WORKING GROUP C30

Microgrid Protection Systems

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KEYWORDS

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CONTENTS

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Abstract: The working group for microgrid protection systems was given the assignment to develop a report to the System Protection Subcommittee of the IEEE Power System Relaying and Control Committee. The report will investigate and assess techniques, approaches, and potential solutions to the challenges of microgrid protection.

ABBREVIATIONS AND SYMBOLS

AC	Alternating Current
APS	Adaptive Protection System
ATP	Alternative Transients Program
BESS	Battery Energy Storage System
CT	Current Transformer
DA	Distribution Automation
DC	Direct Current
DCB	Directional Comparison Blocking
DER	Distributed Energy Resource
DSO	Distribution System Operator
EMTP	Electro-Magnetic Transients Program
EPS	Electric Power System
FLISR	Fault Location, Isolation, and Service Restoration
IED	Intelligent Electronic Device
IVVC	Integrated Volt/VAR Control
LVRT	Low Voltage Ride Through
PCC	Point of Common Coupling
PoC	Point of DER Connection (DER terminals)
POTT	Permissive Overreaching Transfer Trip
PU	Per-Unit
RMS	Root Mean Square
RTU	Remote Terminal Unit
SMS	Storage Management System
SoC	State of Charge (of an energy storage system)
TSO	Transmission System Operator
VT	Voltage Transformer

1. Introduction

Distribution-connected and behind-the-meter distributed energy resources (DERs), including generation and energy storage systems, are being increasingly integrated into electrical power systems. Microgrids help leverage these DERs to keep the power on when the normal supply is unavailable (e.g., due to faults or equipment outages). These systems, however, present unique protection challenges to detect and respond to faults. This report describes some challenges and potential solutions for microgrid protection.

1.1 Microgrid Definition

A microgrid consists of a group of interconnected loads and DERs with clearly defined electrical boundaries which can be operated as a single standalone controllable entity and can be operated either grid-interconnected or grid-isolated. This definition is based on the DOE definition [34].

1.2 Types of Microgrid

Microgrids are typically connected to the larger electrical grid at the distribution or sub-transmission voltage levels. The maximum capacity of the microgrid is limited by the associated equipment current and operating voltage ratings. Examples of areas that may operate as microgrids can include university campuses, industrial parks, small communities, defense establishments, and medical facilities. These areas typically have interconnected loads and DERs with ratings from a few kilowatts to several megawatts, even up to tens of megawatts in aggregate size.

With the proliferation of renewable energy resources and technology advancement in energy conversion systems, several diverse types of microgrids have been proposed to improve overall system efficiency, provide operating flexibility, and reduce capital costs. In general, there are three types of microgrids, defined by the type of power transfer:

- **Alternating Current (AC) Microgrids** are based on AC power transfer as the dominant power delivery scheme. Since the traditional power systems are based on AC power, most microgrids are also AC based.
- **Direct Current (DC) Microgrids** are DC systems with advanced capabilities that enable the control of DC system resources for higher operational performance and/or independent operation from the primary AC system to enhance reliability [1].
- **Hybrid Microgrids** contain one or more AC and DC sub-grids, which contain AC or DC loads respectively, as well as DERs. Hence, a hybrid microgrid can exploit the salient features of both AC and DC microgrids [2].

The scope of this report only covers the protection of AC microgrids.

1.3 Modes of Operation

Microgrids may operate grid-isolated or grid-interconnected. There is also a transition from grid-isolated operation to grid-interconnected and a transition from grid-interconnected to grid-isolated. An overview of considerations for protection are described in this clause. Additional details on the application of the described protection are provided in later clauses of the report.

Microgrid protection issues may be divided into three categories: 1) separation of the microgrid from the local electric power system due to electric power system (EPS) de-energization, faults or other abnormal operating conditions, 2) microgrid re-synchronization to the EPS, and 3) isolation of faults or other abnormal operating conditions within the microgrid, either while operating grid-isolated or grid-interconnected.

1.3.1 Microgrid Protection During Grid-Isolated Operation

Protection within a grid-isolated microgrid includes consideration of short circuits, abnormal operating conditions, and power balance. With the microgrid operating in a grid-isolated mode, available short-circuit current may be significantly less than when in a grid-interconnected mode. Also, coordination of various protection schemes will require different consideration when grid-isolated than when grid-interconnected. The protection could therefore be modified to optimize the reliability of the grid-isolated microgrid when operating in this mode.

Short-circuit protection is used to isolate and de-energize faulted components within the microgrid. These components may include, but are not limited to, rotating machine-based generation, inverter-based generation, power transformers, buses, cables, and lines. Utilization-voltage equipment protection should, at a minimum, conform to any applicable codes but may also need additional fault detection means to have adequate sensitivity and selectivity of operation when grid-isolated. Short-circuit protection is commonly performed with the following protection functions:

- Phase overcurrent (IEEE device 50 or 51) for detection of phase faults [20]
- Ground overcurrent (IEEE devices 50N, 50G, 51N or 51G) and/or negative-sequence overcurrent (IEEE device 46) for detection of ground faults (for grounded systems)
- Ground overvoltage (IEEE device 59N) for high impedance grounded or ungrounded systems
- Sensitive ground fault (IEEE device 50N) for high impedance grounded systems
- Negative-sequence overcurrent (IEEE device 46) for detection of phase-to-phase faults
- Voltage-restrained or voltage-controlled overcurrent (IEEE devices 51VR or 51VC) for detection of low-current faults
- Differential current (IEEE device 87) and ground current differential (IEEE device 87N) as applicable on power transformers (IEEE device 87T) and buses (IEEE device 87B)
- Line current differential (IEEE device 87L) on interconnecting cables or overhead line sections

Some of the above protection functions may be directional for improved selectivity. In some microgrid applications, protective elements may be adjusted, logically combined, or utilize communications for improved sensitivity and/or selectivity. These techniques are discussed in more detail in later clauses of the report.

Rotating machinery protection guidance can be found in IEEE Std 242 [23], IEEE Std C37.96 [24], IEEE Std C37.102 [25], or IEEE Std C37.101 [26] depending on the machine size. Self-protection and interconnection protection for inverter interfaced resources is described in IEEE Std 1547 [27] and UL 1741 [29].

To help balance load and generation in response to events, frequency (IEEE device 81) and voltage protection (IEEE devices 27 and 59) may be utilized. Overfrequency protection (IEEE device 81O) can trip sources of generation where load balance control fails to maintain frequency and frequency gets too high. Underfrequency protection (IEEE device 81U) can trip load where load balance control fails to maintain frequency and frequency gets too low. Overvoltage protection (IEEE device 59) can trip capacitor banks where load balance control fails to maintain voltage and voltage gets too high. Undervoltage protection (IEEE device 27) can trip inductive loads or switch-in capacitor banks where load balance control fails to maintain voltage and voltage becomes too low.

Re-synchronization protection of the grid-isolated microgrid would consist of a combination of the overvoltage (IEEE device 59), undervoltage (IEEE device 27), overfrequency (IEEE device 81O) and underfrequency (IEEE device 81U) elements used on the area EPS (i.e. the system to which the microgrid connects) terminals of any points of common coupling to the EPS [3],[4], [27]. In addition, synchronizing elements (IEEE device 25) would be applied at the area EPS terminals and microgrid terminals of any points of common coupling to ensure the microgrid and the EPS are in synchronism prior to re-synchronization. Auto-synchronization elements (IEEE device 25A) may also be applied at points of common coupling to assist in synchronizing the microgrid to the area EPS. If re-synchronization is possible at multiple points of common coupling, sequencing of re-synchronization may decrease the number of separation points requiring synchronizing elements, or the number and type of synchronizing elements.

1.3.2 Microgrid Protection During Grid-Interconnected Operation

When the microgrid is operating grid-interconnected, protection issues may be divided into protection of the microgrid and the re-synchronization protection to the EPS.

Protection of the microgrid while operating grid-interconnected is applied as described in clause 1.3.1, although different optimization may be applied to the schemes to coordinate with the EPS protection schemes. In other words, microgrid protection challenges in the grid-interconnected mode are mainly of coordination type rather than detection type.

Re-synchronization protection would also be applied as described in clause 1.3.1, with the addition of directional protections at the points of common coupling to the EPS as applicable. The following protection functions may be utilized at the microgrid protective device while operating grid-interconnected:

- Real power applied as low import power (reverse underpower) (IEEE device 32U) or forward overpower (IEEE device 32) can be used for contracted power agreements and also for loss of EPS detection.
- Reactive power applied as low import power (reverse underpower) (IEEE device 32QU) or forward overpower (IEEE device 32Q) to be used for contracted power agreements and also for loss of EPS detection.
- Directional overcurrent elements (IEEE devices 67P, 67Q, 67N) to detect excessive phase directional overcurrent, negative-sequence directional overcurrent, and directional ground fault overcurrent directed from the microgrid towards the EPS, suggesting a fault on the EPS.

1.4 Protection Architecture

The definition of a microgrid does not restrict its size or topology. This would indicate that it is difficult to come up with a generalized protection architecture that could economically be used for an arbitrary microgrid of any size. Assuming that most microgrids will evolve from existing distribution feeders, the cost of retrofitting will vary widely depending on the existing protection architecture on the feeders. For example, urban feeders may be easier to retrofit economically than rural ones.

The choice of protection architecture will be influenced by the size, type, and interconnection of the DERs supplying a microgrid and will have to adapt to widely varying magnitudes of fault currents during grid-interconnected and grid-isolated modes of operation. It is important to make sure that the protection schemes can detect and respond to faults inside and outside of the microgrid and maintain coordination between protective devices in both grid-interconnected and grid-isolated modes and in the presence of varying numbers and types of sources. Finally, it is also important to define the zones of protection in an economical fashion.

A wide range of protection schemes have been proposed in literature, each assuming certain topologies, operating conditions, and source types. Some proposed protection schemes have used principles including overcurrent (IEEE devices 50, 51, 67), undervoltage (IEEE device 27), voltage restrained or voltage controlled overcurrent (IEEE devices 51VR or 51VC), active or reactive power (IEEE devices 32, 32Q), distance (IEEE device 21), current differential (IEEE device 87), over- or under-frequency (IEEE devices 81O, 81U), harmonic-content, and traveling waves, many of them using varying complexities of communication infrastructure. Summaries of many proposed schemes can be found in references [5] and [30].

2. Challenges of Microgrid Protection

Microgrids present unique challenges for protection scheme development due to shorter electrical distances that make coordination challenging, the ability to dramatically change configuration (e.g., grid-interconnected mode vs. grid-isolated or islanded mode), and the inclusion of DERs that can impact the system significantly with their intermittent output. These attributes result in microgrid protection having different needs than traditional protection schemes. The main microgrid protection challenges are:

- Variable fault current levels when grid-interconnected or in grid-isolated operation
- Bidirectional power flow in feeders
- Detecting loss of source
- Adapting to topology and generation changes
- Re-synchronization

Each of these challenges is discussed in the following clauses in detail. Microgrids often have low system inertia and sensitive loads. These characteristics require faster protection operation to rapidly detect and isolate faults to ensure stable recovery. Protection schemes utilizing communications systems may require low latency communications.

Microgrids can have a large percentage of inverter-based generation, which presents challenges to many protection schemes when the microgrid is grid-isolated. Inverter-based systems may produce very low fault currents, and may not produce zero- or negative-sequence current, making detecting faults and employing directional protection very challenging.

As discussed in Clause 1, there is a wide range of microgrid architectures. This presents a challenge to protection engineers that may have to develop a unique protection solution for each case. Although microgrid *control* standards (e.g., [21], [22]) and general protection standards (e.g., [23], [24], [25], [26], [27], [28]) are available, there exists a need for microgrid *protection* standards.

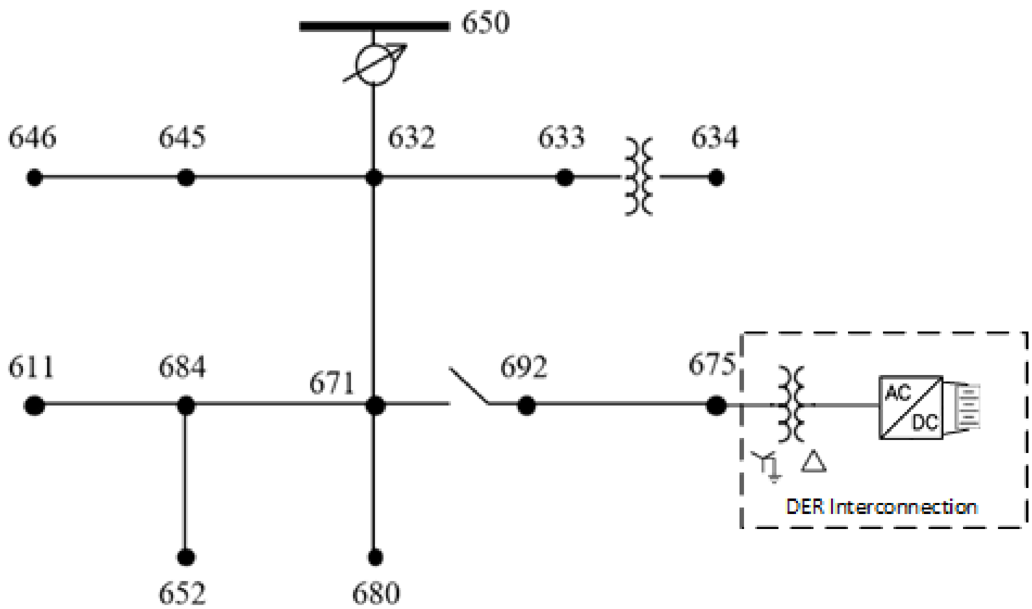
2.1 Variable Fault Current Levels

Sources that contribute to faults in a microgrid may include DERs such as renewable generation, electric vehicles, or energy storage systems that are interfaced through power inverters and transformers, conventional synchronous generators, or induction machines. Fault contribution from synchronous generators is well-documented and is typically divided into sub-transient, transient, and steady-state time-frames. Induction motors and generators typically contribute decaying fault currents that can last for up to four cycles. It is common to consider the peak contribution to be about four per unit. Alternatively, the machine parameters can be considered to calculate the peak contribution. The time of decay depends on the X/R ratio of the system and the generator decrement characteristics. Studies show that the magnitudes of fault currents contributed by synchronous generators and induction motors or induction generators in a microgrid when grid-isolated are generally much smaller than the fault current levels when supplied by the normal source while grid-interconnected, posing problems with coordinating protective devices in grid-interconnected and grid-isolated modes. Inverter-interfaced DERs have very unconventional fault response that can pose remarkable challenges to the sensitivity of the conventional protection [6]. The following sub-clauses further describe the issues.

2.1.1 Fault Current Contribution from Inverter Based Generation

A DER interfacing inverter can be single-phase or three-phase. In either case, the inverter controls include a current limiting function that restricts the maximum output current to a value close to the rated current. This is accomplished in less than two cycles after a fault in the system. During these two cycles, currents typically have high-frequency transients which can exceed the current limit. Thus, inverters no longer behave as linear sources in a faulted power system. In addition, smart inverters can maintain desired power factor while feeding a normal or a faulted system. Though the power factor under normal condition is typically unity or close to unity, the smart inverter may supply reactive power to the system during fault ride through conditions. In either case, the phase angle of the fault current contributed by inverter interfaced DERs may be significantly different than the phase angle of the fault current contributed by the substation source, which will be largely reactive. It should also be noted that inverters are typically ungrounded, and most will only generate positive-sequence currents even during unbalanced faults [7].

This behavior of inverters creates a problem with the traditional overcurrent-based fault detection. In the case of a three-phase interfacing transformer, a utility can choose a wye-grounded (YG) winding configuration on the grid side with a delta (Δ) winding on the generation side. This transformer configuration can enable detection of unbalanced ground faults with the traditional overcurrent methods using appropriate thresholds for zero-sequence currents. Faults not involving ground are challenging to detect with only a current threshold because the inverter will limit fault current contribution. To illustrate this problem, a 480 V, 100 kW three-phase PV connected inverter as described in the noted reference [9] was modeled in PSCAD® with a current limiter set at 110% of the rated current, and connected to node 675 of the IEEE 13-node distribution test system. Connection of the generator is made via a transformer which is connected wye-grounded (YG) on the grid side and delta (Δ) on the inverter side. The YG-Δ transformer connection provides a low-impedance path for zero sequence current on the YG side and causes the transformer to become a source of zero sequence current during unbalanced load or fault conditions. The modeled system is shown in Figure 1. Noted that the test feeder in Figure 1 has a substantially unbalanced load. Inverter input was simplistically modeled as an ideal DC current source. Two types of faults were created at 6 seconds into the simulation – a line to line (BC) fault at node 646, and a line to ground (AG) fault at node 633. Figure 2 and Figure 3 show the currents at the grid side and the inverter side for the BC fault, and Figure 4 and Figure 5 show the currents at the grid side and inverter side for the AG fault.



[8]

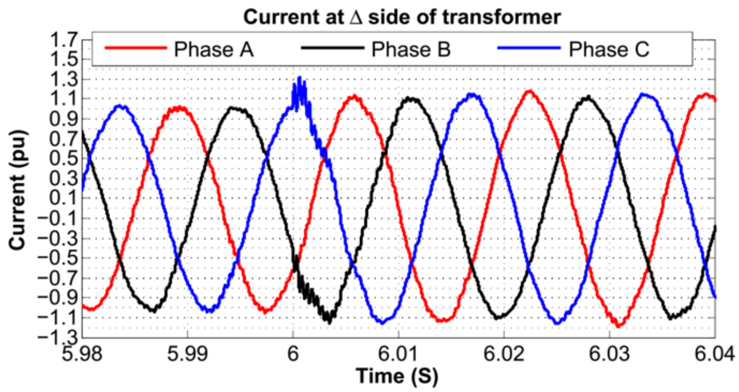


Figure 1

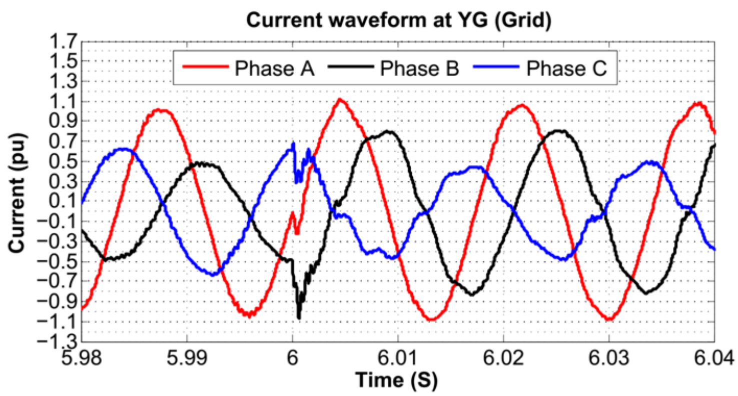


Figure 1

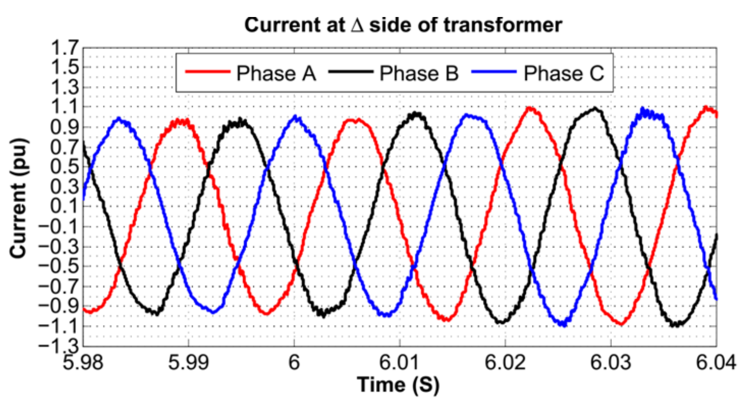


Figure 1

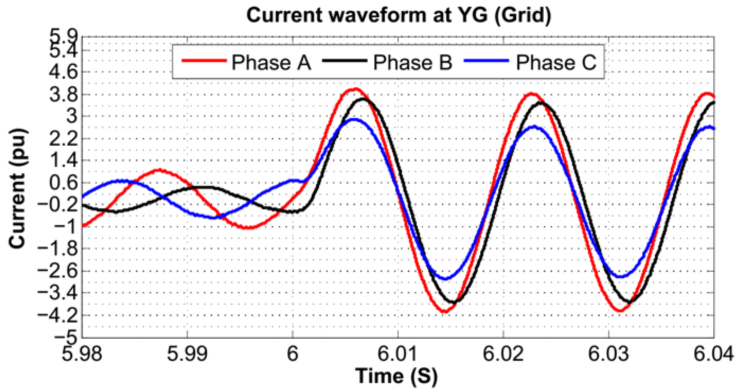
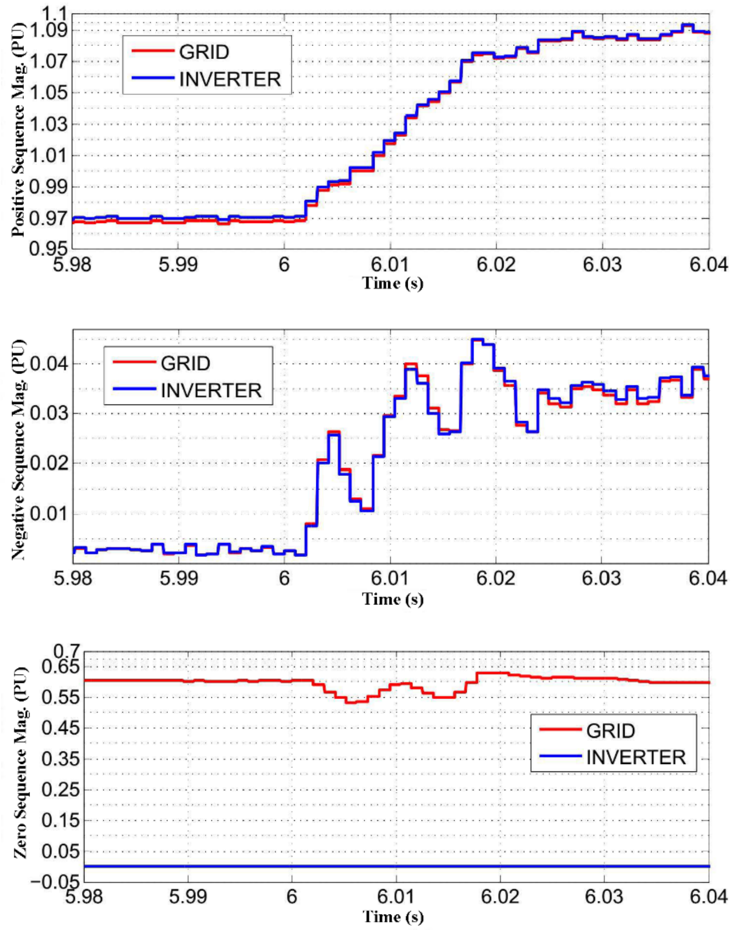


Figure 1

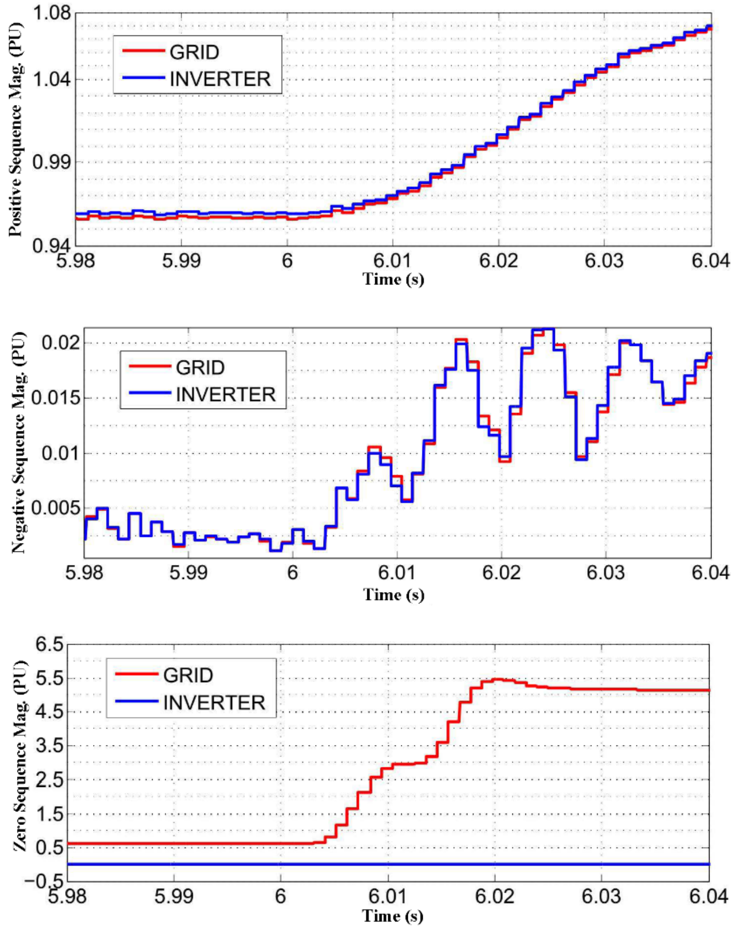
Notice that for both types of faults, the inverter output current remains nearly balanced positive sequence with very little negative or zero sequence, and does not exceed 110% of the pre-fault value. The test feeder's unbalanced load causes in a significant unbalance in the currents being drawn from the DER interconnection transformer throughout the events. On the grid side, currents for the BC fault are also limited, because the fault does not draw any zero-sequence current from the DER interconnection transformer. In such conditions, undervoltage protection may be applied for fault detection. Figure 5 clearly shows the current substantially increasing due to the large zero-sequence current drawn from the DER interconnection transformer by the AG fault.

Since this report focuses on protection, it is worthwhile to analyze the sequence components of currents on both sides of the transformer. Figure 6 shows the per unit sequence components of currents on both sides of the interfacing transformer for the BC fault, and Figure 7 shows the same for the AG fault. Notice the negligible negative-sequence currents – this is because the inverter does not generate significant negative-sequence currents. The positive-sequence currents increase according to the limit imposed by the current limiter, and zero-sequence is completely governed by the unbalance in the circuit before and after the faults. Note that the stepped nature of the curves is caused by sequence-component calculation filters.

1



Positive Sequence Mag. (PU)
1.1
1.09
1.07
1.05
1.03
1.01
0.99
0.97
0.95
GRID
INVERTER
5.98
5.99
6
6.01
6.02
6.03
6.04
Time (s)
Negative Sequence Mag. (PU)
0.04
0.03
0.02
0.01
GRID
INVERTER
5.98
5.99
6
6.01
6.02
6.03
6.04
Time (s)
Zero Sequence Mag. (PU)
0.7
0.65
0.55
0.45
0.35
0.25
0.15
0.05
−0.05
GRID
INVERTER
5.98
5.99
6
6.01
6.02
6.03
6.04
Time (s)



The results shown in this clause assume the inverter operates at unity power factor before and during the fault. This can be different for inverters complying with Low Voltage Ride Through (LVRT) requirements. In such cases, inverter fault contribution will supply reactive power to the system. This behavior is markedly different than the conventional short circuit currents that are largely lagging in nature. Due to this fact, if short circuit analysis is performed on a microgrid fed by conventional and inverter-interfaced DERs, the total fault current can be significantly less than the scalar sum of the fault currents contributed by all sources. This is an unusual feature related to the short-circuit analysis of microgrids.

2.1.2 Maintaining Dependability for Grid-Interconnected and Grid-Isolated Mode

Typically, the substation source feeding a microgrid is a much stronger source of fault current compared to the DERs within the microgrid. This is true even if the DERs are synchronous generators or induction motors feeding the fault for a few cycles. For example, consider a 1.5 MW, 480 V synchronous generator with a 15% sub-transient reactance [10] connected to a 12.47 kV grid through an interfacing transformer of 5% reactance. For a three-phase fault at the interfacing 12.47 kV bus, the generator would contribute 1/0.20 = 5.0 per-unit current based on its rating, which amounts to about 347 A at 12.47 kV. An induction machine of this size would contribute even less (typically 4 per-unit) fault current in the first cycle. On the other hand, in a typical distribution feeder, the fault contribution from the utility source may amount to a few thousand amperes. Consider a scenario depicted in Figure 8, where a fuse is protecting a transformer feeding a radial load-feeder. This fuse will have to coordinate with the upstream source-side protective device as well as the upstream DER-side protective device. However, for a fault at the transformer (marked “X”), the operating time of this fuse in grid-isolated mode will be much longer than that in the grid-interconnected mode because of the significant difference in fault currents flowing through the fuse. Reference [11] describes this scenario in more detail as part of a study performed on a military microgrid about two miles long, supplied by two diesel-powered generating units amounting to a total of 2.2 MW in the grid-isolated mode. The fuse, properly coordinated for the grid-interconnected case and responding promptly to a fault for this case, takes almost 7 seconds to operate in the grid-isolated case. Thus, variability of fault currents can put the dependability of the conventional protection scheme at risk.

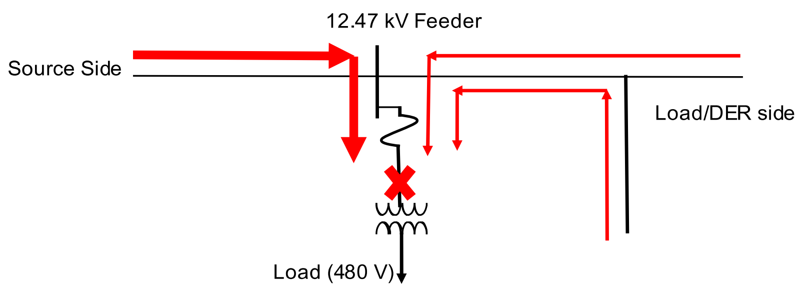


Figure 8: Circuit to illustrate a significant difference in operating time of a protective device for grid-interconnected and grid-isolated modes

2.2 Bidirectional Fault Current Flow

In microgrid systems, fault current flow through the system could be bidirectional. At the location of the protective devices serving microgrid DERs, the fault current can flow in one direction for a fault at the DER, and in the opposite direction for a fault on the system. The bidirectional fault current flow in microgrids introduces several challenges for microgrid protection, including maintaining selectivity, ensuring DER availability after an event, and ensuring faults are properly isolated from all generation sources.

2.2.1 Protection Selectivity Considering Bidirectional Fault Current Flow

Bidirectional fault current flow in microgrids requires consideration to ensure selectivity of microgrid protective devices. For example, consider the simple example system shown in Figure 9, with two generators, a load, and an interconnection with the local utility system on the same bus.

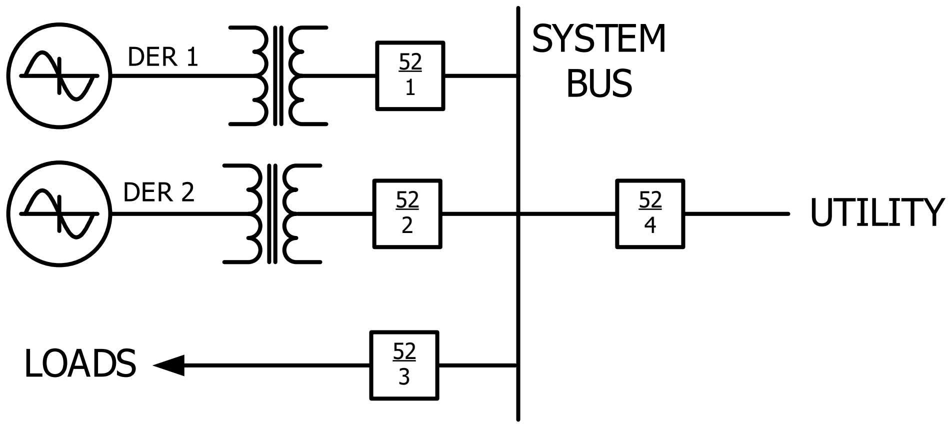


Figure 9: One-line diagram of a simple microgrid system

Consider that DER 1 and DER 2 are identical resources, and the system is operating with breaker 52-4 open and all other breakers are closed. A fault on the generator side of breaker 52-1 and a fault on the load side of breaker 52-3 would both result in similar fault current magnitudes flowing through breaker 52-1. However, different devices should operate to achieve selectivity and isolate the faulted component. In the first scenario, where the fault is on the generator side of breaker 52-1, breaker 52-1 should open. In the second scenario, where the fault is on the load side of breaker 52-3, breaker 52-3 should open and breaker 52-1 should remain closed. From this example, it is clear that the protection at breaker 52-1 must vary its operation based on the direction of the fault in order to achieve selectivity.

Design of a selective microgrid protection system requires consideration of fault directionality. Information on equipment required for directional sensing is included in Clause 3.1.4. Determining the directionality of fault current in microgrid systems can also present a challenge. For example, the off-nominal frequency of fault contributions from inverter interconnected resources can challenge phasor determination. Additionally, the changing system frequency during faults while grid-isolated can challenge some directional determination methods.

2.2.2 Maintaining DER Availability After Events

Operating DERs in parallel with the utility system requires consideration of how protection should respond to an event on the utility system. If a fault occurs on the utility system, local DERs may contribute to this fault. The DER contributions must be isolated from the fault. However, it may be desirable that the resource is available to restore power to a grid-isolated system if the fault causes an outage. This necessitates a coordination between DER protection and point of common coupling (PCC) protection if seamless formation of an island is of interest. Further, the DER may have the capability to ride through specified disturbances.

Again consider the example system shown in Figure 9 with DER 1 and DER 2 operating in parallel with the utility system, and all breakers closed. For a close-in temporary fault on the grid side of breaker 52-4, it may be desirable to allow the upstream utility protection to reclose and restore power to the loads. If breaker 52-4 opens to isolate the fault contributions of DER 1 and DER 2 from the fault, the reclosing on the utility feeder at the source end will not be able to restore power to the local loads supplied by 52-3. If breakers 52-1 and 52-2 operate instead, the system may be unable to island and restore power to the local loads, if the utility source is later unavailable.

Faults while in grid-isolated mode can have a significant impact to system voltage and frequency. This impact to the system may require that protection operate quickly to facilitate a stable recovery. Additionally, if the DERs are capable of riding through these events, it may be desirable to set protective relays so that they do not operate unnecessarily for off-nominal frequency and voltage conditions. Tripping DERs offline during such an event can further challenge the system recovery.

2.2.3 Isolating Fault Contributions From All Generation Sources

A fault must be isolated from all generation sources for the fault to be cleared. When generation resources are interconnected and operating, their contributions to the fault may be detected and isolated. However, when resources are not connected, it may be desirable for the protection system to ensure that they cannot attempt to energize a faulted component. For example, consider the example system shown in Figure 9 with DER 1 and DER 2 not operating (e.g., turned off or in Idle mode), while all breakers are closed. A fault at the system bus will cause fault current to flow through breaker 52-4. This breaker operating will de-energize the faulted component. It may also be desirable to trip and lock out breakers 52-1 and 52-2 for this fault to ensure that these resources cannot attempt to energize the faulted bus.

2.3 Utilizing Protection Relays to Detect Loss of Grid

Microgrid controls can be applied to disconnect and initiate grid-isolated operation when the grid is unavailable. Protective relays can be applied to detect when the grid is unavailable and initiate the transition from grid-interconnected to grid-isolated operation.

2.3.1 Methods to Detect Faults on the Grid

Protection elements such as reverse power, directional overcurrent etc. are used to detect faults in the grid or on the tie-line connecting the microgrid to the grid. In some cases, when the contribution from the microgrid to grid faults is very small and hence undetectable using the traditional protective elements, a direct transfer trip is utilized to disconnect the microgrid. Note that in the case of single phase open conditions, undervoltage and overvoltage-based protection may have difficulty in detecting the condition because of the impacts of the local generation and step-up transformers. In this scenario, zero-sequence overvoltage or negative-sequence overvoltage measurements are sometimes utilized [31].

2.3.2 Methods to Detect Grid Outages

It is important to correctly detect grid outages resulting from a system disturbance upstream of the interconnection between the microgrid and the grid. In some scenarios, undervoltage, overvoltage, underfrequency, overfrequency, rate of change of frequency, and/or rate of change of voltage protection can be used to detect formation of an unintentional island or loss of the grid/utility source [35]. These types of protection schemes may fail to detect a loss of grid successfully, especially when load and generation in the microgrid are comparable. This is known as a non-detection zone. Care should be taken to ensure that grid outages can be detected when the microgrid generation is online. Ensuring microgrid DERs are disconnected from the upstream system is critical for various reasons, including avoiding undesirably energized equipment, isolating microgrid DER contributions to a system fault, and avoiding out-of-phase reclosing or overloaded microgrid DERs. Synchrophasor based islanding detection schemes and/or direct transfer trip are possible solutions for these conditions [31][32].

2.3.3 Temporary Grid Faults

The decision between whether to isolate immediately from the grid or provide ride through for temporary grid faults depends on several factors. One of the key factors in this decision is the mode of operation and capacity of the energy storage and/or generation during the grid-interconnected mode. All DERs must be isolated from the fault. If the microgrid system has enough on-line generation or energy storage to supply all the on-site loads, then the protective relays detecting the outage can respond quickly and attempt to initiate grid-isolated operation. If the isolation from the grid does not occur fast enough, the on-site generation may trip on local protection elements (e.g., overload, undervoltage, or underfrequency protection functions) and can cause an outage. On the other hand, if the microgrid generation is operating in emergency response mode (such as backup generators) and it takes some time for the on-site DERs to start, then the overall system impact may be lowered by riding-through temporary utility system faults.

Regardless, it should be considered that automatic reclosing can potentially cause reconnection of two unsynchronized systems in the presence of DERs. As such, care should be taken to coordinate operation of a microgrid with reclosing schemes. On overhead distribution systems, the majority of faults are temporary. If the microgrid is supplied by an overhead distribution system that frequently experiences such temporary faults, the microgrid owner or operator may pre-emptively elect to operate the microgrid system grid-isolated if outages are anticipated based on weather forecasts.

2.4 Impacts of Microgrid Control Strategy on its Protection

By definition, a microgrid system shall act as a “single controllable entity” from the grid perspective. The microgrid control system, which can be implemented in a centralized or distributed manner, consists of software, hardware or a combination of both. The microgrid control system should be capable of sensing/monitoring grid prevailing conditions and controlling the operation of the microgrid in order to obtain the performance targets specified for the microgrid. Three common performance targets for a microgrid system are (i) reducing outage time of critical loads during all microgrid operating modes (grid-interconnected, grid-isolated, and transitions), (ii) decreasing greenhouse gas emissions, and (iii) improving system energy efficiencies [12].

To meet the objectives of a commercial-scale microgrid, the microgrid control system should be involved in several principal tasks such as voltage/frequency regulation, load sharing/management, islanding, re-synchronization, power flow management, and operating cost/condition optimization. In addition, various distribution automation (DA) schemes are required for the optimized operation of a microgrid. Some examples of microgrid intelligent controls and DA schemes include:

- Fault location, isolation, and service restoration (FLISR)
- Automated load transfer, sharing and circuit reconfiguration schemes
- Fast and/or emergency load shedding
- Integrated Volt/VAR control (IVVC) and optimization schemes

- Energy management and optimization based on equipment health and network status

Since the aforementioned control functions have different levels of criticalities, a hierarchical control structure has been widely accepted for the control of microgrids. In this hierarchical control strategy, three levels of control functions are defined based on the required response time of the control: primary control functions, secondary control functions, and tertiary control functions [13]. Figure 10 illustrates the logical relationship between the three layers of microgrid control functions along with their required time frame.

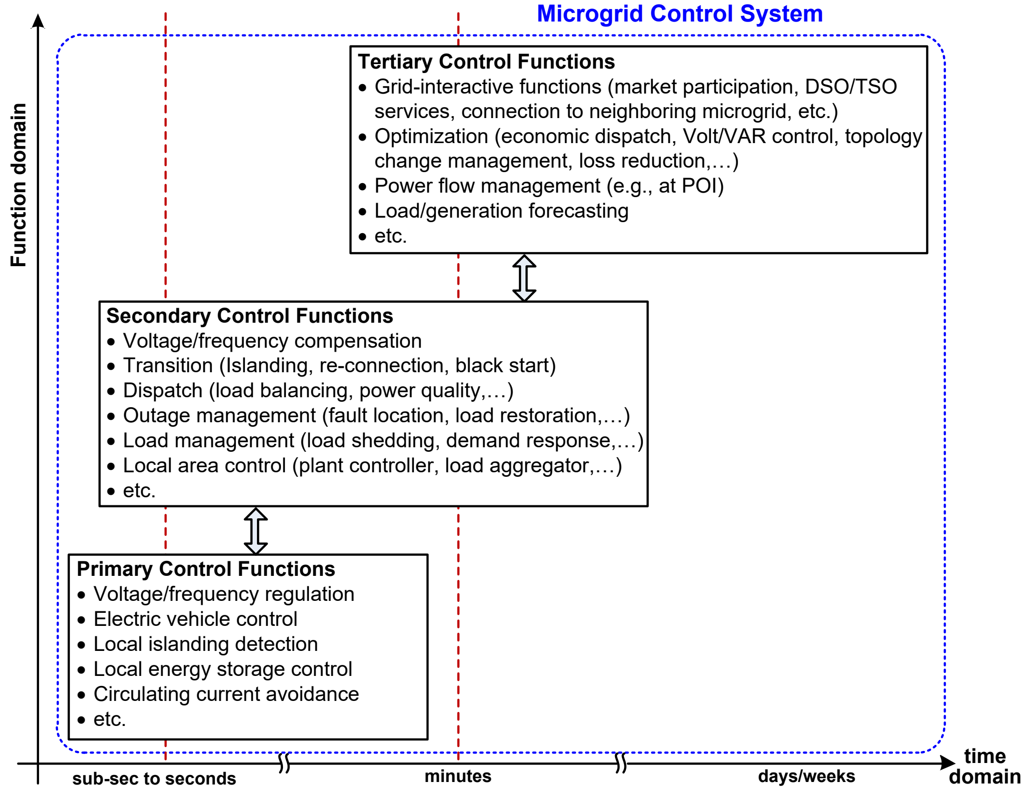


Figure 10: Functional requirements for a microgrid control system (time and action domains)

Advanced control schemes in microgrid systems requires coordinated control of microgrid assets and resources (e.g., DERs, capacitor banks, load tap changers, and voltage regulators). As a result, microgrid operating conditions are constantly changing, leading to the variation of the fault current levels under different conditions. Moreover, the intermittent nature of renewable energy resources as well as periodic load variation will further complicate the protection of microgrid system, particularly in the grid-isolated mode of operation.

On the other hand, the microgrid control system will need to remotely control switches and circuit breakers in order to execute load transfer and/or circuit reconfiguration automatically. Two major benefits of circuit reconfigurations include:

- Supplying customer loads with different paths of possible power flow to enhance system reliability (fast load restoration following the fault location).

- Optimizing microgrid operating condition (loss reduction, minimizing phase imbalance, etc.)

Circuit reconfiguration in a microgrid can be done either manually or automatically and may be done either proactively in anticipation of some developing situation or reactively in response to system events. Regardless, a reconfiguration of the microgrid can potentially affect fault current level and/or direction, especially if the microgrid can operate in a loop or networked mode. Therefore, the protective relay settings/functions of the affected circuits should be assessed under all the possible system configurations/conditions. In other words, it may be necessary to modify protection settings or schemes and/or utilize protective equipment that support reverse fault current direction under the new system condition. With more focus on optimizing the efficiency of microgrid circuits, protection engineers will be increasingly challenged to provide protection concepts that can automatically adapt to the reconfigured state of the circuit [14]. Careful study on the impact of these adaptive controls in real time will be required.

The following are some of the considerations and challenges for the protection system in a microgrid system with advanced control capabilities:

- Change in the maximum loading condition caused by circuit reconfiguration: The total load of the new circuit topology/condition may exceed the overcurrent protection pickup settings.
- Change in short-circuit level caused by circuit reconfiguration: The protection coordination may be disrupted under new circuit topology or operating condition either because available fault current has increased or decreased. In addition, protection zones may need to change with changes in circuit configuration and source connections.
- Change in short-circuit level caused by generator dispatch and operating conditions: The protection coordination may be affected by changes in the microgrid operating condition (e.g. DERs that are online) that alter the available fault current. This is complicated by intermittent renewable generation with constantly changing fault current contributions.
- Reverse power flow caused by potential system looping or networking: Non-directional protective equipment may misoperate if reverse power flow is allowed in the microgrid.
- Increased short-circuit level caused by close-transition switching: Temporary paralleling of the sources can increase fault current level, threatening protection coordination.

2.5 Re-synchronization

When a microgrid with AC PCC connection(s) is operating grid-isolated, a synchronization process may be needed prior to microgrid re-synchronization to the EPS. Synchronization considerations with AC connection at the PCC include:

- The ability of an inverter to handle out-of-phase re-energizations depends on the inverter design. An example of a microgrid that may not require synchronization is a microgrid composed entirely of inverters that can cope with out-of-phase re-energizations. The project design team should consult equipment manufacturers if out-of-phase re-energization protection is not applied. It is typically recommended to apply out-of-phase re-energization protection such as a sync check relay.

- Rotating machinery (motors and conventional generators) is not designed to handle out-of-phase re-energization and should not be subjected to it. An example of a microgrid that would require synchronization is one with a mix of rotating machine-based and inverter-based DER, as well as a microgrid with motor load.

Figure 11 shows how voltage magnitude, frequency, and phase angle may differ. During synchronization, the voltage magnitude and frequency of the isolated microgrid and that of the EPS should be closely matched before paralleling. The actual paralleling of the microgrid and the EPS should occur at a phase angle difference close to or at zero degrees. Significant mismatch of any of these parameters will produce large inrush current to or from the EPS, possibly causing protection mis-operations or damage to equipment. Additional information on microgrid synchronization is available in references [15], [36].

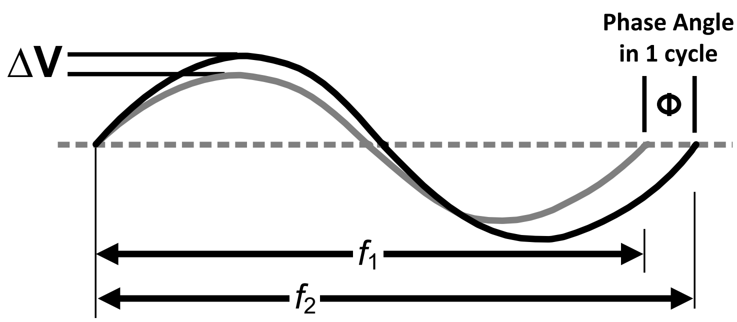


Figure 11: Synchronizing parameters

With an AC PCC between the microgrid and the EPS, two stages of synchronization occur:

- The first is to manipulate the microgrid into a synchronous condition to the EPS by matching frequency and voltage between the microgrid and the EPS
- The second is to affect the proper closing of the PCC breaker(s) at zero degrees phase coincidence using the automatic synchronizing function.

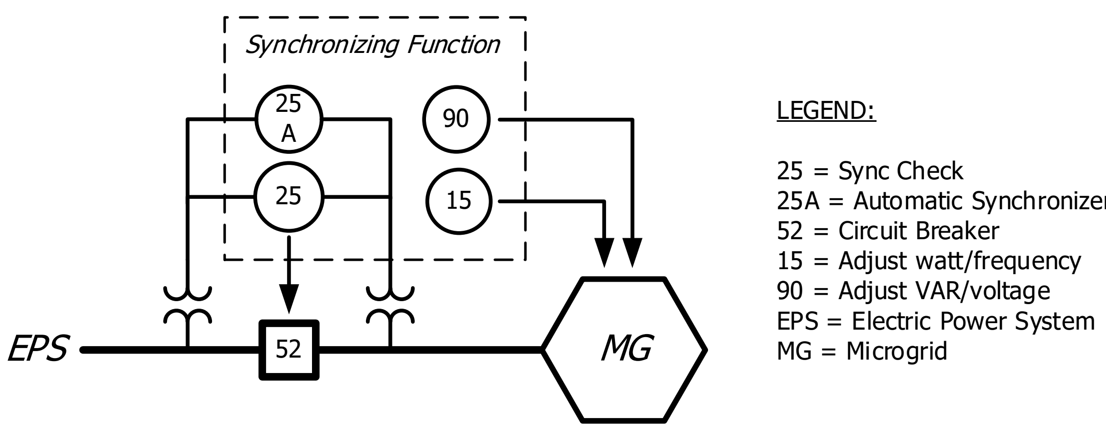


Figure 12: Microgrid with one AC PCC to EPS

In the case of two (or more) PCCs, with the microgrid isolated from the EPS, the first PCC selected to synchronize would effect a breaker closure using an automatic synchronizing function as in Figure 12 above. The second PCC, with the microgrid now synchronized to the EPS through the first selected PCC, would employ a sync check function to close a breaker on a static phase angle difference that is at or close to zero degrees. Figure 13 shows the example of microgrid with two PCCs.

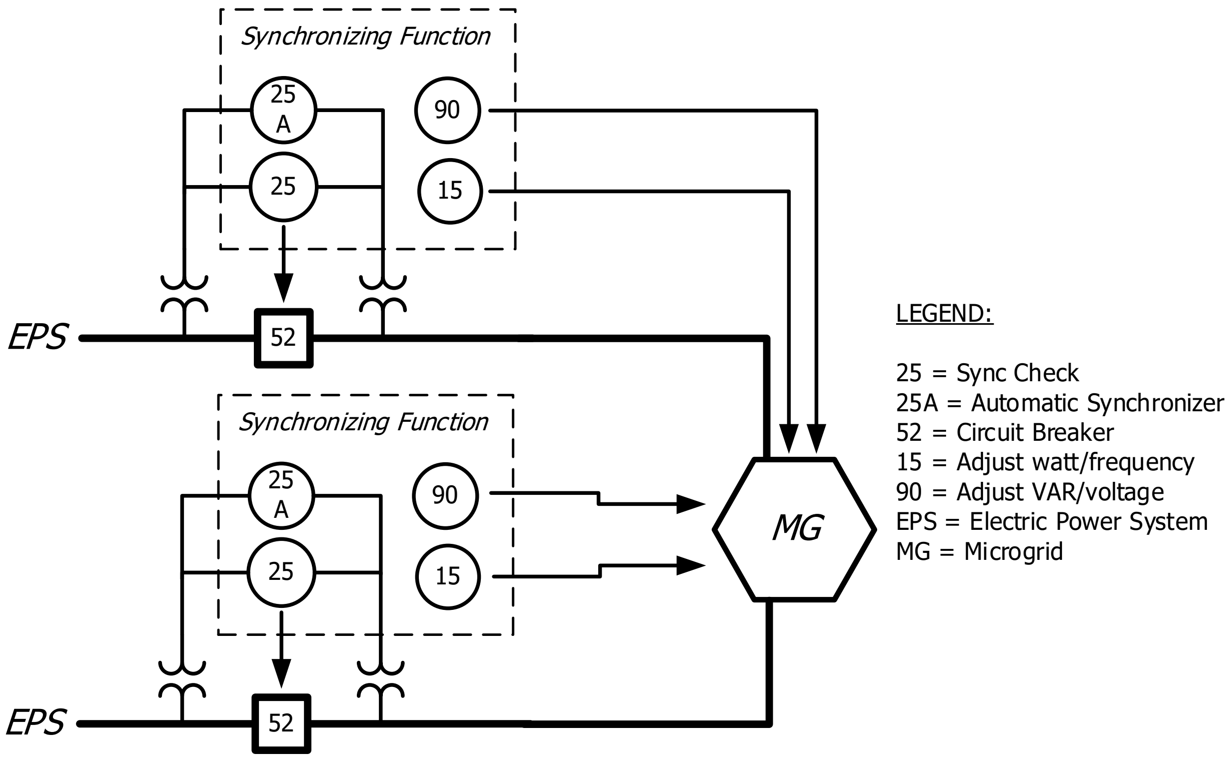


Figure 13: Microgrid with two AC PCCs to EPS

Conventional rotating machinery-based DER in the microgrid typically employ generator controls to allow parallel operation with other energy sources and allow adjustment of reactive and real power output [15].

Inverter-based DER in the microgrid typically employ embedded control systems to allow parallel operation with other energy sources and allow adjustment of reactive and real power output [15].

Figure 14 shows the example of a microgrid with DERs, loads and central microgrid controller. With the microgrid isolated, the microgrid's control system should maintain conditions at or near rated frequency and voltage conditions. This is done by examining each available energy source's capacity, each energy source's output, and the aggregate load. If frequency and/or voltage need adjusting to match those of the EPS for synchronizing, each energy source's real and reactive output are changed to affect the desired outcome and, if necessary, shed load to maintain the desired frequency and voltage. For the energy sources, modes to control output in parallel with other energy sources include isochronous load sharing, combined swing source/baseload, combination isochronous/droop, and droop control [15]. These methods all allow prioritized dispatch of energy sources to supply loads. Typically, the most economical energy sources are prioritized and additional DERs are dispatched to provide contingency reserves.

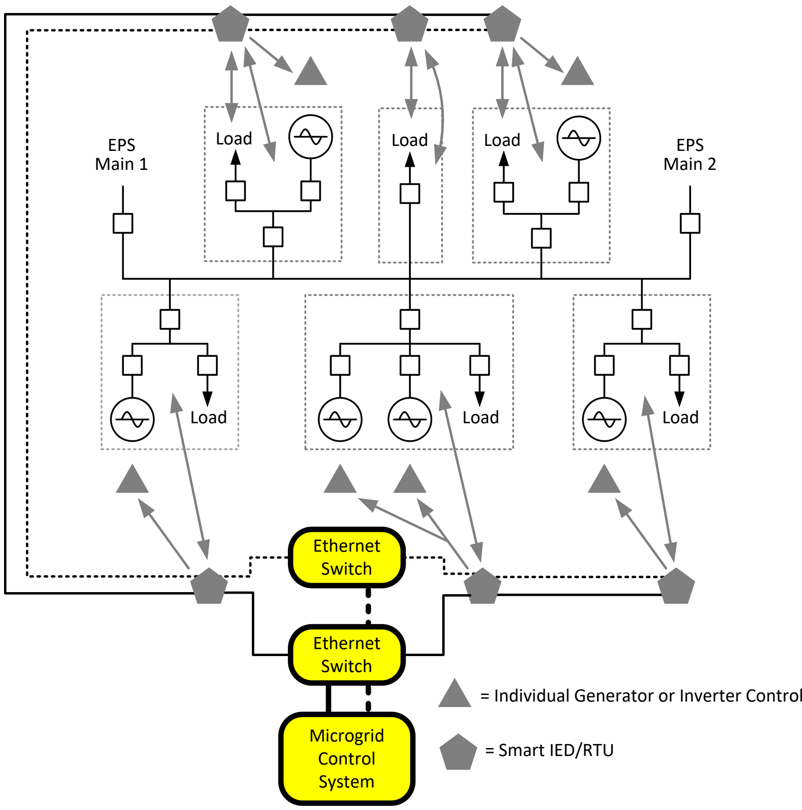


Figure 14: Microgrid with DERs and load with individual controls connected to a central microgrid controller

The individual power sources are adjusted, and load is possibly shed, to collectively adjust the frequency and voltage to fall within acceptable difference limits for synchronizing.

Once the microgrid is synchronized to the EPS, the energy source control modes of the DER typically change to baseload control, where the EPS is the reference for both voltage and the frequency, and output of each energy source is adjusted using economic, power security, or other rationale for dispatch.

3. Microgrid Protection System Design Considerations

Careful selection of protective equipment must be considered to assure that the microgrid can operate in a dependable and secure manner. Protective equipment that may be dependable with the high short-circuit levels of a strong utility source may not provide the same level of dependability when applied in a microgrid environment with varying and bi-directional fault contributions from various source levels due to grid-interconnected or grid-isolated operation [16]. Protective equipment designed to dependably detect faults while islanded may not be secure while grid-interconnected.

3.1.1 System Studies for Microgrid Design

During the conceptual design phase of a microgrid, system impact studies, including short circuit analyses/equipment duty, overcurrent coordination studies, and transient stability studies should be performed to have a thorough understanding of the system's protection requirements for different operating conditions.

These studies need to be performed prior to the completion of designs to avoid protection deficiencies. Additionally, the capabilities of the software tools should be thoroughly evaluated to make sure that the requirements of the studies can be achieved and that results are realistic.

Inverter-interfaced DERs are commonly included in microgrid systems. The inverter-interfaced DERs have different fault characteristics than traditional generation sources and they typically act as voltage dependent current sources, unlike the Thévenin equivalent circuits representing generators, as conventionally used in electric power system analysis software. Inverter-interfaced DERs must be modeled correctly in the software tools during the protection studies to get accurate results from the studies. When appropriate, detailed Electromagnetic Transients Program (EMTP) and/or Alternative Transients Program (ATP) type models can be considered in the simulation studies to accurately represent the source fault characteristics in the time-domain. To test the designed protection scheme under various operating conditions and with different microgrid topologies, hardware-in-the-loop testing combined with relays or virtual protection models can be beneficial.

3.1.2 System Grounding Considerations

System grounding of the microgrid must be thoroughly evaluated to assure safe operation, making certain that protective relaying will function properly and insulation integrity is maintained. Ideally, it would be desirable to have the microgrid system grounding the same whether grid-connected or grid-isolated. For example, consider a microgrid with a high-voltage PCC that is interconnected with a system that is normally operated solidly-grounded. If the microgrid DERs are interconnected through a transformer with a solidly-grounded wye connection on the PCC side and delta connection on the DER side, the microgrid system will be solidly grounded while operating grid-isolated. Alternatively, if each of the microgrid DERs are interconnected through a transformer with a delta winding on the PCC side and there is no other grounding transformer, the microgrid system will not be solidly grounded while operating grid-isolated. To maintain a solidly-grounded microgrid system while operating grid-isolated, transformers with a low-impedance zero-sequence path (e.g. a grounding transformer) may be utilized.

Maintaining an effectively grounded system for a DER unit is necessary so that overvoltage is not excessive during line to ground faults and ground relaying operates as intended. If the DER unit has a step-up transformer that has a low voltage delta winding and high voltage solidly-grounded wye, a low impedance path for ground current can result. Assuring that the step-up transformer is effectively grounded but the zero-sequence impedance is not excessively low may require that a neutral reactor be installed to limit ground current supplied by the DER installation. Alternatively, the main power transformer may be left ungrounded (using either a delta winding or an ungrounded wye) and a smaller grounding bank may be added to the installation to provide a sufficiently low zero-sequence path to limit overvoltage during line to ground faults. The interconnection requirements of the utility should dictate system grounding in addition to primary equipment and protection.

3.1.3 Communication System

A reliable communication system for the microgrid is essential for a variety of functions, including generator dispatch and protection communications. Communication between the utility substation's circuit breaker, the circuit breaker at the PCC, and the DER circuit breakers internal to the microgrid is often valuable; ideally, the communication system would interface with other protective devices of the microgrid as well.

Communication circuits between distribution feeder relays and microgrid protection systems have a minimum of two functions [18]:

1) Transmit a transfer trip signal from the feeder relay or recloser to the microgrid protection systems so the system will know the utility feed is not available. Transmit a signal when the utility feed is restored.
2) Transmit operating status (on or off) from the microgrid protection systems to the feeder relay or recloser or utility command center. Some of the important information is the status of DER systems as well as the status of utility and microgrid protection systems tie points.

Another use of communications is to develop a communication assisted protection system. When utilized for protection applications, the communication must meet availability, reliability, and latency requirements of the protection scheme. Each protective device can communicate with its neighbor(s) during a fault to let other devices know which direction the fault is seen. The other devices can use this information in either a blocking or permissive scheme, so the fault is isolated quickly. This information can also be sent to a central processing device and this device can then determine which devices to trip to isolate the fault.

Communications protocols, media, and infrastructure must be considered to ensure that the system operates at appropriate speeds for the required protection operations. At the same time, the communication path redundancy and the security of the communication system should be taken into consideration. For protection purposes, the communication between the feeder relay and the microgrid protection systems is generally binary information. This means that communication circuits can use any of the commercially available communication technologies, such as power line carrier, spread spectrum radio and two-way pager, as well as available communication media, such as transmission lines, telephone lines, fiber optic cables and air for radio communications. The criteria for choosing the correct medium includes availability, operating speed, maximum latency, reliability, cybersecurity, redundancy and path failover, susceptibility to electromagnetic interference, ownership, maintainability, and cost.

3.1.4 Protective Equipment

The microgrid protection scheme must detect balanced and unbalanced faults in the microgrid, abnormal frequencies, and abnormal voltages. In the grid-interconnected mode, it should also be able to detect faults on the utility side and islanding conditions. Detecting abnormal frequencies or voltages and islanding conditions can be achieved by using conventional methods. However, fault detection and protection coordination in a microgrid is more challenging.

If economically and technically feasible, a protection system utilizing current differential relaying could provide the highest level of reliability. Under grid-isolated conditions with relatively low fault current levels, the current differential scheme would have advantages over permissive overreaching transfer trip (POTT) and directional comparison blocking (DCB) schemes, if these schemes use overcurrent relaying. If current differential relaying is not practical, directional overcurrent relays could possibly accommodate bi-directional fault current on the microgrid. There may be situations where relays that have the capability to switch between setting groups may be advantageous. Three-phase voltage transformers (VTs) or other voltage sensors should be connected to the relays to provide a polarizing source for directional control and over/undervoltage sensing.

The typical application of distribution fuses may not be adequate in a microgrid due to the possibility of low fault currents. To detect faults while grid-isolated additional reclosers or fault interrupters with microprocessor-based relays or controllers may be required. The distribution transformers that step down to utilization voltage are typically protected with high-side fuses, and protection deficiencies that could occur under grid-isolated conditions need to be thoroughly evaluated.

On the utilization voltage systems, fault current levels may be too low for reliable operation of typical overcurrent devices. Additional over/undervoltage sensing may be required that could provide a transfer trip signal to the microgrid grid-isolating device. Additional protection elements, including elements based on travelling wave technology, are also under investigation [34].

4. Protection Scheme Solutions

This clause introduces several types of protection schemes commonly employed in microgrids. Due to the nature of microgrids and their unique challenges, the conventional protection and control schemes may not always meet the requirements. As a result, some customized logic or schemes may be necessary. The major challenges for detecting a fault in a microgrid system are fault current level and its direction. In the grid-interconnected mode, when a fault occurs in the microgrid, there would be ample fault current for the conventional protection to detect the fault; however, when a microgrid is in the grid-isolated mode, due to limited generation capacity and possible inverter current limitation, the fault current level could be very close to load level. Additionally, due to loss of the area EPS, the load and fault directions could be different from that in the grid-interconnected mode. To cope with these issues, some customized logic or schemes have been put into practice or consideration, and many of the schemes include some requirement for low-speed (e.g. adaptive protection) or high-speed communication (e.g. differential protection). In the following clause, some of these schemes are described in detail.

4.1 Negative and Zero Sequence Overcurrent

As described before, due to the fluctuation in the maximum fault current level, the conventional phase overcurrent may not be sensitive enough in the grid-isolated mode. If the system is close to being at a good degree of balance, the negative- and zero-sequence currents under normal conditions should be small compared to the positive-sequence current regardless of the grid-interconnected or grid-isolated mode of operation. Therefore the negative- and zero-sequence currents may be used to detect when an unbalanced fault occurs, if the sources can generate a significant amount of negative- and zero-sequence currents. The pickup thresholds for the negative- and zero-sequence overcurrent protection functions can be based on their absolute magnitude or relative change over the positive-sequence current. Unbalanced fault detection could be more effectively achieved if negative-sequence overcurrent protection is relative change based or combined with the absolute magnitude based element. If fault currents are limited by inverter-based sources, there may not be enough negative-sequence and zero-sequence current to be used for protection purposes. Care should be exercised in setting sensitive negative- and zero-sequence overcurrent elements if single-pole switching is employed on the system. Sequence-based protection schemes can be difficult to coordinate and may require additional protective functions for symmetrical faults.

4.2 Under-Voltage Protection Schemes

A fault within an islanded microgrid can result in a network-wide voltage drop, which could be utilized to detect faults. The main advantage of the undervoltage-based methods (IEEE device 27) is that their performance is independent of the value and/or direction of the fault current. However, since the network voltage can be affected by various transient incidents other than faults, this type of protection would be vulnerable to system transients such as load switching and/or energization of dynamic loads. More importantly, under-voltage-based methods cannot provide adequate selectivity.

4.3 Voltage-Restrained and/or Voltage-Controlled Protection Schemes

Voltage-restrained (IEEE device 51VR) and voltage-controlled (IEEE device 51VC) overcurrent protection allows improved sensitivity of overcurrent relaying by considering the applied input voltage. In a voltage-controlled relay, a sensitive low-pickup time-inverse overcurrent element is controlled by a voltage relay, i.e., the voltage relay prevents the overcurrent relay from operating at acceptable normal voltages. In a voltage-restrained relay, however, the characteristic of the overcurrent relay is adjusted based on the input voltage [1].

Voltage-restrained and voltage-controlled overcurrent relays can provide better fault detection than unrestrained overcurrent relays. This is especially the case where the fault current may vary and drop below the normal rated load under different fault current source conditions. Therefore, the use of these relays has been suggested for the protection of microgrids, mainly because they can have low fault current settings. The disadvantage is that the coordination of these relays for microgrid applications is still problematic as they are supposed to operate for a wide fault current range. Furthermore, achieving selectivity in microgrids may be challenging because faults can cause depressed voltage throughout the microgrid, and low fault currents can cause little voltage difference between relays.

4.4 Adaptive Relay Settings

The strict definition of an adaptive protection system (APS) is still a matter of debate, with no general agreement. One general definition is a real-time, online activity that modifies the preferred protective response to a change in system conditions, business rules, or forecasted reconfiguration in a timely manner by means of externally generated signals or control actions [17]. The "preferred protection response" could potentially include a combination of protection setting group, protection setting values (e.g. pick-up or time delay settings), appropriate protective functions and control logic, and correct switching sequences.

4.4.1 Implementation Approaches

The "preferred protective response" in an adaptive protection system can be calculated by two alternative approaches: either pre-calculated trusted settings, or near-real-time setting calculations. These two approaches can be used for implementing adaptive protection systems and are briefly described as follows.

4.4.1.1 Pre-calculated Trusted Settings Approach

Different microgrid operating conditions typically cannot adequately be protected with a single group of settings. In a pre-calculated trusted settings implementation, operational departments can plan for different system operating conditions, knowing that the protection engineer can prepare the necessary optimized and pre-tested groups of settings in advance for the system operating condition. Switching between protection setting groups can be done by manual command, issued either locally or remotely, or by automatic command upon detection of the changed network operating condition. Automatic detection of changed operating conditions can be achieved by monitoring the status of network circuit breakers or switches, or by measurement threshold of selected function(s), variable(s), and/or value(s) being exceeded.

The pre-calculated trusted settings design of an adaptive protection system with pre-calculated settings consists of four major parts:

- Offline Analysis: All the meaningful configurations and/or operating conditions of the microgrid are identified and studied to determine protection settings for each system configuration/condition.
- Event Table Creation: All possible system topologies/configurations along with their corresponding protection settings are arranged in an event (lookup) table.
- Online Matching: The system topology is continuously monitored through monitoring the state of switching devices or measuring certain parameters. Once a change in the system operating condition is planned or detected, proper relay settings are selected from the event table based on the current system topology/condition. If the detected topology is similar for protection purposes, the relay settings should remain unmodified; otherwise, the relay switches to the new settings.
- Loading Relay Settings: Selected relay settings, if required to change, are transmitted to corresponding relays through a reliable communication medium.

A significant challenge when pre-calculated trusted settings are utilized for adaptive protection system is that the event table needs to be updated when the microgrid undergoes a change (e.g., when a DER is added to the microgrid system). Moreover, since it is necessary to conduct fault and protection studies for all the permitted topologies/conditions, the offline analysis may be an involved task.

4.4.1.2 Near-real-time Setting Calculations Approach

Another approach for the implementation of an adaptive protection system is to calculate protection settings in a near-real-time basis upon a change in the system topology/condition including DER statuses. Like the offline design, the real-time approach can be implemented in either a centralized or distributed fashion with processing of continuous real-time measurement and monitoring of digital and analog signals originated from protection intelligent electronic devices (IEDs) and/or other system components. Therefore, in a real-time adaptive protection scheme, the new system topology/condition is processed, the protection system coordination is analyzed, and protection settings are adapted as required.

It should be noted that protection coordination may not be achieved for all possible system topologies or configurations. Therefore, it may be necessary to take some other corrective actions (e.g., system switching) or to tolerate protection mis-coordination, as allowable to local requirements and the system owner and operator.

Some significant challenges associated with near-real-time settings calculations are system modeling and protection testing. To ensure that appropriate settings are calculated through various system configurations, the power system must be adequately and accurately modeled. Additionally, the modeling tools and techniques utilized must accommodate rapid re-calculation of necessary analyses and automated assessment of results. System protection testing can also be challenging, as there are many possible protection settings, depending on the system topology.

4.4.2 Challenges with Adaptive Relay Settings

One significant issue for the adaptive relay settings approach is determining when to change the settings based on changing operating conditions. For many protective relays, the protection may become inoperative or enter an indeterminate state momentarily while settings are being changed. Transitions where the system is de-energized or while a breaker is already in the open position (i.e., an open transition) are an opportune time to change relay settings. If system configuration is changed while energized and operating, care must be taken to ensure that the system is adequately protected throughout the protection system reconfiguration. If settings are changed after the system is reconfigured (e.g. transitions from grid-interconnected to grid-isolated operation), there may be some time where the system is not adequately protected during the reconfiguration.

When settings are adapted to reflect system reconfiguration, there is a possibility that the present power system configuration does not match what the protection system configuration was designed for. This can occur, for example, if the communication system or device changing protection settings is unavailable and the operator is manually reconfiguring the system. Care must be taken in protection design and in system operation to avoid these scenarios, and to ensure that the system is protected.

4.5 Transfer Trip Signals and Operating Status

Direct transfer trip protection schemes use communication to provide trip signal(s) from one protection device/system to other protection devices and/or the microgrid protection system. This is commonly utilized with distributed generation to prevent unintentional islanding, for breaker failures, and for bus or transformer faults where multiple sources can contribute to the fault. In microgrids, a transfer trip signal may be sent from devices such as the feeder breaker or feeder recloser to the microgrid protection systems, to ensure the microgrid does not form an unintentional island or continue contributions to faults. A diagram representing example transfer trip implementations is shown in Figure 15. In addition, operating status signals can be sent from the microgrid protection systems to the feeder IED. This information may be used by modern digital relays to adapt feeder relay protection settings, as a permissive signal for closing the feeder breaker, as a permissive signal for automatic reclosing, or for annunciation of the microgrid protection system's status for system operators. The communication of the status of the system to various protective devices may also allow for additional adaptive schemes (e.g. to adapt protection settings between the grid-interconnected and grid-isolated modes of operation).

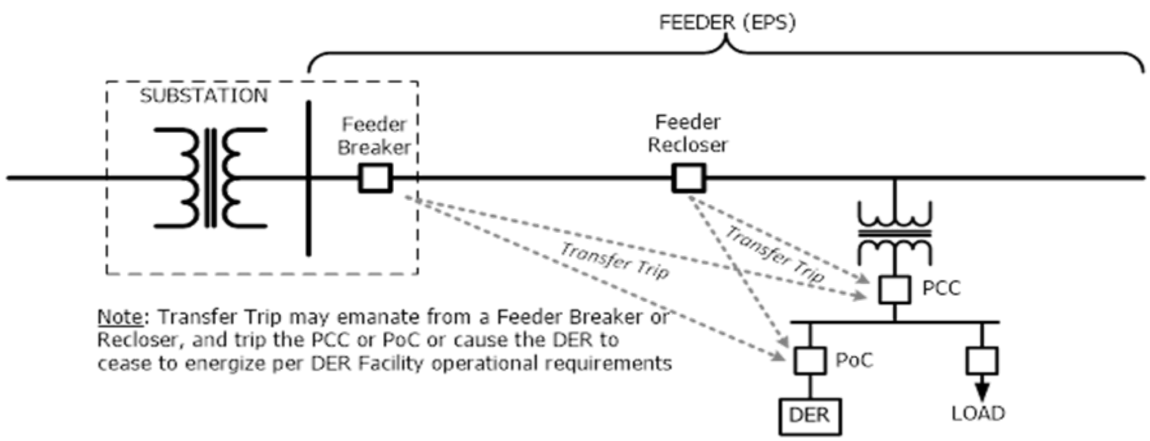


Figure 15. Example of direct transfer trip to a microgrid or DER facility [27]

4.6 Directional Interlocking Scheme

The zone interlocking scheme has been used in radial power distribution systems for many decades and has proven to be a cost effective yet efficient solution to detect and isolate a fault. The interlocking can be done through control wiring or through messaging, such as Generic Object-Oriented Substation Events (GOOSE) messaging in an IEC 61850 system.

Take an example depicted in Figure 16. M1 is the main breaker that connects the microgrid to the area EPS, S1 to S6 are breakers inside the microgrid, and F1 to F4 are the fault locations. The up/down arrows next to breakers indicate the fault current directions. Note that the fault current direction may change depending on the fault location, and their relationship is indicated with colored arrows. For example, fault F1 located downstream of breaker S1 is shown with red color. As such, red colored arrows next to each breaker shows the direction of current through the respective breaker for fault F1.

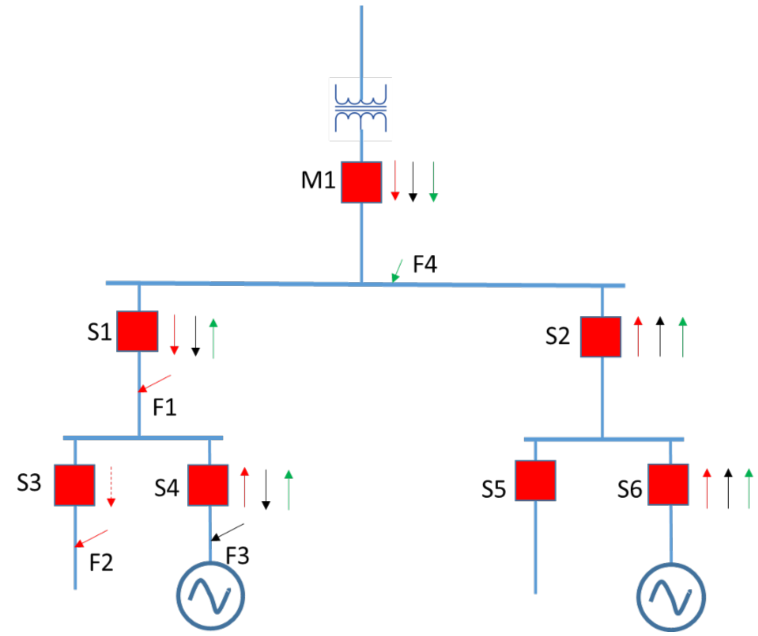


Figure 16: Example directional interlocking scheme

Define BreakerName_P (e.g. S1_P) and BreakerName_T (e.g. S1_T) respectively as the protection pickup and trip signals of an overcurrent element which can be phase, negative-sequence, or zero-sequence overcurrent function. BreakerName_Pb (e.g. S1_Pb) is the interlocking signal when BreakerName_P picks up, and ↓ or ↑ indicates the pickup direction. Assume that there should be two independent directional functions for each direction for a breaker through which current can flow in both directions. In this example, only breakers S3 and S5 have one direction.

Assume the microgrid is operating in the grid-interconnected mode. For all the fault locations other than F4, regardless of M1 position, S1_P↓ should see the faults. But if either S3_P↓ or S4_P↓ picks up, S3_P↓ or S4_P↓ will clear the fault and S1_P functions as a backup. When a device detects a fault, it communicates to the devices in the opposite direction from the fault and the interlocking logic blocks the upstream device. Therefore, the interlocking logic for S1 will be as follows with it blocked for faults downstream of S3 or S4:

S1_T↓ = (S1_P↓ AND (NOT(S3_Pb↓ OR S4_Pb↓))),
S1_T↑ = (S1_P↑ AND (NOT(M1_Pb↑ OR S2_Pb↓))), and
S1_T = (S1_T↓ OR S1_T↑).

S3 does not need to be blocked by other protective devices.

S4_T↑ = (S4_P↑ AND (NOT(S1_Pb↑ OR S3_Pb↓))),
S4_T↓ = S4_P↓, and
S4_T = (S4_T↓ OR S4_T↑).

M1 can be a part of interlocking if desired,

M1_T↓ = (M1_P↓ AND (NOT(S1_Pb↓ OR S2_Pb↓))),
M1_T↑ = (M1_P↑), and

M1_T = (M1_T↓ OR M1_T↑).

Today the common practice is that the M1 will open if there is a fault in the microgrid. If M1 picks up a fault, it opens the main breaker, and the microgrid then clears the fault and reconnects. In this case, M1_T↓ = (M1_P↓ AND (S1_Pb↓ OR S2_Pb↓)).

Similarly, the interlocking logic for S2_T, S5_T and S6_T can be constructed.

In modern relays with GOOSE messaging capability, protection pickup signals can be easily communicated among the locations involved.

Keep in mind that the protection pickup threshold in each direction at each location must be carefully determined in fixed or adaptive fashion so that the intended protection element will be effective in either grid-interconnected or grid-isolated mode.

4.7 Communication-Based Current Differential or Directional Blocking Protection

If the communication infrastructure is well planned and appropriate high-speed communication channels are available in a microgrid network, the communication-based line differential or directional blocking protection can be applied as the primary protection. These protection principles are immune to external load condition and direction. Therefore, they will be effective regardless of any operation mode, grid-interconnected or grid-isolated. Usually the line distance between buses in a microgrid is relatively short, so the coordination with overcurrent protection would be challenging. As a result, the communication based current differential or directional blocking would be a good choice for their primary protection. The current differential protection would be more sensitive than the directional blocking because it acts on the differential current that is immune to external load, but the directional blocking can be set to a very sensitive level because it acts on phase relation between polarizing and operating signals if both quantities exceed their minimum pickup levels. In particular for unbalanced faults, if the negative or zero-sequence quantities are not limited by the sources, the directional element can be based on negative-sequence quantities, which are generally insensitive to load. Note that tapped loads connected to a line can challenge current differential protection of that line, especially during transformer magnetizing inrush scenarios.

The directional interlocking scheme can also be used for constructing the backup protection in a closed loop system. Take an example of S2 and S4 in Figure 17,

S2_T↓ = (S2_P↓ AND (NOT(S8_Pb↓ OR S9_Pb↓ OR S10_Pb↓)))
S4_T↑ = (S4_P↑ AND (NOT(M1_Pb↑ OR S1_Pb↓)))
S2_T = (S2_diffT OR S2_T↓) and
S4_T = (S4_diffT OR S4_T↑).

In the above logic equations, S2_diffT & S4_diffT are trip signals from bus differential scheme associated with breakers S2 and S4.

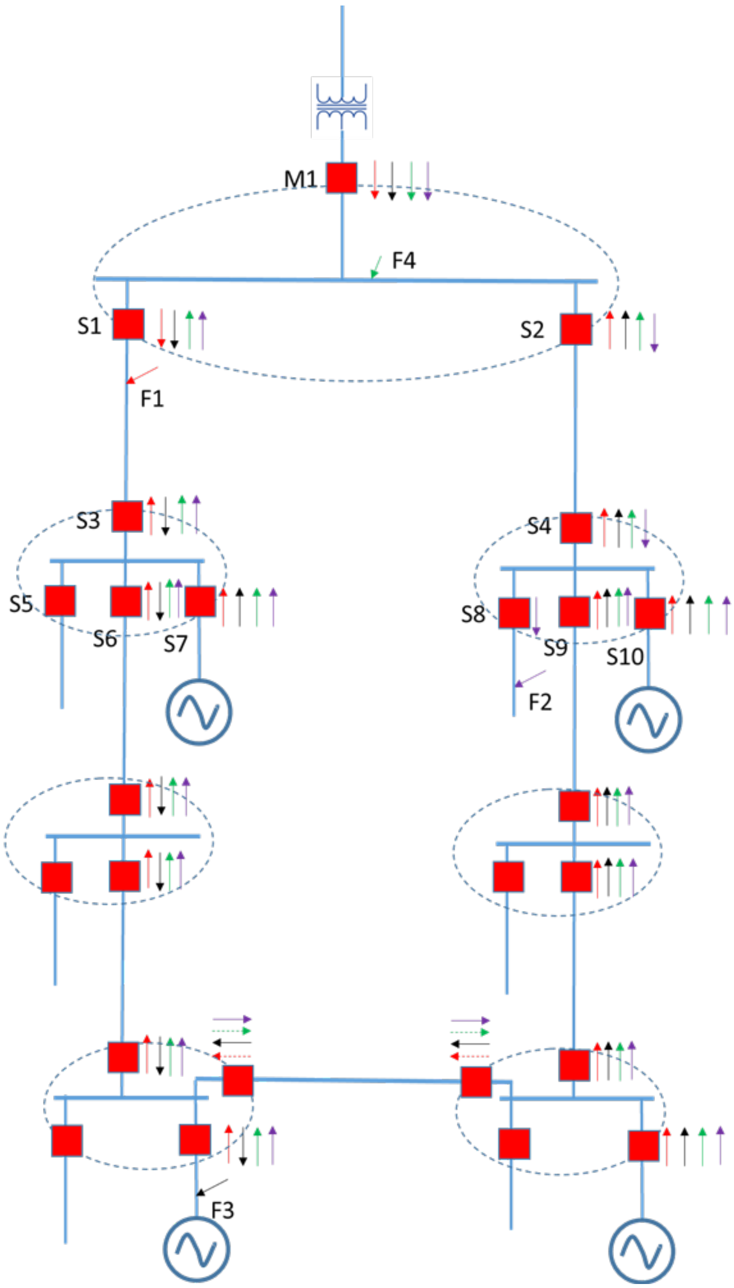


Figure 17: Example of protection scheme in closed loop system

4.8 Bus Differential Protection

While the zone interlocking scheme may be used as a simple and cost-effective solution for a bus fault, more sensitive dedicated bus differential protection can be used, which can be a high impedance or low impedance based differential scheme. If current transformers (CTs) involved in a bus zone (depicted as a dotted ellipse in Figure 17) have the same CT ratio, either high or low impedance bus differential scheme can be used. Of course, a high impedance differential relay is needed for the high impedance-based scheme and a set of CTs at each terminal must be dedicated to the high impedance bus differential scheme. If CTs involved in a bus zone have different CT ratios, the low impedance bus differential scheme may be more convenient since most modern digital relays can scale current magnitude internally. More detail on bus protection can be found in IEEE Std C37.234 [28].

4.9 Centralized Fault Detection System

When a fault occurs in a system, the protection and control devices at multiple locations near the fault would sense the fault. A centralized fault detection system that uses the fault information from multiple sensing devices located throughout the power system may allow for more accurate determination of the fault location or section, so the fault can be quickly isolated, and outage areas can be minimized. Furthermore, the restoration may be done quicker using data from IEDs at different locations along with Faulted Circuit Indicator data from many locations.

After the fault, if the microgrid is in the grid-isolated operation mode, loads need to be rebalanced and load currents in the grid may be redistributed. When the microgrid-wide information is collected to a central location and is used for isolation and restoration, the distributed resources may better be utilized and overall power delivering reliability may be improved. The purpose is to quickly and accurately detect a fault, reduce power outage area, reduce the outage duration, and restore power as quickly as possible. Since all necessary information such as system topology, breaker status, power generation, load distribution, real time voltage, and real time current is available at a central controller, it makes sense to integrate fault detection, isolation and restoration into the same package to optimize the entire process. As an example, the software may run on a central computer to perform fault detection and isolation (e.g. after local protection has operated to clear a fault, the central system can detect the protection operation and isolate the faulted components). The central computer may also perform system restoration functions. First, the communication network must be set up so that the central computer is able to collect the information from all protective relays or other IEDs in the microgrid and to issue commands to all relays or IEDs that control circuit breakers. Then, the user needs to configure the protection system by building up the single line diagram with breakers according to their grid topology so the software will know the grid connection and load distribution.

Under normal condition, the software will monitor generation and load conditions. Depending on the communication infrastructure and processor speeds, there are two main ways to implement centralized protection schemes. In the first method, when a fault occurs, the fault is detected and cleared by the relays close to the fault and then the relays report the breaker status. The backup protection can also be built up in the software running in the central computer. Based on all the information available, the central computer can make optimal decisions to isolate the fault and restore the system as quickly as possible. In the second method, the software at the central computer receives real-time measurements directly from remote IEDs and uses the information to determine whether a fault has occurred and its location. The central computer then communicates trip signals to the appropriate relays and IEDs. An example of a centralized protection scheme is presented in Figure 18. In this figure, red boxes denote closed circuit breakers, and green boxes denote open circuit breakers.

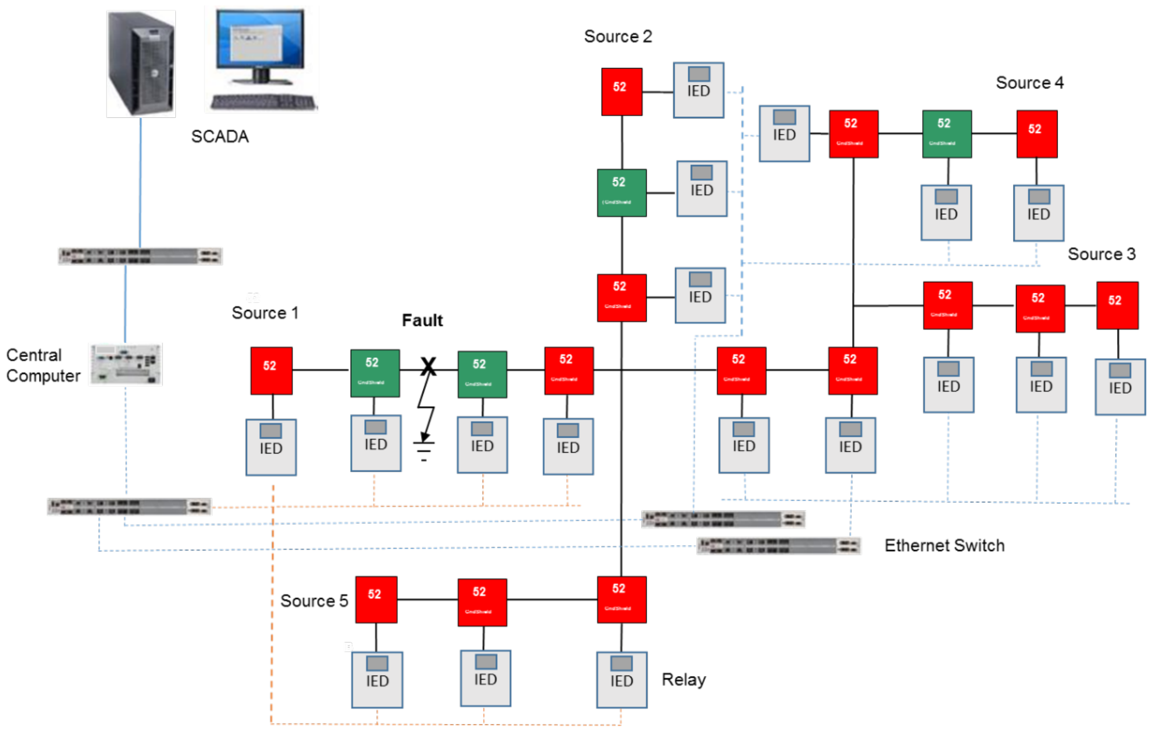


Figure 18: Network and electrical diagram of example microgrid

4.10 Examples of a Real Word Microgrid Systems

Examples of real-world microgrid systems are described in Appendices A, B, and C. These summaries explain the microgrids deployed. Business case information, operating modes, and protection considerations are also included.

5. Conclusion

Integration of microgrids in the power system presents an opportunity to improve power system reliability and resilience. Microgrids present unique challenges for power system protection. This report describes some of the microgrid protection challenges, such as variable fault current levels, bidirectional fault current flow, ability to isolate and resynchronize to the grid, and adapting to topology and generation changes from the microgrid controller. Because of these challenges, microgrid protection system design has unique considerations for protection studies, protection schemes used, communication requirements, and the selection of protective equipment. Finally, this report discusses some microgrid protection solutions that adapt to changing configurations and use communication to assist the protection system. New technologies and protection challenges will require additional research and development of protection standards, schemes, and products.

APPENDIX A Microgrid Example 1

This appendix describes a microgrid system deployed by a Canadian utility to enhance supply reliability during sustained power outages to a remote community and to defer distribution substation upgrades by reducing the overall station demand during on-peak hours.

A.1 Background

In July 2013, a Canadian utility installed a 1 MW, 6.5 MWh battery storage system to enhance supply reliability to a small remote community and allow the community with energy storage to operate as a microgrid during sustained feeder outages. The electricity supply for the remote community is normally provided by a single 25 kV distribution feeder which is about 56 km (35 miles) long. Figure A.1 shows the geographical layout of this feeder connecting the utility substation to the community. The feeder is prone to frequent power outages of significant duration. It passes through challenging terrain and is subject to severe environmental conditions (e.g. falling trees). In addition, the feeder travels adjacent to the railway line, requiring coordination with train schedules for all line repairs. The average outage time for the community was approximately eight hours per outage with multiple outages every year prior to the installation of the microgrid system. As an example, in 2013, the community experienced a 49.5- hour power outage as repair crews had to overcome access and repair challenges to restore service. In the first year after the storage system installation, about 83 hours of power outage time to the community was avoided.

Besides enhancing reliability, the microgrid system curtailed overall substation demand during on-peak hours, thereby deferring expensive station upgrades.

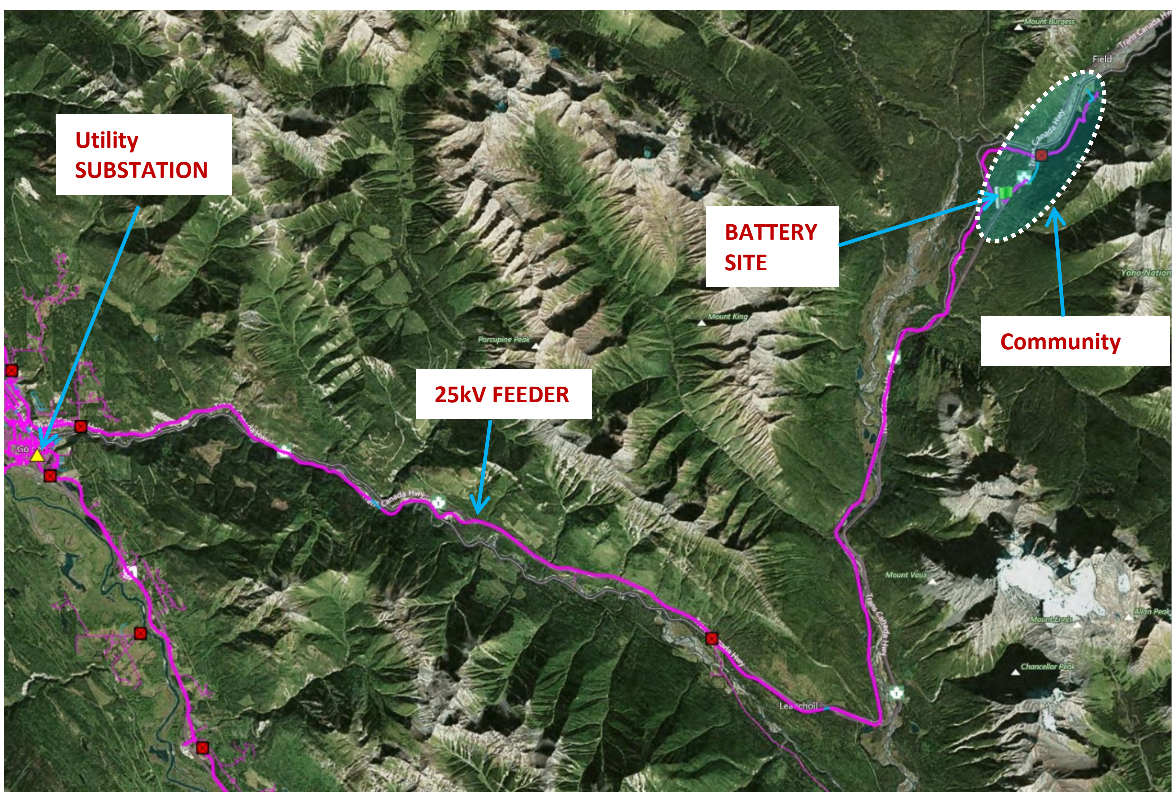


Figure A.1: The 25 kV feeder geographical layout

A.2 Storage System and Connection

The storage system operates in two modes: grid-interconnected and microgrid (grid-isolated). It provides full four-quadrant power operation i.e. it can consume or supply both active power (watts) and reactive power (vars) within the power and energy capabilities of the system. The storage is comprised of 1 MW battery banks which operate between 485 V DC and 780 V DC and connects to a 480 V AC system through a 1.25 MVA inverter and associated control. This is referred to as a Smart Storage Management System (SMS). The SMS then connects to the distribution feeder via a delta/wye-grounded transformer whose wye-grounded winding is on the 25 kV feeder side to maintain effective grounding of the 25 kV system when operating in the microgrid grid-isolated operational mode. Figure A.2 shows the distribution feeder one-line diagram and its connection to the storage system.

A fault sensing and interrupter device with intelligent control, referred to as IR, is physically located where the storage system connects to the feeder and is electrically connected on the station side of the feeder. The IR and the SMS have a 900 MHz radio link providing peer-to-peer communication between them to exchange tele-protection and control signals.

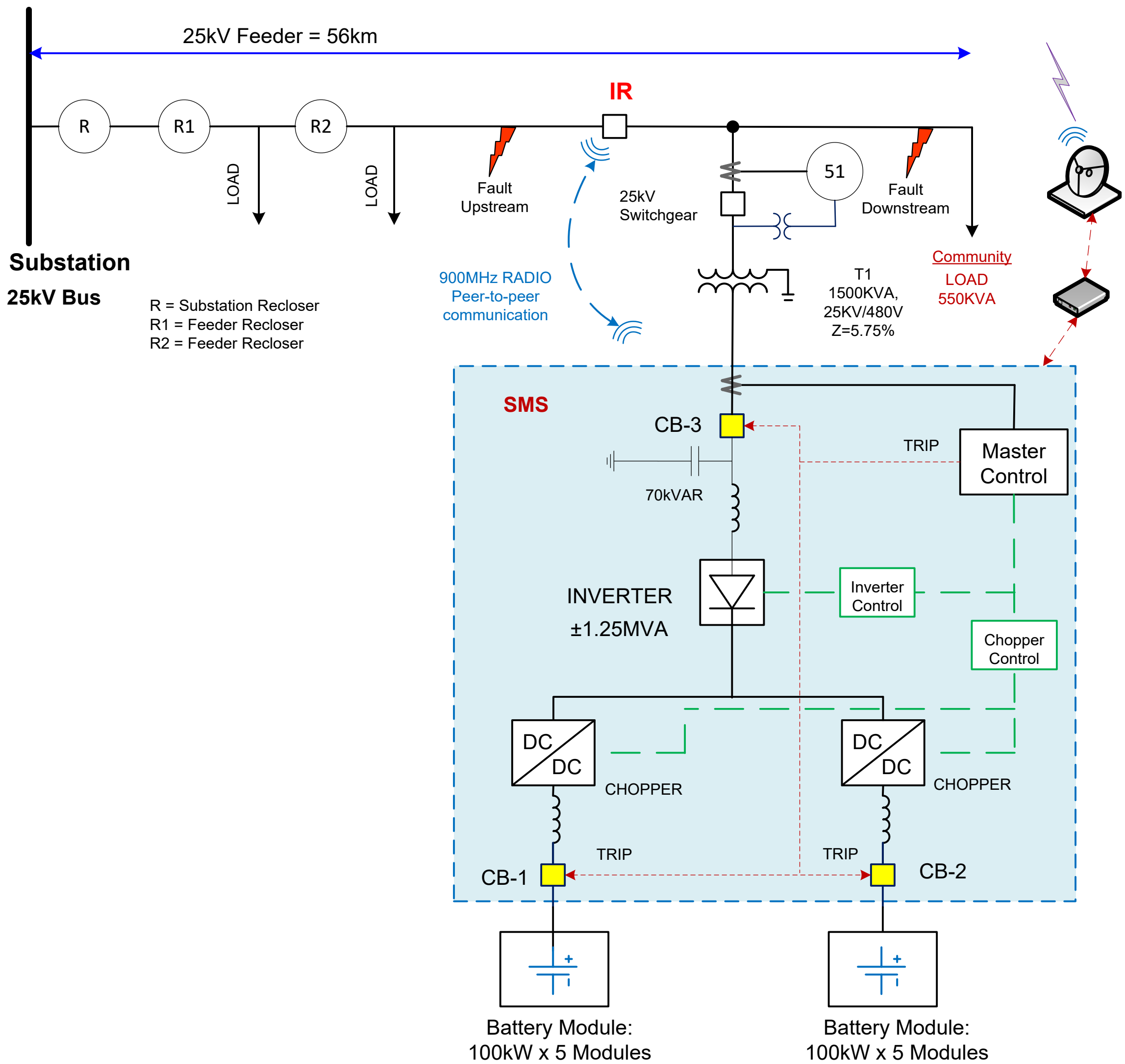


Figure A.2: The 25 kV feeder electrical one-line diagram

A.3 Operational Modes

The storage system operates in two modes: grid-interconnected or grid-isolated (islanded).

Grid-Interconnected Mode:

The normal operation is grid-interconnected mode where the storage system operates in parallel with the main 25 kV feeder. Under this configuration, the community load is largely supplied from the utility substation. The SMS operates as current source to reduce substation load (peak shaving) or may be charging the batteries after a discharge event. In this mode, anti-islanding, comprised of voltage and frequency protection functions, as per IEEE Std 1547-2003, is provided within the SMS to trip the inverter system off-line to prevent it from back-feeding into distribution system faults. The feeder protection, in the substation or in the reclosers along the feeder, trips in time-overcurrent coordinated manner for the feeder faults. Anti-islanding protection also disconnects the storage system to allow for successful auto-reclose attempts by the feeder protection. On occurrence of a permanent fault, auto-reclose attempts fail, and when the fault happens to be downstream of the IR intelligent fault interrupter (i.e. on the small feeder section between IR and the community identified by the directional overcurrent condition in IR), no transition of the load to the battery storage system will take place. For a fault on the upstream side of the IR (the majority of faults due to the length of the exposed line), the fault interrupter will isolate and allow operation in grid-isolated mode.

Grid-Isolated Mode:

Automatic open-system transition of the storage system to the grid-isolated or microgrid operational mode with community load begins only for the permanent faults upstream of IR. Subsequent to the disconnection of community supply from the grid after a permanent fault, load transfer to the storage system is initiated by the IR control when loss of voltage time exceeds the configured value (30 seconds) to confirm that the upstream fault is permanent. The IR opens to isolate from the faulted portion of the feeder. After this, it begins restoration procedures by sending a signal to the SMS to operate in the voltage source mode. Following identification of the microgrid operational mode, the SMS black starts and changes the control mode to "Load Following" to regulate voltage and frequency of the microgrid area. The SMS also has the capability of cold-load pickup (withstand inrush current) and fast voltage/frequency stabilization to maintain the power quality of the load within permissible range as per utility requirements. The maximum load of the grid-isolated community area is estimated to be approximately 550 kVA. However, the storage and SMS system are designed for output up to 1 MW of real power (up to 1.25 MVA apparent power) at a regulated voltage and frequency to supply the load within the island. The energy storage rating of the DC system is 6.5 MWh.

Once the permanent fault is cleared and repairs are made, the system operator restores the feeder from the station. The IR senses return of the utility voltage and after a prescribed time delay begins return to the normal source by sending a signal to the battery to trip off. Then, IR closes and the load at the community is restored to the normal utility feeder.

A.4 Storage System and Microgrid Protection

The SMS inverter has built-in protection functions operating on inverter output current. It includes a fast protection at 480 V having 3008 A (2 per unit) pick-up and inverse-time thermal overcurrent protection having a 1.2 per unit pickup based on the root mean square (RMS) phase current. Upstream of the SMS on the 25 kV side of the interconnection transformer, an inverse-time overcurrent relay (IEEE device 51 in Figure A.2.) provides coordinated protection with the entrance fuses of customers connected on the distribution feeder. In the grid-isolated or voltage-source converter mode, the SMS inverter fast overcurrent protection can over-trip before large customer fuses (25T A and 15T A) respond to some of their in-zone faults. This miscoordination was accepted.

A.5 SMS Negative Sequence Fault Current Characteristic

Distribution loads are not always fully balanced. As discussed in Clause 3.1, inverter-based systems are often not capable of supplying negative-sequence currents drawn by the unbalanced loads and faults. In a system containing a mix of inverter-based and conventional generators, negative-sequence current is largely supplied by the conventional sources. The SMS system had a technical requirement to be able to operate as a standalone grid-isolated system with the distribution loads. Thus, it was specifically built to be able to supply negative-sequence current when operating as voltage source. However, the SMS system negative-sequence current injection to unbalanced faults is significantly lower than the conventional generators as illustrated by analysis of waveforms captured during a double line-to-ground fault [19].

On July 27, 2017, the distribution feeder experienced a permanent phase A-to-C-to-ground fault downstream of the IR intelligent fault interrupter. Distribution feeder protection and SMS anti-islanding protection correctly de-energized the feeder. Since it was a permanent downstream fault, the IR correctly restrained from automatic transition to the microgrid operation as designed. The system operator then unsuccessfully attempted to manually restore the feeder and community load. One of the attempts included restoration through SMS system with the IR open. Figure A.3 shows waveforms captured by the inverse-time overcurrent relay (IEEE device 51) when the SMS switched onto a close-in 25 kV A-to-C-ground fault. The bottom plot shows that the SMS, a converter-based system, had negligible negative-sequence current contribution to the fault because of its higher effective negative-sequence impedance relative to zero-sequence reactance of the 25 kV delta/wye-grounded transformer. Unlike conventional systems, it is thus obvious that the negative-sequence current relay would not provide reliable protection if it were used in this microgrid installation.

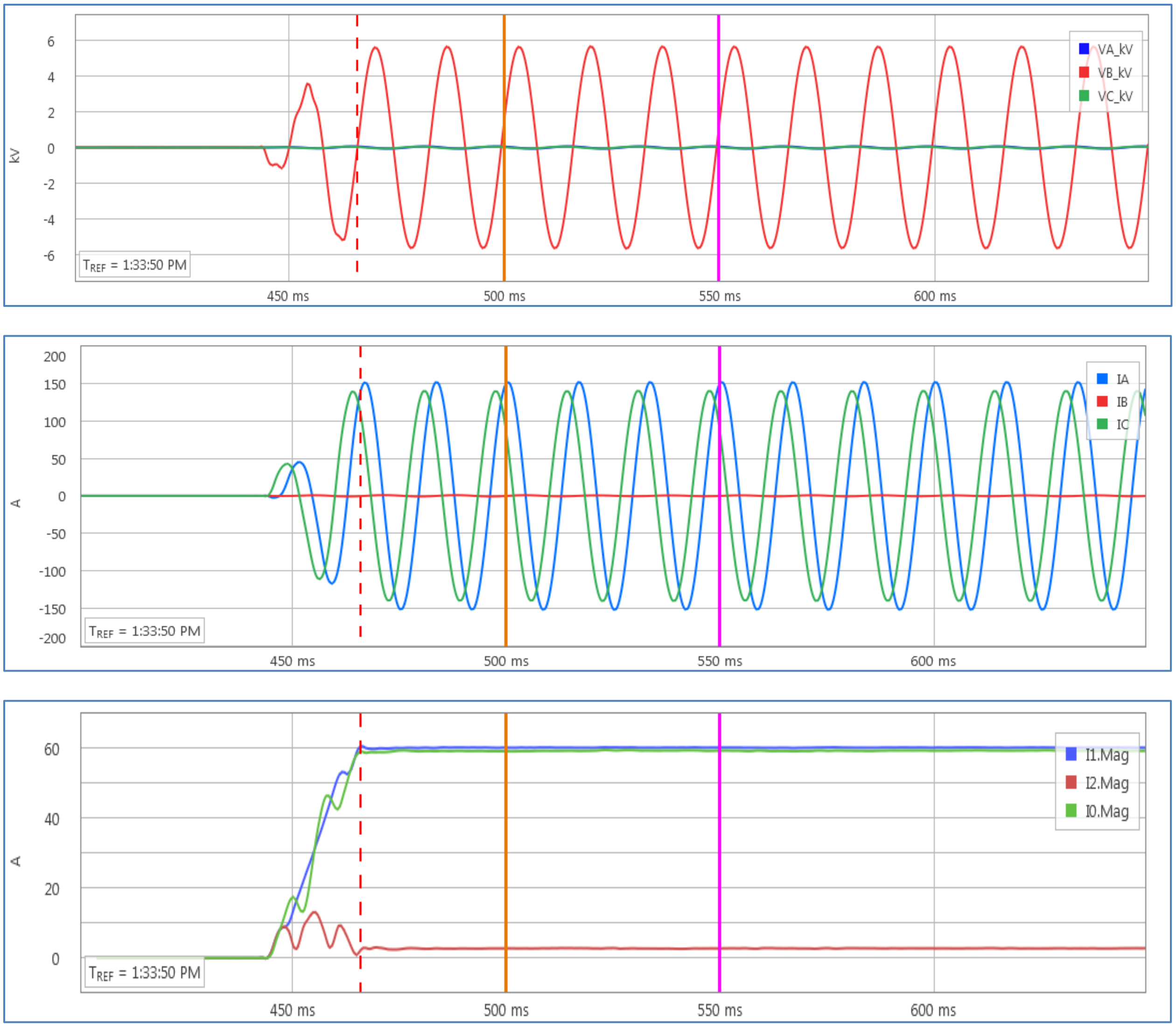


Figure A.3: SMS system response to line-to-line-to-ground fault

A.6 Summary

The reported microgrid installation has significantly enhanced reliability to the remote community since its installation in 2013. Digital fault recording deployed in the microgrid system provided a unique opportunity to learn the behavior of the inverter-based generator during unbalanced faults. Recorded waveforms validated industry concerns that the negative-sequence current relaying can be compromised in a system with large penetration of inverter-based sources.

APPENDIX B Microgrid Example 2

This appendix describes a microgrid system deployed by a US utility to test microgrid and DER use cases.

B.1 Background

In April 2017, a US utility commissioned two nested microgrids with four distributed energy resources (DERs) feeding a suburban community. The system has two 12 kV points of interconnections and is integrated into an existing substation feeding ~200 customers with annual load demand between 300 kW – 950 kW.

The substation consists of a 69 kV transmission system, a step-down transformer from 69 kV to 12 kV, and two 12 kV feeders. Feeder 1 includes the DERs and a 50 kW load. Feeder 2 includes nearly 1 MW of customer load. The system is capable of islanding to serve either the Feeder 1 loads only or both the Feeder 1 and Feeder 2 loads.

The DERs in this microgrid include 125 kW of solar photovoltaic capacity, a 100 kW wind turbine, a 250 kW, 500 kWh Battery Energy Storage System (BESS), and two 500 kW / 625 kVA natural gas synchronous generators. Figure B.1 below shows a simplified visualization of the system. Additional information can be found in [37].

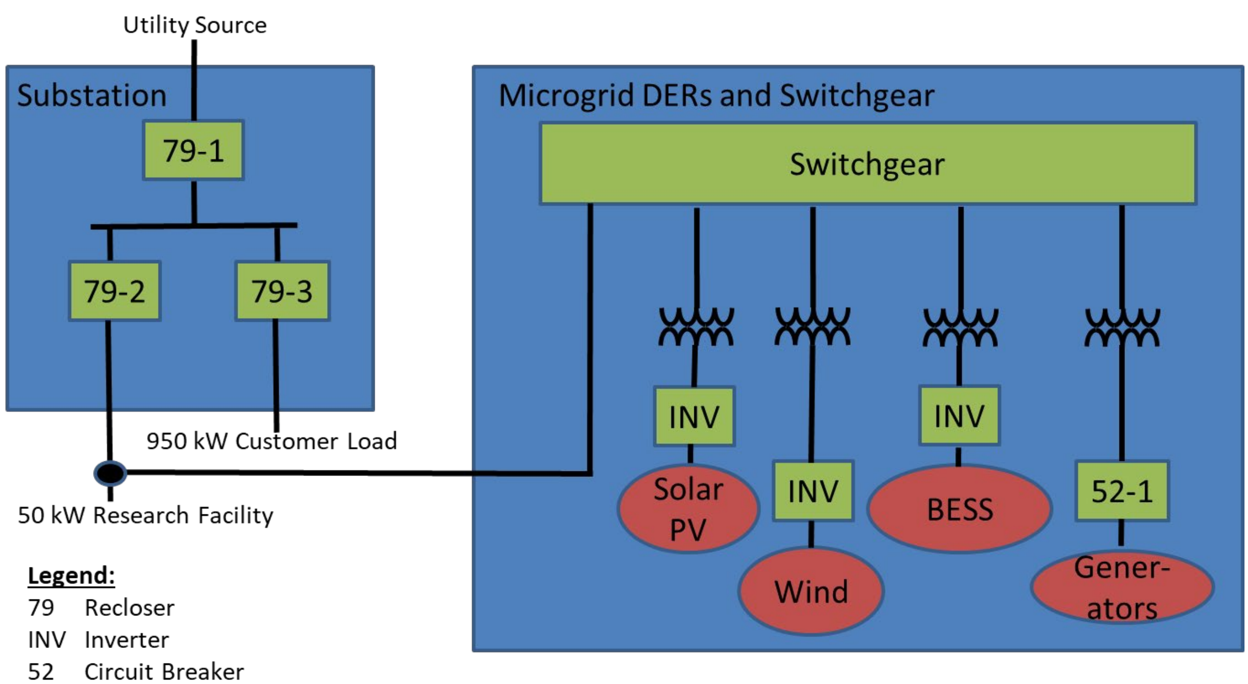


Figure B.1: Microgrid System with 12 kV Substation Interconnection

The system can operate interconnected with the main power grid (i.e. grid-interconnected) or grid-isolated (islanded). The microgrid can be operated grid-isolated with the DERs supplying the system, which can occur when either recloser 79-1 or 79-2 are open. The DERs that can provide the grid-forming or voltage-source functionality when the system is operated grid-isolated are the BESS and/or the natural gas synchronous generators. The system can seamlessly transition between grid-interconnected and grid-isolated modes of operation with no outage (i.e. closed or seamless transition), under certain conditions.

The utility wanted to build a microgrid to test 16 use cases where it saw a potential to create a return on investment. This return could include improving grid resiliency and reliability; more easily incorporating renewable energy; and enabling the utility to transition to grid-isolated operation to supply power, which would be beneficial if a major storm knocks out overhead lines supplying electricity from the main source of power generation. The microgrid was also designed including the ability to "black start" the microgrid and to be able to seamlessly return to the grid-connected mode from the grid-isolated mode without an outage occurring. The following are the microgrid use cases to be studied by the utility:

- DER monitoring, control, & integration
- DER optimal power flow
- Integrating with existing SCADA system
- Seamless transition to grid-isolated operation
- Seamless transition to grid-interconnected operation
- Black start capability in grid-isolated operation
- 100% renewable energy supply while grid-isolated
- Volt/VAR control
- Power quality
- Demand response
- EV integration
- Peak load shaving
- Optimal economic dispatch
- Storm preparedness

B.2 Control System Description

The control system consists of the following:

- Distributed Microgrid Control System
- Battery Energy Storage System
- Advanced microprocessor-based protective relays
- Ethernet network hardware
- Generator paralleling switchgear and control system
- Economic Dispatch controls

The microgrid is controlled by three integrated control systems (layers).

Layer 1 is device-level control. This layer consists of controllers and sensors that provide direct, fast control of each device. In addition to DER local controls, protective relays are considered as integral to the equipment in this layer. The Layer 1 protective devices will be responsible for protection of the DER assets, and will interpret and execute commands issued by Layer 2, if the device determines that it is safe both for the asset and the system to do so.

Layer 2 is system-level control. This consists of the distributed microgrid controller platform. This control platform will perform routine SCADA polling of the Layer 1 control devices and other sensing devices as required to determine system status, and will issue commands to devices based on the desired operating state of the system. This Layer will be responsible for issuing general system commands to each Layer 1 device.

Layer 3 is economic dispatch control. This consists of a centralized economic evaluation platform. This platform will take input on market data for pricing, utility retail power pricing data, and available present and future renewables generation data to calculate an optimal mix of generation production from each DER to maximize economic benefit of the microgrid system. Layer 3 will communicate directly with the Layer 2 control platform to enact system control.

Figure B.2 below shows these layers in a hierarchical visualization.

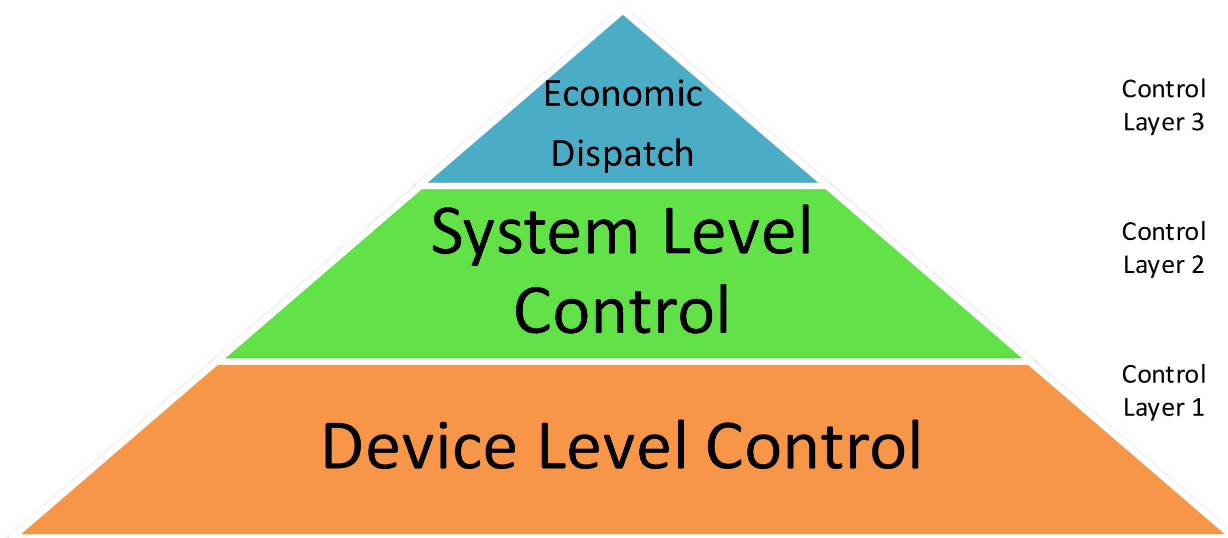


Figure B.2: Microgrid Control Layers 1, 2, and 3

B.3 Protection scheme requirements

To successfully protect the microgrid through grid-interconnected and grid-isolated operation, the protection scheme required adaptive relaying and high-speed communication.

B.3.1 Protection scheme adaptive relaying requirements

This microgrid is capable of operating both grid-interconnected and grid-isolated, with a variety of DERs. Because of the variety of system operating conditions that were possible, protection requirements differ. System short-circuit current levels while grid-interconnected are an order of magnitude higher than maximum short-circuit current levels while grid-isolated, and more than two orders of magnitude higher than minimum short-circuit current levels. Furthermore, minimum short-circuit current levels while grid-isolated are below maximum load current levels.

To ensure protection security and dependability both while grid-interconnected and grid-isolated with differing DERs supplying the system, adaptive protection was needed. In this application, two groups of settings were applied, with several protective elements in each group. The first group is utilized to protect the system while grid-interconnected. The second group is utilized to protect the system while grid-isolated, with different elements to detect faults when different DERs supply the system.

B.3.2 Protection scheme high-speed communication requirements

The two primary drivers necessitating the use of a communication-based protection scheme in this microgrid were system stability and selective coordination.

The faster rate of change of frequency in low inertia microgrid systems challenges system recovery. When the frequency deviates substantially from nominal, more system loads and generation are likely to be impacted. One example of this impact is generation tripping offline, potentially causing cascading generation loss and leading to system collapse. Furthermore, larger deviations from nominal frequency challenge stable system recovery, particularly when the resources installed are diverse (e.g. different energy sources and manufacturers). Consequentially, prompt response by protection and control systems to arrest the frequency changes is particularly critical in low inertia islanded microgrid systems, including this microgrid.

In addition to system stability, selective coordination of the protection system was another driver for usage of a communication-based protection scheme. Conventionally, distribution system protection consists primarily of overcurrent protection, which is coordinated using time-current characteristics (TCCs). This method of coordination results in devices electrically closer to the fault responding faster than series devices electrically farther from the fault across all current levels. This time-grading method of coordination necessarily results in devices electrically closest to the generation responding more slowly. As described above, low inertia microgrid systems require a fast response to events, making time-grading to achieve coordination while islanded an undesirable option.

Time-current coordination in microgrids is also challenging when there are multiple resources supplying fault current. During an event, the current measured by different devices in the system may vary, as the current supplied to the fault is coming from a combination of several resources. Furthermore, directional protection is necessary to achieve selectivity with multiple resources, as the protective device associated with the generation needs to respond first to faults between the protection and the generator but delay response for faults of comparable current magnitudes in the opposite direction. Utilizing a communication-based protection scheme can help to mitigate these challenges in a microgrid system.

B.4 GOOSE-Based protection scheme implementation

The IEC 61850 GOOSE-based protection scheme implemented in this microgrid uses communications to achieve selective coordination and the speed required for stable recovery. The communication-enabled protection scheme was designed to fulfill the requirements of selective coordination and speed for stability. These objectives were attained using GOOSE messaging to communicate the direction of fault current, transfer trip signals, and system configuration.

To selectively and promptly isolate faults in the system both while grid-isolated and grid-interconnected, the direction of fault current is communicated between relays in the system. When the relays identify that a faulted condition is present by monitoring system currents, voltages, and frequencies, the direction of the fault current is communicated between protective devices and their immediate neighbors. Direction is only communicated during fault conditions to minimize unnecessary communication network traffic. Relays monitor the direction of the current measured by their neighbors to determine whether they should operate or delay their response.

This communication-based protection scheme works by measuring and communicating the directions of fault currents flowing into and out of a protection zone. If fault current is detected flowing into a protection zone and is not also detected leaving the zone, the relays will determine the zone is faulted and trip. If fault current is detected flowing into a protection zone and also flowing out of the protection zone, the relays will determine the zone is not faulted, and delay operation to allow other protection to clear the fault.

Yet another piece of information that is communicated over GOOSE messaging is the open/closed status of each breaker in the system. From the breaker status information, each relay can determine the configuration of the system. Most importantly, breaker status information can be used to determine if the system is currently operating in a grid-isolated or grid-interconnected configuration. System configuration is significant to the relays, because the vastly different fault current across the configurations of the system necessitate adjustments in the protection settings. The relays use the system configuration information to ensure that they are appropriately set to protect the system in its present configuration.

B.5 System Operation and Verification

One of the more interesting and unique use-cases of this project was the grid-isolated operation of the 50 kW microgrid with 100% renewable energy supply, utilizing the BESS. The challenges of maintaining reliable operations and quality power supply to the load, as well as balancing the generation, load and storage requirements, are especially unique when attempting full 24-hour island duration.

Storm Mode: This function allows the utility to proactively isolate either of the two microgrids, seamlessly through a closed-transition from the grid, in response to extreme weather conditions and forecasted storms. The microgrid is placed in storm mode at the tertiary control layer (control layer 3). Tertiary control, when scheduling storm mode, requires storm start and end time as inputs to its algorithm. The algorithm would calculate, based on known load demand values, the state of charge that the BESS should attain prior to islanding. With the above in mind, the first step in the 100% renewable energy supplied grid-isolated test was to schedule a 24-hour storm duration in the tertiary layer (start date August 3, 2017 8am and stop date August 4, 2017 8am). The tertiary control algorithm, based on that input, sent commands to stop any tariff and economic BESS management underway and for the BESS to maintain a state of charge of greater than 90% before 8am on August 3, 2017.

Table B.1: DER Status at Start of Test

DER	Status at 8am on August 3, 2017
Battery	Available, SoC = 97%
Solar	Available
Wind	Available
Natural Gas	Available

Enter Grid-Isolated Mode: At 8am on August 3, 2017, the microgrid was manually commanded via Layer 2 control to enter grid-isolated mode. DER states at the start of the event are summarized in Table B.1. This starts the automatic seamless transition from grid-interconnected to grid-isolated operation by commanding the BESS to operate as the system voltage source and slack bus, supplying the microgrid loads. Commands are issued to curtail the renewable resources (wind and solar) to minimize voltage and frequency impacts when disconnecting from the bulk utility system. The BESS is controlled to maintain zero reactive and real power flow across the point of interconnection. From the historical load profile, the average load is 5.7 kW. For the 24-hour grid-isolated test, this means that approximately 136.8 kWh is required. For worst case scenario planning, the peak of the load was considered as 16 kW. For a 24-hour grid-isolated test at peak load, 348 kWh is required. The BESS has adequate stored energy to supply these requirements alone.

Grid-Isolated Operation: Once islanded, the BESS serves as the system voltage source and slack bus. It operates in droop control mode, following the load. The renewable resources are available to come online and support the load when commanded by the Layer 2 control system. The target BESS state of charge (SoC) is 90-97% when renewable resources are available. This means that the Layer 2 control system will curtail the renewables to zero output when the SoC is 97% or higher. When the SoC dips below 90%, the Layer 2 control system issues a command to turn the renewables on, allowing them to charge the BESS. Once the BESS SoC reaches 97%, the Layer 2 control system will issue a curtail command to the solar and wind DERs. Figure B.3 below shows the BESS state of charge and renewable power output during the 24-hour test on August 3, 2017.

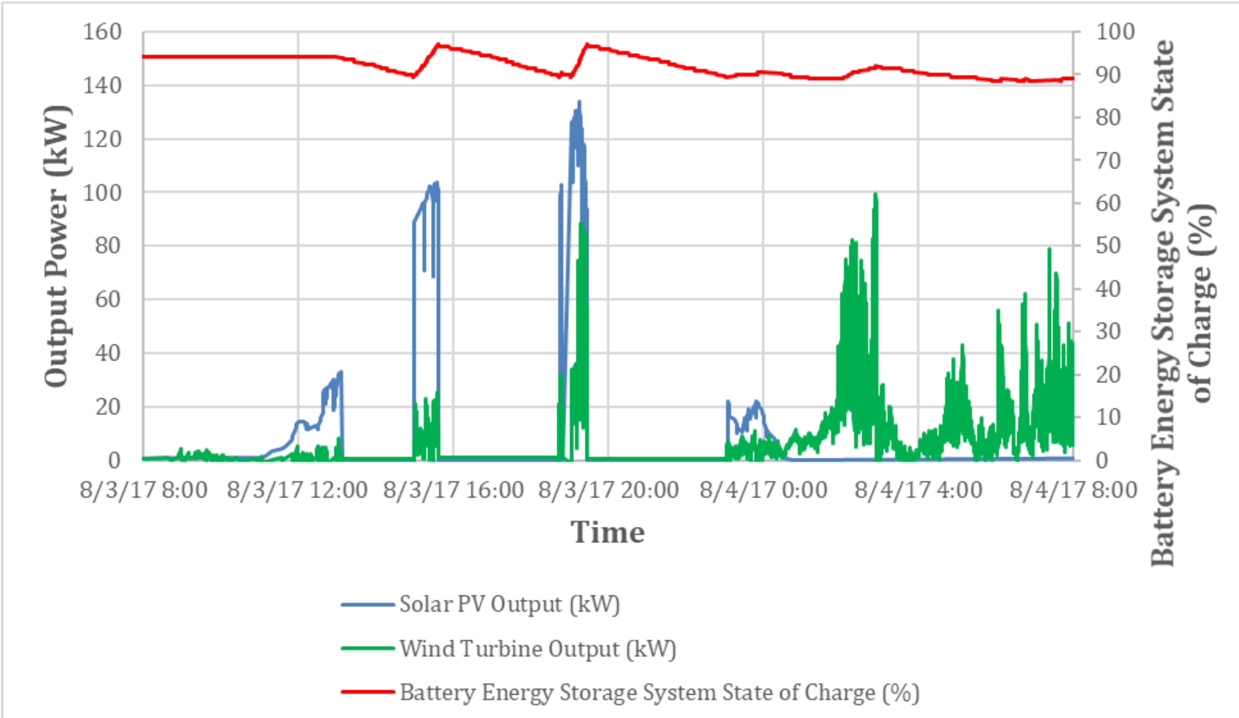


Figure B.3: Power Output and BESS State-of-Charge during 24-hour islanding with 100% renewable power

B.6 Summary

At this utility microgrid, the system is capable of operating grid-isolated with 100% renewable energy supply, and seamlessly interconnecting and isolating from the utility system. The system is supplied by a grid-forming battery energy storage system, wind turbine, and solar photovoltaic panels, each interfaced to the power system via inverters. The inertia-less grid-isolated power system has been demonstrated to achieve stable operation. The system is protected using an adaptive protection scheme which utilizes IEC 61850 GOOSE-based protection. Going forward, each of the 16 use cases mentioned above will be studied in detail, providing much needed research results on medium voltage interconnected microgrids to the power system industry.

APPENDIX C Microgrid Example 3

The example microgrid shown in Figure C.1 is currently in the detailed engineering design stage with the planned implementation in 2019. This project is in the downtown college area of a mid-size city in the Northeast region of the US. The microgrid is being designed to serve, among other loads, several professional colleges, a hospital, a clinic, and a youth center, all of which have elected to participate in the project to improve resiliency and reduce energy costs. The microgrid footprint has a maximum load of about 6,000 kW with a peak generation capacity of just over 7,500 kW comprised of over 1,500 kW of PV, almost 2,000 kW of Fuel Cells, a 1,000 kW battery storage system, and almost 3,000 kW of back-up diesel generation. The microgrid backbone is 15 kV class new underground cable system, and loads and generation are at various service voltage levels, including 480 V and 208/120 V.

Descriptions of loads, types of generation, IED functionalities are provided in Table C.1 and Table C.2 respectively. The microgrid has a communication network comprised of four fiber rings connecting all IEDs to the microgrid control center for load and generation monitoring and management - all IEDs also monitor voltage, current, active and reactive power flows and send the information to microgrid controller. Frequency is also monitored at all generation points as well as utility interface points for microgrid control and synchronization. Microgrid control strategy and black-start procedure are beyond the scope of the discussion but are important for design and coordination of the protection system.

The microgrid utilizes three MV tie circuits to interconnect designated distribution system loads and sources. Each of the tie circuits is normally supplied from a common Utility PCC, Connection #1 at node 1. In addition, a second Utility PCC, Connection #2, supplies the microgrid via a "back-feed" connection at node 7 into one of the three MV tie circuits as shown in Figure C.1. Each of these three tie circuits in turn supplies two to six load center transformers, which are used to connect designated distribution system loads into the microgrid distribution system. Selected load center transformers are also used to connect distribution system sources (Back-up Diesel Generators, PV Arrays, BESS and Fuel Cells) into the microgrid. These sources can be used to supply microgrid loading if both Utility PCC Connections are out of service. Some of these sources feed the microgrid even when the utility connection is in service.

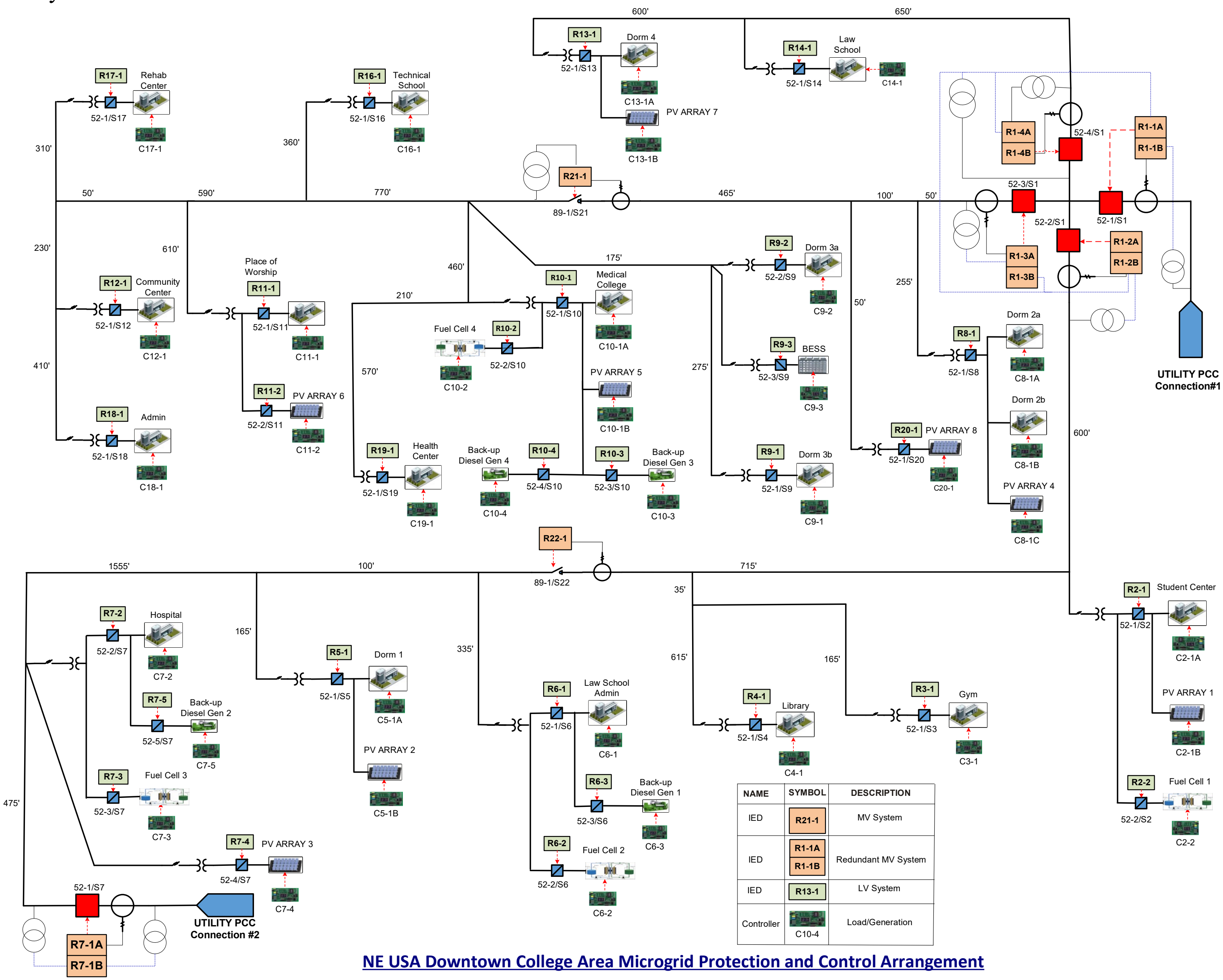
Due to relatively short distances between adjacent nodes of the microgrid, protection coordination of overcurrent relays is achieved using definite minimum time coordination instead of inverse time-overcurrent characteristics. In some cases, voltage control overcurrent relays are used for coordination.

Table C.1: Description of loads, generation and IEDs from Node 1 to Node 9 of the microgrid

Location	IED	Volt	Sensor Inputs	Controller	IED Functions/Load (kW)/Gen(kW)
Node 1 - PCC 1	R1-1 A/B	MV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25 59,27,81O,81U,32
	R1-2-4A/B	MV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
Node 2 - Student Center	R2-1-2	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	C2-1A			Load	400
	C2-1B			PV	100
	C2-2			Fuel Cell	500
Node 3 - Gym	R3-1	LV	CT and PT		51P, 50P, 51G
	C3-1			Load	150
Node 4 - Library	R4-1	LV	CT and PT		51P, 50P, 51G
	C4-1			Load	200
Node 5 - Dorm 1	R5-1	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	C5-1A			Load	400
	C5-1B			PV	100
Node 6 - Law School Admin	R6-1-2	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	R6-3	LV	CT and PT		51V, 50P/67P, 51G, 25
	C6-1			Load	250
	C6-2			Fuel Cell	500
	C6-3			Diesel Gen	400
Node 7 - PCC 2 and Hospital	R7-1A-1B	MV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25 59,27,81O,81U,32
	R7-2-4	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	R7-5	LV	CT and PT		51V, 50P/67P, 51G, 25
	C7-2			Load	1400
	C7-3			Fuel Cell	500
	C7-4			PV	500
	C7-5			Diesel Gen	1700
Node 8 - Dorm 2	R8-1	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	C8-1A			Load	100
	C8-1B			Load	100
	C8-1C			PV	50
Node 9 - Dorm 3	R9-1-2	LV	CT and PT		51P, 50P, 51G
	R9-3	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	C9-1			Load	300
	C9-2			Load	300
	C9-3			BESS	1000

Table C.2: Description of loads, generation and IEDs from Node 10 to Node 22 of the microgrid

Location	IED	Volt	Sensor Inputs	Controller	IED Functions/Load (kW)/Gen(kW)
Node 10 - MC	R10-1-2	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	R10-3-4	LV	CT and PT		51V, 50P/67P, 51G, 25
	C10-1A			Load	800
	C10-1B			PV	300
	C10-2			Fuel Cell	500
	C10-3			Diesel Gen	400
	C10-4			Diesel Gen	400
Node 11 - Place of Worship	R11-1	LV	CT and PT		51P, 50P, 51G
	R11-2	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	C11-1			Load	100
	C11-2			PV	150
Node 12 - Community Center	R12-1	LV	CT and PT		51P, 50P, 51G
	C12-1			Load	300
Node 13 - Dorm 4	R13-1	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	C13-1A			Load	400
	C13-1B			PV	100
Node 14 - Law School	R14-1	LV	CT and PT		51P, 50P, 51G
	C14-1			Load	100
Node 15 (Not Used)					
Node 16 - Technical School	R16-1	LV	CT and PT		51P, 50P, 51G
	C16-1			Load	100
Node 17 - Rehab Center	R17-1	LV	CT and PT		51P, 50P, 51G
	C17-1			Load	200
Node 18 - Admin	R18-1	LV	CT and PT		51P, 50P, 51G
	C18-1			Load	100
Node 19 - Health Center	R19-1	LV	Ct and Pt		51P, 50P, 51G
	C19-1			Load	300
Node 20 - PV Array	R20-1	LV	CT and PT		51P/67P(2), 50P/67P, 51G/67G(2), 25
	C20-1			PV	500
Node 21 - Switch 21	R21-1	MV	CT and PT		51P/67P(2)
Node 22 - Switch 22	R22-1	MV	CT and PT		51P/67P(2)



NE USA Downtown College Area Microgrid Protection and Control Arrangement

APPENDIX D References

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