Summary of Distributed Resources Impact on Power Delivery Systems

Working Group on Distributed Generation Integration

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***Abstract*—Because traditional electric power distribution systems have been designed assuming the primary substation is the sole source of power and short-circuit capacity, DR interconnection results in operating situations that do not occur in a conventional system. This paper discusses several system issues which may be encountered as DR penetrates into distribution systems. The voltage issues covered are the DR impact on system voltage, interaction of DR and capacitor operations, and interaction of DR and voltage regulator and LTC operations. Protection issues include fuse coordination, feeding faults after utility protection opens, impact of DR on interrupting rating of devices, faults on adjacent feeders, fault detection, ground source impacts, single phase interruption on three phase line, recloser coordination and conductor burndown. Loss of power grid is also discussed, including vulnerability and overvoltages due to islanding and coordination with reclosing. Also covered separately are system restoration and network issues.**

***Index Terms*—DER, distributed generation (DG), distribution resources (DR), DG integration.**

I. Introduction

ELECTRIC power distribution systems have traditionally been designed assuming that the primary substation is the sole source of power and short-circuit capacity. Distributed resources invalidate this assumption by placing power sources onto the distribution system. As a result, DR interconnection results in operating situations that do not occur in a conventional system without generation directly connected at the distribution level. Careful engineering can effectively eliminate the potentially adverse impacts that DR penetration could impress on the electric delivery system, such as exposing system and customer equipment to potential damage, decrease in power quality, decrease in reliability, extended time to restoration after outage, and potential risks to public and worker safety.

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This paper is a summary compilation of the system issues which may be encountered as DR penetrates into a distribution system. These issues will not always occur, and are not very likely to occur at very low penetrations. However, the distribution system planner or designer should consider these issues, and perform appropriately detailed studies where warranted.

II. Voltage Issues

Load currents through the power and distribution transformer and line impedances cause voltage drops, which reduce voltage magnitude at the loads. Voltage magnitudes at service locations must be maintained within specified ranges. This is accomplished in both fixed designs of the system (e.g., conductor selection, substation and distribution transformer tap settings and fixed capacitor banks) and by voltage control equipment such as automatic load tap changers, step-type voltage regulators (SVR), and switched capacitors. The fixed design of the feeder is based on the assumption that loading profiles generally follow a predictable pattern, with real power loading on the feeder causing voltage to decrease monotonically from the substation. SVR controls continuously monitor voltages and load currents to adjust tap positions accordingly. Capacitors (switched and fixed) compensate reactive current, reducing the current from the source to the capacitor location, resulting in reduced line voltage drop. However, capacitors will cause a current increase in feeders if the capacitor size is greater than the load reactive demand due to overcompensation. This will also happen if the capacitor size meets the reactive demand of the total distributed load connected to a feeder, but is installed at a location where it compensates more than the downstream reactive power demand, resulting in voltage increase.

When a distributed resource (DR) is interconnected to the distribution system, it can significantly change the system voltage profile and interact with SVR and/or capacitor control operations.

A. DR Impact on the System Voltage

Standards [1] specify that DR should not actively regulate distribution system voltages. This should be interpreted as prohibiting closed-loop adjustment (automatically or manually) of DR reactive power in response to voltage changes. In general, an attempt by a DR to regulate distribution system voltage can conflict with existing voltage regulation schemes applied by the utility to regulate the same or a nearby point to a different voltage reference. Even if DR does not actively control the system voltage, DR can cause a voltage increase or decrease along the feeder depending on the DR type, control method, its delivered power and feeder parameters and loading.

The incremental flow of real power, interacting with feeder resistance, will tend to make the voltage at the DR location rise. Injection of reactive power by the DR will increase the voltage rise and consumption of reactive power will tend to offset the voltage rise caused by the real power flow.

Induction generators can produce real power, but they take reactive power from the system. Capacitors (fixed and/or switched) are typically used to compensate reactive power consumed by induction generators.

Synchronous generators can produce real power and produce or consume reactive power. When used as DR, they are commonly controlled using a constant power factor mode of operation. When synchronous generators consume reactive power from the system, effects on the voltage profile are similar to an induction generator operation when they consume the same amount of reactive power.

Even though Standards [1] prohibit active voltage regulation, it is permissible to perform voltage regulation if a mutual agreement between the utility and DR owner exists. DR, such as synchronous generators and self-commutating inverters, can control the system voltage profile by reducing (or absorbing, if necessary) its reactive power output. In general, an attempt by a DR to regulate distribution system voltage can conflict with existing voltage regulation schemes applied by the utility to regulate the same or a nearby point to a different voltage reference. The utility voltage regulation may be implemented by switched capacitor banks, SVRs, or substation transformer onload tap changers.

Where regulation by the DR is permitted by a mutual agreement with the utility, DR reactive power output can be varied in an attempt to achieve the desired voltage. However, the DR regulation range may not be sufficient to control excessive voltages. In these cases, SVRs could provide desired voltage regulation. To control distribution voltage at the point of common coupling (PCC), the generator should operate in constant voltage mode. The effectiveness of regulation depends on the short circuit ratio of the DR and the system. If the ratio is small, influence on the voltage change may be small, causing very low DR power factor under low or high system voltage condition, and thus limiting the ability of DR to generate real power. In real life applications, the DR will not operate at low power factor to control the voltage. When the DR control approaches an operating limit in constant voltage mode, it will automatically switch to the constant power factor mode.

DR can cause high voltages when interconnected in small residential areas sharing a distribution transformer. If the transformer primary voltage is already at the upper limit, the DR can reduce voltage drop through the transformer and secondary conductors, which will cause high voltages to be experienced by other customers on the transformer [2].

DR will also impact losses on the feeder, resulting in the voltage profile change. When DR is sized to closely match the local load and is located near the load, it can provide a significant reduction in line losses.

If DR is located far from the substation and delivers power towards the substation or even back to the transmission network through the substation transformer, losses can increase in the distribution system, but losses in the transmission network will decrease.

Restoration after outages is an important issue with high DR penetration when the system relies on DR to support voltages. Presently, DR is required to automatically disconnect from the system during faults [1]. With the DR disconnected, it may be difficult to meet the system load while still ensuring adequate voltage along the feeder length. These issues have to be addressed in the future.

B. Interaction of DR and Capacitor Operations

DR impact on capacitor switching depends on the DR type, control mode, location, and capacitor switching controls that include system voltage, line current, reactive power flow, time of day, and ambient temperature. As discussed before, DR can cause system voltages and currents to increase or decrease. Voltage controlled capacitor banks should not be impacted by the DR if the DR does not operate in a voltage regulating mode. To avoid "voltage hunting" between DR and capacitors, set points should be adjusted and time delays extended. If line current control is used, DR can impact capacitor switching since it can offset the line current, since the current monitored by the capacitor control will not adequately reflect the current profile downstream on the feeder. The switching set point is set assuming current elsewhere on the feeder is a reasonably constant ratio to the current at the control location. The reactive power flow control will not be impacted when operating DR at unity power factor. However, if a DR downstream of the reactive power control is operating in a unity power factor mode and the capacitor control senses reactive flow towards the downstream loads that exceeds the threshold, it will switch in the capacitor. This is the correct action from the reactive power demand requirement, but it may aggravate a high feeder-end voltage caused by reversed power flow from the DR. The DR impact when it operates at a constant power factor other than unity can aggravate the voltage more. As a result, some adjustment to the reactive power generation may be needed. Time of day and ambient temperature controls can also be impacted by DR. If the capacitor bank is switched on while a local DR is operating, resultant voltages could exceed the limits.

C. Interaction of DR and Voltage Regulator Operations

SVRs hold line voltages within predetermined limits and assure consumer voltage magnitudes are kept within standards [3]. Some consumers can be far from the regulator location, and due to the line voltage drop, voltages at the load location can be below the specified limit although the voltage at the SVR location is maintained within limits. The line drop compensation (LDC) feature, which is an integral part of the SVR control, estimates the line voltage drop and performs voltage corrections based on line current, line R and X parameters, and load side voltage. It is inherently assumed that current flow downstream of the regulator is roughly proportional to current at the regulator location, with the constant of proportionality steadily decreasing with increasing downstream distance from the regulator.

During reverse power flows, the LDC must have adequate control algorithms to properly perform voltage corrections. The

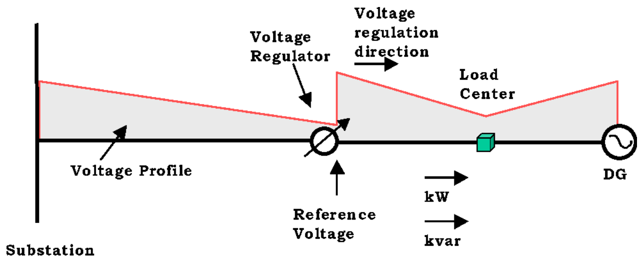

Fig. 1. Normal bidirectional mode (forward mode).

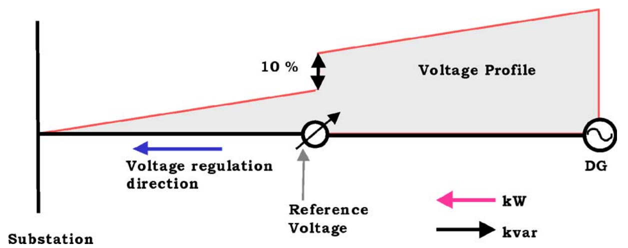

Fig. 2. Normal bidirectional mode (reversed mode).

reverse power flow may result from switching operations that reconfigure the feeder, or it may be due to DR supplying power back to the substation. There are several modes of operation presently available in modern SVR controls. The impact of DR is different on each.

Normal Bidirectional Mode: An SVR control determines the direction of operation (forward or reverse) based on the direction of real power flow. This mode of operation may not be suitable for applications on feeders with DR connected.

In Fig. 1, the DR generates less real power than the feeder load downstream of the SVR. The real power flow through the SVR is from left to right (from substation to DR). With normal bidirectional sensing the regulator will be in Forward Mode, regulating the voltage on the DR side. This control mode is acceptable during these system conditions.

When DR real power (kW) generation exceeds the customer demand between the SVR and the DR, the real power flow through the SVR is from DR to substation and the regulator will operate in Reverse Mode and regulate the voltage on the substation side (Fig. 2). If the source side voltage (substation side) is greater than the SVR set-point voltage, the SVR will tap down in an attempt to lower the voltage. Since the substation voltage is "fixed," the net effect is to raise the voltage on the DR side. This sequence will continue until the regulator taps to minimum tap, resulting in a 10% (or greater) overvoltage on the DR side of the SVR. Therefore, this control mode is unacceptable for system operation with DR.

Co-Generation Mode: Fig. 3 shows the principle of co-generation mode operation for a lumped load. When the local DR generates real power that does not meet the load, some real power is imported from the system. The SVR regulates voltage at the customer location (Bus 2, Fig. 3) in forward mode as previously described.

When the DR generates real power that exceeds the load, some real power is exported to the system. The SVR continues to regulate voltage on the same side as earlier. This is accomplished by not reversing the control sensing input voltage when

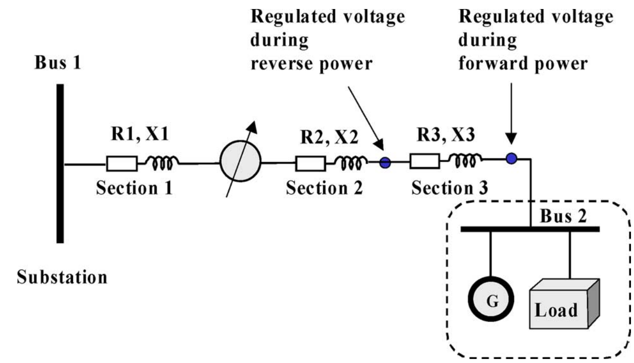

Fig. 3. Co-generation regulation points.

reverse power is detected. The alternate LDC settings can be programmed to account for this change in power flow direction.

However, if the load is distributed on the feeder, the DR can impact LDC operation of the SVR. Without DR, as long as the load profile shape remains constant, the SVR will regulate the selected load center (based on chosen equivalent R and X values) on the feeder to a constant voltage.

With DR on the feeder, this regulating point will not necessarily be at a location for which R and X were selected. This is because the DR disrupts the effective, or net, load profile shape. This disruption of regulation does not require the DR to exceed local load levels.

Reactive Bidirectional Mode: Fig. 4 shows a loop scheme with tie recloser normally open and a DR (with constant power factor control) consuming some reactive power from the system. Without DR, substation S/S 1 supplies power for the load on its feeder and the SVR controls voltage on its load side. With DR, to avoid problem described for normal bidirectional mode, the SVR continues to control voltage on the same side (DR side) irrespective of the DR real power production that can be in both directions as monitored by the SVR. However, when the tie recloser is closed and CB 1 open, the SVR should regulate voltage for loads on the CB 1 side. In this case, reactive power through the SVR changes. This mode of operation can be impacted by shunt capacitors if they are located between the SVR and DR, causing reverse reactive power flow through the SVR. The threshold set point must be adjusted to account for this impact.

The SVR control determines direction of operation based on direction of reactive power flow by sensing real and reactive components of the current.

The control operates in the forward direction whenever the magnitude of the reactive component exceeds the threshold in the negative direction. This corresponds to a reactive power flow from source to load through the regulator. The direction of real power flow does not impact the control's direction of operation.

The control operates in the reverse direction using the reverse settings whenever the magnitude of the reactive component exceeds the threshold in the positive direction. This corresponds to a reactive power flow from load to source through the regulator.

D. Impact on LDC Operations

Both DR and capacitors can impact LDC operation. DR interconnected to the feeder immediately downstream of the

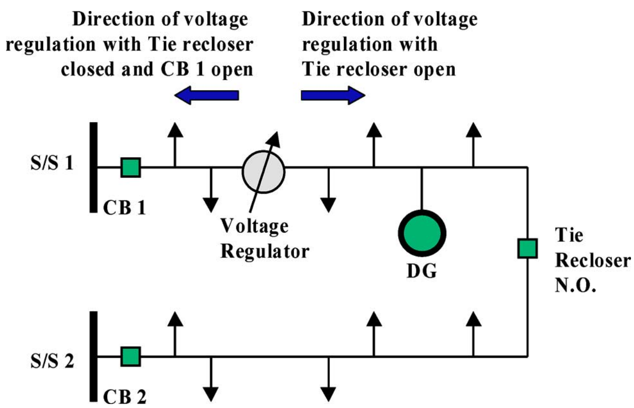

Fig. 4. Application of reactive bidirectional mode voltage control for loop schemes

SVR can impact LDC operation if it generates a significant percentage of kW or kVA power compared to the load flow through the SVR. Because of the DR contribution, current flow through the SVR will be reduced. However, currents from the DR to the load (vector sum of currents from the source and DR) will not be reduced and the line voltage drop will be almost the same as without DR or may even increase, depending on the load type and DR control. The reduced current flow through the SVR will appear as a light load, and the SVR may tap down, causing reduced voltage at the load center.

Capacitors may affect SVR operation in a fashion similar to DR, depending on their size and location. If capacitors are installed on the SVR source side or at the load, they will not affect regulator operation since currents through the regulator will be the same as line currents. The SVR source side voltage will change (increase), but the regulator will detect this change and operate to maintain the desired voltage.

When capacitors are located immediately downstream of the SVR, capacitors will compensate reactive current (reduce total current) from its location back to the source and through the SVR. Currents from the capacitor to the load will not be reduced, and the line voltage drop will be almost the same as without capacitors or may even increase, depending on the load type. Reduced currents through the SVR will appear as a light load, and the SVRs may decrease the voltage causing reduced voltage at the load center.

III. Protection Issues

A. Fuse Coordination

One of the first things utility engineers expect to be sacrificed as the amount of DR on a distribution feeder increases is the ability to save fuses for temporary faults. This is a difficult task without the extra infeed from DR. DR contributes additional current to the fuse and slightly reduces the current seen by the breaker. This tightens the already slim timing margin available in this process.

The DR contribution should make permanent fault coordination more certain.

B. Feeding Fault (I^2t) After Utility Protection (Recloser, Breaker, etc.) Opens

Ideally, all DR would disconnect by early in the first reclose interval so that the utility fault clearing equipment can proceed normally. Failure to have the proper protection has several potentially negative consequences, including:

1) The fault does not clear requiring the breakers to go through at least one more reclose cycle. One adverse effect this has is that it subjects substation transformers to unnecessary short circuit forces.
2) Allowing the fault arc to continue to burn causes more damage to conductors and insulators. Even for restorable insulation, this means that the chances of future failures are greater.
3) If the DR remains on line during the reclose interval, it can be damaged upon reclosing of the utility breaker. This is particularly true of synchronous machines. Out-of-phase reclosing can also result in transient overvoltages, high electromechanical torques on customer equipment, and much greater inrush currents than for normal reclosing.

C. Impact of DR on Interrupting Ratings of Devices

DR, particularly those using synchronous generators, can increase the amount of fault current flowing through utility breakers, reclosers, and fuses. Some utility systems will already have locations where these devices are at their limits with the normal contribution from the utility system. This can also occur at the low-voltage level, which might be customer-owned. Failure to identify these situations could result in increased failures of fault interrupters.

The amount of fault current contributed by DR varies widely. Inverter-based DR may supply twice rated current for a brief period. The concern occurs when the contribution is still there once the contacts part in the interrupting device. Rotating machines can contribute several times rated current for prolonged periods. This includes induction machines, which some would believe to be benign. Most faults do not result in a complete collapse of voltage and there may very well be sufficient excitation available to supply a fault.

D. Faults on Adjacent Feeder—Nuisance or Sympathetic Tripping

Faults on adjacent feeders cause two problems related to DR.

1) DR is supposed to trip off line when it senses something wrong on the utility system. Voltage is the key sensing quantity. Unfortunately, faults on adjacent feeders create very similar voltages as faults on the DR feeder and it is difficult to discriminate. The usual effect is that the DR is tripped off too often, which is a common complaint, especially when the DR is located near the substation.
2) The DR feeds the faults on an adjacent feeder back through the DR feeder's breaker. Most feeders do not have directional sensing on the overcurrent relays. This can easily result in sympathetic tripping of the DR feeder's breaker for faults elsewhere in the system.

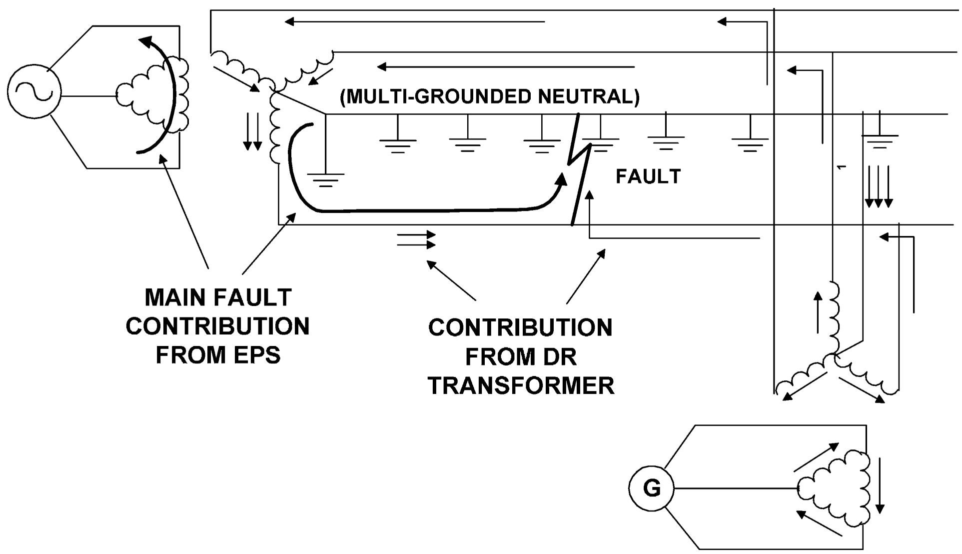

Fig. 5. Ground fault contribution from a DR interconnected using a grounded-wye delta distribution transformer.

E. Fault Detection—Relay Desensitizing

As the penetration of DR increases on a distribution feeder, the contribution of the DR to faults makes it more difficult for conventional utility relays to detect, or sense, the presence of high-impedance faults. Utility fault detection on distribution systems is almost universally based on overcurrent. The devices are set to "see" a certain minimum fault current, which normally includes the ends of the feeder with some margin. As more DR is installed out on the feeder, it will cut into the margin. The solution is generally to add another fault interrupter (e.g., a line recloser) in the circuit to extend the zone of protection.

F. Ground Source Impacts

Many argue that the best connection for DR is grounded wye-delta (grounded Wye on the utility side). In fact, this is the way most utility-owned generation is connected at the transmission system level. The protection considerations for this connection are well known. It is also a little more tolerant of generator imperfections such as third harmonic voltage generation. Unfortunately, this connection is not permitted on most utility distribution systems without considerable study. The main reason is that the ground fault contribution from the transformer alone can be sufficient to upset the ground fault coordination of the utility breakers and reclosers, which do not typically use directional sensing. Fig. 5 illustrates the issue.

The grounding (zero sequence admittance), provided by the DR installation, must be compatible with the distribution system to which it is connected. In uni-grounded and ungrounded systems, sensitive ground fault relaying is typically used. Therefore, a DR interconnection must not provide a ground source.

In multi-grounded wye systems, too strong of a ground source can desensitize ground fault detection schemes. However, there is a risk that, if no ground source is provided by the DR, overvoltages could occur if the feeder becomes islanded during a ground fault. This is discussed later in the section on islanding considerations.

G. One Phase Interruption on 3 Phase Line—Loss of 1 or 2 Phases

Negative sequence currents can cause severe overheating of rotating machines in a relatively short time. Therefore, rotating machine DR is usually equipped with some means of sensing unbalance on the incoming utility feed as a means of protecting the generator. This is also sometimes a more sensitive means of detecting utility-side faults so that the disconnection can be accomplished more promptly. This is normally desirable, but there are some considerations. For example, when the disconnection takes place on the low-voltage side of the service transformer, this leaves the transformer isolated on the open phase condition with no load. This is a prime condition for ferroresonance, which can result in damage to the transformer or some load-side devices that remain connected.

For this reason, it is generally considered good practice to avoid using fuses and single-phase reclosers or sectionalizers between a 3-phase DR and the next three-phase breaker or recloser upline from the DR.

H. Recloser Coordination

DR is expected to disconnect by early in the first reclose interval after a recloser has operated. Two potential conflicts with common utility practices arise.

1) Many utilities employ what is known as "instantaneous" reclose, which is commonly 12–18 cycles. This is done to reduce power quality complaints from their customers. If there is any delay at all in the detection of the fault by the DR relaying and the disconnection by the DR switchgear, there is a significant risk that the DR will still be connected when the recloser re-energizes the circuit.
2) Reclosers that are used for fuse saving interrupt the fault current very quickly. While they may be rated for 3-cycle interruption, the EPRI DPQ [4] project captured many interruptions as fast as 1.5 cycles. This makes it very difficult for DR protection devices to detect the fault before the utility system operates. Many devices have a 6- or 10-cycle

time delay. Thus, if the voltage seen from the DR does not promptly deviate from normal after the recloser opens, there is a good chance the DR will still be connected upon reclosure or the fault arc will not clear due to prolonged infeed from the DR.

I. Conductor Burndown

Conductor burndown is a potential adverse side effect of any of:

1) prolonged fault clearing due to relay desensitization;
2) failure to clear the fault due to DR infeed;
3) increased fault current due to DR infeed.

IV. Loss of Power Grid

Separation of an operating DR from the utility source is called islanding. Opening of a utility circuit breaker, recloser, fuse, or other interrupting device can result in a DR becoming islanded along with a portion of the utility system and other utility customers. Unless the system is carefully designed for intentional islanded operation, unintentional islanding places the system at risk for a number of reasons including overvoltage and damage to equipment.

A. Vulnerability

The risks of sustained energization by a DR of an unintentional island are dependent on the generation technology:

- Synchronous generators supply their own excitation from onboard rectifiers. Special detection methods are required to determine that a primary source supply system outage has occurred, and a method must be devised for deciding whether there should be an automatic disconnection. Unlike induction generators, synchronous generators are not held in synchronism with a common source. Thus, where two or more are to be paralleled, some means must be provided to synchronize them as they are brought onto the line and to maintain them synchronized as they run.
- Induction generators, on the other hand, depend upon the utility supply for excitation. Thus, they are never independent of the line. However, induction generating equipment with significant capacitance can become self-excited upon loss of the primary source and experience severe overvoltage as a result. Induction generators are simple to parallel because they automatically synchronize with the source field excitation (usually the utility service).
- The ability of an electronic power converter (inverter) to continue operation when islanded depends upon the type of inverter (current source or voltage source) and the method of control. Current-source inverters, based on thyristors, are not generally capable of continued sourcing of an isolated system. Voltage-source inverters, which are now more common, are capable of islanded operation. However, voltage-source inverters intended solely for grid-parallel operation are typically controlled as virtual current sources and will generally not continue operating in an islanded system unless the connected load (real and reactive) is closely matched with the generated power.

B. Overvoltages Due to Islanding

Islanding can lead to severe overvoltages on the islanded system due to loss of grounding, self-excitation, or a combination of these phenomena.

1) Loss of Grounding in Multi-Grounded Wye Systems: A single phase fault can cause a breaker or recloser to operate, islanding the DR and a portion of the distribution system. This isolates the island from the ground source provided by the substation. If the DR does not provide adequate grounding, the unfaulted phase voltages to ground can rise to values on the order of 1.5 to 2 times rated voltage. Although the island should not persist long, these overvoltages can be damaging to utility equipment, particularly surge arresters, and customer equipment. Therefore, it is necessary that the DR installation provides a grounding source, or other means of ensuring primary-side overvoltages will not occur for even a brief period. Too strong of a grounding source, however, can desensitize feeder ground current relaying, and may expose the grounding equipment to excess duty from utility faults, load unbalance, and open-line conditions.

2) Self-Excitation: Islanding a rotating generator DR with a portion of a distribution system having excess capacitive compensation can result in high overvoltages due to self excitation of the machine. Saturation of transformers in the isolated subsystem introduces large harmonic current components which can resonate in the circuit formed by the DR and the capacitive compensation. Although saturation reduces the fundamental overvoltage to some degree, the potentially large harmonic voltage components can result in very high peak overvoltages. This can result in failure of utility and customer equipment.

C. Coordination With Reclosing

The usual practice on overhead radial feeders is to automatically reclose circuit breakers and circuit reclosers after a trip. Typically, several reclose attempts will be made. The delay time on the initial reclose attempt can be very short, on the order of 200 ms open-close cycle time, if an "instantaneous" setting is used. If a DR connected to the downstream side of the breaker or recloser is not removed prior to the reclose, the reclose can be into an energized system which is not synchronized with the system on the source side of the switchgear. It is possible that the two systems are 180° out of phase. If an out-of-phase reclose occurs, a very severe transient is produced. While such a reclose is often considered only a threat to the DR, it can also have severe impact on the local distribution system and its customers. The utility and customer impacts of out-of-phase reclosing include:

1) A severe switching surge, with voltage magnitude ideally approaching 3 p.u. in a lightly damped system. Fig. 6 illustrates a simulated out-of-step reclose transient.
2) Large simultaneous inrush currents into transformers and motors, which could cause nuisance operation of fuses and other overcurrent protective devices on the utility system and within customer facilities.
3) Severe torque transients on motors and their mechanical loads.

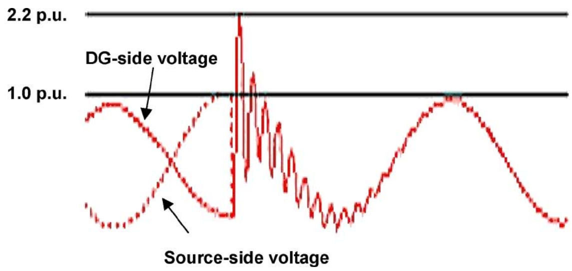

Fig. 6. System voltage for a breaker reclosing into a DR-supported island out of step.

V. System Restoration

Another concern, not well considered by the industry, is the difficulty of reconnection should the utility system be inadequate to provide proper power quality upon reconnection. Up until this time, distributed resources have been used primarily as emergency backup and to supplement on-site loads. The utility system has traditionally been capable of supplying all generation needs without these units. If DR becomes a method to actually reduce utility generation, transmission, substation and feeder investments i.e. replace infrastructure, its importance multiplies greatly because the utility system can, now, not operate properly (in terms of overload, voltage level, etc.) without the DR capacity to supplement its requirements. In the event of an outage and the consequent increase in load due to cold load pickup, it may be more complicated to restore normal system conditions.

VI. Networks

The design of urban secondary networks raises DR integration issues which are unique. For this reason, network issues are covered here separately from the previous discussion applicable to ordinary radial distribution feeders.

A. Primary Feeder Faults

In a network system without DR, network relays in protectors supplied from a faulted primary feeder see a tripping condition after the breaker for the faulted feeder opens. Prior to opening of the breaker for the faulted feeder, the relays in protectors on the faulted feeder may or may not see a tripping condition, depending on fault type, loading, and system characteristics. Regardless, only the protectors on the faulted primary feeder will trip.

When a large DR is installed in a spot network, a fault on the primary feeder near the substation may trip all protectors in the spot network. Or a fault on a primary feeder, not associated with the spot network, may trip all of the protectors in a spot network. DR parameters must be limited and or relaying installed such that such faults on the primary do not trip all protectors in the spot network.

B. Network Protector Interrupting Capacity

When a network protector in a conventional low-voltage network opens because of a fault on the primary feeder, the normal frequency recovery voltage at the protector will not exceed the line-to-ground voltage of the secondary system. The recovery voltage will not exceed five to ten percent of the line-to-ground voltage of the secondary system if the protector opens due to low loading on the secondary system, with the associated primary feeder and network transformer remaining energized. If phases have been rolled on the primary feeder following a repair and the feeder re-energized, the normal frequency recovery voltage at the open protector will equal full line-to-line voltage of the secondary system. Network protectors have operated under these conditions in the real world for many years.

For a fault on a primary feeder, the maximum backfeed current in a protector will not exceed that allowed by the impedance of the network transformer. Regardless of the size of the DR installed on the spot network, the current will not exceed the rated interrupting current of the network protector for primary feeder faults.

Should a DR create conditions that open all protectors in a spot network, in absence of a fault on the primary feeder, the normal frequency recovery voltage at contact parting is small. But the sustained normal frequency recovery voltage following current interruption can reach twice the system line-to-ground voltage. Most network protectors have not been tested to interrupt under these conditions. Either the protector must be rated to interrupt for these conditions, or else control/protective relaying installed that will prevent the protector from separating two non-synchronized systems. Recently a new-design protector has been introduced that is rated to separate two non-synchronized systems.

C. Network Protector Time Delay Tripping

Some network operators have provided time delay tripping of network protectors over the last 60 years. The purpose is to allow the protector to remain closed during small-magnitude temporary reverse power flows. Prior to DR, temporary power reversals could occur from elevator and crane operation. Such relay schemes will bypass the time delay for high-current backfeed conditions as occur for many faults on the network primary feeders.

When emergency power systems, supplied from spot networks, are tested with closed transition switching, temporary reverse power flows may occur in the network protectors during switch overlap. With modern transfer switches, the normal overlap time is 100 milliseconds, which may extend to 500 milliseconds in a failure scenario. Similarly, when DR is running in parallel with a spot network, reverse power flows may occur in all network protectors from load dropping in the network, or from improper control of the generation.

Time delay tripping of the network protector is one means of allowing closed transition switching of critical loads under many, but not all conditions. It further allows for coordination of protective relays in the DR system with network protector tripping, so that the DR or a portion thereof may be tripped before the network protectors can trip.

Without time-delay tripping, closed transition load transfers and parallel DR operations on spot networks are not possible in many situations.

Parallel DR operation, where the generation on the spot network exceeds the load, is not possible under any circumstances.

D. Islanding

Islanding in a spot network system occurs if all protectors are open, the DR energizes the paralleling bus to which one or more protectors are normally connected, and the secondary of one or more network transformers is energized. From the perspective of the requirements of the load supplied from the DR, voltage magnitude, frequency, and grounding must be maintained within an acceptable range.

From the perspective of the utility, the formation of the island must be prevented through DR control and installation of protective relaying. Protective relaying also should be installed to block protector closing should the DR control and/or protective relaying fail to prevent the formation of the island.

E. Network Protector/Network Relay Response in Non-Synchronized Systems

The electro-mechanical, solid-state, and micro processor relays presently installed in a network protector were never intended to function when the protector is open, and the two systems on opposite sides of the protector are not synchronized. They function properly when the systems on opposite sides are synchronized through at least one other closed protector, or if one side of the protector is energized with the other side dead (de-energized).

If DR can maintain an island on the network side of open protectors in a spot network, the systems on opposite sides of the protector are not synchronized. Existing relays controlling network protector closing may allow the protectors to close under phase angle conditions that will damage the protector, the DR, or both. With DR in place, either network relay logic must be modified to function with non-synchronized systems on opposite sides of the protector, or else supplemental relaying added to the system to allow for non-synchronized operation.

F. Network Reliability

Spot networks are installed because they provide the highest levels of reliability possible with conventional types of power systems. The spot network is most effective when all network protectors are closed. Operation with one or more protectors open degrades the reliability and power quality for most spot network systems.

The spot network equipment normally is sized to carry the peak load without DR. In designing a spot network, transformers and protectors should not be oversized as this prevents open protectors from automatically closing under normal operating conditions, and may cause unnecessary opening of closed network protectors. The effect of operating DR in parallel during certain times is to reduce the loading on the network equipment. Thus, DR will degrade the reliability of the spot network if it causes protectors to open, or if it prevents and open protector from automatically reclosing. DR in spot networks must be controlled such that it does not degrade the reliability of the system.

G. Network Protector Cycling

Every operation of a network protector results in mechanical wear of various parts and erosion of the arcing contacts. With an excessive number of operations, maintenance and repair expenses can increase significantly.

DR on a spot network must be controlled such that it does result in an unacceptable increase in number of protector operations, and so that it does not impact the maintenance expenses for the network protectors.

VII. Conclusion

Existing distribution systems were designed with the assumption that power would flow from the substation to the load. The application of distribution resources (DR) on a distribution feeder can change this assumption. Without careful engineering, DR penetration can potentially have adverse system effects, including exposing system and customer equipment to potential damage, decrease in power quality, decrease in reliability, extended time to restoration after outage, and potential risks to public and worker safety.

Understanding the issues related to the integration of DR on the distribution system is required if the reliability and power quality of the system are to be maintained. The issues related to DR integration are not insurmountable, but neither are they negligible. Proper knowledge and engineering can result in effective DR integration in distribution systems.

VIII. Working Group Membership

The Working Group on Distributed Generation Integration is a part of the IEEE Power Engineering Society, Transmission and Distribution Committee, and Distribution Subcommittee. The following are the current members with affiliations:

- J. Reese Adomaitis—Allegheny Power;
- John Ainscough—XCEL Energy;
- Greg Ardrey—Alliant Energy;
- John Banting—Cooper Power Systems;
- Jerry Baskin—Federal Pacific;
- David Beawais—Hydro-Quebec Dist.;
- Ed Bevers—Rural Electric Cooperative;
- Richard Bingham—Dranetz-BMI;
- Jim Bouford—National Grid;
- Jim Burke—Infrasource;
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- Randy Collins—Clemson Univ.;
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[4] EPRI DPQ Project Ref.

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