters are commonly operated in Grid-Following (GFL) mode or Grid-Forming (GFM) mode. GFL inverters use phase-locked loops (PLLs) to track the grid voltage angle at the POI for the internal park transformation [3] [4]. The inverters use the desired real power (P) and reactive power (Q) dispatch set points to determine the current to be injected at their terminals relative to the voltage angle obtained from the PLL, as shown in Fig. 5. Thus, GFL inverters require an external "stiff" voltage source to "follow" and act effectively as current sources [3]. Upon loss of the grid, anti-islanding control schemes, like ones discussed in [5], will prevent the inverter from carrying the load and the inverter will shut down.

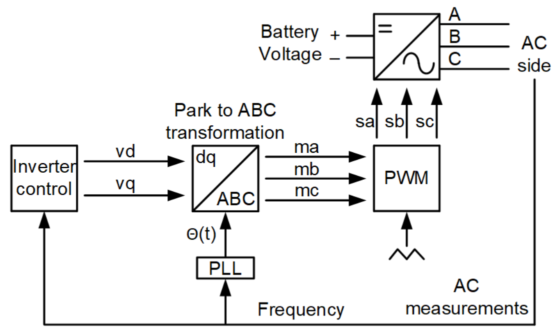

Fig. 5. GFL inverter control [3]

GFM inverters, shown in Fig. 6, generate their own voltage and frequency references without needing an external source acting effectively as voltage sources. These inverters are dispatchable without the dependence on the phase angle tracking limitations of PLLs [3]. They typically use droop controls to dispatch real and reactive power, behaving similar to conventional synchronous generators. Upon loss of the grid, GFM inverters can continue to carry the load.

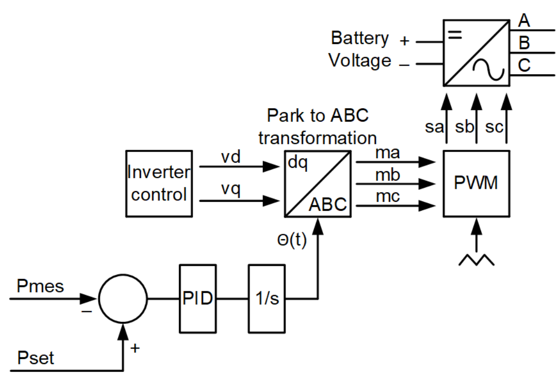

Fig. 6. GFM inverter control [3]

To support a local microgrid upon the loss of utility source, the inverters must be operated in GFM mode. However, during grid-parallel operation, the inverters may be operated in GFL or GFM mode. If the inverters are operated in GFL mode, the inverters will shut down upon loss of utility source and result in an outage to the customers.

The inverters cannot provide effective grounding for microgrids, so a ground reference in the form of a grounding transformer(s) must be connected to the circuit prior to restarting the inverters in GFM mode. Once started in GFM mode, the inverters can black start the microgrid.

Alternatively, the inverters can be operated in GFM mode during grid-parallel operation. In this case, the inverters can seamlessly island the microgrid load upon loss of the grid; however, the grounding transformer(s) must be connected under grid-parallel operation to provide effective grounding upon loss of the grid reference. This results in desensitizing the recloser controllers on the circuit as discussed in Sections VI and VII of this paper. The level of desensitization is dependent on the zero-sequence impedance of the grounding transformer(s). A lower impedance results in a lower voltage rise on the un-faulted phases for a ground fault on the distribution circuit while operating in an island; however, this results in a lower contribution of zero-sequence current from the grid during grid-parallel operation. The grounding transformer selection must achieve a healthy balance between effective grounding upon loss of grid source and minimizing the impact on ground fault protection during grid-parallel operation.

V. Inverter Control

The 16 inverters at the BESS plant are always configured to be GFM inverters operating as voltage sources. This provides the flexibility to support seamless islanding and seamless restoration. The controllable parameters for GFM inverters are voltage and frequency. Just like synchronous generators, active and reactive power can be dispatched by controlling the voltage angle and amplitude, respectively. The inverters are configured to use droop control. The main benefit of using the droop technique is the paralleling of multiple inverters and a proportional sharing of load based on the inverter ratings without communications between the inverters [6]. Other benefits include it being a positive feedback avoidance circuit, hence providing inherent stability.

To calculate the frequency and voltages, based on the active power and reactive power desired, voltage and frequency droop coefficients are programmed into the inverters. The output frequency is equal to a frequency reference biased by an active power offset multiplied by the frequency droop coefficient, as shown in (1). The output voltage is equal to a voltage reference biased by a reactive power offset multiplied by the voltage droop coefficient, as shown in (2).

The following are the simplified equations for droop [6]:

$$f = f_{ref} + \text{frequency droop} \bullet \left(P_{ref} - P_{inst}\right) \quad (1)$$

$$V = V_{ref} + \text{voltage droop} \bullet \left(Q_{ref} - Q_{inst}\right) \quad (2)$$

where:

f_{ref} is the reference frequency.
P_{ref} is the reference real power.
P_{inst} is the measured real power.
V_{ref} is the reference voltage.
Q_{ref} is the reference reactive power.
Q_{inst} is the measured reactive power.

All 16 inverters have the same rating and are programmed with the same frequency and voltage droop coefficients. For a 1 per unit (pu) change in the output real power, there is a corresponding 0.25 Hz change in the frequency as shown in Fig. 7, which corresponds to a 0.4 percent droop.

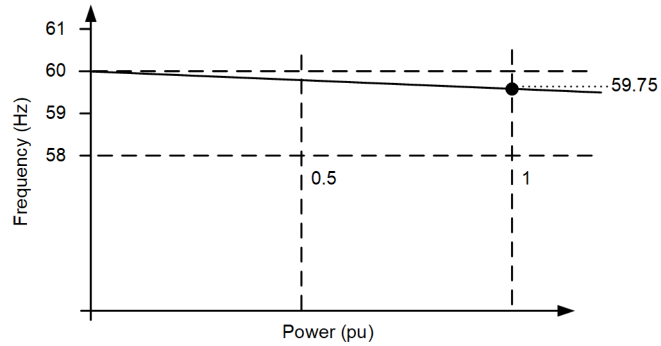

Fig. 7. Droop control characteristics

As shown in Fig. 3, each MDAC has visibility of the entire distribution circuit. The MDAC uses a topology tracker to determine if each BESS is grid-connected or islanded based on the statuses it receives from the recloser controllers and substation breaker relays every four milliseconds (ms). The topology tracker continuously looks at the 52A status and voltage information from the recloser controllers and, based on the various system lineups, determines if a BESS is grid-connected or islanded. The frequency and voltage references are written by the MDACs to the inverters via the centralized BESS controllers. For a grid-parallel operation, the voltage reference is set to 1.03 pu and can be adjusted by the operator depending on voltage support needs. The frequency reference is the measured filtered frequency of the grid from the POI recloser controllers: POI1 for BESS1 and POI2 for BESS2. This results in matching the grid frequency and keeps the power flow at the POIs close to zero. There might be small real power fluctuations around the zero mark because of the error in frequency measurements at the POIs.

In grid-parallel operation, the MDAC provides the operators with four real power modes: standby, real power dispatch, peak shaving, and SOC management. Through these modes, the operator can discharge the BESS for peak shaving needs or charge the BESS to have adequate SOC in preparation for an islanding event.

Charging and discharging is accomplished by adjusting the active power offset, which is determined by the MDAC to support the real power operating mode and is distributed to each BESS inverter via their centralized BESS controllers. This biases the frequency output of the inverters to achieve the desired active power set point and support the active power needs in grid-parallel operation.

The MDAC can dispatch BESS1 and BESS2 independently depending on the SOC. Each centralized BESS controller provides an average SOC of its power blocks; BESS1 centralized controller provides the average SOC for power blocks 1–8 and BESS2 centralized controller provides the average SOC for power blocks 9–16. The MDAC provides SOC balancing using the average SOC values provided by the

BESS centralized controllers. For discharging, it biases the BESS with the greater average SOC with a greater active power offset. For charging, it biases the BESS plant with the greater average SOC with a smaller active power offset. For individual battery racks, the associated battery management system handles the SOC balancing, state-of-health balancing, and intercell distribution of charge.

Upon detecting loss of the grid, the MDAC automatically adjusts the voltage reference to 1.04 pu and the frequency reference to 60.05 Hz. With the inverters programmed with the same droop and frequency coefficients, the load in the island is proportionally shared between the inverters without requiring communications between the inverters. Similar to grid-parallel operation, the MDAC biases the active power dispatch from each BESS independently when it detects a difference in the SOC between BESS1 and BESS2 if this difference is greater than a predetermined threshold of 10 percent.

It is important to note that it is possible for one BESS to be grid-connected while the other BESS is islanded if RCL9 is open. In this case, the voltage reference, frequency reference, and active power offset sent by the MDAC to the centralized BESS controllers will be different depending on the configuration of the BESS as determined by the MDAC topology tracker.

VI. Grounding Transformer Selection and Design

Providing effective grounding to the distribution circuit upon separation from the grid is critical to supporting seamless islanding with GFM inverters. Effective grounding is needed for microgrids to provide temporary overvoltage (TOV) reduction on un-faulted phases during line-to-ground (LG) faults, grid synchronization, load protection, and microgrid stability. An effectively grounded microgrid system is defined as one with a coefficient of grounding (COG) of less than 0.8, which yields a maximum voltage of 138 percent or less on the un-faulted phases at any point on the circuit for an LG fault [7].

Two grounding transformers were selected for this project to provide effective grounding: one connected to BESS1 via GTX-1 and the other connected to BESS2 via GTX-2, as shown in Fig. 3. The two grounding transformers are connected during grid-parallel operation to provide effective grounding when one or both BESS seamlessly island upon loss of the grid. This was chosen in lieu of grounding the neutrals of all GSU transformers at the BESS plant to reduce the challenges associated with multi-point grounding as described in [8].

The following considerations must be evaluated when specifying grounding transformers for grid-parallel and islanding operations:

- Higher overall short-circuit MVA, which may lead to equipment rating upgrade.
- TOV regulation during islanding events.
- Ground relaying desensitization and, consequently, the complexity of the protection scheme.
- Saving lightning arresters from operating during LG faults or overvoltage load rejection because of circuit switching.
- If effective grounding cannot be achieved, fault clearing times need to maintain TOV under arrester rating or installation of higher-voltage-class rated arresters should be considered.

An initial grounding transformer impedance was calculated to be 60 percent of the base impedance of each BESS total inverter rating, with an X_0/R_0 of ≥ 4 [9].

The grounding transformers with the initial calculated impedance, inverters, GSUs, and distribution circuit shown in Fig. 3 were modeled using Power Systems Computer-Aided Design (PSCAD), which is an electromagnetic transient (EMT) software. Several loading and short-circuit scenarios were simulated to validate the effectiveness of the grounding transformers under grid-parallel and island operating scenarios. The greatest observed TOV conditions were for LG faults at the furthest point electrically from the BESS plant during no- or light-loading conditions.

Once PSCAD results validated the impedance of the grounding transformers, other parameters of the grounding transformer were developed using CYME, which is a phasor domain distribution circuit analysis software.

A comparison was made between delta-grounded wye and zig-zag for grounding transformer configurations with the same impedance values. The analysis showed the zig-zag having a TOV that is 2–6 percent higher than the delta grounded-wye; however, the zig-zag configuration was ultimately selected because of better harmonic filtering, smaller physical size, and cost trade-off. To match the TOV performance of the delta grounded-wye configuration, the zig-zig needed to be specified with a smaller impedance. Table I lists the final electrical specifications for the grounding transformers.

TABLE I
GROUNDING TRANSFORMER SPECIFICATIONS

Parameters	Value	Comments
Line-to-Line (LL) Voltage (kV)	22.8 kV	Distribution circuit LL voltage.
Impedance (Ohms/Phase)	6.4 Ohms	This value was selected to satisfy the TOV requirements based on PSCAD simulations, while factoring the impact on ground relaying sensitivity.
Continuous Neutral Current [10]	140 A	Highest continuous system current unbalance considering largest single-fuse operation.
Thermal Rating Current [10]	6000 A	Greatest fault current through the grounding transformer under any operation.
Frequency	60 Hz	System frequency for grid-parallel and islanding operations.

The two grounding transformers specified for this project provide effective grounding for the microgrid area between the BESS plant and BKR1. If one grounding transformer is offline during islanding operation, the MDAC will trip the associated POI and the PCC to reduce the size of the island to Provincetown. This is because one grounding transformer cannot provide effective grounding for the entire distribution circuit. If the second grounding transformer is tripped during islanding operation, the MDAC will trip the remaining POI.

Grounding transformers installed away from the substation result in desensitizing the ground fault protection on the distribution circuit. This is because they provide a low zero-sequence impedance path for ground fault currents to flow when operated parallel to the grid. The lower the grounding transformer impedance, the greater the ground fault desensitization impact [11]. For ground faults near the BESS plant, the grid fault contribution may not be great enough for the ground relaying observing the grid fault contribution to isolate it until the plant contribution is isolated first. The opposite is true for ground faults near the substation. This desensitization may result in sequential tripping to completely isolate the ground fault contribution from both ends. This is one of the main reasons IEC 61850 GOOSE is used to ensure the ground faults are quickly isolated by sending a direct transfer trip (DTT) signal to the end with higher desensitization.

VII. Protection Scheme Using IEC 61850

The need for seamless islanding required the inverters to be operated in GFM mode when connected to the grid.

To provide effective grounding upon islanding from the grid, the grounding transformers needed to be connected during grid-parallel operation, resulting in the desensitization of ground fault protection on the distribution circuit as discussed in Section VI. Furthermore, the large number of recloser controllers on the circuit made maintaining reasonable coordination time intervals using traditional time-overcurrent protection challenging. This necessitated using a protection scheme that can rapidly identify and isolate faults using peer-to-peer IEC 61850 GOOSE communications to isolate BESS1 and BESS2 fault contributions, while maintaining traditional distribution circuit schemes used by Eversource. These schemes include fuse saving, cold load pickup, two-shot reclosing, recloser-to-recloser coordination, recloser-to-fuse coordination, and recloser-to-sectionalizer coordination.

Two types of reclosers are shown in Fig. 3: backbone and lateral. Faults downstream of lateral reclosers do not result in BESS islanding and will be referred to as Type A faults. Faults between backbone reclosers may result in BESS islanding depending on the fault location and the distribution circuit lineup and will be referred to as Type B faults.

For Type A faults, the lateral recloser will see the combined fault contribution of the grid and BESS plant, whereas for Type B faults, the backbone recloser may see the fault contribution from the grid side only, BESS plant only, or both depending on the fault location and distribution circuit lineup.

The general protection philosophy for lateral and backbone recloser controllers uses definite-time and fast-curve time-overcurrent elements on the first trip only to quickly isolate the fault and save the large fuses, where applicable, to implement a fuse-saving scheme. These elements have a minimum six-cycle time delay to allow smaller fuses to operate faster than the reclosers on the first trip where fuse saving is not feasible. The recloser controllers use slow-curve time-overcurrent elements with a coordination time interval (CTI) of 0.3 seconds to allow large fuses and sectionalizers to operate on the subsequent trips.

The upstream devices definite-time overcurrent elements receive a blocking signal, via IEC 61850 GOOSE, based on the pickups of the time-overcurrent elements in the downstream device closer to the fault to prevent them from operating for out-of-zone faults. This signal is also used to block upstream time-overcurrent elements where CTI of 0.3 seconds is not possible.

Fast-overcurrent elements are disabled under the following conditions: loss of IEC 61850 GOOSE communications, loss of potential to the controller voltage inputs, detected cold load pickup, or disabled reclosing.

For overcurrent elements, lateral recloser controllers will use non-directional overcurrent elements while backbone recloser controllers use directional overcurrent elements.

A. Type A Fault Protection Philosophy

For Type A faults, the lateral recloser controller uses non-directional definite time-overcurrent elements (50P1T and 50G1T) or fast-curve time-overcurrent elements (51P1T and 51G1T) to operate faster than large fuses on the first trip. Once it recloses, the lateral recloser controller blocks the fast-overcurrent elements and uses slow-curve time-overcurrent elements (51P1T and 51G1T) with a CTI of 0.3 seconds to allow downstream fuse(s) or protective device(s) that do not use IEC 61850 GOOSE to operate. If there are no downstream protective devices and the fault is permanent, the lateral recloser controller goes to lockout on the third trip after two reclosing shots.

Lateral reclosers will use the pickup of the time-overcurrent elements (51P1 and 51G1) to block, via IEC 61850 GOOSE, the upstream backbone reclosers from operating. If fiber communication is lost between the lateral recloser controller and the upstream recloser backbone controllers, the fast-overcurrent elements of the upstream backbone recloser controllers will be blocked from operation and they will use the slow time-overcurrent elements for the first, second, and third trips. During loss of communication, disabling fast-overcurrent elements prevents the upstream recloser controllers from overtripping for an out-of-zone fault.

B. Type B Fault Protection Philosophy

Type B faults are more challenging because the fault isolation may result in islanding the BESS plant.

For Type B faults between BKR1 and the PCC, the relay or backbone recloser controller closest to the fault from the grid side uses forward definite-time overcurrent (67P1T and 67G1T) or forward fast-curve time-overcurrent (51P1T and 51G1T) elements to detect the fault contribution from the grid to trip, and send a DTT signal to the PCC recloser to stop the fault contribution from the BESS plant and seamlessly island Provincetown. Once it recloses, the relay or backbone recloser controller blocks the fast-overcurrent elements and uses forward slow-curve time-overcurrent elements (51P1T and 51G1T). This maintains coordination with downstream reclosers if they lose fiber communication, or if the device closest to the fault does not use IEC 61850 GOOSE like reclosers not included in the scheme, sectionalizers, or fuses. In these cases, a temporary overtrip may occur on the first trip, but coordination will be maintained on the subsequent trips. If there are no downstream protective devices and the fault is permanent, the relay or backbone recloser goes to lockout on the third trip after two reclosing shots.

Reverse slow-curve time-overcurrent elements (51P2T and 51G2T) are always enabled in the backbone reclosers. This provides backup protection for isolating the BESS plant fault contribution when the BESS plant is grid-connected and primary protection when the BESS plant is islanded.

For Type B faults between the PCC, POI1, RCL9, and RCL11, the PCC uses the forward fast-overcurrent elements to detect the fault contribution from the grid to trip and send a DTT signal to POI1 and RCL9 to stop the fault contribution from BESS1, and seamlessly island BESS2. If the fault is permanent and is upstream of ASU1, the PCC will use the forward slow-curve time-overcurrent elements to isolate the fault on the third trip after two reclosing shots; however, if the fault is downstream of ASU1, the PCC will remain closed after the second reclosing shot and ASU1 will sectionalize the fault.

For Type B faults between RCL9, POI2, and RCL10, RCL9 uses the forward fast-overcurrent elements to detect the fault contribution from the grid and BESS1 to trip and send a DTT signal to POI2. If the fault is permanent, RCL9 uses the forward slow-curve time-overcurrent elements to isolate the fault after two reclosing shots.

For Type B faults downstream of RCL10 or RCL11, their recloser controllers will use forward fast-overcurrent elements to detect the fault contribution from the grid and BESS plants to trip. If the fault is permanent and is upstream of ASU2 or ASU4, respectively, the recloser controllers will use the forward slow-curve time-overcurrent elements to isolate the fault upon reclosing after two reclosing shots; however, if the fault is downstream of the sectionalizers, the reclosers will remain closed on the second shot and the ASU will sectionalize the fault.

The backbone reclosers will use the time-overcurrent elements pickups (51P1 and 51G1) to block, via IEC 61850 GOOSE, the upstream backbone reclosers and breaker relays from operating.

Because IEC 61850 GOOSE is not available for the switchgear relays at the BESS plant, fast-overcurrent elements were not configured in these relays. This resulted in disabling the forward fast-overcurrent elements in POI1 and POI2 recloser controllers and using forward slow-curve time-overcurrent elements to provide backup protection for the relays providing primary protection for faults in the BESS plant.

Lastly, the BESS plant configuration allows, via TB, the dispatching of BESS1 and BESS2 entirely through POI1 or POI2 if there is a permanent fault in the distribution circuit section where they are connected. Under this lineup, the POI recloser controllers are configured with less sensitive overcurrent set points because the power dispatched and fault contributions through the POI are doubled.

VIII. Protection Scheme Challenges

Because of the distribution circuit operating requirements, the protection scheme needed to account for two main challenges: fault directionality and load encroachment. Additional features and custom logic not typical of distribution protection were implemented to address these challenges.

A. Directionality Involving Inverter-Based Resources

Inverter-based resources (IBRs) are non-traditional generation sources. IBR output may contain apparent positive- and negative-sequence quantities that are not coherent with each other; as such, the traditional phasors used to determine fault direction do not reliably indicate the direction of faults sourced by IBRs [12].

The inverters used for this project operate in GFM mode with droop under normal system conditions. The inverters enable Virtual Impedance mode when the inverter algorithms detect a short-circuit fault.

When operating in Droop mode, the inverter controller regulates the negative-sequence current to 10 percent or less of the positive-sequence current per the inverter specification used for this project. Therefore, during a fault, the inverter attempts to inject balanced steady-state currents even for unbalanced faults if the inverter algorithms cannot detect the short-circuit condition, as shown in Fig. 8.

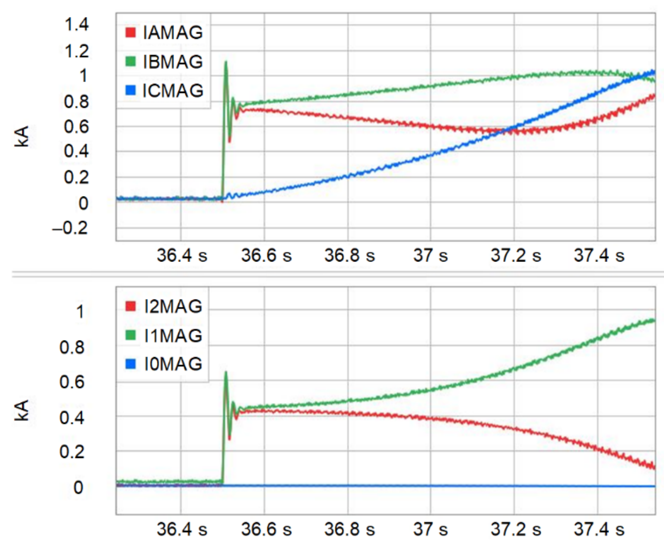

Fig. 8. Phase and sequence currents of a bolted AB fault when the inverter is in Droop mode

When the inverter detects a short-circuit condition, it activates Virtual Impedance mode where the inverter limits the phase fault currents to 1.2 pu by adjusting the virtual impedance observed by the inverter. Thus, the inverter may inject negative-sequence current to the system during a fault, as shown in Fig. 9.

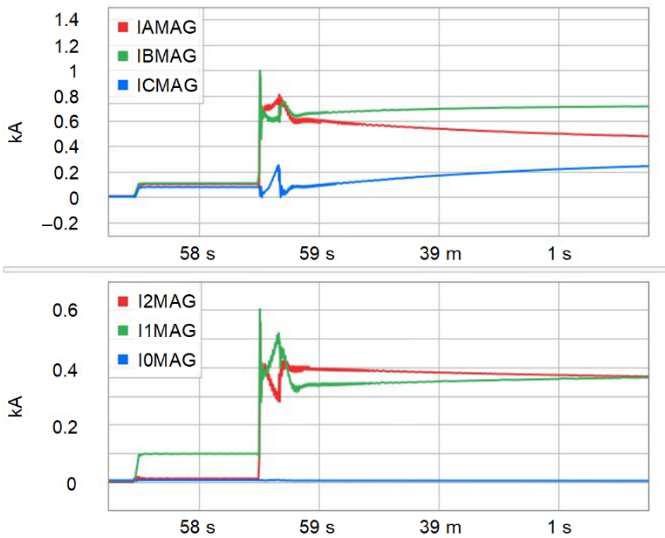

Fig. 9. Phase and sequence currents of a bolted AB fault when the inverter is in Virtual Impedance mode

The fault direction designations in Fig. 3 show the grid fault contribution as the forward fault direction and BESS fault contribution as the reverse fault direction. Directional settings (AUTO2) offered by the recloser controller were initially used for the analysis. The expectation is for the protective devices to have no issues detecting faults in the forward direction.

Based on the observed behavior of the inverter voltages and currents, the first approach was to set the a2 (I2/I1 negative-to-positive sequence restraint factor) to 0.05 and 50QRP (reverse directional pickup threshold) to 0.1 A secondary. This ensured that protective devices were sensitive enough to detect the 10 percent negative-sequence current regulation by the inverters even if they operated in Droop mode during a fault condition.

The inverters are connected to delta ungrounded-wye GSU transformers and cannot inject zero-sequence current for ground faults on the distribution circuit. However, the protective devices on the circuit will observe zero-sequence current contribution in the reverse direction from the grounding transformers located at the BESS plant. Thus, the recloser controllers were configured to prioritize zero-sequence voltage polarization for ground faults.

To validate the proposed directional settings, the distribution circuit was modeled in PSCAD with the inverter model and configuration files provided by the inverter manufacturer. Thousands of fault scenarios were simulated under various loading conditions and distribution circuit lineups. The results were saved as Common Format For Transient Data Exchange (COMTRADE) files and played back to recloser controllers programmed with these settings at different locations on the circuit.

The recloser controllers correctly determined the direction of the faults in the forward and reverse directions for the vast majority of the faults. However, for some ground faults near the BESS plant, the zero-sequence current contribution observed by backbone recloser controllers from the grid was small because of the desensitization caused by the grounding transformers. For these cases, either the phase-overcurrent elements torque controlled by positive- or negative-sequence directional permissive tripped, or sequential tripping occurred where the fault was cleared from the BESS side first; then, the recloser controller would see the zero-sequence current rerouted through the grid and trip. Furthermore, for ground faults farther from the BESS plant, some recloser controllers did not detect the fault in the reverse direction because they were desensitized by the grid ground-fault contribution. For these cases, the PCC recloser controller that observed the fault contribution from the BESS plant required a DTT from the grid end or relied on the phase-overcurrent element torque controlled by positive- or negative-sequence directional permissive to trip.

Lastly, there were a few cases in the islanded condition that required additional custom logic to bias the recloser controllers toward dependability. During phase faults, the inverter operating mode may cause directional elements to de-assert momentarily for a few cycles into the event; this is because of the inverter algorithms attempting to regulate the negative-sequence current in Droop mode or to adjust the impedance observed by the inverter in Virtual Impedance mode. In both modes, the recloser controllers correctly detected the fault direction at fault inception.

To address this issue, a latch was created to prevent the forward and reverse time-overcurrent elements from de-asserting before timing out. This latch, which was programmed in the forward and reverse overcurrent elements torque control equations, was set when the forward directional elements asserted and reset when the reverse directional elements asserted. This ensures that each recloser controller always has at least one overcurrent element enabled to operate during a fault. The COMTRADE files were played back to the recloser controllers, and the results demonstrated that the additional logic helped the recloser controllers operate dependably for faults.

In February 2022, an event occurred that demonstrated an additional advantage of the custom-logic directional latch. The circuit experienced a heavy sandstorm that resulted in a fault on the circuit section between RCL6 and RCL7. The fault was evolving between an LL fault and a three-phase fault.

RCL6 recloser controller operated correctly and isolated the fault quickly with the help of the additional directional latch (LT_DIR). During the fault evolution, forward-phase and negative-sequence directional elements dropped out momentarily; however, the 51P1P did not drop out because the LT_DIR remained solidly asserted, as shown in Fig. 10. This helped the 51P1P in RCL6 recloser controller to continue timing and eventually trip. The event also demonstrated that RCL6 coordinated properly with upstream recloser controllers. At the time of this event, the fiber backbone was not in-service, so the fast-overcurrent elements were blocked from operation.

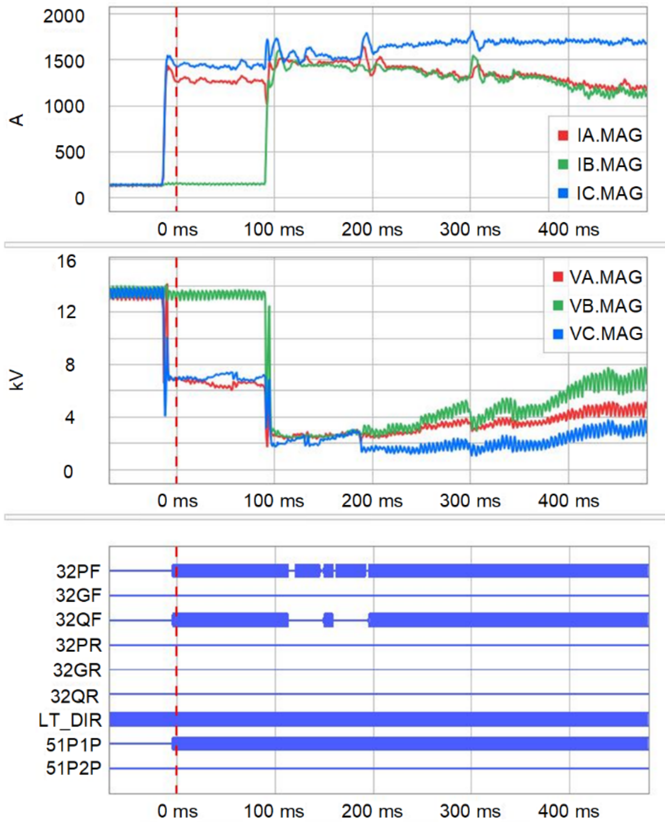

Fig. 10. Evolving fault at RCL6

B. Load Encroachment

For this project, the distribution circuit can be fed from Line 2, which is a weaker source than Line 1. Under this circuit configuration, it is not possible to set the phase-overcurrent element pickups greater than load and maintain a sensitivity ratio of 2.0 between the fault current magnitudes and overcurrent element pickups for grid fault contribution. Thus, load encroachment was enabled for forward phase-overcurrent elements to meet the sensitivity requirement, while maintaining security during maximum loading conditions. The load angles were set to not exceed 40 degrees, meaning the power factor cannot exceed 0.77 lag.

The total rating of the inverters at the BESS plant was twice the maximum circuit load. One of the key advantages of inverters is they can act as current sources during a fault, meaning the fault current magnitude is not significantly impacted by the circuit impedance. Thus, the pickup for the reverse phase-overcurrent elements could be set greater than the maximum load.

The number of online inverters is critical to providing fault detection during islanding conditions. The MDAC will limit the size of the island to Provincetown by tripping the PCC if the total number of online inverters drops below nine and will trip both POIs if the total number of online inverters drops below seven.

IX. Seamless Islanding, Seamless Restoration, and Distribution Automation

The MDAC receives the statuses of the breakers, reclosers, and sectionalizers shown in Fig. 3 via IEC 61850 GOOSE. It uses a topology tracker to maintain centralized awareness of the distribution circuit and determine whether to operate one or both BESS plants in grid-parallel or islanding operation.

The control scheme is designed to seamlessly island one or both BESS plants upon separation from the utility source and form a microgrid. The islanding event could be intentional through operator action or unintentional because of a fault on the distribution circuit.

If the islanding event is a result of a temporary fault, the MDAC will automatically restore the circuit back to its original lineup with no operator intervention once the fault has been cleared. This is accomplished by synchronizing the microgrid back to the grid, without interruption to the island load, and returning the BESS plants to their grid-support functions prior to islanding. This is because the impact on the BESS SOC is minimal as a result of the short duration of the islanding event.

If the islanding event is a result of a permanent fault, the MDAC will automatically isolate the faulted section once the tripping devices go to lockout and will automatically extend the size of the microgrid to the unfaulted section without operator intervention. Once the fault is cleared by line crews, operating procedures require the energization of the isolated section caused by the fault from the grid. The operator will then command the MDAC to synchronize the microgrid back to the utility source without an interruption to the microgrid load. The MDAC will command the BESS to Standby mode to prevent further drop in the SOC after a successful synchronization. The operator can command the BESS to charge or resume grid-support functions depending on SOC.

Fig. 11 is used to demonstrate how the protective devices and MDAC work together to isolate faults and minimize customer interruptions. A smaller subset of the reclosers between BKR1 and PCC is shown for simplicity; however, the islanding and restoration sequences for the reclosers between BKR1 and PCC are identical for temporary and permanent faults.

The system is designed to provide an islanding point at the PCC whenever there is an islanding event in Zone 1, shown in Fig. 11. This prevents BESS1 and BESS2 from picking up the entire circuit load in one step.

The PCC is the primary point of restoration back to the grid; however, based on the system topology and the island that was formed after a temporary or permanent fault, the point of restoration could be a different node on the circuit. As a result, every blue recloser and breaker in Fig. 3 is configured to be a potential point of restoration or synchronization to the grid. This satisfies the project requirement of seamless restoration to the grid with minimal interruption to the customer on the distribution circuit.

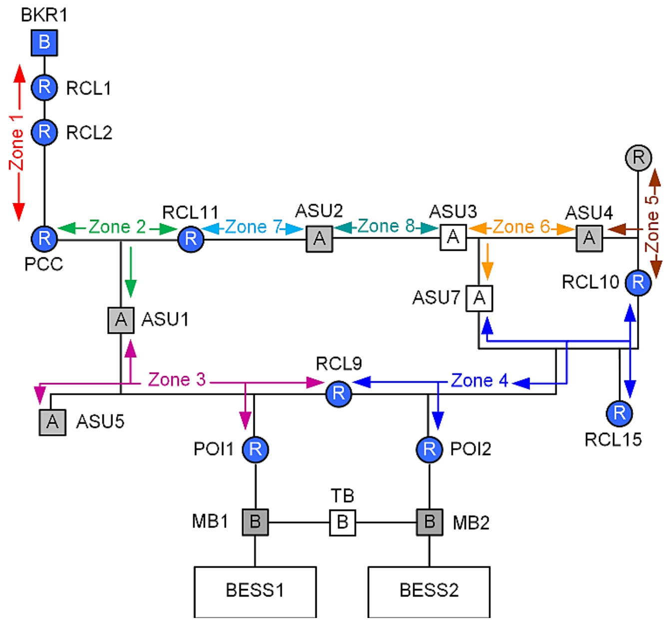

Fig. 11. Distribution circuit fault zones

A) *Zone 1 Faults*

For a fault between RCL1 and RCL2, both BKR1 and RCL1 protective devices detect the fault based on the current contribution from the grid. RCL1 trips and sends a blocking signal to BKR1 to prevent it from tripping. RCL1 sends a DTT signal via IEC 61850 GOOSE to the PCC to isolate the BESS plant fault contributions. BESS1 and BESS2 seamlessly island and continue to carry the load in Provincetown.

If the fault is temporary, RCL1 will reclose successfully and the load between RCL1 and PCC will be re-energized from the grid. The PCC will be the remaining open point with utility voltages on one side and BESS voltages on the other side. The MDAC will automatically synchronize the BESS plants to the grid while carrying the Provincetown load. Upon successful synchronization, the MDAC will command both BESS plants to resume their grid-support functions prior to islanding. This entire sequence takes place without operator intervention.

If the fault is permanent, RCL1 will go to lockout state after two reclosing shots. The MDAC will open RCL2 to isolate the faulted section and close the PCC to extend the size of the microgrid to RCL2, with no operator intervention. Once line crews clear the fault between RCL1 and RCL2, the local or remote operator manually closes RCL1 to pick up the cleared section from the grid. RCL2 will be the remaining open point with grid voltages on one side and BESS voltages on the other side. The operator initiates a close command to RCL2 and the MDAC will automatically synchronize both BESS to the grid while carrying microgrid load. The MDAC will command the BESS to Standby mode after a successful synchronization.

B) *Zone 2 Faults*

For Zone 2 faults, the PCC will detect the fault contribution from the grid. The PCC trips and sends a blocking signal to the upstream reclosers to prevent them from tripping, and a DTT signal to POI1 and RCL9 to isolate BESS1 and BESS2 fault contributions. BESS2 seamlessly islands and carries Provincetown loads between RCL9 and ASU3.

If the fault is temporary, the PCC will reclose successfully and the load between the PCC and RCL9 will be re-energized from the grid. RCL9 will have utility voltages on one side and BESS2 voltages on the other side. The MDAC will automatically synchronize BESS2, while carrying load, to the grid using RCL9. After successful BESS2 synchronization, the MDAC will automatically synchronize BESS1 to the grid using POI1. The MDAC will command BESS1 and BESS2 to resume their grid-support functions prior to islanding upon their successful synchronization to the grid.

If the fault is permanent, the PCC will go to lockout state after two reclosing shots. The MDAC will open ASU1 and RCL11 to isolate the faulted section and close ASU3 and RCL9 to extend the size of the microgrid to the de-energized unfaulted sections of Provincetown. The MDAC will synchronize BESS1 to BESS2, while carrying island load, using POI1 as the synchronization node. Once line crews clear the fault in Zone 2, the local or remote operator will manually close RCL11, close ASU1, and open ASU3. The operator initiates a close command to the PCC and the MDAC will automatically synchronize both BESS to the grid while carrying Provincetown load.

C) *Zone 3 Faults*

Similar to Zone 2 faults, the PCC trips and sends a blocking signal to the upstream devices to prevent them from tripping. The PCC also sends a DTT signal to RCL9 and POI1 to isolate BESS1 and BESS2 fault contributions. BESS2 seamlessly islands and carries Provincetown load between RCL9 and ASU3.

If the fault is temporary, the restoration sequence will be identical to Zone 2 faults.

If the fault is permanent, ASU1 will sectionalize the faulted section. As a result, the PCC will remain closed after the second reclosing shot. ASU3 will have grid voltages on one side and BESS2 voltages on the other side; however, ASU3 is not capable of synchronization. Thus, the MDAC opens the PCC and closes ASU3. The MDAC will automatically synchronize BESS2, while carrying island load, to the grid using the PCC.

Zone 3 permanent faults result in the unavailability of BESS1 through POI1. Automatically tying BESS1 to BESS2, via TB, using the MDAC was outside the scope of this project. The operator may choose to manually tie BESS1 to BESS2 via TB after following the Eversource switching procedure and enabling less sensitive settings on POI2. The MDAC will recognize that BESS1 and BESS2 are grid-connected and dispatch them accordingly.

Once line crews clear the fault in Zone 3, the operator will manually open ASU3 and close ASU1; RCL 9 will have grid voltages on one side and BESS2 voltages on the other side as a result. The operator initiates a manual close command to RCL9 and the MDAC will automatically synchronize BESS2 to the grid using RCL9. After successful BESS2 synchronization, the operator initiates a close command to POI1 and the MDAC will automatically synchronize BESS1 to the grid.

D) Zone 4 Faults

For Zone 4 faults, RCL9 will detect the fault contribution from the grid and BESS1. RCL9 trips and sends a blocking signal to POI1 and PCC to prevent them from tripping. RCL9 sends a DTT signal to POI2 to isolate BESS2 fault contribution. BESS1 remains grid-connected and continues its grid-support functions while BESS2 is isolated by POI2.

If the fault is temporary, RCL9 will reclose successfully and pick up the isolated Provincetown load from the grid and BESS1. The MDAC will automatically synchronize BESS2 to the grid through POI2, with no operator intervention, and command it to resume its grid-support functions prior to islanding due to the temporary fault.

If the fault is permanent, RCL9 will go to lockout state after two reclosing shots. The MDAC will open RCL10 to isolate the faulted section and close ASU3 to pick up the de-energized unfaulted section of Provincetown.

Zone 4 faults result in the unavailability of BESS2 through POI2. The operator may choose to manually tie BESS2 to BESS1, via TB, after following the Eversource switching procedure and enable less sensitive settings on POI1. The MDAC will recognize that BESS1 and BESS2 are grid-connected and dispatch them accordingly.

Once line crews clear the fault in Zone 4, the operator will manually open ASU3, close RCL9, and close RCL10. The operator initiates a close command to POI2 and the MDAC will automatically synchronize BESS2 to the grid using POI2.

E) Zone 5 Faults

For Zone 5 faults, RCL10 will detect the fault contribution from the grid, BESS1, and BESS2. RCL10 will trip and send a blocking signal to POI1, POI2, RCL9, and the PCC to prevent them from tripping. This fault location will not result in islanding BESS1 or BESS2 and they will continue their grid-support functions once the fault is cleared.

If the fault is temporary, RCL10 will reclose successfully. If the fault is permanent, RCL10 will go to lockout after two reclosing shots. The MDAC will open ASU4 and close ASU3 to restore the unfaulted de-energized section of Provincetown. Once line crews clear the fault in Zone 5, the operator will manually open ASU3, close ASU4, and close RCL10.

F) Zone 6 Faults

Similar to Zone 5 faults, RCL10 will detect the fault contribution from the grid, BESS1, and BESS2. RCL10 will trip and send a blocking signal to POI1, POI2, RCL9, and the PCC to prevent them from tripping. This fault location will not result in islanding BESS1 or BESS2 and they will continue their grid-support functions once the fault is cleared.

If the fault is permanent, ASU4 will sectionalize the fault and RCL10 will remain closed on the second reclosing shot. Once line crews clear the fault in Zone 6, the operator will manually close ASU4.

G) Zone 7 Faults

For Zone 7 faults, RCL11 will detect the fault contribution from the grid, BESS1, and BESS2. RCL11 will trip and send a blocking signal to POI1, POI2, RCL9, and the PCC to prevent them from tripping. This fault location will not result in islanding BESS1 or BESS2 and they will continue their grid-support functions once the fault is cleared.

If the fault is temporary, RCL11 will reclose successfully. If the fault is permanent, RCL11 will go to lockout after two reclosing shots. The MDAC will open ASU2 and close ASU3 to restore the unfaulted de-energized section of Provincetown. Once line crews clear the fault in Zone 7, the operator will manually open ASU3, close ASU2, and close RCL11.

H) Zone 8 Faults

Similar to Zone 7 faults, RCL11 will detect the fault contribution from the grid, BESS1, and BESS2. RCL11 will trip and send a blocking signal to POI1, POI2, RCL9, and the PCC to prevent them from tripping. This fault location will not result in islanding BESS1 or BESS2 and they will continue their grid-support functions once the fault is cleared. If the fault is temporary, RCL11 will reclose successfully.

If the fault is permanent, ASU2 will sectionalize the fault and RCL11 will remain closed on the second shot. Once line crews clear the fault in Zone 8, the operator closes ASU2.

X. Multi-Point Synchronization

The different fault zones discussed in Section IX show that there are multiple points on the circuit that must allow synchronization to provide seamless restoration. Each blue recloser or breaker shown in Fig. 3 is a potential restoration point to the grid. These recloser controllers and breaker relays are configured with three-phase voltage sensing on both the grid side and the BESS side to allow synchronization. The synchronization process is a combined effort of the MDACs for control, the relays for status information and protection, and the BESS plant as the generation source.

To initiate a reconnection to the grid after a permanent fault or an intentional islanding event, an operator issues a close command to the relay or recloser controller either via SCADA or front-panel pushbutton. Upon receipt of the close command, four scenarios are considered by the relay or recloser controller based on the voltage sensing measurements: Live Grid-Dead Plant, Dead Grid-Live Plant, Dead Grid-Dead Plant, and Live Grid-Live Plant. For the first three scenarios, the relay or recloser controller allows an immediate close of the breaker or recloser. The synchronization requirements for the fourth scenario at each device are a voltage difference of 3 percent, a slip frequency of –0.03 Hz, and a phase angle difference of 10 degrees. The slip frequency calculation is the frequency of the microgrid minus the frequency of the grid source. A negative slip means the grid frequency needs to be greater than the microgrid frequency during synchronization. Tight synchronization windows were chosen to minimize power swing at the instant of closure given the tight droop settings chosen by Eversource planning group and the size of the BESS plant. Furthermore, the slip requirement was set to a negative value to ensure the transient power swing after synchronization be toward the BESS plant and not the substation to avoid tripping on the reverse overcurrent elements in BKR1.

With live voltages on the grid side and the BESS side of the reconnection point, the relay or recloser controller performs additional checks before the synchronization process begins. The relay or recloser controller verifies the grid-side voltage is within ±5 percent of nominal, the recloser is open, the relay or recloser controller does not have a frequency tracking problem, there are no standing trips on the relay or recloser controller, hot-line tag is disabled, and reclosing is enabled in all relays and recloser controllers. The relay or the recloser controller sends a synchronization initiation to the MDACs to start the synchronization process. Upon receipt of the synchronization initiation, the MDAC collects voltage, slip frequency, and phase angle information from the corresponding device via IEC 61850 GOOSE. Using the grid as a reference, the MDAC adjusts the voltage and frequency of the BESS to be within the specified synchronization requirements. The breaker or recloser will close immediately after all synchronization requirements are satisfied if the synchronization initiation status is asserted.

Prior to the BESS project, the Eversource standard recloser devices were set up for basic remote operation with metering and fault detection along with automatic reclosing. Synchronization was not a function used in the Eversource pole-mounted reclosing devices until the BESS plants were installed. With seamless restoration required, a version of the standard recloser was used and ordered with voltage sensors on both the “load” side and the “source” side of the recloser head as shown in Fig. 12. The “source” side was designated as the direction of the recloser toward the substation and the “load” side was toward the BESS plant. The recloser manufacturer used an Internal Voltage Sensor (IVS) built into the head of the recloser on the source side and an external voltage sensor was installed on the load side of the recloser.

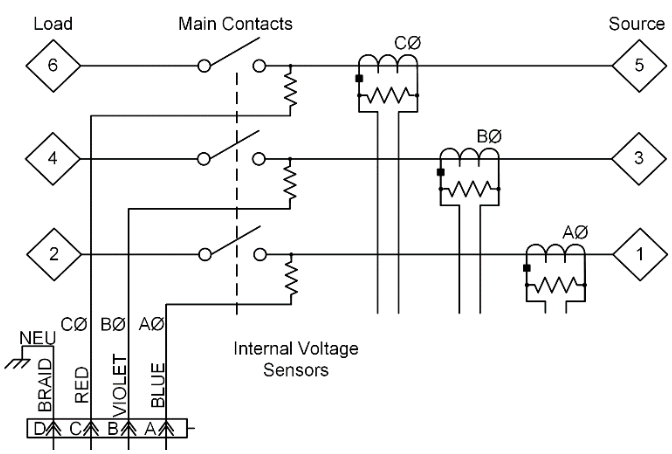

Fig. 12. Recloser controller secondary voltage connections

Given the tight synchronization windows, it was critical that the measurement accuracy of the hardware could perform at a level acceptable for the critical sync check programming. To maintain the voltage signal as clean as possible from interference, a shielded control cable was used between the base of the pole and the recloser head. In addition, the auxiliary power in the recloser head, used for outlet power and heaters in the control box, was wired in separate cables. As the accuracy of the secondary voltage was crucial for these installations, it was decided to have the secondary voltages from both voltage devices routed through separate shielded cables.

During the first round of sync close testing, it was discovered that the voltages were still not within the window to allow for a successful close. The measured voltage difference between the source- and load-side voltage readings was observed to be 6.6 percent, greater than the 3 percent sync requirement. Later, it was deemed that the accuracy of the IVS was not at the level required compared to the external voltage sensors. A second set of higher-accuracy external voltage sensors was installed on the “source side” of all reclosers. The accuracy requirements were satisfied and allowed for seamless reconnection of the BESS to the grid at multiple nodes on the distribution circuit.

XI. Scheme Validation Using HIL and Onsite Testing

To validate the protection and control schemes used for this project, a representative model of the distribution circuit and inverters was needed. Using a representative model was challenging because the circuit was modeled in CYME, which is a phasor domain distribution circuit analysis software used by Eversource for load-flow and short-circuit analysis, whereas the inverter model was provided by the inverter manufacturer as a black-box dynamic link library (DLL) in PSCAD, which is an EMT software. Furthermore, neither software could integrate the hardware intended to implement the protection and control schemes as part of the circuit analysis; this necessitated a multi-step process to create a representative model.

A. PSCAD Model Development

The distribution circuit model was reduced to a boundary equivalent in CYME to the nodes of interest shown in Fig. 3. This boundary equivalent was modeled in PSCAD and was benchmarked against CYME using load flow and fault comparisons with a variance of less than 10 percent. The inverter model, which has the same firmware source code of the physical onsite inverters, was integrated into the PSCAD model and linked to the inverter configuration file with the protection and control parameters and their set points used for this application.

All classical fault types, LG, LL, line-to-line-to-ground (LLG), and three-line-to-ground (3LG), were simulated throughout the circuit under various loading conditions and circuit lineups. The loading conditions were maximum, moderate, and minimum loading. The circuit lineups were BESS1 and BESS2 inverters operating in GFM mode parallel to a strong utility source, Line 1, weak utility source, Line 2, and islanded.

The voltage and current waveforms were captured as COMTRADE files at all the breakers and reclosers highlighted in blue in Fig. 3.

B. Protection Scheme Validation Using HIL Testing

A Real Time Digital Simulator (RTDS) was configured to apply voltage and current waveforms to the substation breaker relays and recloser controllers, which were configured with the logic and set points to be implemented in the field. The RTDS captured the operation of the digital elements of interest that were connected to their output contracts through hardwired I/O.

The COMTRADE files were applied to the relays and recloser controllers in an automated sequence using a COMTRADE playback tool and their output contact statuses were captured for analysis. The relays and recloser controllers determined correctly if the fault was in the forward or reverse direction, operated for in-zone faults, and restrained for out-of-zone faults.

This approach allowed adequate analysis of the protection schemes because it captured the transient response of the inverter voltage and current waveforms for distribution circuit and BESS plant faults, which may vary significantly based on the inverter firmware revision even if it is installed on the same inverter hardware.

C. Control Scheme Validation Using HIL Testing

Although the previous modeling approach was adequate for validating the protection scheme, it offered limited value in validating the control scheme because it could not capture the control system response after the relays or recloser controllers operated for a system fault.

This resulted in the need to recreate the PSCAD model in the RTDS test environment, this time setting up the breaker relays, reclosers controllers, MDACs, and battery management systems in-the-loop as shown in Fig. 13.

The boundary equivalent modeled in the RTDS test environment was benchmarked against CYME with comparable results to the PSCAD model. A GFM inverter model was created in the RTDS test environment and tuned until a comparable dynamic fault response of the PSCAD model was achieved. The RTDS model with HIL was used to validate the following:

- Tripping and reclosing schemes after temporary and permanent faults along the distribution circuit and inside the BESS plant.
- Multi-point synchronization between the grid and the BESS plant at the blue devices in Fig. 3.
- Seamless islanding and seamless restoration of one or both BESS plants.
- Fault isolation and automatic circuit reconfiguration by the MDAC to minimize customer interruptions following a permanent fault.
- BESS plants real-power and reactive-power modes during grid-parallel operation.
- Load-shedding scheme during islanding operation.

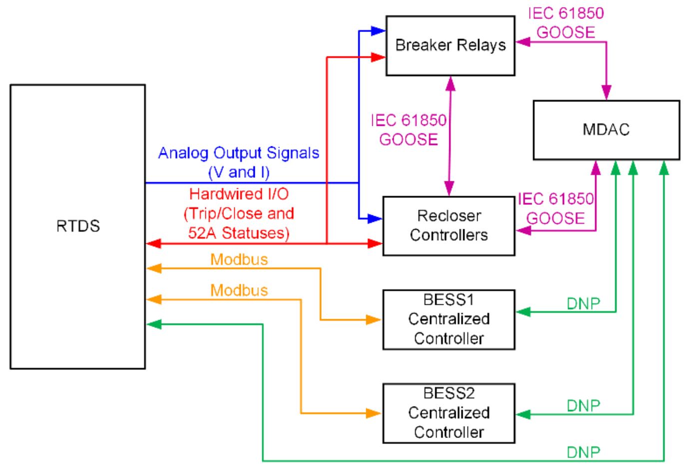

Fig. 13. Real Time Digital Simulator HIL setup

D. Onsite Testing

When a new recloser is installed on the distribution circuit, a traditional approach is to “benchtop” test all protection and control functions in a lab environment or operation center. As the recloser is moved to installation onsite, a functional test is conducted with the recloser head. This allows in-depth testing to be completed in a controlled environment and reduces the number of operations required onsite. A typical control box loaded with final proposed settings consists of schemes that would rely mostly on overcurrent protection elements and operational logic. These schemes include fault detection with automatic reclosing, hot-line tag for working on the system, ground elements enabling, and cold load pickup for switching. Therefore, the typical recloser work force is comfortable with basic control logic and overcurrent testing. Traditional overcurrent tests can usually use a preprogrammed, off-the-shelf recloser test set operated by a power system technician.

With the addition of necessary protection and control schemes to the recloser controllers to meet the project requirements, it was clear that traditional recloser testing was not adequate. Directionality was added for selectivity, load encroachment was added to maintain sensitivity under weak source configuration, sync check was added for multi-point synchronization, etc., in addition to the necessary logic for IEC 61850 GOOSE messaging needed for protection and automatic restoration schemes. While testing directionality is common for transmission line and substation field test engineers, it is not common for distribution power system technicians. Simultaneous voltage and current injections with phase angle at multiple devices, for example, became a challenge when benchtop testing.

While some advanced testing was completed, mainly to support training, it was determined that overcurrent and traditional schemes testing would be sufficient to test the performance of each recloser controller. Eversource relied primarily on HIL testing with the RTDS to validate the protection and control schemes. However, Eversource decided to perform additional onsite functional testing with the complete system installed to validate some of the RTDS test scenarios, mainly because this was the first project of its kind within its service territory.

Sequenced installation and functional onsite testing required organized and detailed planning for each recloser controller. Loss-of-communication logic built into the recloser settings allowed each recloser controller to operate as a traditional overcurrent recloser if communication was lost or IEC 61850 GOOSE messaging was disabled. The installation team took advantage of this by replacing the existing recloser controllers with ones capable of supporting the new protection and control schemes and placing them in service. For system operators, this meant the original circuit functions were maintained during the construction stage. The new devices were functionally tested traditionally, open, close, local, and remote before the fiber network was ready. This allowed the recloser controllers to be placed in service with the new configuration files while retaining the functionality of the devices they replaced. Once all the devices were placed in service with fiber connectivity back to the BESS plant, the system was ready for integrated system testing. This testing was scheduled for overnight hours during off season when load was low. Acceptance testing procedures identified locations within the circuit where faults would require a reasonable number of relay elements to pick up and a reasonable number of devices to operate via the automatic restoration scheme. Testing was scheduled using GPS time-synchronized test sets onsite at multiple locations. As recloser devices are typically only tested when isolated from the system, there was usually no need for the controller to have test switches installed to isolate the device from the system. Therefore, to perform the required onsite testing, a specialized cable harness was built to allow current injection to the controller secondary side from the test set while being isolated from the system current on the primary side. Furthermore, this harness allowed the use of actual external voltage sensors measurements on both sides of the device to allow real synchronization to take place between the BESS plant and the grid after the device operated for a simulated fault. Testing was limited to no more than three street devices requiring injection at the same time. This limited the number of resources and test equipment required. Using automated test plans developed before testing to simulate temporary and permanent faults, current signals were injected to simulate faults behind or in front of devices. This testing simulated seamless islanding and seamless restoration with the primary equipment and operated as designed, which validated the RTDS HIL testing results.

XII. Configuration Control

Typical distribution systems are radial in nature and designed to accommodate varying amounts of electrical load types and connections. Primary configuration control considerations for distribution feeder design typically consist of accounting for and verifying that the connected load does not exceed the rating of the feeder, and that available fault current and installed protective elements can sense and isolate phase and ground faults on the entire feeder, including the remote end from the source. Feeder loads of various types are added and removed on a day-to-day basis and attention to balancing load across all three phases is a general consideration but not a strict requirement. With the widespread installation of distributed energy resources (DERs) on distribution systems, more detailed configuration control practices are required to study and account for the possibility of unintentionally islanding generation against feeder load, especially when the grid source is disconnected under light loading conditions. The results of these studies often dictate the need to install DTT from the source substation to ensure DER generation is disconnected quickly in these circumstances. Effective grounding and the effect the added DER has on protective element sensitivity is also examined and adjusted accordingly. There is typically no restriction on the amount of interconnected DERs other than the physical equipment limitations of the feeder or station transformer that must accommodate the maximum possible backfeed onto the system. When there is an emergent situation, such as a feeder outage caused by storm damage, the distribution engineering teams and field operation resources are very adept at taking immediate and creative action with the materials available to restore the system quickly. This may mean temporarily bypassing backbone or side tap reclosers, bypassing or modifying the performance of feeder reactive devices, or temporarily reconfiguring feeders to transfer a portion of one feeder onto an adjacent feeder at various locations in the system. The Provincetown project highlighted the need for Eversource to place new configuration controls on the subject feeder. These controls ensure that significant changes in the interconnected DERs and load, or new operating configuration, are not approved without the full range of thermal and transient analysis studies being performed to ensure stability, thermal margins are not exceeded, and protection sensitivity under normal and contingent conditions can be maintained. Likewise, the distribution engineering group must review all modifications of load connection to maintain tighter tolerances on loading balance across all three phases and ensure there are not significant variances in the distribution of load along the feeder from what the DER is designed to support. If there is a planned need to significantly change the loading configuration on the circuit, a full modeling and study of these changes must be performed prior to the project being accepted and approved. In summary, the controls Eversource has imposed on this Provincetown feeder are similar to the configuration controls long established and practiced by the industry on the transmission system. This is a significant shift in thinking for the DER planning and distribution engineering organizations at Eversource, but these actions are vital to ensure continued expected operation of the BESS and microgrid under all allowable operating configurations.

XIII. Conclusion

A BESS can improve the overall distribution circuit reliability by providing grid-support functions, like peak shaving and voltage support, during grid-parallel operation and backup supply upon loss of the grid.

Significant design decisions had to be made to support seamless islanding and seamless restoration for Provincetown. BESS1 and BESS2 inverters needed to be always configured as GFM, the distribution devices were equipped with higher-accuracy voltage sensing on both sides to allow muti-point synchronization along the distribution circuit, and high-speed controllers were used to provide protection and control of the distribution circuit and BESS. Selecting and sizing the grounding transformers properly was a critical aspect of the scheme design because Eversource needed to provide effective grounding upon islanding while minimizing the impact to ground-fault protection on the distribution circuit.

A high-speed communications network to provide support for IEC 61850 GOOSE was critical for protection and control. The backbone of a high-speed communication network not only allowed faster clearing of faults, but also allowed faster detection of islanding to provide the appropriate voltage and frequency to the system. It also facilitated multi-point synchronization of BESS1 and BESS2 along the distribution circuit to the grid without impacting the island load.

Properly modeling the dynamic fault response of the inverters was key to developing a protection scheme for the distribution circuit during grid-parallel and islanding operations. If significant changes are made to the distribution circuit, such as adding another distribution circuit feed, expanding the BESS, or adding a photovoltaic plant, additional studies and analysis may be needed to evaluate the impacts on the protection and control schemes.

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XV. Biographies

Enmanuel Revi received his BS in electrical engineering from University of Massachusetts Lowell and his MS in electrical engineering from Worcester Polytechnic Institute. He currently serves as manager of capital projects engineering for Eversource Energy and previously served as P&C technical lead on the project. He has over 16 years of practicing engineering in the T&D utility industry with focus on power system design, operations, and controls.

George Wegh received his BS in electrical engineering from Purdue University and his MS in electrical engineering from Worcester Polytechnic University. He is the director of protection and controls engineering for Eversource Energy and previously served as the director of system planning. He has over 22 years of experience working in the utility industry in the fields of protection and control engineering and system planning.

Stuart Hollis received his BS in electrical engineering from Northeastern University and his masters in power system management from Worcester Polytechnic Institute. He is the manager of eastern Massachusetts protection and controls engineering for Eversource Energy. He has over 18 years of experience working in the electric utility industry in the protection and control engineering department.

Ahmed Abd-Elkader received his BS in electrical engineering, with honors, from Ain Shams University, Cairo, Egypt, in 2008 and an MBA, with honors, from Wake Forest University in Winston-Salem, NC, in 2015. He is currently pursuing a Ph.D. in electrical engineering from the University of North Carolina at Charlotte. He is a senior engineer with Schweitzer Engineering Laboratories, Inc. (SEL) with over 14 years of experience in power systems protection and control.

Fred Amuna received his BS in electrical engineering in 2014 and his MS in electrical engineering in 2017. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2017 as an associate automation engineer. Fred is currently an automation technical lead at SEL Engineering Services, Inc. (SEL ES) and supervises a team of four engineers. At SEL, he has worked on many SCADA, distribution automation, PV control, and battery solutions.

Rona Vo received his BSEE and MSEE, magna cum laude, from the University of North Carolina at Charlotte in 2014 and 2016, respectively. Upon graduating in 2014, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as an associate protection engineer in the engineering services division. In 2018, he became a professional engineer registered in North Carolina. Currently, he is protection lead engineer at SEL Engineering Services, Inc. (SEL ES) with over 8 years of experience in power systems protection and control.