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Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources

Technical Report
NREL/TP-550-46698
January 2010

J. Keller and B. Kroposki

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Abstract and Keywords

One of the most important aspects of planning and operating an electrical power system is the design of protection systems that handle fault conditions. Protection engineers design protection systems to safely eliminate faults from the electric power system. One of the new technologies recently introduced into the electric power system is distributed energy resources (DER). Currently, inverter-based DER contribute very little to the power balance on all but a few utility distribution systems. A significant increase in DER is expected to come on line in the near future. As the penetration level of DER increases, the effect of DER may no longer be considered minimal. As DER become prevalent in the distribution system, equipment rating capability and coordination of protection systems merit a closer investigation. This report discusses issues and provides solutions for dealing with fault current contributions from inverter-based DER.

Keywords:
Distributed energy resources, distributed generation, inverter, fault, fault current, short circuit, low-voltage ride through

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1 Introduction

One of the most important aspects of planning and operating electrical power systems is the design of protection systems. Protection systems are designed to detect and remove faults. A fault in an electrical power system is the unintentional conducting path (short circuit) or blockage of current (open circuit). The short-circuit fault is typically the most common and is usually implied when most people use the term fault (Grigsby 2001). We have limited our discussion to the short-circuit fault variety for this technical report. A fault occurs when one energized electrical component contacts another at a different voltage. This allows the impedance between the two electrical components to drop to near zero allowing current to flow along an undesired path from the one initially intended. The short-circuit fault current can be orders of magnitude larger than the normal operating current (IEEE 2001). The current from such an event can contain tremendous destructive energy (heat and magnetic forces), that can damage electrical equipment and pose safety concerns for both utility and non-utility personnel.

Common sources of faults on electrical distribution systems include the following (IEEE 2008):

- Insulation breakdown caused by system overvoltages from lighting strikes and switching surges, improper manufacturing, improper installation, and aged or polluted insulation.
- Mechanical issues such as animal contact, tree contact, vehicle collisions, wind, snow, ice, contamination, vandalism, and major natural disasters.
- Thermal issues such as overcurrent and overvoltage.

Protection engineers are familiar with designing protection systems to safely clear short-circuit faults from the electric power system. One of the technologies that has been recently introduced into the electric power system is Distributed Energy Resources (DER). DER are sources of power located at or near loads and interconnected with the electrical distribution system. Typically, the individual DER unit ratings are less than 10MVA and include fossil-fuel, renewable resources and energy storage technologies (Figure 1). DER are becoming more and more common on distribution systems and present many challenges to protection engineers. Adding new sources of energy into the electric power system will increase the amount of available fault current and therefore influence protective devices that are required on the distribution system. This report discusses issues and provides solutions to address fault current contributions from inverter-based distributed energy resources.

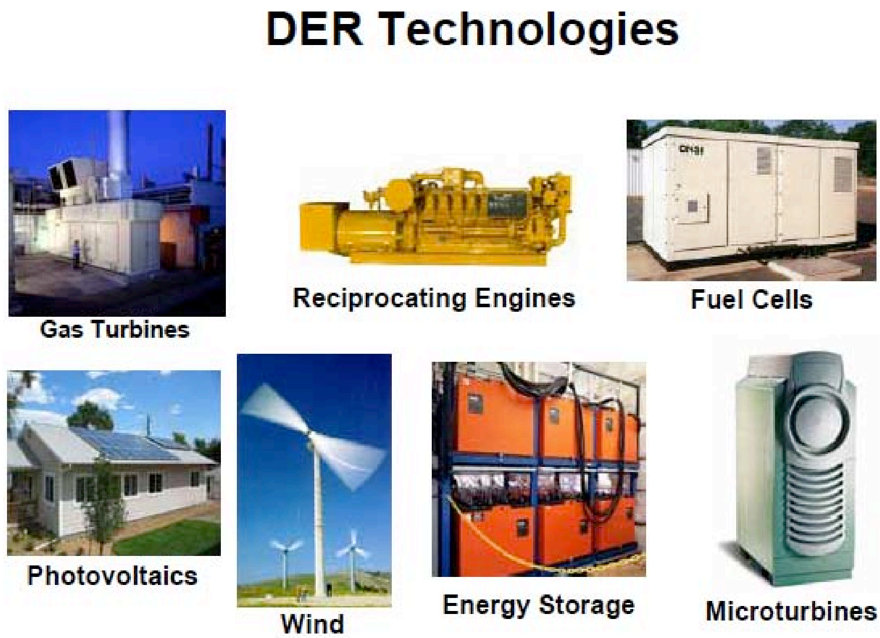

Figure 1. DER Technologies

2 Protection and Coordination Issues

The purpose of the electrical power system is to deliver high-quality, safe, and reliable electric power to homes, industrial plants, and commercial businesses alike. A typical electrical power system is shown in Figure 2. Large generation stations are connected through high-voltage transmission lines to substations. These substations contain transformers that reduce the voltage levels for the subtransmission and distribution systems. The electrical distribution system (EDS) in particular consists of substation transformers, three-phase and single-phase distribution circuits, protection and switching equipment, power factor improvement equipment, distribution transformers, and service drops.

Protecting the EDS and coordinating the components are of utmost importance to an electric utility. When adding DER into the EDS, the system impacts must be understood.

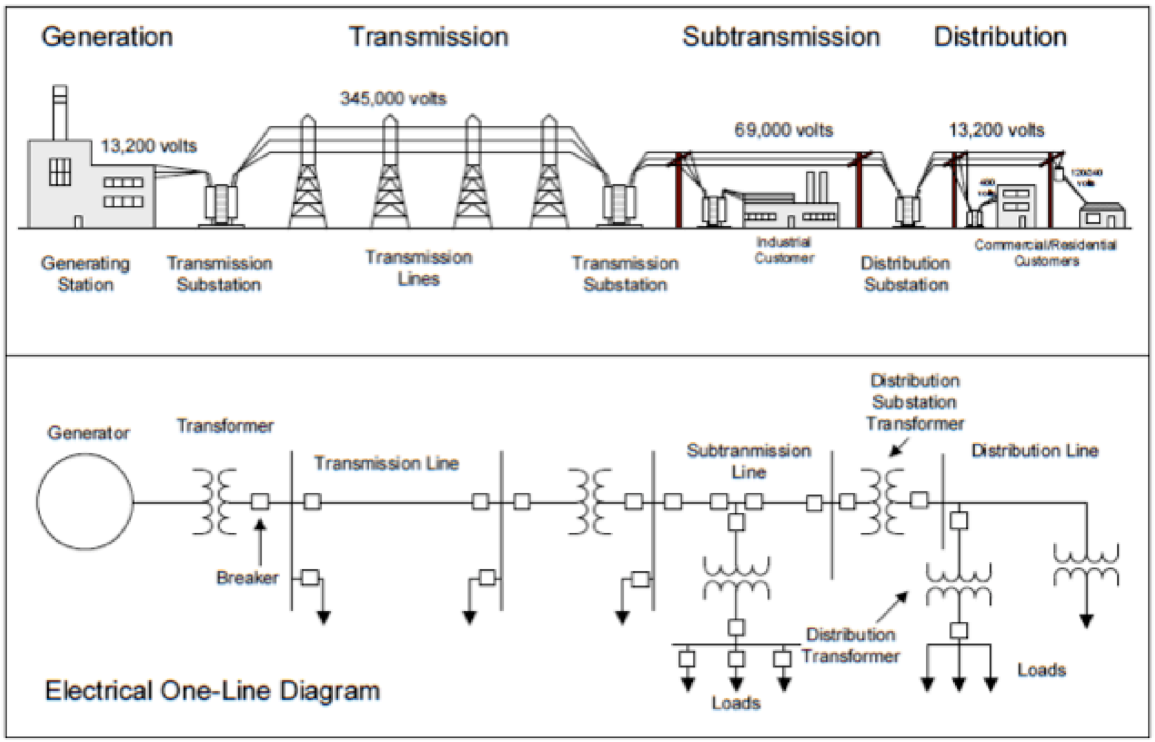

Figure 2. Typical electric power system single-line diagram

2.1 Protective Relaying

Protective relays are required on a distribution system in order to cause the quick removal from service of any electrical equipment associated with the power system when a short-circuit fault occurs or when the power system begins operating in abnormal conditions. Protective relays are essentially the brains that determine when the appropriate circuit breaker tripping action should take place. The mechanical device capable of disconnecting the faulty element and physically isolating the electrical power system from short circuit disturbances is called a circuit breaker.

Figure 3 describes the protective relaying input and output control procedure. The protective relay receives information about the EDS (voltage, current, and frequency) through current and voltage transformers. These transformers transform the measured voltage and current value to a more appropriate power level to be utilized by the protective relay. This information is processed by the protective relay and reacts to any abnormal conditions detected. Each protective relay needs to be set or programmed for the desired tripping time (i.e., time delay for relay coordination and system reliability purposes). The decision to trip open or to close the circuit breaker is made by the relay logic algorithms and must be programmed by a relay engineer.

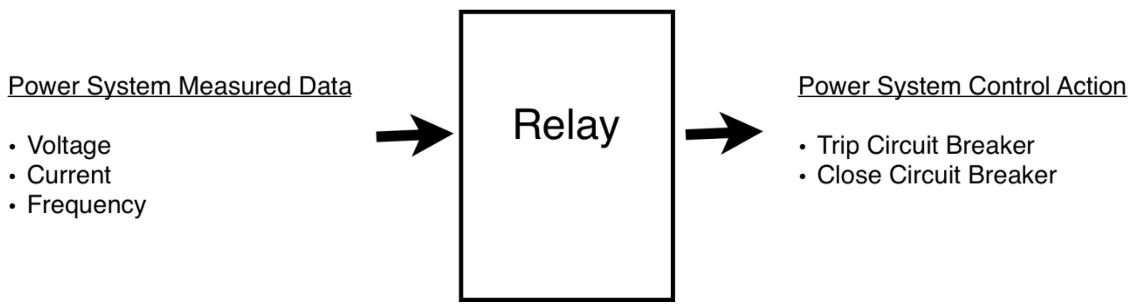

Figure 3. Input and output control of a protective relay

Two basic types of protective relay devices are used in today's electrical power system.

- Electromechanical relays were first introduced in the early 1900s. A typical electromechanical relay is pictured in Figure 4. Electromechanical relays are either magnetic attraction type or induction disc relaying type. Magnetic attraction relays use a plunger or hinged armature operation. The magnetic attraction is proportional to the current flowing through the sensing coil, In most cases, closing the contact initiates a circuit breaker tripping action. The induction disc relay produces a circular motion that is propostional to the coil current. Both designs have performed reliably since their introduction over 100 years ago. Utilities, however, are starting to replace electromechanical relays with new microprocessor-based relays.

Figure 4. Electromechanical relay (Glover/Sarma)

- Microprocessor relays were first introduced in the 1980. Microprocessor relays bring selectivity, speed, and reliability to protective relaying (a typical microprocessor based relay is shown in Figure 5). They are also capabile of recording and storing large data sets when system disturbances, such as faults, occur. Another important feature of microprocessor-type relays is their ability to communicate with utility operations personnel. This is typically performed via a Supervisory Control and Data Acquisition (SCADA) system. This feature allows utility operators to determine the location and type of fault that occurred on the power system without dispatching a specialist, saving time and often improving reliability.

Figure 5. Microprocessor relay

2.2 Relay Coordination

Relay coordination involves coordinating studies which utilize time current curves (TCC). These curves describe the time to trip characteristics based on the relay settings. Figure 6 shows a typical TCC. The vertical axis represents the magnitude of the fault current and the horizontal axis represents the time the relay will initiate a trip signal to operate the circuit breaker. Two important TCC parameters to observe are the minimum pickup time and the instantaneous trip time. The minimum pickup time setting will send a trip signal to the circuit breaker for measured fault current magnitude at or above this threshold. The instantaneous setting region will send a signal to the circuit breaker to trip as soon as possible if the measured fault current magnitude is at this threshold. The circuit breaker trip time decreases as the amount of fault current increases. It is between these two set points that the protection engineer will adjust the shape of the TCC to meet various protection coordination objectives.

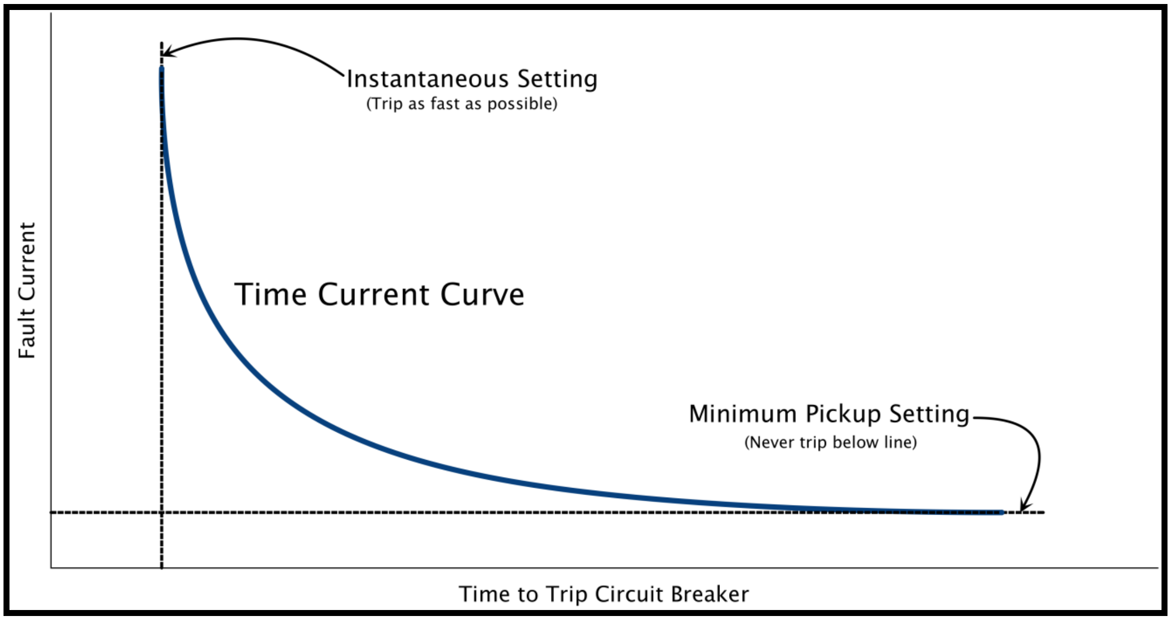

Figure 6. Example of a time current curve

Figure 7 shows a small section of a typical electrical distribution single-line diagram. Single-line diagrams are simplified drawings that show the major electrical equipment as well as relays that are used in the EDS being studied. The diagrams are an essential part of the protection engineer's tools for understanding the behavior of the EDS and what relays are utilized for coordination purposes.

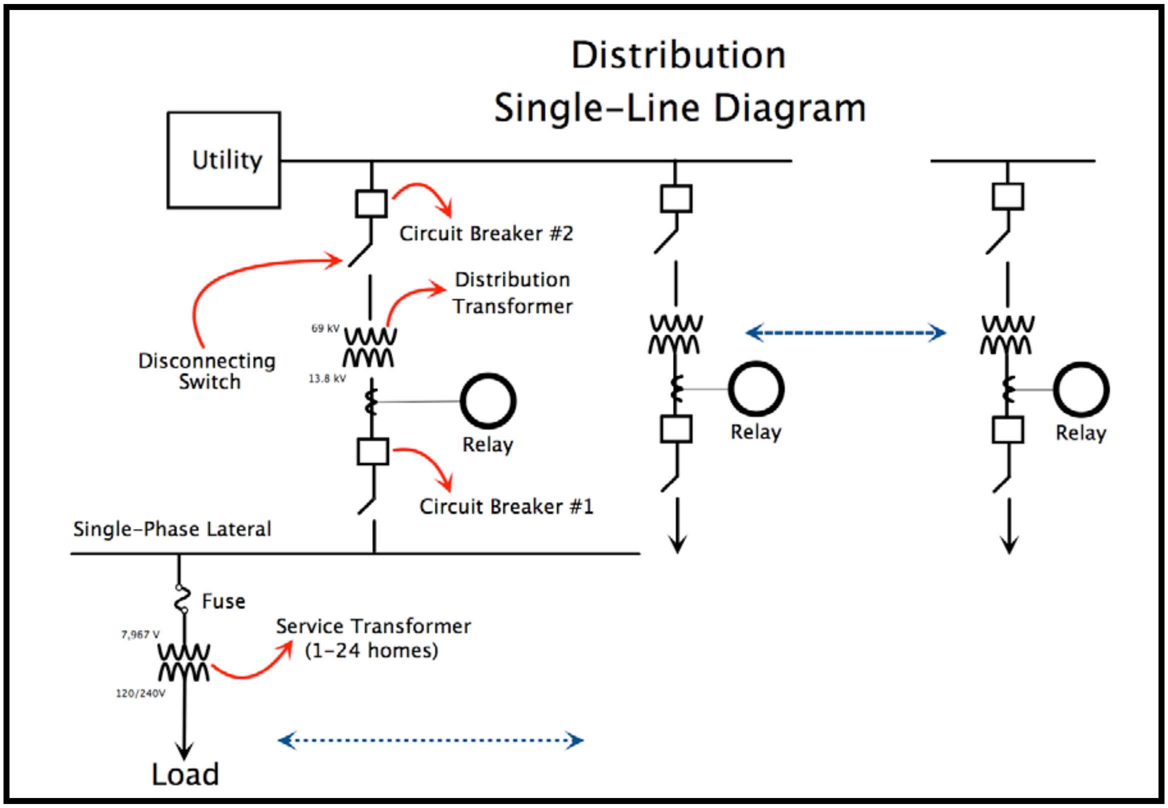

Figure 7. Typical single-line diagram

The goal of relay coordination is to increase the reliability of the system by isolating the fault current source as fast as possible while maintaining power to the rest of the distribution system. For example, if a fault occurred on the load side of the downstream circuit breaker #1 shown in Figure 7, operators would want to clear that feeder circuit as fast as possible while continuing to supply service to the remainder of the distribution system. The upstream distribution circuit breaker #2 would only act as a secondary back-up device and initiate a tripping signal if the downstream circuit breakers failed. Once the circuit breaker receives a trip signal from the relay (which depends upon the circuit breaker vintage and manufacture type) the typical fault clearing times can be anywhere from 2 to 9 cycles.

2.3 DER Related Relaying

There are considerable differences in the performance under fault conditions among the three basic types of DER: synchronous machines, induction machines, and inverter-based sources. These differences are discussed in the remainder of this report with a focus on the characteristics of inverter-based DER. DER, such as fuel cells, wind turbines, solar photovoltaics (PV), and microturbines, often require inverters to interface with the utility grid (Kramer 2009).

Currently, inverter-based DER provide minimal contribution to the power balance on all but a few utility distribution systems (Begovic et al. 2001). However, a significant increase in DER is expected to come on line in the near future. As the penetration level of DER increases, the effect of DER may no longer be considered minimal. As DER become prevalent in the distribution system, equipment rating capability and coordination of protection systems merit a closer investigation (Kroposki 2008).

The fault contribution from a single, small DER unit is not significant; however, the total contributions of many small units may alter the fault current level enough to cause overcurrent protection miscoordination and nuisance fuse operation or hamper fault detection (General Electric, 2003). A DER system may impact the fault coordination of a system to the point that relay setting and fuse sizing changes are required. By adding a fault source to the system, the overall fault current seen by the relay is reduced, which effectively de-sensitizes it (Kroposki 2008; General Electric 2003).

The amount of DER on a specific distribution circuit is referred to as the penetration level. Typically this is defined as the rated output power of the DER divided by the peak load of the circuit. Some reports have shown that even at relatively low penetration levels (10%), it may be important to analyze the impact this would have on system operation (Baran and El-Markaby 2005). DER may have a major impact on feeder protection, but the level at which this would occur depends on how the DER is distributed along the feeder. Continued research in this area is desired for a complete understanding of what this penetration level might be. For DER penetration levels above 10% (DER are heavily dependent on supplying loads), voltage regulation can be a serious issue and may need to be evaluated as well (General Electric 2003).

Higher fault current can also affect recloser (RC) operation. RCs are devices that act very much like circuit breakers. However, RCs may be programmed to try and reestablish circuit connection a few cycles after a fault has occurred. This action is warranted on the distribution level because most faults are of the single line-to-ground type and typically are temporary in nature and often last for only a few cycles. It is possible that the extra fault current from the DER may expose RCs to mechanical and thermal stress that is beyond their limits. Extra fault current may also impact fuse operation, as it may cause the fuse to clear sooner or later than the protection engineer desired. This may cause RC-fuse miscoordination and impact the feeder’s reliability considerably (Baran and El-Markaby 2005).

A unique property of inverter-based DER is the power electronics interface. Power electronics have the ability to control fault current contributions from DER systems. This adjustability can thereby optimize the system protection coordination issues by controlling fault current levels (Tang and Iravani 2005). Typically, inverter-based DER are designed to act as ideal current sources. Therefore, they provide minimal fault current contributions and have little effect on overcurrent protection and coordination strategies for fuse and circuit breakers (General Electric 2003). However, this might not always be true with increased DER penetration (10% or more) (General Electric 2003; Baran and El-Markaby 2005).

3 Short Circuit Analysis

Short-circuit studies ensure that the wide range of electrical equipment used to generate, transmit, and distribute electrical power is sufficiently sized to interrupt or withstand short-circuit current. Electrical equipment and protective devices must be properly sized and set for such events. However, short circuits on the EDS cannot be eliminated completely. Instead, the overall goal is to mitigate and, to a certain extent, contain their damaging effects (IEEE 1997). The first goal for short-circuit protection is to clear faults quickly to prevent fires and explosions and further damage to utility equipment such as transformers and cables (Short 2004). The second goal is to establish practices that reduce the impact of faults and improve the following.

- Reliability by properly coordinating protective devices to isolate the smallest possible portion of the system and affect the fewest customers.
- Power quality by reducing the duration of voltage sags. Coordination practices affect the number and severity of momentary interruptions (Short 2004).

There are several types of faults that can occur on the EDS. A 3-phase fault occurs when all three phases come into contact with each other and is the least common type of fault. A single line-to-ground fault is the most common type of short circuit and occurs when one phase of the transmitted power comes into contact with alternative current path or ground. For example, a tree limb inadvertently falls across a power line. A line-to-line fault occurs when two electrical phases come into contact with each other.

The 3-phase fault current typically provides the highest available fault current. However, there are situations where this is not the case. For instance, if a single line-to-ground fault occurs and there is an effective ground path for current to flow (zero-sequence network), then several current sources could contribute to this fault and exceed the 3-phase fault current. This will depend on how the fault current source or sources are connected to the system (i.e. transformer connection delta or wye).

Under steady-state operation, the power generated by the source is equal to the power being consumed by the load. The load impedance is the principal determinant of the current magnitude (IEEE 2001). When an additional load (e.g. air conditioner) is turned on, the total load impedance is reduced, resulting in an increase in current flowing in the armature winding of the rotating machine. This increase in current will cause the machine's rotor to actually slow down due to the armature reactance. Due to this increased load demand, the frequency of the power system will deviate slightly lower. In order to maintain constant frequency (60 Hz in the United States) the generator turbine must respond with additional torque (prime mover) to match this new power demand.

A fault in a typical EDS behaves very much like a resistive-inductive (RL) circuit (see Figure 8) with the switch in the closed position. Closing the switch simulates a faulted condition. Bypassing the predominantly resistive load, an extremely low impedance path (a large load has been added to the circuit) has been created to ground, causing the generator to supply a higher level of current. The fault current is limited by the machine's internal impedance and the transmission impedance path ($R+jX_L$).

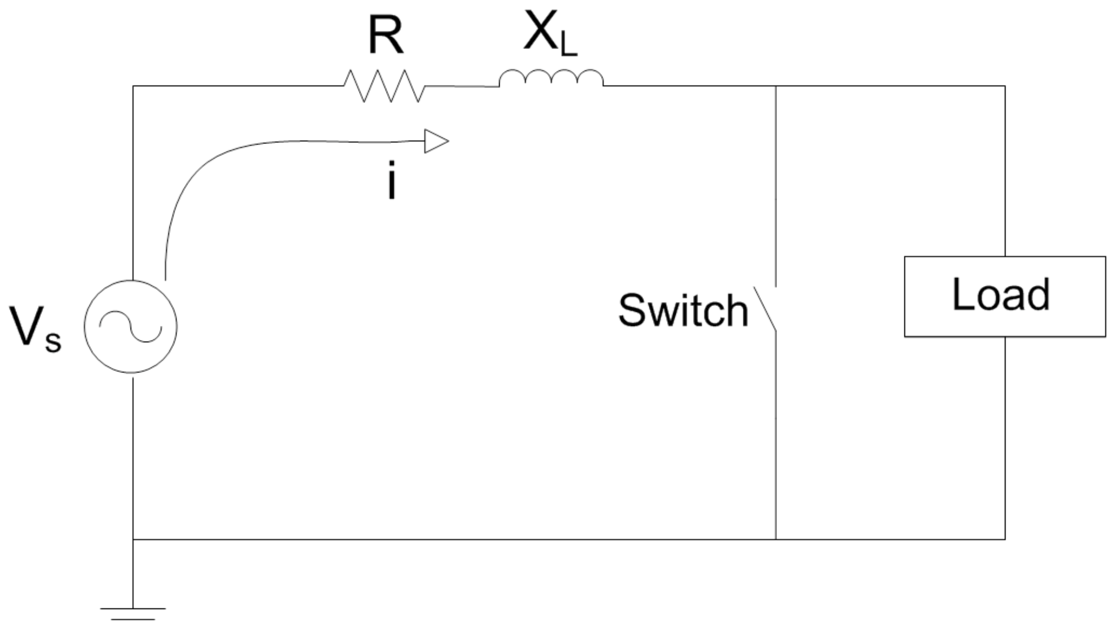

Figure 8. Circuit model for asymmetrical fault current

In order to explain the fault current behavior of such an event, we need solve for the current when the switch is closed (see Figure 8). Writing a Kirchhoff's Voltage Law (KVL) equation around the circuit we get Equation 1.

$$V_S = Ri + L\frac{di}{dt} \qquad (1)$$

Where R is circuit resistance, i is the current, and L is the circuit inductance. The inductance L can be determined using

$$X_L = \omega L \qquad (2)$$

where, ω is angular frequency. Solving the differential equation for the symmetrical or alternating-current (AC) steady-state fault current we get Equation 3.

$$i_{ac} = \frac{V_S}{R}(1 - e^{-(\frac{t}{T})}) \qquad (3)$$

where,

$$T = \frac{L}{R} = \frac{X}{\omega R} \qquad (4)$$

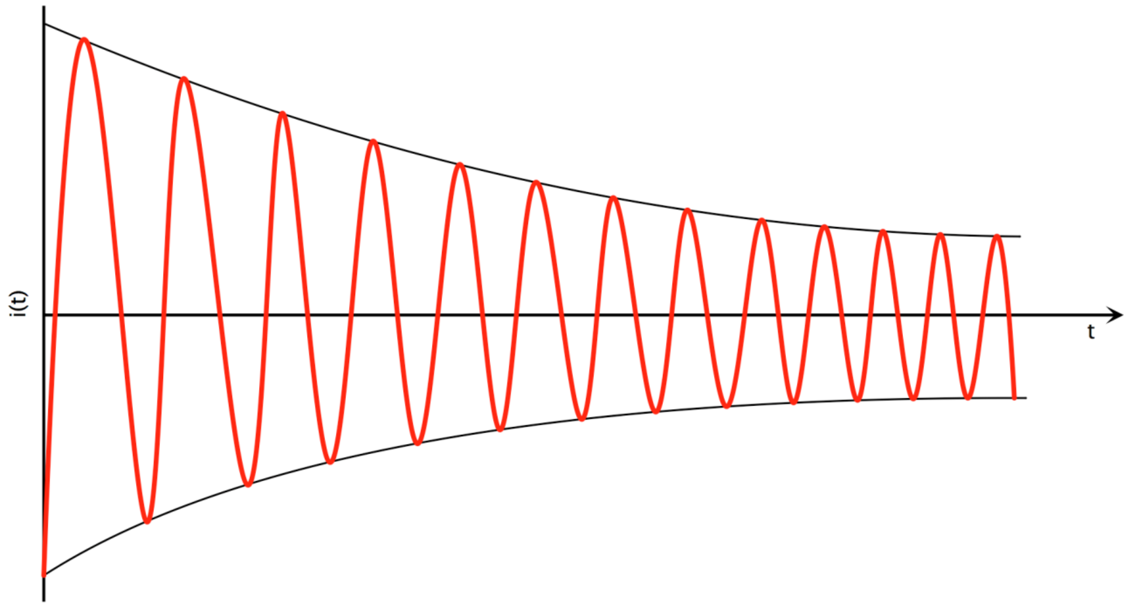

Figure 9. AC symmetrical short-circuit current

Figure 9 shows the AC symmetrical fault current for a synchronous generator. The AC symmetrical fault current is characterized by the magnetic flux trapped in the stator windings (mostly inductance) of the rotating machine and cannot change instantaneously. This is why synchronous machines under fault conditions feature different flux variation patterns compared to induction machines. The flux dynamics dictate that the fault current decays with time until a steady-state value is reached.

Equation 3 describes the temporary direct-current (DC) offset fault current.

$$i_{dc} = I_0 e^{-(\frac{t}{T})} \qquad (5)$$

Equations 4 and 5 describe the time constant (how fast it will decay) and the reactance as the product of the angular frequency and the inductance. A detailed solution can be found in, IEEE Red Book, Std 141-1993.

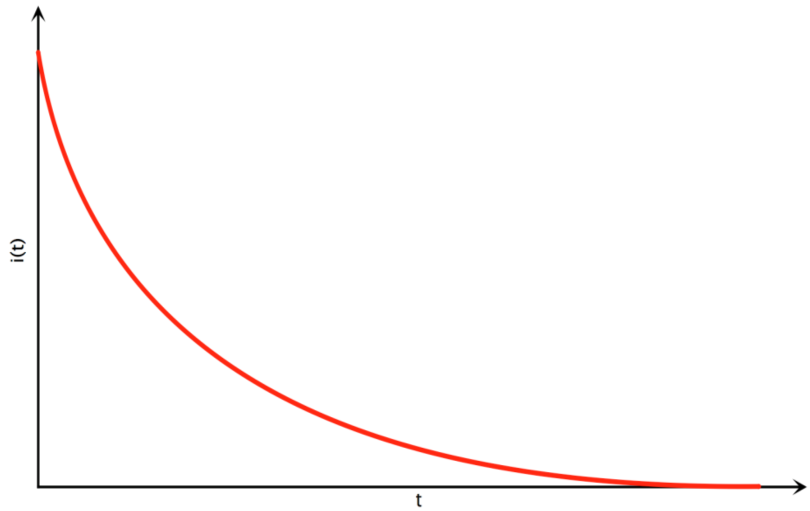

Figure 10. Decaying DC offset short-circuit current

The DC fault component is characterized by the fact that inductors and capacitors store energy. This energy decays exponentially with time and is released during a short circuit. The contribution from the stored energy during a fault decays rapidly as seen in Figure 10.

The total fault current or the asymmetrical fault current solution includes the AC current plus the DC offset current as shown in Equation 6.

$$i_{asym} = i_{ac} + i_{dc} = \frac{V_S}{R} + (I_0 - \frac{V_S}{R})e^{-(\frac{t}{T})} \qquad (6)$$

A representation response of current versus time that includes both DC and AC contributions to a short circuit is given in Figure 11.

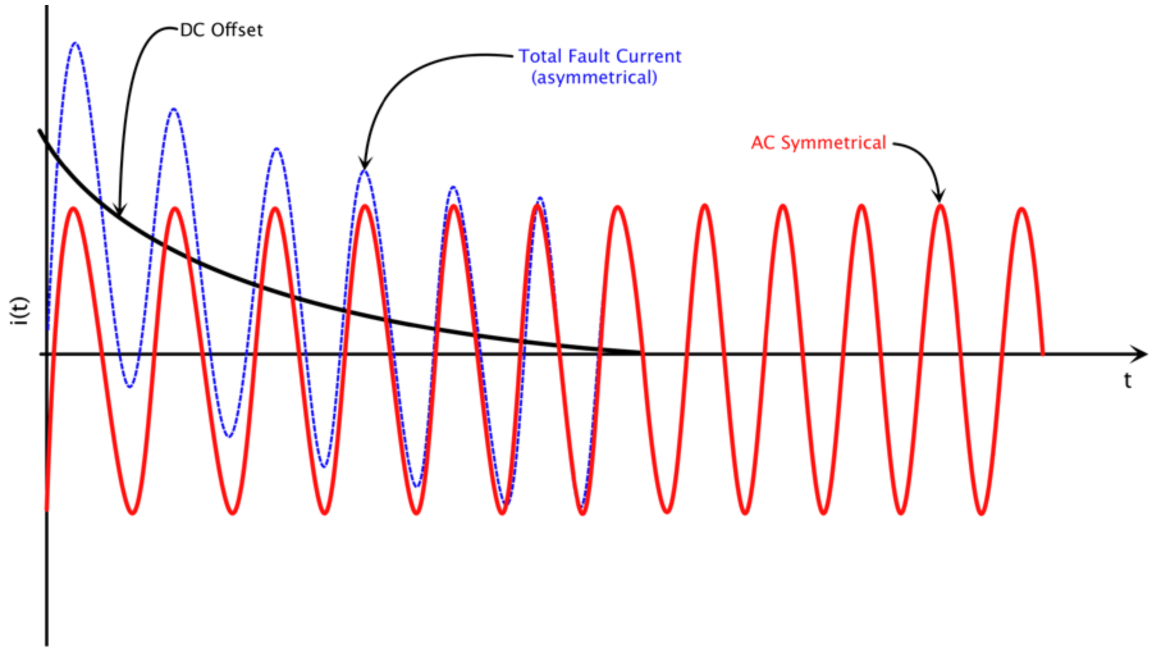

Figure 11. Total (DC and AC components) short-circuit asymmetrical current

In today's electric power system, synchronous generators and induction motors are the main sources of short circuit currents and they respond differently under transient (i.e., fault) conditions.

3.1 Synchronous Machines

If a short circuit is applied at the terminal of a synchronous machine, the current will start out very high and decay to a steady-state value. Synchronous machines generally deliver about six times the rated current for several cycles before decaying to between 400% and 200% of rated current (see Figure 12, DC offset removed) (Kroposki 2008; Baran and El-Markaby, 2005). In a synchronous machine the field current is supplied by an external DC source. This external source will continue to supply voltage to the field windings of the generator. The prime mover continues to drive the rotor that produces the required induced voltage in the stator winding which in turn supplies a continuous fault current. The steady-state short-circuit current value will persist unless interrupted by a switching device such as a circuit breaker.

As short circuit current continues flowing in the circuit, the machine's impedance increases due to the increase in winding temperature. This helps the AC envelope to decay faster. The industry has established three reactance variables called subtransient, transient, and synchronous reactance (IEEE 1993).

X''_d= subtransient reactance; determines current during first cycle after fault occur. This condition lasts for approximately 0.1 seconds.

X'_d = transient reactance; assumed to determine current after several cycles. This condition lasts from about 0.5 to 2 seconds.

X_d = synchronous reactance; this is the value that determines the current flow after steady-state condition is reached.

Most manufacturers include two values for the direct axis subtransient reactance. The X''_{dv} is at rated voltage, saturated, and smaller than X''_{di} which is at rated current, unsaturated, and larger. During a short-circuit event the generator may become saturated. Therefore, for conservatism, the X''_{dv} value is used when calculating fault currents (IEEE 1993).

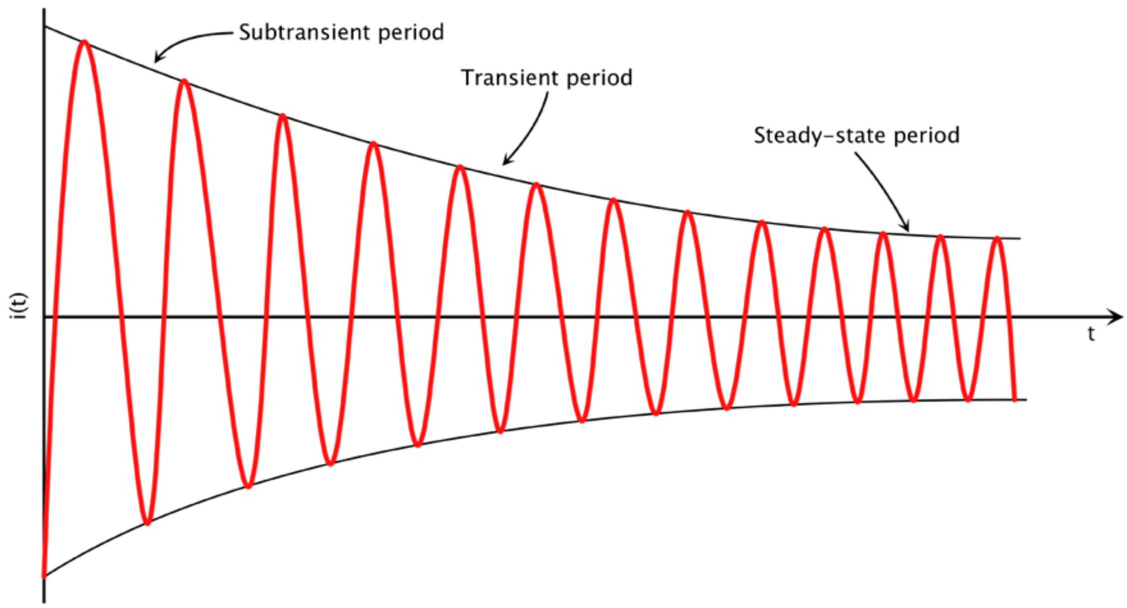

Figure 12. Synchronous machine response to 3-phase fault (DC offset not shown)

The characteristic of this decaying envelope also depends upon the machine's magnetic field. The magnetic energy stored in the generator windings cannot change instantaneously but decays over time.

3.2 Induction Machines

If a short-circuit is applied at the terminal of an induction machine, the current will start out very high before decaying completely. The induction machines deliver about six times rated current during this time (see Figure 13) (Kroposki 2008; IEEE 2008; IEEE 1993). This fault characteristic is generated by inertia driving the motor in the presence of the field flux produced by induction from the stator rather than by a DC field winding (synchronous machine). This flux decays on the loss of source voltage caused by a fault at the machine terminals. Because field excitation is not maintained, there is no steady-state value of fault current and the current decays to zero.(IEEE 1993).

The values of transient and synchronous reactance approach infinity under steady-state fault conditions. Therefore, the induction motors are assigned only a subtransient value of reactance. This value varies upward from the locked rotor reactance to account for the decay of the motor current contribution to the fault. For fault calculations, an induction generator can be treated the same as induction motor. Wound-rotor induction motors normally operating with their rotor rings short-circuited will contribute short-circuit current in the same manner as a squirrel-cage induction motor (IEEE 1993).

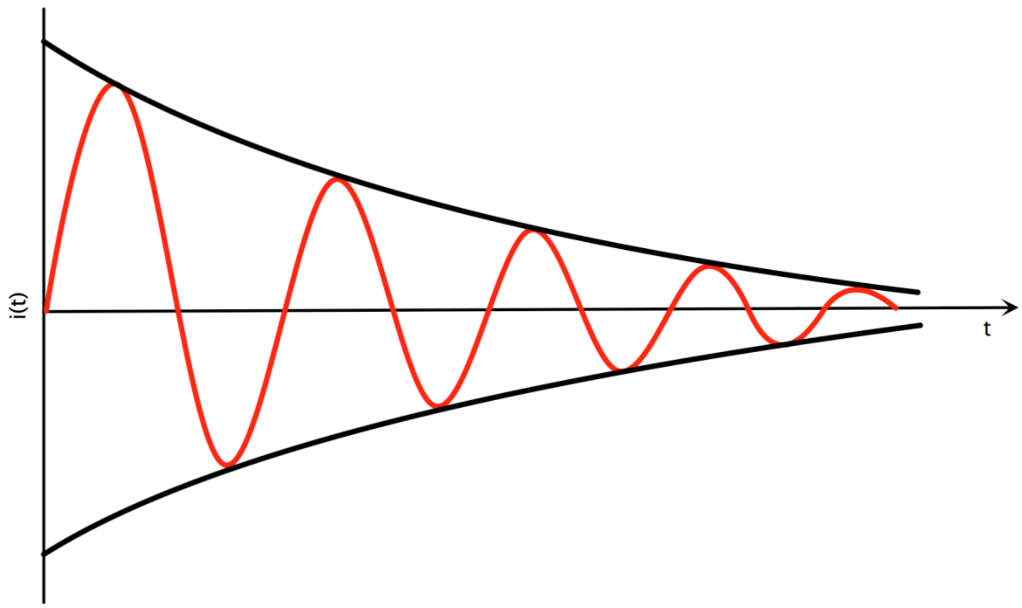

Figure 13. Induction machine response to 3-phase fault

4 Short Circuit Current Analysis of Inverter-Based DER

4.1 Background on Power Electronics

Today, power electronics (PE) play a significant role in DER systems because they make utility grid interconnection possible for a wide variety of energy sources. The fundamental building blocks of power electronics are semiconductor-based switching devices such as transistors and thyristors. In power applications, these electronic switches are most commonly used to create or convert voltage and current waveforms. For DER applications, the most common power electronics systems are inverters and converters. Benefits of power electronic switches include switching speed, package size, and the ability to be finely controlled by other electronic systems and software. Proper design and use of PE-based systems can be approached in a modular fashion by targeting overall system needs. (Kroposki et al. 2006)

PE interfaces can improve power quality by improving harmonics and providing extremely fast switching times for sensitive loads (e.g., computers). PE can also provide utilities with reactive power control and voltage regulation at the DER connection point (Kroposki et al. 2006).

PE inverters are based on three fundamental technology areas (Kroposki 2008):

- Power semiconductor devices
- Microprocessor and digital signal processor technologies
- Control and communications algorithms.

PE interfaces typically contain some level of metering and control functionality. This ensures that the DER system can operate as designed. Figure 14 shows a block diagram of the DER system and PE interface for a variety of applications.

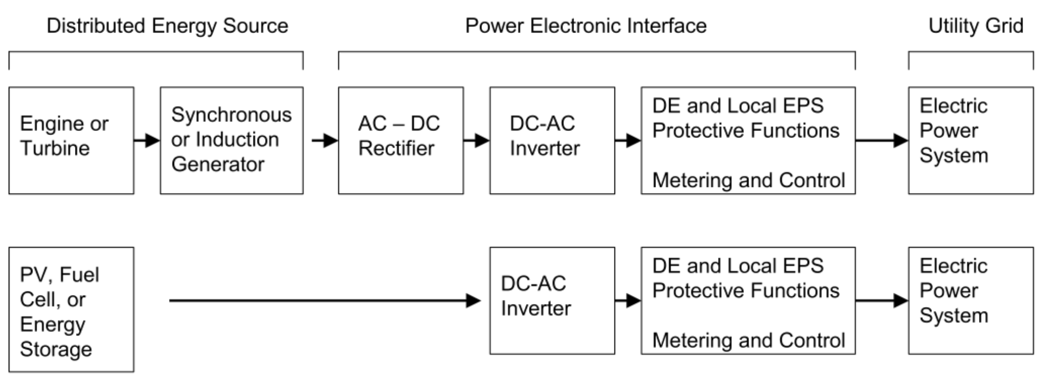

Figure 14. DER system and PE interface block diagram (Kroposki et al. 2006)

4.1.1 PE Devices

PE devices are the individual electrical devices that turn on and off in a controlled way to regulate the flow of electricity. There are several types of PE devices that have specific properties. These include:

- Diodes
  A diode is a two-terminal PE device that can conduct current in only one direction and block voltage in the reverse direction. The diode is typically used in circuits in which unidirectional current flow is required and reverse voltage levels must be blocked. Diodes exhibit a negative temperature coefficient, which makes them difficult to parallel when higher current levels are required (Kroposki et al. 2006).

- Thyristors
  Thyristors have the highest power handling capabilities—including high-voltage (115 kV or greater) transmission levels—of all semiconductor devices. Thyristors act like a diode with gate control signal that initiates a change in conduction state if the unit is forward-biased. Thyristors have slower switching frequency than other modern devices by orders of magnitude (Kroposki et al. 2006).

- Insulated gate bipolar transistors
  PE systems today rely on this type of switching the most. Insulated gate bipolar transistors (IGBTs) control power flow in the switch by gate voltage and can switch at high frequency. They are typically available on distribution systems of 3 kW and higher. The switching frequency is lower than metal-oxide-semiconductor field effect transistors but orders of magnitude faster than thyristors (Kroposki et al. 2006). IGBT inverters have limited capability to supply fault currents. When the inverter controls detect something wrong, they shut down immediately (Dugan et al. 2002).

- Metal-oxide-semiconductor field effect transistor
  The metal-oxide-semiconductor field effect transistor (MOSFET) is a gate voltage controllable switch. Usually found in low-voltage (<500 V) and low-power systems, MOSFETs are capable of the highest switching frequencies—a feature that is highly desired when the amounts of magnetic materials in a circuit are being minimized. Unlike thyristors, MOSFETs can quickly start and stop forward conduction even with a constant forward voltage applied. This makes them highly useful in switch mode power supply applications in which DC power is being converted to another magnitude or to AC. By their nature, MOSFETs have large conduction losses at high voltages, which make them uncompetitive with other types of devices in higher-power systems. Also, because of the nature of their construction, MOSFETs allow uncontrolled (and inefficient) reverse current to flow when a reverse potential is applied. This feature is due to their "body diode" and is usually accounted for by manufacturers during packaging. MOSFETs have a positive temperature coefficient, making them relatively easy to parallel (Kroposki et al. 2006).

4.1.2 Applications

There are a variety of PE applications that are used to convert electricity from one form to another or control the flow of electricity. These include:

PE are used in a variety of applications to convert electricity from one form to another or to control the flow of electricity (Kramer 2008). Some examples of these applications are as follows:

- AC-to-DC rectifiers provide control of DC voltage from an uncontrolled AC source or utility (such as a microturbine, variable frequency drive (VFD), or small permanent magnet generator (PMG) wind turbine).
- DC-to-DC converters are almost always found in renewable-to-battery applications. They take uncontrolled, unregulated input DC voltage and groom it to a specific load application. DC-to-DC converters are found in photovoltaic battery charging systems.
- DC-to-AC inverters regulate AC supply from DC input. They are found in standalone AC power applications as well as utility-connected DER systems.
- Solid-state breakers have the potential to standardize and greatly simplify the installation of grid-connected DER technologies and could hold the key to real grid modernization. Solid-state breakers replace SF6, air, oil, and breakers with a semiconductor switch. They provide much faster switching speeds along with advanced sensing and controls that can be used to eliminate fault current contributions, thus making DER coordination negligible (Kroposki et al. 2006).

4.2 Prior Research on Inverter Based DER Fault Current

To validate the inverter-based DER fault current contribution numbers, a literature search was conducted to see if this information was published. Although there are very few references that show actual fault currents from inverter-based DER, there are a number of papers that have some discussion on this topic. Several inverter-based fault current contribution research documents contain a "rule of thumb" of one to two times an inverter's full load current for one cycle or less (Kroposki 2008; Dugan et al. 2002; Barker and de Mello 2000; IEEE 2000; IEEE 1994; Begovic et al. 2001).

In 1985 and 1986, New England Electric installed 30, 2-kW PV static power converters on one phase at the end of a 13.8-kV feeder in Gardner, Massachusetts. The utility performed extensive testing to determine if the static power converter could reliably detect island conditions and faults with and without a utility source. During the experiment, inverters were shown to contribute a small, short current transient during faults. This transient was less than 200% rated peak inverter current and lasted less than 200 microseconds. The inverter shut down within 0.5 cycle of the fault and did not affect normal feeder protection systems (IEEE 1994).

In the 1990 EPRI report covering the Gardner, Massachusetts, study, the findings were similar. The fault current provided by the inverters was limited; maximum observed fault current was no more than 150% of rated converter current. The final conclusion of the EPRI report was that the 37% penetration of PV at Gardner was achieved with no observable problems in any of the four areas studied (steady-state slow transients such as cloud transients; PV response under fast transients such as unintentional islanding, faults, and lighting surges; PV effects on system harmonics; and impact on distribution system of a high penetration of PV). At relatively high penetration levels the PV systems did not adversely affect distribution system operations.

The GE study *DG Power Quality, Protection, and Reliability Case Studies* found that, for DER penetration levels of 40% (DER is heavily dependent on supplying loads), voltage regulation can be a serious problem (GE 2003). The sudden loss of DER, particularly as a result of false tripping during voltage or frequency events, can lead to unacceptably low voltages in parts of the system. Since GE assumed that inverter-based DER did not contribute significantly to fault currents, the DER did not adversely affect coordination strategies for fuse and circuit breakers. However, studies also indicate that this might not always be true if the DER is connected at a point where the utility source impedance is unusually high (weak system). These results show that at higher penetration levels it may be beneficial to have inverters ride-though fault conditions. This will be further examined in Section 6.

4.3 Fault Characteristics of Inverter-Based DER

Inverters do not dynamically behave the same as synchronous or induction machines. Inverters do not have a rotating mass component; therefore, they do not develop inertia to carry fault current based on an electro-magnetic characteristic. Power electronic inverters have a much faster decaying envelope for fault currents because the devices lack predominately inductive characteristics that are associated with rotating machines. These characteristics dictate the time constants involved with the circuit. Inverters also can be controlled in a manner unlike rotating machines because they can be programmed to vary the length of time it takes them to respond to fault conditions. This will also impact the fault current characteristics of the inverter.

The inverter interface between the DER and the utility system connection can use a voltage control scheme or a current control scheme. The DC link capacitor between the DC/AC converter and the DER unit holds the voltage near constant during transient conditions. The voltage control scheme has higher initial current overshoot, while the current control scheme has a much slower increase and decreases back to steady-state values. The fault contribution will be higher during the transient period (i.e., the first 5–10 cycles) if the DER is under the voltage control scheme (Baran and El-Markaby 2005).

The potential exists for cutting-edge PE interface systems to orchestrate topologies with fast, sub-cycle semiconductor switches in a manner that mitigates negative consequences of DER systems (Kroposki et al. 2006). In order to determine the short-circuit current characteristic of an inverter, testing should be conducted. These test results can be used to develop DER inverter models that can be used in distribution models.

5 Testing Methods for Determining Fault Contributions

5.1 Testing Background

Since understanding the fault current characteristics of inverter based DER will be important in understanding their impact on the distribution grid, accurate characteristics should be known. Currently the industry has set a “rule of thumb” of 2 times rated current for the amount of fault current contributed by inverter-based DER. In order to evaluate the rule of thumb, testing was conducted at NREL and inverter manufacturer facilities to determine if these values are accurate for current inverter technology.

5.2 Test Procedure

The testing procedure in this section is designed to characterize the inverter’s response when subjected to an output faulted condition. The testing method used for this experiment is based on Underwriter Laboratory UL 1741 Section 47.3 as described below:

- The DC battery circuit terminal and the AC output circuit terminal of a unit are to be shorted separately. The shorting is to be from line to neutral (when applicable) and from line to line.
- When shorting the unit, the source (DC input or AC output/utility) is to be disconnected by a relay or similar device.
- Measure the maximum inverter peak output fault current and power factor immediately after the short is applied for 2 seconds.
- The short circuit test is to be performed a total of four times. Each iteration shall be performed at a different portion of the line cycle.
- For a unit with multi-phase output, the test is to be performed with shorts applied from phase to phase and from phase to neutral or ground. If the output circuitry of the product is essentially symmetrical, the test iterations may be split between the phases. If the output circuitry is not essentially symmetrical, the four test iterations shall be performed on the non-similar phases.
- For a unit intended for use with external isolation transformers, the short is to be applied before and after the external transformer.
- The location of the applied short in the test circuit shall not direct the output short circuit test current through any ground fuse.

5.3 NREL Experimental Setup

The UL test procedure and equipment set-up was utilized for this inverter short-circuit experiment. The test circuit in Figure 15 is designed to limit the fault current coming from the grid source by using a fuse in series with the utility source.

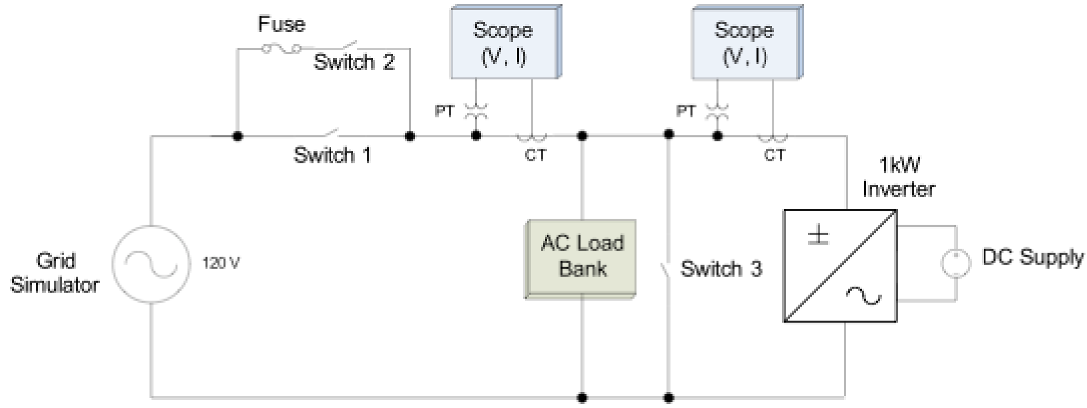

Figure 15. Test circuit single-line diagram

To conduct the short-circuit test, a 1 kW, 1-phase, DC input: 47-92V (used 85 V in experiment), AC output: 120 V, 8 amperes rated continuous current inverter was used.

The following electrical equipment was used during the inverter testing:

- Grid simulator: 15 kW constant voltage source, 120 V, 60 Hz (max fault current is 300 amperes constant voltage source).
- DC Power Source ratings: 16-17 kW, 0-20 A, 0-60 Vdc, output is 120 Vac.
- AC load banks: 3 kW, 30A, 90A max, 50 – 500 V maximum.

When the inverters are connected to the utility, the inverter is run in current control mode which does not allow the inverters to control voltage. Voltage is regulated by the utility grid simulators at the point of connection.

5.3.1 Test Procedure

The following short-circuit test procedure outlined below was recommended by UL. See Figure 15 for the following test procedure.

1. Close switches 1 and 2.
2. Set AC load similar to inverter output (1kW). This will limit the current coming from the grid to less than the fuse low current rating (20A).
3. Open switch 1.
4. Set fast and accurate storage oscilloscope for estimated current level.
5. Close switch 3 to simulate fault, for approximately 2 seconds.

5.3.2 Test Results

The 60 Hz, steady-state inverter current and voltage waveforms are displayed in Figure 16. Figure 16 is a recorded snapshot of the inverter AC voltage and current waveform before a single-phase fault was applied across the AC side of the 1 kW. The blue colored sinusoidal waveform represents the inverter AC voltage and the red represents the inverter AC current sinusoidal waveform. During steady-state conditions, the 1kW inverter produces a maximum peak current of 11.9 A (8.4 A RMS) at peak voltage 171.1 V (121V RMS).

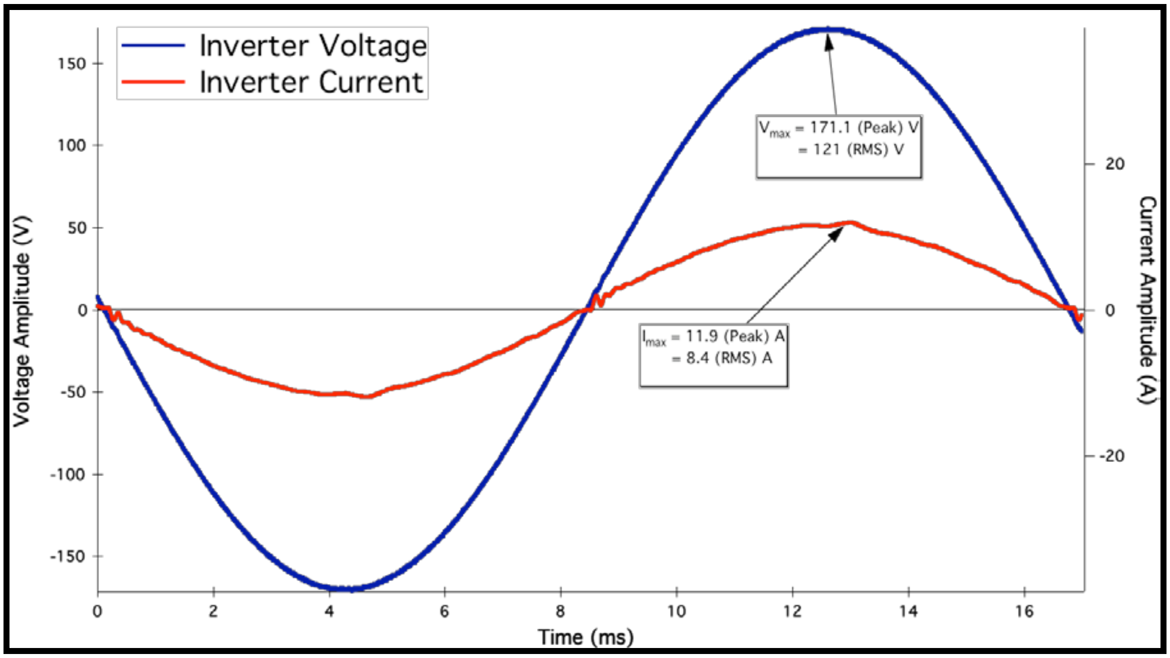

Figure 16. Pre-fault waveform of 1 kW inverter

The inverter is then short-circuited and the inverter fault current magnitude and duration are shown in Figure 17 below. The maximum measured peak fault current is 42.7 amperes which is approximately 5 times the steady-state pre-fault peak current. This is about twice the rule of thumb that is stated in the literature. The duration of the fault (from t_1 to t_2) lasts for only 1.6 ms or 0.1 cycle. The measured fault time is much quicker than the fault current times stated in the literature.

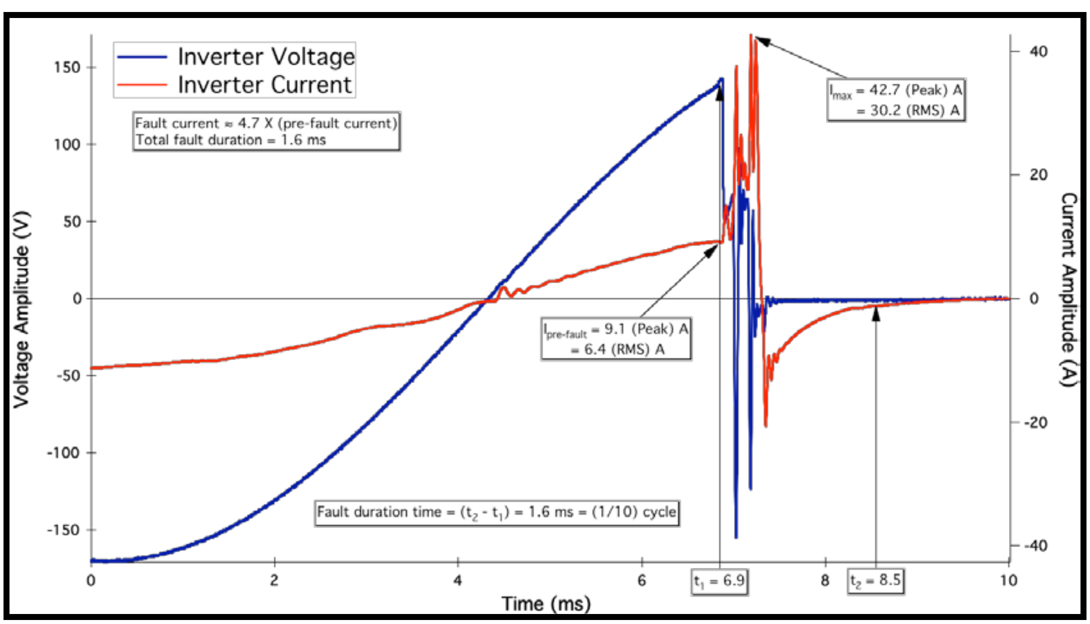

Figure 17. Fault current test result of 1 kW inverter

5.4 Inverter Manufacturer's Results

Similar testing was conducted at an inverter manufacturer's facility using a larger inverter. The fault current waveform from a 500 KVA 3-phase grid-tied inverter that has been subjected to a bolted 3-phase fault is shown in Figure 18. The purple trace is the recorded inverter AC current. The yellow trace represents the trigger. A trigger is the command that sends a signal to the contactor to close and short-circuit the phases. The difference between the start of the trigger signal and the actual short-circuit event is due to the contactor closing time.

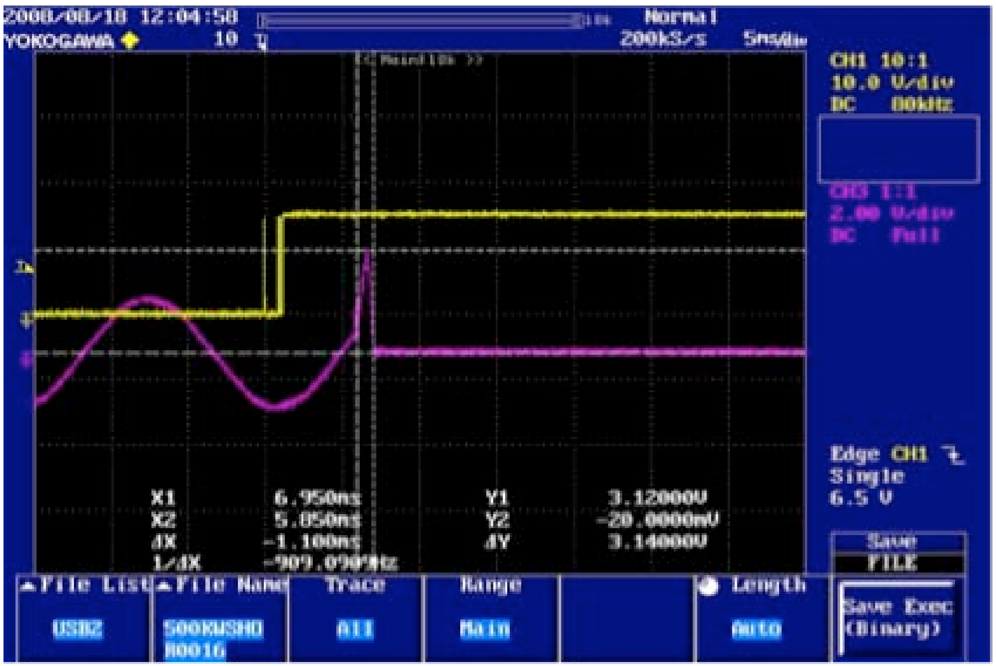

Figure 18. Manufacturer's 500 KVA inverter output short circuit test results between B-C phases

Digital snap-shots traces were captured by a power analyzer during each short-circuit current event and the fault current between two electrical phase, A-B, A-C, and B-C were recorded. The maximum fault current peak and duration time are summarized below in Table 1. Each phase combination was faulted according to standard UL 1741.

Table 1. 500 kVA Inverter Short Circuit Test Results

Test Number	Between B-C Phases	
	I max	Duration
1	3.14 kA	1.1 ms
2	2.5 kA	1.25 ms
3	2.52 kA	1.75 ms
4	3 kA	1.2 ms
	Between A-C Phases	
	I max	Duration
1	2.56 kA	4.25 ms

2	3.92 kA	1.25 ms
3	3.82 kA	1.5 ms
4	3.66 kA	1.2 ms
5	3.78 kA	1.2 ms
	Between A-B Phases	
	I max	**Duration**
1	3.72kA	1.25 ms
2	3.68 kA	1.45 ms
3	2.44 kA	1.65 ms
4	3.76 kA	1.45 ms
5	2.66	1.35ms

The manufacture inverter fault current is approximately 2 to 3 times the rated peak output current with a duration time of approximately 1.1 to 4.25 ms. The results from the manufacturer's 500 KVA 3-phase inverter and NREL's 1 kW 1-phase inverter testing results are similar with respect to the fault duration times. Both inverters test results suggest that inverters designed to meet IEEE 1547 and UL 1741 produce fault currents anywhere between 2 to 5 times the rated current for 1 to 4.25ms. Depending on the inverter type, single-phase or a 3-phase. The single-phase inverter NREL tested results in a slightly higher fault current 4-5 times rated peak current. The larger 3-phase manufacture 500 kVA inverter was around 2-3 times rated peak current. The values for the single-phase type inverters are different than those found in the published literature, but are still significantly less than the fault current contributions of a machine-based DER.

6 Low Voltage Ride-Through (LVRT)

Most faults on the EDS are temporary in nature (i.e. a lighting strike). The power system is designed to open the line circuit in an attempt to clear the fault and then automatically reclose the line to reconnect the circuit once the fault has cleared. There is a delicate balance between disconnecting for permanent faults and having the ability to "ride through" temporary faults.

With the increase of DER penetration levels, electrical grid operators will need to maintain control of the overall power generation connected to the grid. If DER is required to disconnect for all fault conditions (per IEEE-2008), this will lead to severe voltage and dynamic stability concerns at high penetration levels. Typically, when faults occur on the transmission system, a short voltage sag will occur. During this short time, conventional synchronous generators are able to ride through such disturbances (before tripping off-line). To address this concern, grid operators require that any generator (including wind) needs to have ride-through fault capability. This is known as "low-voltage ride through" (LVRT). LVRT requirements stipulate that generation facilities need to stay connected through a temporary fault scenario to provide post-fault voltage support. In addition, generation facilities need to stay connected to the distribution or transmission system to help maintain grid stability.

The electric power delivery policies that govern the interconnection of power systems in the United States and Canada involve multiple organizations, including transmission owners, load serving entities, and regional transmission organizations, share in the responsibility for maintaining the reliability of the bulk power system. This effort maximizes the stability, reliability, and security of the electric power network.

6.1 Fault Ride Through Requirements for Large Generators

6.1.1 Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) of the U.S. federal government administers the Federal Power Act (FPA) as amended by the Energy Policy Act of 1992. The core of the act ensures that transmission providers offer wholesale transmission service at rates that are just, reasonable, and not unduly discriminatory.

In July of 2003 FERC initiated Order No. 2003 responding to non-uniformity in interconnection practices regarding new generators. Industry players such as the American Wind Energy Association (AWEA) and the Western Electricity Coordinating Council (WECC) proposed interconnection standards and guidelines for all new generators greater than 20 MW. No distinction was made between conventional synchronous or variable speed machines with power electronic inverters. It was in March of 2004 that FERC recognized the differences in technologies and how they affected interconnection to the electric grid and developed an Appendix G, Order No. 661 in 2005.

FERC Orders No. 661 and 661-A, Interconnection for Wind Energy, include standardized interconnection agreements for wind generation above 20 MW. This Order requires transmission providers to append new provisions to the standard agreement for interconnecting large generating facilities, which are required under their open-access transmission tariffs, in order to address technical requirements and procedures for integrating large wind power facilities into their transmission systems. A key provision of the Order is that wind generating facilities must remain operational during voltage disturbances on the grid. Large wind plants must, if needed, also meet the same technical criteria for providing reactive power to the grid as required of conventional large generating facilities (Zavadil et al. 2005).

6.1.2 American Wind Energy Association

In a May 2004 petitions, the American Wind Energy Association (AWEA) initiated requirements that uniquely characterized wind power plant requirements. The major petition covered a number of issues but one in particular was LVRT. AWEA recommended adoption of an LVRT standard developed by a German grid operator (E.ON Netz). The standard was developed assuming significant levels of wind generation capacity. FERC Order No. 661 adopted the standard. A description of how the LVRT behaves is given in Figure 19. This requires that the generator remain on-line for voltages as low as 15% of nominal voltage for 0.625 seconds (Zavadil et al. 2005).

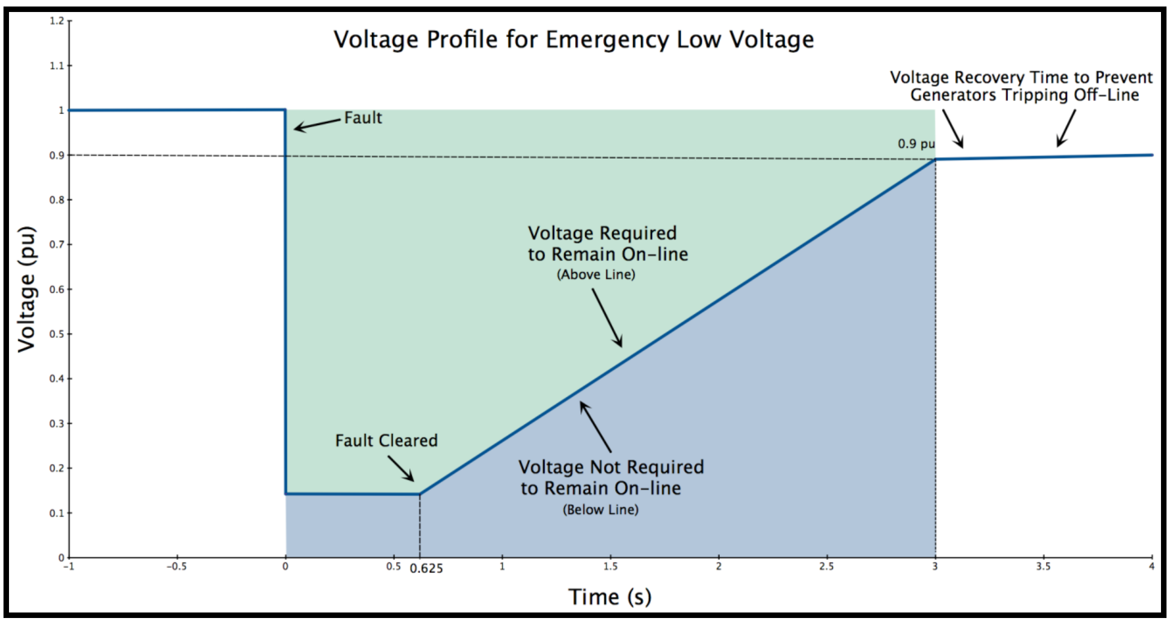

Figure 19. LVRT requirement per FERC Order No. 661

6.1.3 Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) initiated its own LVRT standard and guidelines. The proposal required that all generating units in the WECC organization remain on-line or tied to the system for three-phase faults with normal clearing and single line-to-ground faults with delayed clearing and tolerates the post-fault transient characteristic specified in Figure 20 (Zavadil et al. 2005). This standard does not apply to individual units or to a site where the sum of the installed capabilities of all generators is less than 10 MVA, unless it can be proven that reliability concerns exist.

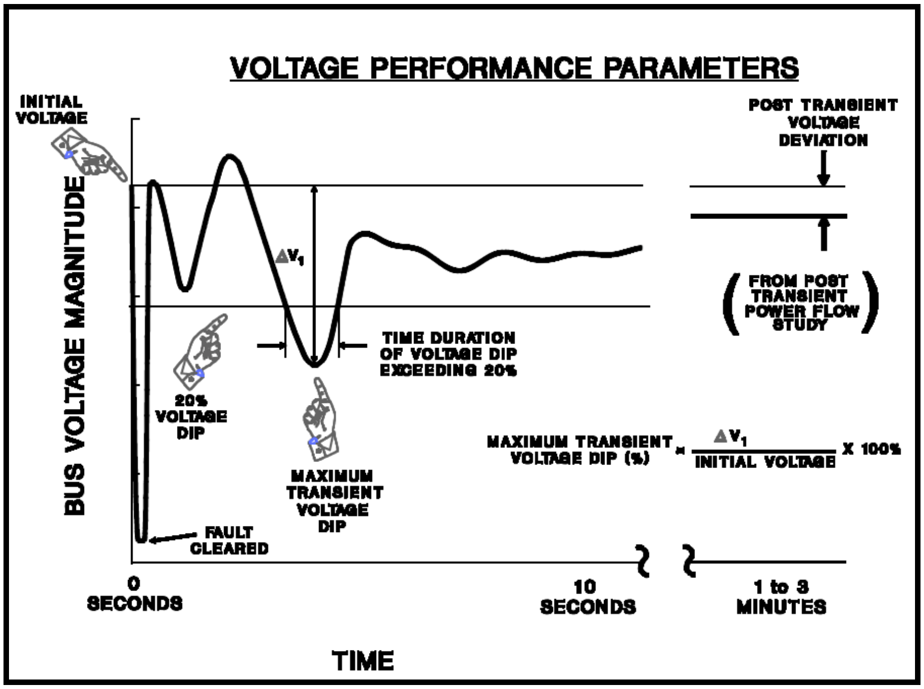

Figure 20. WECC system performance criteria from Table W (WECC System Performance Criteria, TPL – WECC – 1 – CR, 2008)

In April 2005 WECC officially issued a LVRT standard for wind plant as shown in Figure 21. Currently a new WECC Criteria, PRC-024-WECC-1-CR, (Figure 22) has been going through the WECC review process to change the existing WECC LVRT standard. The reason for this new standard is to bring the WECC LVRT standard in line with the current FERC Order No. 661A.

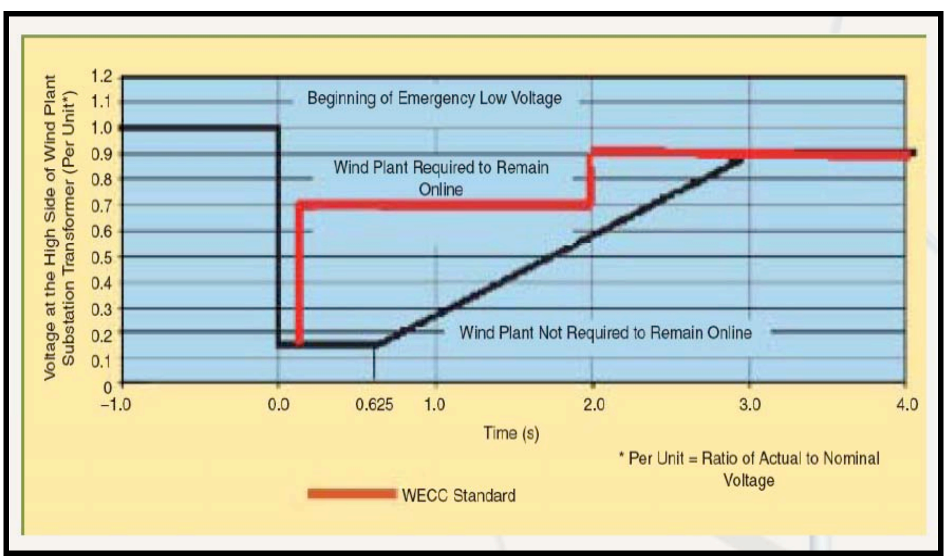

Figure 21. 2005 WECC LVRT standard (Zavadil et al. 2005)

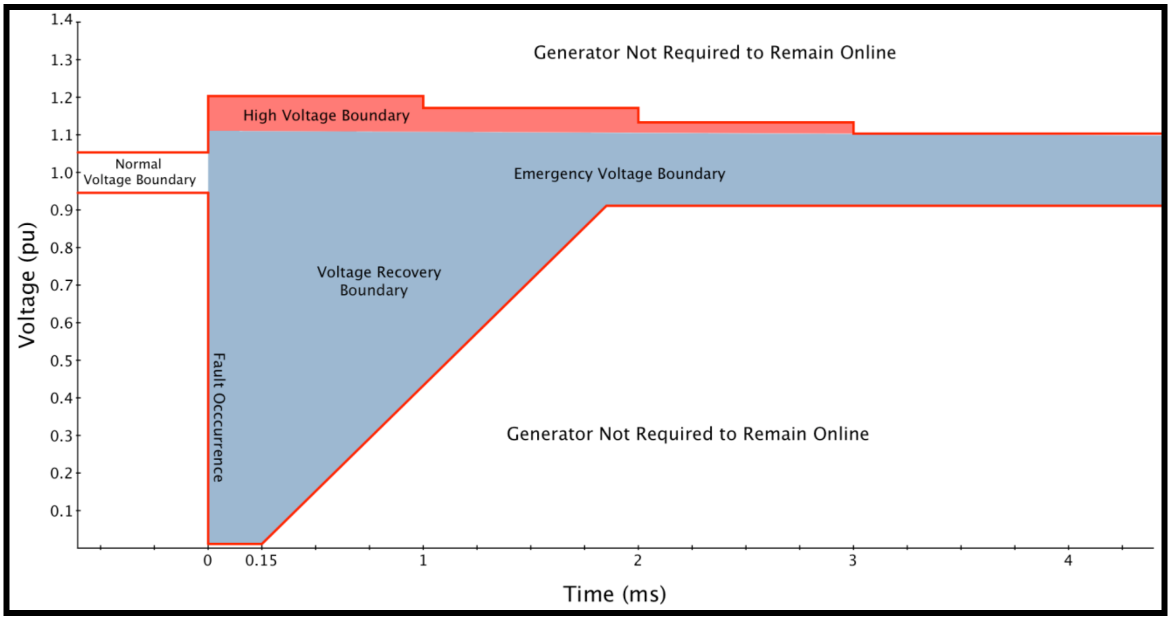

Figure 22. 2009 proposed WECC LVRT standard

6.1.4 North American Electric Reliability Council

The North American Electric Reliability Council (NERC) was formed in response to the blackouts in the northeastern United States in the 1960s to establish policies and standards for ensuring the reliability of the power system (Zavadil et al. 2005). NERC standards and guidelines for system reliability are implemented by the ten regional reliability organizations (RROs) (Figure 23). The interconnected nature of the bulk system demands close coordination and cooperation between these individual entities.

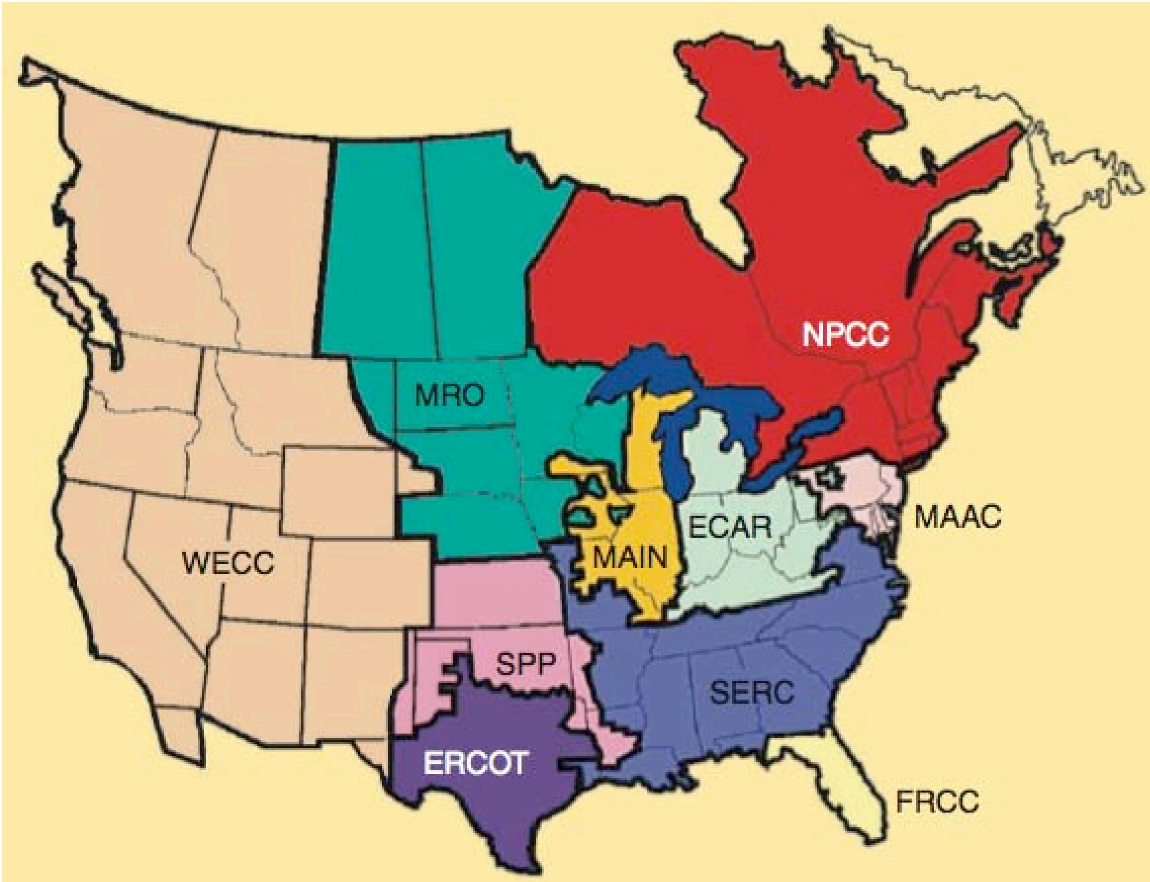

Figure 23. NERC (RROs) members (IEEE Power and Energy Magazine 2005)

In 2005, NERC established a wind integration task force to address planning and reliability issues associated with wind generators interconnected to the electric power grid. Subsequent to FERC Order No. 661, NERC filed a request for rehearing on the following two aspects.

- The LVRT requirement in FERC Order No. 661 Figure 19 should be modified to incorporate wind plants, like other generating facilities, be required to ride through a "normally cleared single line-to-ground fault or three-phase fault on the transmission line connected to a (wind) plant switchyard or substation." This would have the effect that a wind plant be able to stay connected to the grid if the voltage at the high voltage side of the substation transformer were reduced to zero for a period up to about 0.15 second (Zavadil et al. 2005).
- NERC asserts "shifting the burden to transmission providers of justifying on a case-by-case basis what most regard as good utility practice is unwise." (Zavadil et al. 2005)

NERC and AWEA were ordered by FERC to convene and resolve the issue associated with FERC Order No. 661.

6.2 IEEE 1547 Requirements

Currently, most utilities have adopted IEEE 1547 for interconnecting distributed resources on the distribution system. IEEE 1547 covers interconnection of all types of DER up to 10MVA at the point of common coupling (PCC) with the utility, Figure 24 gives Table 1 from IEEE 1547, which stipulates default clearing times for system disturbances with abnormal voltages.

Voltage range (% of base voltage[a])	Clearing time(s)[b]
V<50	0.16
$50 \leq V < 88$	2.00
110<V<120	1.00
$V \geq 120$	0.16

[a]Base voltages are the normal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DER $\leq$ 30 kW, maximum clearing times; DER>30 kW, default clearing times.

Figure 24. IEEE 1547 (Table 1) Interconnection system response to abnormal voltages

The information from Figure 24 above is displayed graphically in Figure 25 below. When the voltage levels stays within the blue area, the DER may remain parallel with the utility. When the voltage level falls outside the blue and into the red, the DER must cease-to-energize the PCC within the allowed time limit. Also note that these are cease-to-energize times only and are the maximum times based on voltage levels. The DER is not required to stay on line if the voltage limits are reached. Typically manufacturers will design their interconnection system to cease-to-energize the utility well within the limits to pass certification tests.

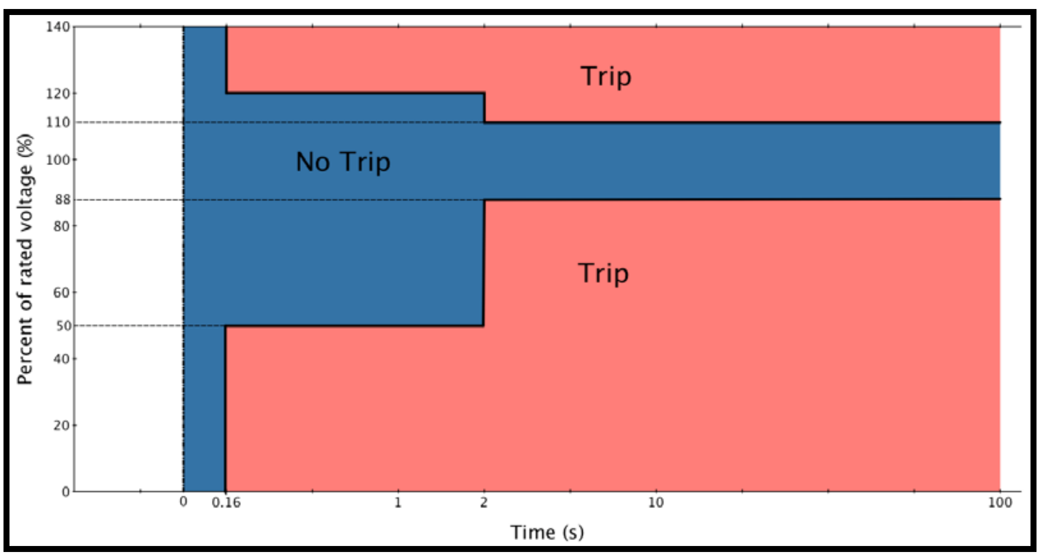

Figure 25. IEEE 1547 Interconnection system response to abnormal voltages from IEEE 1547 (Table 1)

6.2.1 German LVRT requirements for DER

In 2008, Germany released a new fault current ride through grid code for DER interconnected at the medium voltage level with minimum voltage characteristics outlined in Figure 26. The nominal voltage per-unit is displayed on the vertical axis. The horizontal axis represents time in milliseconds. The generators are not allowed to disconnect when the voltage is above Boundary Line 1. If the voltage drops below Boundary Line 2 and below the Boundary Line 1, generating units shall pass through the fault without disconnecting from the system. If the voltage falls below the blue line, there is no need to stay connected to the grid (Piwko et al. 2009). This is the first time that LVRT requirements have been implemented on DER interconnected at distribution voltage levels. Germany has a much higher level of penetration of DER in their EDS and is using this method to address issues related to system stability with high levels of DER.

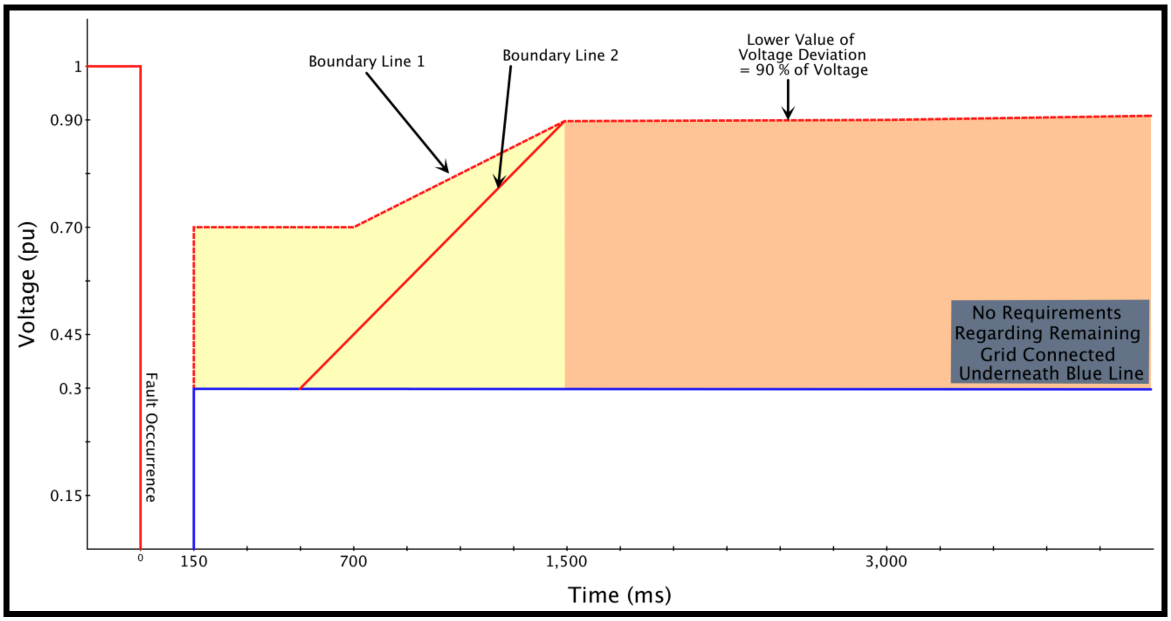

Figure 26. Germany's new LVRT grid code

6.3 LVRT Testing Requirements

The utility voltage and frequency variation test under UL 1741 Section 68 requires production line testing for each specified condition, Figure 27. The UL Table 68.1, shown in Figure 27 below, is used to verify the inverter's ability to comply within the specified time. The targeted test conditions range from A through F. These voltage conditions are very similar to those specified in IEEE Table 1, shown in Figure 25 above. The difference is in the maximum voltage and time of disconnection from the utility. The standard UL 1741 has a time of disconnect of 0.33 seconds for voltages greater than 137% rated voltage. The IEEE 1547 standard has a disconnect time of 0.16 seconds for voltages greater than 120% rated voltage.

Condition	Simulated utility source: Voltage, V	Simulated utility source: Frequency, Hz	Maximum time, seconds (cycles) at 60 Hz[a] before cessation of current to the simulated utility	
A	$< 0.50\ V_{nor}$[b]	rated	0.1	(6)
B	$0.50\ V_{nor} \le V < 0.88\ V_{nor}$	rated	2	(120)
C	$1.10\ V_{nor} < V < 1.37\ V_{nor}$	rated	2	(120)
D	$1.37\ V_{nor} \le V$	rated	2/60	(2)
E	rated	f > rated + 0.5[c]	0.1	(6)
F	rated	f < rated -0.7[c]	0.1	(6)

[a] When a utility frequency other than 60 Hz is used for the test, the maximum number of cycles it takes to cease to export power to the simulated utility shall not exceed the number of cycles a utility frequency of 60 Hz takes regardless of the time the inverter takes to cease to export power to the simulated utility.

[b] V_{nor} is the nominal output voltage rating.

[c] The rate of change in frequency shall be less than 0.5 Hz per second.

Figure 27. UL 1747 Table 68.1 Voltage and frequency limits for utility interaction

Example inverter test results for voltage ride-through capability is shown in Figure 28. The figure shows the results of testing a 1 MW inverter. The yellow trace represents the trigger that initiates the short-circuit event. Again, the difference between the start of the trigger signal and the actual short-circuit event is due to the contactor closing time. The time delay between the start of the trigger signal and the actual short circuit event is due to the contactor closing time. The light blue trace represents the line voltage and the purple trace represents the inverter AC fault current. Typically, the inverter manufacturer will perform a short-circuit test by using a contactor device that will close and create the short-circuit event. The green trace represents the actual fault current flowing through the contactor device used to fault the circuit.

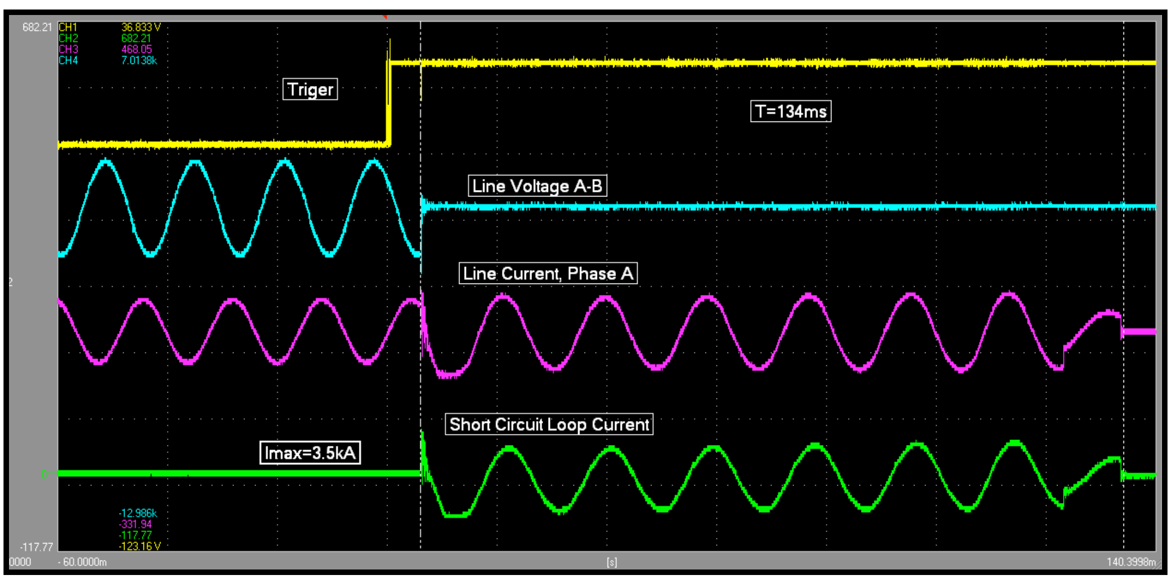

Figure 28. Manufacturer testing inverter for voltage ride-through

In Figure 28, the fault continues propagating for approximately 7 cycles and at a magnitude of approximately 1.2 times steady-state current before shutting down. This is within the WECC fault duration time of 0.15 seconds or 9 cycles. This example shows that inverter-based DER can provide low-voltage ride though capability.

It should be noted that the fault clearing time response shown in Figure 28 could be adjusted as desired either to conform with interconnection standards or for fault clearing coordination.

6.4 LVRT Summary

The present status of the LVRT grid codes is still ongoing. Recently, WECC underwent a review process to change the existing WECC LVRT Standard, approved in April 2005, as a regional criterion to match what is listed in FERC Order 661A. The Planning Coordination Committee and Reliability Subcommittee are questioning the value of continuing with this process. The Planning committee remanded the LVRT Criterion (PRC-024-WECC-1) back to the Reliability Subcommittee. After reviewing the comments submitted to Planning Committee, the Reliability Subcommittee concluded there is no acceptable solution for modifying the current approved WECC LVRT Standard to conform to FERC Order 661A (WECC, 2009).

The WECC LVRT Standard is applicable to all generation types. It conflicts with the FERC Order 661A, which requires that wind generators must ride-through voltage dips to zero volts on the high side transformer. Currently, NERC PRC-024 is being written to be applicable to all generation.

The new German Grid code applies some of the LVRT requirements to medium voltage connected DER. This is a significant change from existing standards that required DER to disconnect from the utility quickly and remain off line for a specified time period. As penetration levels of DER increase in the United States, it may become necessary to review and update IEEE 1547 to provide for LVRT of DER.

7 Computer Modeling Techniques

In today's complex and increasingly demanding electrical power system, sophisticated software programs are required to accurately model the electrical infrastructure. Performing hand calculations at this level is not practical and nearly impossible. Software programs available today typically concentrate on either the transmission or the distribution side of the electrical power system; however, some software programs have the capability of combining these different parts of the electrical power system. Distribution system analysis has been traditionally perceived as modeling small, radially connected systems with simple power-flow methods. Despite their seemingly simple structure, distribution systems are considerably more complex than transmission systems because of the unbalanced nature of these systems and the often large number of modeled elements.

7.1 Modeling and Simulation

Due to shortcomings of any single software modeling tool, a utility may find it necessary to create many different models maintained and used by different departments within the utility. Protection may build and maintain a separate model from operations; operations may build and maintain a separate model from planning, and so on. At the same time, multiple data collection systems throughout the utility such as billing, outage management systems, Geographic Information Systems (GIS), and Supervisory Control and Data Acquisition (SCADA) systems may be gathering and storing vast amounts of data without a clearly defined relationship with each other or the distribution system models.

As utilities find new applications for data from their various collection systems, distribution simulation environments are expanding to provide non-traditional analyses based on these data. Furthermore, by expanding the capabilities of any single model to perform protection, operation, and planning analyses, utilities are able to maintain a more accurate model. Table 2 provides a representative list of commercially available software packages and their applications.

Table 2. Commercial software comparisons*

	ASPEN	PowerWorld	PSS Sincal	CYMEDIST	SKM-Dapper	DEW	SynerGEE	PSLF	PSS/E	PowerFactory	PSCAD	SimPowerSystems
Steady-state Performance												
Balanced Power Flow	x	x			x			X	x	x		
Unbalanced Power Flow		x	x	x	x	x	x			x		x
Voltage Drop	x	x	x	x	x	x	x			x		
Flicker Analysis			x	x		x	x			x		
Power Quality Analysis	x		x	x						x	x	x
Fault Analysis												
Short circuit analysis	x	x	x	x	x	x	x	x	x	x		
Protection and Coordination	x		x	x	x	x	x			x		
Dynamic Performance												
Rotor Angle Stability			x					x	x	x	x	x
Voltage Stability			x					x	x	x	x	x

* Known software capabilities as of October 2009.

7.2 Commercial Products

- **ASPEN**: Advanced Systems for Power Engineering (ASPEN) used primarily to determine equipment ratings, fault current levels, and protection coordination on the transmission level network.
- **CYMEDIST**: CYMDIST performs power systems analysis on balanced or unbalanced three-phase, two-phase and single-phase systems that are operated in radial, looped or meshed configurations. The module includes voltage drop and power flow analysis, fault calculations and, protective device coordination.
- **SKM-Dapper**: DAPPER performs traditional short circuit analysis with an integrated set of modules. The module includes design and analysis including load flow and voltage drop calculations, motor starting, demand and design load analysis, feeder, raceway and transformer sizing.
- **DEW**: DEW has an open architecture and utilizes an Intergraded System Models (ISM). The architecture and ISM provide the developer with a mechanism to directly

use the results of existing (relay) analyses, model parameters, and external data to create custom calculations, analyses, and reports.

- **PowerFactory**: PowerFactory offers a research version that allows the user to create custom models and control strategies as Matlab or programmed functions.
- **PowerWorld**: PowerWorld is a visualization tool used to analyze the system performance under different power demand scenarios. Transmission planners, power marketers, and system operators typically use the software.
- **PSCad**: PSCad offers the ability to create custom components as well as custom control algorithms.
- **PSLF**: GE Positive Sequence Load Flow Software (PSLF) is a full-scale program designed to perform load flow, dynamic simulation, and short circuit analysis. Typically used by power system engineers for simulating the transfer of large blocks of power across a transmission grid.
- **PSS Sincal**: PSS SINCAL software package offers time and frequency domain solutions for stability and harmonics respectively. Also includes planning and analysis of utility and industrial networks.
- **PSS/E**: The Power System Simulator for Engineering or PSS/E, essentially has the same system capability as PSLF a software program. Again, this package is typically used by electrical transmission planners performing load flow, dynamic simulation, and short circuit analysis for obtaining a reliable power system.
- **SimPowerSystems**: Built on the Matlab solution engine, SimPowerSystems offers the flexibility to create custom algorithms, interfaces, and components.
- **SynerGEE**: SynerGEE performs power system analysis using detailed load modeling on radial, looped and mesh network systems comprised on multiple voltages.

The primary analyses used by distribution engineers are steady-state power-flow, and short circuit. Presently, these analyses are performed using many different methods. It would be beneficial to the utility industry to have uniformity in distribution system analysis so comparisons can be made across platforms. The IEEE Distribution System Analysis Subcommittee has developed a number of “test feeders” for benchmarking distribution system analysis programs (Kersting 2006).

A short circuit study is essential for determining parameters used in relay settings. Combining short circuit analysis with dynamics analysis can contribute greatly to the understanding of how DER will interact with a utility protection system. The time-dependant behavior of the protective devices is represented along with the dynamic characteristics of the machine and inverters. At present, no such tools are readily available without resorting to an electromagnetic transient computer program. This is one area for continuing research in the development of DER-related engineering tools (Dugan et al. 2002).

There is a need for accurate short circuit models to assess DER fault contribution during both subtransient (first cycle) and transient (3–10 cycles) periods. Extending the conventional fault analysis to include inverter-based DER is challenging because it requires more detailed modeling than the models used to represent AC generators (Baran and El-Markaby 2005). Conventional fault current analysis has been done using Zbus matrix algorithms. With the addition of DER, this may be very complicated to perform because of the difficulty of estimating the inverter impedance (IEEE 2008). If the internal impedance of an inverter could be determined then it would be possible to accurately model the inverters fault characteristics using power system modeling software.

8 Conclusions and Future Recommendations

8.1 Conclusions

This report discusses several key issues regarding the development and challenges of integrating inverter-based DER into the existing electrical utility distribution system with a focus on short-circuit current capability. It is important to emphasize the different characteristics of fault current contributions from various DER sources. Inverter-based fault contributions behave differently than traditional power sources such as synchronous and induction generators and motors connected to electrical distribution systems.

Currently, inverter-based DER provides insignificant or minimal contribution to the power balance on most utility distribution systems. A significant increase in DER is expected to come on-line in the near future. As the penetration level of DER increases, the effect of DER may no longer be considered minimal. The electrical equipment ratings, capability, and coordination of the protection systems will indeed merit a closer investigation (Kroposki 2008; Nimpitiwan 2007).

The current industry's practice regarding fault current level assessment for setting protective relays has been to apply a "rule of thumb" of 2 times rated continuous current for DER. This seems to be the standard practice at low levels of DER penetration. Tests of 2 grid tied inverter systems at NREL suggest that the fault current is typically higher, but for much shorter time periods (2-4 times rated current for 0.06 – 0.25 cycles). This time period is typically within the subtransient reactance values for synchronous generators and trip times for circuit breakers, and therefore can possibly be ignored. What effect this may have on the protective relays at higher levels of DER penetration is not well understood and warrants continued research in this area.

A unique property of a PE interface is the ability to program in the fault characteristics from the inverter, thereby allowing negligible impacts on protection coordination (Kroposki et al. 2006; General Electric 2003). In the future, inverter based systems may be developed that will further optimize system coordination by having a controllable fault current level (Tang and Iravani 2005). Past research has indicated that PE can optimally regulate and limit DER fault current, improve power quality, and provide the utility with reactive power control and voltage regulation at the DER connection point. Continued testing of actual inverter fault characteristics is needed to develop information that could be used in modeling and fault analysis programs.

The LVRT standards are continually being developed and should introduce other areas to consider regarding protective relay coordination settings. These LVRT implications come from the fact that the inverter-based DER has to remain on-line (connected to the grid or distribution system) for a period of time before tripping off. This allows the DER (mainly wind turbines in this case) to help support the voltage and stabilize the power grid during transient faults. Low voltage ride-through test of an inverter showed that it could produce 1.2 times peak current for a period of approximately 7 cycles. This confirms the adequacy of inverter-based DER fault current-ride-through capability but it is not clear what effect this might have on the distribution system protection scheme.

Most commercially available software simulation environments are designed with traditionally synchronous generation in mind. A paradigm shift needs to take place regarding new renewable inverter-based renewable energy coming on-line in the near future. New inverter-based DER control modules (e.g. PV) capable of using commercially available software packages will need to be developed. Developed software models must be validated through hardware testing. Fast, robust, accurate inverter based DER models will allow utility planning engineers to safely and reliably provide continued service to the consumer.

8.2 Future Recommendations

- Develop validated models for inverter short-circuit and LVRT characteristics. Based upon NREL and manufacturer inverter short circuit test results, research should be expanded to include larger 3-phase inverters characterizing the response to different types of faults. Including, 3-phase, single line-to-ground, and phase-to-phase faults. This expanded short-circuit testing type will be beneficial and more applicable to the utility type scale. This will help in validating the DER software modules being developed.
- Expand fault current software model parameters for use with protective device coordination studies. It will be necessary to obtain accurate short circuit models to assess DER fault contribution during both subtransient (first cycle) and transient (3–10 cycles) periods. Extending the conventional fault analysis to include inverter-based DER is challenging because it requires more detailed modeling than the models used to represent AC generators.
- Perform inverter-based DER testing and computer simulation to determine the penetration levels at which inverter-based DER will impact the utilities distribution system. This percentage will be instrumental in determining the protective relaying settings as well as the stability of the distribution system.
- It would be beneficial to the utility industry to have uniformity in distribution system analysis so comparisons can be made across platforms. Combining short circuit analysis with dynamics analysis can contribute greatly to the understanding of how DER will interact with a utility protection system. At present, no such tools are readily available. This is one area for continuing research in the development of DER-related engineering tools.
- In order to study system stability issues for high penetration levels of PV, an electrical control model needs to be developed. Utilizing a new set of differential equations to characterize the dynamic behavior during a system disturbance is essential for the electrical power industry. Incorporating this development into a usable software control model that can be imported across multiple software platforms, such as PSLF and PSS/E is essential.
- Determine the LVRT capability of inverter-based DER and defining how protective relay coordination will be effected during such events.
- Update existing interconnection standards to allow the use of LVRT parameters for DER.

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