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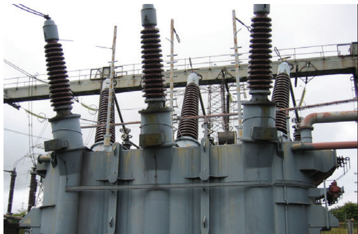

PQ Implications of DER and the Role of IEEE 1547

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Contents

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SUMMARY

Distributed energy resources (DER) have altered the grid's power quality environment. The presence of generation in the distribution system can cause customer service voltages to be driven outside of the acceptable range. DER tripping and restart can cause voltage sags and swells in distribution systems with high DER penetration levels. Swells can also occur as the result of utility feeder ground faults, and severe overvoltage transients can potentially occur if DER are switched off under load. DER facility operations can also cause objectionable voltage variations. DER are also sources of harmonic injection that can potentially distort voltage supplied to other customers.

Some power quality problems related to DER are not caused directly by the DER but are the result of how the utility addresses other concerns related to DER interconnection. Other assumed power quality issues that are often attributed to DER turn out not to be a real problem in most circumstances—for example, flicker and current imbalance.

Recent revision of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 has provided new DER requirements and limitations that more directly address power quality impacts. New DER capabilities required by IEEE 1547-2018 provide tools that can greatly mitigate power quality concerns.

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THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.

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The higher levels of distributed energy resource penetration now being experienced in many distribution systems can have profound impacts on power quality.

INTRODUCTION

The well-ordered, top-down electrical system depicted in the figure below has served the electrified world for more than 100 years. Power distribution systems have traditionally been designed to serve loads. With rare exception, sources of power and short-circuit current capacity other than the utility's primary substation were not present in the distribution system.

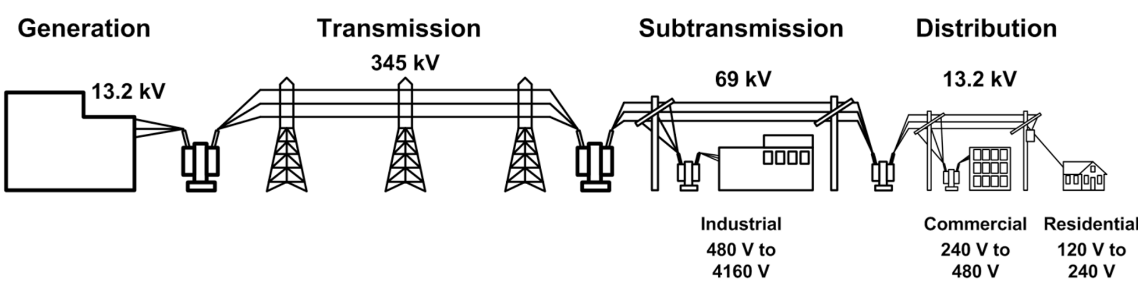
Although customer-owned generation was allowed by the Public Utilities Regulator Power Act (PURPA) of 1978, few such installations were interconnected to distribution systems until the past couple of decades. Several things happened in the meantime: In the 1990s, many service areas of the United States were deregulated, separating the generation owners from the delivery operations. This change has been followed by the decreasing cost of distributed generation. Advancements in gas-fired generators, microturbines, and fuel cells started things off in the early 2000s, but these technologies have since been overwhelmed and outpaced by the wide-scale deployment of solar photovoltaic (PV) power generation in the past 10 years. In many areas, the majority of generation capacity interconnected at the distribution level has been in the form of utility-scale generation facilities. These facilities, with generation capacities ranging from several 100 kW to over 10 MW, are typically owned and operated by nonutility independent power producers (IPPs).

Small amounts of distributed energy resources (DER, inclusive of both generation and energy storage) scattered about a distribution system do not have a significant impact on customer power quality. However, the higher levels of DER penetration now being experienced in many distribution systems, particularly where large IPP facilities are interconnected, can have profound impacts on power quality. The presence of high DER penetration can also result in the expectation of power quality issues by the utility that may or may not actually occur. The power quality issues attributed to DER penetration include:

- Customer service voltage levels outside of acceptable limits for extended durations
- Voltage swells and sags
- Voltage imbalance
- Rapid voltage change
- Repetitive voltage fluctuations
- Extension of momentary interruption duration
- Harmonics and interharmonics
- Transient overvoltage

DER interconnection requirements are specified by IEEE 1547, and this standard has been adopted by most utilities and utility regulatory agencies across North America. The original version of this standard, approved in 2003, addressed some of these power quality issues, but sometimes in a vague and ambiguous manner. IEEE 1547 has recently undergone a major revision, with the new IEEE

Typical Electric Power Delivery System Prior to Proliferation of Distributed Energy Resources



Distributed energy resources disrupt the normal feeder voltage profile, which can lead to voltages above or below acceptable limits.

1547-2018 approved by the Institute of Electrical and Electronics Engineers (IEEE) Standards Board in February of 2018. The publication of this new standard is anticipated in the second quarter of this year. The revised IEEE 1547-2018 addresses DER interconnection requirements with regard to power quality impacts much more definitively and adds a number of new requirements intended to minimize the adverse power quality consequences of DER interconnection to the grid.

FEEDER STEADY-STATE VOLTAGE PROFILE

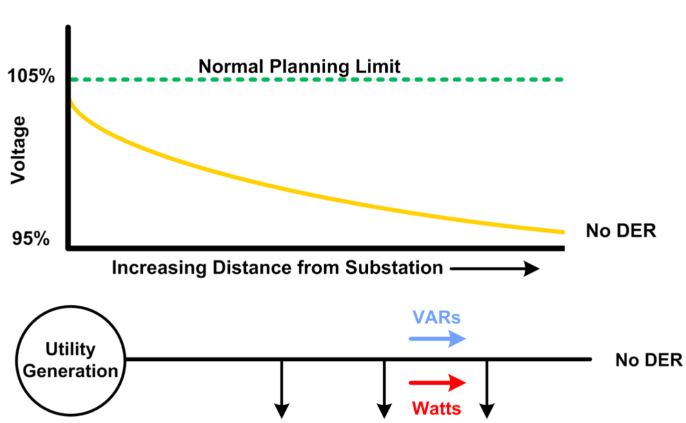
When a distribution system serves only loads, the general trend is that voltage magnitude decreases smoothly from the substation to the ends of the feeders as illustrated in the figure below at left. In some cases, utilities apply line voltage regulators to step up the voltage in the middle of a feeder, but the normal trend is for the voltage magnitude to decrease downstream beyond the regulators toward the ends of the feeder or to the next regulator location. Utilities may also install fixed or switched capacitor banks along a feeder that may boost voltage near that location. The installation and control of regulators and capacitor banks, however, are the responsibility of the utility, and they are carefully planned and controlled to provide voltage within acceptable limits under all load conditions.

DER disrupt the normal feeder voltage profile. At small levels of penetration, DER merely offset some of the load. At higher levels of DER penetration, power flow on a portion of a feeder, or even the entire feeder, may reverse. This can cause a voltage profile that increases with distance from the substation, potentially causing some customers to experience voltage above the acceptable limit as shown in the figure below at right.

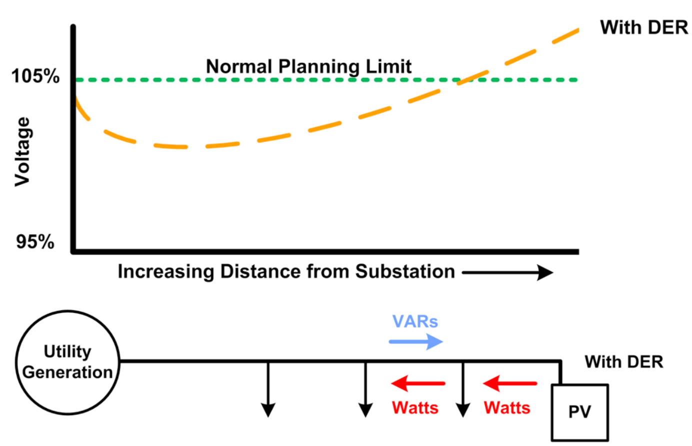
Voltage Regulator Interaction

DER can also cause customer service voltages to fall below minimum limits. Utilities frequently use a line-drop compensation scheme in feeder voltage regulator and primary substation transformer on-load tap changer controls that increase the regulated voltage in order to accommodate the predicted voltage drop along the feeder. If a large DER facility is located close downstream of a regulator, the reduction of power flow at the location of the regulator may cause its controls to insufficiently boost voltage to account for the drop beyond the DER interconnection to the feeder. This can cause customer service voltages toward the feeder ends to be below acceptable limits. Similarly, DER power output will decrease the net distribution system load supplied by the substation transformer. When the DER capacity is concentrated on just one or a few of the feeders supplied by a substation, the substation bus voltage may not be held high enough

Distribution Feeder Voltage Profile Under Conventional Circumstances



Feeder Voltage Profile with a Large DER Connected Near the End



In selecting the control modes of feeder voltage regulators, utilities must consider the impact of DER on power flow.

to accommodate the voltage drop of feeders having little DER penetration.

Feeder voltage regulators often have a control feature where the direction of power flow is used to indicate which side of the regulator is connected toward the supplying substation. This is valuable for feeders that may be reconfigured to be fed from an alternate source. It is critical that the regulator always controls the voltage that is away from the stiff source. When DER downstream of a regulator have sufficient power output to cause power flow through the regulator to reverse, the regulator with this control mode will try to regulate the substation-side terminals. Because the substation is almost always a much stiffer source than the DER causing the power reversal, voltage on the unregulated side will move instead of the regulated side. As a result, regulator movement to correct a too-low voltage will just make the voltage go lower, and an attempted correction of a too-high voltage will make the voltage yet higher. The regulator will continue to move in one direction or the other and will be driven to its upper or lower tap limits causing either a severe overvoltage or a severe undervoltage to customers downstream. Feeder voltage regulators have other control modes that can avoid this scenario. Therefore, selection of the control modes by the utilities must consider the impact of DER on power flow.

IEEE 1547-2018 allows DER to participate in feeder voltage management, requiring that the DER have substantial reactive power capability along with specified control functions for implementing this capability.

IEEE 1547 Addresses Service Voltage Issues

The impact of DER on service voltage levels was addressed by both the original IEEE 1547-2003 and the recently revised IEEE 1547-2018. The original standard specifies that the DER shall not cause any other customer service point to have voltage above the upper limit specified by ANSI C84.1, Range A. The revised standard specifies that the voltage at any service point, including the one to which the DER is connected, must be in compliance with ANSI C84.1. The DER's service point is only exempted from this requirement if the DER service is via a dedicated transformer or feeder. The revised standard does not specify Range A or Range B, but rather allows the definitions of each range contained in ANSI C84.1 to determine applicability of the appropriate range. IEEE 1547-2018 also specifies that the utility primary voltage at any location may not be driven outside of the applicable primary voltage range specified in ANSI C84.1. This is so that a utility may add a new distribution transformer in the future at any location on the feeder to serve a load with acceptable voltage, and also to ensure that utility primary equipment is not exposed to excess voltage as a result of DER operation.

Although a DER is not permitted to drive voltages outside of the specified ranges, the reality is that the DER does not measure voltages at other locations. Thus, the conformance with this requirement is established by the utility's interconnection study or DER hosting capability study. While good DER screening and interconnection study practices minimize the possibility of DER-caused out-of-range voltages, such situations will inevitably occur from time to time. This can be due to study deficiencies such as incorrect system data or assumptions, unanticipated changes in feeder loading, or reconfiguration of the feeder.

IEEE 1547-2018 also provides new DER tools that can be used to minimize voltage impacts. The original IEEE 1547-2003 forbade DER from "actively regulating" the utility voltage, meaning that a DER could not change its reactive power in response to measured voltage. It had been widely, but inaccurately, assumed that DER were required to operate at only unity power factor by the old standard. As a result, many DER had no reactive power capability and most DER were operated only at unity power factor.

The revised standard not only allows DER to participate, with the utility's concurrence, in feeder voltage management but also requires that the DER have substantial reactive power capability along with specified control functions for implementing this capability. The utilization of these reactive power functions, along with the control parameters, is at the discretion of the utility. In addition, the new standard requires DER data interoperability capability that can allow the DER to be integrated

IEEE 1547-2018 was revised to relax undervoltage tripping requirements and to mandate voltage ride-through capability, changes that will reduce the possibility of short-duration sag events being turned into long-duration sags due to the abrupt loss of DER output.

with advanced distribution management systems such that the DER reactive capability can be managed in real time. The advanced capabilities of new DER, implemented in accordance with IEEE 1547-2018, can be applied to mitigate or even eliminate DER-caused voltage issues and might be used to mitigate voltage issues not caused by the DER as well.

SAGS AND SWELLS

The presence of a large amount of DER capacity in a distribution system can lead to voltage sags and swells. Although not directly addressed by either the original or revised versions of IEEE 1547 as a specific prohibition (with some exception for severe overvoltages), the new revised IEEE 1547-2018 has several provisions that tend to reduce the severity and probability of such events. In addition, the reactive power capability and control modes now required of DER may mitigate voltage sags and swells from other causes as well, providing a power quality benefit.

DER Group Behavior

Simultaneous tripping of a substantial amount of DER power injection can cause a large drop in voltage if the distribution system's voltage management equipment (voltage regulators, switched capacitor banks, and substation transformer tap changers) had been adjusted to accommodate the DER output. While the equipment settings can be adjusted to respond to the new load-flow condition without the DER power injection and return the distribution system to an acceptable voltage profile, this equipment does not respond instantaneously. As a result, the voltage may decrease between the time of tripping and the completion of voltage management equipment readjustment. Because a *sag* is defined as a voltage drop below 0.9 per unit, the DER penetration would have to be large for the temporary undervoltage to be correctly termed a sag.

Simultaneous tripping of DER is most commonly caused by DER responding to a severe voltage sag event from other causes, such as a fault on another feeder, a fault downstream of a protective device on the same feeder, or a transmission system fault. The original IEEE 1547-2003 imposed no requirements for DER to not trip (i.e., ride-through) for any event, and furthermore mandated rather sensitive undervoltage tripping requirements. This made DER quite susceptible to mass-tripping scenarios. Recognizing that mass DER tripping could have severe consequences to the bulk transmission system if large amounts of DER output were to trip across a wide area as a result of a transmission fault, IEEE 1547-2018 was revised to relax undervoltage tripping requirements and to mandate voltage ride-through capability. These changes will reduce the possibility of short-duration sag events being turned into long-duration sags due to the abrupt loss of DER output.

Just as abrupt tripping of DER might cause voltage sag, simultaneous turn-on of a large amount of DER capacity can potentially cause a voltage swell. The original IEEE 1547-2003 required DER to wait for a settable delay, nominally 5 minutes, after satisfactory voltage is restored, such as after a feeder trip and reclose event. There was no limitation on how quickly a DER could return to full output once restarted. If the same time delay setting were used for all DER units on a feeder, a voltage swell could occur as a result because all the DER would turn on and resume full output simultaneously. To address this issue, the revised IEEE 1547-2018 specifies that there be not only a settable restart delay, but also a settable power ramp-up rate. This ramp rate would normally be set so that the utility's feeder voltage management equipment can follow the changing power flow condition and avoid creating a swell.

Ground-Fault Overvoltages

Another type of severe voltage swell can result from a single-phase fault on the utility feeder, with the overvoltage appearing on the unfaulted phases prior to DER tripping but after the utility breaker or upstream recloser has tripped. This is called a *ground-fault overvoltage* and is related to the issue of system grounding. Note that only loads connected phase-to-neutral and not interfaced with a delta (utility-side) wye transformer are subjected to this overvoltage. While the old IEEE 1547-2003

Large DER facilities using three-phase generators or inverters produce a balanced output, but there can be the perception that the DER causes feeder load imbalance when the percent current imbalance increases.

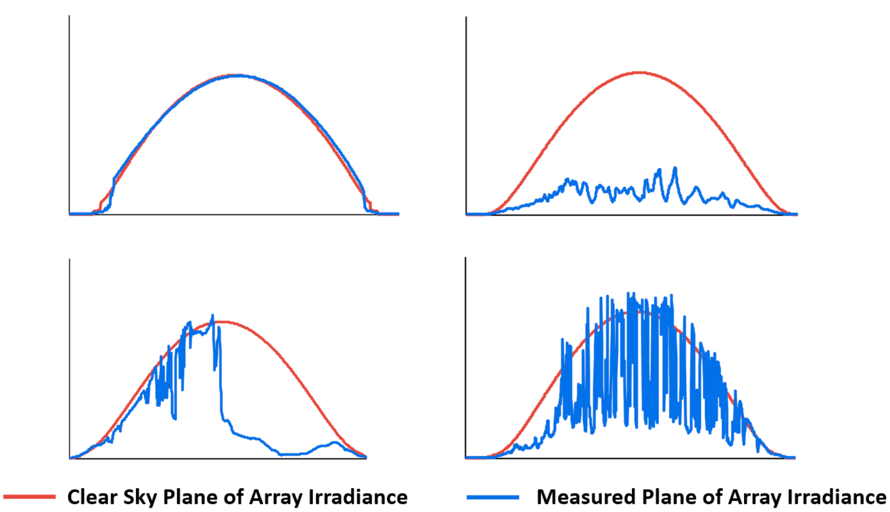
only stated vaguely that the voltage ratings of equipment connected to the utility system shall not be exceeded due to grounding miscoordination, the newly revised IEEE 1547-2018 provides much more definitive requirements with regard to overvoltages such as produced by ground faults. DER may not cause phase-to-ground voltages in excess of 138% of nominal on utility systems designed to be effectively grounded. (This value is the unfaulted phase overvoltage value that defines effective grounding per IEEE C62.92.1.) The ground-fault overvoltage issue is a definite concern for rotating generator DER, but much less of a practical issue for inverter DER. The reasons for this difference are described in the new IEEE C62.92.6-2017 and are too complicated to present here in this article.

VOLTAGE IMBALANCE

Most large DER facilities use three-phase generators or inverters. In some cases, large PV facilities use a large number of small single-phase "micro-inverters," but the design of such facilities normally assigns a near-equal amount of solar generation capacity to each phase. In either case, the DER output is balanced. There can be the perception, however, that the DER causes feeder load imbalance. This is because the balanced output of the DER offsets some of the balanced component of the load, leaving the unbalanced component unchanged. Thus, the percent current imbalance increases, but the imbalance measured in amps is not increased. What matters to the utility is the amps of imbalance as this is the parameter that drives voltage imbalance, neutral and ground current flow, and potential for ground current relay pickup.

Small-scale DER, such as residential rooftop PV, are single-phase units. A utility typically assigns single-phase transformers and connections of single-phase laterals to backbone three-phase feeders so as to minimize current imbalance. Because single-phase laterals tend to serve small sections of neighborhoods that may have similar demographics, and because PV adoption tends to be clustered (neighbors keeping up with their neighbors), the patterns of installed PV capacity possibly may not stay in proportion to the load demand and some increase of imbalance may occur. This type of imbalance can be difficult for the utility to resolve because it tends to be time-of-day dependent—the net load may be well balanced in the evening but poorly balanced in the midday period. Measurements by EPRI have not shown DER penetration resulting in significant imbalance increases, however, so this hypothetical scenario is probably an outlier that occurs only infrequently.

Typical PV Variability



Source: EPRI [1]

VOLTAGE VARIATIONS

DER can result in unusual variations in the voltage supplied to other customers. These variations can be due to the natural variations of the primary energy source—solar irradiance in the case of PV, wind speed in the case of distributed wind generation—or to switching operations performed at a DER facility. The figure at left shows typical solar variability over daytime hours compared to that of a clear day.[1]

Rapid Voltage Changes

Abrupt changes in voltage magnitude that are nonrepetitive in nature are termed *rapid voltage changes* (RVCs). As defined in IEEE 1547-2018, an RVC is a change in voltage taking place in less

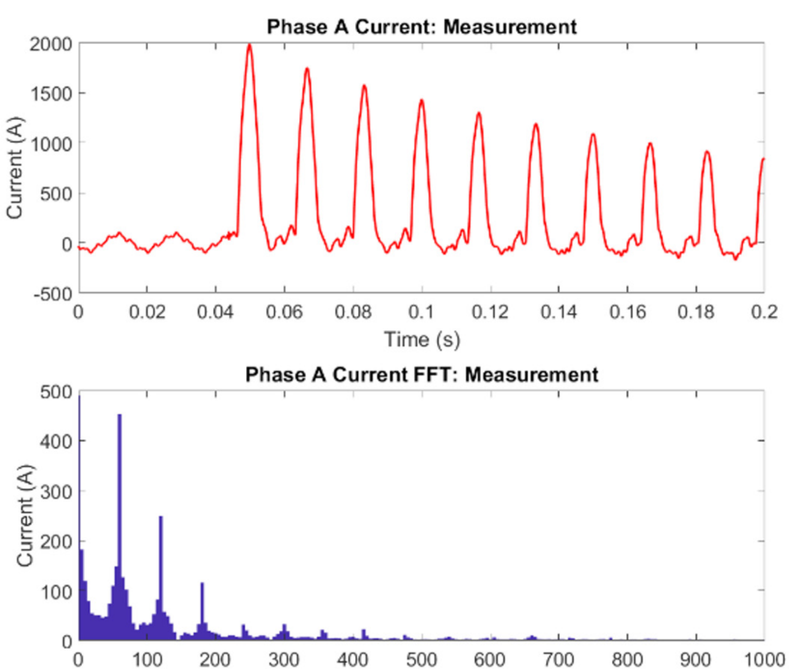
Inrush to DER facility transformers is no different from inrush to similar load-serving transformer capacity; however, timing of DER facility transformer energization events may cause them to stand out and become individually problematic.

than 1 second. This power quality impact was not addressed in the original 2003 version of this standard, but the recently revised standard now limits RVC to 3% voltage change at the primary distribution level and 5% at the secondary level.

RVC can be the result of abrupt turn-off or turn-on of a large DER facility, energization or de-energization of shunt capacitor banks, transformer switching, or other similar events. It should be noted that the variation of PV output due to cloud shadow movement is not, in practice, a cause for significant RVC. This is because, for reasonable cloud movement speeds (dictated by wind speed at cloud altitude), the transition time of a cloud shadow across a PV array larger than approximately 20–40 kW is longer than 1 second. A PV DER of this size is unlikely to cause a voltage change greater than the specified limits unless the utility system is unusually, and impractically, weak.

Energization of a substantial amount of transformer capacity can cause significant RVC due to the magnetic inrush phenomenon. In addition to dips in the RMS voltage, the nonlinearity of the energized transformer cores inject large magnitude low-order harmonic currents that decay as the inrush subsides, sometimes over a period of seconds. The inrush current for a typical transformer energization is shown in the figure below.[2] Both the voltage change and the harmonic distortion can be disruptive to sensitive customer loads connected to the distribution system.

Transformer Energization Inrush Current Waveform and Spectral Content



Source: EPRI [2]

Inrush to DER facility transformers is no different from inrush to a similar amount of load-serving transformer capacity. Inrush is the same if the transformers are unloaded, loaded, or connected to generation facilities. However, the timing of DER facility transformer energization events may cause them to stand out and become individually problematic. At least one utility has experienced significant customer power quality complaints from DER transformer energization. In this case, the utility installed a recloser in series with a large PV facility interconnection. This recloser was relayed to trip off the facility in response to voltage dips, and reclosing was intentionally delayed until 5 minutes later. The sensitive customer load rode through the initial voltage dip, but was tripped off due to the harmonic distortion caused by the simultaneous energization of all of the PV facility's inverter step-up transformers.

IEEE 1547-2018 RVC limits specifically include in their scope of applicability frequent transformer energizations (e.g., a PV operator decides to de-energize the facility every night to save on no-load losses and re-energizes every morning), frequent switching of capacitors, and DER misoperations. The standard excludes, however, switching, tripping, or transformer energization related to commissioning, fault restoration, or maintenance. Most DER facilities do not cause RVC over the prescribed limits, but imposing the limits is a safeguard to prevent DER facility designs that do cause excessive RVC. For example, a DER facility could be designed to use large capacitor banks to provide the reactive power capability now required by IEEE 1547-2018. The present practice is that DER facilities generate the required reactive power using their inverters

Relaying of reclosers should not defeat or override the voltage ride-through requirements placed on DER to protect the grid.

or generators. However, a facility developer might choose to use capacitor banks to reduce inverter power losses. The RVC limits of the standard ensure that voltage changes caused by switching of these capacitors are limited.

The power quality problem caused by recloser operation, described above, is not covered by IEEE 1547-2018, however, because the transformer inrush was the result of restoration of electrical service by the utility, which is an exclusion of the RVC limitations. The potential for introducing such transformer energization disturbances should be considered by utilities when reclosers are applied to large DER interconnections. Relaying of reclosers also should not defeat or override the voltage ride-through requirements placed on DER to protect the grid.

Flicker

PV output can be quite variable. During partly cloudy conditions with strong wind at cloud altitudes, PV output can frequently switch back and forth between the clear-sky output value for time of day and date, and a value of about 20% to 40% of the clear-sky output when the PV array is shadowed by clouds. Many utilities have applied the voltage change caused by a 100% DER output variation with clear/shadow cycle times that are unrealistically short to the old "GE flicker curves" that appeared in former versions of IEEE 519. This flicker curve was based on square-wave oscillations of voltage magnitude with zero ramping time between voltage levels. In addition, some utilities also assumed that all PV on a feeder varied in synchronism. As a result, many utilities had become concerned that PV could cause flicker, which is the subjective human perception of incandescent lamp luminance.

While flicker is not a realistic concern for properly operating photovoltaics, some infrequently encountered types of DER can cause true flicker.

As described in the RVC discussion, a finite period of time is required for a cloud shadow to transit across a sufficient amount of PV panels to cause a significant voltage variation. Also, IEEE 519 no longer includes the old GE curve and IEEE 1453 has now adopted the IEC flickermeter algorithm as the means to quantify the objectionable nature of flicker (P_{st} and P_{lt}). The flickermeter algorithm processes complex voltage variations to determine their potential for human perception. Flicker perception is substantially reduced when the voltage variations are ramped rather than stepped abruptly. With consideration of the more realistic degree of PV variation between shaded and sunny conditions, the ramping effect of finite cloud shadow transit time, and realistic solar irradiance versus time profiles, an individual PV facility can be seen to be highly unlikely to cause objectionable flicker. For flicker to be objectionable, the facility capacity would have to be sufficiently large relative to the utility system resistance at the point of interconnection as to make the interconnection totally infeasible due to many other more constraining considerations. Furthermore, when the PV capacity is spread out over a distribution feeder's footprint, geospatial diversity tends to smooth aggregate power variations even more—the assumption of all dispersed PV capacity on a feeder varying in synchronism is not supported by the facts. Measurements made by EPRI at the points of interconnection of large distributed PV facilities show virtually no difference in P_{st} or P_{lt} between periods with the PV facilities in and out of operation.

The fact that PV output is not a step change is illustrated by the following example: an individual PV facility would need to have a capacity on the order of 1 MW to be the cause of 1% voltage variation, even if located 5 miles from the substation on a typical 12.47 kV feeder. The amount of area required for 1 MW of solar panels is on the order of 6 acres, or 261,360 square feet. If the PV array is square, the distance across such an array is slightly over 500 feet. With a very strong wind aloft, 40 mph, the shadow transit time across the array is more than 8 seconds. This produces a far lower flicker metric than an abrupt voltage change or even a 1-second ramp time that is assumed by some utilities.

While flicker is not a realistic concern for properly operating PV, some infrequently encountered types of DER can cause true flicker. One type is wind generation using induction generators. When the wind turbine blade passes by the tower, there is a slight pulse in the power output with a period of 1 second or less. Humans are very sensitive to luminance variations at this fast rate, so this

IEEE 1547-2018 requires the DER to detect and cease to energize islands within 2 seconds. Most DER meet the island detection requirement using proprietary "active anti-islanding algorithms," which generally work by intentionally destabilizing the islands and causing a voltage or frequency trip.

flicker issue has been observed in practice. (More modern wind turbines using electronically coupled generation smooth out these variations and are not a realistic source of flicker.) Another obscure source of flicker can be engine misfiring at a landfill gas energy recovery system due to quality issues with the gas.

Previously discussed in this article is the new voltage regulation capability now being required by IEEE 1547-2018. This capability can be very useful in minimizing voltage impact of DER as well as addressing feeder voltage management in general. However, every tool has its adverse consequences. For the reactive power as a function of voltage (i.e., "volt-var") mode of reactive power control, the function effectively forms a closed control loop. Voltage affects reactive power via the regulation mode, and the reactive power acting through the grid impedance affects voltage. If the voltage regulation mode is made too aggressive (i.e., the control loop has too high a gain), this control loop can possibly become unstable. Typically, control instability is manifested in the form of uncontrolled oscillations. The voltage oscillations produced by unstable, incorrectly set DER controls will be perceived as voltage flicker.

The original version of IEEE 1547 stated simply that a DER shall not cause objectionable flicker without further elaboration or indication of the metric to be applied. While the common forms of DER, properly implemented, do not cause flicker, having the recently revised IEEE 1547-2018 specify very explicit flicker emission limits is useful. These limits are specified in terms of P_{st} and P_{lt} according to the IEC TR 61000-3-7 definitions to avoid ambiguity, providing the basis for utilities to address potential and actual flicker issues, which will generally be confined to outlier situations.

EXTENSION OF MOMENTARY INTERRUPTIONS

Opening of a utility breaker or recloser could leave a DER energizing the load on the part of the feeder to which it is connected, downstream of the opened switchgear. This situation is called *unintentional islanding*. Both the original and revised versions of IEEE 1547 require the DER to detect and cease to energize such islands within 2 seconds. Furthermore, the original IEEE 1547 version stated that DER must "cease to energize the Area EPS [i.e., the utility system] circuit to which it is connected prior to reclosure by the Area EPS." Reclosing into an energized island may not harm inverters, which are self-protected, but does pose a threat to utility and customer equipment connected to the feeder. Examples of the possible consequences of an out-of-phase reclosing into an energized island include:

- *Potentially severe voltage transients.* If a capacitor bank is present, an out-of-phase reclosing is similar to a capacitor switchgear restrike transient and can potentially cause damaging overvoltages.
- *Severe magnetic inrush to transformers and motors.* This can result in overcurrent protective device operations and nuisance fuse blowing.
- *Severe motor mechanical torques due to the abrupt change in voltage phase angle.* Motors with long mechanical drive lines are particularly susceptible to this.

Most DER meet the island detection requirement using proprietary "active anti-islanding algorithms," which generally work by intentionally destabilizing the islands and causing a voltage or frequency trip. DER using this approach are tested, as specified by IEEE 1547.1, with a load that is equal to the generation output and is resonant at the fundamental frequency in order to make the most adverse situations for island detection. Some DER, particularly synchronous generators for which these active schemes are difficult to implement, use direct transfer tripping (DTT) initiated by the utility protection system.

Various utilities have different feeder reclosing practices. Some utilities use reclosing delays longer than the required 2-second DER island detection

While stating that "appropriate means" must be implemented to avoid adverse consequences of out-of-phase reclosing, IEEE 1547-2018 does not state who is responsible for this implementation as that is a regulatory matter outside the scope of IEEE.

time. Used by these utilities even where there is no DER connected, the longer delays provide greater assurance that the fault is cleared. Other utilities prefer to use short reclosing delays because, in their opinion, this reclosing practice has an adequate fault-clearing success rate and also provides the benefit of shorter momentary interruptions of affected customers—a plus for power quality as many sensitive loads are capable of riding through these short interruptions. The DER using active anti-islanding, however, are not tested for island detection in less than 2 seconds, and it is unlikely that such algorithms can coordinate with very fast reclosing times.

Ambiguity has existed in the industry regarding the interpretation of the reclosing coordination requirements of the original standard. Many interpreted the requirements to mean that the DER is responsible for ceasing energization in the lesser of 2 seconds or the utility's chosen reclose time, unless some other means is used to avoid reclosing into an energized island, such as hot line blocking (otherwise known as undervoltage-permissive reclosing). Others interpreted the same clause to mean that utilities are responsible for increasing their reclosing delays beyond 2 seconds to accommodate DER interconnection. Even where the first interpretation is made, utilities sometimes extend reclosing delays rather than force the DER to implement and pay for other means, such as DTT, in response to public and regulatory pressure to be more DER-friendly.

Where reclosing delays are extended, a negative impact on power quality can occur due to lengthened momentary outages that may extend beyond the capability of loads to ride through, even with typical load-based mitigations applied. The revised IEEE 1547-2018 states that the "appropriate means" must be implemented to avoid adverse consequences of out-of-phase reclosing. The standard does not state who is responsible for this implementation as that is a regulatory matter outside the scope of IEEE.

All types of DER inject distortion into the grid, including synchronous generators as well as inverters, and limitation of this "pollution" is important to maintain adequate power quality.

HARMONICS AND INTERHARMONICS

All types of DER inject distortion into the grid, including synchronous generators as well as inverters. With the increasing penetration of DER, limitation of this "pollution" is important to maintain adequate power quality.

Inverter Characteristics

Virtually all electronically interfaced DER inverters use voltage-source inverter technology. Internally, these inverters generate a highly distorted waveform by switching the DC voltage on and off rapidly using transistors (insulated-gate bipolar transistors or metal-oxide-semiconductor field-effect transistors) to synthesize a fundamental frequency (60 Hz) voltage component. In addition to the fundamental component, the switching process generates other frequencies that are primarily clustered around the switching frequency and multiples of the switching frequency. Because the switching frequency is typically high (several kilohertz or greater), the nonfundamental distortion components are well suppressed at the terminals by relatively small filters, allowing these inverters to comply with stringent harmonic performance standards.

In most inverters the switching frequency is not at a multiple of the fundamental frequency. As a result, most of the distortion components are not at integer-order harmonics, but are instead "interharmonics." Interharmonics are components of voltage or current at frequencies greater than the fundamental frequency but not at integer multiples of the fundamental (i.e., they are between the integer harmonic frequencies).

Older line-commutated inverter technology, based on thyristors, and the diode rectifiers used on the line side of many load devices are satisfactorily approximated as ideal current sources for the purposes of harmonic analysis. In other words, the amount of harmonic current these devices produce is relatively independent of the impedance to which the device is connected and is insensitive to the presence of external harmonic sources. It is upon this assumption that the conventional harmonic

Recognizing that modern inverters typically produce much of their distortion as interharmonics, IEEE 1547-2018 leads the way by now imposing interharmonics limits that are equal to the lesser of the limits imposed on the adjacent integer harmonics.

performance standards, such as IEEE 519, have been based.

Modern voltage source inverters (VSIs), however, do not act like ideal harmonic current sources. The amount of harmonic current flowing from these devices can depend on the impedance of the external grid system at harmonic frequencies. Harmonic current flow "from" VSI is also dependent on external harmonic sources. Effectively, the external sources drive harmonic current into the VSI. The impedance presented by a VSI to external distortion sources is complex and is greatly influenced by the inverter's controls. At frequencies well above the control's ability to regulate the current (inverter current regulator bandwidth), the effective VSI impedance is defined by the physical output filter—typically a "T" or "L" network of series inductors and shunt capacitors and resistors. However, within the regulator bandwidth, the impedance is defined by the control's software. Typically, this impedance becomes greater and more capacitive the lower the frequency of the external source.

Distortion Performance Standards

The conventional approach to specification of harmonic performance of interconnections to the grid is to set harmonic current limits. This is the approach used in IEEE 519 as well as the IEC standards. While this works well for most distorting loads and older inverter technology, it is an imperfect fit with modern VSIs. Tests of inverters performed in a lab can yield harmonic currents within limits, but the same inverter in an actual system environment may produce greater or lesser harmonic current magnitudes. This discrepancy is due to the harmonic impedance of the actual system, which typically has resonances at multiple frequencies, and to background voltage distortion that is omnipresent in the field.

IEEE 1547-2003 applied harmonic current limits that are the same as specified in IEEE 519 for generation. Both standards, however, did not specify any interharmonics limits. In the revision of the IEEE 1547 standard, the harmonic requirements have been updated to be more congruent with modern technology. In IEEE 1547-2018, distortion specifications are still in the form of current limits due to the absence of a suitable and well-accepted alternative. The odd-harmonic limits remain the same as specified in IEEE 519. The greater restrictions placed on even-harmonic currents by IEEE 519 are phased out with increasing frequency until the 8th harmonic, above which the even and odd harmonic limits are the same. Recognizing that modern inverters typically produce much of their distortion as interharmonics, IEEE 1547-2018 leads the way by now imposing interharmonics limits that are equal to the lesser of the limits imposed on the adjacent integer harmonics.

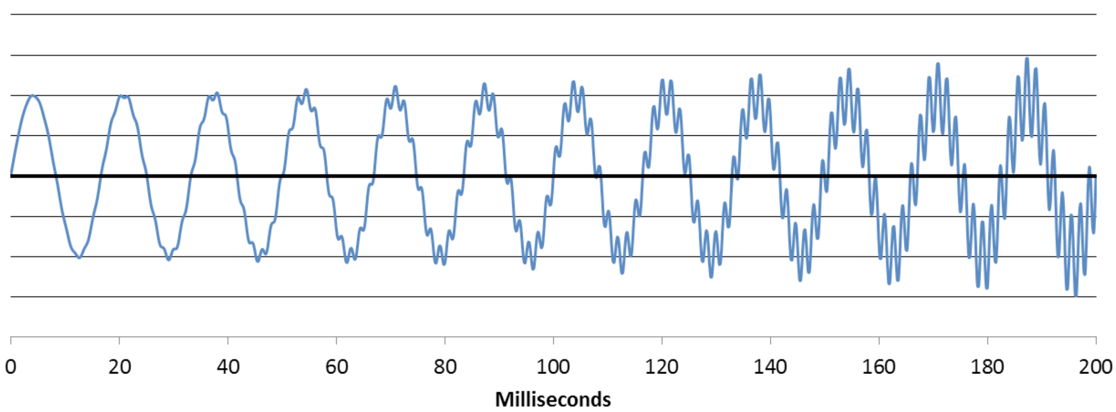
Harmonic and Interharmonic Performance

Large DER facilities typically consist of many individual DER units. In the case of VSI-based DER, the switching of the various inverters are typically not synchronized with each other. As a result, the harmonic currents produced have random phase angle relationship. By the laws of random phasor summation, the aggregate harmonic current magnitude produced by N inverters is equal to $\sqrt{N}$ times the current produced by 1 inverter. A facility with 36 inverters has a harmonic output, in amps, equal to six times the output of 1 inverter. On a percentage or per-unit basis, the aggregate is the percent harmonic current of one unit divided by $\sqrt{N}$. Thus, harmonic output of large DER facilities is typically substantially self-canceled due to phase diversity.

Because of phase diversity as well as the tight distortion limits imposed by IEEE 1547 on DER, relative to most load devices, field harmonic issues related to DER are quite infrequent. Resonances can potentially amplify harmonics to a great degree, however, so occasional harmonic issues correctly attributed to DER do occur, just as it is quite possible for standards-conforming loads to also cause occasional issues due to resonances.

A misoperation phenomenon exists that can cause inverters to produce high-magnitude frequency

Illustration of Current Resulting from Inverter Current Regulator High-Frequency Instability



Inverter current regulator high-frequency instability can be avoided by ensuring that the grid connection point is sufficiently strong relative to the amount of DER connected, and by proper consideration of grid resonances in the inverter control design.

components in the harmonic frequency range. Although VSIs synthesize a fundamental voltage, the phase and magnitude of the synthesized fundamental voltage are controlled such that the inverter regulates the fundamental-frequency output current to a reference value set by a slower outer-loop regulator, such as a constant power control. This current regulation is very fast, with a control bandwidth on the order of 100s of Hz to kHz. When connected to a grid that is too weak or has poorly damped resonances within critical ranges of frequency, the current regulator may become unstable, producing current such as shown in the figure above. Unlike the volt-var control instability, discussed earlier, that will generally create voltage oscillations of a few hertz, VSI current regulator instabilities typically result in oscillations at 100s of Hz that are not necessarily at an integer harmonic frequency. This high-frequency injection is not directly due to the inverter switching patterns that generate harmonics during normal operation, but are instead due to the control instability. This situation can be avoided by ensuring that the grid connection point is sufficiently strong relative to the amount of DER connected, and by proper consideration of grid resonances in the inverter control design. This is not an issue that is addressed by inverter testing defined by IEEE 1547.1. However, the distortion limits of IEEE 1547-2018, because they are not limited to integer harmonics, provide justification for utilities to require DER owners to address such misoperation events.

TRANSIENT OVERVOLTAGES

Because VSIs are controlled at high speed as effectively constant fundamental-frequency current sources, abrupt opening of the grid connection causes the inverter to try to push its current into a very high impedance. As a result, a load-rejection overvoltage transient tends to occur. The magnitude of this event depends on the inverter's operating current level, the design of the inverter, and the amount of load remaining connected to the inverter when the grid connection opens. The duration of the overvoltage, however, tends to be very short. Many inverters have control algorithms to sense this overvoltage and immediately trip, sometimes in a fraction of a cycle. Even without such controls, the inverter cannot maintain stable operation in the absence of a grid connection for more than a few cycles.

The most severe load rejection overvoltage occurs when there is no load left connected to the inverter or DER facility. But the problem in this case is not related to power quality because no load is subjected to the resulting overvoltage. So, from a power quality standpoint, the worst load rejection overvoltage occurs when only a small amount of load remains connected to the inverter.

This overvoltage phenomenon was not addressed in IEEE 1547-2003. In fact, this phenomenon was not even recognized at that time. The new IEEE 1547-2018 directly addresses the potential problem with a time-overvoltage curve that DER may not cause the utility voltage to exceed.

CONCLUSION

Distributed energy resources have changed the nature of the electrical distribution system. Penetration of DER is increasing rapidly and will continue to increase into the future. With high levels of DER penetration comes the potential for significant power quality degradation. Some power quality issues related to DER have come not from the DER directly, but rather as a result of utility practices implemented in response to the DER presence.

The recent revision of IEEE 1547 addresses many of these issues with new requirements and limitations imposed on DER. Additionally, DER are now required to have capabilities that can be used to mitigate not only power quality issues caused by the DER, but also issues caused by other system events and load behaviors. Proper application of IEEE 1547-2018 and the tools that it provides, along with careful consideration of PQ-related impacts of utility-specified DER interconnection practices, can allow DER penetration to continue on its trajectory without compromising power quality.

NOTES

1 *Variability of PV on Distribution Systems Analysis of High-Resolution Data Measured from Distributed Single-Module PV Systems and PV Plants (0.2kW to 1.4MW) on 3 Distribution Feeders* (Palo Alto, CA: EPRI, 2012), 1024357.

2 *PQ Case Studies from DER and Smart Grid Integration* (Palo Alto, CA: EPRI, 2017), 3002010257.

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