Protection System Design for Practical Microgrids Connected to a Distribution Network

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***Abstract*—Protection systems of electric distribution grids are traditionally designed using non-directional overcurrent protective devices such as relays, reclosers, fuses, network protectors, etc. The main assumption in the distribution protection system design is the unidirectional power flow from upper voltage level down to the customer along the feeders. This enables straightforward coordination of protective devices via proper selection of time-current protection curves and settings such that the smallest part of the distribution system is isolated when a fault occurs.**

As the penetration of Distributed Energy Resources (DERs) increases, microgrids are gaining more attraction as an alternative solution to enhance the grid reliability, resiliency, and/or power quality. Some utilities are also adopting microgrids to minimize impacts on customers from Public Safety Power Shutoff (PSPS) events. On the other hand, despite their advantages, microgrids challenge the conventional protection philosophies in distribution systems. This is mainly due to the dynamic changes in the microgrid operational mode, load, generation, and short-circuit characteristics (magnitude, direction, sequence components, etc.)

Protection systems are typically designed for worst-case scenarios to manage the impacts of expected changes in the system. Such an approach, however, will not be effective for microgrid systems whose operating conditions are expected to change constantly. In this paper, the main challenges associated with the protection of microgrids will be briefly described, and the mitigation solutions to address those protection issues are discussed and illustrated through post-event analyses. More specifically, the paper will focus on a design philosophy for microgrid protection systems including protection of interconnection lines, power transformers, and DERs. The framework will be explained to show different steps, various considerations, and lessons learned in the design of an effective protection system for a reliability-centered microgrid system.

***Index Terms*— Microgrid Protection, Distributed Energy Resources (DERs), Inverter-Based Resources (IBRs), Adaptive Protection, Fast Load Shedding (FLS).**

NOMENCLATURE

IEEE device 21	*Distance protection*
IEEE device 24	*Volts-per-Hertz/Overfluxing protection*
IEEE device 25	*Synchronism-check*
IEEE device 27	*Undervoltage protection*
IEEE device 32	*Reverse power protection*
IEEE device 40	*Loss of excitation protection*
IEEE device 46	*Phase balance current protection*
IEEE device 47	*Phase balance voltage protection*
IEEE device 50	*Phase Instantaneous overcurrent (OC) protection*
IEEE device 50G	*Ground Instantaneous OC protection*
IEEE device 50Q	*Negative sequence Instantaneous OC protection*
IEEE device 51	*Phase Time OC protection*
IEEE device 51G	*Ground Time OC protection*
IEEE device 51Q	*Negative sequence Time OC protection*
IEEE device 51VC	*Voltage-controlled OC protection*
IEEE device 51VR	*Voltage-restrained OC protection*
IEEE device 59	*Overvoltage protection*
IEEE device 59X	*Auxiliary overvoltage protection*
EEE device 59G	*Ground overvoltage protection*
IEEE device 60	*Voltage or current balance protection*
IEEE device 60P	*Phase current unbalance protection*
IEEE device 60N	*Neutral current unbalance protection*
IEEE device 64F	*Field ground protection*
IEEE device 64G	*Stator ground fault protection*
IEEE device 67	*Directional OC relay*
IEEE device 78	*Out-of-Step protection*
IEEE device 79	*Auto reclose*
IEEE device 81O/U/R	*Over-/Under-/Rate-of-change frequency protection*
IEEE device 87	*Differential protection*
IEEE device 87N	*Ground current differential protection*
IEEE device 87VN	*Neutral voltage differential protection*
IEEE device 87S	*Stator phase fault differential protection*

I. INTRODUCTION

THE protection of the distribution system, where most of microgrids are connected, is primarily achieved by overcurrent protection devices such as protective relays, reclosers, fuses etc. The overall protection system consists of protection at Point of Interconnection (POI), interconnection transformer protection, busbar protection, feeder protection, and generator protections. Those protection devices are coordinated by overcurrent operation curves with a typical coordination time interval of 0.3-0.5s. A microgrid can connect to the utility grid at the POI and operate on a grid-connected mode. In case of power outages caused by a fault or extreme weather conditions such as a storm or earthquake, a switch or circuit breaker can isolate the microgrid from the utility grid. This isolation can either be automatic or manual. In the islanded mode of operation, the available short-circuit current may be significantly less than when in a grid-connected mode.

Voltage control and current control are two popular control schemes applied on inverters interfacing Distributed Energy Resources (DERs) with area Electric Power System (EPS). The short circuit characteristics of the DER inverter largely depends on its control scheme. The voltage control scheme has higher initial fault current contribution while a current control scheme has slower fault current rise [1]. The fault current contribution of the voltage controlled DER inverter will be higher during the transient period (5-10 cycles). The slower rise of fault current in a current control scheme stems from the nature of the dc link inductor, which limits the rate of change of current. There is no established standard regarding the fault current contribution of the inverters. This parameter is defined based on control strategy, type of semiconductor switches, rating of the inverter, and dc link capacitor size. As a rule of thumb, industry considers the fault current contribution of DER inverter in the range of 1.2-1.3 p.u [2]. Testing can be used to determine the accurate short circuit characteristic of an inverter.

Despite lack of a standard on DER inverter fault current contribution, there are multiple standards and grid codes that define the behavior of the inverter in response to voltage deviations. These requirements usually are referred to as Low Voltage Ride-Through (LVRT) and High Voltage Ride-Through (HVRT) requirements. The most prominent standard which has been adopted by many system operators is the IEEE std. 1547 [3]. This standard defines three categories related to the response of DER inverters to area EPS.

To summarize, the main microgrid protection challenges are listed below:

- Fault current may change significantly from grid-connected mode to islanded mode.
- Bidirectional power flow. The direction of power flow and its magnitude may change, which could result in lower sensitivity if protection is setup based on the grid-connected mode.
- Loss of Utility (LOU) detection. A microgrid can operate in islanded mode. However, the detection of LOU function is critical so that the transition of grid-connected mode to islanded mode does not cause any stability or power quality issue.
- Applying adaptive overcurrent protection coordination settings based on the topology and generation changes.
- Seamless transition from grid-connected mode to islanded mode or vice versa.

To address the protection challenges and facilitate the microgrid or DERs connecting to utility grids, standards and guides are published to guide the design of microgrids. Among them, the IEEE 1547, establishes criteria and requirements for testing, interconnecting and the interoperability of DERs to the electric power systems. Requirements on response to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests are also included. IEEE PES WG C30 also published the Microgrid Protection Systems report (PES-TR71) [4], which describes the protection challenges and potential solutions for microgrid protection.

Protective relays in the power industry have evolved from single function electro-mechanical relays to modern digital relays, which have multiple protective functions, self-diagnosis, data recording and enhanced communication capabilities. All these technology improvements help bring the era of digital substations and smart grids, which also enables new solutions to protect the distribution systems with microgrids. This paper will focus on designing the microgrid protection system using the digital relays and their communication capabilities.

II. Component Protection of Microgrids

Microgrid protection encompasses the protection devices and schemes required for the detection and isolation of faults and other abnormal operating conditions within the microgrid. This also includes the separation of the microgrid from the EPS when the EPS is deenergized and the re-synchronization of the microgrid to the EPS.

The integration of DERs in EPSs has been known to have a couple of impacts on protection. These include variable fault currents, protection blinding, sympathetic tripping, nuisance fuse blowing, bi-directional relay requirements, and protection for various operating modes [5].

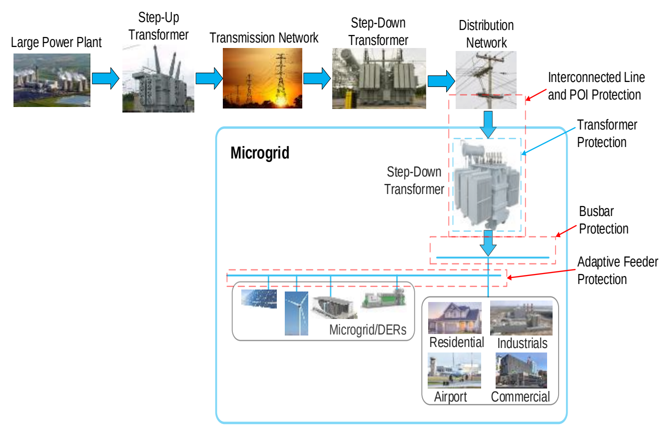

Fig. 1. An example of a microgrid connected to a utility grid.

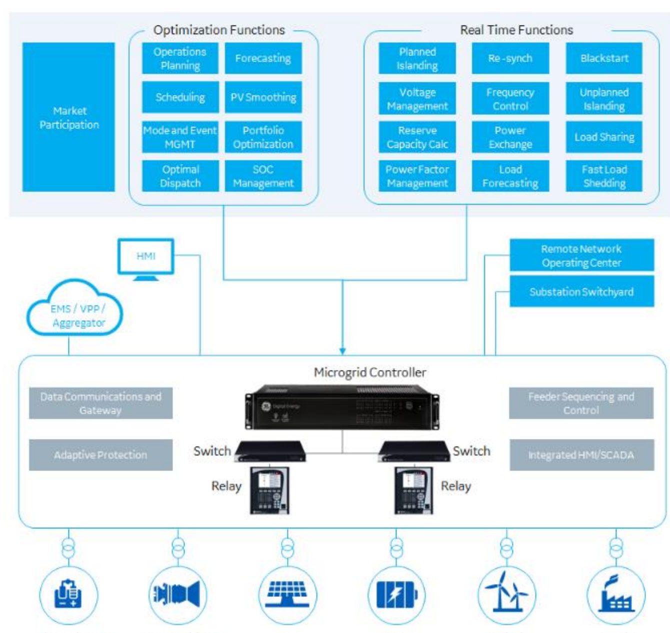

Fig. 2. Microgrid control functions.

As part of microgrid protection design philosophy, dependability, selectivity, sensitivity, speed, cost (protection equipment, communication systems, labor), and technology readiness level play a big role [5]-[7].

The protection philosophy adopted will depend on the type of DERs present in the microgrid, size of the DER assets, microgrid topology, operating conditions, functional requirements, performance requirements, utility requirements, and costs.

Fig. 1 shows the various protection zones in an example microgrid. The main protection zones are the Point of Interconnection (POI), transformer zone, busbar zone, feeder zone, and DER zone. Fig. 2 highlights some optimization and real-time control functions that are commonly deployed in microgrid controllers. The optimization control functions typically include operations planning, optimal dispatch, scheduling, forecasting, PV smoothing, whereas the real-time functions include fast load shedding, planned and unplanned islanding, black start, voltage, frequency control, power factor management etc. The design of protection functions must also consider the timing-performance of micro-grid control functions.

This section discusses the protection of the various equipment or components that are commonly found in a microgrid. The example microgrid (shown in Fig. 3) is a grid-connected microgrid that consists of three gas turbine generators, two diesel generators, and a Battery Energy Storage System (BESS). The microgrid has a total load of over 18,000 kW and is interconnected to the utility grid via a 34.5 kV tie-line. This example microgrid is not allowed to feedback the excess electricity generated into the grid.

A. Generator Protection

Distributed Energy Resources (DERs) in microgrids can be rotating machines or power electronic converter (inverter)-based generators. Rotating machine-based DERs include synchronous and induction generators used in gas turbine generators, diesel generators, Combined Heat and Power (CHP), landfill gas, small hydro, and Types I-III Wind Turbine (WT) generators. Inverter-based DERs include Battery Energy Storage Systems (BESS), solar photovoltaic (PV), Type IV WT generators, and fuel cells.

Generator protection is required to detect internal short circuits, loss of field, reverse power, over-excitation, unbalanced currents, and other abnormal operating conditions that could affect the operation of these generators.
A rotating machine is often represented as a voltage source behind an impedance (Thevenin source) and can contribute large fault currents to a fault [6]. An inverter-based DER is represented as a voltage-controlled current source in parallel with an impedance (Norton source) and have short circuit currents that are quickly limited by their controllers in order to protect their power electronic switches from thermal damage. Hence, the fault current contribution by inverter-based DERs is limited to about 1.2 p.u of their rated current [2], [6].

Consequently, the characteristics of these DER technologies in the grid-connected and islanded modes of operation and their impact on microgrid protection should be considered in the design of generator protection.

Commonly used protections for various microgrid energy resources are given below:

1) *Rotating Machine DERs:* Conventional generator protection functions can be applied in the protection of rotating machine assets. Typically used protection functions include 25, 27, 50P/67P, 51VC, 51G, 59, 81O/U/R as shown in Fig. 4 (circles in solid lines). Optional protection functions (circles in broken lines) for large DER assets are 24, 32, 40, 46, 47, 50P, 51P, 64G, 64F, 78, and 87.
2) *Inverter-Based DERs:* Asides from the technological differences between rotating machines and inverter-based DERs, inverter-based resources are unable to provide significant inertia or fault current contributions. Also, they do not produce any substantial amount of negative sequence- or zero sequence currents. Therefore, Conventional generator protection functions that rely solely on current magnitudes should be applied with caution in the protection of inverter-based DER assets especially in the islanded mode of operation. Typically used protection functions include 25, 27, 50P, 51P, 50G, 51G, 59, 67, 81O/U.

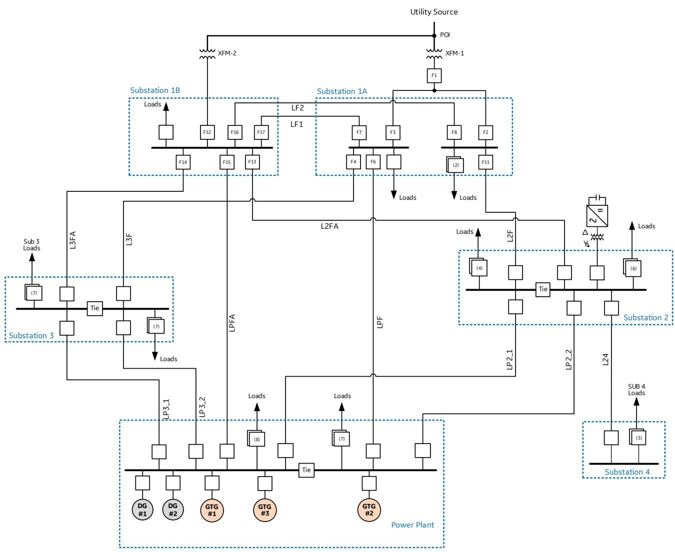

Fig. 3. An example of a practical grid-connected microgrid.

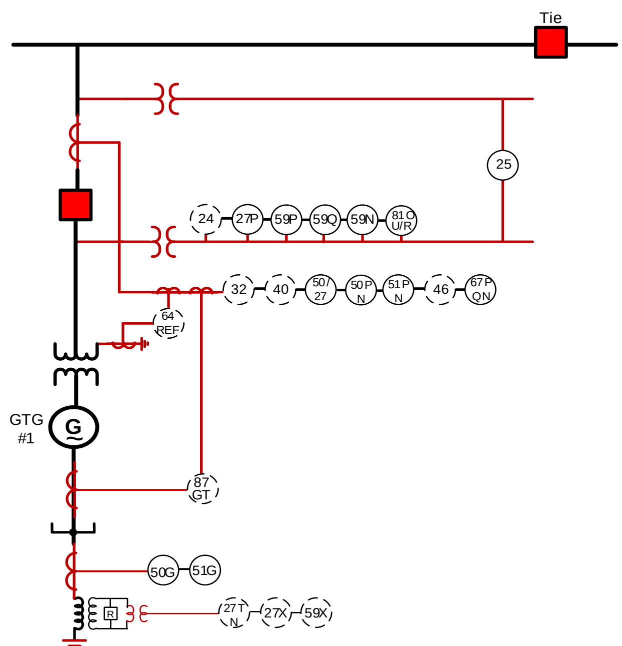

Fig. 4. Single line protection diagram for generators.

B. Busbar

The most common type of busbar in microgrids is the single bus arrangement. Commonly used protection functions are shown in Fig. 5. Overcurrent protection (50P/51P, 50G/51G) are typically used in the protection of single busbar arrangements. Bus differential protection (87B) can also be used depending on the available budget, the size of the microgrid, and the number of incoming and outgoing feeders.

Reverse blocking (interlocking) protection scheme could be implemented using 50P/50G protection functions on incoming- and outgoing feeder overcurrent relays. The 50P/50G protection function on the incoming feeder relay will operate for a fault at the bus if no blocking signal is sent by any of the outgoing feeder relays.

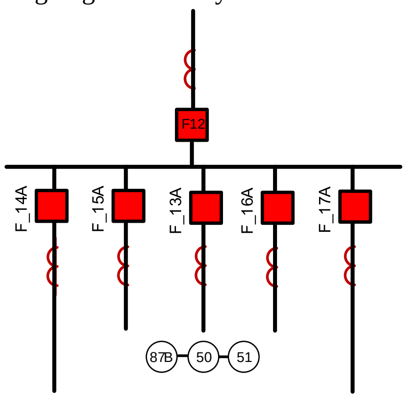

Fig. 5. Single line protection diagram for a single busbar arrangement.

C. Feeder

Microgrid feeders are characterized by high short circuit source impedances and lower short circuit currents. They can be categorized into main feeders and laterals. Main feeders in microgrids can be radial- or loop-feeders. Radial feeders are usually protected using 50 and 51 protection functions (and optionally – 79), while loop feeders are protected using 67P and 67N/G (and optionally – 25 and 79) as shown in Fig. 6. Laterals emanating from the main feeders can be protected using the 50P, 51P, and 50G protection functions depending on the line length, line loading, protection practice, and budget. Alternatively, they could be protected using fuses installed at tap points. The pickup current and time delay settings to use for the above-mentioned overcurrent functions should be carefully chosen to maintain the security of operation and coordination with upstream and downstream protection devices.

For collector circuits used in solar PV or wind turbine power plants, 50P protection function can be used to detect phase faults. The pickup current should be set lower than the fault current seen by the protection relay for collector end phase faults in order to cover the full length of the collector cable. Also, the pickup current setting should be set higher than the transformer inrush current to avoid tripping during energization or supervised by a 2nd harmonic restraint element.

The maximum inrush current from the transformers should be taken into consideration in the determination of the 50P pickup current.

The current rating $I_{N,HV}$ at the high voltage side of a DER step-up transformer is given as:

$$I_{N,HV} = \frac{MVA}{\sqrt{3} * kV_{L-L}} \tag{1}$$

where MVA is the transformer power rating, and kV_{L-L} is the transformer line voltage.

The maximum current rating (I_{rated}) for the total number (N) of connected step-up transformers is given as:

$$I_{rated} = N * I_{N,HV} \tag{2}$$

The maximum inrush current is given as:

$$I_{inrush} = k_{inrush} * I_{rated} \tag{3}$$

where k_{inrush} is a multiplying factor usually taken as 10-15 times the total MVA rating.

In this example microgrid (Fig. 3), the pickup current (I_{50P}) for the 50P protection function is set to 1.1 times the inrush current value as given in (4). A time delay greater than the transformer inrush current decay time should be used.

$$I_{50P} = \frac{1.1 * I_{inrush}}{I_{rated}} \tag{4}$$

The pickup current for the 51P protection function at a collector circuit can be set to 150% of the total generation. 50G protection function can be set as a factor (e.g. 50%) of the 50P pickup with no time delay. 51G protection function can be used to provide sensitive protection for ground faults and should be set higher than the steady-state unbalance current and higher than 20% of the rated current.

Voltage-controlled or voltage-restrained overcurrent protection (51VC or 51VR) can be applied when the microgrid is operating in the islanded mode or connected to a weak system. The combination of the voltage drop and overcurrent magnitude can effectively detect and discriminate against short circuits in such operating conditions. However, voltage supervised protection schemes require Voltage Transformers (VTs), and this could add to the overall project costs of the microgrid protection system.

Inverter-based DERs do not have a significant negative sequence contribution during unbalanced faults. This could affect the dependability of directional protection that uses negative sequence component as the polarizing- (or reference) and operating-quantities. This should be carefully reviewed before it is applied in microgrid feeder protection.

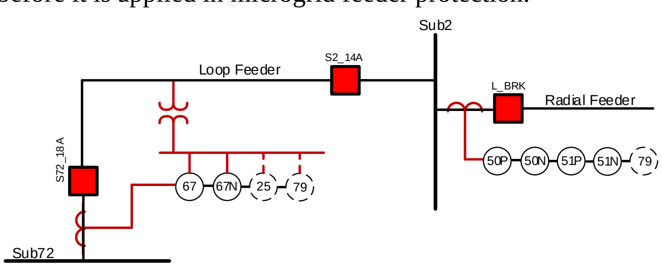

Fig. 6. Single line protection diagram for feeders.

D. Shunt Capacitor Bank

Feeder Shunt Capacitor (FSC) banks are used in microgrids to maintain a unity power factor, provide reactive power support, and improve the voltage profile in microgrids. The particular protection function to use in the protection of FSC banks depends on the configuration of the capacitor bank (i.e.

single- or double-wye) and if the capacitor bank is grounded or ungrounded.

Commonly used protection functions in FSC bank protection are shown in Fig. 7. Optional protection functions include 27P, 50Q, 51Q, 59X, 59G, 60P, and 60N as backup protection functions.

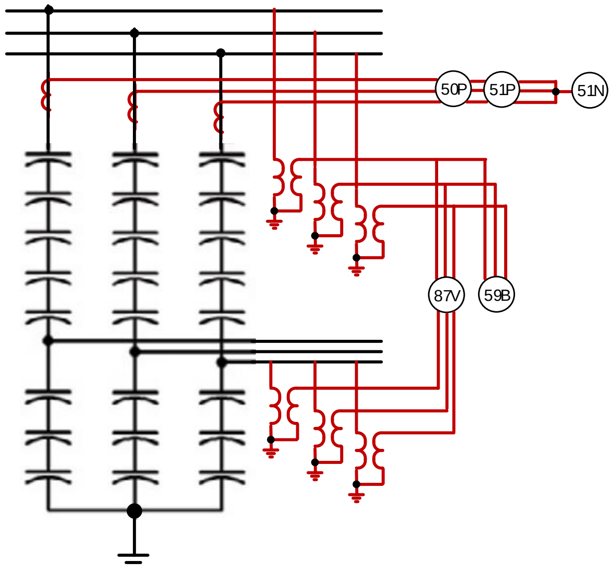

Fig. 7. Single line protection diagram for a grounded-wye shunt capacitor bank.

E. Step-up Transformers

DER assets are connected to the microgrid via step-up transformers. Five transformer configurations commonly used in the interconnection of DERs to the system are [8]:

1) *Transformer Configuration #1:* Delta (Pri)/Delta (Sec), Delta (Pri)-Wye Grounded (Sec), and Wye-Ungrounded (Pri)/Delta (Sec).
2) *Transformer Configuration #2:* Wye-Grounded (Pri)/Delta (Sec).
3) *Transformer Configuration #3:* Wye-Grounded (Pri)/Wye-Grounded (Sec).

The type of transformer configuration used will determine the fault current contribution by the DER assets, and the response of protection devices to various fault types. Transformer configuration #1 has been known to supply microgrid feeder(s) from an ungrounded source after the substation breaker has been tripped due to a ground fault. This loss of the utility transformer solid ground connection could lead to an overvoltage in the microgrid [8]. Transformer configurations #2 and #3 provide an unwanted fault current contribution to ground faults on the feeders. Transformer configuration #3 could also cause remote protection relays to respond to ground faults on the transformer secondary [8].

The type of protection to use will depend on the size of the transformer, transformer configuration, type of grounding, etc. Commonly used primary protection for step-up transformers of inverter-based DER is an expulsion fuse in series with one or more current limiting fuse. Commonly used protection functions for protecting large microgrid step-up transformers and main transformers are shown in Fig. 8. These include 87T protection function, with 50P, 51P, and 50G protection functions as backup protection for the transformer protection zone, bus zone, and feeders.

Feeder protection 51P/G function can be used as a backup protection for faults on step-up transformer, bus, and collector circuits. The settings for 51P and 51G in this example microgrid is calculated using (5)-(6), respectively. A typical value for k_1 is from 1.2 to 1.5, while k_2 is set to 0.2. A setting of 1.5 to 2.0 is used for the 51P protection of main transformer backup protection.

$$I_{51P} = k_1 * I_{rated} \tag{5}$$
$$I_{51G} = k_2 * I_{rated} \tag{6}$$

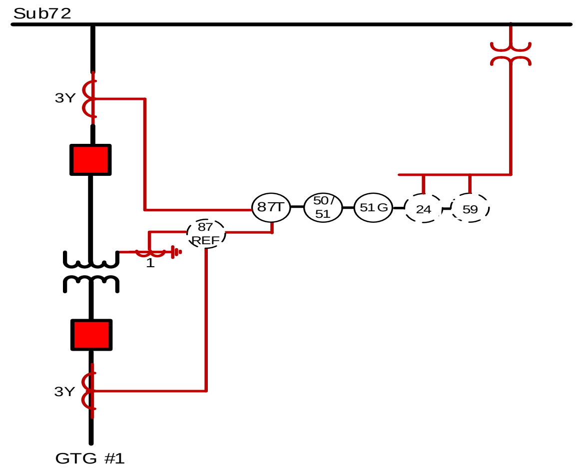

Fig. 8. Single line protection diagram for step-up transformer.

F. Protection at POI (Point of Interconnection)

Protection at the Point of Interconnection (POI) is required in order to isolate the microgrid during forward faults (towards the microgrid) and reverse faults (towards the utility). Complete fault isolation is provided by tripping both the substation breaker and microgrid breaker.

In the design of microgrid POI protection, it is important to ensure that faults within a microgrid do not affect loads (customers) on the utility side. The type of protection at the POI is usually determined by the interconnecting utility and often depends on the size and type of the DERs or microgrid, point of interconnection, interconnecting transformer winding configuration, speed of operation, and utility protection requirements [8].

The protection at the POI can either be located at the secondary of the interconnecting transformer, or at the primary side, or both sides of the interconnecting transformer [8]. Typical POI protection functions are shown in the protection diagram in Fig. 9. Optional protection functions are 21, 32, 46, 47, and 50.59G protection function can be used in detecting -phase-to-ground faults on the utility side of the 34.5/13.2 kV Delta/Wye-Grounded transformer shown in Fig. 9. A broken delta Voltage Transformer (VT) connection is required for this.

The Instantaneous 59G protection function for the example microgrid is set to 110% of the rated single-phase VT, while the Time 59G protection function is set to 20% of the of the rated single-phase VT with a time delay. The 27P and 59P protection functions are set to 0.9 p.u. and 1.15 p.u., respectively, with a suitable time delay. The 81O/U protection functions is set to 60±1.0 Hz, respectively.

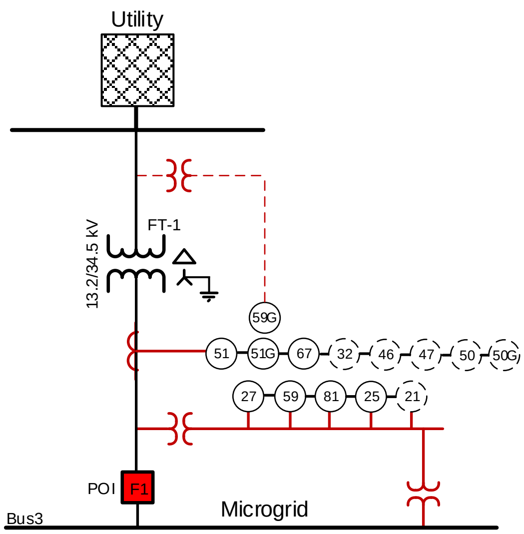

Fig. 9. Single line protection diagram at the POI.

Directional protection can be applied to detect faults in the reverse direction towards the utility and for forward faults towards the microgrid. Single-phase-to-ground fault on the 34.5 kV side of the transformer shown in Fig. 9 will be detected as a phase-to-phase fault by a relay located at the Wye-Grounded (13.2 kV) side of the transformer. Negative Sequence Directional protection function could be used to detect single-phase-to-ground reverse faults on the 34.5 kV side of the transformer. The pickup current setting for this function should be set lower than the minimum single-phase-to-ground fault current seen by the relay for faults at the line end and should be higher than the maximum unbalanced load current.

Similar to the Negative Sequence Directional protection function, Phase Directional protection function can be used to detect phase faults on the 34.5 kV side of the transformer. In this case, the pickup setting should be set higher than the maximum three-phase fault current for a fault at the remote end of incoming feeders.

A Phase Time Directional Overcurrent function can be used in detecting three-phase reverse faults on the 34.5 kV (utility) side of the transformer. The pickup setting could be set lower than the minimum three-phase fault current at the remote end of the incoming feeder, and higher than the maximum generation current from the microgrid to utility.

Three phase faults towards the microgrid (13.2 kV transformer side) can be detected using a forward Phase Time Directional Overcurrent. The pickup setting should be lower than the minimum three-phase fault current contribution (from the utility alone), and higher than the maximum load current at the transformer secondary.

Note that the overcurrent characteristic curve and time dial (or time delay) settings to use with the above-mentioned protection functions should be carefully chosen to provide protection coordination.

For the example microgrid shown in Fig. 9, 51G protection function might not detect single-phase-to-ground faults on the utility (34.5 kV) side of the interconnection transformer especially when the breaker on the utility feeder is tripped, while the microgrid beaker remains closed. This is because the POI protection is unable to trip for such low fault current contribution from the microgrid. This can be addressed using the following protection schemes: i) Direct Transfer Trip (DTT) scheme in which the utility protection relay sends a direct trip to the POI protection relay, and ii) Overvoltage (59G) element (energized by a Wye-grounded broken-delta VT) at the utility-side of the interconnection transformer.

The challenges with the above-mentioned schemes are installation and maintenance costs associated with high-speed communication systems, sensitivity issues with protection settings, and delayed fault clearing time. A distance protection method [9] based on residual voltage compensation can be installed at the microgrid side of the interconnection transformer to provide protection against single-line-to-ground faults at the utility side.

Another important function of POI protection is to detect grid outages, which will cause unintentional islanding. Non detection zone may exist, especially when load and generation are comparable, if protection functions like under/over-frequency function, rate of change of frequency or rate of change of voltage are used. DTT from utility station and new protection algorithms to address the challenges of microgrid or DERs brought to the protection is required.

The reconnection of an islanded microgrid to the utility grid requires re-synchronization as the microgrid transitions from the islanded mode to the grid-connected mode. This is done using the Synchronism-Check function (25) typically available in most generator and line multifunctional microprocessor protective IEDs. This could also be deployed on Bay Control Units (BCUs) or Remote Terminal Units (RTUs). A close command is sent by the protective IED, BCU, or PLC to the POI breaker once the synchronization criteria (frequency, voltage, or phase angle) are met.

III. System Protection

The microgrid, when running in islanded mode or in transition from grid-connected to islanded mode, should be protected at the system level to maintain system stability and provide reliable power supply to its own customers. Typical system protections such as load shedding or generation rejection need to be considered. A control system that dynamically manages the protection settings may also be required due to the change in network topology.

A. *Fast Load Shedding (FLS) Scheme*

In case of unplanned islanding due to loss of utility power supply or loss of generation under islanded mode, a Fast Load Shedding (FLS) scheme can be deployed to help maintain the system stability of microgrid. Failing to shed an appropriate level of electrical load following the loss of utility or a large generator could result in a drop in grid frequency and subsequent cascading failure of the remaining online generators. This typically leads to a complete facility blackout taking several days for production to recover. The FLS scheme should coordinate with protection system of microgrid generations and should be able to perform the load-shedding within 100 ms (including breaker operation time). During operation, the FLS is informed of present system power flows and contingencies via real-time communication protocols. If contingency for FLS is met, the controller will shed the load according to the following calculations [10]:

$$P_{shed} = \left\{ \begin{matrix} 0, & \text{if contingency timer is Off} \\ i \sum_{\text{all } i} P_L[i] \text{ if } Lost[i] - j \sum_{\text{all } j} P_R[j] \text{ if not } Lost[j] & \text{otherwise} \end{matrix} \right\} \quad (7)$$

where P_{shed} is the load to be shed, $P_L[i]$ is the steady-state infeed power of infeed or *i*th generation, and $P_R[j]$ is the steady-state reserve power of infeed or *j*th generation.

Load groups with priority assigned have to be defined based on load characteristics. Load groups with lower priorities are shed in preference to load groups with higher priorities. Loads with Priority Level 0 indicate these loads are not assigned to get shed. Similarly, for generation trip, generation with less efficiency can be defined as lower priorities, which can be tripped first.

Trigger of FLS scheme varies from projects. It could be:

- Tripping elements of circuit breakers at POI and major generators.
- A detection of circuit breaker open statuses at the above-mentioned locations or some tie-line locations. A transient stability study can be performed to decide the contingencies.
- Power output measurements are also required to calculate the generation and load balance. Power limit can be assigned on some triggers as a trigger condition.

The timing performance requirement of FLS scheme requires a reliable communication network that can support fast message transmission. A typical solution of such a system would be a high-speed Ethernet with IEC 61850 compatible hardware. IEC 61850 GOOSE can be used to transmit the analogue and digital statuses for fast load-shedding. Redundancy of hardware and communication paths are recommended.

Some large microgrids also implement load rejection scheme in addition to FLS. Traditional generation/load shedding schemes such as under-frequency load shedding, overload load shedding, and over-frequency generation shedding can still serve as backup of the FLS scheme.

B. Adaptive Protection

Protection of electric distribution networks is primarily achieved using non-directional overcurrent protective devices such as relays, reclosers, sectionalizers, and fuses. The main assumption in the design of distribution protection systems is the unidirectional flow of power, which enables straightforward coordination of protective devices via proper selection of time-current protection curves and settings. In addition, protection systems are typically designed for worst-case scenarios and validated under minimum and maximum fault currents in the protection zone to manage the impacts of expected changes in the system. However, this conservative approach will not be effective for microgrid systems with constant changes in operating conditions such as operating mode, topology, DER status (off-line vs on-line), DER power output, etc. These changes cause the fault current level and power flow direction of a microgrid to vary constantly.

Operation of a microgrid in the islanded mode causes the available short-circuit current to drop significantly compared to the grid-connected mode. Adaptive protection is one of the improved methods proposed for microgrid protection. The protective relays in the power industry have evolved from single-function electro-mechanical relays to modern digital relays that offer multiple protective functions, self-diagnosis, data recording, and communication capabilities. In particular, the advanced communication technologies have enabled high performance peer-to-peer communications amongst protection relays as well as communications to a central controller.

An Adaptive Protection System (APS) is defined as a near-real-time activity that modifies the protection system response to a change in system configuration and/or operating condition in a timely manner by means of externally generated signals [11]. The protection response modification can include changing the protection setting group(s), setting value(s), and/or protection functions.

Some of the main considerations and challenges in the design and implementation of an APS are as follows:

- The effectiveness of the APS can be impacted by fuses, electromechanical relays, and solid-state relays that do not provide flexible protection settings/characteristics.
- The use of a reliable communication medium (PLC, fiber, etc.) and a standard communication protocol (DNP3, IEC 61850, etc.) is essential for the development of an APS.
- Dependency on the communication system and central processor may necessitate redundancy.
- Due to bidirectional power flows in microgrids, using directional elements is essential. Thus, protection coordination should be done for forward and reverse directions, with relays supporting different settings and/or settings groups.
- The microgrid configuration lookup table should be updated when a new system configuration is allowed; it is important to conduct protection studies for all the permitted configurations.
- The APS function should coordinate with other distribution automation functions in place (e.g. service restoration and/or load transfer applications).

IV. Lessons Learned and Conclusion

This paper has highlighted some of the challenges caused by the integration of DERs in microgrids, the protection of some of the components commonly found in microgrids, and some adaptive protection schemes that can be applied.

Asides from the technological differences between rotating machines and inverter-based DERs, inverter-based resources are unable to provide significant inertia or fault current contributions. Also, they do not produce any substantial amount of negative sequence- or zero sequence currents. Therefore, Conventional generator protection functions that rely solely on current magnitudes should be applied with caution in the protection of inverter-based DER assets especially in the islanded mode of operation. Ground Time Overcurrent (51G) protection function to detect single-phase-to-ground faults on the utility side of the interconnection transformer could fail for operating scenarios where the breaker on the utility feeder trips, while the microgrid beaker remains closed. DTT schemes, 59G, and 21 protection functions can be used instead.

Directional (67) protection function based on negative sequence polarizing quantity might fail for single-phase-to-ground faults since inverter-based DERs do not have a significant negative sequence contribution during unbalanced faults. This should be carefully reviewed before it is applied in microgrid feeder protection.

The type of transformer configuration used will determine the fault current contribution by the DER assets, and the response of protection devices to various fault types. Some transformer configurations might supply microgrid feeder(s) from an ungrounded source after the substation breaker has tripped or even provide an unwanted fault current contribution to ground faults on the feeders. This could lead to protective relay misoperation. Commonly used protection functions for protecting large microgrid step-up transformers and main transformers is the 87T protection function, with 50P, 51P, and 50G protection functions as backup protection for the transformer protection zone, bus zone, and feeders. Feeder protection 51P function can be used as a backup protection for faults on step-up transformer, bus, and collector circuits. The settings for 51P and 51G can be calculated using (5)-(6), respectively as mentioned in Section II.

A FLS scheme can be deployed to help maintain the system stability of microgrid following the loss of utility or a large generator. If the criteria for FLS is met, the controller will shed the loads in the microgrid according to the calculated load shed order.

Adaptive protection can be used to meet the protection requirements in the grid connected- and islanded modes. For example, automatic settings group change can be implemented as a microgrid transitions between the grid connected- and islanded- modes. Multiple settings groups can be created with pickup current levels and time delays suitable for various pre-determined events or operating scenarios.

V. Reference

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