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Effective Grounding of Utility-Scale Microgrids: Methods and Considerations

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SUMMARY

Distribution systems should be effectively grounded to protect the system apparatus against Temporary Overvoltages (TOV) while achieving adequate ground fault protection. The effective grounding is normally achieved by solid or low-impedance grounding of the main substation transformer(s). Interconnection of Distributed Energy Resources (DERs) introduces additional power sources across the feeders, and as a result, the possibility of higher TOV levels. Another impact of the high proliferation of DERs is de-sensitization of the utility feeder ground overcurrent protection due to ground fault contribution of DERs. The situation will become more complicated when the island operation of the whole/partial distribution feeder with embedded DERs is allowed. The main objective of this paper to discuss proper grounding of utility-scale microgrid with various types of DERs, including Inverter-Based Resources (IBRs), to manage TOV levels and ground overcurrent protection coordination. Two different methods of effective grounding will be presented in the paper. Advantages and disadvantages of each technique will also be discussed based on the outcomes of system studies conducted on a utility-scale inverter-based microgrid equipped with Battery Energy Storage System (BESS) and Solar PV System.

KEYWORDS

Selective grounding, Effective grounding, Microgrid, Relay de-sensitization, Protection, Temporary overvoltage,

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I. INTRODUCTION

In a grounded distribution feeder, system equipment is rated for 124% to 138.6% of the system line-to-ground voltage. This equals to a Coefficient of Grounding (COG) of 72% to 80%, as per IEEE Standard C62.92.1 [1]. COG is defined as the ratio of the highest root-mean square (rms) line-to-ground power-frequency voltage on a sound phase during a ground fault to the line-to-line power-frequency voltage when the fault is removed, i.e., $V_{LG\text{-}Fault}/V_{LL\text{-}Rated}$. These overvoltage values on healthy phases during a fault are called Temporary Overvoltage (TOV). To prevent experiencing high TOVs in a distribution system feeder, the main substation transformer is grounded using a solid connection to ground or by a very low impedance such that the COG is controlled below 80%. It should be noted that various utilities use different levels of acceptable COG for effective grounding.

High proliferation of Distributed Energy Resources (DER), particularly Inverter-Based Resources (IBRs), introduces additional power sources that can cause the risk of high TOVs and violate COG at their Point of Interconnection (POI). As such, the interconnecting step-up transformers or switchgear should be grounded to control the COG. Yet, there exists another impact on the system, and that is the underreach of the upstream ground overcurrent relays. This phenomenon is referred to as relay desensitization (or protection blinding). In this paper, two different methods of effective grounding of the DERs will be discussed to allow microgrid operation. The first method is based on using a grounding bank, and the second one is based on employing the readily available neutral of the generator step-up transformers. Design considerations, requirements, advantages, and disadvantages of the methods will be discussed and supported by transient studies conducted in a PSCAD model of a microgrid.

II. GROUNDING CHALLENGES

Grounding of a DER interconnection or microgrid project might seem straightforward in the first encounter but it is one the undervalued and underestimated aspects of the microgrid design. It is, in fact, a problem that involves several criteria to be met for a proper design. The first criterion is ensuring that TOVs are limited to acceptable levels (COG < 80%). This might be a simple task that can be done by phasor domain software if the DER can be properly represented/modelled. However, for IBRs such as Solar PV systems or Battery Energy Storage Systems (BESS), Electro-Magnetic Transient (EMT) studies should be performed to ensure acceptable TOV levels. This is mainly because most of the phasor-based software tools do not provide an accurate model of the IBR control, which varies with the technology. One of the main challenges associated with IBRs is their unknown negative-sequence current behaviours during an unbalanced fault.

To best mitigate high TOV levels in the presence of DERs, it is desired to minimize the zero-sequence impedance of the DER interconnection means. However, the lower the zero-sequence impedance, the higher the ground fault current contribution. Under such condition, the upstream ground overcurrent relays may be de-sensitized or even underreached. Therefore, the zero-sequence impedance should be calculated such that the COG is below 80% while the DER ground fault current contribution is not significant. This problem involves two competing criteria which push in different directions. Proper balance between the two factors is the point of discussions in this paper.

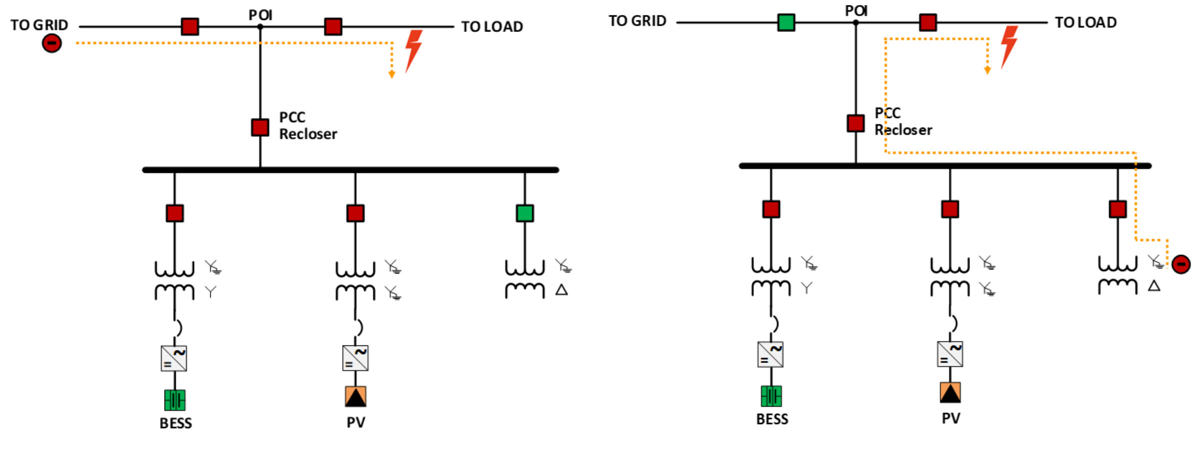
Utilities are not interested in any additional grounding across the feeder, especially in case of a DER interconnection. Some utilities only allow specific generator step-up transformers to prevent excessive ground fault current contribution by the DERs along the feeder. Two examples of the acceptable generator step-up transformers configuration are Delta/wye-grounded (Delta on high side) and Wye-grounded/wye-ungrounded (Wye-grounded on high side). Under such conditions, a grounding bank should be used in case the system can operate in the island mode to maintain effective grounding. However, since the grounding banks is normally disconnected during normal operation, the feeder or microgrid will be ungrounded immediately after the isolation from the grid. This is another challenge that is often not well-understood across the industry [3]. Another grounding method is by controlling the grounding impedance of a Wye-Grounded/Delta step-up transformer (Delta on high side). This technique will also be presented in this paper.

III. SELECTIVE GROUNDING

As discussed earlier, the challenge of accomplishing an effective grounding design is to control TOVs without de-sensitizing the ground protection relays; this can potentially be addressed by using different grounding impedances depending on the operating mode. In other words, a high zero-sequence impedance in the presence of the utility grid and a low zero-sequence impedance in the absence of the utility grid may be utilized to ensure proper grounding under both modes. This implies a “selective approach” for effective grounding impedance depending on the absence or presence of the grid. In this paper, two different techniques for selective grounding are discussed.

a. Selective Grounding Using a Grounding Bank

In this method, the zero-sequence path of the generator step-up transformers is open (i.e., no ground path is provided by the transformer). Thus, the generator step-up transformer configuration is either Delta/wye-grounded with Delta on the utility grid side, or Wye-Grounded/wye-ungrounded with the utility side being solidly grounded. As a result, the DER cannot contribute to ground faults on the system, and the utility feeder relays are not impacted. In addition, it should be ensured that the TOVs at the Point of Interconnection (POI) and downstream are still acceptable after the DER interconnection. However, isolation from the grid will cause loss of the ground, risk of high TOVs, and undetected SLG faults. As such, once the microgrid is islanded, a solidly grounded Wye-Grounded/delta grounding bank (delta on the low side) is connected to the system (interconnection switchgear) to ground the islanded system (see Figure 1). The grounding impedance is intentionally minimized to drive the maximum ground fault current from the DERs for sensitive and selective overcurrent protection in the absence of the grid.



a) Grid-connected Mode **b) Island mode**

Figure 1. Selective grounding using a grounding bank.

The advantages of this method are prevention of utility feeder ground overcurrent relay de-sensitization, maximum possible ground fault current in the island mode for reliable ground overcurrent protection, and single point of grounding. Disadvantages of this technique are temporary loss of ground current source after isolation from the grid [2], high TOVs after loss of the grid, reduced chance of seamless transitioning to island mode due to the grounding bank being disconnected after the loss of grid, the need for an additional equipment for grounding, necessity of grounding bank protection, and single point of failure.

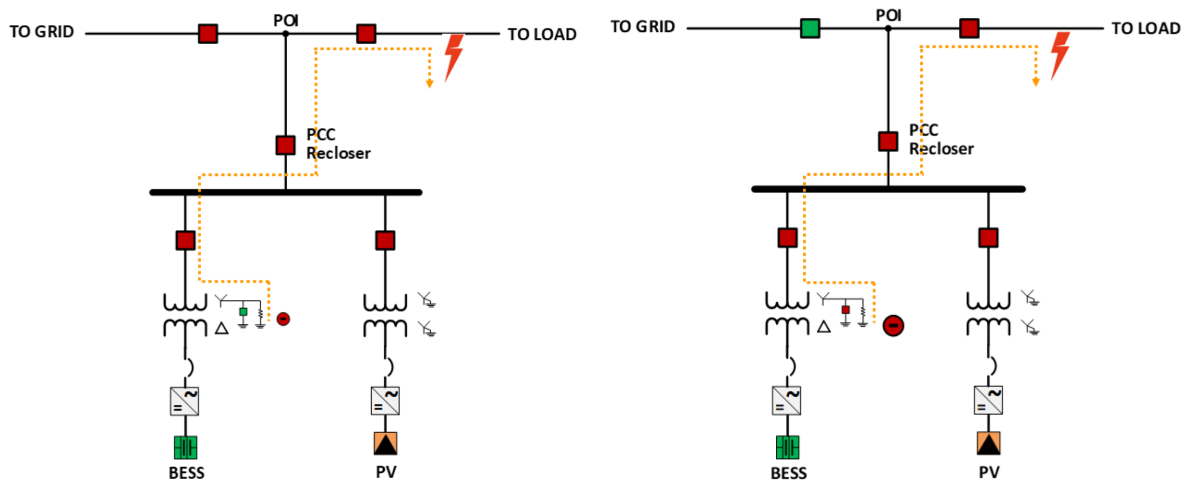
The grounding bank should be the first equipment to be connected when performing load restoration or black-start. It shall also be the last equipment to trip in case of a ground fault in island mode so that no part of the system is left energized with undetected ground faults. These are important considerations when developing the microgrid Sequence of Operation (SOO).

b. Selective Grounding Using Neutral Impedance

If suppressing the ground fault current is a necessity to avoid de-sensitization of the utility relay ground overcurrent elements, controlling the zero-sequence impedance of the generator step-up transformers is another approach to achieve this goal. For instance, if Wye-Grounded/delta transformers are used for interconnecting the DERs with the Grid (delta on low side), as shown in Figure 2, the neural grounding impedance can be chosen high enough in the grid-connected mode to reduce the injected ground fault current to such a level that the utility feeder relay is not impacted. Further, the TOV analysis can be performed to ensure that the COG is controlled to less than 80% with selected impedance. Once the system is islanded, this high neutral grounding impedance can be by-passed by a switch to a solidly grounded system in the absence of the grid to achieve maximum level of ground fault current. This scheme is another type of selective grounding since it chooses proper grounding impedance depending on the system operating condition.

The advantages of this method are using the readily available neutrals of the generator step-up transformers, removal of the grounding bank and its protective relay from the design, enhanced possibility of seamless islanding, easier ground overcurrent protection coordination, simpler SOO for microgrid operation. On the other hand, disadvantages of this technique include multiple points of grounding (one per each step-up transformer), addition of neutral grounding devices, and necessity of monitoring the health of the grounding devices [4], [5].

It should be noted that intactness and integrity of the neutral grounding impedance is mandatory per Canadian Electric Code (CEC) [4] and recommended per the National Electric Code (NEC) [5]. This means that each grounding device should be monitored using a separate relay to ensure its integrity. This is an important consideration when designing this grounding scheme.



a) Grid-connected Mode b) Island mode

Figure 2. Selective grounding using available neutrals.

IV. SIMULATION RESULTS

The aforementioned grounding schemes have been studied for a utility-scale microgrid, and the simulation results are presented in this section. The microgrid system operates at 24kV voltage level, with a BESS/PV generating facility connected to the middle of the feeder. The capacity of the BESS and PV are 6.9MW and 2.1MW, respectively. About 5MW of the feeder loads are planned to be islanded using this generating facility upon loss of the grid. In the following subsections, the simulation results for the two grounding methods are presented.

a. Selective Grounding Using a Grounding Bank

A comprehensive ground fault current analysis was performed to investigate the level of reduction in the ground current contribution of the grid when a Generating Facility (PV and BESS) is connected to the middle of a distribution feeder and is in service (see Figure 1). The fault analysis results are shown in Table 1 for four grounding resistances on the neutral of the grounding bank, i.e., 0Ω, 25Ω, 40Ω, and 50Ω. This study was done to determine the grounding bank resistance if it is to be connected in the grid-connected mode. It should be noted that grounding bank is normally disconnected during grid-connected mode.

In the absence of the Generating Facility, the first relay upstream of the POI and the first relay downstream of the POI experience 621A and 589A of ground current, respectively. The addition of the BESS and PV should not change these values significantly so that the existing protective relays are not desensitized/sensitized. This should be achieved by proper sizing of the neutral grounding resistance (NGR). With 40Ω NGR, the first upstream relay experiences about 593.16 A of residual current (4.5% below the residual current seen in the absence of the BESS/PV) while the first downstream relay experiences 715.16A of residual current, which is 15.2% higher than that experienced in the absence of the BESS/PV. This level of fault current change cannot impact protection coordination.

Another step was taken to further reduce the NGR resistance to 25 Ω so that the TOV's are reduced to a safe level. With this resistance at the neutral of the grounding bank, the TOV's are controlled to 82.3% (not longer than 4ms) which is close to acceptable COG of 80% while the impact on the upstream overcurrent protective relay remains low. Therefore, it is concluded that the 25Ω NGR at the neutral of the grounding transformer is also a proper design especially due to further reducing the TOVs and lesser relay de-sensitization. When the system operates in the islanded mode, the grounding resistor can be bypassed (through switching) or kept at the same level.

b. Selective Grounding Using Available Neutrals

The same analysis as the previous section was performed for this method, and the results are shown in Table 2 for four neutral grounding resistances, i.e., 0Ω, 25Ω, 40Ω, and 50Ω. In this method, the NGRs are added to neutral of the generator step-up transformer (see Figure 2).

It can be observed that with a 40Ω NGR, the first upstream relay experiences about 556.7A of residual current (10.4% below the residual current seen in the absence of the BESS/PV) while the first downstream relay experiences 769.1A of residual current (30% higher than that experienced in the absence of the BESS/PV). Therefore, it is concluded that the **40Ω** NGR at the neutral of the BESS transformers is also a proper design especially due to further reducing the TOVs. The process of selecting a proper grounding impedance is automated to reduce the design time.

Table 1. Ground fault current analysis and utility relay de-sensitization based on PSCAD studies.

Case Study	Maximum Phase Voltage (pu)			Ground Fault Current in Grid-Connected Mode (A)					
				First Upstream Relays of the POI			First Downstream Relays of the POI		
	Grid Mode	Isolated Feeder	Island Mode	No DERs	BESS	BESS+PV	No DERs	BESS	BESS+PV
Solidly Grounded GND Banks	1.19 (0.1s)	1.19	1.251	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 646.4 IB = 136.4 IC = 38.0 IG = 479.1	IA = 643.3 IB = 136.5 IC = 33.4 IG = 481.9	IA = 610.6 IB = 107.4 IC = 109.4 IG = 589.2	IA = 908.4 IB = 108.7 IC = 110.8 IG = 896.6	IA = 907.2 IB = 109.9 IC = 111.1 IG = 892.2
NGR = 50Ω (Peak Load)	1.325 (0.11s)	1.603 (0.008s)	NA	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 592.7 IB = 141.3 IC = 94.7 IG = 605.6	IA = 589.5 IB = 143.4 IC = 93.05 IG = 607.3	IA = 610.6 IB = 107.4 IC = 109.4 IG = 589.2	IA = 746.5 IB = 110.2 IC = 112.6 IG = 699.2	IA = 747.1 IB = 108.4 IC = 113.0 IG = 700.4
NGR = 40Ω (Peak Load)	1.3152 (0.11s)	1.5465 (0.005s)	NA	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 598.2 IB = 145.9 IC = 95.7 IG = 593.2	IA = 594.9 IB = 147.9 IC = 93.4 IG = 595.1	IA = 610.6 IB = 107.4 IC = 109.4 IG = 589.2	IA = 764.2 IB = 109.6 IC = 113.5 IG = 715.5	IA = 764.7 IB = 108. IC = 113.4 IG = 716.2
NGR = 25Ω (Peak Load)	1.288 (0.11s)	1.426 (0.004s)	NA	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 612.1 IB = 154.4 IC = 95.1 IG = 560.4	IA = 608.3 IB = 156.0 IC = 91.96 IG = 563.1	IA = 610.6 IB = 107.4 IC = 109.4 IG = 589.2	IA = 809.9 IB = 107.7 IC = 115.6 IG = 760.3	IA = 809.1 IB = 106.1 IC = 115.9 IG = 760.5

Table 2. Ground fault current analysis and utility relay de-sensitization.

Case Study	Maximum Phase Voltage (p.u.)			Ground OC Relay Underreach/Overreach Analysis only in Grid Mode			
	Grid Mode	Isolated Feeder	Island Mode	First Upstream of the POI Ground OC Relay Maximum Phase Current (A)		First Downstream of the POI Ground OC Relay Maximum Phase Current (A)	
				Without BESS	With BESS	Without BESS	With BESS
Solidly Grounded BESS TX's	0.935	0.907	1.05	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 778.6 IB = 396.6 IC = 238.8 IG = 144.3	IA = 610.6 IB = 107.44 IC = 109.42 IG = 589.2	IA = 1374.9 IB = 133.1 IC = 131.5 IG = 1333.4
50Ω resistance at the neutral of each BESS TX in grid mode (Peak Load)	1.339 (0.11s)	1.45 (0.080s)	NA	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 607 IB = 183.3 IC = 128.2 IG = 575.5	IA = 610.6 IB = 107.44 IC = 109.42 IG = 589.2	IA = 813.7 IB = 109.8 IC = 118.7 IG = 741.3
40Ω resistance at the neutral of each BESS TX in grid mode (Peak Load)	1.334 (0.122s)	1.4168 (0.02s)	NA	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 616.98 IB = 196.5 IC = 140.08 IG = 556.7	IA = 610.6 IB = 107.44 IC = 109.42 IG = 589.2	IA = 847.2 IB = 109.2 IC = 121.4 IG = 769.1
25Ω resistance at the neutral of each BESS TX in grid mode (Peak Load)	1.31 (0.11s)	1.31 (0.023s)	NA	IA = 603.9 IB = 133.9 IC = 133.4 IG = 621.1	IA = 644.4 IB = 230.5 IC = 172.3 IG = 504.3	IA = 610.6 IB = 107.4 IC = 109.4 IG = 589.2	IA = 938.3 IB = 107.5 IC = 129.7 IG = 849.6

V. COMPARATIVE ANALYSIS

this section provides a comparative analysis between the two grounding schemes. The technical comparison between the two methods is listed in Table 3 providing design consideration, requirements, advantages, and disadvantages.

VI. CONCLUSIONS

In this paper, two methods of effectively grounding a utility-scale microgrid equipped with Inverter-Base Resources (IBRs) were discussed. The main considerations in the design of grounding scheme are temporary overvoltage values and ground overcurrent coordination. A detailed technical comparison between the two methods was also performed to help with the selection of a right method, depending on the system requirements. While using the available neural of the generator step-up transformers is more convenient, attention should be given if several parallel generator step-up transformers are used in a generating facility affecting the ground fault detection.

The two grounding methods presented in this paper can be employed with various types of distributed energy resources; however, the design of the microgrid grounding scheme with high penetration of IBRs should accommodate for unknown behaviour of negative-sequence contribution from IBRs during unbalance conditions. An iterative approach was used to design the grounding resistance with IBRs.

Table 3. Technical comparison between selective two grounding methods.

Comparison Factors	Grounding Method 1: Using Grounding Bank	Grounding Method 2: Available Neutrals
Considerations	BESS step-up transformers should be Delta/delta, Delta/wye-grounded (Delta on MV side), or Wye-ungrounded/wye-grounded).	BESS Step-up transformers should be Wye-grounded/delta (delta on LV side).
	The grounding bank should not be connected in grid mode to not cause relay de-sensitization. Otherwise, it needs to be resistance-grounded to reduce the utility relay de-sensitization.	The neutral of the BESS transformers should be solidly grounded in island mode to maximize the ground fault current and resistance-grounded in grid mode to minimize the TOVs.
	The grounding bank must be connected before forming an island. It must also trip as the last equipment in the island to not leave the system ungrounded before de-energization.	Neutral of the BESS step-up transformers should be sized to tolerate LG voltage for 60sec due to intentional resistance insertion.
Advantages	No need for installation of several NGRs, one per each BESS transformer.	There is no need for having a reserve grounding bank for replacing in case of its failure.
	Several grounding resistances are not normally required.	A separate grounding bank is not required.
	Grounding resistances monitoring is not required.	Grounding bank relaying is not required.
	Lower impact on utility overcurrent relays.	Requires higher (2 times) grounding impedance for mitigating relay de-sensitization.
	Single point of grounding suitable for easier ground overcurrent coordination design.	Multiple points of grounding meaning higher reliability.
		Readily available neutral of the BESS step-up transformers will provide grounding in both island and grid-connected modes (balanced three-phase voltage and no high TOV).
Disadvantages	Single point of failure.	Multiple points of grounding cause reduced ground fault current (lesser accuracy).
	Risk of high TOVs after loss of the grid, as the grounding bank is not normally connected in the grid-connected mode.	This method always provides the system with at least one grounding point.
	The grounding bank adds to the equipment cost of the project.	The NGRs at the neutral of the transformers require additional space.
	The grounding bank needs protection (additional engineering cost and complexity).	The grounding resistors need monitoring per each resistor.
	The grounding bank should be first equipment to connect and last to disconnect in the islanded mode, impacting microgrid sequence of operation.	The switch at the neutral of the BESS step-up transformers should be closed before transitioning to the island mode.

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