An Overview of Issues Relevant to Protection and Restoration of PV Systems at Distribution Level

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***Abstract*—This paper discusses the protection and restoration challenges for high penetration of inverter−based resources at the distribution level, particularly with grid-connected solar photovoltaic (PV) generation. The discussion starts by providing a brief overview of three cascaded solar PV farms' interruptions in Southern California and their corresponding impact. Then, the distribution level solar PV integration architecture is discussed. The discussion is extended with the nature of inverter fault transients characteristics and available standards on evaluating transients at distribution level. Further, the difficulty of analyzing transients in less than one cycle time frame (i.e., sub−cycle transients) using existing fault analysis techniques and their limitations will be addressed. Finally, a summarized discussion of IEEE 1547 standards and available smart inverter modeling as applied to the aforementioned topic is given.**

***Index Terms*—Distribution systems, Solar PV Systems, Faults, Protection and Restoration, Sub−cycle transients, Standards**

I. Introduction

THe electrical power system is often subjected to numerous types of system faults during operation. These faults can be symmetrical or asymmetrical by nature and change system operating variables (voltages, currents etc) to new values during faults [1]. The most common types of faults that can be identified in the system are single line to ground (SLG), line-line (LL), and double line to ground (DLG) [1]–[4]. The time when the fault is originated is unknown a priori and brings an abnormal condition to the system. Therefore, in general, the fault transient starting point is only known after the event, and the characteristics of the transient depend on the equivalent network parameters (equivalent inductance, capacitance, resistance and other network elements) from inverter terminal to the point of fault [5]. In a traditional grid, synchronous generators provide nearly six times bigger than rated current during system faults [6], [7]. This large amount of fault current is often used as a fault signature and is the basis for time overcurrent relay protection. However, this nature is changed with the integration of inverter-based resources (IBR) and smart grid technologies. Inverter-based energy resources such as solar cannot produce significantly larger fault currents during a faulty situation.

Studies have been performed in the past to analyze the impacts and challenges of large scale solar integration on system protection and stability. The North American Electric Reliability Corporation (NERC) reported three major grid disturbances that happened in three years (2016, 2017, and 2018) in California. These three transmission level events happened in a row where large-scale inverter-based generation units went off-line. These cascading impacts suggest that further study and research are required to analyze the protection and restoration challenges in both transmission and distribution level with large scale solar integration [2]–[4].

Event 1 happened on 08/16/2016 due to the Blue Cut fire. The fire quickly spread towards 500 kV transmission lines and 287 kV lines [2]. This resulted in thirteen 500 kV transmission line faults and two 287 kV line faults. These faults resulted in a significant reduction of solar PV generation. The major event, which occurred at 11:45 am Pacific Time, resulted in a loss of nearly 1,200 MW solar generation [2].

In *Event* 2, two transmission system faults occurred near Anaheim Hills, California, on 10/09/2017 due to the Canyon 2 Fire [3]. The first part of *Event* 2 was a line-to-line fault on a 220 kV transmission line, and the second part was a line-to-line fault on a 500 kV transmission system. In both cases, solar PV generation reduction of nearly 900 MW resulted in a vast region of Southern California being blacked out. In general, many inverter trippings happened due to sub-cycle transient overvoltage and instantaneous protective actions.

Third event (*Event* 3) identified in two parts, happened within a month's time frame. On 04/20/2018, the Angeles Forest disturbance resulted in a line-to-line fault in Southern California. The first part was originated by a L-L fault in a 500 kV transmission line [4]. The second part on May 11, 2018, the Palmdale Roost disturbance also happened in 500 kV transmission line. In both cases of *Event* 3 solar PV resources connected to the bulk power system were tripped in response to the transmission faults [4]. The reasons for inverter tripping were identified as ac under-voltage, ac overcurrent, transient sub-cycle ac overvoltage/current, and dc reverse current [4].

According to NERC the *Events* 2 and 3 are classified as short-duration events at the transmission level that produce waveform distortions [2]–[4]. During these events, several inverters triggered momentary cessation [8] due to sub-cycle transient overvoltages: transients were less than one cycle time

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frame during fault protection and restoration period [2]–[4]. Further, improper response of protection functions, inaccurate low and high-frequency reaction of IBRs, and incorrect ramp rate interactions during the restoration processes were identified as important reasons for these disturbances [2]–[4]. The NERC discussions are focused more on the transmission level, while some information and recommendations are related to distribution level protection. For example, the ride-through capability and momentary cessation (MC) restoration of inverters during transmission level faults could impact the distribution level. The IBRs inject comparatively lower fault current (compared to synchronous generators), which makes it difficult for traditional over current protection to operate properly [9], [10]. In many inverters this current limiting is done using the methodology implemented in inverter control to protect the semiconductor devices in the IBRs.

At distribution level IBRs resources such as solar PV generates multiple power flow directions in the feeder and result in significantly different profile on the feeder compared to the situation which does not contain solar PVs [9]–[13]. In addition, other types of protection issues include desensitization, impacts on fuse saving schemes and fault location impacts which complicate the distribution level fault transient detection and isolation functions. However, these adhoc topics are well discussed in literature and in this review paper primary attention was given to the inverter fault response characteristics. Also, other types of protection schemes such as distance protection are normally not used in distribution systems, since they need additional equipment, complicated network topologies and cost for observing both current and voltage [9]. Therefore, it is important to investigate issues and challenges in distribution system protection with high penetration of IBRs. Further, it is important to have a theoretical foundation for sub-cycle transients using current analytics and study the limitations of current standards on explaining this type of transients with large scale IBRs [14]. The short circuit analysis used during fault analysis gives fault current at a defined time. Next, the applicability of symmetrical component for unbalanced faults requires a defined fundamental frequency in the system during transient. The definition of fundamental frequency during sub-cycle transients is challengeable. Inverter transients generate non stationary signals which contain a changing time-frequency spectrum particularly during fast transients. Therefore, time domain simulations are more popular and provide more details during faults with solar PV resources. This paper will investigate these issues based on the material available in current literature. In section II, the paper will discuss the IBR fault characteristics at distribution level. Then, we present the definitions available in IEEE standards to explain this type of non stationary transient signals, prevailing issues and gaps in understanding. In section III, we will discuss the difficulty and challenges associated with sub-cycle transients. Finally, the impact of the IEEE 1547 standard on IBR faults at the distribution level and smart inverter modeling for transient analysis will be summarized.

II. Fault transients in the distribution system

The solar PV units in distribution levels are connected to the system through power electronic interfaces. The maximum power point tracking action is managed by DC-DC converter control. The inverter unit converts the DC voltage to the required AC voltage. The inverter operates as a current source whose level is dictated by MPPT tracking. When active power is lower than the rated power, reactive power can be injected.

Since an inverter operates as a power regulated current source, it does not maintain constant voltage during system faults [14]. As indicated before, when the number of PV systems on a feeder increases, the characteristics of fault current will be considerably dissimilar than that of the distribution feeder without solar PVs where current analytics have limitations. To understand the picture in detail first we will discuss the nature of fault current characteristics with IBRs.

A. Inverter Current Response during System Faults

In general, the fault response of a grid-tied inverter can be observed as shown in Fig. 1 [13], [14]. It is possible to identify three transient regions soon after the fault occurs namely: initial spike, regulation, and current limited period [14]. Recall the well-known subtransient, transient and steady time periods of a synchronous generator fault transient [7]. The inverter response regions are closely analogous to the synchronous generator three regions. A good discussion and reasons for these three regions are provided in [14].

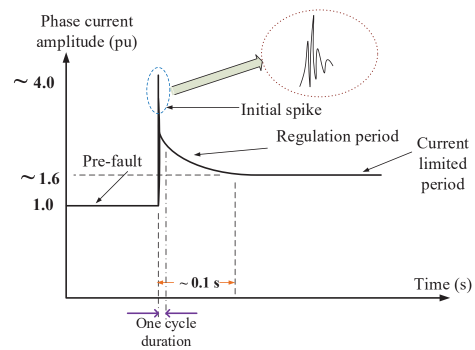

Fig. 1. Typical inverter phase fault current response.

1) Initial spike: Soon after the fault an initial spike of output phase current is observed. The inverter output terminal contains a filter capacitor which is fully charged during prefault time period. Soon after the fault this filter capacitor stored energy is released into the fault showing a larger spike. As [14] reported this spike current instantaneous value jumps to 3-4 p.u of the inverter rated current and lasts only a few hundred microseconds or less. This initial spike magnitude also depends on the fault angle, system impedance and could be a reason for instantaneous tripping of IBRs. This magnitude get shorter, if the fault is created near a zero crossing. This spike is significantly damped in distribution applications by the inductance, transformers, and conductors. However, if spikes exceed a certain threshold, the inverters may have a possibility

to jump to momentary cessation (MC) mode. The equivalent impedance seen from the inverter terminal to the fault location will be a factor for the initial spike's oscillations.

2) Regulation period: The inverter external controls are attempting to regulate the DC link voltage back to a normal level. The time required for this task depends on the speed of the current regulation loop and typically lasts a few milliseconds to as much as 200 ms.

3) Current limited period: In this time period, the inverter phase current approaches nearly to a constant value. This is the maximum fault current that the inverter can inject to a fault. When a fault occurs on a distribution bus, the IBR starts to inject current to the fault following constant power characteristics. As discussed above the PV tries to follow constant power characteristics even under low voltage conditions (which is observed during a fault). If this fault current gets significantly higher than the maximum current rating of the inverter, the power electronics components of the inverter may become damaged. Therefore, by design the inverter maximum fault current is limited to a certain value, which can be handled by the inverter hardware. Thus, for the system fault analysis purposes the maximum inverter fault current from an inverter is generally accepted as a known quantity [14].

The theoretical foundation given above provides a good overview of inverter current response during system faults. However, in real world the actual response of an inverter to a fault may diverge significantly from the above behavior. Some of these factors are summarized in [14] as:

- The initial spike magnitude and time duration will be contingent on system and inverter impedances. This impedance may not always be present.
- In an arcing fault clearing the inverter terminal voltage becomes very noisy and, the inverter output may become nonsinusoidal. Then, the inverter attempts to follow the noisy voltage as the control reference.
- The IBR may stop injecting power at any point during these three periods due to several reasons. Some inverters do not enter the current controlled or power controlled mode due to fast protective mechanisms. These protective mechanisms operate prior to reaching inverter limits.
- This response will also depend on the inverter control strategy and customer requirements.

In the above discussion only a limited attention is given to the in-depth study of sub-cycle transients. A conventional viewpoint, the transient time is very short. According to IEEE 1159, transient waveforms can be categorized based on their characteristic components such as amplitude, rise time, duration, frequency of ringing polarity, energy delivery capability, amplitude spectral density, position with respect to the main waveform and frequency of occurrence [5].

B. Oscillatory transients

The IEEE 1159 defines Impulsive and Oscillatory transients [5], [15]. In oscillatory type transients, the waveform starts to oscillate at a higher frequency for a shorter time frame. The definition used for Oscillatory transients in IEEE 1159 can be summarized as follows: "An oscillatory transient is a quick, nonpower frequency variation from the steady-state of voltage, current, or both, that includes both negative and positive polarity values" [5]. An oscillatory transient includes voltage or current whose instantaneous magnitudes change their polarity quickly multiple times and normally decaying within a fundamental-frequency cycle [5]". This transient oscillation is also called ringing and is explained by its magnitude, time period, and spectral content (mainly frequency that can be used to determine rise time). Oscillatory transients can be analyzed with or without the fundamental frequency information. Therefore, with the transient, it is necessary to label the magnitude with and without the fundamental component. At the distribution level, oscillatory transients can arise due to system faults, equipment switching, capacitor bank switching, ferroresonance, and fast-acting over-current protection equipment. Oscillatory transient frequency at a level higher than 500 kHz is considered as high, while 5-50 kHz as medium and lower than 5 kHz is considered as low-frequency transient [5]. As indicated above, it is possible to view the sub-cycle transient with much higher frequency oscillatory transient or as impulse transient during this period depending on the result of network equivalent inductive and capacitive influences. The time-domain mathematical transformations will help to obtain the time-frequency signal information for these non-stationary fault transients.

C. Harmonics and transient waveform

Harmonics are defined in IEEE 1159 as "current or voltages having sinusoidal frequencies that are integer multiples of the fundamental supply frequency at which the system is designed to operate (termed the fundamental frequency; usually 50 Hz or 60 Hz) [5], [15]. Combined with the fundamental current or voltage, harmonics waveforms will produce distortion in the system. Harmonic distortion occurs mainly due to the nonlinear nature of devices and loads on the power system" [5], [15]. Any nonsinusoidal repetitive waveform can be expanded using the Fourier series (FS) and can be decomposed as the addition of fundamental component and harmonics. Then, the frequency of harmonics content is a direct integer multiple of the fundamental frequency. The impact of harmonic distortion can be characterized by analyzing the spectrum of complete harmonics with their magnitudes and phase angles of each separate harmonic component. Further, it is also common to apply a single quantity, the total harmonic distortion (THD), to quantify the harmonic distortion [15].

III. Sub-cycle Transients and Limitations

The steady-state solution of the power system is analyzed using phasor domain solution, which does not provide any transient stage insight. As discussed before, during system faults in the network, steady-state concepts vanish in the faulty impact region and switch to transients. This could last millisecond to several cycles. For larger transients (lasting several cycles) the system can stay either balanced or unbalanced depending on the situation [7]. The applicability of current methodology used for analyzing faults using short circuit analysis or an unbalanced three-phase system using symmetrical components has limitations for sub-cycle transients. The short circuit analysis technique typically provides information of the system at one instance of time. In the unbalanced three-phase faults the waveform is transformed into a sum of decoupled balanced three phases positive, negative, and zero sequence components, which are known as symmetrical components [1], [7]. These circuits are relatively easy to analyze, and sequence networks are connected at the point of unbalance, depending on the type of fault. Therefore, it is possible to obtain sequence components of the voltages and current of the faults which last several cycles. However, the applicability of symmetrical component-based analysis is challenging and not applicable to sub-cycle transients. During this period, it is challenging to define fundamental frequency components and their amplitudes, which makes it challenging to apply symmetrical components [5], [7]. We anticipate that the complex nature of sub-cycle transient has a significant impact on the performance of system protection and restoration. Another issue with IBRs under sub-cycle voltage transient is the Momentary Cessation (MC): also called blocking, during which no current/power is injected into the bulk energy system. Inverter operating voltage under the MC condition will be $V < 0.50$ p.u, or $V > 1.1$ p.u [8]. When the contribution of inverter-based resources in the power system is dominant, MC will critically affect system stability and protection. MC was originally introduced by inverter manufacturers to limit the fault current injection during the fault period and nature of voltage and current characteristics in MC are shown in Fig. 2 [16]

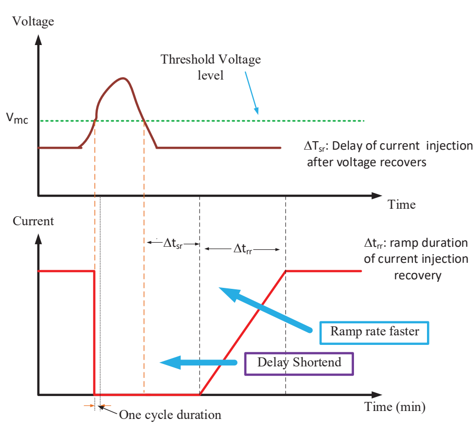

Fig. 2. Momentary Cessation characteristics.

In MC mode the IBR active fault current injection goes to zero if the IBR output terminal voltage is below or above a specified MC threshold voltage. Subsequently, an IBR provides the normal fault current contribution when it is not in MC mode. This concludes that the current contribution of IBR depends on the MC mode control.

A. *Improved standards*

The standard IEEE 1547-2003 was first written for distributed energy resource (DER) generation performance considering a low penetration level of DER. In the past, DER integration level was low and was insignificant for stability and protection studies. In other words, its impact could be removed from the grid without affecting grid stability and protection. However, today we see a significant level of DER integration to the grid. Therefore, the new IEEE 1547-2018 standard included the DER contribution and furthermore included advanced features like smart solar PV inverters. Additionally, the updated IEEE 1547-2018 standard include the following [8], [14]:

- DER's specific dynamic voltage support requirements to control the local voltage.
- More advanced set of conditions of the smart PV inverter which includes voltage ride through, frequency ride through, ramp rate and frequency control.

As indicated before, the PV module disconnects due to abnormal voltages presents at the inverter terminal. The protection scheme implemented in the inverter directly affects the fault current contribution from the inverter. IEEE standard 1547-2018 specifies the conditions for PV module to disconnect when it faces abnormal transient voltages as indicated in Table I [8], [11]. According to this, several features influence PV's fault current contribution, including the momentary cessation (MC).

TABLE I
IEEE 1547-2018:IBR RESPONSE AND TRIP TIME DURING FAULTS.

Terminal voltage (pu)	Time (s) , operation mode
$V < 0.5$	2.0, momentary cessation
$0.5 \le V < 0.88$	21.0, mandatory operation
$0.88 \le V \le 1.1$	−, no trip
$1.1 < V \le 1.2$	13.0, momentary cessation
$V > 1.2$	0.16, trip or may ride through

The IEEE 1547-2018 covers many requirements needed for single inverter integration. The new standard calls for low voltage ride through in the 0.3-0.65 p.u range instead of tripping off at 0.88 p.u, which is intended to result in fewer trip offs of IBRs in transmission faults [4]. However, with future increases in IBR penetration, it is unclear if the new standard is sufficient. Therefore, further studies and experience are required. Typically utilities run studies/simulations to understand how 1547 ride-through capabilities could impact the performances. It is difficult for the legacy inverter (inverters may not have ride through capabilities) to adopt the new standard. Since the new 1547 standard appeared in 2018, it is unclear how much percentage inverters were there with ride-through capabilities in NERC study cases. However, multiple inverters interaction with generation, multi direction power flows, and integration with loads are not well covered in IEEE 1547 particularly in high penetration scenarios [14]. The Standard P1547.8 (recommended practices) was introduced to discuss the expanded use of 1547-2018: innovative designs identification, processes, and operational practices. However, further work is required in standardizing measurement and protection functions, including ride-through requirements, developing requirements, and recommended practices for how voltage measurements and filtering are applied to voltage-based protections [14].

B. Inverter modeling for protection studies

In steady state smart inverter units can be modeled as a generator. The inverter control makes the generator operate in voltage control mode as a PV bus, fixed reactive power mode, or as a constant power factor mode [14]. The dynamic var support provided during these control modes is comparable to those offered by smart inverters. However, the failure to represent transient events including sub-cycle type transients is one major limitation of phasor domain smart inverter modeling [14]. When smart inverters are modeled as generators, the modeling follows the synchronous generator classical modeling: voltage source behind an impedance. This analogy does not reflect the inverter current limitation performance. Lastly, the modeling assumes the system is balanced, and the single-phase equivalent is used to represent the three-phase system. This methodology removes the representation of unbalanced system conditions and the corresponding response [14].

More detailed smart inverter models found in Electromagnetic Transient (EMT) software programs represent transient and dynamic characteristics [14], [17]. These models take into account the power electronics characteristics, DC components, timing of inverter response to events, and control dynamics. Simulation packages such as ATP, PSCAD, PSAT or EMTP use these inverter models for simulations and implement both single and three phase inverter systems [14], [17]. Further, unbalance operation conditions can be implemented. However, the simulation time is a limiting factor for this type of offline simulation packages. The simulation time steps used for the analysis can go simulate transients to the microsecond level, which will bring additional computational challenges and require high computer processing. Also, to model detailed information in the inverter, it is necessary to give extra modeling effort in the packages. Also, the control dynamics are capable of bringing the system to steady state in a shorter time, which is much smaller compared to the offline simulation time [14]. For the best operating performances, it is required to identify the area of interest in the network for EMT modeling. Finally, the unavailability of a universal EMTP inverter model for protection studies is another limiting factor in EMTP simulations.

IV. Concluding remarks

This paper discusses the fault transient characteristics of inverter-based solar resources and their impact on distribution level protection and restoration. The inverter fault current magnitude shows three significant stage variations, including the initial spike during system faults. We highlight the sub-cycle transient characteristics, which has more impact on the protection and restoration of large-scale solar PV integration. As summarized by NERC, three major solar plant interruptions in California exposed the restriction of existing technologies for sub-cycle transient issues. With a review of fundamental fault analysis techniques and following existing standards definitions, we identify the challenges in dealing with sub-cycle transient protection issues at the distribution level. Though the time-domain simulation will be a powerful tool for dealing with transients, it may not solve this type of problem. Therefore, further work is required to understand the real impact of this type of transient on protection and restoration structure at the distribution level. In many inverter operating cases, the sub-cycle transient problem becomes more complicated as shown in California during the protection and restoration period. New research and improved analytics are needed to better understand and define these complicated interactions in the sub-cycle time frame considering inverter dynamics.

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