

Using Protective Relays for Microgrid Controls

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Abstract—This paper explains how microprocessor-based protective relays are used to provide both control and protection functions for small microgrids. Features described in the paper include automatic islanding, reconnection to the electric power system, dispatch of distributed generation, compliance to IEEE specifications, load shedding, volt/VAR control, and frequency and power control at the point of interface.

I. INTRODUCTION

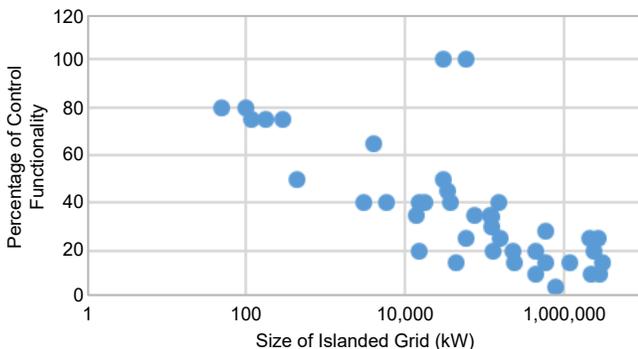
This paper elaborates on the most common forms of microgrid control accomplished in modern protective relays for grids with less than 10 MW of generation. The control strategies described include islanding, load and generation shedding, reconnection, dispatch, and load sharing.

Multifunction protective relays are an economical choice for microgrid controls because the hardware is commonly required at the point of interface (POI) to the electric power system (EPS) and at each distributed energy resource (DER). The relays at the POI and DER provide mandatory protection and human safety. The cost, complexity, and commissioning efforts of microgrids are reduced by consolidating more control functionality into the relays.

II. BACKGROUND

The plot shown in Fig. 1 was formed by evaluating 40 recently completed microgrid projects commissioned by the authors' team. Microgrid control system (MGCS) functionality, in this case, is defined by the upcoming IEEE 2030.7 and IEEE 2030.8 microgrid controller standards. Protection functions were not considered in this analysis.

In Fig. 1, the horizontal axis shows the size of the grid in kilowatts and the vertical axis shows the percentage of control functionality performed by protective relays. The remainder of the functionality, in every job, was completed by a centralized real-time controller. The plot in Fig. 1 shows that smaller microgrids tend to use protective relays for more of the microgrid control functions.



prevent damage, whereas microgrids use islanding relays to keep the lights on in a microgrid.

B. Proactive Islanding

Proactive islanding is when a relay trips the POI breaker under short-circuit, open-circuit, and backfeed conditions or for contractual requirements. Backfeed conditions are when a microgrid delivers power to a local load. Open-circuit conditions occur as a result of broken conductors or when upstream breakers are opened. Open circuits and backfeed conditions commonly occur when upstream protective relays open distant circuit breakers following a faulted circuit.

The protective relay must be capable of distinguishing normal power system transients from unacceptable events. A properly configured protective relay will not trip during the voltage and frequency transients associated with load pickup, generator synchronization, recloser operation, inverter tripping, transformer energization, line energization, remote power system faults, or other similar switching transients.

Voltage and frequency ride-through requirements are common parts of utility contracts. Based largely on IEEE 1547 characteristics, the microgrid is required to stay online until it reaches the trip points. A typical ride-through requirement showing frequency over time is shown in Fig. 3.

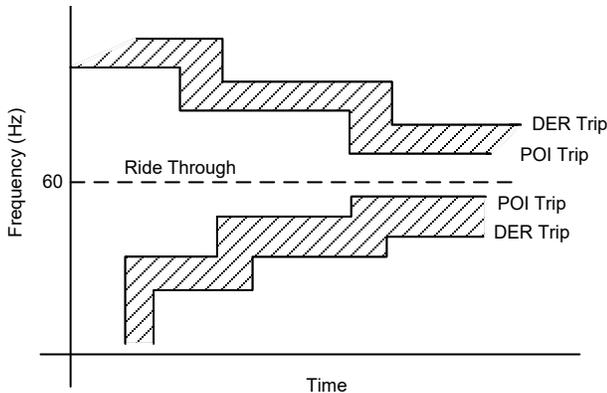


Fig. 3. Typical POI Ride-Through Requirement

Legal contracts between microgrid and EPS owners define the disturbance ride-through requirements at the POI. Fig. 3 depicts the IEEE 1547 standard frequency ride-through requirements; similar requirements are often referenced in legal contracts. These contracts require the POI breaker to stay closed (i.e., prohibit decoupling) while the grid frequency is within a tolerance (ride-through) band.

The ride-through region of Fig. 3 is designed to support the resiliency of the EPS with no benefit to the microgrid. These frequency ride-through requirements extract significant spinning kinetic energy reserves out of the microgrid in an effort to save the EPS. In order to avoid a microgrid blackout as a result of these challenging requirements, proactive and seamless islanding techniques are required.

It can be very challenging to achieve a seamless island for a microgrid when the POI opens at the POI trip point of Fig. 3. This is because the frequency has fallen so far by the time the POI opens that turning the frequency around may not be possible before other relays trip off the DER.

One solution to this problem is to use an 81RF element, as shown in Fig. 4. In this method, the relay sends the trip command in anticipation of crossing the contractual boundary. Applying 81RF elements improves the probability of a microgrid staying online after the POI trips; this is known as seamless islanding.

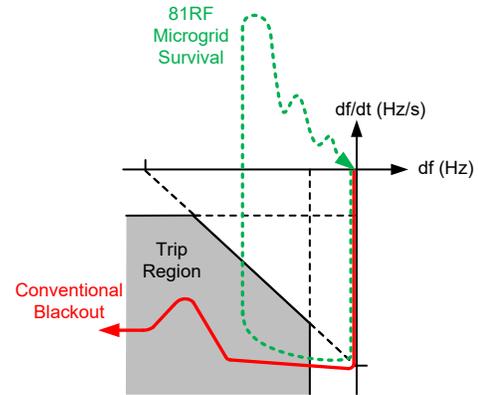


Fig. 4. 81RF Element Assists Microgrid Survival

Fig. 4 and Fig. 5 depict the same typical unplanned microgrid islanding event. The solid red line labeled “Conventional” in both figures illustrates what commonly happens when only underfrequency elements are used. The dashed green line labeled “81RF” shows a typical seamless transition with the 81RF element in use.

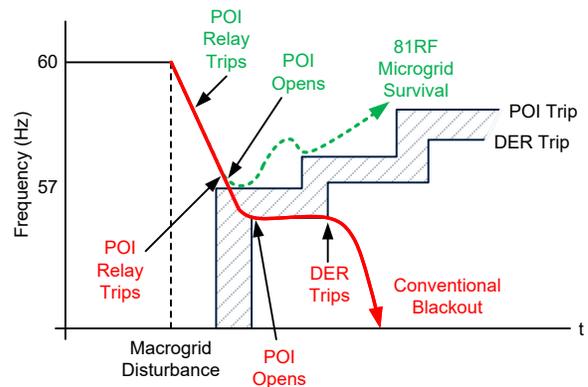


Fig. 5. Proactive Automatic Islanding Before a Microgrid Blackout

The red lines in Fig. 4 and Fig. 5 depict a typical sequence of events for an islanding event with only underfrequency tripping of the POI. In this case, the frequency falls at the rate (df/dt) proportional to the power disparity between generation and load consumption [2]. This initial frequency freefall occurs the same way for both the red and green systems.

For the red lines in Fig. 4 and Fig. 5, the POI opened some time after the relay element crosses the contractual POI trip point. This time delay is the circuit breaker opening time and the underfrequency element pickup conditioning timer. The time delay results in the frequency falling substantially below the contractual trip point before the circuit breaker opens.

The red lines in Fig. 4 and Fig. 5 show that although the power system islanded successfully, the microgrid blacked out because the DER protection tripped off the generation, resulting in further frequency decay.

The dashed green lines in Fig. 4 and Fig. 5 depict the same event as the red lines; however, the green line events use a properly configured 81RF element. In these cases, the 81RF element detects the high rate-of-change of frequency and starts the circuit breaker tripping process prior to reaching the contractual POI tripping point. Properly tuned, the POI circuit breaker opens at exactly the contractual ride-through boundary, as shown in Fig. 5. Because the frequency was turned around, the microgrid never went to blackout.

C. Seamless Islanding

Seamless islanding techniques are used to avoid microgrid power outages when the POI is opened under load current. Seamless islanding avoids process outages for industrials, preserves research for universities, and avoids interruption for military facilities. While industrials, universities, and military microgrids commonly require a seamless (“no blink”) transition to islanding, community microgrids are focused on cost reduction, revenue growth, and human safety. Therefore, community microgrids do not commonly require seamless islanding.

Close coordination between relays and microgrid controllers, deterministic data, and fast communication between relays are required for successful seamless islanding. Programmable logic controller-based (PLC-based) microgrid controllers struggle to achieve seamless islanding transitions, whereas relay-based microgrid control systems achieve it easily.

Once the POI relay opens and separates the microgrid, a high-speed load-shedding system response may be required to turn around the voltage and/or frequency. If the microgrid has less generation than load, the system DERs will experience an overburden condition and a frequency decay.

Alternatively, if onsite generation exceeds the system loading, the newly formed islanding system frequency increases and high-speed generation runback (curtailment) or generation shedding are used to rapidly bring down the frequency [3].

Fig. 6 shows an unplanned island scenario with a fault on the EPS, well upstream of the microgrid POI. The data in this plot were collected by a POI relay under closed-loop testing with a real-time, hardware-in-the-loop simulator. The event starts with a fault, and about 200 ms later, the directional relay element decides to trip the POI. About 100 ms later, the circuit breaker opens, followed by fault current termination and microgrid voltage recovery. Following the POI opening, a load-shedding system opens several sheddable load breakers and the microgrid frequency recovers.

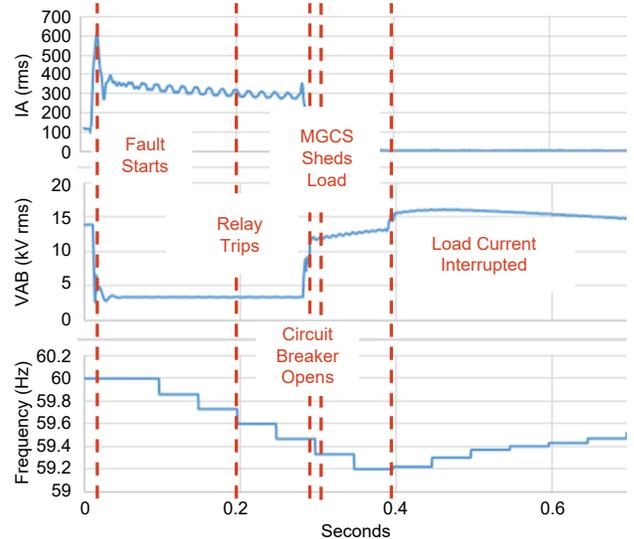


Fig. 6. Typical Reverse Fault Detection Scenario Using a POI Relay

IV. LOAD AND GENERATION SHEDDING

Time lags associated with conventional prime movers (turbines or reciprocating engines) can require load and/or generation shedding to preserve power system frequency [4]. The first law of thermodynamics (conservation of energy) and Kirchoff’s current law require that electrical generators and loads are always instantaneously balanced at the speed of light. Prime movers and control loops (governors, exciters, and inverters) have varying time lags of up to several seconds. The difference between the speed of light and the time lags creates a power disparity that can cause power system blackouts [4].

For example, the sudden disconnection of a generator from a microgrid can cause adjacent (online) generators to expel kinetic energy into the grid until the remaining connected prime movers and generators catch up to the power disparity. Power system frequency falls when the generators expel kinetic energy, thus load shedding is required to preserve the power system. The sudden disconnection of a large block of load can conversely cause the generators to overspeed (overfrequency), thus requiring generation shedding.

Generator and inverter overload capabilities can also create conditions that require load and/or generation shedding. For example, the sudden disconnection of a generator from a microgrid can cause adjacent (online) prime movers and inverters to reach their output limits, creating a frequency free-fall condition that requires load shedding to correct.

There are many different types of load- and generation-shedding systems available. Not all of them are applicable for relay-based microgrid controls. These load-shedding systems are summarized as follows:

- Subcycle contingency-based load shedding. These systems operate in less than 1 cycle (16.6 ms for a 60 Hz system) to prevent frequency collapse and out-of-step problems with DERs. These systems can be implemented using protective relays for very simple microgrids; however, most contingency schemes require centralized real-time automation controllers in addition to relays.

- Underfrequency-based load shedding. These systems are commonly implemented in relay-based microgrid control schemes regardless of the size of the microgrid.
- Undervoltage-based load shedding. These systems are commonly implemented in relay-based microgrid control schemes regardless of the size of the microgrid.
- Inertial-compensated and load-tracking load shedding. These systems are underfrequency-based load-shedding schemes that compensate for varying microgrid inertia and load composition [3]. These systems are commonly implemented using protective relays for small microgrids.
- Slow load shedding. These systems usually operate in the time frame of seconds or minutes. They are used to prevent overload conditions for DERs and transformers, assist with synchronization, fulfill EPS POI curtailment requests, and avoid demand charges. These systems are commonly implemented in relay-based microgrid control schemes.

V. RECONNECTION

Reconnection control systems are also known as autosynchronization systems. The ANSI symbol for manual synchronism-check functionality is 25. A25 is used when the relay also automatically dispatches generation prior to closing the circuit breaker. Relay 25 schemes with dispatch and extensive automation are also referred to as advanced automatic synchronizers (A25A) [5].

A25A functions are now commonly performed in relays. Relay-based A25A systems speed up the reconnection process, do not require synchroscopes, eliminate PLCs, and allow the entire process to be initiated and monitored remotely [5].

The POI multifunction protective relay shown in Fig. 7 has both a synchronism-check and a dispatch function. For safety, the A25A process is always initiated by a human. Once the process is initiated, the A25A system operates autonomously to dispatch the DERs and close the breaker.

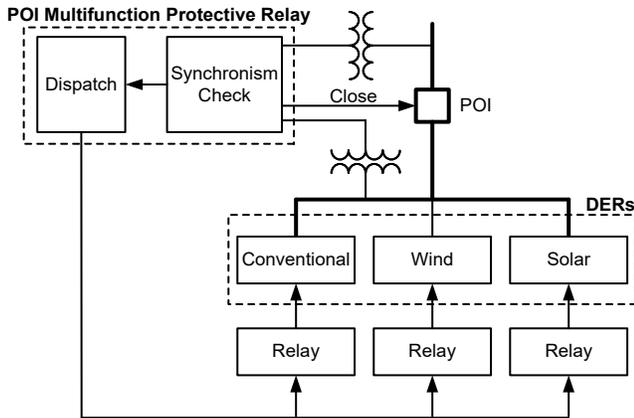


Fig. 7. Multifunction Protective Relays at the POI and DER Simultaneously Performing POI A25A and DER Dispatch

The A25A relay dispatch functionality sends new dispatch set points to DERs to bring the frequency, voltage, and angle difference across the POI down to acceptance limits. The relay sends a close command to the POI breaker once the frequency, voltage, and angle difference criteria are met.

Fig. 8 shows what the angle ($\Delta\delta$), voltage (ΔV), and slip (δ) signals look like for typical ac waveforms at the POI breaker.

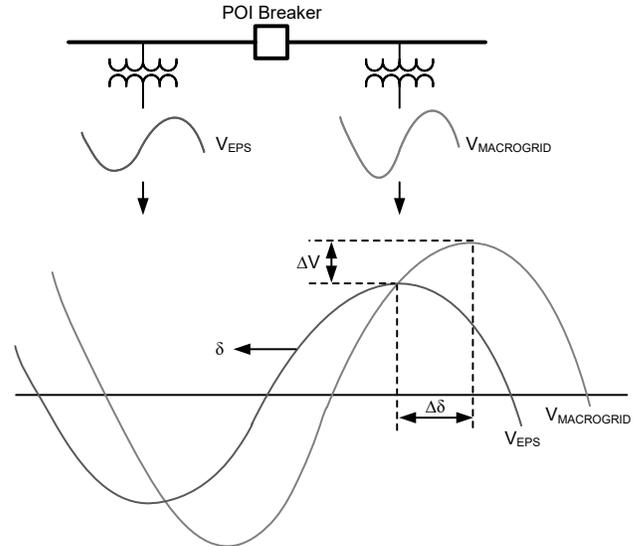


Fig. 8. Synchronism Check in a Relay

Equipment can be damaged if the POI breaker is closed with the voltage out of phase. A proven way to prevent such damage is by using breaker close delay logic. This logic compensates for the breaker mechanism close delay times by closing the breaker before it gets to zero degrees, thus ensuring a zero-angle close [6].

Table I compares the IEEE C50.12 and IEEE C50.13 synchronous generator synchronization settings with the typical A25A settings used in a POI relay.

TABLE I
TYPICAL A25A RELAY SETTINGS

Setting	IEEE C50.12 and IEEE C50.13 [7] [8]	Typical A25A Acceptance Criteria
Angle	$\pm 10^\circ$	Target 0°
Voltage	+5%	$\pm 5\%$
Breaker close time	n/a	3 cycles
Slip	± 0.067 Hz	± 0.04 Hz

VI. DISPATCH

POI relays configured for A25A can also be used for grid-connected DER dispatch. The POI relay uses the same DER raise and lower controls for both A25A and dispatch controls. When the POI breaker is closed, power and power factor (reactive power) are controlled by the POI relay. The POI relay is dispatched to a particular power and power factor by an upstream energy management system (EMS). These dispatches become internal set points for the POI relay control loops.

As shown in Fig. 7, the POI relay sends raise and lower commands to DER relays to meet the EMS dispatch set point. The DER relay then dispatches the DER (generator or inverter-based source) to its commanded active and reactive power set points.

VII. LOAD SHARING

Outputs from all DERs must be continuously balanced based on either an optimal economic or optimal stability criteria. Optimal stability and optimal economic criteria cannot be met simultaneously.

For example, having one generator running at full capacity while an adjacent generator is idling puts an islanded power system (microgrid) at risk of losing a generator because of reverse power or overloaded protection elements. Optimal stability criteria are met when adjacent generators are equally dispatched. On the contrary, optimal economic dispatch for the same scenario is most commonly achieved by running each generator close to its optimal efficiency point, which is very rarely an equal dispatch condition. Adding intermittent, inverter-based DERs to a microgrid creates further complications to a dispatch scheme.

Load sharing is the balancing of conventional prime movers. It is a mechanical engine term and is not associated with electric generators or motors. Because of the traditional usage of the term “load sharing,” the simultaneous dispatch of intermittent, inverter-based DERs is also called load sharing. Today, the term load sharing is used ubiquitously in reference to a variety of methods of balancing DER (conventional and inverter) output.

The term “generator paralleling control” is synonymous with load-sharing controls. The term “paralleling” is most commonly used among reciprocating engine suppliers to describe their particular set of controls, which keep the output from parallel-connected generators balanced.

POI relays configured for dispatch are now commonly used for grid- and island-connected DER dispatch and load sharing. When the POI breaker is closed, power and power factor are controlled by the POI relay. When the POI breaker is open, the islanded frequency and voltage are controlled. In both grid and islanded mode, the POI relay works with the DER relays to provide DER load sharing.

In this load-sharing scheme, relays are placed at each DER. The POI relay communicates to the DER relays via serial or Ethernet communication. The POI relay sends dispatch requests to each DER relay. The DER relays control the active and reactive output of the individual DERs to meet POI relay dispatch requests.

When the complexity of the dispatch schemes becomes too complex for a single POI relay to manage, an additional microgrid controller is commonly added. This is required when the number of DERs is too great or when the microgrid requires complex frequency and voltage control strategies. Microgrid controllers are usually not required until there are three or more DERs under dispatch.

A. Frequency and Voltage Control

When the POI opens, the POI relay dispatches DERs to control the frequency of the islanded microgrid. Simultaneously, load balancing is required to keep the DERs equally loaded; this is load sharing, as described previously. With the POI open, there are several methods to achieve microgrid frequency control while load sharing between DERs [9]. These methods are summarized in the subsections below.

1) All DERs in Grid-Forming Mode (Isochronous)

Parallel-connected DERs in grid-forming mode require a high-speed, isochronous-sharing control system to dispatch the governors, exciters, and inverters simultaneously and provide electrical oscillation damping between DERs. These schemes are also called isochronous (ISO) parallel controls. The central controller, communications links, and associated power supplies, wiring, and communications cabling become single points of failure. These schemes also have a long history of tuning instabilities as DERs deteriorate with age or load compositions change. Therefore, this method is not recommended for use on any microgrid.

2) One DER in Grid-Forming (ISO) Mode, Remainder of DERs in Grid-Supporting (Droop) Mode

In this scenario, the ISO unit keeps the power system at a constant frequency. The remaining droop units must therefore be dispatched to ensure that all of the units are sharing load equally. The logic associated with these schemes, both to ensure that only one unit is in ISO mode and to handle potential single points of failure, can become very complex. This is a second-choice method for load sharing with protective relays.

3) All DERs in Grid-Supporting (Droop) Mode

Most power systems throughout the world operate with all units in droop mode. In this mode, the POI relay (or a central controller) adjusts the droop set points of all units simultaneously to keep the power system at nominal frequency. This system does not require DER mode changes upon transition to islanded operation. Another advantage with this method is that all microgrid DERs provide fast transient frequency support of a failing EPS. Droop mode is the first-choice method for load sharing with protective relays.

B. Volt/VAR Control

Relay-based volt/VAR control of a DER has a similar solution to that of the active power dispatch descriptions in Section VI. Putting all DERs in constant voltage mode with reactive compensation (reactive droop) terms provides optimal stability and control under all operating conditions. This requires the POI relay to send voltage reference signals to all microgrid DERs. Droop mode is the first-choice method for volt/VAR load sharing with protective relays.

VIII. AUTOMATIC BLACK START

Automatic black start is a microgrid function that automates recovery from a blackout. This functionality includes islanding, load shedding, grid topology reconfiguration, DER starting, and load reacceleration.

Automatic black start functionality is commonly used on community microgrids, which can withstand a temporary power outage when transitioning to islanded operation. Conversely, even temporary outages for critical infrastructure—such as military, oil and gas, or data center applications—can be catastrophic. While some community microgrids use black start functionality on every island transition, critical infrastructure microgrids rarely use black start functionality.

When a blackout occurs, relays are configured to automatically perform switching procedures to island the microgrid (open the POI) and temporarily disconnect the loads (load shed), as discussed in Section VI.

Reconfiguration of microgrids involves the automatic opening and closing of circuit breakers, disconnects, reclosers, and other circuit-interruption devices. Multiple islands may be present at the moment of blackout; relays automatically synchronize the islands into a single grid. Another common reconfiguration technique is to reconfigure distribution feeders (loads) to prepare for DER re-energization.

DER starting varies greatly by technology. Diesel generator sets can be started remotely within seconds or minutes of an outage (depending on the technology). Inverter-based generation, such as photovoltaic, most commonly requires strong voltage sources (e.g., conventional generator sets or battery-based systems) to start. Battery systems with ac inverters are commonly the first to be started in a black start sequence because they can respond within seconds.

After the DERs are online and the grids are reconfigured, the relays restore power to the loads. Loads are incrementally re-energized while maintaining voltage and frequency stability. The process of reconnecting loads is often referred to as load reacceleration.

Automatic black start is most often entirely performed by relays. Relays communicate to perform the entire sequence of islanding and re-energization. While community microgrid black start schemes commonly initiate automatically, black start systems for critical infrastructure microgrids are most commonly human-initiated.

IX. PRACTICAL IMPLEMENTATION

Microprocessor-based relays include hardware, firmware, and configurable settings and logic. The hardware and firmware are set by the manufacturer, but users can set the configurable settings and logic.

The relay microgrid control functions described in this paper are not available in off-the-shelf firmware from relay manufacturers. They must be programmed into the relay settings and logic.

Because of the complexity of the microgrid control schemes described in this paper, experienced engineers are recommended for implementation. Relays have minimal user-configurable logic, which must be used judiciously to achieve these features. Should the relays have insufficient capacity to perform the desired logic, real-time automation controllers can be used to augment the relay logic.

X. OPTIONAL CENTRAL CONTROLLER

This paper focuses on the microgrid control capabilities provided by microprocessor-based relays. For a variety of reasons, some microgrid owners may add a centralized microgrid controller to augment relay functionality.

Relay-based controls are a cost-effective solution for smaller microgrids. The additional cost, complexity, and testing of centralized controller-based systems are generally only warranted on large microgrids with more than 10 MW of generation. These large microgrids can include many DERs, loads, and complex topologies. For large microgrids, the process of managing system functionality with distributed relays may be cumbersome. For example, making a change in functionality to a relay-based black start scheme may require changing the settings on every relay. A centralized controller offers the convenience of a single platform for development, testing, and maintenance.

Microgrids with the primary objective of cost savings tend to use centralized controllers. These systems require unit commitment, which uses forecasts for scheduled economic dispatch of DERs. Algorithms that account for multivariable cost functions, integrate large numbers of generation assets, incorporate complex battery-charging strategies, react to market pricing signals, and constantly change forecasted weather conditions typically require more processing power than is available in microprocessor-based relays.

Complex visualization systems, remote access requirements, or interfaces to other control systems may steer designers toward centralized controllers. While relays have built-in front-panel HMIs that are excellent for local monitoring and control, a remotely monitored system can be more conveniently monitored from a single display point. For example, a single centralized microgrid controller can simultaneously host an HMI, perform economic dispatch, perform data collection from relays, and act as a protocol gateway for an energy management system.

Modern centralized microgrid controllers do not use hardwired signals like legacy PLC systems do. Instead, they use communications networks to extract real-time data from the microprocessor-based relays. A centralized controller using a communications network instead of hardwired signals is less costly, more reliable, easier to test with controller hardware-in-the-loop techniques, and faster to modify for new functionality.

XI. CONCLUSION

The key takeaways in using microprocessor-based protective relays for small microgrids include:

- 81RF islanding prevents microgrid blackouts and simultaneously meets interconnect requirements.
- A25A functionality is performed in multifunction protective relays.
- Although the relays are commercial and off-the-shelf, the functionalities described in this paper must be designed and tested by skilled engineers.

- Control of small microgrids with limited functionality requirements can be accomplished entirely within protective relays.
- Capabilities of multifunction protective relays that often already exist at the POI can prevent microgrid blackouts, automate grid resynchronization, achieve POI dispatch, and make islanded frequency and voltage control a reality.
- Modern protective relays provide the functionality needed to meet many existing and upcoming IEEE 1547, IEEE 2030.7, and IEEE 2030.8 specifications.
- Microprocessor-based relays can provide automatic black start functions, including islanding, load shedding, grid topology reconfiguration, DER starting, and load reacceleration.
- Centralized controllers can be used to augment a relay-based solution for larger microgrids, systems with complex economic optimization, or remote visualization.

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XIII. BIOGRAPHIES

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