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Modeling Distribution Feeder with Distributed Generation (DG) in ASPEN

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SUMMARY

Distributed Energy Resources (DER) on electric distribution feeders resulted in Dominion Energy System Protection Engineers rethinking the way we model feeder zone 1 impedances in ASPEN. Fault current contributions from inverter sources have a direct impact on the effective current seen by the feeder breaker relays. Impedance modeling, for the propose of creating protective settings for feeder relays, have traditionally required a simple model of impedances to represent impedances from the feeder relay to a downline zone 1 protective device. However, with the proliferation of DG, it is found that our simple model will provide inaccurate results for non-radial distribution circuits. Our simple model format 'single-bus' underestimates fault currents from the utility side and therefore could result in relay mis-coordination. A more representative model of distribution impedances will provide accurate fault current flows and therefore better protection.

KEYWORDS

Modeling, SynerGEE, ASPEN, Distribution, Impedances, DER Impact

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Background

Dominion Energy uses SynerGEE to model Electric Distribution's impedances up to the feeder breaker and ASPEN to model all of Transmission's impedances down to the feeder breaker and zone 1(the portion of the primary feeder protected by the feeder breaker). Protection settings for the feeder relay are developed using ASPEN. Traditionally, System Protection Engineering (SPE) has modeled this zone 1 impedance in ASPEN by use of a simplified 'single-bus' format (Figure 1). The 'single-bus' format of modeling contains line impedance and device setting information of first zone devices in ASPEN format. In Figure 1, '307 72' represents the location of the feeder breaker relay. Despite the fact that circuit topology and device relative connectivity are not represented, the 'single-bus' model has traditionally been considered adequate for documenting reach and time coordination for radial distribution lines. Modeling the true topology of the distribution circuit's zone 1 as mainlines, braches, and taps will be considered in this paper and will be referred to as the 'Mainline & Branch' format herein.

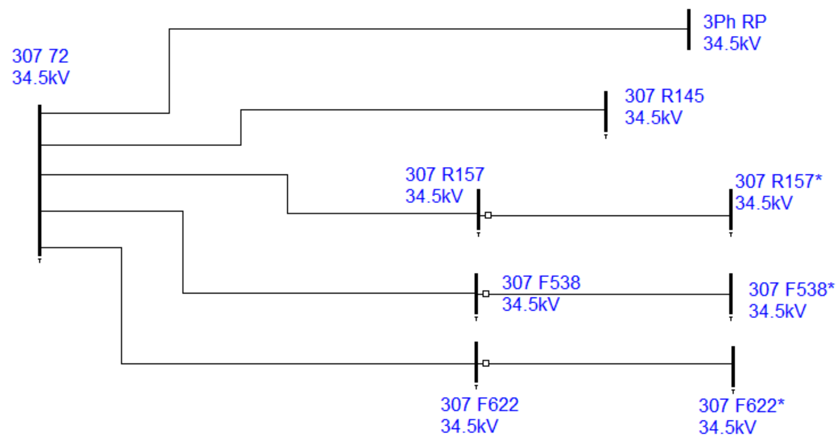

Figure 1. The Single-bus Format.

As DG penetration reaches higher levels, their fault current contribution has to be carefully evaluated. Figure 2 shows a simplified topology of DER that is connected to a utility source. Within the Dominion territory, inverter based solar generation is the dominant distribution generation resource and thus studied in this report for illustration purpose. The solar inverter is characterized as providing solely positive sequence current no more than a pre-defined current limit during fault period. The current limit is typically at 1.1 to 1.2 times of full DG output current.

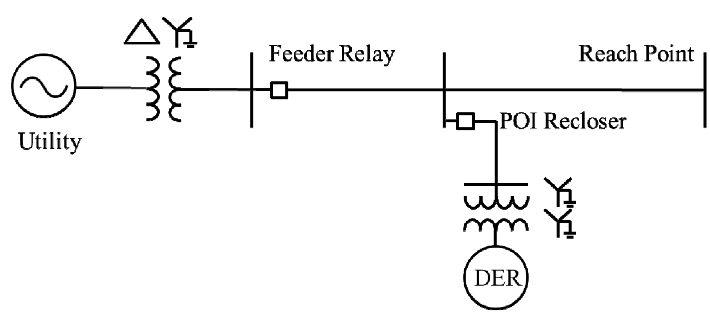

Figure 2. Simplified Feeder Topology with DERs.

Simulation Study – Underestimated Fault Current

To illustrate the difference in simulated fault current between two modeling approaches, i.e. the 'single-bus' format versus a 'mainline & branch' format, a feeder is studied (Figure 3). The feeder parameters are based off real values. A first zone recloser, R1, is located at the end of the circuit and needs to coordinate with the feeder relay. Two 20 MW (40 MW in total) solar generation sites are connected to the point of interconnection (POI) through 34.5/0.6 kV transformers. For simplicity, the two sites are aggregated into one single generator. The POI is located at the mid-point of the circuit.

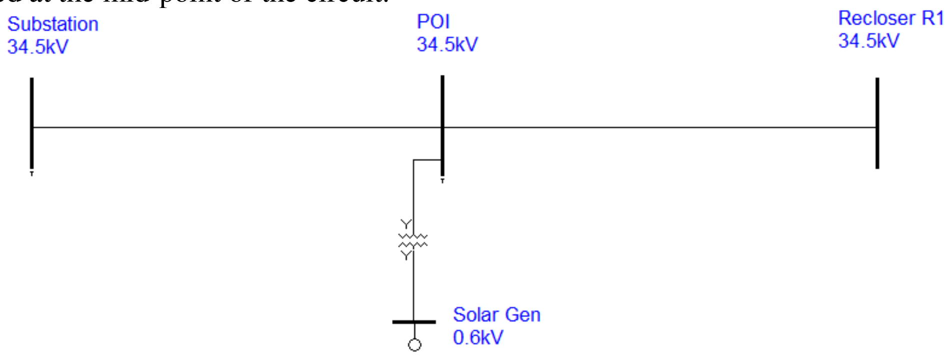

Figure 3. The Simple Feeder for Simulation Study

Figure 4 shows the feeder models as built in ASPEN. The circuit on the top, suffixed by _O, is modeled using the 'single-bus' model approach. The POI is connected to the substation through a line segment, although the POI is physically located half-way between the feeder and the recloser. The circuit at the bottom, suffixed by _N, is modeled using the 'Mainline & Branch' model approach. The topology is identical to the actual feeder.

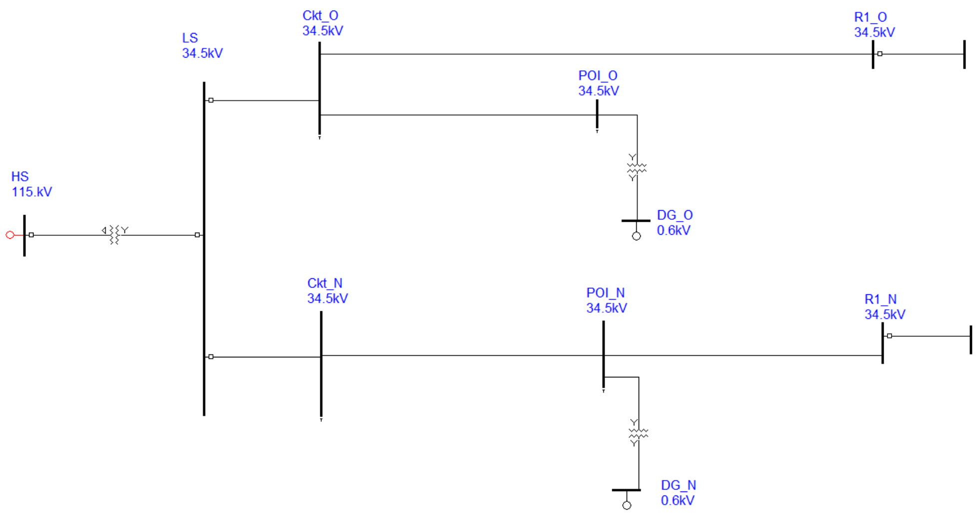

Figure 4. Feeder Models in ASPEN

To simulate the coordination between the feeder relay and Recloser R1, a close-in fault is applied on the recloser. Table 1 summarizes the difference in simulated fault current observed by the feeder relay. It is noticed that the single-bus model underestimates the fault current by over 100 A.

Table 1 Comparison of Simulated Fault Currents

	3 phase fault (Ip)	**1 phase ground fault (3*I0)**
Single-Bus Format	2305 A	2591A
Mainline & Branch Format	2422 A	2774A
Mismatch	117 A	183 A

It is also found that larger mismatch can be observed if the solar site is located closer to Recloser R1. Assuming the POI is located 75% between the feeder and recloser, the discrepancy in fault current increases by 50% (Table 2). The modeling approach significantly changes simulated fault currents.

Table 2. Comparison of Simulated Fault Current with the POI Closer to the Recloser

	3 phase fault (Ip)	**1 phase ground fault (3*I0)**
Single-Bus Format	2305 A	2568A
Mainline & Branch Format	2480 A	2842A
Mismatch	175 A	274 A

The discrepancy in simulated fault current can be understood by decomposing the fault current contribution from the utility side and the DG. As shown in Figure 5, there are two sources feeding the fault. The utility source consists of dominantly synchronous generators and is therefore acting as a constant voltage behind impedance source. The DG source is electrically close to the fault location and provides fault current at its maximum limits. The DG behaves as a constant current source during a fault. By applying the superposition principle, the faulted circuit can be decomposed into two separate circuits: i.e. the no DG circuit and the DG circuit. In the single-bus model, the DG fault current dividing point is located at the feeder bus (instead of a midpoint on the distribution line as in the 'Mainline & Branch' model), leaving more fault current flowing to the utility side due to smaller impedance. As a result, the net fault current from utility side, $I_{utility} = I_{utility\text{-}No\ DG} - I_{DG\text{-}utility}$, is smaller in the single-bus model.

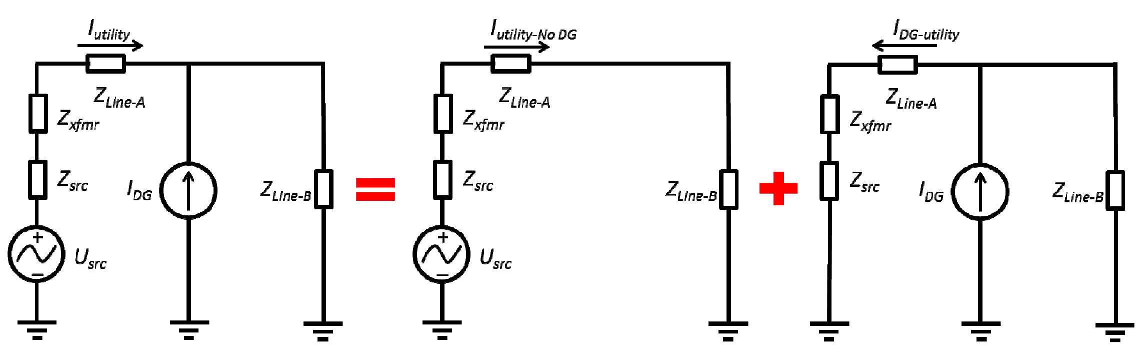

Figure 5. Fault Current Superposition

Mathematically, the fault current difference can be expressed as $I_\Delta = \frac{Z_{Line-A}}{Z_{total}} \cdot I_{DG}$, where $Z_{total} = Z_{src}+Z_{xfmr}+Z_{Line-A}+Z_{Line-B}$. There is no difference in fault current if the current dividing point is located at the feeder bus. And the difference increases as the current dividing point is moved towards Recloser R1 or the capacity of the DG increases.

Relay Mis-coordination

Since the single-bus model underestimates the fault current from the utility side, there are potential risks of mis-coordination between feeder relays and the first zone recloser under study. Using the previous feeder example, clearing time separation derived from the single-bus model is 0.400 seconds, whereas the separation in the 'Mainline & Branch' model is 0.357 seconds (Table 3). A 10% reduction in time margin may become a concern for circuits that have tight time coordination. Additionally, it is noticed from Table 3 that the single-bus model also underestimates DG's in-feed contribution to the fault at the recloser.

Table 3 Feeder Relay and Recloser Time Coordination

	Fault current seen by feeder relay (A)	Feeder relay clearing time (s)	Fault current seen by Recloser R1 (A)	Recloser clearing time (s)	Clearing time separation (s)
Single-Bus Format	2305	0.731	3106	0.331	0.400
Mainline & Branch Format	2480	0.657	3282	0.300	0.357

Over-reach of Instantaneous Tripping

Instantaneous tripping protection is enabled at feeder relays to obtain optimum equipment protection. Both phase and ground instantaneous values are set, above which feeder relay breakers will trip on high speed. The high speed tripping protects against high fault current close to the bus and relieves transformer through-fault current duty. Ideally, instantaneous tripping covers feeder's primary zone. However, due to switching transient and coordination with down-line over-current devices, instantaneous settings are set in a manner that will not over reach the closest down-line recloser.

Since the single-bus format underestimates fault current on down-line devices, the instantaneous settings, which are set to a percentage of the recloser close-in fault current, will be lower than the ideal values and potentially over reach down-line reclosers. Using the example in the above section, the instantaneous setting is set at 2700 A and gives a ratio of 117% (2700 A/2305 A), which gives a false sense of adequate under-reach margin. However, using the accurate mainline & branch format model, the actual margin is 109%, which may lead to over-reach of the down-line recloser. Therefore, the single-bus format should not be used for instantaneous tripping settings.

Conclusion

In this paper, two types of distribution feeder model formats are compared. The conventional single-bus format, which only represents the impedance between substations and first zone devices without topology information, underestimates true fault current with the presence of distributed generation. The mainline & branch model is recommended to be used for DG studies for accurate simulation result and relay settings.