Impact of Distributed Resources on Distribution Relay Protection

A report to the Line Protection Subcommittee of the Power System Relay Committee of The IEEE Power Engineering Society

prepared by working group D3

Abstract

This report covers how the addition of distributed resources will impact the distribution relay protection of the system. The issues covered include protective device coordination problems due to infeed and bi-directional current flow; effects on synchronizing and autoreclosing; the potential for forming small islanded systems; and issues related to ground fault detection. The types of interface transformer connections are compared. Their influence on the protection of the system is based on the type of connections. Changes to relay protection in response to the problems encountered and other solutions that have been applied are also covered. The protection of the generators and the interface protection are specifically omitted from this report. Some issues related to control of voltage levels and capacitor switching are included.

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Introduction

The use of distributed resources has increased substantially since 1998 because of the potential to provide increased reliability and lower cost of power delivery to customers. The addition of a distributed resource (DR) to a power system, particularly to the distribution system, introduces system conditions not otherwise encountered. These conditions can have a serious impact on the operation and integrity of the electric power system as well as cause damaging conditions to equipment. The main objective of this paper is to study some of these issues, particularly with respect to system protection. These issues include:

- Utility systems are designed for radial i.e. one-way current flow and fault sensing.
- The loss of the ground reference on a normally wye grounded distribution system.
- Relays applied to radial systems may lack directional sensing, coordination for reverse faults, and adequate sensitivity to detect some reverse faults
- Safety may be compromised
- Voltage control is affected
- Islanded operation of the DR
- Autoreclosing schemes must be revised
- System area stability affected
- Breaker failure affected
- Ferroresonance problems can occur

1.0 Types of Distributed Resources and History

Deregulation of the power industry, advancements in technology, and a desire of the customers for cheap and reliable electric power has led to an increased interest in distributed energy resources. DRs are attractive due to lower capital cost, potential for reduced emissions, and possibility of deferment of transmission upgrades. Unlike bulk power resources the DRs are directly connected to the distribution system, most often at the customer end. In some cases, utility installed DRs are located in the distribution substation. [1]

Wind, solar, microturbine, mini-hydro, mini-turbines, engine gensets, biomass generators, combined heat and power sources, super magnetic energy storage, and fuel cells are some the common technologies available for DR [2]. Cost associated with these technologies is still reasonably high, and must be considered along with technical issues such as increased capacity, improved efficiency and better power quality and reliability of the systems. Issues related to reliability and maintenance also have impeded the penetration of DRs. The most common application of DRs has been for situations where extremely high reliability of power supply is needed, especially for businesses with very critical loads. Automated electronics fabrication facilities, manufacturing facilities with computer-based controls, hospitals, and data processing center are examples of such businesses.

Penetration of DRs in the residential sector is far from realization. Poor reliability and steep rise in the price of electricity from the grid coupled with reduction in cost may make DR attractive for residential customers. None of these are forthcoming in the near future in the USA and other developed countries. DRs are a viable alternative for developing countries where grid supply has reliability below desirable levels. Microturbines have the potential of being a popular DR for the industrial sector. Since the utilities are not embarking on building large generating plants, they could use DR as an opportunity to develop generating resources. As a possible scenario, they could subsidize the purchase of DR by the customers and provide them maintenance services at a reasonable cost. Also, they can buy the excess energy generated by the customers.

Significant penetration of DRs will also raise new challenges in the operation of distribution systems. Currently, most of the distribution systems operate in the radial configuration, that is, the power flows only in one direction. Installation of DRs will not alter the topology of the system, but the power will be able to flow in multiple directions. The biggest impact of this is on the protection of distribution systems. Present protection schemes are simple in which fuses are used for protection of laterals and the fuses are backed by reclosers on the main feeder or the breaker at the substation. Such simple schemes will not always work with DRs. Advanced protection schemes, which can adapt to the changing distribution system configuration, would be essential. They will depend on measurement of data at strategic locations and communication of these data to intelligent relays for protection of the system. Therefore, protection will become an integral part of distribution automation. Large numbers of DRs could also lead to stability and frequency control problems. The problems that were only relevant to transmission systems will become relevant to distribution systems too. Therefore, new technologies to operate and manage the micro-grid at the distribution system will be needed.

Regulatory issues are also significant for the growth of DRs. At present regulations on siting and metering are not very well defined. 'Net metering' is the most important issue. Regulations on net metering will alter the rules for the buying and selling of power between the utility and the customers. Such rules will be very crucial for the growth of DRs.

2.0 DR Interface Transformer Connections

The selection of the interconnection transformer connection has a major impact on how the dispersed generator will interact with the utility system. [3] There is no universally accepted "best" connection. Figure 1 shows five commonly used connections. Each of these connections has advantages and disadvantages to the utility with both circuit design and protection coordination affected. Each connection should be addressed by the utility as they establish their interconnect requirements.

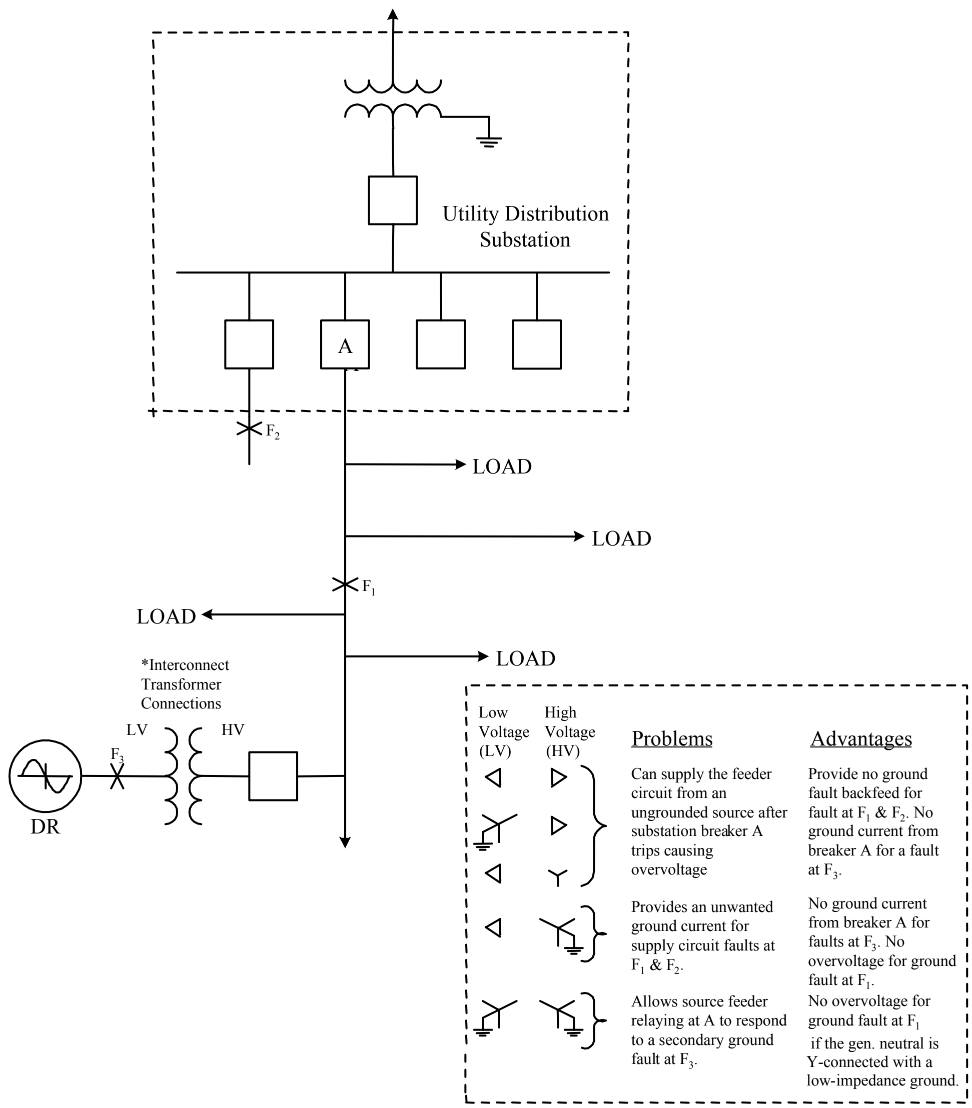

Figure 1 Interconnection Transformer Connections

2.1 High Side Delta or Ungrounded Wye

Consider the first three connections: Delta (HV)/Delta (LV), Delta (HV)/Wye-Gnd (LV) and Wye-Ungnd (HV)/Delta (LV) where (HV) indicates the primary winding and (LV) indicates the secondary winding. The major concern with these connections is in the area of circuit design. An advantage of this connection is that there is no source of zero sequence current to impact the utility ground relay coordination. Referring to figure 1, for ground faults at F1 and F2, all of the fault current will come from the utility. In addition, any ground fault on the secondary of the transformer at F3 will not be detected at the breaker A location. If breaker A is tripped for a ground fault at F1, voltage on the unfaulted phases will rise as explained in clause 3.1 of this paper. With the ungrounded connection, phase faults will have two sources of fault currents. Coordination problems can arise for fused multiphase laterals and for back feed of phase faults on adjacent feeders.

2.2 High Side Grounded Wye/ Low Side Delta

The next connection Wye-Gnd (HV)/ Delta (LV) establishes a zero sequence current source for ground faults on the distribution system, which could have a significant impact on the utility's ground relay coordination. As figure 2 shows, for a ground fault at F1, the zero sequence fault current will be divided between the breaker A location and the grounded neutral of the distributed generator interconnection transformer. The distribution of this fault current will be dependent on the circuit and transformer impedances. Figure 3 is the symmetrical component equivalent circuit for this connection. Due to the presence of the delta secondary configuration, the zero sequence current source is independent of the status of the generator and the generator breaker. In addition, any unbalanced load on the distribution circuit would normally return to ground through the utility transformer neutral. With the addition of the generator interconnection transformer this unbalance will be divided between the utility transformer neutral and the generator interconnect transformer. During serious unbalance conditions such as a blown lateral fuse, the load carrying capability of the interconnection transformer can be reduced. The advantages are that the relaying at breaker A will not see a ground fault at location F3 in figure 1 and no overvoltage problems are associated with this connection.

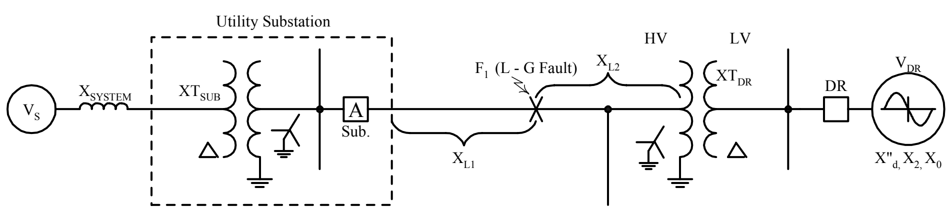

Figure 2 - Single-Line Diagram for Wye-Grounded (HV) / Delta (LV)
Interconnection Transformer

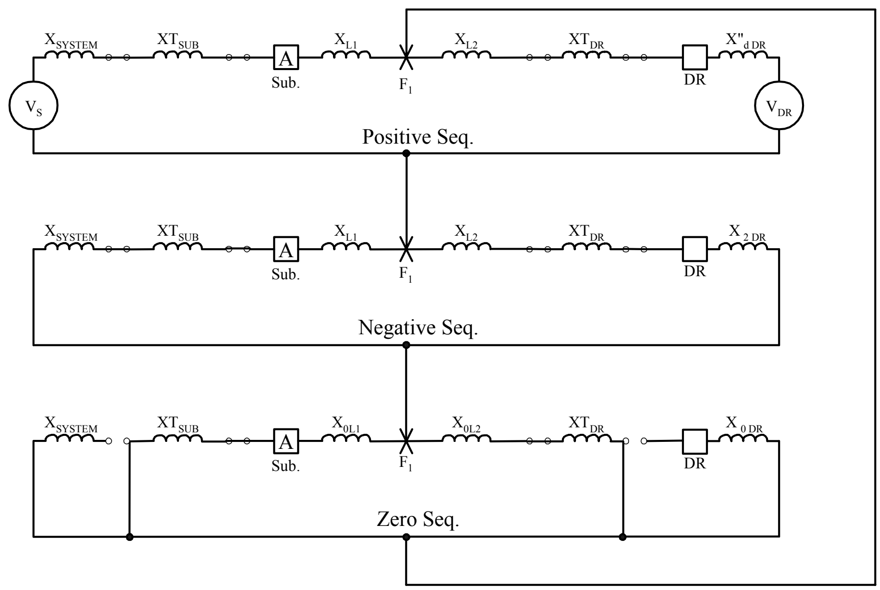

Figure 3 - Symmetrical Component Circuit for
Wye-Grounded (HV) / Delta (LV)
Interconnection Transformer

2.3 Wye-wye

The last interconnection transformer connection to be considered is the Wye-Gnd (HV)/ Wye –Gnd (LV). This connection establishes a zero sequence current source as in the previous example if the generator is wye connected with a grounded neutral. Ground relay coordination at breaker A is impacted and unbalance can be a problem as described earlier. The absence of a delta connection to circulate the zero sequence currents adds additional complexities for the relay engineer. Referring to figure 4, sensitive settings on ground overcurrent relays at breaker A can detect and trip for ground faults at F3. An analysis of the symmetrical components circuit for this connection demonstrates that the zero sequence contribution to ground faults on the distribution system is dependent on the status of the generator. When the generator is off line, there is no zero sequence source for ground faults on the distribution circuit. With this connection, there are no problems with overvoltage.

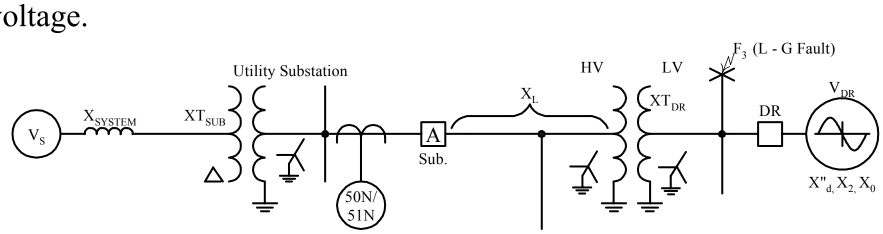

Figure 4 - Single-Line Diagram for Wye-Grounded (HV) / Wye-Grounded (LV)
Interconnection Transformer

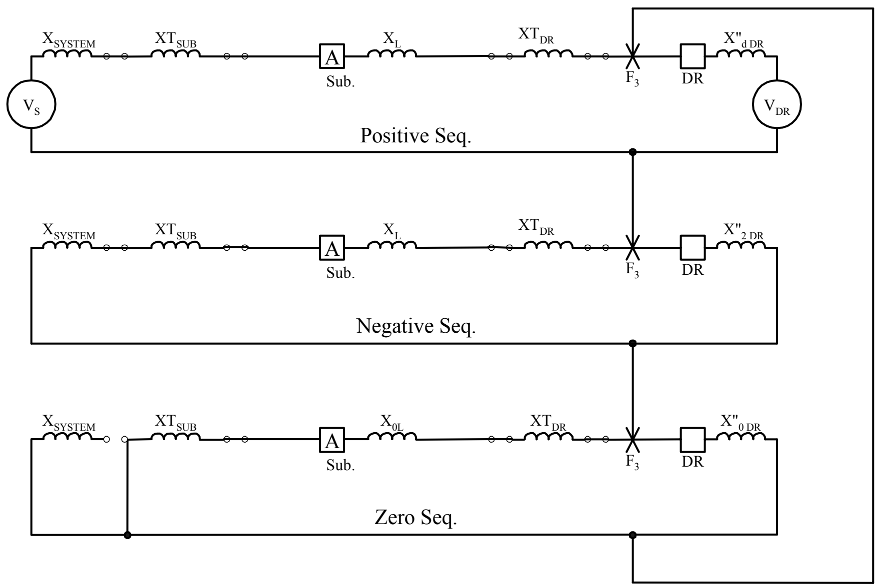

Figure 5 - Symmetrical Component Circuit for
Wye-Grounded (HV) / Wye-Grounded (LV)
Interconnection Transformer

3.0 Possibility of Ungrounded Systems

3.1 Generation with ungrounded transformer primary windings

If the DR is connected to the utility by a transformer with an ungrounded primary (delta or ungrounded wye connection); the utility substation transformer may be the only ground current source on the feeder. When a line to ground fault occurs on the utility feeder, the utility breaker may trip with the generator still connected. The resulting system is not effectively grounded. Line to neutral voltages on the unfaulted phases approach the normal line to line voltages. This can cause a severe overvoltage of line to neutral connected equipment. If the insulation of the connected equipment has not been selected for those voltage levels, the result will be serious damage to the equipment. The connected distribution transformers will become saturated and damaged, insulators and lightning arrestors will likely flash over and the breaker bushings may fail. It is generally accepted that if the connected generator is rated at less than half of the minimum load on the circuit, it will be unable to sustain more than line to ground voltages. Therefore the ungrounded primary connections should only be considered if the distributed generator is rated at less than half of the load on the circuit. If this type of transformer connection is used, voltage relays must trip the DR for an overvoltage condition. Minimum load data on a feeder may not be readily available and special data may need to be obtained for this evaluation.

3.2 Loss of primary source to substation power transformer

The loss of primary power to the utility substation transformer(s) means complete loss of the utility supply to the station. As can be shown in Figure 6, primary power can be lost via a switching or interrupting device at the station, or at the remote line terminal breakers. Loss of primary power presents some relaying challenges and introduces some operational issues.

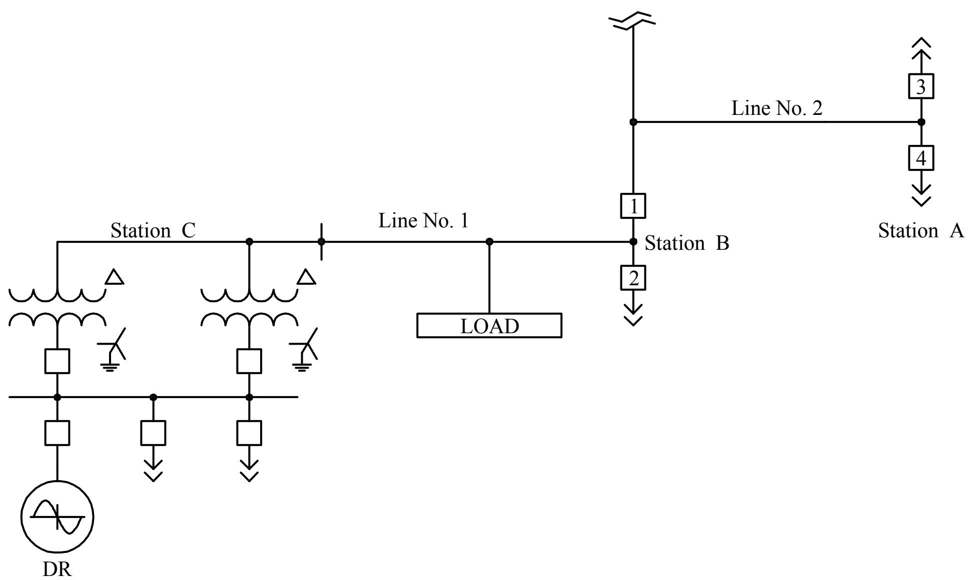

Figure 6 - System One Line

3.2.1 Islanded Operation

With the separation of the utility station from the grid (for example tripping of CBs 1 and 2 in figure 6) the station may successfully island if there is a reasonable balance between load and generation.

Generally, islanded operation is not an allowable practice. For example the opening of breakers 1 and 2 may send a transfer trip to the DR. In rare instances however, islanded operation may be desirable. For example if transmission line no. 1 is in an isolated area and has a high exposure to permanent faults, then it may be desirable to attempt to let the DR serve the load.

For islanded operation, the adequacy of the existing station relaying in Station C of figure 6 must be evaluated. With reduced fault levels, the existing relaying may be inadequate in terms of sensitivity with the DR as the sole source of generation. Consideration may need to be given to:

- Numerical relays using alternate setting groups for islanded operation
- Undervoltage protection which can provide time delayed protection if conventional overcurrent protection will not operate
- Resynchronizing the islanded system

3.2.2 Protection for High Side Faults

With the station C transformers isolated via its high voltage disconnect. There is a small section of bus from the high voltage side of the transformer to the isolating device. If there is a possibility of the DR back energizing the transformer, protection must be considered for this bus, in particular for ground faults. This will require the addition of ground fault detection. For situations of this type, it is common to use a ground overvoltage relay on the transmission system to isolate the DR from the fault. Other schemes could involve a transfer trip of the DR whenever the high side disconnect switch is open.

3.2.3 Requirements for Line Protection at the Utility Substation

The DR will be a source for transmission line faults. For DRs, where the size of generation is very small compared to the minimum load, line protection may not be required as voltage and frequency collapse (after CBs 1 and 2 are tripped in figure 6) will cause the DR relay protection to operate. Where there is any possibility that the DR will not separate, a transfer trip system from station B to station C or the DR may be required. Some schemes may use undervoltage relaying at station bus "C" to detect loss of system source. A thorough analysis of these situations should be done a part of the interconnection study.

3.2.4 System Overvoltage Issues

Overvoltages can result from transmission line single line to ground faults that are only fed from the utility distribution substation (station C in figure 6). In extreme cases, line protection tripping at Station B for line no. 1 will have to be delayed to ensure that DR generation is tripped off before the utility breakers are tripped.

3.2.5 Other Issues

When evaluating DR issues, a system wide approach needs to be taken. Protection impacts can go back far into the system. For example, in Figure 6, depending upon the load at stations B or C, synchronism check facilities may be required for automatic reclosing of CBs 1 and 2 if an island has developed.

4.0 Fault Current from Distributed Resources

When a DR is connected to a utility feeder, three different systems must be considered for fault currents. These are the utility system without the DR, the combined utility and DR system and the DR alone. It is desirable to maintain proper coordination of relays, reclosers and fuses on the utility system with and without the DR on line. Although the DR would not normally be connected to the distribution feeder without the utility source; this can occur due to sequential tripping during a fault. As explained in section 2.2, a wye grounded (HV) – delta (LV) transformer can be a source of current for line to ground faults even when the DR is off line. When modeling the impedance of the DR for determining relay operation for fault current, consider the speed of operation of the protective relays. If the protection does not operate in the time frame of the subtransient impedance for the DR the transient impedance may need to be used. This will reduce the current contribution from the DR.

4.1 Increased Duty

There are three considerations for fault currents. The fault current must not exceed equipment short time ratings. Overcurrent devices must be sized appropriately for the level of fault current. Proper coordination of relays, reclosers, fuses and other overcurrent devices must be based on the available fault current. Depending on the interconnection transformer connection, some or all of the feeder fault current levels will be increased due to the DR. Equipment ratings, such as recloser withstand capabilities, should be examined as part of the interconnection study.

4.2 Direction of Power Flow

In many cases, the substation transformer is a much stronger source of fault current than the DR installation. In this case, the fault current from the utility substation will not be significantly decreased for faults between the utility substation and the DR. As long as the current does not exceed equipment capability, this can increase coordination margins between substation relays and feeder fuses. If the DR is between the utility substation and the fault, the DR may cause a decrease in fault current from the utility substation, which needs to be investigated for minimum tripping or coordination problems.

If the DR source (or combined DR sources) is strong compared to the utility substation source, it may have a significant impact on the fault current coming from the utility substation. This may cause failure to trip, sequential tripping, or coordination problems.

5.0 Effects on Relay Application and Settings

It is desirable to leave other connected loads and resources largely unaffected by the addition of a DR. At issue is the effect of DR on distribution relay protection, particularly coordination problems.

5.1 Coordination Problems

The introduction of DR into a system usually designed for serving only load radially causes a number of problems with the protective device coordination. A simple system is depicted in figure 7. An actual system would have numerous load tap along the circuits and may have more than one protective device in the line between the substation and the DR. Any protective devices downstream from the DR will likely benefit from improved coordination from the extra current contribution. Faults between the downstream protective device and the substation will experience reverse current flow in the protective device which can prevent the primary source from clearing the fault unless the protective device is allowed to trip for reverse current before the primary source is reclosed. Consideration for faults on adjacent circuits must take in account the added contribution and infeed effect from the DR. The circuit feeding the DR will experience reverse flow for these faults and must be coordinated to ensure reliability. Some of these coordination issues are covered in more detail in this section.

5.1.1 Relay, Fuse, and Line Recloser

The addition of DR requires that time coordination is maintained between protective devices on adjacent circuits as the effects of DR on coordination is not limited to the circuit to which it is connected. Faults on an adjacent circuit can cause protective devices on the DR circuit to operate. This is undesirable because service can be interrupted to customers who would normally be unaffected by this scenario.

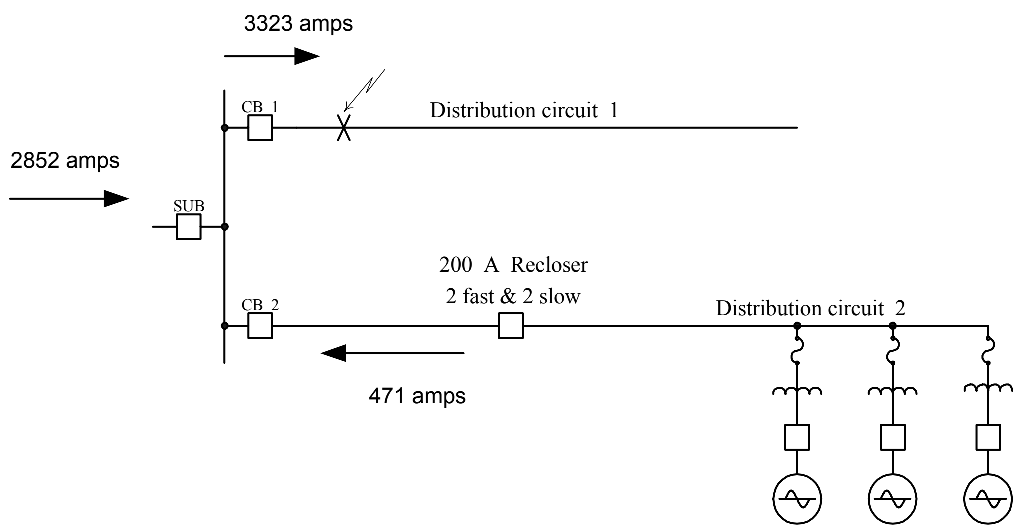

Figure 7 - Fault on Circuit Adjacent to DR

The diagram in figure 7 shows that for a fault on distribution circuit 1 there will be fault current contributions from both the substation and the DR. The fault will be sensed by circuit breaker (CB1), circuit breaker (CB2), the 200 amp recloser, and the DR fuses. Normally it is expected that CB1 will clear this fault. However if the relay setting for CB1 is too slow there is a possibility that either the recloser or the DR fuses will operate for this fault.

Consider the case of a three phase to ground fault on distribution circuit 1 as shown in figure 7. The total 3 phase to ground fault current contribution by the DR without the contribution from the system is approximately 750 amps. When the DRs are paralleled to the system the contribution decreases to 471 amps as shown in figure 7. The recloser and the relay characteristics are shown plotted on the same time-current scale in figure 8.

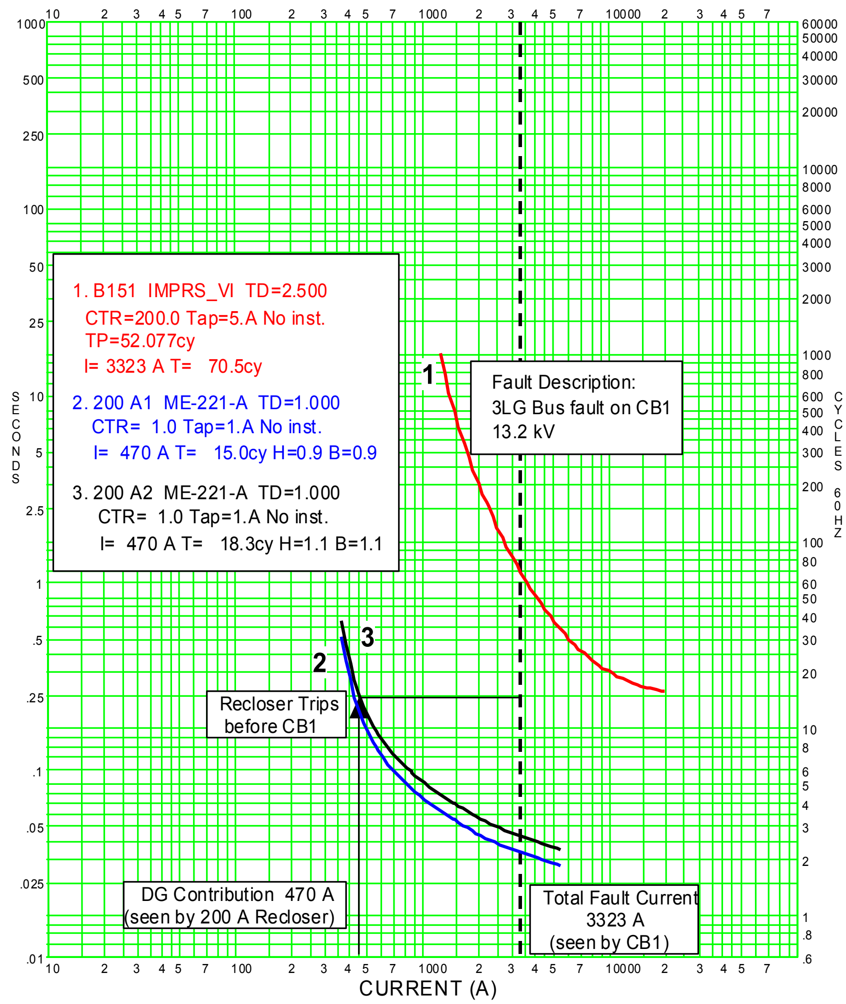

Figure 8

Figure 8 shows the curves for the CB1 relay and the recloser plotted for total fault current on distribution circuit 1. The plot indicates that the recloser will trip before the relay has a chance to respond. Customers on distribution circuit 2 that are fed beyond the recloser will experience an interruption of their electric service and the DRs will also be cleared from the system. To correct this coordination problem, the recloser will need to be slower or the CB1 relays faster or both. The modified settings will need to be checked for coordination with the other protective devices on this system for other fault scenarios. An ideal coordination for all fault conditions may not be possible with non-directional overcurrent protective devices. The addition of directional overcurrent relay elements in the recloser and/or at the substation may be needed.

5.1.2 Impact on Fuse Saving Schemes

Installing DR on distribution circuits may impact the operation of fuse saving schemes. The same principle is true whether fuse saving is implemented in conjunction with reclosing at the breaker or by using a line recloser. The purpose of reclosing is to try and clear temporary faults without having a permanent interruption in service. Utilities often locate overhead fuses on the circuit for additional protection or sectionalizing. Utilities may try to "save" the fuse on the circuit for temporary faults by de-energizing the line with the fast operation of the upstream interrupting device before the fuse has a chance to be damaged. Then the interrupting device recloses, restoring power beyond the fuse. This practice is due to the fact that many faults are temporary in nature, and "saving" the fuse prevents a permanent outage due to temporary faults. However, adding a distributed resource to the distribution system could affect the timing coordination between the interrupting device and the fuse due to the additional fault current contribution from the distributed resource. The fuse could blow first or both the fuse and interrupting device could operate at the same time.

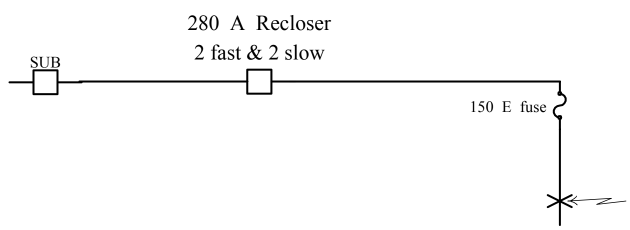

Figure 9 - Fuse Saving Example

Under normal conditions, the fuse saving scheme would appear as in figure 9. The particular system depicted shows a 280 amp recloser in series with a 150E fuse. For a temporary fault , such as trees touching the power lines past the fuse, the recloser fast curve will operate first as shown on the time-current plot in figure 10. When the recloser recloses, the line beyond the fuse will be re-energized. The fuse will be intact and therefore the fuse is "saved". However, for a permanent fault beyond the fuse, after the recloser operates two times on its fast curve and the fuse blows to clear the fault while the recloser is timing to operate on its delayed curve.

The plot in figure 10 shows the time overcurrent characteristic of the 280 amp recloser versus the 150E fuse curve. Curves 1 and 2 represent the minimum and maximum times for the recloser to operate on the fast curve. Curves 3 and 4 represent the minimum and maximum times for the recloser to operate on the slow curve. From the plot in figure 10, it can be seen that the recloser slow curve will operate faster than the fuse for faults up to 3300 amps. So for fault currents smaller than 3300 amps the fuse will be "saved" by the recloser because the fault will be interrupted by the recloser and the fuse will not blow.

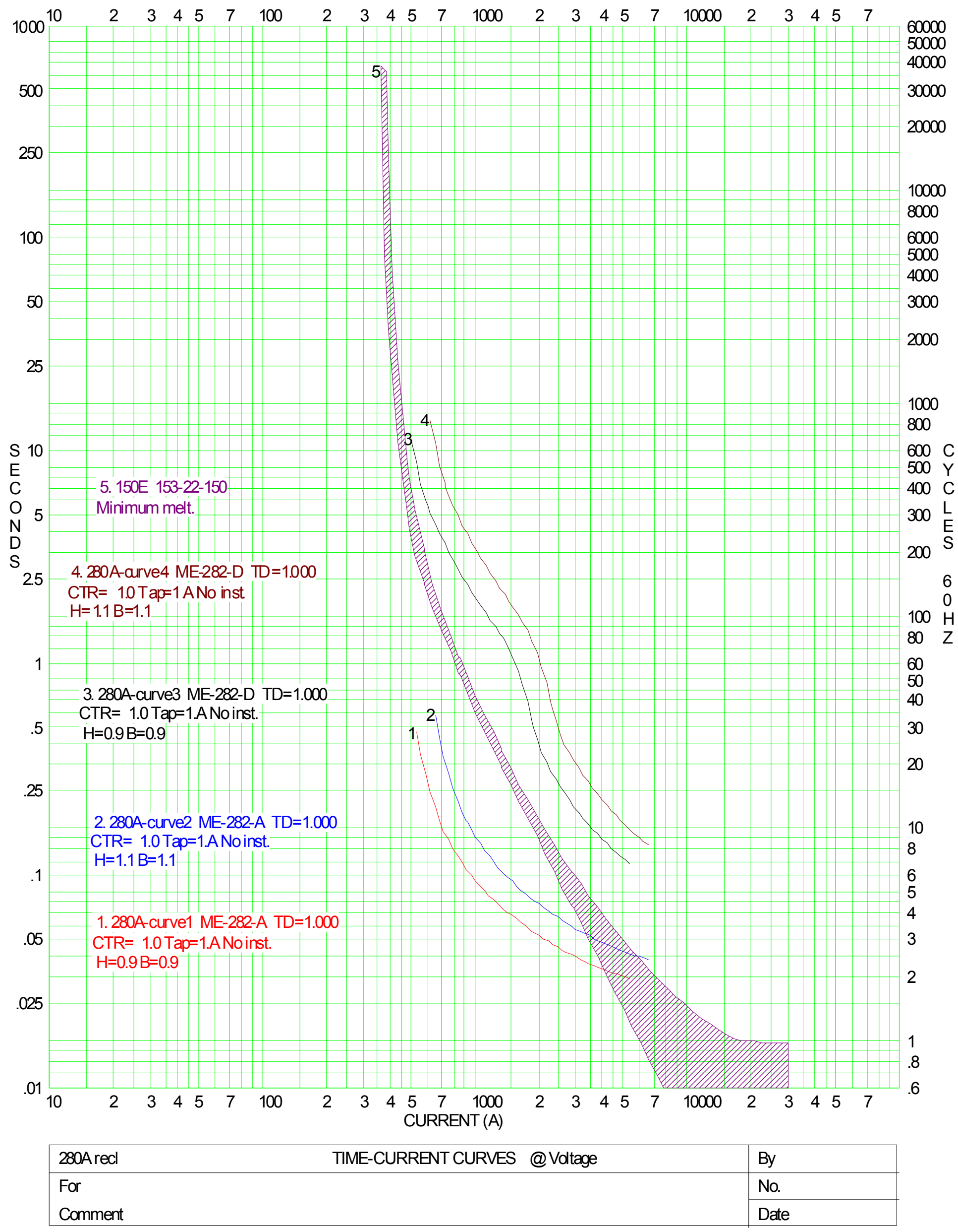

Figure 10

Consider the same system with DR added. As shown in figure 11. Assume a three phase fault on the lateral fused with the 150 E fuse.

The expected total fault current is:

I fault system = 3000 amps
DR fault contribution = 300 amps
total fault current = 3300 amps

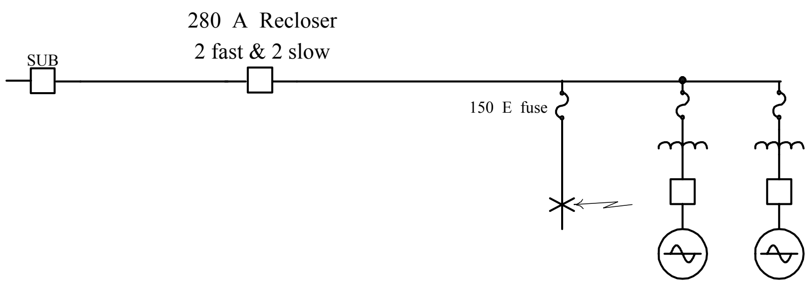

Figure 11- Effect of DR on Fuse Saving

The fault current beyond the fuse is now 3300 amps due to the increased fault current contribution from the DRs. The 280 amp recloser is still only seeing 3000 amps of fault current. Therefore, for the system just described, it is no longer possible to save the fuse as shown in figure 12. Preventing nuisance fuse blowing is a well-established utility practice. It helps minimize the impact of outages and improves reliability. However, there might be instances where fuses can no longer be saved due to the increased fault current contributions from distributed generators. Selectivity may have to be studied on a case by case basis for those instances. Adding higher cost sectionalizers could be a solution.

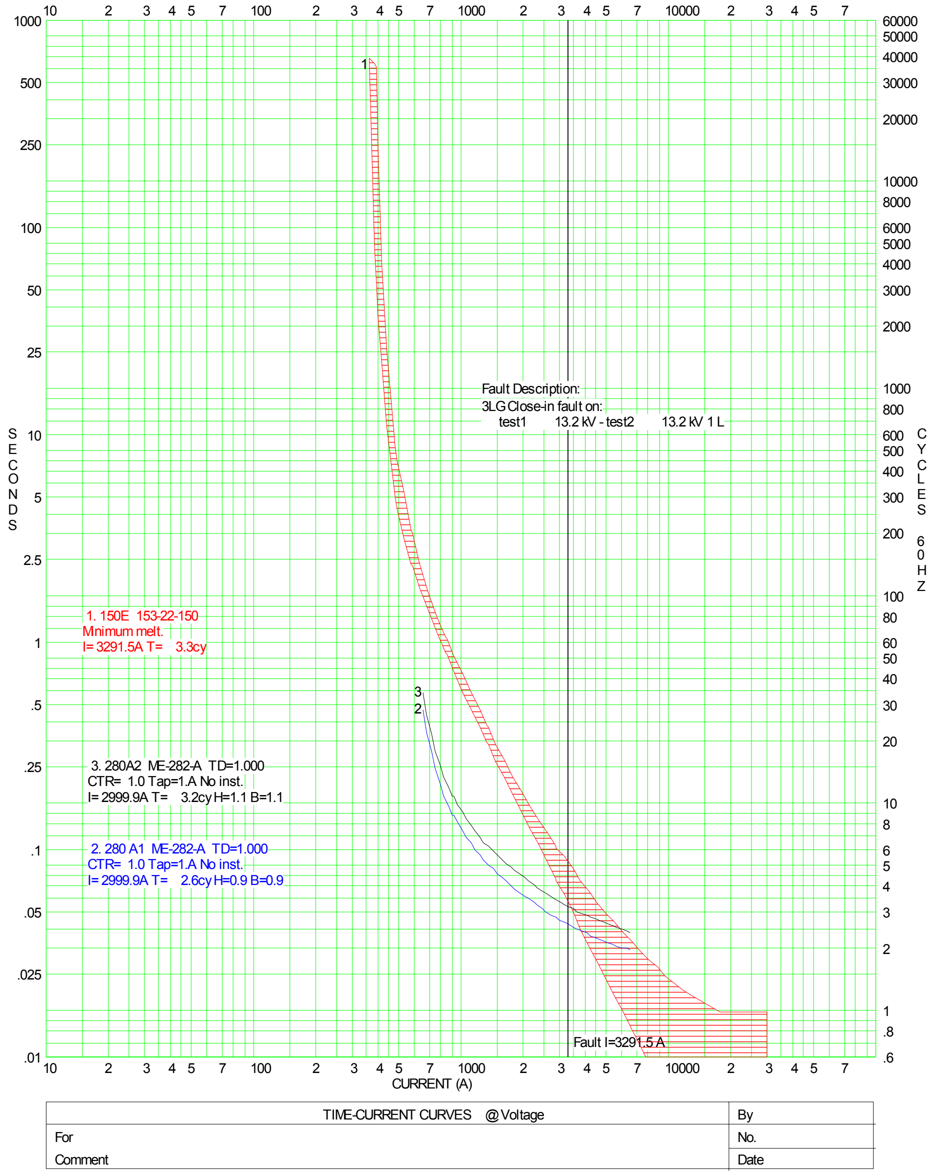

Figure 12

5.1.3 Sensitivity & Clearing Times

5.1.3.1 Grounded DR Interconnection

Ground overcurrent relays are used in distribution protection in order to provide more sensitive protection for phase to ground faults. The zero sequence impedance of the distribution circuit is greater than the positive sequence impedance. This causes the ground fault levels to decrease rapidly, as the fault location is moved farther away from the substation. In some cases the ground fault current levels can be less than the full load current levels. Ground relays can be set below the value of full load in order to provide the sensitivity needed to detect these low current ground faults. The sensitivity is limited only by the expected maximum unbalance on the circuit. This unbalance can be a result of single phase load unbalance, blown lateral fuses, etc. When a DR is connected to the system using a grounded Wye/Delta transformer connection as in figure 13, the unbalance current and ground fault current is no longer fed radially from the substation transformer. The DR transformer will share the unbalance current with the substation transformer. The zero sequence current (I_0) splits into the two components I_{0DR} and I_{0S}. This reduces the amount of ground fault current that is seen by the substation ground relay, which has previously seen the entire ground fault current. The ability to detect low level ground faults is thus reduced by the presence of a DR with a grounded Wye (system side)/ Delta connection. The reduced fault current will increase the clearing time of the faults that are detected, unless the ground relay settings are reduced when the DR transformer is connected.

Another undesired complication of this connection is a variation in the substation ground fault current (I_{0S}) based on the location of the DR on the feeder relative to the location of the fault. This further complicates the coordination of the ground relays with fuses or recloser, protection on tapped circuits. The worst case situation is when the DR is located at the end of the circuit.

As the size of the DR, relative to the substation transformer size, increases the loss of sensitivity becomes more pronounced due to the reduced value of Z_{0T} for the larger generator transformer. The grounded connection is often specified for larger DR installations in order to prevent the potential damage caused by neutral shift. Therefore the loss of ground sensitivity often must be addressed for larger installations.
When a small three phase unit is connected using a grounded high side transformer the sensitivity loss is not as great due to the higher impedance of the unit transformer. However, if multiple units are connected on a circuit they will have an effect similar to one larger equivalent unit.

The effect of a DR on three phase and phase to phase fault sensitivity is not as pronounced as for the phase to ground fault. The effect on fault current levels measured by the substation relays is not as significant and only minimally affects the phase relay sensitivity. The total fault current levels are increased due to the additional current supplied by the DR. This may create coordination problems with fuses and other protective devices on the circuit.

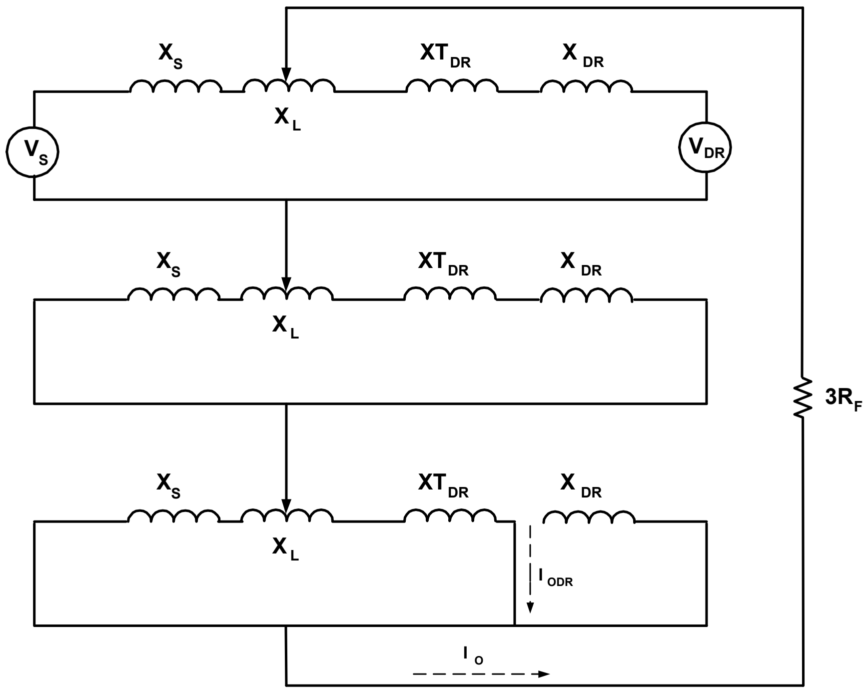

Figure 13- Grounded DG Sequence Network

5.1.3.2 Ungrounded DR Connections

When the DR is connected to the distribution circuit using an ungrounded transformer connection (Utility Side) the DR does not provide a path for unbalance currents or for ground fault currents. The zero sequence network in figure 13 is open circuited on the DR side, X_{0TR} is an open circuit. Therefore the entire ground fault current flows through the substation transformer ground connection. The ground fault current may be slightly higher due to the lower impedance of the positive and negative sequence networks. However the effect is minimal and the sensitivity of the ground fault relays at the substation is not affected.

The effects on sensitivity of phase relays for three phase or phase to phase faults is the same as discussed for the grounded transformer connection.

5.2 Need and Availability of Communications Circuits

Communication circuits between distribution feeder relays and distributed resources (DR) generally have two basic functions:

1. Transmit a transfer trip signal from the feeder relay or recloser to the DR.

2. Transmit operating status (on or off) from the DR to the feeder relay or recloser.

Feeders with DR may require communications circuits for status and control purposes if there is a possibility that the DR may stay online when the feeder breaker or recloser opens. In this case status and control shall be necessary to indicate the DR is online and allow the utility to direct trip the DR breaker. In cases where it is desirable to allow the DR to carry the islanded load, provisions will be required to coordinate the synchronization with the utility to close the feeder breaker. In most cases, the DR will be required to trip its breaker and allow the utility to reclose as the utility seldom has the ability to modify speed or angle to sync with the DR. A sync-check relay on the feeder breaker or recloser could be used to permit the feeder breaker to close. Communications may not be required if the DR will always trip if the feeder breaker or recloser opens under a range of light load to heavier normal load conditions.

5.2.1 Transfer Trip Signals

Transfer trip signals are sent from the feeder relay or feeder breaker to the DR to ensure the DR is removed from service when the feeder breaker operates. The criteria for installing transfer trip signal capability is normally the capacity of the DR. Of particular concern are situations where the DR may be large enough to remain in service after the main feeder breaker opens. The DR may create island situations, posing possible risk to operations personnel, or may continue to supply a fault, resulting in increased equipment damage and possibility for injury.

5.2.2 Operating Status

Operating status signals (on or off) are sent from the DR to the feeder relay. This information may be used to adapt feeder relay protection settings, as a permissive signal for closing the feeder breaker, as a permissive signal for automatic reclosing, or for annunciation of DR status for system operators.

5.2.3 Communication Medium

For protection purposes, the communication between the feeder relay and the DR is binary information. This means that communications circuits can use any of the commercially available media, including power line carrier, telephone, fiber optic, radio, spread spectrum communications, and two way pager. The criteria for choosing the correct medium include availability, operating speed, reliability, and cost.

6.0 Safety Concerns

Utility distribution systems are typically designed as radial systems with a single source feeding distribution load. While system conditions may result in variable circuit configurations, distribution systems and their associated protection systems are designed for one-way current flow and fault sensing. In the case of a typical distribution feeder protective system, when a fault occurs the various protective relays sense the associated increase in fault current, and trip a circuit breaker to deenergize the system, thus clearing the fault. Reclosing may be present in order to restore service in the case of temporary faults, but for permanent faults the feeder will lock out and stay deenergized until the source of the fault can be identified and repaired. In this way, protective systems assure the safety of the general public that may come into contact with energized or faulted distribution system equipment, as well as the safety of utility personnel responsible for the identification, switching, and repair of the system.

Proper application and setting of interconnection protection is meant to assure that the DR trips and separates from the distribution system for fault conditions. Improper device application or settings can result in the DR not sensing the faulted circuit conditions. In cases where large DR's are applied, short circuit studies must be completed to assure that 'backfeed' from the DR source does not result in the desensitizing of feeder relays or reverse current flow through feeder positions for faults on adjacent circuits. In some operating cases, such as the case of a substation breaker being opened manually, the DR generation could match the system load and not trip the DR. Each of these scenarios poses a threat to the safe operation of the distribution system.

Utility personnel may be accustomed to operating under the assumption that in a radial system, if an upstream switching or protective device has operated, the circuit is deenergized and therefore safe. The DR may in fact keep the circuit energized creating an unsafe working environment for these personnel. While operating and safety procedures may be in place to verify that a circuit is deenergized prior to beginning work, extra caution should be taken in cases where DR is present. Visual inspection of the DR interconnection to assure that it has separated from the utility system should be considered. Many utilities require that the interconnection point or 'point of common coupling' includes a visible and lockable switch operable by utility personnel. The ability of a DR to continue to energize the circuit can create safety concerns for the public as well.

The addition of DR to a feeder can result in conditions resulting in equipment damage or failure. Increased fault duties due to this addition can result in equipment being subjected to faults beyond their short circuit current ratings. In some cases this can lead to 'eventful' unsafe conditions. DR that does not trip under fault or open substation breaker conditions can result in equipment damage if reclosing is applied without synchronism check in place. For certain types and sizes of DR with delta high side transformer connections, backfeed on unfaulted phases under fault conditions can result in overvoltages that damage equipment such as surge arresters, affecting both the utility and other customers in the vicinity of the DR. These conditions can result in unsafe conditions for utility and customer operating personnel.

If a sustained island is created, there is danger to utility personnel who may not know that the system is islanded and attempt to close a tie switch to an adjacent energized feeder.

7.0 Voltage Issues

The addition of Distributed Resources on a distribution feeder may subject the feeder to voltage levels that were not originally intended.

7.1 Line Drop Compensation

Line drop compensators are used in load tap changing transformer and regulator control circuits to maintain a predetermined voltage at some point downstream from the regulated location. If a DR is located on the line, then line drop compensators may make an incorrect determination of the downstream voltage and may cause overvoltages on the circuit.

Line drop compensators use measured current, in part to calculate the voltage for a specific point on the feeder circuit. Historically the line drop compensators have been employed on radial lines and thus there is no source of backfeed. Current flow is assumed to be only in the direction from the voltage regulator towards the load. With the addition of a DR, there is the possibility of reduced current flow through the line drop compensator that leads to incorrect voltage compensation.

The response speed of the line drop compensator may be an issue. A line drop compensator attempts to maintain an acceptable voltage profile on the feeder under all generation conditions. Consider the case where the generator is operating and then trips off-line. The line drop compensator may not respond fast enough to maintain the voltage profile. During the time that the regulator is attempting to recover, the voltage on the line may drop to some point that causes operational problems for some loads. These types of issues have to be addressed to determine if the compensator and voltage regulator will continue to operate correctly.

7.2 Switched Capacitors

Shunt capacitors added to distribution feeders may be controlled by several different means but the most common are timer controlled and voltage controlled. The introduction of a source of voltage support from local generation may create operating difficulties with the shunt capacitors; therefore the system should be reviewed with and without the DR in service.

7.2.1 Timed Capacitor Banks:

Typical timed capacitor switching operates purely on a time of day clock with no voltage supervision. If the timer switches the capacitor bank while a local DR is operating, this may result in overvoltage on equipment or the capacitors themselves. Overvoltage may cause customer problems or in severe cases, may cause equipment damage. Capacitor banks typically are designed to allow up to about a 10% overvoltage. It is conceivable that the DR operating in conjunction with the capacitor bank could allow an overvoltage that is above this 10% limit. This will depend on the excitation/voltage control system of the DR. Customer voltage needs to remain within ANSI C84.1 limits. The replacement of time clock based capacitor controls with other capacitor control strategies should be considered on feeders that have DR installed.

The higher voltage may also result in overvoltage damage to other system equipment, possibly even lightning or surge arresters. Even if damage is not done to the arresters, it is certainly conceivable that they will fire and introduce nuisance faults to the system.

7.2.2 Voltage Controlled Capacitor Banks:

The operating difficulties described for timed capacitor banks are overcome by the use of voltage supervised controllers. With the proper voltage setting the capacitor bank could remain off when the DR is used. If the DR is not providing enough voltage support, then the capacitor bank could be switched in until the proper voltage is obtained.

The voltage controller should probably be time delayed so that "voltage hunting" will not be an issue. Too short of delay may lead to the generator voltage regulator fighting the capacitor bank controller as the two systems attempt to settle on a stable operating point.

7.3 Ferroresonance

Ferroresonance is a phenomenon that may be encountered in the interconnection of DR. Extreme overvoltages can develop when the DR is connected to a section of the distribution circuit that has been isolated from the utility. These extreme voltages can be damaging to any connected equipment on the distribution circuit that does not have adequate insulation. Although the protection against ferroresonance may be applied at the point of interconnection, the impact of the phenomena should be well understood by the engineer responsible for the distribution line relay protection.

Ferroresonance can occur under a variety of circumstances. Three conditions must exist after the DR circuit is isolated from the distribution system for ferroresonance to occur. First, the DR must be capable of carrying the connected load. Second, if the DR is an induction generator, there must be enough connected capacitance to provide for generator excitation and finally, there must be a transformer connected to the circuit to provide nonlinearity. The size of the capacitance, the transformer and the load are not critical for resonance to occur although the magnitude and severity are related to those characteristics. Capacitive kVar of one-third the kVA rating of the generator is normally sufficient to support ferroresonance overvoltages. The use of synchronous generators does not eliminate ferroresonance. In fact, if both synchronous and induction generators are connected to the same circuit, the interaction of the two systems can enhance the ability of the system to produce extreme ferroresonance overvoltages.

Ferroresonance detection at the substation or midline recloser can be accomplished with a peak detecting overvoltage element. This type of element is able to respond to the sub cycle high peak voltages that are characteristic of the ferroresonance phenomena. Standard overvoltage elements typically employ RMS calculations to the waveform and may not be able to detect the high peaks as they will be averaged with low peak values that also may occur. Although the detection of the ferroresonance can take place at the substation interruption device or midline recloser, there is little that can be done at that location, as the breaker or recloser is already tripped.

If ferroresonance is detected at a tripped interrupting device on load side (the islanded feeder), it indicates that the amount of induction and/or synchronous generators left connected to the islanded feeder, combined with the capacitance connected to the islanded feeder, is favorable for ferroresonance to occur. The detection can alert the protection engineer to investigate the occurrence and devise a remedial scheme that may consist of detuning recommendations (i.e., changing capacitor bank values) or additional protection at the DR installations to detect and trip when islanding and ferroresonance occurs.

8.0 Load Shedding Issues

8.1 Underfrequency Load Shedding

It is common to apply underfrequency load shedding in distribution substations. The operation of the underfrequency relays will trip the feeder circuit breakers disconnecting the load from the utility source.

Underfrequency relays typically include an undervoltage inhibit function to prevent load shed for events like the temporary opening of transmission lines. The undervoltage setting must be low enough to allow the frequency element to operate during wide area system disturbances where reduced voltage is expected but set high enough to prevent unintended load shed.

With the distributed resources on the feeders the loss of the primary source will cause a slower decay in the voltage on the isolated system. The circuit voltage may stay high enough to allow the underfrequency load shedding relay to operate during a temporary outage of the primary source.

Underfrequency relays are usually applied at the point of coupling between the DR and the utility that will disconnect the DR before the circuit load shedding scheme operates. This approach has several advantages and one disadvantage. The substation underfrequency load shedding does not have to be modified. The more sensitive and faster setting on the DR protects the customer equipment on the feeder should the distributed resource become islanded. If the DR connection does not provide ground currents to single line to ground faults, conventional fault detecting relays cannot sense a line-to-ground fault on the feeder to disconnect the DR. In this case, load and the underfrequency relay may force the isolation of the distributed resource, or an ungrounded system ground fault detection scheme can be applied.

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The disadvantage in having the DR disconnected before the load shedding scheme is that during the system underfrequency disturbance, the generation is tripped before the load. This will worsen the generation load unbalance. With a small number of DRs the impact would not be an important factor; but as the number of DRs increases this may not be an acceptable solution.

Another solution is to move the load shedding to different substations without DRs. This solution will only work if there are limited DRs. Large numbers of DRs will necessitate innovative ways of accomplishing the underfrequency load shedding for the system.

8.2 Undervoltage Load Shedding

Undervoltage load shedding programs are implemented in many distribution substations to trip feeder breakers or transformer banks during major system disturbances. (E.g. loss transmission line or loss of system VAR support.) Typically the distribution substations selected for undervoltage load shedding don't have DR.

If the generation is added to a distribution substation, undervoltage relays can be either relocated to a substation that has no DR or the scheme and relay settings may be modified such that it will trip the selected feeder breaker instead of the substation transformer.

If the DR can be counted on to provide adequate voltage support, it may eliminate the need for undervoltage load shedding scheme. This will require system studies to simulate the DR during major system disturbances.

9.0 Breaker Closing

In almost all circumstances, synchronization of the DR to the utility will occur only at the DR location. If the utility breaker trips, the DR should isolate from the utility feeder. In most applications, the DR is not capable of supporting the local load and will separate by the interconnection protection at the DR.

9.1 Need for Synch Check or Dead Voltage Closing

If the DR can form a sustainable island when it is separated from the system, restoration of the connection becomes an issue. In many instances, the DR will go off line via its interconnection protection. However, there is still the possibility of an out of synch close occurring on the bus breakers if the DR is able to island with the connected load. The utility feeder breaker must not close before the DR is isolated. The provision of synchronism or voltage check facilities will prevent this. This will either allow for closing within a narrowly prescribed window of synchronism or simply prevent closing until the DR has been tripped. A more rapid restoration of the primary connection can be achieved by adding a communication circuit between the substation and the DR in order to transfer trip the DR and allow for immediate reclosing.

9.2 Effect on Substation Reclosing Practices

The main concern on reclosing settings is the effect on instantaneous closing. A high speed autoreclose will be less likely to be successful if the DR is slower to trip and still sustains the fault arc. One solution is to add a short delay to the close. Another possible solution is to monitor the line voltage and only allow closing if the line is “dead”. The most reliable practice is to install communications between the substation and to transfer trip the DR if the main or feeder breaker or down line recloser are tripped.

Conclusion

The addition of distributed resources to a distribution or subtransmission system has the potential to impact relay systems well beyond the point of common coupling. Of concern is the effect on protection systems traditionally designed for radial operation. Among the issues to be considered are bi-directional flows, increased fault levels, safety, voltage control, equipment ratings, and autoreclosing. These effects are not limited to the line or lines serving the DRs; but can affect the relay protection on adjacent lines as well. Careful study to identify and resolve these issues are required whenever a DR is to be added to ensure continuing safe reliable operation of the system.

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