Distribution Bus Protection Upgrade Considerations When Integrating Distributed Generation

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***Abstract*—Distributed generation owners and the interconnecting utilities must fully understand all of the costs associated with the installation and operation of distributed generation when determining its feasibility and negotiating interconnection agreements. Protection systems for most distribution substations were designed assuming that there was no distributed generation on the feeders.**

It is common knowledge that feeder protection schemes may need to be modified to accommodate distributed generation. It is less known that the costs of modifying or upgrading the distribution bus protection to handle the distributed generation must be considered as well. This paper helps identify possible bus protection upgrades that may be required to maintain coordination, minimize equipment damage, and prevent misoperations that can result from the addition of distributed generation.

Many distribution substations rely on simple overcurrent element or differential schemes to protect distribution buses. The addition of distributed generation increases fault current levels and the likelihood of saturation of current transformers (CTs) originally selected for different fault current levels. Time-domain CT simulations are used in this paper to demonstrate the effect of the increased CT saturation on the following distribution bus protection schemes:

- **Coordination of time-delayed overcurrent curves**
- **Zone sequencing**
- **Low-impedance bus differential with paralleled CTs**
- **Low-impedance bus differential with dedicated CTs**

Without careful review and modification of these distribution bus protection schemes, a substantial increase in distributed generation can lead to equipment damage due to miscoordination or misoperation of bus protection for external faults. This paper identifies potential problems with each of these existing bus differential schemes and suggests possible solutions.

I. Introduction

Increased focus on renewable energy has resulted in the addition of distributed generation connected to utility distribution feeders. This distributed generation includes traditional rotating machines powered by new biogas sources and inverter-based photovoltaic or fuel cell sources. Interconnection agreements and feasibility studies focus on protection at the common point of coupling and anti-islanding detection, but the effects of the increased fault current should also be studied at other parts of the system [1].

Any addition of distributed generation increases the available fault current on the bus, potentially affecting existing bus protection scheme speed, sensitivity, security, and selectivity. The effect on these protection schemes depends on the magnitude of the fault current contribution from the distributed generation, the effect on the system X/R ratio, and the duration of the fault contribution. These factors differ based on the type of distributed generation installed.

The addition of traditional synchronous generators to the distribution system generally results in the greatest impact on fault current. Maximum fault current contributions typically range from 400 to 600 percent of the rated load of the synchronous machine [1]. Traditional synchronous generators also raise the system X/R ratio, resulting in longer time constants and greater dc offsets.

The fault contribution from inverter-based distributed generation generally is less than that from rotating generators with similar load capacity. The fault current from the inverter also has no dc offset. The behavior of inverters under fault conditions varies depending on the inverter design [2]. The current output of some inverters will spike and turn off after a few milliseconds, whereas other inverters with low-voltage ride-through capabilities will continue to feed fault current at 110 to 200 percent of their load current rating. Although the fault current impact of these sources is less than that of traditional synchronous machines, the overall impact of these sources can be significant at higher penetration levels [3].

Regardless of the type of distributed generation used, the distribution bus protection should be reviewed to ensure adequate speed, security, sensitivity, and selectivity when distributed generation is added.

II. Coordination of Time-Delayed Overcurrent Curves

Many utility distribution buses rely on time-delayed bus overcurrent relays to provide primary bus protection and backup feeder protection. The bus time-delayed overcurrent elements are coordinated with feeder overcurrent elements, assuming no fault contribution from distributed generation. The bus time-delayed overcurrent elements must operate faster than the damage curves for the distribution transformer and bus. The operate time for the bus overcurrent relays must also be minimized to limit arc-flash energy.

When distributed generation is added to the feeder, two fault conditions must be considered, as shown in Fig. 1. Fault F1 corresponds to a fault on the bus, and Fault F2 corresponds to a fault on a distribution feeder without distributed generation or with the least amount of distributed generation. With distributed generation online and a fault applied at F2, the total fault current seen by the feeder relay is the sum of the contribution from the distributed generation and the contribution from the utility. The bus overcurrent relay only measures the contribution from the utility source, whereas the feeder relay measures the contribution from the utility and the distributed generation. The differences in currents seen by the two relays result in a delay of the operation of the bus overcurrent relay with the distributed generation in service.

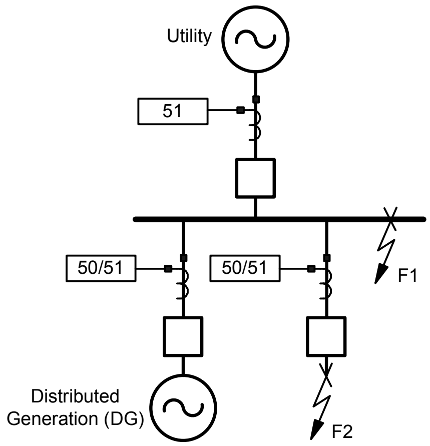

Fig. 1. Overcurrent-based bus and feeder protection.

In Fig. 2, the operate time of the curve associated with distributed generation in service is based on the utility providing 80 percent of the total fault current seen by the feeder relay. For a 10,000 A fault at F2, the operate time of the bus overcurrent relay is approximately 20 percent longer with the distributed generation in service than without the distributed generation. For a 2,000 A fault, the operate time for the bus overcurrent relay is doubled when distributed generation is online. This results in slower backup clearing for faults at F2 if the feeder breaker fails and slower clearing of bus faults at F1.

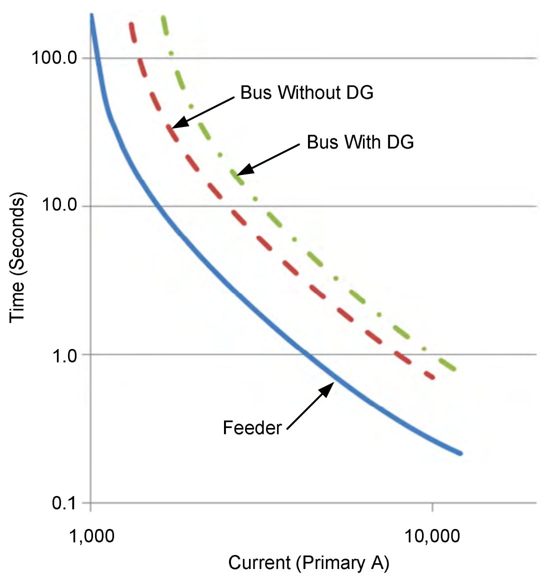

Fig. 2. Inverse-time overcurrent curves with and without distributed generation.

Arc-flash hazard calculations are based on the system voltage level, contribution from the utility source, and operate time of the bus overcurrent relay. Addition of distributed generation increases the fault current magnitude for faults at F1 without decreasing the operate time of the bus protection. This increases the arc-flash hazard energy. The resulting energy may require additional bus protection schemes such as differentials, light-based arc-flash relays, or zone sequencing to reduce the clearing times for bus faults.

III. Zone Sequencing

Zone-sequencing or fast bus schemes are frequently applied to distribution buses to accelerate the tripping time of bus overcurrent relays. In radial distribution schemes, instantaneous nondirectional overcurrent elements in the feeder relays are used to detect faults beyond the distribution bus and block a definite-time overcurrent element in the bus overcurrent relay. For faults within the bus, feeder relays without any distributed generation should detect little or zero current. The feeder relays do not send blocking signals, allowing the bus overcurrent relay to trip a high-speed overcurrent element. For feeder faults, an instantaneous overcurrent element in the feeder relay will detect the fault and block the high-speed bus overcurrent element from operating.

When distributed generation is added, feeder relays see a non-zero fault current during both feeder faults and bus faults. Depending on the magnitude of the fault current contribution from the distributed generation, the feeder relay may issue a blocking signal to the bus overcurrent relay, resulting in no high-speed operation for a bus fault. When sufficient distributed generation is added, zone-sequencing bus protection schemes need to be modified to use directional relays or be replaced with differential relays to maintain reliable high-speed clearing for bus faults.

IV. Low-Impedance Bus Differentials

Two-winding percentage differential relays have been applied to distribution buses to provide high-speed clearing for bus faults. The single source is connected to a dedicated input on the differential relay. With distribution feeders initially having no source of fault current, current transformers (CTs) from the feeder breakers are paralleled and connected to the second input on the differential relay. In digital percentage differential relays, the operate current (I_{OP}) and restraint current (I_{RT}) are calculated based on (1) and (2) [4] [5]. The operate quantity is compared with the restraint quantity times slope (k), as shown in (3), to generate a tripping decision.

$$I_{OP} = |IW1 + IW2| \quad (1)$$

$$I_{RT} = |IW1| + |IW2| \quad (2)$$

$$I_{OP} > k\, I_{RT} \quad (3)$$

Without any fault contribution from distributed generation, the slope (k) setting can be calculated based on the saturation voltage (V_s) shown in (4) and (5) [4].

$$V_s = (1 + X/R)I_r Z_b \quad (4)$$

where:

I_r is the maximum fault current in per unit of the CT rating.

Z_b is the burden in per unit of the standard burden.

X/R is the X/R ratio of primary fault current.

$$k = 0.824(V_s) - 0.00242(V_s)^2 \quad (5)$$

For the distribution bus differential application described in Table I, when the distributed generation is not in service, a percentage differential relay in this scenario requires a minimum slope of 45 percent to be secure for worst-case CT saturation. The saturated outputs of CTs were simulated, and the resulting operate and restraint currents were calculated. Fig. 3 shows that the 45 percent slope is secure for operate and restraint currents for a 10,000 A external fault under worst-case dc offset and CT saturation conditions.

TABLE I
SIMULATION CONDITIONS

Simulation Parameter	Value
Maximum Utility Fault Contribution	10,000 A
Maximum Distributed Generation Fault Contribution	2,000 A
System X/R Ratio	40
CT Ratios	1200/5
CT Accuracy Class	C200
CT Effective Burden	0.4 ohms
Remanent Flux	0 pu

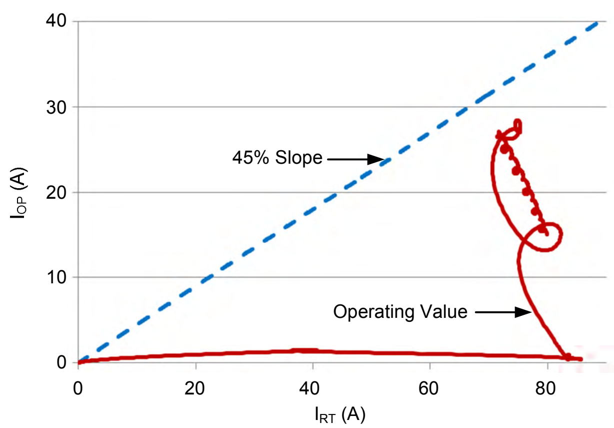

Fig. 3. Differential relay operate and restraint quantities for an external fault without distributed generation fault contribution.

Equations (4) and (5) can be applied to calculate a minimum secure slope setting when distributed generation is added as long as the feeder with distributed generation is connected to a dedicated restraint input on the differential relay, as shown in Fig. 4. With the addition of the distributed generation, (4) and (5) yield a minimum secure slope setting of 52 percent. The outputs of all three CTs were simulated and applied to the logic shown in Fig. 5 to calculate the operate and restraint currents. The additional fault current contribution from the distributed generation resulted in increased operate and restraint quantities.

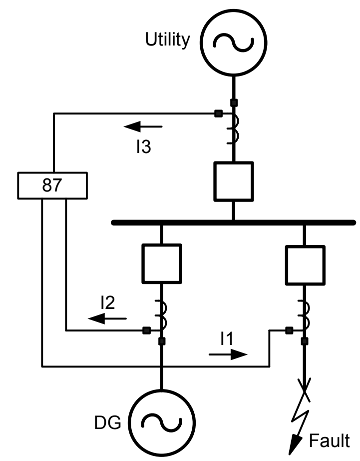

Fig. 4. Dedicated restraint input for each source.

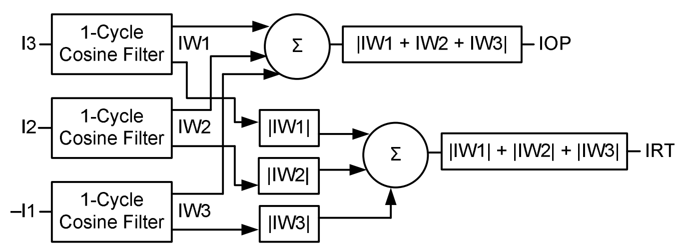

Fig. 5. Calculation of operate and restraint quantities when dedicated differential relay inputs are used for each source.

The 45 and 52 percent slope characteristics are shown in Fig. 6 along with the operate and restraint quantities when distributed generation is added. The 45 percent slope that was secure without distributed generation may result in an undesirable trip for an external fault when distributed generation is online. Increasing the slope setting to a minimum of 52 percent is necessary to secure the differential relay for external fault conditions.

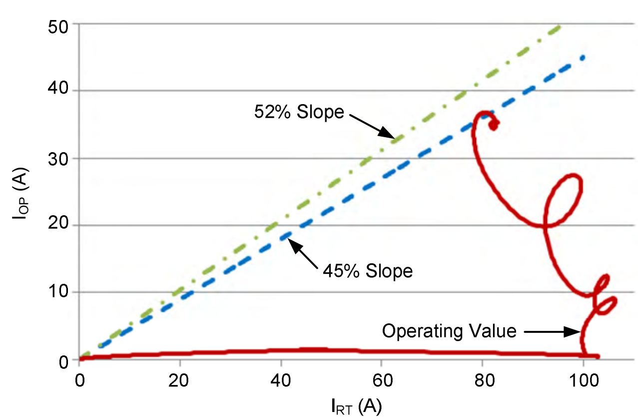

Fig. 6. Differential relay operate and restraint quantities for an external fault with distributed generation fault contribution and dedicated inputs for each source.

Additional care must be taken when CTs from feeders with distributed generation are paralleled with CTs from other feeders, as shown in Fig. 7. The resulting current into the input of the differential relay is composed of the difference between the feeder currents. This increases the operate current based on the fault contribution from the distributed generation without increasing the restraint current. The resulting logic associated with this simulation is shown in Fig. 8.

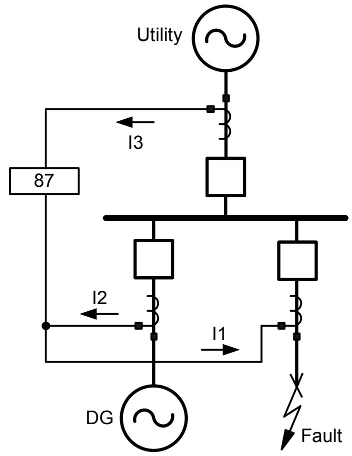

Fig. 7. CTs paralleled before connecting to a differential relay.

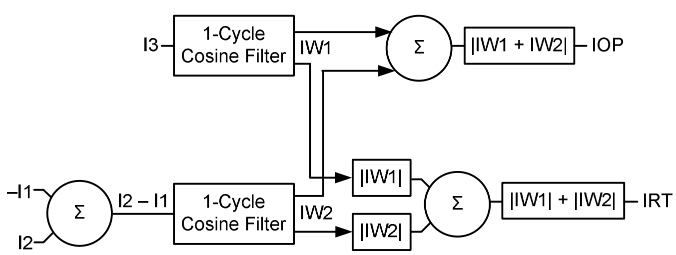

Fig. 8. Calculation of operate and restraint quantities when source and faulted feeder CTs are paralleled.

The outputs of the CT simulations are summed to emulate the paralleling of the CT secondary circuits before routing the data to the differential element. The resulting summation of the feeder currents is shown in Fig. 9. This parallel sum is then compared with the contribution from the utility source I3, as shown in Fig. 10.

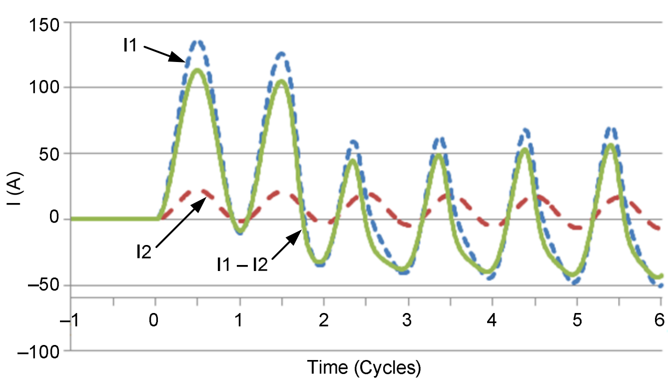

Fig. 9. Summation of the current waveforms from CT simulations.

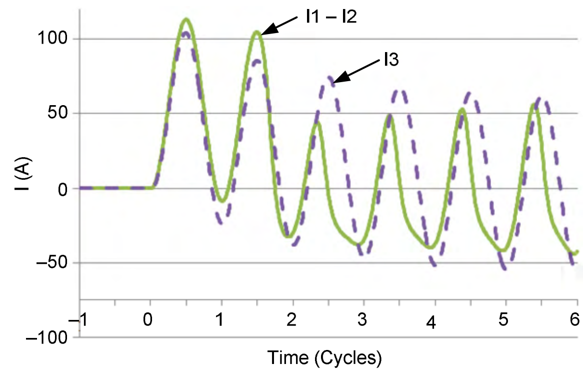

Fig. 10. Inputs into differential relay elements.

The resulting operate and restraint currents in Fig. 11 show that the 52 percent slope calculated using (4) and (5) is no longer secure if a CT from a feeder connected to distributed generation is paralleled with a CT from the faulted feeder. Additional increases beyond the previously calculated minimum slope may be necessary to secure the differential relay, resulting in reduced speed and sensitivity. Paralleling CTs from source feeders as described in this scenario is generally not recommended [5].

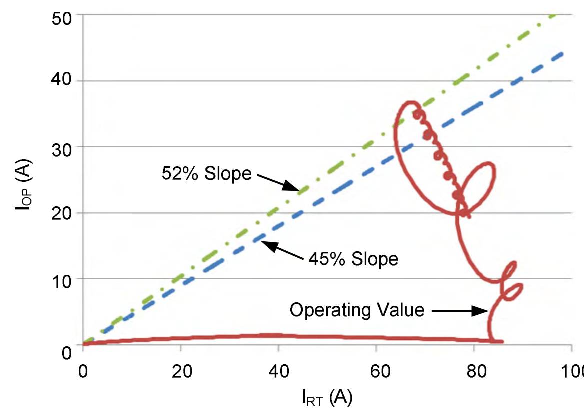

Fig. 11. Differential relay operate and restraint quantities for an external fault with distributed generation fault contribution and paralleled feeder CTs.

In both example scenarios, an increase in slope is required to secure the low-impedance percentage differential relay for external faults when distributed generation is added. This increase in slope also reduces the sensitivity and speed of the differential relay for internal fault conditions. Changing to a dual-slope characteristic will regain some speed and sensitivity for lower-magnitude internal faults, but it still results in decreased speed and sensitivity for high-magnitude internal faults. Adaptive slope characteristics with additional internal and external fault detection logic can also be applied to enhance both sensitivity and speed for all internal faults while remaining secure for external faults under the worst-case dc offset and CT saturation [6]. If dedicated, matched CTs are available, high-impedance bus differentials provide better sensitivity for internal faults and increased security for external faults than low-impedance differentials do when distributed generation is added.

V. Conclusion

Significant increases in fault current from distributed generation can affect the speed, sensitivity, security, and selectivity of distribution bus and feeder protection. Operation of bus inverse-time overcurrent elements is delayed when distributed generation is online. Additional bus protection schemes may be required to improve speed to reduce arc-flash hazards. Directional overcurrent elements may need to be added to zone-sequencing and fast bus schemes to improve sensitivity. CT connections and fault contribution from distributed generation can have significant effects on the minimum secure slope settings of bus percentage differential relays. As the penetration of distributed generation increases, more advanced bus protection schemes will be necessary to protect distribution buses.

VI. References

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VII. Biography

Edsel Atienza received his BSEE from the University of Idaho in 2001. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2002 as an international field application engineer. In 2006, Edsel joined Tampa Electric as a substation operations engineer responsible for relay testing and maintenance. He returned to SEL in 2008, serving the southeastern United States as a field application engineer.

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