

A Protection and Grounding Strategy for Integrating Inverter-Based Distributed Energy Resources in an Isolated Microgrid

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Abstract—Reliable protection and grounding schemes have been well established for power systems. With the advent and proliferation of microgrids, however, these subjects need to be revisited as traditional philosophies are no longer sufficient to cope with reduced short circuit levels of distributed energy resources (DERs). A DER dominated microgrid will experience a limitation in the functionality of traditional overcurrent elements. This can degrade protection coordination and selectivity and requires a philosophy that is nonstandard in distribution systems. Furthermore, with most DERs operating as constant current sources and not naturally supplying ground current, performance grounding also becomes a fundamental problem of microgrids. Additional ground sources are required and must be appropriately sized for the needs of the microgrid. This paper proposes a practical protection and grounding scheme for an isolated microgrid that is being retrofitted with a large solar facility and a battery energy storage system (BESS). Much of the theory was developed tailored for this system and serves to reinforce the need for new philosophies that consider practical aspects of real systems.

Index Terms—Distributed energy resources, inverter-based generation, microgrids, power system protection, temporary overvoltage.

I. INTRODUCTION

ISOLATED communities have relied upon isolated generation as a proxy to the transmission network. In Canada, there are about 300 diesel-based isolated communities with a total population exceeding 200,000 dwellers [1]. In the past two decades, the Canadian federal and many provincial governments have introduced several incentives to decrease diesel reliance and the corresponding greenhouse gas emissions, hedge electricity supply, and increase system reliability [2]. With considerable uptake from electric utilities, many Northern isolated systems have been retrofitted with distributed energy resources (DERs), predominantly photovoltaic (PV) and the reinforcement of battery energy storage systems (BESS). If a resulting topology includes a sufficiently large penetration of renewable energy, a microgrid controller is also required. The microgrid controller includes several benefits, such as managing the balance of generation and load, smooth transition between grid-connected and

islanded modes, generation dispatch and curtailment, load management, and integrated blackstart mechanism [3].

When dealing with microgrids, one of the most important and challenging aspects, namely protection and grounding, is often overlooked until a microgrid is its final stages of design. The addition of inverter-based DERs results in completely different fault current characteristics that highly depend on inverter controls and represent many challenges for protection and grounding engineers. These inverters are an integral part of PV and BESS systems and produce very low fault currents as compared with synchronous generators [4]. This becomes a major problem for microgrids when operating in islanded mode because typical overcurrent protection elements, which are the norm in distribution systems, no longer is effective [5].

There are emerging research streams on microgrid protection today. The authors of [6] are some of the precursors envisioning the need to propose adaptive strategies to protect distribution systems with high penetration of DERs, even though they do not explicitly address microgrids. The application of differential relays for microgrids was suggested by [7]–[8], proposing local and communication-assisted digital relays, respectively. The limitation with differential scheme is the cost and number of relays required. The authors of [9] propose an approach for protecting low-voltage microgrids based on a coordinated low voltage circuit breaker scheme. Similarly, this scheme requires numerous relays and increased cost and complexity. The authors of [10] propose post-fault switching of operational modes and protecting the islanded microgrid based on current sequence components. However, the method does not ensure full protection against three-phase faults. A voltage-based scheme has been proposed in [11] using a dq rotating reference frame. While suitable for islanded microgrids, it does not appear to have considered the grid-connected operation mode.

Most published literature addressed systems that are experimental, demonstration projects, or part of pilot initiatives intended to demonstrate technologies. A robust integrated protection and grounding scheme is imperative for mission-critical applications. In this paper, the author proposes a practical, simple, and easily workable method to ensure protection and grounding reliability of an isolated microgrid. The method is derived based on practical considerations and dictates operational procedures, blackstart decisions, reclosing strategies, and reclosing philosophies. The paper is structured as follows. Section II presents the microgrid system under

Manuscript received June 30, 2020; revised August 22, 2020; accepted September 6, 2020. Date of publication September 30, 2020; date of current version September 23, 2020.

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Digital Object Identifier 10.24295/CPSSPEA.2020.00021

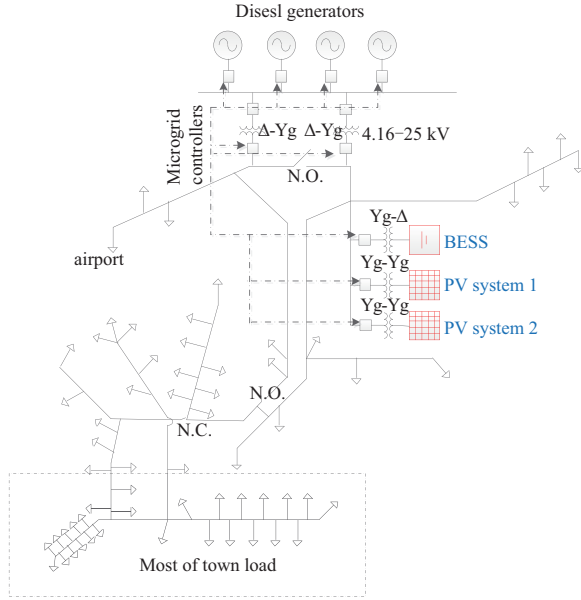


Fig. 1. Microgrid under study.

study. Sections III and IV review traditional protection and grounding philosophies, respectively. Section V calculates and reports the protection and grounding characteristics of the microgrid under study. Section VI introduces the proposed microgrid operation, protection philosophy and restoration strategy. Sections VII and VIII conclude the paper.

II. MICROGRID SYSTEM

Fig. 1 shows a single-line diagram of the real microgrid system used to investigate the application of protection and grounding techniques proposed in this paper. The distribution system is supplied by four diesel generators, each of which rated 1.15 MW/1.29 MW/1.41 MW (nominal/prime/overload ratings). The electricity in the plant is then stepped up via two 4 MVA Δ -Yg, 4.16–25 kV transformers (Δ on the 4.16 kV side). The distribution system comprises two 25 kV feeders, which supply some load near the plant and emanate about 8km south, where they supply most of the town load. Both feeders have a continuous multi-grounded neutral (MGN).

The total loading of this microgrid has increased over the years. A historic yearly data for both feeders combined is shown in Fig. 2. The data contains 8760 hours of substation metered data. The data displays the typical load profile of a northern community, with higher consumption during fall and winter, and lower consumption during spring and summer. During warm summer days, the load is sufficiently low that only one diesel generator unit is enough to supply the entire community, while during dark winter nights three diesel generators run simultaneously to supply the system.

The community has been experienced unprecedented load growth recently, supporting municipal infrastructure upgrades such as the uprate of three sewage lift stations, a refurbished waste water treatment pumping system, and a new recreational center. As part of this project, the load growth sensitivity

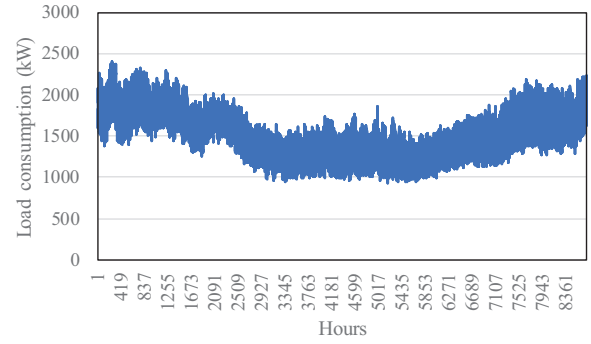


Fig. 2. Historic yearly total load supplied by the system.

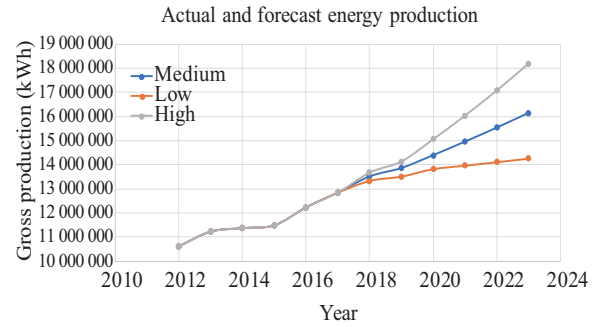


Fig. 3. System load forecast up to 2023.

analysis was completed until 2023. A portion of this analysis is shown in Fig. 3. Three forecast levels were produced, but all of them suggest a substantial and continued growth.

The community is only accessible by an ice road in the winter, for an average of 6 weeks when the ice road sufficiently strong to support refueling trucks. The main issue with this community is that it only contains 12 diesel tanks, with total storage of about 3 300 000 L capacity. This projected load growth reveals that the diesel storage capacity will soon be insufficient to supply the community between times refueling is possible. In response, the electric utility has spearheaded planning efforts that employ two PV farms, phased in into two stages. In 2019, a 450 kWac/600 kWdc plant was commissioned to offset some of the load consumption. This size was chosen to optimize the diesel savings to offset the immediate shortage of diesel storage and to ensure system frequency stability. To further address the issue of diesel storage, a larger solar farm, sized 1.9 MWac/2.2 MWdc was installed in the second stage of the project. This amount of generation is very large as compared with the historic system load shown in Fig. 2. In response, the utility has also employed a 1.8 MW/1.6 MWh BESS, as well as a microgrid controller. These components are also illustrated in Fig. 1. The reasoning for choosing a combination of PV and BESS, as well as the sizing optimization exercise, was presented in [12] and is outside of the scope of this article.

The architecture of the microgrid controller is as follows. Each of the indicated components in Fig. 1, namely each of the four diesel generators, the main feeder breakers and

reclosers, the PV systems and the BESS, were supplied with a decentralized microgrid controller, represented by the dot-dashed lines. This allows a high degree of system visibility and controllability. The optimization to arrive at these sizes and topologies is outside of the scope of this paper.

III. TRADITIONAL AND EMERGENT PROTECTION PHILOSOPHIES

Distribution system protection is mostly achieved by employing non-directional overcurrent protection. These elements are enough to reliably protect a system that has only one source (such as the substation or a single generation plant). In systems with multiple sources, torque control of overcurrent elements is needed. However, as explained earlier, systems with high penetration of DERs introduce a new problem, related to low short-circuit levels, rendering static overcurrent protection ineffective. Even with adaptive protection schemes [6], this detection may not be possible because most inverters supply a constant current balanced supply, and at least one element, such as the BESS, can supply system current imbalances but typically not substantial fault current. Hence, other protection philosophies are imperative, as it is not possible to rely only on overcurrent for fault detection. At the same time, adaptive schemes are complex and should be avoided in mission critical systems.

The use of undervoltage protection in microgrids has been suggested in [9] and represents a common element present as part of protection suites of generators. In the case of generators, undervoltage elements are used to protect the generator, rather than the system, and may not have adequate range to do so. Relying on this element represents a paradigm shift because:

1. This is an element not typically used to protect distribution systems. As such, settings ranges may not be adequate.
2. It is difficult to ensure required trip times are achieved as the voltage behavior is not as predictable as current.
3. Protection coordination between undervoltage and overcurrent schemes is not easy to perform.

In the case of the microgrid presented in this paper, undervoltage should be considered to protect the system when in islanded mode. Additionally, underfrequency elements can also be used. Both voltage and frequency behaviors of the BESS cannot be characterized easily by using generic models. While a vendor-provided model can help with characterizing the voltage envelope by conducting short-circuit studies, the frequency behavior requires electromagnetic transient (EMT) simulations and the use of a very accurate BESS model. As it will be explained later, this paper focuses on voltage-based elements and uses short-circuit analysis.

IV. EFFECTIVE GROUNDING IN MICROGRIDS

The following excerpt from IEEE Std. C62.92.1 [11] is very useful in highlighting the importance of grounding and serves as a preamble to its application. “There is no simple answer to the application of grounding. Each of a number of possible solutions to a grounding problem has at least one feature that is outstanding, but which is obtained at some sacrifice of

other features that may be equally worthy” [11]. For power systems, it is well known that protection and grounding have conflicting requirements. Namely, a very large ground current injection is required to reduce temporary overvoltages (TOV), and conversely, insufficient ground current injection does not mitigate TOV. This section contains a review of effective grounding parameters.

A. Degree of Grounding and Effective Grounding

IEEE Std. 142 [13] prescribe the requirements for a system to be considered effectively grounded. It defines the degree of grounding K as

$$K = Z_0/Z_1. \quad (1)$$

According to IEEE Std. 142:

1. If $X_0/X_1 < 3$, and $R_0/X_1 < 1$, the location is called effectively grounded.
2. If any location in an area of a network meets the above condition, that area is called effectively grounded.
3. The ratios I_{f1ph}/I_{f3ph} and TOV can be represented as a function of K .

B. TOV

TOV is defined as the voltage ratio between the highest phase voltage of an unfaulted phase during a ground fault and the pre-fault voltage (both are phase-to-ground voltages). It can be proven that TOV can be expressed as a function of the degree of grounding K (proof omitted to save space):

$$TOV = \left| \frac{1-K}{2+K} + 1 \angle -120^\circ \right| \quad (2)$$

This equation allows the following observations:

- for $K = 1$ ($Z_0 = Z_1$), $TOV = 1$ (fully grounded system);
- for $K = 3$, $TOV = 1.25$ (boundary condition);
- for $K = \infty$ ($Z_0 = \infty$), $TOV = \sqrt{3}$ (ungrounded system).

C. Coefficient of Grounding (COG) and Effective Grounding

The coefficient of grounding is defined as the highest RMS line-to-ground power-frequency voltage on a sound phase, at a selected location, during a line-to-ground fault affecting one or more phases [13]. It can be formulated as:

$$COG = \frac{V_{\max_line-to-ground}(\text{during fault})}{V_{\text{line-to-line}}(\text{pre-fault})}. \quad (3)$$

If the COG is below 80%, the location is called effectively grounded.

D. Grounding Practices When Integrating DERs

DER interconnection standards, such IEEE 1547–2018 [14] and the Canadian Standards Association CSA C22.3 No. 9:2020 [15], address the several possible grounding conditions

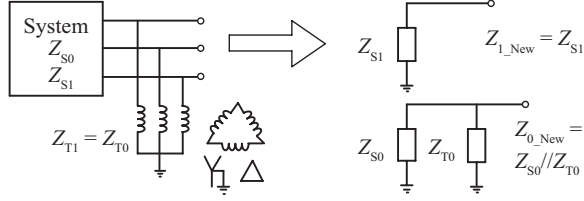


Fig. 4. Illustration of a grounding transformer connection a generic power system and how it impacts the zero-sequence equivalent network.

when interconnecting DERs. However, no standard prescribes transformer winding configurations, leaving it up to the electric utility how to achieve effective grounding. As explained in [16], some utilities do not allow a DER transformer connection configured as a Δ LV – Yg MV, because this transformer provides a low impedance ground path, effectively reducing the ground current flowing through upstream protective devices. This effect was analytically quantified and described in [17]. With high penetration of DERs, this effect can indeed become unmanageable by the electric utility. However, the configuration (Δ LV – Yg MV) has many advantages:

- Improving K improves grounding in weak systems.
- Large synchronous DGs often require an ungrounded, or high impedance grounded system, typically through an NGR. This is often done to avoid overheating and consequential damage due to elevated single-line to ground fault levels at the generator side.
- Large string inverters and central inverters are sometimes connected in delta as well. Even if connected in wye, they do not supply zero-sequence current as they are balanced current sources.

Hence, to provide a grounding reference on the distribution feeder, it is necessary to either employ a Δ LV – grounded wye MV or to install a grounding transformer. The next subsection addresses the second option.

E. Grounding Transformer Design

Grounding transformers can come in several configurations. In distribution system applications, a grounding transformer is typically a Zig-Zag- Δ or an Yg- Δ (low side Δ winding is kept unloaded). The grounding transformer provides a ground source by providing a very low impedance zero-sequence path. Fig. 4 illustrates the design of a grounding transformer. In a system with Z_{S1} and Z_{S0} impedances at a given location, a grounding transformer with Z_{T1} and Z_{T0} is installed.

The new zero sequence system impedance Z_{0_New} can be calculated as (given the typical high X/R ratio of the transformer, it is assumed it does not alter the system positive-sequence impedance meaningfully):

$$Z_{0_New} = Z_{S0} // Z_{T0} \quad (4)$$

Utilizing (1), which represents a criterion for effective grounding, Z_{T0} can be obtained. The required transformer rating, in kVA, can then be calculated by

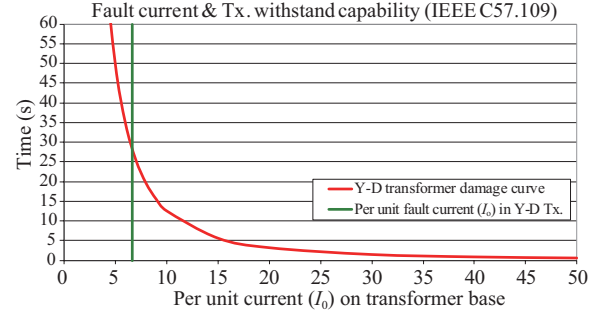


Fig. 5. Transformer damage curve vs. per unit ground current supplied by the transformer during fault.

$$S = Z_{base} \% \times V^2 / Z_{T0} \quad (5)$$

Furthermore, the transformer needs to be properly rated and verified not be damaged during system faults, as per [18], which prescribes minimum requirements for through-faults of transformers (damage curve). This is the minimum manufacturing requirement and results in a decaying curve that relates fault current ($3I_{T0}$) and clearing times. A calculated as per [18] is shown in Fig. 5 (decaying curve). The fault contribution of a sample grounding transformer (obtained from short-circuit software) is shown in the vertical line. In this example, the transformer contributes about 7 times its rated current to the ground fault, and it will suffer damage if the fault persists longer than 28 s.

V. CHARACTERISTICS OF THE SYSTEM UNDER STUDY

As most microgrids with high penetration of inverter-based generation, the system under study has many of the same limitations experienced in other similarly sized microgrids.

A. Available Short-Circuit Current in Islanded Mode

As discussed earlier, the microgrid is equipped with a 1.6 MWh BESS and an aggregate 2.2 MWac PV system. Their inverter short-circuit capabilities, as provided by the manufacturer, are 1.13 p.u. and 1.0 p.u., respectively. This is maximum line-line-line (LLL) fault contribution. Conversely, the BESS is coupled through a Δ -Yg (Δ low side) transformer, resulting in substantial line-ground (LG) fault contribution (due to the transformer, not the BESS). Hence, it is not possible to use overcurrent protective elements to adequately protect the system for LLL faults, and only possibly to protect against LG faults. Tables I, II, and III show the fault current contributions of each component (diesel plant, PV farm, and BESS) for LLL, LG, and impeded LG (20 Ω faults placed at the end of the feeder when the microgrid is grid-connected). When operating under grid-connected mode, the medium-voltage fault interrupters installed at the BESS and PV point of common coupling (PCC) should not trip, as these do not have auto-reclosing enabled (for obvious reasons). In these tables, DiG stands for diesel generator and I_{Plant} denotes the current detected at the feeder head emanating from the diesel plant.

TABLE I
SHORT-CIRCUIT RESULTS FOR AN LLL BOLTED FAULT AT THE END OF LINE

Parameters	1 DiG	1 DiG + BESS	1 DiG + BESS+PV	2 DiG	3 DiG	3 DiG + BESS+PV
I_{total}/A	123	160	214	214	282	357
I_{Plant}/A	123	121	117	214	282	269
I_{BESS}/A	-	39	38	-	-	34
I_{PV}/A	-	-	46	-	-	42
V_{DiG}/V	380	480	600	720	1000	1080
V_{BESS}/V	-	50	60	-	-	100
V_{PV}/V	-	-	70	-	-	120

LLL ($I = I_p$).

TABLE II
SHORT-CIRCUIT RESULTS FOR AN LG BOLTED FAULT AT THE END OF LINE

Parameters	1 DiG	1 DiG + BESS	1 DiG + BESS+PV	2 DiG	3 DiG	3 DiG + BESS+PV
I_{total}/A	192	223	278	291	348	407
I_{Plant}/A	192	137	167	291	348	245
I_{BESS}/A	-	86	104	-	-	153
I_{PV}/A	-	-	6	-	-	9
V_{DiG}/V	900	1000	1000	1240	1470	1530
V_{BESS}/V	-	100	110	-	-	140
V_{PV}/V	-	-	130	-	-	280

LG_0Ω ($I = 3I_0$).

TABLE III
SHORT-CIRCUIT RESULTS FOR AN IMPEDED LG FAULT AT THE END OF LINE

Parameters	1 DiG	1 DiG + BESS	1 DiG + BESS+PV	2 DiG	3 DiG	3 DiG + BESS+PV
I_{total}/A	176	199	235	242	272	299
I_{Plant}/A	176	123	141	242	272	180
I_{BESS}/A	-	76	88	-	-	112
I_{PV}/A	-	-	6	-	-	7
V_{DiG}/V	1000	1100	1270	1500	1700	1830
V_{BESS}/V	-	110	130	-	-	180
V_{PV}/V	-	-	210	-	-	270

LG_20Ω ($I = 3I_0$).

The overcurrent protection for an LLL fault at the diesel plant is not significantly affected by the addition of the DERs and can be just as effective as it was prior to their interconnection. For ground faults, however, the fault sensed at the feeder head can reduce as much as 30% due to the apparent effect characterized in [17]. However, it is still possible to work with the existing protection philosophy.

Table IV shows the short-circuit results for islanded operation (when the BESS forms the grid). In a stark contrast to the results shown in Tables I, II, and III, overcurrent no longer works.

B. Voltage Excursions and Undervoltage Protection

The voltage envelope was obtained through short-circuit studies. The calculated voltages for the grid-connected operating mode are shown in Tables I–III, and those for the

TABLE IV
SHORT-CIRCUIT RESULTS FOR A FAULT AT THE END OF LINE (ISLANDED)

Parameters	LLL ($I = I_p$)	LG_0Ω ($I = 3I_0$)	LG_20Ω ($I = 3I_0$)
I_{total}/A	102	140	132
I_{Plant}/A	0	84	80
I_{BESS}/A	40	52	50
I_{PV}/A	48	3	3
V_{DiG}/V	220	930	740
V_{BESS}/V	30	110	90
V_{PV}/V	40	70	120

TABLE V
SYSTEM CHARACTERISTIC FOR GRID-CONNECTED AND ISLANDED MODES

Parameters	1 DiG	1 DiG + BESS	1 DiG + BESS+PV	3 DiG	3 DiG + BESS+PV	BESS+PV
R_0	16	15	15	16	15	15
R_1	12	11	11	12	11	13
X_0	24	20	20	24	19	20
X_1	116	89	66	49	38	141
X_0/X_1	0.2	0.2	0.3	0.5	0.5	0.14
R_0/X_1	0.14	0.17	0.24	0.3	0.4	0.1
K	0.25	0.28	0.6	0.6	0.6	0.18
TOV	0.8	0.9	0.94	0.9	0.97	0.94
COG	0.45	0.5	0.54	0.5	0.6	0.54

islanded mode are shown in Table IV. To note, the nominal voltage of the DiGs, BESS and PV are 4.16 kV, 480 V, and 600 V. These calculations reveal that the voltage drop at the BESS and PV systems (measured in their low voltage bus) are somewhat, under either grid-connected or islanded modes, similar to each other.

C. Performance Grounding Assessment

Tables V shows the system parameters when grid-connected (first 5 columns), and when islanded (last column and denoted as BESS+PV), calculated by using the same short-circuit software. To note, the diesel plant step-up transformers are not removed from the system, as the entire plant station service remains energized. This results in the step-up transformers acting as very strong ground sources (and essentially being grounding transformers to the system).

These results allow us to draw some observations:

1. The zero-sequence impedances do not vary significantly among the multiple operation modes. The reason being the fact the system always operates with the diesel plant step-up transformers energized. Because of their Δ -Yg configuration and size (4 MVA each), they are the major system ground sources. The additional ground source provided by the BESS step up transformer (which is a 2 MVA Δ -Yg transformer) reduces X_0 by only about 17%. Finally, the system MGN contributes to reduced degree of grounding.

2. The positive sequence impedance depends very substantially on the system configuration. Naturally, the stronger the source (more diesel generators), the smaller will X_1 be. To note, the equivalent model of the BESS and PV results in very large X_1 when the system is operating in islanded

mode. This relies on the assumption the generic BESS and PV inverter models are correct.

3. The system is effectively grounded under all operating scenarios. $K < 3$ under both microgrid operating modes.

4. The calculated $TOV < 125\%$ (condition for effectively grounded as per [13]) under both microgrid operating modes. In fact, $TOV < 100\%$ under all operating scenarios. This means that no phase will swell for a grounding fault. The calculated COG is less than 80%, the condition for effectively grounded as per [13].

VI. PROPOSED MICROGRID OPERATION, PROTECTION PHILOSOPHY, AND RESTORATION STRATEGY

The integration of the PV and BESS installations in the isolated system and its conversion to a microgrid requires new protective devices and protection philosophy. Even though the topic of microgrids has been in vogue for over two decades, most deployments have been either proof-of-concept or demonstration projects, and a notable example was presented in [19], which suggested employing a separate grounding transformer and not allowing the DER step-up transformers to introduce ground sources. There have been a few isolated microgrid implementations backstopped by similar drives of the project presented in this paper, but so far there is no consensual recommendation on how to manage performance grounding. Hence, there is no “traditional” or “baseline” topology. In response, this paper proposes an effective strategy to manage performance grounding that was suited to the unique conditions of this system. The following items were important decisions made leading up to microgrid energization.

A. BESS Transformer Configuration

The 1.6 MW BESS is being coupled with a 2 MVA, 25 kV-480 V isolation transformer. Much thought was put towards determining the transformer winding configuration and a Δ -Yg configuration was chosen. This configuration for the BESS transformer has the following advantages:

- This step-up transformer is suitable for supplying single phase-to-ground loads. It adds a ground source and allows feeder restoration even if the diesel plant is completely removed from the system, even though this is not a planned scenario.
- This transformer reduces the degree of grounding, TOV, and COG, improving performance grounding. The disadvantages of this configuration are:
- The additional ground source de-sensitizes the main feeder interrupter. As seen in Tables II, I_{Plant} reduces from 192 A, when the BESS is disconnected, to 137 A when the BESS is connected, or about 29%. The original ground overcurrent pick-up value is 50 A, which is suitable to detect LG faults, but with a longer time delay. A similar conclusion can be extracted by analyzing Table III, which shows the results for an impeded fault. The de-sensitization effect was analytically characterized in [17].
- There will be a large infeed from the BESS for LG faults (see I_{BESS} in Tables II and III). For proper operation, the

BESS overcurrent protection needs to be torque controlled by voltage (polarized).

Overall, the flexibility of allowing operation with the feeder isolation from the diesel plant (a scenario deemed not to be needed now but may be in the future) led to the choice of a Δ -Yg configuration, even considering the above disadvantages.

B. Overcurrent and Reclosing Settings at BESS and PV Fault Interrupters

The proposed settings for PV and BESS distribution fault interrupters are based on their fault contribution and intended purpose. For foreground, below are the existing feeder fault interrupter settings:

- Main feeder (where the BESS and PV, as well as most of the load, are connected to): Phase pick-up 100 A, ground pick-up 40 A. The first trip is a fuse-saving fast trip that does not coordinate with downstream fuses; subsequent reclosing enables a slower curve, with the same pick-up values.
- Adjacent feeder (which mainly supply the town airport): Phase pick-up 80 A, ground pick-up 40 A. As in the case of the main feeder, this feeder also has a fuse-saving fast trip in the first activation of the interrupter.

1) Autoreclosing Philosophy

Both fault interrupters are protecting DERs. As such, in no case, they are protecting the distribution system, but rather the equipment beyond the PCC (on the DER side). For this reason, no autoreclosing is enabled. Having said that, the microgrid controller has the capability of closing them without human intervention, as required by the operational and restoration algorithms.

2) Voltage Polarization (Torque Control)

As discussed earlier and presented in Table IV, the PV fault contribution is about the same as its steady-state current output (see I_{PV} for an LLL fault). Hence, it was determined that voltage polarization for the PV interrupter is not needed and the pick-up values chosen were 80 A phase and 40 A ground, with the same curves as those of the feeder slow settings.

However, for the BESS, while the short-circuit contribution is only slightly higher than the rated output for an LLL fault (but still below the proposed pick-up value, see I_{BESS} in Table IV), it is much higher for an LG fault (see I_{BESS} in Table IV for the LG cases), where it does exceed the proposed ground pick-up value. The latter is due to the transformer winding configuration, as discussed in the previous section. Hence, the settings chosen for the BESS interrupter are the same as those used for the PV interrupter, but with voltage polarization to avoid tripping on an upstream fault on the distribution system, which is to be cleared by the main feeder fault interrupter.

For a faulted system, and upon tripping the main feeder breaker, it is deemed that the PV inverters will detect the fault by sensing low voltage at their terminal, as well as their active anti-islanding scheme. The same is deemed for the BESS, and this is further discussed in the next section.

TABLE VI
SHORT-CIRCUIT RESULTS FOR AN FAULT AT THE END OF THE ADJACENT FEEDER
(ISLANDED MODE)

Parameters	LLL ($I = I_p$)	LG_0 Ω ($I = 3I_0$)	LG_20 Ω ($I = 3I_0$)
I_{total}/A	88	124	120
I_{Plant}/A	88	124	120
I_{BESS}/A	35	0	0
I_{PV}/A	42	0	0
V_{DiG}/V	244	1070	860
V_{BESS}/V	60	135	118
V_{PV}/V	70	90	121

C. PV and BESS Inverter Voltage Settings and Other Elements

To determine the undervoltage settings to allow detecting faults in the system, the worst-case scenario, namely a fault at the end of the adjacent feeder, was simulated in the short-circuit software. The fault currents supplied by the BESS and PV are zero because it is in series with the two plant transformers that contain a Δ in the low side, discontinuing the zero-sequence path. The results are shown in Table VI. This table also reveals that the current supplied by the PV and BESS is insignificant and incapable of activating any protection element. Hence, other elements need to be used, in this case undervoltage (27). The table also reveals that, even for an impeded fault in the adjacent feeder, the voltages at the BESS and PV drop to less than 50% of nominal, triggering energization cessation at the PV plant in 160 ms (as required by [14]) and being easy to set up in the BESS settings.

D. Islanded Configuration (Grounding Transformer)

Much of the load supplied by the microgrid is single-phase. This requires a ground source for steady-state operation, as well as to enable ground fault detection under fault condition. Hence, it was decided to install the BESS in the system with a Δ -Yg (Δ low side) transformer. This configuration provides flexibility as it would allow, if desirable, to operate the right-hand side feeder to operate islanded from the adjacent feeder.

Furthermore, as it will be described in the next subsections, the diesel plant step-up transformer will always be in the circuit when the microgrid operates in islanded mode, as the entire plant station service must remain energized. This results in the step-up transformers acting as very strong ground sources (and essentially being grounding transformers to the system). This is further illustrated in Fig. 6.

To allow supply of the adjacent feeder, reclosers R1 and R2, as well as low voltage breakers B1 and B2, must always be closed. This results in the plant transformers serving as ground sources for both feeders. In fact, this configuration results in very effective grounding, which would not be possible should these transformers not be connected.

E. Interlock-Based BESS Operation

It was decided to include in the microgrid controller logic

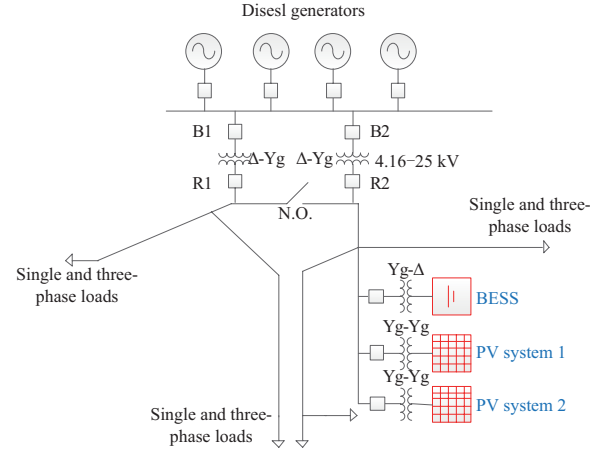


Fig. 6. Microgrid topology showing the grounding sources.

the removal of the BESS from the circuit in case any of the breakers B1-B2, and reclosers R1-R2, have their status off. This decision was based on the following logic:

- If B1 or B2 trip, this means a fault in the plant step-up transformer, requiring human intervention for diagnostics and troubleshooting. Service continuity is deemed to be of secondary importance and can be restored manually.
- If recloser R2 trips and automatically recloses, this can result in out-of-synch closing between the diesel plant and the BESS.
- If recloser R1 (adjacent feeder) trips and auto-recloses, it can result in reclosing out-of-synch (see next subsection).

F. Fifth Generator and Microgrid Controller Interlock

Given the load growth in the area, a fifth generator has been interconnected during the winter to cater for N-1-1 contingency. This is because there are times where three generators are needed to support the community, which result in only one generator being a spare. If this generator is under temporary maintenance, the system will experience a system-wide blackout, as all load in the community is critical.

As per the ISO, the isolated supply is a proxy for transmission and availability must be to the same standard. Therefore, the fifth diesel generator is required. This unit is normally connected downstream of recloser R1. To avoid potential out-of-synch reclosing, the microgrid controller directs the BESS offline if R1 trips.

G. Recloser Logic at BESS

Reclosing in the BESS fault interrupter is never enabled. These are the reasons:

1. Under grid-connected mode, reclosing should not be enabled.
2. To simplify and avoid two settings groups, it was decided not to have it enabled under islanded mode.
3. Even if reclosing was enabled under islanded mode, the BESS would be unable to ride through its trip and reclose anyways, as the entire PV plant would trip upon experiencing

an outage and would not return to service for 5 minutes, requiring entering the plant restoration procedure.

H. Restoration Procedure and Blackstart

It is not expected the microgrid configuration will noticeably disturb the system stability and reliability. It is also expected it will not require modifying the blackstart procedure from what is in place prior to the microgrid implementation. Currently, if a system-wide blackout occurs, the following are the steps followed to restore the system:

1. Plant operators initiate a start of all available diesel generators. The microgrid controller directs the BESS and PV offline.
2. Generator breakers are closed, energizing the plant 4.16 kV bus.
3. Breakers B1 and B2 are closed with a 1-minute time-delay in between.
4. Recloser R2 is closed. If there is a system fault, the normal fault finding, isolation and restoration is followed by servicemen. If there is no system fault, proceed to next step.
5. Recloser R1 is closed. If there is a system fault, the normal fault finding, isolation and restoration is followed by servicemen. If there is no system fault, proceed to next step.
6. After a settable time delay (set to 3 minutes), if the system voltage and frequency are normal, the BESS is started in grid-following mode.
7. After a settable time delay (5 minutes by default [14]), if the system voltage and frequency are normal, the PV starts production in grid following mode (this is the only mode the PV inverters can operate).

VII. 2019 INCIDENT AND FINAL CONSIDERATIONS

An incident happened in the fall of 2019. Only the first phase of the PV farm (450 kWac) was operational. In a sunny day, two diesel engines were running. The PV output ramped up to its maximum, leading one engine to start its shut-down procedure. Meanwhile, a very large cloud rapidly covered most of the PV plant, causing the single running engine to exceed its prime rating (but below its overload rating), while a third engine started its power-up procedure. This scenario was predicted and should not have caused any problems, as each engine is designed for short-term operation between the prime rating and the overload rating. However, the engine started to overheat for mechanical reasons, a situation that lasted a few minutes.

This incident indicated that the Phase 1 PV, which is not visible to the plant control algorithm, presents a risk to disturb the system balance of power and frequency. Though the ramp down of solar generation due to cloud covering cannot be controlled by an inverter, the microgrid controller introduces visibility over the generation status of the Phase 1 PV. The Phase 1 PV output can be taken into account in the instantaneous balance of system generation and load.

The added visibility of Phase 1 PV will help determine instantaneous spinning reserve of diesel generating units and BESS to avoid this problem. The commissioning date for the Phase 2 PV and BESS is in progress at the time this paper is being written, but the utility has already accumulated a large amount of lessons learned.

VIII. CONCLUDING REMARKS

Protection and grounding are among the most complex and important subjects of a microgrid. It is imperative to ensure the distribution system is effectively grounded and protection is not de-sensitized. While experiences from real microgrid deployments have presented different ways of managing performance grounding, no consensual strategy has constituted a baseline to be followed. This became apparent to the engineers of this electric utility during the planning, design, and construction of a real isolated microgrid.

In response, a performance grounding strategy had to be developed. Very importantly, it was noted a grounding source is required under islanded operation, which was supplanted by the BESS step-up transformer itself if configured as Δ -Yg (Δ low side). In addition, it was proposed to keep the feeder supply transformer, which has the same configuration, always connected to further reduce COG and TOV. The protection behavior also changed because of the consequential reduction in short-circuit levels, especially those of line-to-line contacts, an expected consequence of high penetration of inverter-based generation. A frequency and voltage-based scheme had to be developed and was detailed in this paper. Conversely, the protection philosophy had to be adjusted to ensure conventional overcurrent protection would remain effective when connected to the diesel plant supply. This paradigm shift is a new reality in forward-looking systems that are dominated by DERs.

ACKNOWLEDGMENT

The author is grateful to ATCO for the impressive project case. The author acknowledges the support of multiple ATCO employees that have significantly contributed to this project: Lloyd Sawatzky, Phil Borgel, Matt Wright, Scott Heinrich, Hesam Yazdanpanahi and Sridhar Rao.

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