Considerations for Connecting Photovoltaic Solar Plants to Distribution Feeders

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I. Introduction

When any non-utility generation is connected to a distribution feeder there are a several factors that need to be considered. For many utilities the customer owned generation connected to distribution feeders in the past has been mostly engine driven synchronous generators. These rotating machines have electrical characteristics that are well known and fairly predictable. The majority of these installations were for emergency use and rarely exported power into the utility system making protection relatively straight forward. Typical protection schemes consisted of sensitive reverse power and sometimes a zero sequence voltage relay on the utility side to detect ground faults on the feeder if the zero sequence network was isolated from the generator.

The introduction of numerous photovoltaic solar installations has presented new challenges. The first one is all of these installations are exporting power into the utility system. Inverter based generation has very different characteristics from rotating machine based generation, particularly in fault current capability. A conventional synchronous generator can produce many times its rated load current into a fault for many cycles. An inverter based system may only produce fault current that is slightly above normal load current. In the past distribution connected generation was non-exporting so islanding was usually not a consideration, protection schemes were only concerned with separating the customer generation from the system when a fault occurred or the feeder was de-energized.

When a solar facility requests service into a distribution feeder, the following concerns need to be addressed:

- Utility responsibilities.
- Customer responsibilities.
- The solar facility maximum output.
- The feeder minimum load.
- The connecting transformer configuration: wye, delta, wye-grounded, etc.
- Type of converter: Utility Interactive or Utility Independent.
- Other generation on the same feeder.
- Type of protective device at the utility interface.
- Feeder reclosing sequence.
- Interaction with automatic restoration scheme.
- Will protective devices be owned by the utility or the customer?
- Will a communications aided protection scheme be necessary?
- Verification of proper operation of protective equipment.

This paper provides a summary of potential challenges what could be faced when integrating distributed generation in general, and exporting photovoltaic solar installations in particular. It discusses issues identified during field testing and offers recommendations based on lessons learned.

II. Potential challenges faced when integrating distributed generation

Multiple standards and guides have been developed by the industry to address requirements, installation and testing of non-utility generation. General requirements for interconnecting distributed resources with electrical power systems are specified by IEEE-1547-2003 standard [1], IEEE 1547.1-2005 standard specifies conformance test procedure for equipment interconnecting distributed resources [2]. Further requirements are provided by UL 1471 Standard for Safety [3]. Insights on testing devices compliant to UL 1471 are provided in section III. IEEE C37.95 Guide for Protective Relaying of Utility-Consumer Interconnections has been published in 2014 [4]. Guide for Protection Systems of Transmission to Generation Interconnections is under development in the IEEE PES Power System Relaying Committee, Working Group C18 [5]. Utility companies develop their own specifications for interconnection projects, as those found in [6], [7] and [8].

This section discusses potential challenges that could be faced when integrating distributed generation in general, and exporting photovoltaic solar installations in particular. It focuses on challenges related to protection, modelling, communications, synchronization and interdisciplinary knowledge.

1. Protection-related challenges

Protection-related challenges when integrating non-utility generation in general and photovoltaic solar generation in particular have been captured in various papers and presentations [9], [10] and [11]. Protection and coordination issues have also been covered in details in [12], [13], [14] and [15]. These studies will be referenced in the appropriate sections of this paper.

A diagram of a system with non-utility generation interconnection is shown on Fig. 1. It should be noted that protection of systems with interconnections at distribution level can generally be divided into feeder protection and interconnection protection. Interconnection protection includes ant-islanding protection discussed further later in this paper.

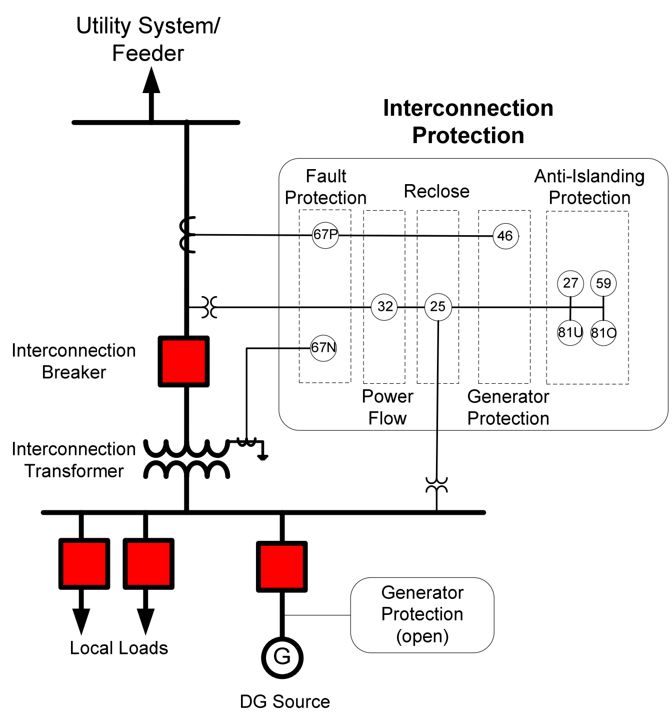

Figure 1 Diagram of a typical system interconnected with a non-utility generation.

Specific cases with known protection challenges include undetected islanding when load and generation are equal, overvoltage with large generation and light load, and ARC protection with large generation.

Fault current capability and short circuit analysis

Fundamentally important protection related issue that exist for photovoltaic solar generators is their fault current capability, as it differs significantly from characteristics of generators based on rotating machines, and has high dependency on sun and load. Traditional protection schemes used for synchronous generators are not suitable for such generators, as explained in [10].

Fault current contribution of inverter-based distributed energy resources has been analyzed in details in [12]. In particular it was found that fault current is typically higher, but for much shorter time periods (2-4 times rated current for 0.06 – 0.25 cycles). It also showed that low voltage ride-through test of an inverter could produce 1.2 times peak current for a period of approx. 7 cycles. This confirmed adequacy of inverter-based distributed energy resource fault current-ride-through capability, however it is not clear what effect this may have on the distribution system protection scheme.

Results of other studies on fault current contributions of photovoltaic (PV) inverters contributions to faults is provided in [15]. The following conclusions were reached based on testing PV inverters from different vendors. It was found that PV inverters fault current contribution is non-zero and varies by design. Most PV inverters tested continued to provide current to the feeder during fault for a duration of 4-10 cycles. The current contribution level depends on voltage level at the inverter during a fault that is determined by the type and location of the fault. For most inverters current during fault was above rated current, and reached up to 120% of the rated current. For a few inverters fault current during fault remained at the pre-fault level. For one inverter, current during fault dropped to zero and inverter was disconnected in less than 0.5 cycles (for a particular test when terminal voltage reached below 50% on any phase). It should be noted that this studies used Generic PV Inverter Models.

Per varying fault current capability that depends on design, load and sun, modelling and short circuit analysis of PV inverters presents challenges. While some good work has been done in this area, there seem to be not enough clarity on how PV should be modelled [10]. Recent work led to realizations that PV inverters could be modelled as Wind Turbine Generators Type IV with low voltage ride through capability [17] and [18]. Further work on modeling of PV inverters is provided in [19]. All these updates were provided by Aspen, CAPE, Electrocon and Walling Energy System Consulting at the IEEE PSRC meeting in January 2015. At the same meeting EPRI presented an on-going project on phasor domain modelling of converter interfaced renewables for protection studies. Results of this interesting work will be available to the public.

Synchrophasor-based protection schemes

Synchrophasor measurements could be and have been successfully used for interconnection protection of distributed generation. Such schemes are presented in [21], where it has been shown that tripping based on wide area measurement has faster operating time than tripping based on local measurements, frequency or voltage.

Another example of using synchrophasor-based scheme for controlled islanding is described in [22]. Out-of-step protection and blocking were used, that led to reducing load shedding compared to current practices utilized by 18% and 30% respectively.

Synchrophasors, however, rely on both accurate time synchronization and communications. Both present various challenges, described in the sections that follow.

Communication-independent protection schemes (stand-alone)

As communication-assisted schemes present challenges related to availability, quality, installation, maintenance and cost of the communication channel, communication-independent schemes have been studied, and could be preferred for some applications especially at the transmission level [10]. Such schemes can be based on power factor, harmonics, sequence components or fault current curve emulation.

At the distribution level frequency bumping method has been used by some utilities [10]. As described in [13], this active method relies on responses to an injected stimulus to determine connection status. The presence of the injected signal in the loopback circuit response indicates absence of the connection to the utility system. If connection to the utility system is present, the loopback circuit response will differ from the injected signals due to system's inductance, capacitance, resistance / reactance [13]. This method, however presents challenges when integrating with multiple PV inverters, as synchronized injections are required, section II.3 discusses challenges related to synchronization. Protection schemes for interconnection with multi-inverter sites have been discussed in [14].

2. Communication-related challenges

Many interconnection projects rely on communications to perform fast tripping of a generator site (within 2s or 0.16s per IEEE 1547, depending on the level of the voltage drop). Usually, a direct transfer trip (DTT) circuit is used to perform this function. Requirements for availability and maximum delay of communication circuits for 4 types of applications are provided by electrical energy coordinating authorities. For example general requirements for utilities connected to Western interconnect are provided by Western Electricity Coordinating Council [23] and [24]. Unfortunately, the use of DTT brings multiple challenges described below, many of these are also discussed in [10].

Leased Telecommunication Lines

The use of communication circuits form a telecommunication provider introduces a number of issues, related to quality and availability of required circuits, as well as leasing and maintenance cost.

To perform fast tripping, some utilities require Class A channel, e.g. a circuit that will work before, during and after the fault [8]. Leasing such circuits from telecommunication providers becomes increasingly difficult, and sometimes impossible. Thus, alternative solutions could be considered, such as the use of own communication infrastructure, the use of communication-independent schemes, etc.

Some utilities mandate the use of communication channel for interconnections with generator facilities rated of 1MW or greater. They also specify the use of older VG36 leased line of Class B, Type 3, Full-Duplex Data Circuit with sealing current, 1200 Baud and require the customer to ensure the quality of the phone line through the telecommunication Point of Presence (POP) [6]. With technological developments, telecommunication companies are ceasing to support older VG36 circuits, thus a migration plan to newer technologies (such as fiber optic lines) should be considered. If using copper cabling, grounding issues should be considered. Copper interfaces with cables longer than 2m must meet be hardened to meet environmental requirements specific by IEEE 1613. The use of fiber optics communication cables is superior to copper cables, as it provides noise immunity (electromagnetic compatibility), thus is much more suitable for the use in electrical substation environment. However, fiber optic cabling and equipment (media converters, switches, and transceivers) tend to be costly. Care also should be taken when using multi-mode (orange) and single mode (yellow) fiber cables with different wavelengths (850nm, 1300nm and 1500nm are typical) and different connector types (ST, SC, LC are the most common).

Financial challenges also manifest themselves in lease cost for the communication circuits, equipment installation and regular maintenance.

Utility Owned Telecommunication Infrastructure

If utility company can invest into its own telecommunication infrastructure, communication issues could become easier to manage, provided that a good understanding is achieved between communication and protection engineers. With good inter-department coordination suitable communication technologies would be selected and appropriate communication system architectures will be installed. Latest developments in telecommunications area led to introduction of new technologies for utility use. Currently Multi-Protocol Label Switching (MPLS) and Carrier Ethernet technologies have been discussed and are being deployed [25].

With development in both electrical power systems and communication technologies it becomes increasingly important, and difficult to select the best approach. When selecting communication technology one needs to consider compatibility with existing interfaces, migration path for existing and future applications, in addition to availability, quality, maximum latency, and cost.

When evaluating communication system architectures, it should be taken into account that hieratical centralized architectures rely on the communication to control center. Selecting the location of the control center is critical as if communication to the control center fails, no communication between other sites will be possible. This is true even if no failure exists on the direct communication links between remote sites. It should be noted that as DTT circuits typically require simple point-to-point communications, distributed or mesh communication architectures could be considered.

Utilities that have own telecommunication infrastructure may utilize additional own communications for interconnection projects at transmission and distribution levels, or rely on the leased circuits.

Communication Media: Wireless and Power Line Carrier Communications

For some applications, especially for interconnections in the remote rural areas, the use of wireless technologies offers many benefits. It, however, as well introduces multiple challenges, related to licensing, frequency space registration, requires considerations of line-of-sight constrains, data quality, availability, reliability and security.

The use of wireless technologies in unlicensed or registered space is not recommended for critical application communications [23]. These technologies, however, can be used for secondary protection, and communication redundancy. The use of licensed spectrum technologies may involve administrative challenges, associated with obtaining the required spectrum, and financial challenges associated with the licensing cost.

Experimental deployment with the use of IEC 61850 GOOSE messages for fast tripping over a utility owned Wi-Max system revealed multiple learnings [9]. While Ethernet technology does not guarantee GOOSE message delivery, the use of multicast messaging, (i.e. message repetitions at randomized time intervals sent to all devices in the group) ensures message delivery. In that deployment it was found that only one older profile of IEEE 802.16 B works reliably with Ethernet switches selected for that project. Another utility also deployed a Wi-Max system over the mainland and nearby islands. Experiments with 900 MHz unlicensed radio were also performed and are considered for some installations [10].

Power Line Carrier (PLC) communications can also be used for fast tripping over DTT circuits. It has been believed to be the best method and communication media for the use in remote rural areas. A diagram of a PV system is shown on Fig. 2.

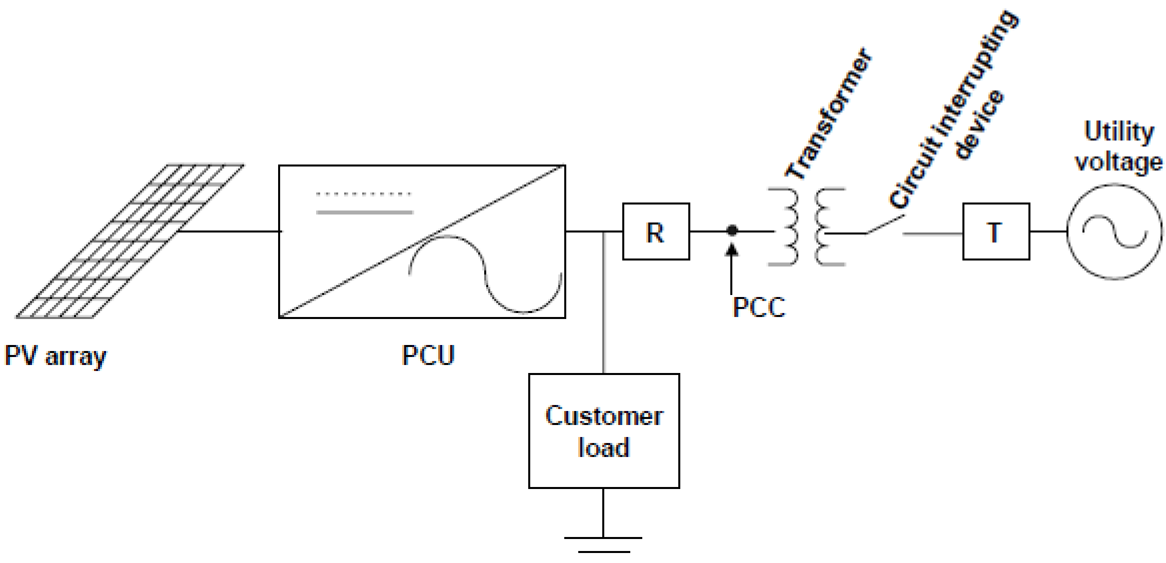

Figure 2 A diagram of a PV inverter system.

Benefits and challenges with this approach are well described in [13]. Non- technical advantage is that as PLCs use power lines as communication media, they partially fall into responsibility of the protection groups and are better understood and accepted by protection engineers (as opposed to other communication technologies and media that clearly separate communication and protection parts, often making difficult the much needed understandings and expertise).

The PLCs can be used to transmit a low energy “link integrity” signal on the interconnection line, this signal should also travel through an interconnection transformer. This provides an additional feature of “link integrity check”. This signal will obviously disappear when the line is disconnected, and that in turn will initiate a disconnection of the generator facility. An additional side benefit of these scheme is that PV inverters in this case do not need to be switched off and can continue to generate and store energy.

This scheme, however, presents some special requirements, and challenges. The signal sent on the interconnection line needs to be continuous and should also be able to travel through transformers. PLCs with such characteristics are not common and could be costly. Signal immunity to noise could also be an issue, as environmental noise could couple to the signal and distort it. Using more frequencies (harmonics) to transmit more signals improves error detection but introduces complexity.

3. Synchronization-related challenges

Requirements for time synchronization in the Western Interconnected System are specified in [26] and [27]. The use of dedicated Global Positioning System (GPS) receiver is recommended for each electric power substation. Recent additions and testing of new GPS satellites introduced challenges to various GPS receivers installed world-wide. GPS installation and future testing plans are available at [28]. Attention should be given to these issues and other time distribution methods should be considered, such as IRIG-B, Precision Time Protocol (PTP), etc.

Time and frequency synchronization is required for frequency bumping (when used for multiple inverters) and synchrophasor-based schemes. The use of frequency bumping scheme for interconnections with multiple inverters requires synchronization of signal injections between these inverters. Time of the injection and signal frequency need to be synchronized, but synchronization to the absolute time, e.g. Universal Time Coordinated (UTC) may not be required. Synchrophasor measurements could be used for anti and controlled islanding schemes. This technology requires synchronization to the absolute time (UTC) with accuracy of 1 microsecond.

4. Interdisciplinary knowledge-related challenges

When communication-assisted schemes are used, protection and communication departments need to work jointly to achieve a common goal of meeting protection system security and dependability requirements. If leased communication circuits are used constructive involvement of telecommunication companies is also required. For some schemes, for example those based on synchrophasors, personnel of the operational control center need to be involved as well. Constructive and effective cooperation between all these groups is necessary. Differences in areas of expertise and responsibilities, department and company boundaries can artificially create various technical and non-technical challenges.

Given the above challenges, it is not surprising that deployment and testing of PV inverter-based installations have been and continue to present difficulties. The section that follows describes field experiences and lessons learned to assist in understanding of possible issues and possible resolutions.

III. Test Experiences with PV inverter installations

Some common misconceptions amongst utilities are that inverters listed as UL1741 compliant will not

- Island
- Cause transient over voltages
- Produce power when single phased
- Produce power at anything accept unity power factor
- Produce power within 5 minutes after an outage
- Regulate the local voltage
- Cause Radio Frequency Interference

Unless witness tested to compliance after installation, most programmable inverters are capable of doing any or all of the above. Most people familiar with microprocessor based relays would agree that all relays need to be tested before being placed in service. Just like microprocessor relays, most inverters have parameters that require settings to be calculated and implemented correctly before the equipment will work as intended. Unlike many microprocessor relays, protection personnel seldom have insight into the actual parameters and programming of inverters and rely on witness testing for verification of operation.

The following sections are intended to provide some insights into what to look for and what to guard against during witness testing.

1. *The single phase disconnect test*

Test Review

When single phase testing an inverter based generation facility, the test requires that one phase be disconnected from the utility source on the utility side of the point of common coupling (PCC) and the response of the facility be measured at the PCC. For the facility to pass the test, the facility must stop producing power within a specified time – usually 2 seconds. This test procedure was developed based on IEEE1547.1.

The test can be done by disconnecting either a riser fuse or bay-o-net fuse upstream from the PCC. It must be noted that the voltage on the transformer winding will not be zero when a phase is removed. The voltage on the opened phase may increase above normal phase-to-neutral voltage as the open phase is then floating, especially if the transformer is not loaded or there is generation connected to the secondary side of the transformer and the transformer experiences ferroresonance [29]. Experience has shown that during this test, the fuse must be disconnected and reconnected to reduce the time spent single-phasing the transformer.

The following is an example of a facility that produces power but fails to detect a single phasing condition and keeps on producing power to the system, refer to Fig. 3.

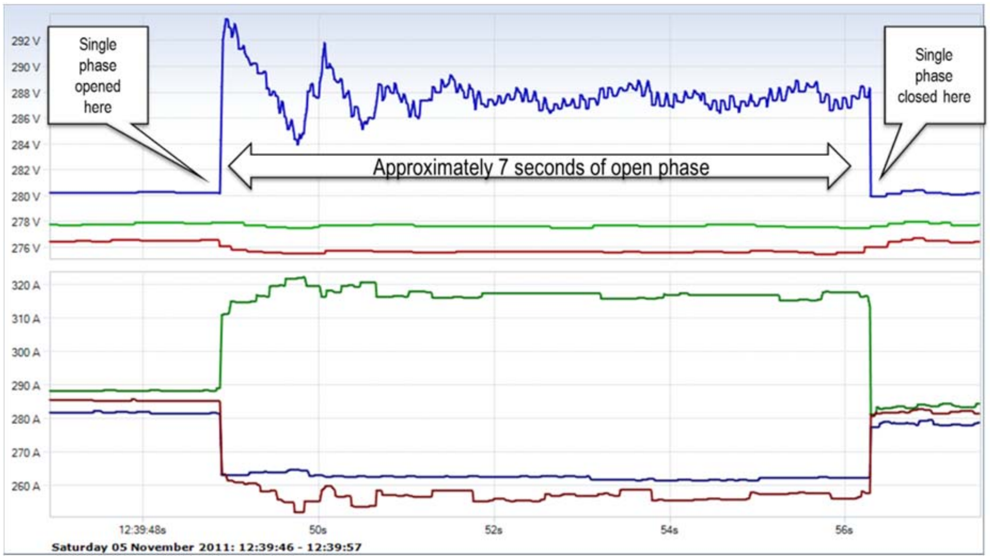

Figure 3 Customer generation does not detect single phasing and continues to provide power to the grid. This is more common when generation side of transformer is Delta connected.

The above customer had a wye-grounded utility side / Delta inverter side transformer. It also seems that the inverter was in fact trying to regulate the terminal voltage. After the customer failed this test, the manufacturer sent an Engineer to site and re-programmed the inverter. The inverter was then re-tested and produced the following result:

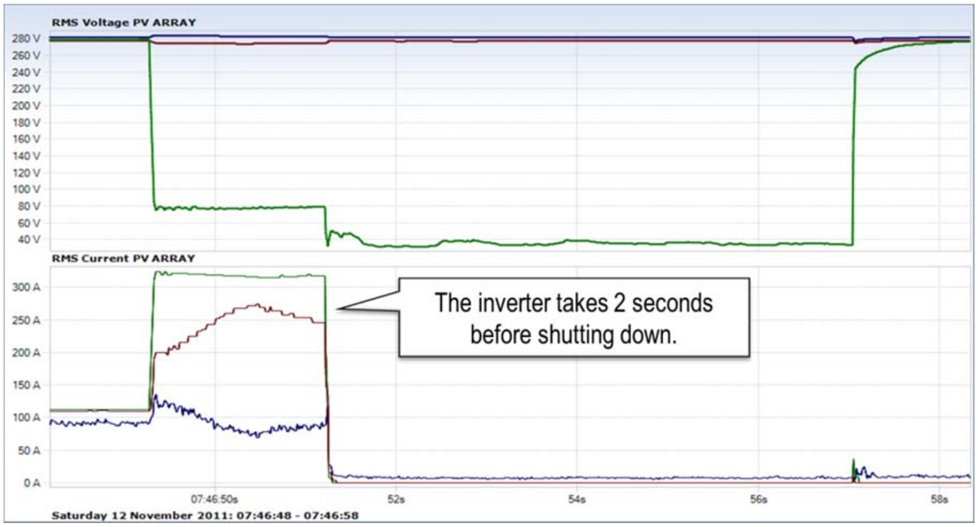

Figure 4 Customer generation now detects single phasing and shuts down within 2 seconds.

Test Experiences

a. Low oil in transformer

During a single phase test where it was decided to pull the bay-o-net fuse, it was not apparent that the transformer was low on oil and consequently the bay-o-net fuses were not immersed in oil. When the single phase test was carried out by extracting the bay-o-net fuse, the transformer had an internal flash from one bay-o-net to the other. The testing procedure was then modified to verify transformer oil level before testing when possible.

Shown on Fig. 5 below are the voltages and currents recorded during the fault.

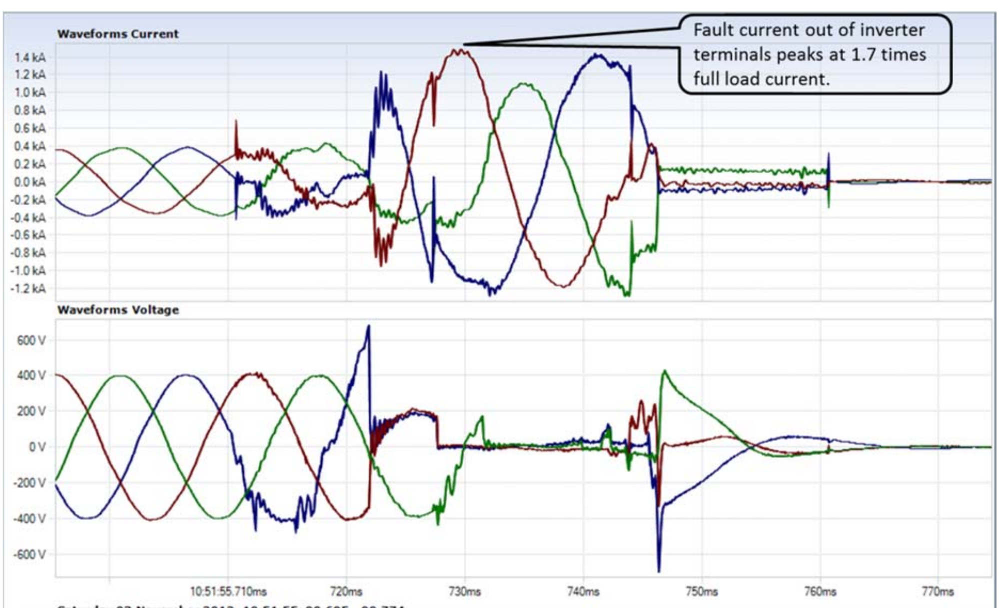

Figure 5 Three phase fault on primary side of transformer, recorder on output terminals of inverter on secondary side.

Notice how the inverter contributed up to 1.7 times the full load current to the fault even though the terminal voltage has dropped away.

At the time, it was uncertain what transpired in the transformer and the transformer was replaced and inspected at a later stage. Below Fig. 6 is a photo of the bay-o-net fuse holders. One can clearly see the flash marks on the tip of the connectors.

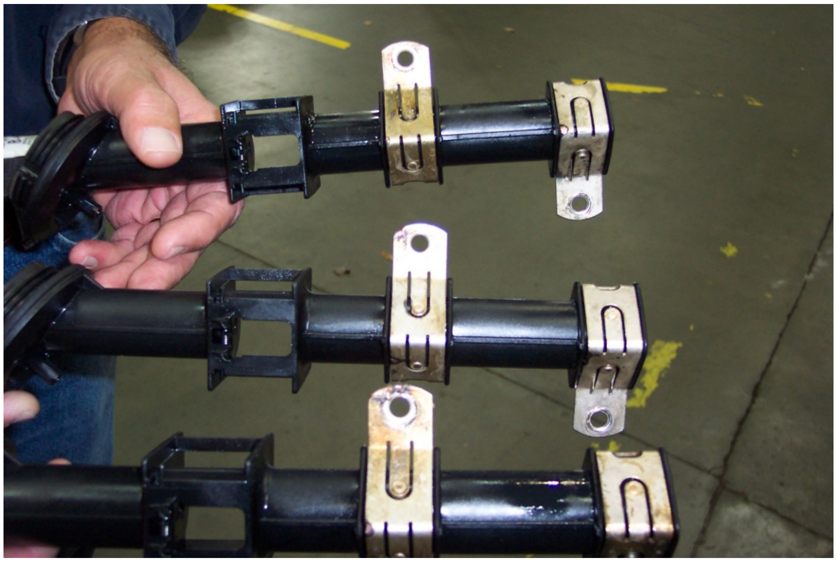

Figure 6 Damage to bay-o-net fuse holder.

Testing procedures were altered to verify the transformer oil level when possible before the test.

b. Damaged fuse insulator

A 1MW solar facility was being tested. The PCC is located at the high voltage side of the facility interconnection transformer. The only means of conducting the single phase test was to use a load breaking device to open the riser fuse to the facility.

When opening the middle phase, an arc originated between the top of the fuse insulator and the T-bracket holding the fuse switch. It is assumed that the switch insulator may have had a crack and moisture in the crack caused the breakdown to occur. The fault started as a single phase to ground fault but soon included an adjacent phase. Testing procedure now includes a cursory inspection of the fuse insulator to check for any obvious damage. Below Fig. 7 is a photo of the damage to the fuse insulator.

Figure 7 Damage to fuse insulator.

The recording of the test is shown on Fig. 8 below:

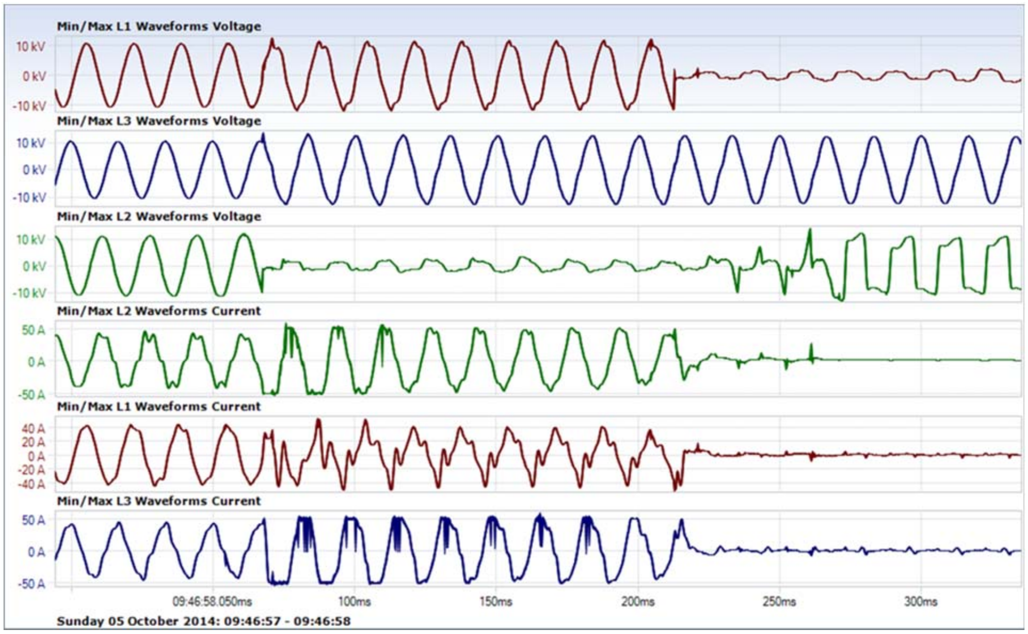

Figure 8 Recording of the faulted facility.

At the onset of the fault, notice a 180 degree phase shift in the L3 current. The recorder CT saturates indicating that the fault current through this phases flowing towards the transformer and back out is very high.

c. Elbow Surge Arrestor failure

When single phase testing a three phase facility, make sure any primary side surge arrestor elbows are rated to withstand the continuous overvoltage. During one single phase test, the primary side elbow surge arrestor failed. When single phase testing a three phase transformer with no load or negative load (generation), one must expect that there could be some ferroresonance present [29]. In this case, the transformer was of a wye-grounded/ wye-grounded configuration. This is heard in the form of “growling” of the transformer and not unusual. What is not usual is if the “growling” suddenly stops for no apparent reason. This could mean that a surge arrestor has shorted the winding to ground. Reinstalling the fuse in this phase that is now grounded through the shorting surge arrestor will cause a single phase to ground fault. Again, realizing that during single phase events of lightly loaded or negatively loaded transformers (generation) could lead to rising phase voltage on the open phase, make sure that the surge arrestors are rated to handle the over voltage by checking the Maximum Continuous Operating Voltage (MCOV) rating of the surge arrestor. Refer to Fig. 9 for the photos taken during this test. Testing procedures now include temporarily removing undersized surge arrestors of the customer owned transformer before the test if the customer so wishes.

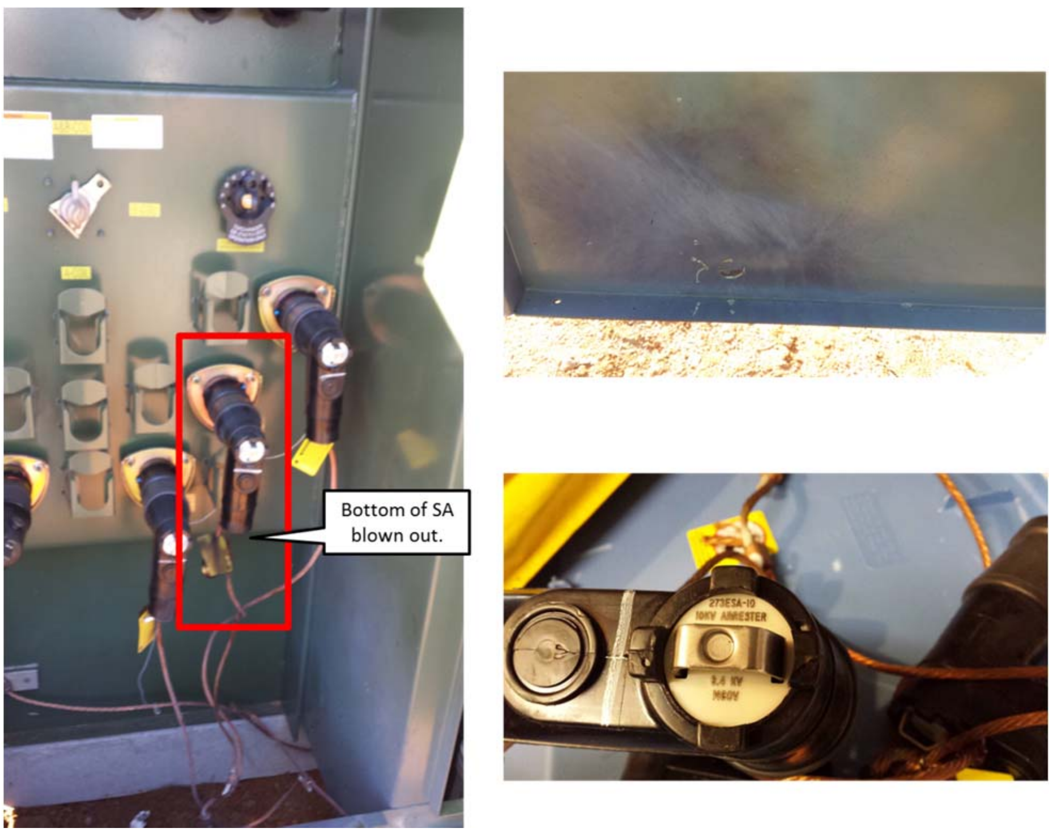

Figure 9 Left: Damage to surge arrestor that did not have sufficiently high MCOV rating. Top right: Damage to transformer door. Bottom right: MCOV rating show 8.4 kV.

Also shown on Fig. 10 and Fig. 11 is the recording on the utility side of the fault in the transformer for both a normal test and the actual test during the failure.

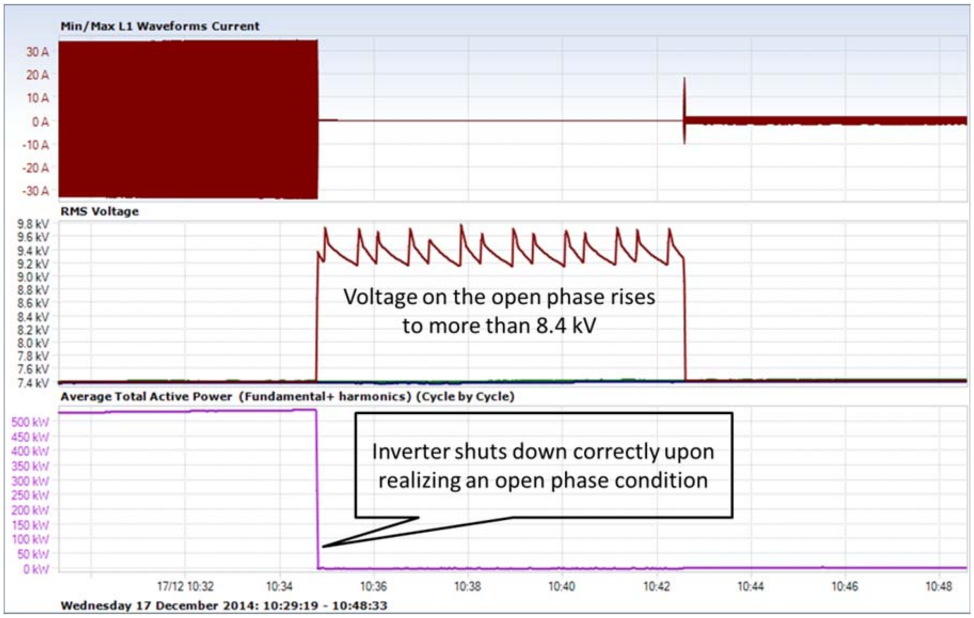

Figure 10 Recording of a normal test.

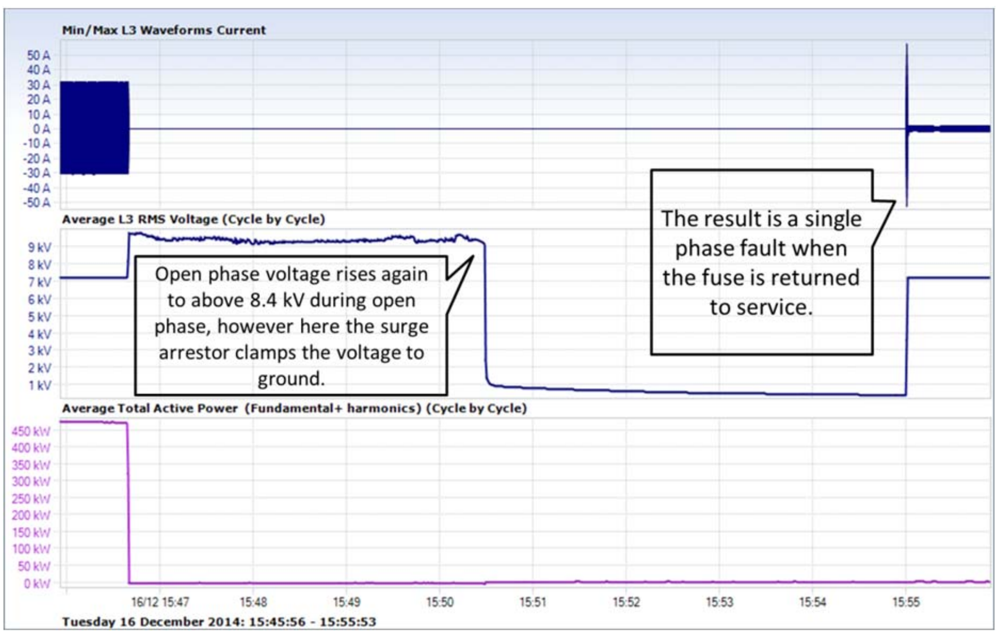

Figure 11 Recording of failed surge arrestor.

Notice how the floating voltage is pulled to zero midway through the test as the surge arrestor conducts to ground. At that time it was noticed that the “growling” of the transformer stopped.

Lessons Learned

- Keep single phase open test times as short as possible. Three seconds should be sufficient to know if the inverters responded correctly. This is best achieved by pulling bay-o-net fuses and simply replacing them after three seconds.
- Verify that surge arrestors are capable of withstanding the expected over voltage on the open phase.
- Check the disconnecting device for any abnormalities if possible such as cracks in insulators or low oil in transformer.
- Listen to the transformer. If the growling suddenly stops before the fuse was closed in, disconnect the transformer and inspect.

2. Checking the generation start-up time

Test Review

After a disturbance on the Distribution system has caused the generating facility to stop producing power, the facility is expected to wait a pre-determined time before starting generation again. In this case, once all phase voltages have been restored and have been stable for a minimum of 5 minutes, the generating facility will be allowed to start producing power again. After each disconnect test, the time of reconnect is measured.

Below Fig. 12 is a recording of inverter systems that at first did not pass the reconnect time delay test.

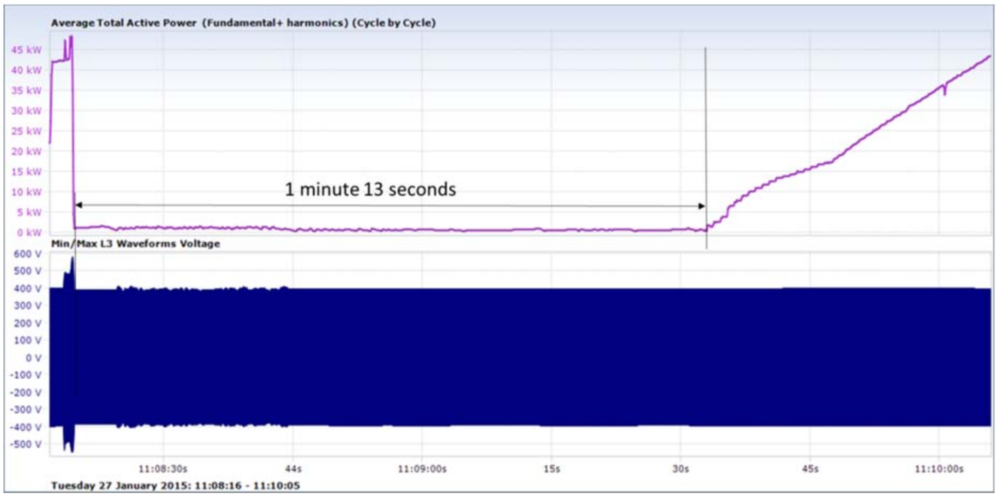

Figure 12 After a single phase disconnect test, the inverters fail to wait the required 5 minutes before producing power.

Even though the inverters are UL1741 listed, the settings in the inverters had to be altered to ensure the inverters wait the minimum 5 minutes before producing power again, refer to Fig. 13.

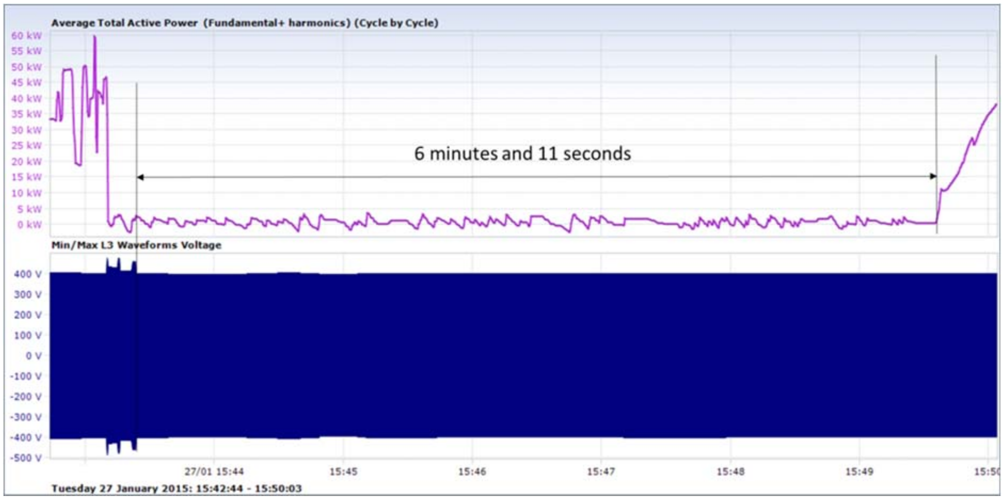

Figure 13 After being reprogrammed, the inverters pass the reconnect delay time test.

Test Experiences

Always check the generation startup time after any disconnect test, three phase or single phase. It is also a good idea to vary the three phase open time. This will check that the inverters are actually waiting for the 5 minutes after the voltage came back normal on all three phases and are not simply pulse-testing to see if the voltage stayed on during the past 5 minutes before starting to generate. The difference is illustrated on Fig. 14 below:

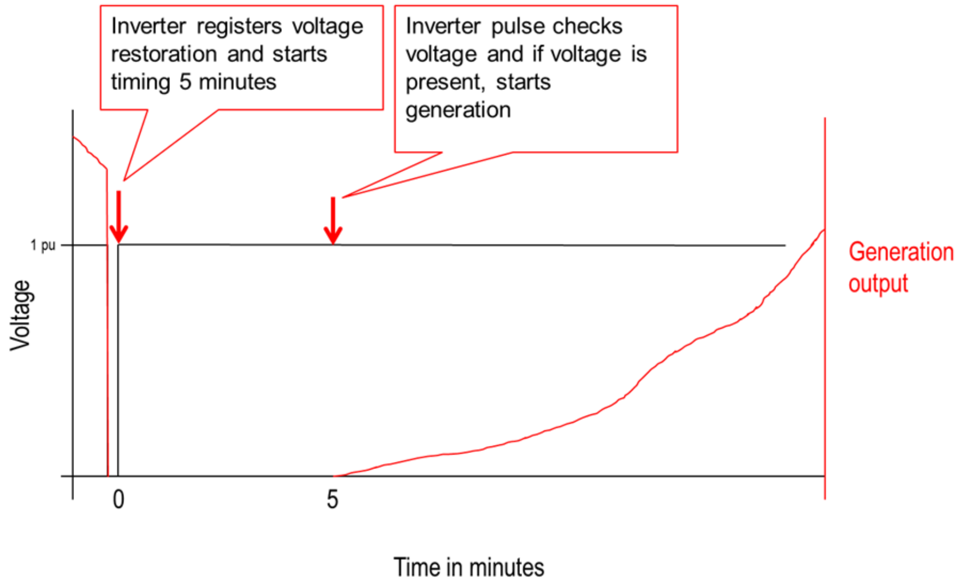

Figure 14 False test for inverter generation startup time.

After the initial shut down, the inverter waits for the restored voltage and starts back after 5 minutes. Fig. 14 shows how a restart of an inverter can seem to be correct but there is a flaw in this method as shown in Fig. 15 below.

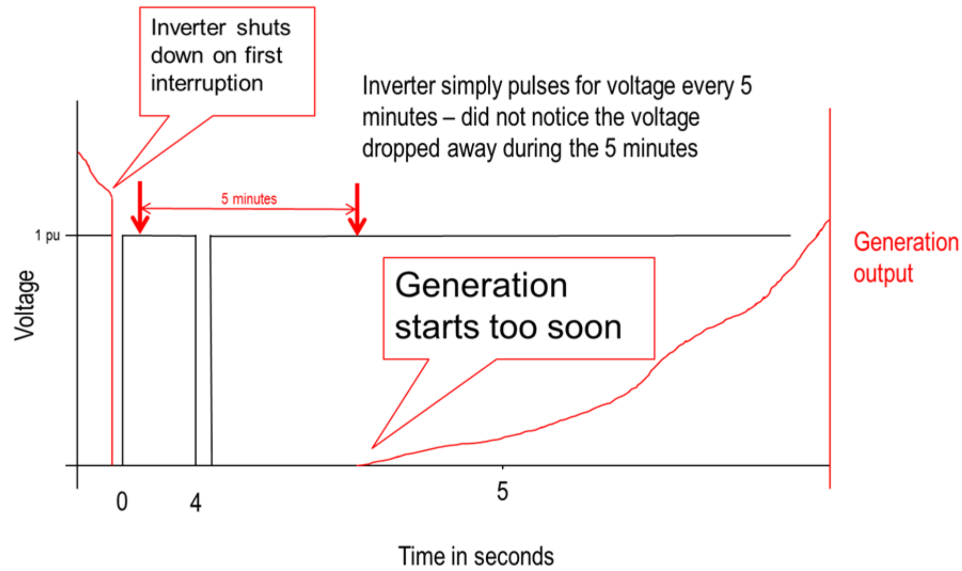

Figure 15 Incorrect restart time of generation.

After the initial shut down, the inverter waits for the restored voltage and starts back after 5 minutes. The inverter fails to see the voltage was not healthy between pulses.

On typical feeders, multiple reclose shots are used in a coordinated method to isolate the faulty section of the feeder. If the above reclose sequence occurs, the inverter that simply pulses for healthy voltages after noticing restoration would not know that the voltage has not been healthy for 5 minutes and start generation too soon.

Below Fig. 16 shows how the inverter is supposed to check for healthy voltages before starting generation.

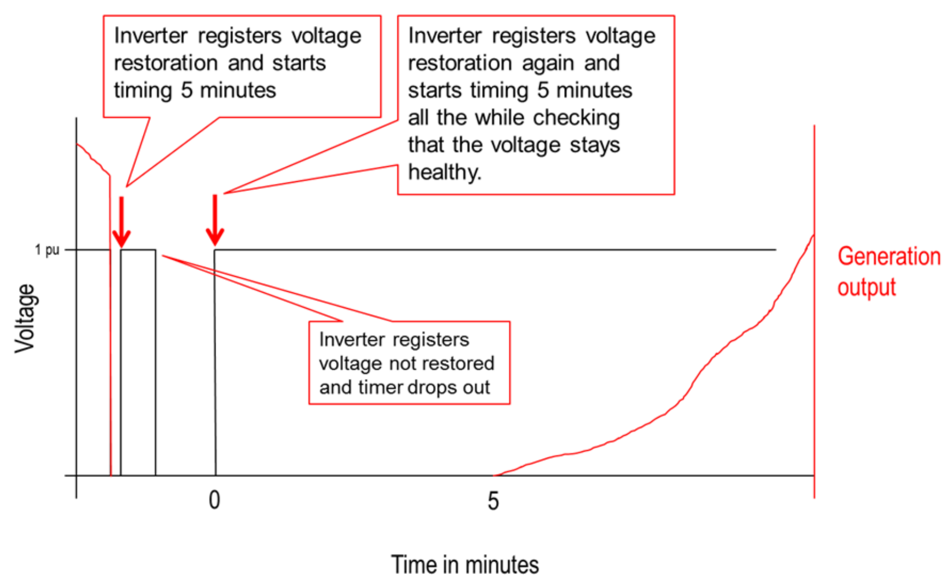

Figure 16 Correct restart of generation after outage.

After the initial shut down, the inverter waits for the restored voltage and starts timing 5 minutes. If the voltage should go outside the limits, the timer is stopped and restarted once the voltage returns to normal.

Lessons Learned

It is easy to misinterpret a 5 minute delay on startup as being correct. Here are some ways to check for issues:

- Vary the restoration time after three phase disconnect tests.
- For a 5 minute restart time, open the three phase switch again after “X” minutes and immediately close it back in again, start timing from the last close.
- Repeat the test at different delay intervals between open and closing, simulating reclose shots of upstream devices.

3. Three phase disconnect test

Test Review

Three phase disconnect over voltages can be damaging to equipment and customers on the Distribution System, as discussed in [30] and [31].

The worst case for over voltages is when disconnecting the inverters at maximum output and leaving no load connected to the inverters after the disconnect takes place. Having the facility produce maximum output is not always possible since most PV system rarely achieve this. To make the test more practical, it was decided to require all PV facilities to produce 85% or higher output during the three phase disconnect test, refer to Fig. 17.

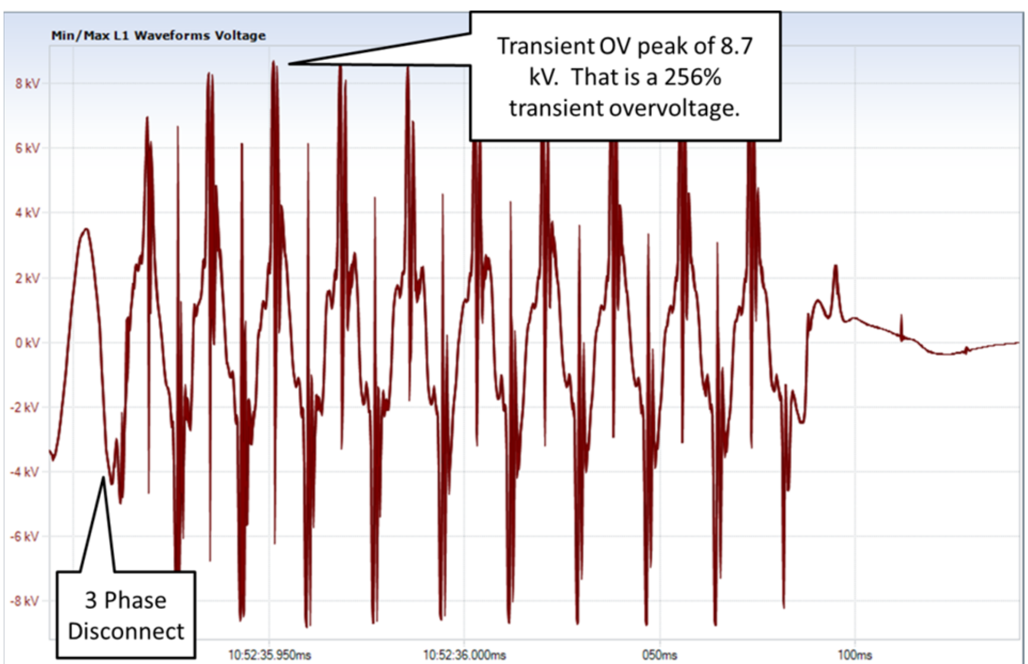

Figure 17 Transient overvoltage after a three phase disconnect.

During this test, a three phase disconnect switch is opened at 85% or higher output from the facility and the resulting voltages at the PCC is recorded. The overvoltage is then evaluated and checked that it does not exceed pre-established voltage criteria. This test involves checking that Transient Overvoltage spikes are not excessive in peak and duration and that the RMS voltage stays within certain limits.

Once a transient overvoltage as the above is detected, an analysis is made taking into account the deviation amplitude and duration to determine if the transient will be a problem for equipment and customers on the Distribution system. Next we start checking for the RMS overvoltage amplitude and duration as shown below in Fig. 18.

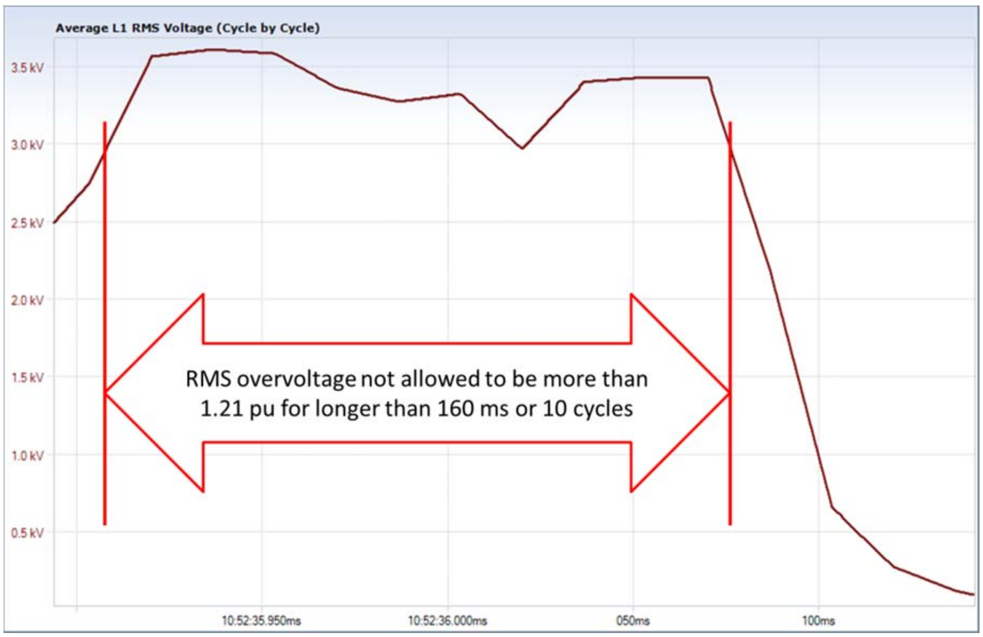

Figure 18 RMS overvoltage after a three phase disconnect.

On each test, the total shutdown time is also recorded.

Test Experiences

The results of the three phase disconnect test depend greatly on where the point of common coupling (PCC) is located. If the PCC is on the secondary side of the transformer, the over voltages are usually much higher when three phase disconnecting the customer on the primary side of the transformer. The argument here is that the more likely scenario being a three phase disconnect switch being opened on the primary side could cause any other customers connected to the secondary of the transformer to experience these over voltages if they remain connected to the inverters. On the other hand, if the load remaining connected to the inverters are large enough they will simply absorb the overvoltage and help the inverters shut down faster. Again, the test is intended to evaluate the worst case scenario for example, one small load from another customer left on the secondary when the primary disconnect switch is opened.

Lessons Learned

- Most overvoltage conditions seem to be as a result of long underground AC cables between the inverter and the transformer connecting to Distribution feeder causing some ringing effect.
- Large inverters more often have overvoltage issues than multiple small inverters or string inverters.
- The same inverters used in the same design with the same type of interconnection transformer, voltages and grounding systems have shown to produce different over voltages. It has become clear that over voltages seem to be unpredictable and must be tested per installation.
- Although it cannot always be averted, it is better not to have other customers on the secondary side of a transformer that is also connected to the generating facility.
- At one facility, the customer adjacent to the solar facility had large motors running while we were performing the three phase disconnect tests. An upstream hydraulic recloser tripped and reclosed when the solar facility transformer was disconnected and re-energized. Since then, upstream hydraulic reclosers are bypassed while doing three phase disconnect tests.

4. Customer equipment failure

It was noticed that customer equipment failure was most likely to occur during the first few days of maximum output. It has therefor become practice to have the facility produce power for seven days before a witness test is attempted. During that time, no energized work on the feeder will be allowed until the disconnect switch to the facility has been opened and locked out.

5. Radio Frequency Interference

Radio Frequency Interference can sometimes be detected due to the production of power using some inverter systems. A simple handheld AM band radio suffices to detect when the inverter(s) are causing RFI. The RFI increases as power production increases but never goes completely away until the inverter(s) shut down.

4. Conclusions

This paper discussed challenges faced and lessons learned when integrating distributed generation, in particular exporting photovoltaic solar installations. Challenges discussed are related to protection, modelling, communications and synchronization. Lessons learned from field installations suggest specific test setups and procedures to prevent undesirable behaviors during operation. Given these complexities no ‘one fits all’ solution exists, and each case and application require individual analysis for selecting the best solution. For further enhancements leading to maturity of this technology collective industry-wide knowledge exchange is highly encouraged.

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