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Utility Experience with Inverter-Based Resource Impacts on Transmission Protection

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ABSTRACT

High penetration of inverter-based resources (IBR) can adversely affect the transmission protection schemes in the area. With the proliferation of IBRs, utilities are finding out that conventional protection schemes are not adequately equipped to protect the electric systems because the existing system has been designed based on the fault current response of conventional rotating-machine-based generators. In several cases, the available literature does not provide any clear solution for the issues when the protection scheme does not operate properly near IBRs.

This report identifies various protection challenges due to IBRs that industry is facing, from the utility perspective. It includes a broad review of all challenges that system protection has experienced so far with high penetration of IBRs. Key issues have been identified based on a survey of different utility protection engineers. Finally, fault event recordings are shown to demonstrate some actual cases of mis-operations of relays near IBRs.

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ACRONYMS AND TERMS

Acronym/Term	Definition
AEP	America Electric Power
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CT	Current Transformer
DER	Distributed Energy Resources
DFR	Digital Fault Recorder
DFT	Discrete Fourier Transform
EMT	Electro Magnetic Transient
EPIC	Electric Program Investment Charge
ERCOT	Electric Reliability Council of Texas
FIDS	Fault Identification Selection
HIL	Hardware-In-the-Loop
IBR	Inverter Based Resource
IEEE	Institute of Electrical Engineers, Inc.
NATF	North American Transmission Forum
NERC	North American Electric Reliability Corporation
OOS	Out-of-step
OST	Out-of-Step Tripping
PG&E	Pacific Gas and Electric
PMU	Phasor Measurement Unit
POTT	Permissive Overreach Transfer Trip
PRC	Public Resources Code
PSB	Power Swing Blocking
PSRC	Power System Relaying and Control Committee
PTP	Precision Time Protocol
PV	Photovoltaic
RTDS	Real-Time Digital Simulator
SAR	Standards Action Request
SCADA	Supervisory Control and Data Acquisition
SME	Subject Matter Expert
SSCI	Sub Synchronous Control Interaction
SSO	Sub Synchronous Oscillation

Acronym/Term	Definition
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
ZPM	Zero Power Mode

1. INTRODUCTION

US Department of Energy (DOE) issued a funding opportunity announcement in September 2022 through its subsidiary Energy Efficiency and Renewable Energy (EERE) and sought proposals to demonstrate wind and solar plants to provide grid services and improve grid reliability. PG&E in partnership with other organizations submitted the proposal to EERE on the topic of Protection of Bulk Power Systems with High Contribution from Inverter-Based Resources and won the award in September 2023. PG&E partners include ETAP (Software vendor), Quanta Technology (Engineering Consultancy organizations), Sandia National Laboratories (Research laboratory), University of New Mexico (University), and Duke Energy (Utility).

The main goals of this project are to improve short-circuit models for Inverter Based Resources (IBRs), identify protection issues associated with high IBR penetration, propose potential solutions that can be used for wide-area coordination, and create a Sensitivity-Driven Wide-Area Protection (SWAP) coordination analysis tool for systems with high penetration of IBRs.

This report focuses on reviewing the protection challenges that utilities face due to high IBR penetration levels. Instead of focusing on one or two aspects, the report relies on information from various papers, working groups, vendors, and protection engineers to present a wide range of protection challenges with high IBR contribution. As part of data gathering, we collected real fault data for events associated with IBRs and summarized some of the interesting events. We also sent questionnaires to Subject Matter Experts (SMEs) of various utilities, and responses to the questionnaire are summarized in the report.

Based on this report, future work includes improving IBR models, developing protection schemes that mitigate the protection challenges, and developing a software tool to study wide area protection issues.

2. OVERVIEW OF IBR PROTECTION CHALLENGES AND IMPACTS

IBRs exhibit a fault current response that differs from predictable and repeatable fault current characteristics of traditional rotating-machine generators. Conventional protection elements and practices have been specifically designed around the stable fault current profiles of traditional machines, making the integration of IBRs challenging for existing protection schemes. IBR's non-traditional fault current behavior is due to the IBR control scheme. The control scheme is configured to provide a clean AC output, but also protect the inverter's sensitive power electronics devices from damage, one source of which is overcurrent. This results in low fault current magnitude, low or no negative-sequence current injection, the variability of sequence component currents, the variability of voltage with respect to current angles, and the lack of inertia. The control scheme and control settings also result in a fault current response that can vary between manufacturers and between models of the same manufacturer.

High penetration of IBRs can adversely affect the protection schemes applied in areas with high penetration of IBRs. If conventional protection schemes fail to operate during fault simulations, then unconventional protection schemes need to be considered. In several cases, the available literature does not provide any clear solution for the issues when the existing protection scheme does not operate properly near IBRs. These result in protection challenges that are described in the following subsections.

2.1. Modeling Challenges

All protection system studies begin with a thorough fault current analysis. This analysis is essential for specifying the type of protection required for a given system configuration and for developing protective relay settings. Further, fault studies are critical to determine what protection equipment and changes are required and if coordination is maintained after the introduction of a new IBR generation.

As noted above IBR fault current response to system disturbances does not have the same characteristic as machine-based generation and is determined for the most part by the IBR inverter control algorithm. This can vary between manufacturers and between models of the same manufacturer. The most accurate method of modeling IBRs is the Electromagnetic Time-Domain (EMT) modeling in software tools such as EMTP-RV and PSCAD/EMTDC; however, EMT modeling and analysis is not practical for large power systems. EMT tools lack relay models, coordination tools and are not intuitive for usage by typical protection engineers. While various commercial software and technical groups have suggested modeling approaches in the phase domain, these models are based on the control schemes of IBRs for which the data is not readily available from manufacturers. Due to the evolving nature of control schemes and fault current characteristics, there is a need to investigate other methodologies and alternatives for IBR short-circuit modeling.

During unbalanced faults, it appears that loading will affect the IBR short-circuit characteristic which, in turn, could influence how the protective elements operate [1]. Presently, loading is not typically considered in fault current analysis, which can impact fault response during full-load conditions. More research needs to be conducted to investigate the effect of loading and high penetration of IBRs on this modeling approach.

Despite some improvements, there are discrepancies regarding IBR modeling utilizing voltage control current source techniques, and the accuracy is dependent on the IBR manufacturers following the generic IBR fault models. Industry studies indicate that models can have inaccuracies of up to 40% [2].

There is ongoing industry effort by IEEE Power System Relaying and Control (PSRC) Committee, C45 Working Group (protection and short-circuit modeling of systems with high penetration of IBRs), to improve the modeling of IBRs and protection schemes with high penetration of IBRs.

Some of the utilities in Europe are using EMT models to run hardware in the loop (HIL) testing of protection systems and exporting the data into phase-domain protection programs for regular protection engineer work [2]. The interface between time-domain models and commercially available phase-domain model software tools will be useful for the industry.

Pacific Gas and Electric Company (PG&E) has previously utilized its RTDS facilities to test the protection functions in microgrids and to study the ability of IBRs to sense and respond to changes in system frequency.

PG&E and California IOUs have noticed convergence issues when modeling a large number of IBRs and running fault studies in common commercially available fault simulation programs [2]. This issue will become critical with the high penetration of IBRs.

Another issue of IBR modeling relevant to breaker rating evaluation is how to model IBRs during the uncontrolled fault current phase that can take 1-3 cycles. The uncontrolled fault currents can cause erratic magnitude calculations for protective relays until the inverter controls achieve a steady state [3]. This could result in either replacing equipment that is not overstressed, or not replacing overstressed equipment.

Due to the above modeling issues, the North American Transmission Forum (NATF) report on Inverter-Based Resource Interface states "Conventional short-circuit modeling techniques and software available for protection design are of little use in simulating the fault response of IBRs [3]. Utilities have noticed that model verification (whether it is Aspen/Cape or an EMT model) needs to be performed with methods such as HIL testing or using system fault data". For more details see References [4], [5], [6], and [7] .

In the following paragraphs, several of the challenges that IBRs introduce to the protection of the electric power grid are discussed.

2.2. Low fault current contribution

Fault Current is a function of proprietary IBR control schemes, and IBRs limit fault current to protect the inverter hardware. Low IBR fault current presents challenges to phase overcurrent protection because the protection element cannot be set low enough for reliable fault detection. Low fault contribution from IBRs can also result in slow fault clearing or, in the worst case, prevent protection from detecting and isolating faults. Relays at the IBR terminals can have distance element fault detectors not picking up or overcurrent elements not operating correctly.

For overcurrent relays, assume the phase element's pickup is set to a value that is above the full-load condition. Yet, in an IBR-dominated system with lower fault current levels, the calculated pickup current might fall below the load currents. This complicates the relay's ability to differentiate between normal load and fault conditions, especially when the fault current contribution from the IBR is relatively small. This issue highlights that the traditional phase overcurrent scheme may not be reliable in systems with a high IBR penetration.

Additionally, phase overcurrent settings are difficult to determine using steady-state short-circuit analysis because of unknown contributions from the IBRs [1].

2.3. Unavailability or unreliability of IBRs' Negative-sequence quantities

Most of the existing IBR installations inject only positive-sequence currents in response to unbalanced faults. Protective relays widely use negative-sequence quantities for directional control and phase selection of distance applications. The lack of negative-sequence current injection could also result in mis-operation of the direction elements and unbalanced (i.e., phase to phase) faults not being detected or the protection capability for unbalanced faults being significantly degraded. This will become a more significant issue for protection systems with higher penetration of IBRs [3]. In particular, distance protection, negative-sequence directional elements, and polarization may be challenged.

For IBRs that inject negative-sequence current, the current and voltage phase angle must be stable and of the correct value [8]. With the dynamic nature of IBR control and lack of standardization, the response from inverters is not repeatable, and generic models do not represent the actual controls of inverters. Inconsistency in phase relationships between negative-sequence current (I2) and negative-sequence voltage (V2) poses challenges to protection applications.

German VDE grid code has standardized the negative-sequence current injection from inverter-based resources. The German grid code specifies the requirements for the angles of the positive- and negative-sequence current phasors to the corresponding positive- and negative-sequence terminal voltages, addressing the issue of unexpected angular differences between the phasors.

Organizations that manage transmission grids in the US (like CAISO[1]) have not incorporated IEEE Std. 2800 requirements around negative-sequence current during faults but may address in future.

The magnitude of negative-sequence current provided by IBR varies from manufacturer to manufacturer but is always significantly lower than in magnitude produced by conventional sources. To detect such low magnitudes of negative-sequence current, the relays must be set very sensitively, which jeopardizes the security of the protection scheme.

2.4. Challenges with rapid frequency change

For a conventional system, inertia keeps the system stable for 3 seconds or longer [9], which is sufficient for the relays to operate. This is not the case for IBR dominated systems.

Frequency can change suddenly due to low or no inertia of IBRs. This can result in several issues such as high rate of change of frequency, low memory polarization, and accuracy of frequency tracking by numerical relays.

Frequency response of IBR may cause issues with frequency tracking and with high penetrations of IBRs, protective relays may not track frequency accurately and result in protection system errors.

PG&E has observed frequency tracking issues by microprocessor relays when the transmission system separates, leaving only IBRs on the distribution system connected to the isolated electric system. For one incident on a 70 kV system, a sudden frequency shift exceeded the relay's frequency tracking limit and the voltage signal reported by the relay was oscillating which prevented the overvoltage element from operating. When the frequency was calculated by Discrete Fourier

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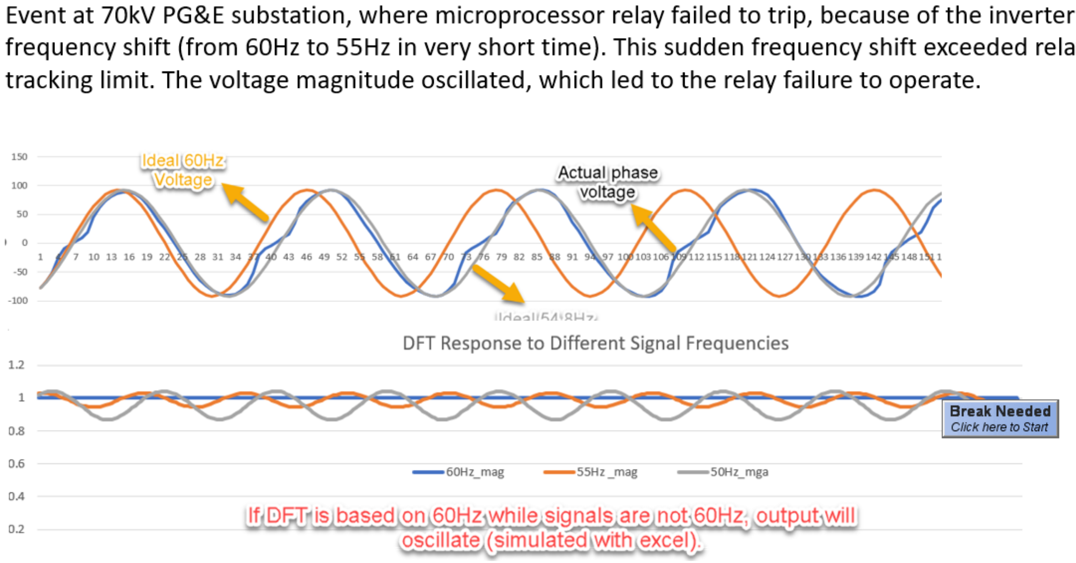
[1] California Independent System Operator

Transform (DFT), the frequency was found to be much lower (54.8 Hz) than the frequency reported by the relay (60 Hz), and the voltage magnitude was stable for the 54.8 Hz signal.

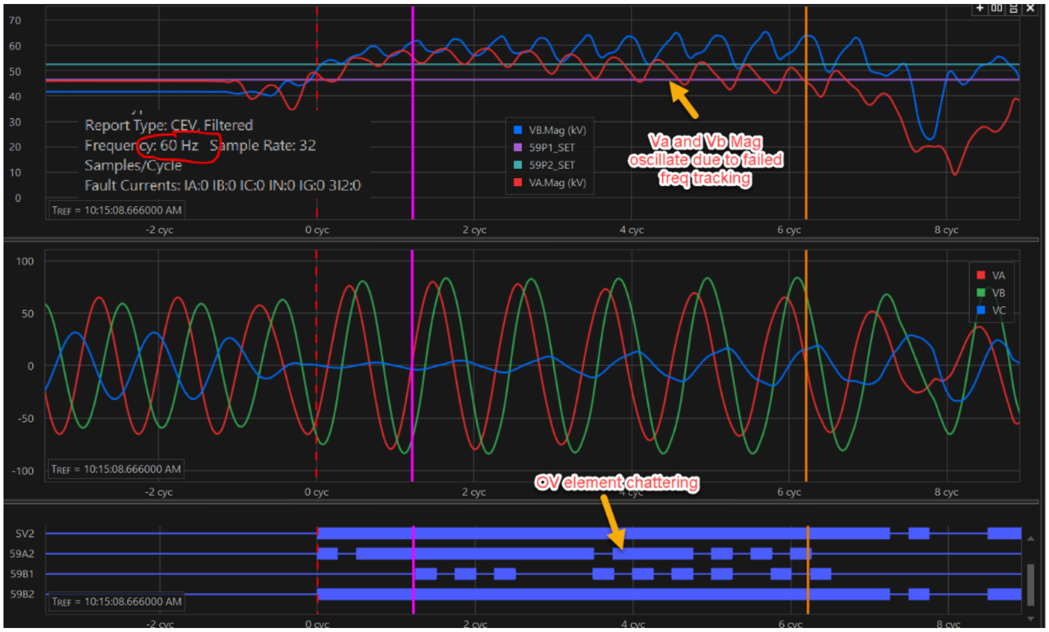
Figure 1 below shows the actual phase voltage and frequency response calculated using the DFT method performed in Excel.



Event at 70kV PG&E substation, where microprocessor relay failed to trip, because of the inverter sudden frequency shift (from 60Hz to 55Hz in very short time). This sudden frequency shift exceeded relay's frequency tracking limit. The voltage magnitude oscillated, which led to the relay failure to operate.

Figure 1. DFT Analysis of phase voltage after a frequency change event recorded by the relay

Figure 2 below shows the voltage signal oscillations that prevent the overvoltage element from tripping. More information can be found in Section 4.9.



Report Type: CEV, Filtered
Frequency: 60 Hz Sample Rate: 32 Samples/Cycle
Fault Currents: IA:0 IB:0 IC:0 IN:0 IG:0 3I2:0

Figure 2. Oscillography from the relay shows overvoltage on the distribution transformer when the transmission system separates.

The inverter frequency measurements have also been found incorrect as they may not represent the true system frequency. Inverters can measure near-instantaneous frequency changes of fault voltage waveforms that do not represent the true system frequency. NERC report on the 2016 Southern California event suggests implementing a minimum time delay for frequency detection and/or filtering.

2.5. Memory Polarization Issue

With conventional sources, memory polarization will expand the mho circle for forward faults and shrink the mho circle for reverse faults. This helps the dependability of protection schemes for close-in faults.

The shift of generation mix to IBR-dominated generation decreases the total inertia of spinning mass connected to the Electric Grid. Memory polarization may not work with IBR sources that have low inertia, and the mho circle will shrink for forward faults and not be able to detect faults. The loss of inertia could result in a mis-operation of the distance elements that use "memory" or "Cross-Phase" polarization. The relatively high source impedance of IBRs and the possibility that the IBR may produce off-nominal current and voltage frequencies may result in an incorrect operation of the memory or cross-phase polarization of the distance element and inadvertent operation of the distance element [3].

Source impedance depends on the IBR control system, the mho expansion can be anywhere on the R-X plane – not necessarily behind the relay. It makes memory polarization unreliable.

2.6. Distance Protection Performance

In systems with a high penetration of IBRs, the angle between memory voltage and the measured fault voltage will be variable because the phase angle relation will depend on the controls of the IBR as opposed to the physics of the synchronous generators. Also, due to the low system inertia associated with IBR, the frequency slip between the pre-fault system and the faulted system may render the use of memory voltage vector invalid. Self-polarized distance relays, on the other hand, will determine the direction of the fault correctly in systems with IBRs, if fault voltage and current are of sufficient magnitude to make phase comparisons. However, these relays most probably will find the polarizing voltage magnitude to be too small to reliably process for comparison in the relay. This is because IBR-dominated systems are weak and have high source impedance behind the relay compared to the impedance of the protected zone.

Most of the phase and ground distance relays are supervised by phase and ground fault detectors, respectively, which are set to pick up under fault currents. The fault detectors will face the same issues as overcurrent elements. For ground distance elements, the unbalanced current magnitude may be close to the minimum current that the ground fault detectors can detect due to low negative-sequence currents from IBRs.

In summary, for the distance elements, (i) the low amount of fault current may prevent supervising fault current detectors from operating resulting in distance element security issues, (ii) lack of negative-sequence current injection by IBRs may prevent the directional element from operating correctly during unbalanced faults which, in turn, can prevent proper operation of the distance element, (iii) dynamic change of IBR source impedance may result in further mis-operations due to memory polarization issues, (iv) inconsistence expansion of the mho circle resulting in reduced reach accuracy and risk of overreach or underreach tripping, and (v) there could be problems identifying the faulted phase for unbalanced faults.

The non-homogeneous phase angle relationship between IBR and remote source impedances negatively impacts the reliability of distance relays too. For more information, see References [9], [10], and [11].

2.7. Faulted Phase Identification Logic

Fault-type identification may misbehave due to currents injected by IBRs. Positive and negative-sequence currents by IBRs during faulted conditions can vary in frequency from the frequency of their respective terminal voltages. The frequency of voltage is determined by the Thevenin equivalent of sources which have infinite inertia and keep the frequency constant. The frequency of current from IBRs is determined by IBRs which have low inertia and may not increase the power to counteract the disturbance and support the grid frequency. This results in unstable frequency for currents from IBRs and unpredictable relationships between zero-sequence current (I0) and negative-sequence current (I2). Fault Identification Selection (FIDS) logic in microprocessor relays identifies the faulted phase for all faults involving ground by comparing the angle between I0 and I2. In these cases, the FIDS logic utilizing I2 and I0 for directional reference determination will not operate properly. This was shown by the study led by Sandia Laboratories using Electromagnetic Transient (EMT) simulations for an unbalanced faulted system with IBRs and then playing back the output of simulations on two relay manufacturer relays. Sandia's study results showed inconsistent fault identification for ABG faults.

The phase distance element (ZP) for a Line-to-Line (LL) element can operate and overreach for a resistive Line-to-Ground (LG) fault. Similarly, the ground distance element (ZG) can operate and overreach for Line-to-Line-to-Ground (LLG) faults. To prevent overreach, the relay utilizes faulted phase identification logic to determine if it is AG fault, or BC fault, or BCG fault. If the faulted phase identification logic is not working properly, there is a possibility that the distant element may overreach.

Faulted phase identification logic is also useful for single-pole tripping and targeting. See References [12], [13], [14], and [15] for more information.

2.8. Directional Element Performance

Directional relays operate by comparing the phase shift between an operating quantity and a polarizing quantity. This is usually done by comparing the phase angles of the operating current and polarizing voltage against the maximum torque line in a plane that has polarizing voltage on the horizontal axis and operating current on the vertical axis. Conventionally, the fault voltage serves as the polarizing quantity, while the fault current acts as the operating quantity. Directional elements can utilize positive-, negative-, or zero-sequence quantities to ascertain the fault direction. In electric grids predominantly comprised of IBRs, the negative-sequence fault response from different IBRs varies from one manufacturer to another, and some IBRs may generate little or no negative-sequence current in response to an unbalanced fault. The phase angle of the negative-sequence current in an IBR with respect to its negative-sequence terminal voltage can remain uncontrolled during the initial 1-2 cycles after the fault inception. This can result in not sensing the directionality of the fault correctly and has caused relay mis-operations in the past, where the relays were polarized by negative-sequence quantities.

For microprocessor relays, it is common practice to use the negative-sequence voltage polarized elements for determining the direction of fault. For a forward fault, the negative-sequence current would lead the negative-sequence voltage, whereas for a reverse fault, the negative-sequence current would lag the negative-sequence voltage. Negative-sequence directional elements are enabled only when the respective sequence current is above a minimum threshold value.

The inverter control system of solar generation and BESS facilities will likely restrict the magnitude of negative-sequence current during unbalanced faults. While Type III wind turbines generate negative-sequence current, the response of this component is unlike that of conventional synchronous sources and is not readily known.

With the uncertainty of negative-sequence response from IBRs, a negative-sequence-current-based scheme cannot be relied upon to provide reliable directional protection. Various analyses of IBR responses for line-to-ground faults have also confirmed that negative-sequence directional elements or current elements cannot be applied to a line connecting an IBR facility to the rest of the grid.

Zero-sequence polarization can be an option for directional elements when negative-sequence voltage or current polarization cannot be applied. Depending on the transformer configuration, zero-sequence currents and voltage can be low for the directional elements. However, thorough analysis is required to make sure that directional elements operate correctly.

See References [1], [12], and [16] for more information.

2.9. Apparent Impedance Oscillations

Negative-sequence current (I2) injected by an IBR may have a different frequency than negative-sequence voltage (V2), and this can result in an oscillatory behavior of distance elements for LG and LL faults. The frequency of V2 is held stable by the power system that has strong inertia, whereas I2 from the IBR is supplied by a source that has low inertia and does not maintain a fully stable frequency.

Due to the unstable behavior of the negative-sequence fault current injected by an IBR, the measured apparent impedance oscillates significantly. In the time-domain fault simulations with IBR models, I2 appears to have a higher frequency than V2. This makes the I2 phasor rotate with respect to V2 (illustrated in Figure 3 below), resulting in a loss of security and dependability for protection elements that use I2. The same behavior has been observed from the relay events that are close to IBR terminals.

Inconsistent I2 frequency causes the following issues for distance protection elements:

- Potential overreach for Zone 1
- Potential underreach for Zone 2

Oscillating impedance can result in potential overreach for Zone 1, causing this protection zone to potentially pick up for a fault outside of Zone 1. Similarly, phase distance element Zone 2 may drop out because of an oscillating apparent impedance resulting in an underreach condition.

Phase distance Zone 1 may also overreach due to CVT transients. This is common for all weak sources and IBRs. See References [9] and [12] for more information.

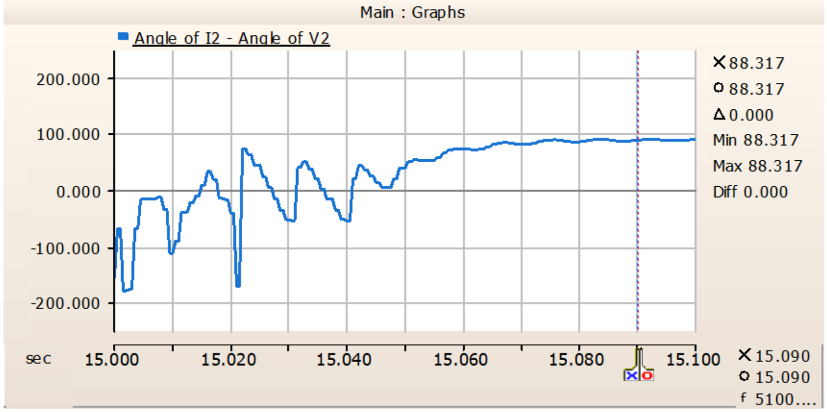


Figure 3. Angle of I2 versus Angle of V2 for an IBR during fault

2.10. Challenges with Type-3 Wind Turbine Generators

Type-3 wind turbine generators (WTGs) have trouble with three-phase (3P) faults since this type of fault decreases the flux in the generator more rapidly over time, and the loss-of-voltage at the generator terminals may adversely impact the frequency of currents injected into the rotor.

A study led by Sandia Lab and NERC[2] in collaboration with inverter and relay manufacturers showed that Type-3 wind turbines behaved well for LG faults, with all relay elements operating reliably. The I2 and V2 are stable during the fault, and I2 had a coherent frequency with other signals, such as V2 and I0, allowing protection to behave reliably. The well-behaved response is due to Type-3 WTGs effectively behaving as an induction generator, depending on the operating point, and the flux in the generator being maintained during the fault. For more information, see [9].

2.11. Uncontrolled Response Challenge

The controlled response of an IBR to a fault is not instantaneous, resulting in a timeframe greater than one power cycle during which the response is not standardized or consistent. On the other hand, due to the criticality of the system protection, relays can respond in this one-cycle timeframe.

For many IBRs, it takes two or more cycles for their control system to respond to a faulty condition and adjust their output currents accordingly. This is the typical time interval during a fault when protection elements are expected to operate. In many cases, this can result in delayed protection response or a relay mis-operation.

2.12. Momentary Cessation or Zero Power Mode (ZPM)

IBRs may exhibit momentary cessation when no current is injected into the electric grid by the IBRs during low- or high-voltage conditions outside the continuous operating range [17]. Momentary cessation can affect the fault current and reliable operation of protection devices, but it can be difficult to incorporate into short-circuit software tools [18]. Design parameters for transmission-connected IBRs need to be established so that they do not exhibit momentary cessation.

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[2] North American Electric Reliability Council

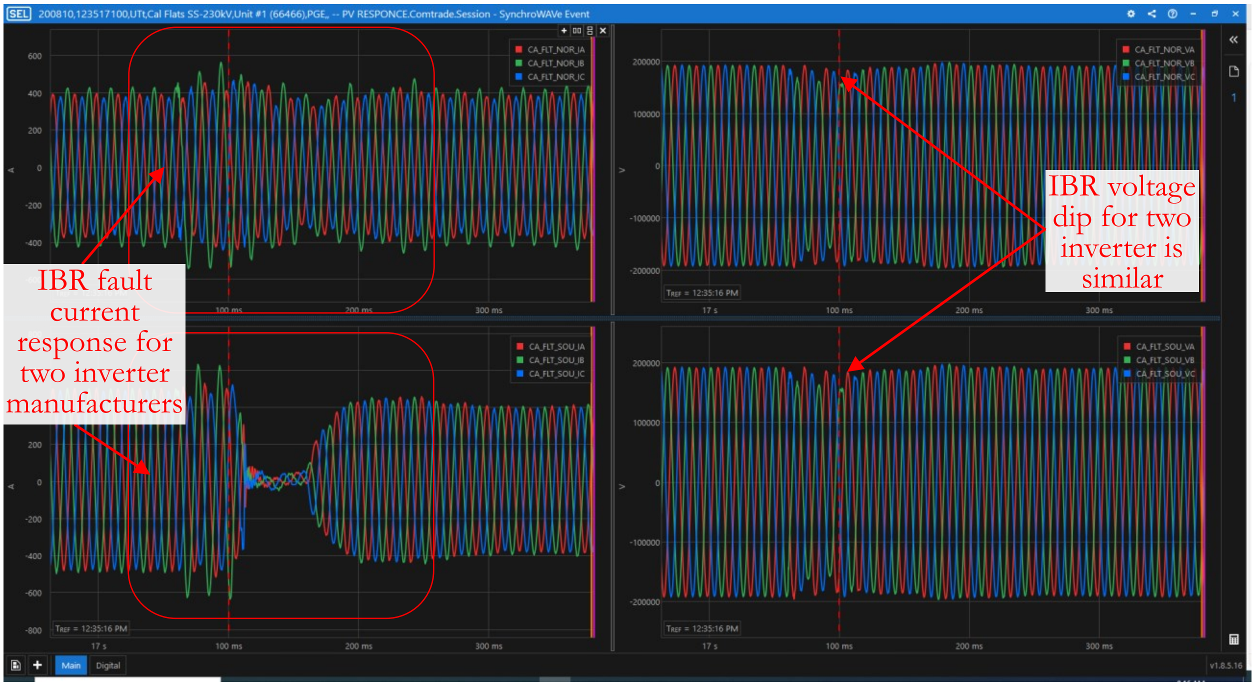
In addition to the loss of generation on the transmission system, frequency drop, and operational stability challenges, the momentary cessation also impairs the functionality of distance (or overcurrent) protection for internal line faults.

For the Blue Cut Fire in California (Southern California 8/16/2016 event) caused by a fault on the 500 kV system, approximately 1200 MW of solar generation was lost, the majority of which was caused by momentary cessation for voltages outside the continuous operating range of IBRs.

After the Blue Cut Fire event, inverter manufacturers recommended changes to the inverter settings to add a time delay to inverter frequency tripping that will allow the inverters to ride through the transient period without tripping or momentary cessation. NERC issued several additional recommendations to alert the industry of the risk of momentary cessation. NERC Standard PRC-029 for frequency and voltage ride-through requirements for IBRs is prepared to add clarity to the frequency and voltage tripping areas for IBRs[3].

During routine fault event investigations, PG&E has seen a few momentary cessation phenomena from IBRs connected to PG&E Electric Transmission System. IBRs from different manufacturers connected to the same transmission bus behave differently in that one manufacturer IBR will exhibit momentary cessation while other IBR manufacturers do not. Figure 4 shows the oscillography for Manufacturer 1 showing momentary cessation while the oscillography for Manufacturer 2 for the same event shows the inverter rides through the disturbance. It should be noted that the inverter started injecting current soon after the voltage returned to the normal range.

California ISO does not allow momentary cessation on transmission-connected IBRs.



IBR fault current response for two inverter manufacturers

IBR voltage dip for two inverter is similar

Figure 4. Relay oscillography for two IBRs connected to the same transmission bus and experiencing voltage dip from an external fault.

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[3] https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-029-1.pdf

2.13. Inadvertent Tripping of Inverters

The NERC Report on the 2022 Odessa Disturbance analyzed the widespread loss of solar PV and synchronous generation caused by a normally cleared fault in Texas on June 4, 2022 [19]. The report detailed how the fault triggered momentary cessation and inadvertent tripping of solar PV resources, alongside challenges in maintaining stable system operations under such conditions.

Inverters may have internal instantaneous overcurrent tripping that is not settable and, thus, they may trip before the AC overcurrent protection of the plant. Additionally, inverters may trip due to PLL loss of synchronism. As such, NERC guidance is that that PLL should resynchronize to the grid within a couple of electrical cycles and should not result in tripping.

There can be multiple layers of protection functions within the inverter that can result in inadvertent tripping. NERC report on detailed findings about Odessa events list several causes of abnormal solar PV performance that include inverter AC overvoltage, inverter DC bus voltage unbalance, incorrect ride-through configuration, PLL loss of synchronism, etc. The report's list of causes includes several cases where the cause was unknown or not analyzed. The NERC report recommends to comprehensively study the event through EMT models of the inverters.

According to the NERC report, inverter instantaneous AC overvoltage tripping is a recurring cause of IBRs connected to bulk electric systems. Current standards of PRC-024-3 (NERC Standard for Frequency and Voltage Protection Settings for Generating Resources) do not solve the problem of instantaneous overvoltage tripping and there is a need for a new compliance standard for transient overvoltage ride-through for IBRs, which is discussed in the latest version of IEEE Std. 2800.

Finally, the NERS report stated that, during the Odessa event, multiple solar facilities tripped for unknown reasons that were attributable to firmware issues. Internal logs were overwritten, and there was no data to determine the cause of the trip.

The challenges posed by inadvertent tripping cannot be resolved by protection settings. Inverter controls are complex and have their own settings that conflict with the ride-through standards. NERC reports on major events (like Odessa events in 2021 and 2022) involving IBRs show that protection relay settings have been unable to stop these events. In addition to Standards, Testing procedures need to ensure that IBRs do not trip inadvertently. Protection settings would then be coordinated with the updated standards.

2.14. Fault ride-through issues:

There have been several cases where IBRs tripped for out-of-zone faults. This has resulted in unnecessary loss of generation, making the electric grid vulnerable to cascaded outages. Protection scheme security is required to ensure that IBRs stay online for external disturbances.

Existing NERC voltage and frequency ride-through standards (PRC-024-3) are not adequate for ensuring IBRs remain connected and support the electric grid during disturbances. NERC accepted the Standards Action Request (SAR) in 2023 to modify PRC-024-3 or replace the standard with a performance-based frequency and voltage ride-through standard (PRC-029) that ensures that the generator remains connected to the Bulk Power System during system disturbances. NERC is also developing a standard for Disturbance Monitoring and Reporting Requirements for IBRs (PRC-028) and a standard for Unexpected IBR Event Mitigation (PRC-030). These three standards would support IBR ride-through and help reduce inadvertent trips that are affecting the reliability of the electric power system.

2.15. Issues with POTT schemes

POTT scheme often uses either directional ground distance or directional zero-sequence overcurrent or directional negative-sequence overcurrent relays for ground fault detection. Mis-operation of the directional elements (67N, 67Q) and or phase distance elements can result in a mis-operation or non-operation of the pilot scheme. 67Q element may malfunction due to either low negative-sequence current magnitude or changes in angular relation of V2 and I2 (see Section 2.3 for details).

Due to unreliable negative-sequence current from the IBR, the relay located near the IBR may not detect the directionality of fault correctly and could result in a mis-operation. For example, the impacted relay can see the fault in front of the relay as a reverse fault and fail to send the permissive trip signal, resulting in the remote relay not tripping for an in-section fault. Another example could be that the relay near the IBR facility incorrectly sends an echoed back permissive signal because it had failed to detect the reverse fault [1].

2.16. Issues with Blocking Schemes

Line relays near the IBR facility may have difficulty in sensing faults on its line due to low levels of fault currents produced by IBRs. As a result, DCB scheme may have difficulty in detecting line faults due to the low IBR current value. This could result in a blocking signal not being sent to the remote end, resulting in a subsequent trip of the remote end and loss of the line.

2.17. Challenges with Power Swing Protection Schemes

An increased footprint of IBR within a region significantly reduces the regional inertia that challenges the reliability of the existing power swing blocking or out-of-step protection systems.

Simulations of a test system show that the power swing relay successfully detected stable and unstable power swings under synchronous generation scenarios. However, when synchronous generation was replaced with wind generation, the power swing protection failed to detect the power swing and did not issue a power swing blocking (PSB) signal [1]. In another test case, the impedance trajectory reversed direction and the relay mistakenly declared an OOS condition and issued an OST signal.

Conducted simulations show that IBRs affect both the rate of change of the swing impedance and the swing trajectory and can impact the operation of both PSB and OST [1], resulting in mis-operation of these protection elements.

2.18. Interactions of IBR with Series Compensated Transmission Lines

The control system of an IBR, particularly Type-3 wind generation, can interact with a series compensated transmission line to create a sub-synchronous oscillation (SSO) phenomenon, which is often categorized as sub-synchronous control interaction (SSCI).

There were three reported SSCI events in 2017 on the AEP transmission system within ERCOT. All three events started after wind farms were radially connected to series compensated transmission lines after adjacent transmission lines outages [1]. The sub synchronous oscillations were around 22 to 26 Hz.

The quickly rising voltage and current magnitude from the oscillation can damage primary equipment including series capacitor banks, synchronous generators turbine shafts, power transformers, etc. Most relays operate on the fundamental frequency and are slow to act for current and voltages with a sub-synchronous component [1].

2.19. Unintentional Islanding

Unintentional islands can cause safety hazards and power quality issues that are detrimental to the customers served by transmission owners and operators. Special protection schemes (automatic anti-islanding schemes, direct transfer trip, etc.) and operating procedures are required to separate the generation sources forming the island. These anti-islanding schemes are expensive to install and maintain.

Inverter-Based Distribution Energy Resources (IB-DERs) have onboard/active anti-islanding detection mechanisms, which can disconnect them in 2 seconds after the grid separates. These methods work to actively perturb the frequency or voltage of the IBR, which is stable when connected to the system. When the IBR is disconnected from the system the perturbation results in a frequency or voltage trip. Due to this instability characteristic, most of the IBRs on transmission do not have active anti-islanding detection, and there is a concern that active anti-islanding on transmission may impede LVRT capabilities and produce power quality issues.

2.20. Large amount of IBRs on Distribution affecting the Transmission

High penetration of IBRs on the distribution system can also introduce some unique challenges to the transmission system, including high voltages under unbalanced faults, high phase voltages during LG faults due to neutral shift, ferro-resonance, transformer overloading, and unintentional islanding. The aggregate total amount of Distribution Energy Resources (DERs) may become significant enough to affect the transmission system protection, and DERs may contribute fault current to transmission line faults. During the design of Protection schemes, the impact of distribution connected DER on the transmission needs to be evaluated.

Distribution-level generation has historically not been modeled in the transmission for fault studies. With the shift in generation to distribution, utilities must figure out how to model distribution generation for fault studies on transmission. This shift requires utilities to adopt methodologies and tools that effectively model the impact of DERs on fault current levels, relay coordination, and overall system stability to ensure accurate and reliable fault analysis.

DERs connected to ungrounded transformers can result in overvoltage of the transmission system and interconnected equipment during Single-line-to-ground faults after the remote transmission breakers have opened to clear the fault. The interconnected transmission equipment that is normally subjected to phase-to-ground voltage will be subjected to phase-phase values on the healthy phases. Transformer bushings, lightning arrestors, and insulators must be checked to verify that they can sustain phase-phase voltages. If required, a ground fault overvoltage scheme could be installed on the transformer's high side, tripping the station feeder breakers to separate the transmission equipment from the DERs. This may require the installation of a new voltage transformer.

Large amounts of DERs can result in power flow from distribution to transmission and in some cases overload the distribution transformers. If required, reverse power relays can be installed to protect the transformers from damage or measures are applied to limit the generation from DERs.

3. PERSPECTIVE FROM UTILITIES ON ISSUES TODAY

A questionnaire was developed to gather information from subject matter experts (SMEs) of different utilities about protection challenges, modeling approaches, and fault responses and to discuss ideas on how they foresee solving the problem that higher penetrations of IBRs will pose in the future. A similar gap analysis and expert interviews was published with a focus on grid-forming inverters [20]. Questions and their responses are compiled here to see the current practices and how utilities foresee in future.

Participating utilities include AEP, TEPCO, SDGE, SMUD, Duke Energy, and Southern Company

3.1. How are you modeling IBRs for Fault duty and Protection studies?

- Utilities are modeling the IBRs as synchronous machines and adjusting the R, X and/or current limits of the synchronous machine models. Utilities have tried newer modeling methods introduced by fault simulation software vendors (like Aspen and Gridscale X Advanced Protection Assessment (formerly PSS®CAPE) – referred to as APA-CAPE in this report) but have moved away from using the new methods because these models are still evolving. One of the issues with newer model types like voltage-controlled current sources is that newer model types are removed when reducing the network or providing a Thevenin equivalent. For the neighboring utilities, it is common to exchange the Thevenin equivalent with each other, and utility companies need the ability to reduce the network. One utility complained that Type 4 shuts down in software (due to convergence issues).
- Some utilities are adding tags to generators and distributed sources to identify what type of generation is being modeled. This allows the generator of a particular type to be toggled off/on in the future.
- One international utility is using EMT analysis tools for modeling IBRs and doing plant-level studies.

3.2. Have you established guidelines for modeling Type 3, Type 4 wind turbines, PV plants, and Battery Energy Resources for the above studies?

- Some Utilities have not established any guidelines for modeling IBRs, some rely on the software vendor (like APA-CAPE or Aspen) to establish guidelines, and some have established guidelines and are adopting to the evolving models.
- One utility is not modeling wind turbines as sources. There are also questions about modeling the generation source as both PV and BESS.

3.3. What are the protection challenges that your utility is currently facing with IBRs interconnecting your Transmission system?

- Absence of fault current, when the IBR is on a radial feed, is a big challenge. Utilities are applying current differential or direct transfer trip.
- Utilities with compact systems (i.e. short lines) that presently require line current differential protection are not facing issues.
- Based on one response, when anti-islanding detection is enabled for IBRs, voltage flicker has resulted. There is also a concern that in case of fault on a transmission with multiple IBRs,

once the transmission circuit breakers will open, the multiple IBR anti-islanding detection relays/elements may interfere with each other.

- IBRs can continue to generate power during grid outages. This poses an anti-islanding risk, where the IBR unintentionally operates as an unintended islanded.
- During disturbances, IBRs may experience momentary cessation or trip offline if voltage or frequency deviates significantly (IBRs are sensitive to grid voltage and frequency variations).
- IBR's controls often suppress the injection of unbalanced currents during faults, which renders negative-sequence components used for fault detection undependable.
- With IBRs interconnecting to the Transmission system, the utility is relying on transfer-trip-based anti-islanding protection which has been challenging to implement, especially when there is a series of ring buses between two network sources.
- Some utilities are running protection studies based on peak cases, i.e., all generation online. With higher penetration of IBRs, utilities may want to analyze protection performance for off-peak cases.

3.4. What are the protection challenges that you foresee in future with high penetration of IBRs?

- There is concern with high penetration, that system fault current will decrease, and conventional protection schemes may be degraded or in the worst case do not operate. SMEs think that synchronous generation will still be required for existing protection philosophy that relies on impedance-based protection or overcurrent protection.
- Utilities will have to employ current differential across the system on all lines. However, this is not being investigated and we don't know what kind of redundancy in communication would be required to make that work reliably.
- Utilities with large hydroelectric facilities may have less adverse impact from high penetration IBR. Hydroelectric facilities provide inertia and fault current and reduce the impact of IBRs.
- IBRs may not be capable of generating sufficient negative-sequence fault current with guaranteed angles. Consequently, this desensitizes protection functions reliant on negative-sequence components, such as polarization units in distance relays, which carries over to communication-aided protection schemes, such POTT and DCB schemes.
- High penetration of IBRs in power systems create weak systems prone to fast power swings. Conventional distance relays may be susceptible to these fast power swings, potentially causing overtrips. They can generate off-nominal fault currents which are filtered out in the relays. These off nominal currents or voltages can be dangerous to the system but will not be detected by relays due to filtering.
- Commercialized short-circuit software such as CAPE and ASPEN, commonly used in utilities for protection coordination and breaker rating studies, lack a comprehensive IBR model. This deficiency introduces several uncertainties in grid operation and planning.
- Utilities see protection challenges with higher IBR penetration, but they cannot quantify them due to modeling challenges.

3.5. Do you receive the events from IBRs facilities, and do you analyze them?

- Utilities are not analyzing IBR responses for all the events. It has to do with the timeliness of the event retrieval process, effort and coordination required to get the event from the IBR generation owner. There is also lack of industry standard for fault event data retrieval for IBRs.
- One utility observed that upon request, IBR generation owners will provide records. However, record retrieval may take a long time. PRC-030 should address the fault record issues with the timeliness of records.
- Utilities are not receiving events from the IBR facilities and have hard time capturing anything of significance with their DFR and PMU infrastructure.

3.6. Do you analyze IBR events? Any interesting events to share?

- Utilities have seen some sub-synchronous oscillation issues, one utility observed interesting oscillations soon after commissioning of IBR plant that needed mitigation along with interactions with an adjacent combined cycle gas-powered large generation facility.
- There have been cases of IBRs going offline for system disturbances many buses away. Utilities have also observed that at night solar plants are not contributing any fault current (it could be a setting in the inverters).
- Utilities have observed some cases where momentary cessation was observed.

3.7. What are the things that you would like the industry to focus on with higher IBR penetration?

- Timely retrieval of fault records
- Lack of SCADA data form IPPs
- Synthetic inertia capability from BESS
- Negative-sequence current injection during fault conditions.
- Developing accurate and efficient short-circuit models for IBRs, considering their fast dynamics and interactions with the grid. Modeling in traditional short-circuit programs is the highest priority for another utility.
- Understanding performance of traditional protection schemes in high penetration IBR systems is next in line (after modeling).
- With higher penetration of IBRs, the overall strength of the Bulk Power System decreases. More research and development are needed around advanced protection schemes tailored to IBRs to ensure grid stability and reliability.
- Researching backup protection measures like undervoltage safeguards and zero sequence overcurrent elements to mitigate risks associated with IBRs, especially during communication failures or fault conditions.

3.8. What items would you want Inverter Manufacturers to support or provide for higher IBR penetration?

- Model information comes very late from the manufacturers. This causes delays with the Short-Circuit studies and relay settings.

- Inverter manufacturers are reluctant to share the model with utilities. It is difficult to obtain time domain models (PSCAD models) or phasor domain models unless non-disclosure agreement is signed. This can take a long time. Time domain models are needed to validate phase domain model data.
- Inverter Manufacturers provide accurate EMT models.
- Inverter manufacturers should collaborate with ASPEN and CAPE to develop a comprehensive and reliable Inverter-Based Resource (IBR) model for short-circuit and protection coordination studies. Additionally, they should provide the necessary data required to accurately model IBRs in these software platforms.

3.9. Have you observed any differences in the fault response for BESS during charging and discharging modes?

Normally, the failure response in charging mode is thought to be delayed. However, we have also confirmed cases where there is no difference in failure response between charging and discharging modes.

3.10. In your short-circuit model, do you currently model load? Do you model cap banks, shunt reactors, or other forms of reactive support (e.g. SVC, STATCOM)?

Utilities are not modeling load in the fault simulation software. One utility is modeling cap banks and shunt reactors. One utility has started looking into modeling loads and shunt reactive devices with mixed results.

4. ANALYSIS OF FAULT EVENT DATA FROM IBR

PG&E collected events from the relays on the transmission lines connected to IBRs and reached out to other utilities to share relay events for studying IBR response to faults.

PG&E applied sensitive undervoltage triggers to relays on transmission lines connected to IBRs. Sensitive triggers allowed capturing the relay events for external faults even when the relay did not call for a trip. We found some interesting events when the IBR response varied from one manufacturer to another and provided some insights into the IBR behavior during voltage fluctuations.

Other utilities shared the mis-operation events and other interesting events. Analyzing the events proved that protection challenges are real, and utilities are experiencing protection issues on lines that connect IBRs to the transmission system.

4.1. Event 1: 160MW Solar Facility

A relay is located at the remote end of a Solar facility tie line. The fault occurs between Station A and Station B (reverse fault for the relay at Station B looking towards the Solar facility). A simplified single-line diagram with the fault location is shown in Figure 5 below.

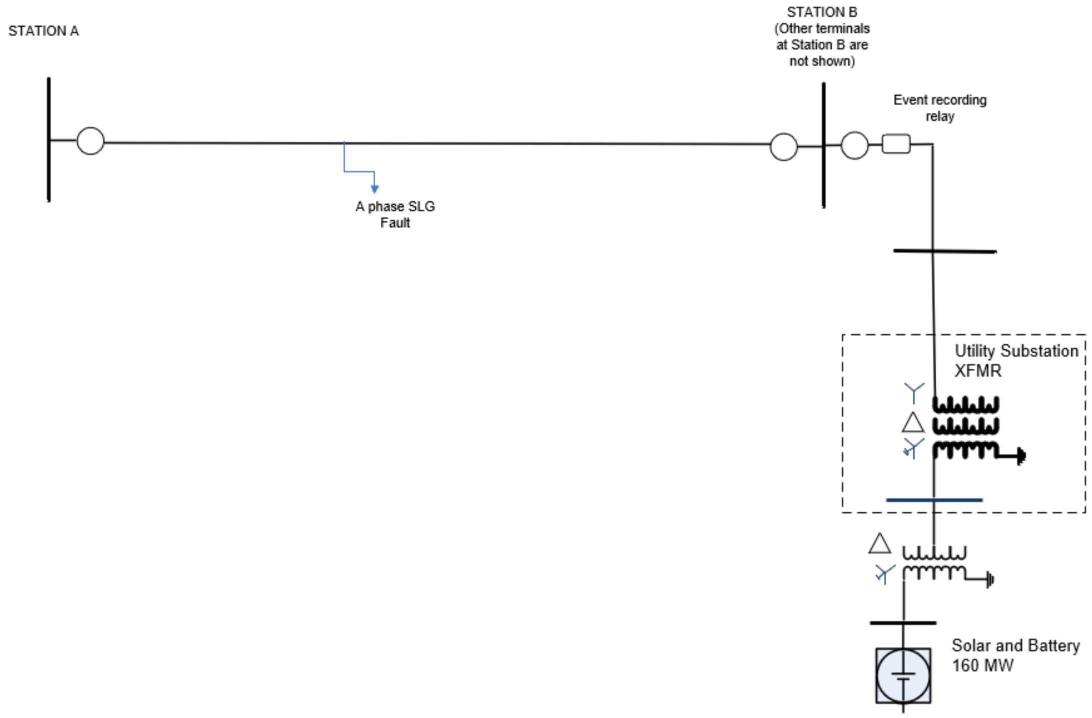


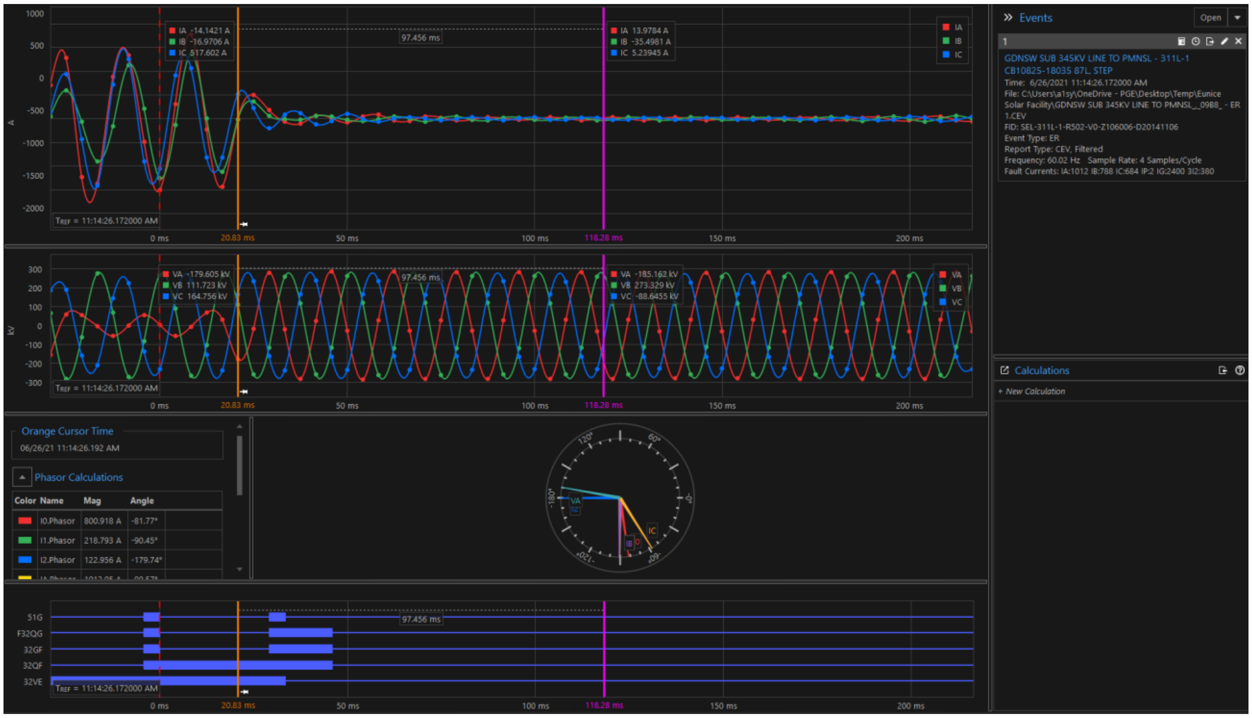
Figure 5. Single-line diagram showing a 160 MW solar facility, location of Event 1's recording relay, and location of the fault

Issues Observed:

- Relay momentarily showed forward fault for a reverse fault based on the negative-sequence directional elements.
- Relay was not able to identify faulted phases.

The above two issues can also be attributed to unpredictable negative-sequence current. We looked at the relay settings and directional priority was set to prefer negative-sequence voltage. Relay initially declared the forward fault for a fault occurring in the reverse direction. Zero sequence directional element did not declare the forward fault.

An unstable relationship between zero and negative-sequence currents (I0 and I2) was shown in this case, and the relay under study was unable to determine the faulted phase.



1

GDNSW SUB 345KV LINE TO PMNSL - 311L-1
CB10825-18035 87L, STEP
Time: 6/26/2021 11:14:26.172000 AM
File: C:\Users\a1sy\OneDrive - PGE\Desktop\Temp\Eunice Solar Facility\GDNSW SUB 345KV LINE TO PMNSL_,_09B8_ - ER 1.CEV
FID: SEL-311L-1-R502-V0-Z106006-D20141106
Event Type: ER
Report Type: CEV, Filtered
Frequency: 60.02 Hz Sample Rate: 4 Samples/Cycle
Fault Currents: IA:1012 IB:788 IC:684 IP:2 IG:2400 3I2:380

Orange Cursor Time
06/26/21 11:14:26.192 AM

Phasor Calculations

Color	Name	Mag	Angle
🟥	I0.Phasor	800.918 A	-81.77°
🟩	I1.Phasor	218.793 A	-90.45°
🟦	I2.Phasor	122.956 A	-179.74°

Figure 6. Oscillography from the Event 1 recording relay

32QF = Asserted

32QR = Asserted

Figure 7. Phasor diagrams (V2 and I2) plotted from the oscillography of Event 1’s recording relay

4.2. Event 2: Wind power plant end relay (145MW Type-IV WTG)

As seen in the below figure, the relay is located at Station A (on the high-voltage side of the substation transformer). In addition to the contribution from wind turbines, the relay is seeing the zero-sequence contribution from the system through a Y/D/Yg transformer.

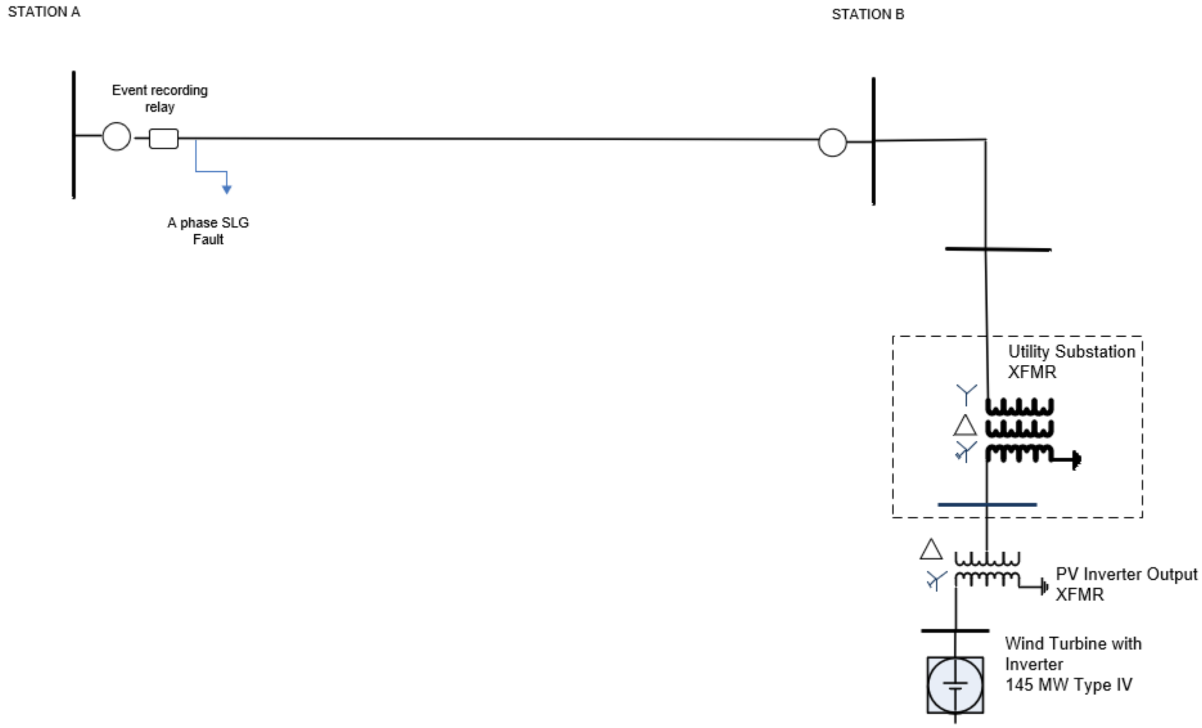


Figure 8. Single-line diagram showing a 145 MW Type IV wind turbine, location of Event 2's recording relay, and location of the fault

Issues observed:

- Relay incorrectly reported s CG fault for an AG fault.

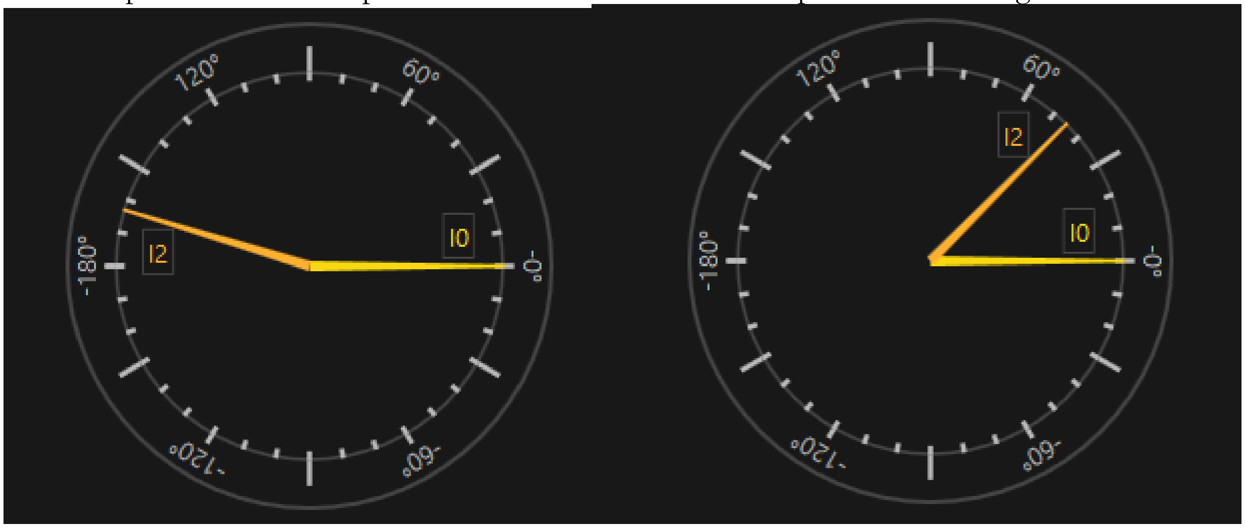
The angle between I0 and I2 is seen rotating during the event. I0 is contributed from the system (through delta winding of the transformer) and is stable whereas I2 is contributed from the IBR (Type-IV WTG) and has unstable frequency. This results in an unpredictable and changing angular relationship between I0 and I2. Fault identification selection (FIDS) logic utilizes I2 and I0 for directional reference and does not operate properly as shown by the event below.

1

Station HACKBERRY - SEL421-1
Time: 3/20/2021 10:43:20.828000 PM
File: C:\SEL\IBR Fault Events-NATF\Cookfield Rd to Hackberry Wind IPP - 03-20-2021\Hackberry Wind IPP\C4_32992.CEV
FID: SEL-421-2-R123-V0-Z010010-D20070223
Event Type: CG
Report Type: CEV, Filtered
Frequency: 59.99 Hz Sample Rate: 4 Samples/Cycle
Fault Currents: IA:747 IB:944 IC:571 IG:2173 3I2:151

🟥	IA.Phasor	802.612 A	-13.33°
🟩	IB.Phasor	942.737 A	-50.08°
🟦	IC.Phasor	597.633 A	-60.86°
🟨	I0.Phasor	734.637 A	-40.45°
🟪	I1.Phasor	290.673 A	54.44°
🟧	I2.Phasor	76.5006 A	46.17°

Figure 9. Oscillography from Event 2's recording relay near the IBR


I0 and I2 phasor at fault inception

I0 and I2 phasor at later stage of fault

Figure 10. I0 and I2 phasors plotted from Oscillography from Event 2's recording relay

4.3. Event 3: 1.96 MW Solar Facility

The relay is located at the remote end of a Solar facility tie line. The solar facility is connected to distribution (34.5 kV), the event is shown to illustrate an issue that is common for IBRs connected to transmission with limited negative sequence current. The fault is between Station A and Station B. There is no positive-sequence or negative-sequence contribution from IBR as seen from the event. The only contribution is zero-sequence current, and it is from the tertiary winding of the step-up transformer. Most likely, the event happened when there was no sun (relay recorded 4:56 AM on 1/2/2022).

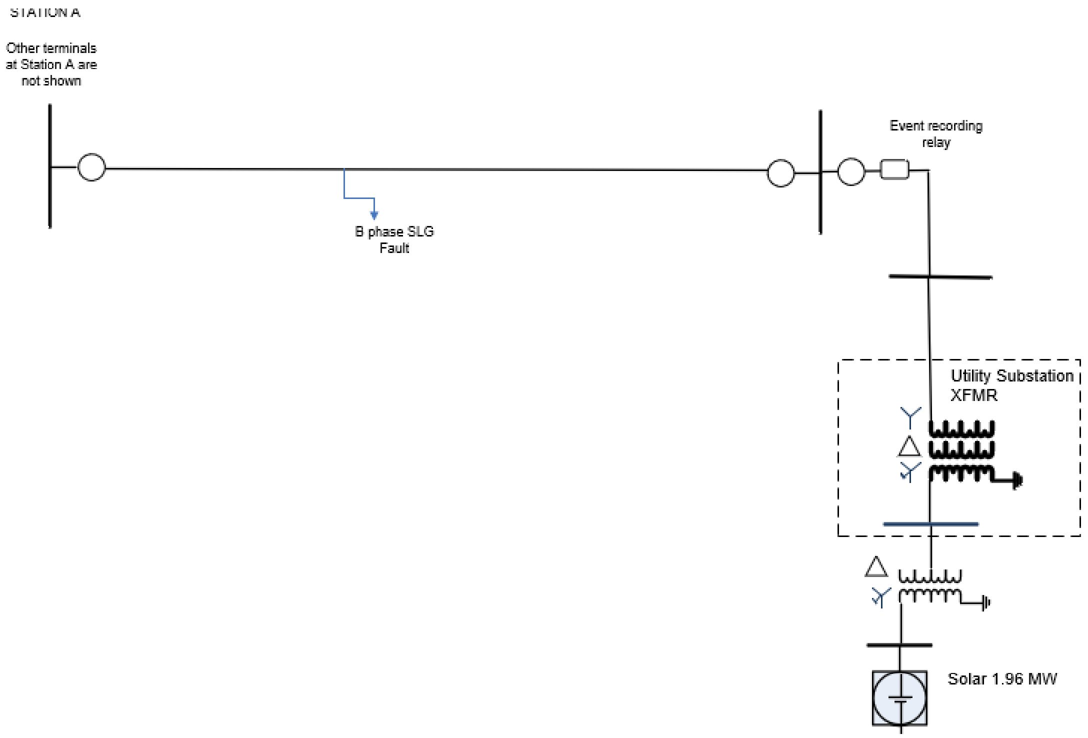


Figure 11. Single line diagram showing 1.96 MW solar facility, Event 3's recording relay, and location of the fault.

Issue observed:

- Relay was not able to determine the faulted phase.

In this case, the relay is not able to determine the faulted phase because of the absence of positive- and negative-sequence currents.

1

RLKSW 138kV Line to Oberon - SEL-421-4 2CB DCB MB for CB17185-17190
Time: 1/2/2022 4:56:41.691000 AM
File: C:\SEL\IBR Fault Events-NATF\Red Lakes to Moss - 01-12-2022\Red Lakes CB 17185-17190 to Oberon Solar IPP \SEL-421-4 2CB DCB MB FOR CB17185-17190_,_0AD2_SEL-421-401_02_202204_56_41_691_500.CEV
FID: SEL-421-4-R317-V0-Z020013-D20131231
Event Type: ER
Report Type: CEV, Filtered
Frequency: 60.01 Hz Sample Rate: 4 Samples/Cycle
Fault Currents: IA:482 IB:484 IC:475 IG:1440 3I2:5

🟥	IA.Phasor	441.742 A	-120.52°
🟩	IB.Phasor	445.405 A	-122.26°
🟦	IC.Phasor	435.409 A	-121.6°
🟨	I0.Phasor	440.818 A	-121.46°
🟪	I1.Phasor	6.77566 A	-47.76°
🟧	I2.Phasor	1.28297 A	22.44°
🟦	V2.Phasor	15.7098 kV	-163.83°
🟫	V1.Phasor	67.6096 kV	-128.16°

Figure 12. Oscillography of Event 3 from the relay located close to the IBR

4.4. Event 4: Mis-operation of protection scheme for Interconnection lines connecting a Solar system to a 230 kV transmission system

In another event shared by a utility, mis-operation of the interconnection line protection resulted in the separation of IBRs and activation of the anti-islanding protection scheme. Figure 13 below shows the single-line diagram of the IBRs connecting to the transmission line through Switching Station C.

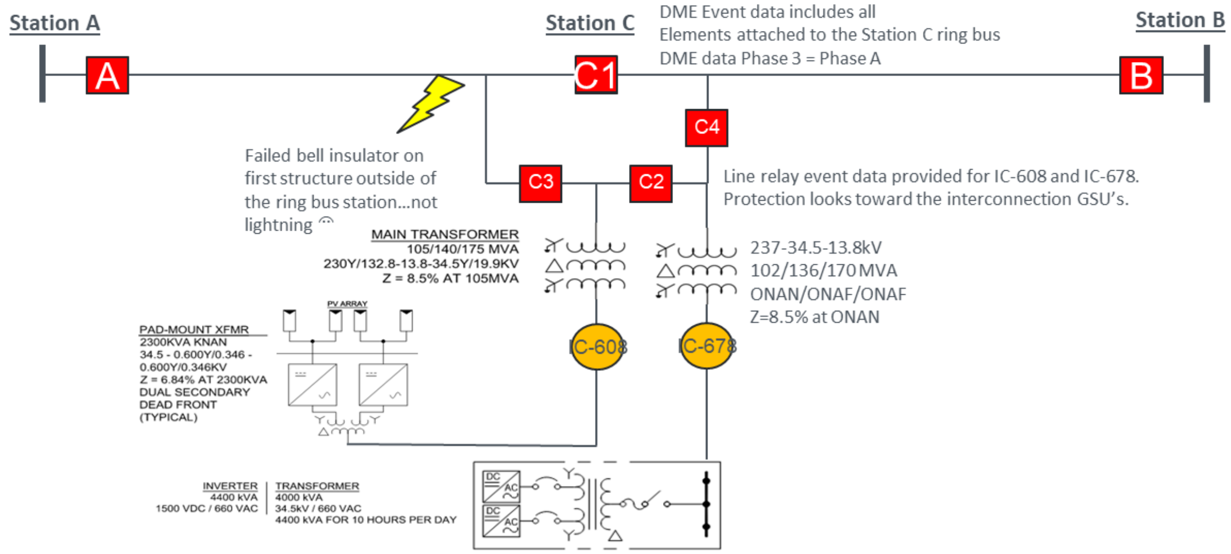
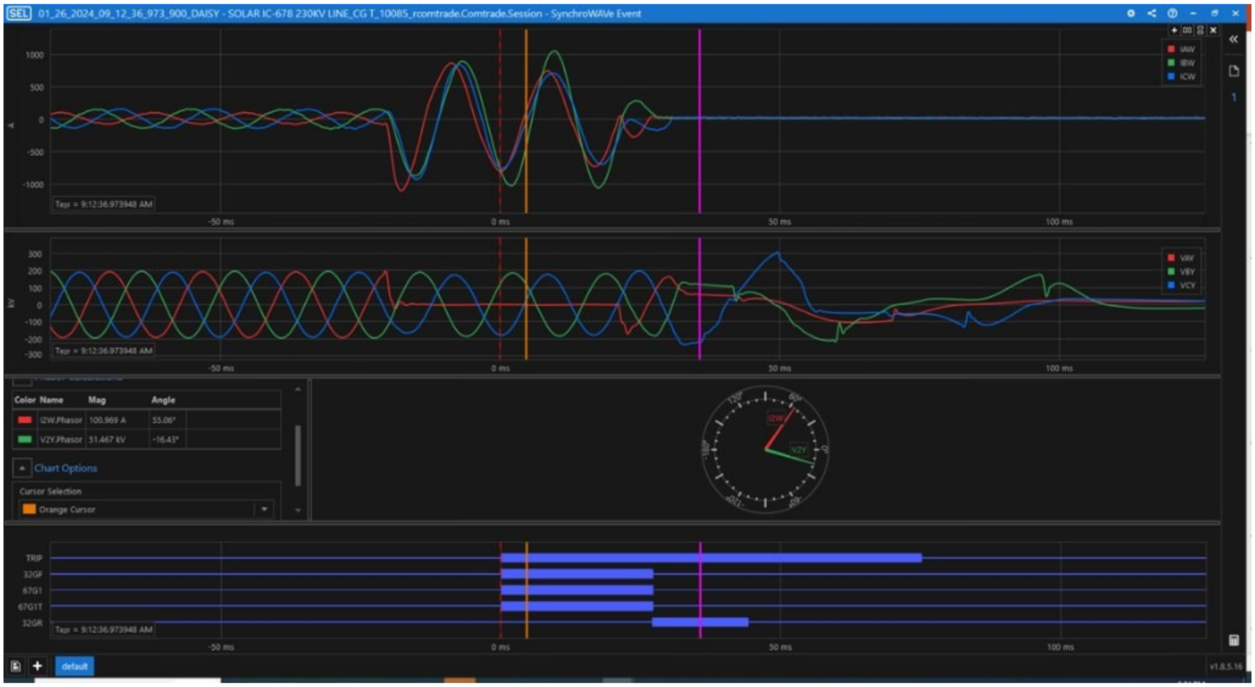


Figure 13. Single line diagram of the system in Event 4


SEL 01_26_2024_09_12_36_973_900_DAISY - SOLAR IC-678 230KV LINE_CG T_10085_rcomtrade.Comtrade.Session - SynchroWAVe Event

Color	Name	Mag	Angle
🟥	I2W.Phasor	100.969 A	55.06°
🟩	V2Y.Phasor	51.467 kV	-16.43°

Chart Options

Cursor Selection: Orange Cursor

Figure 14. Oscillography of Event 4 from the relay located close to the IBR

At the time of fault, around 35MW of generation was being injected into the transmission from each solar interconnection. A close-in AG fault happened on the 230 kV line between Station C and Station A. The protection relay(s) on the 2 interconnection lines, that connect the Solar facility to Station C, misinterpreted the fault as a forward fault and tripped breakers C2, C3 and C4 for an out-of-section fault (reverse direction). The IBR contribution to the AG fault lasted 3 cycles. Protection on Station C – Station A operated correctly.

The mis-operation of the interconnection line protection resulted in all four breakers at Station C to open, which activated the anti-islanding trip scheme.

Analysis of the oscillography showed that negative-sequence current from IBR was inconsistent and contributed to the relay wrongly determining the fault as a forward fault, whereas the fault was in the reverse direction. Another interesting observation from this event was that the relay did not pick up the overcurrent and directional elements for the first two cycles of the fault when the fault current was not stable.

4.5. Event 5: BESS Event showing fault response during charge mode

In this case, the BESS was initially in charge mode. A CG fault occurs on the 115 kV system that the BESS is connected to (please see the single line diagram below in Figure 15). During the fault, the system configuration changed, leading to the modified behavior of the plant controller as it adapts to the new system configuration (the remote end opens). While it is necessary to perform longer simulations considering system configuration changes to study the inverter response, the initial assessment indicates variations in the fault current contribution from the IBR.

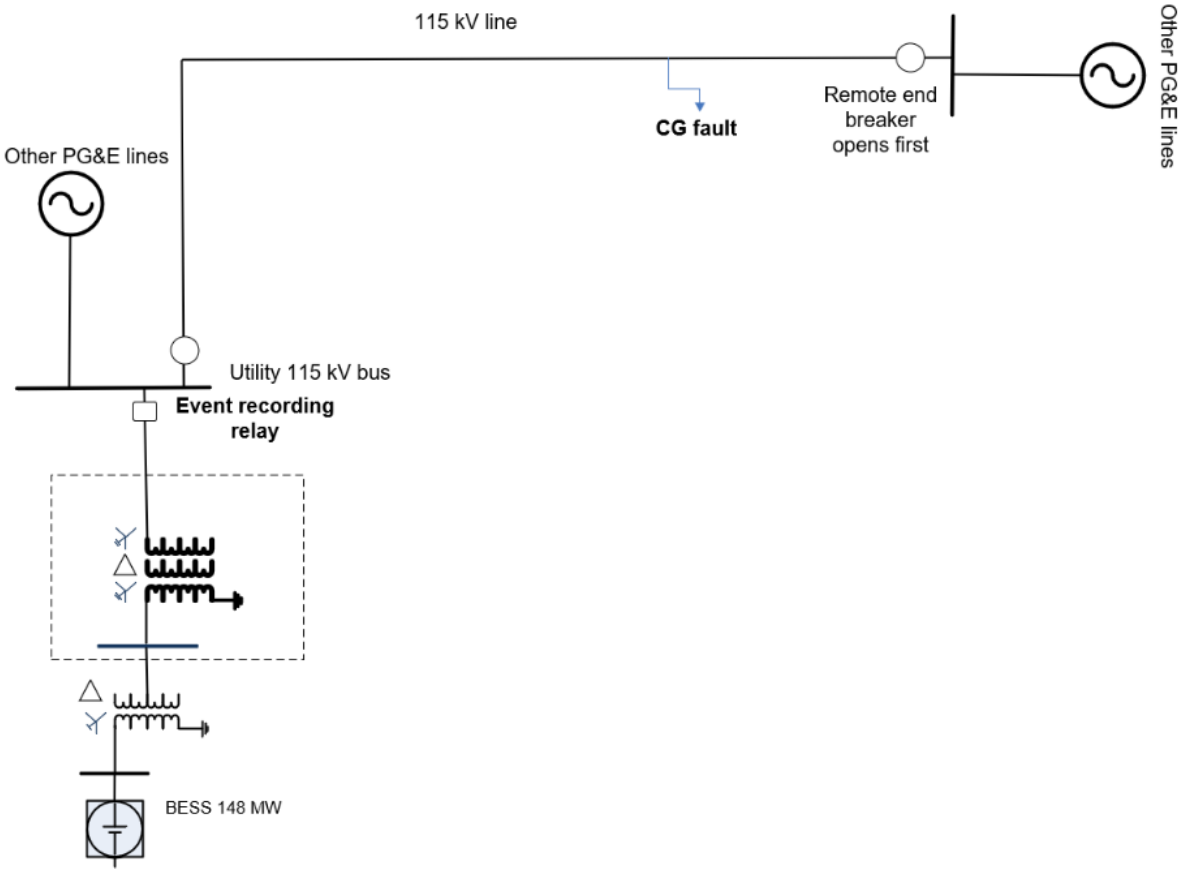


Figure 15. Single line diagram of the system in Event 5

One interesting behavior observed during the fault event was the reduction in the fault phase current contribution from the BESS. Additionally, the fault current magnitudes fluctuated, changing multiple times during the event. These variations highlight the complexity of fault current contributions from IBRs.

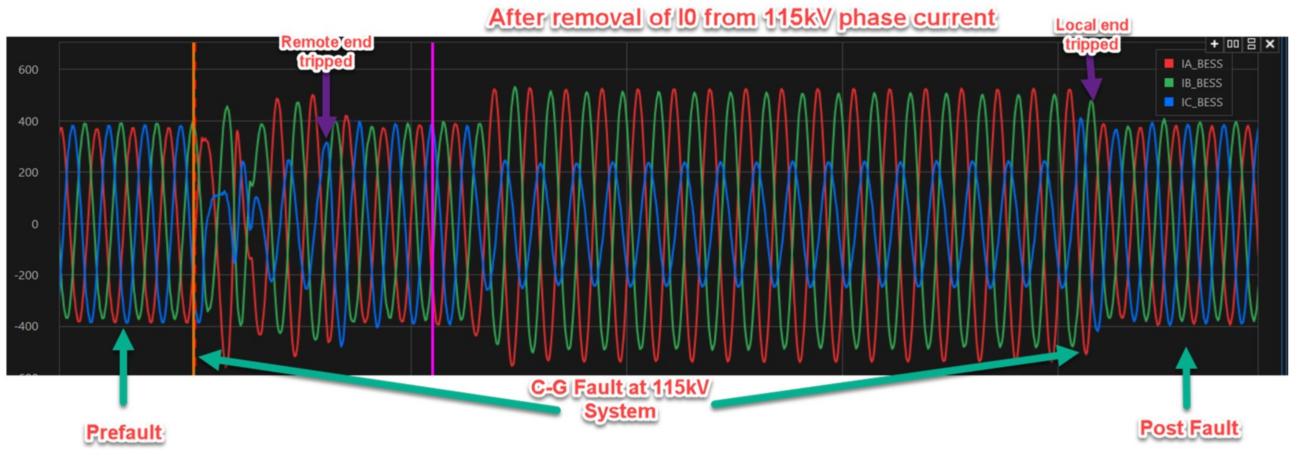
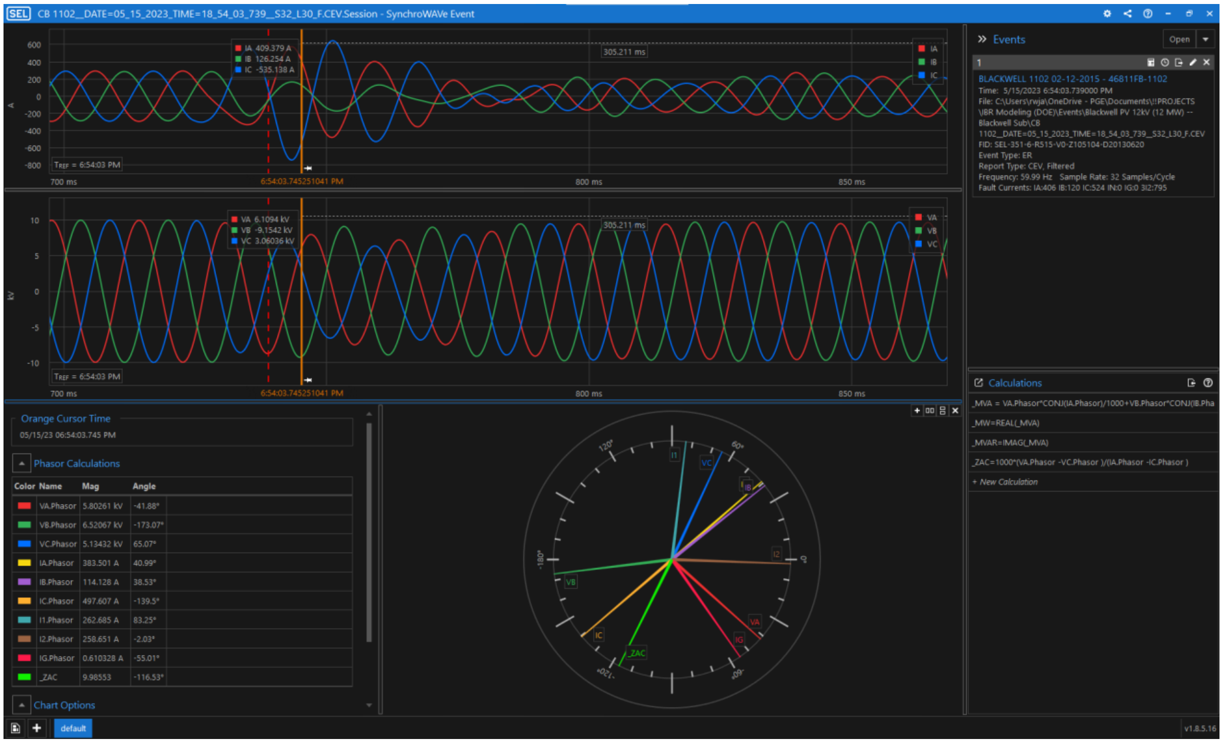


Figure 16. Oscillography from the relay in Event 5 showing the changes in the response with the fault and remote breaker opening

4.6. Event 6: 12 MW PV system Connected to the 12 kV system

This case focuses on the performance of a relay located on a 12 kV distribution feeder that host a 12 MW solar PV system. The relay is looking into the PV plant when an out-of-zone AC fault occurs on the feeder. For this case, the IBR provided ample negative-sequence current.



BLACKWELL 1102 02-12-2015 - 46811FB-1102
Time: 5/15/2023 6:54:03.739000 PM
File: C:\Users\rwja\OneDrive - PGE\Documents\!!PROJECTS \IBR Modeling (DOE)\Events\Blackwell PV 12kV (12 MW) -- Blackwell Sub\CB 1102__DATE=05_15_2023_TIME=18_54_03_739__S32_L30_F.CEV
FID: SEL-351-6-R515-V0-Z105104-D20130620
Event Type: ER
Report Type: CEV, Filtered
Frequency: 59.99 Hz Sample Rate: 32 Samples/Cycle
Fault Currents: IA:406 IB:120 IC:524 IN:0 IG:0 3I2:795

_MVA = VA.Phasor*CONJ(IA.Phasor)/1000+VB.Phasor*CONJ(IB.Pha
_MW=REAL(_MVA)
_MVAR=IMAG(_MVA)
_ZAC=1000*(VA.Phasor -VC.Phasor)/(IA.Phasor -IC.Phasor)
+ *New Calculation*

Orange Cursor Time
05/15/23 06:54:03.745 PM

Color	Name	Mag	Angle
🟥	VA.Phasor	5.80261 kV	-41.88°
🟩	VB.Phasor	6.52067 kV	-173.07°
🟦	VC.Phasor	5.13432 kV	65.07°
🟨	IA.Phasor	383.501 A	40.99°
🟪	IB.Phasor	114.128 A	38.53°
🟧	IC.Phasor	497.607 A	-139.5°
🟦	I1.Phasor	262.685 A	83.25°
🟫	I2.Phasor	258.651 A	-2.03°
🟥	IG.Phasor	0.610328 A	-55.01°
🟩	_ZAC	9.98553	-116.53°

Figure 17. Oscillography from 12 kV feeder relay looking into the PV during out-of-zone fault

The feeder relay under study did not have directional elements, but the significant negative-sequence current produced during this short fault period resulted in a consistent reverse fault impedance characteristic as calculated from the phasors shown below (calculated _ZAC value). There was no unintentional operation in this case. The example demonstrates that if the directional element were set, it could have mis-operated.

4.7. Event 7: PV Event showing current oscillations

The Oscillography of Figure 18 below shows the fault response of 225 MW Solar facility connected to a 230 kV line. The fault was an out-of-zone LL fault impacting a 115 kV line. As can be seen in the figure, there is a significant DC offset and prominent second harmonic content in the fault current. In addition, the Oscillography shows current oscillations with each oscillation lasting approximately 100 milliseconds.

During the event, the nominal 230 kV voltage dropped to approximately 0.9 pu due to this external fault on the 115 kV line. Single Line diagram for the fault is shown in Figure 19 below.

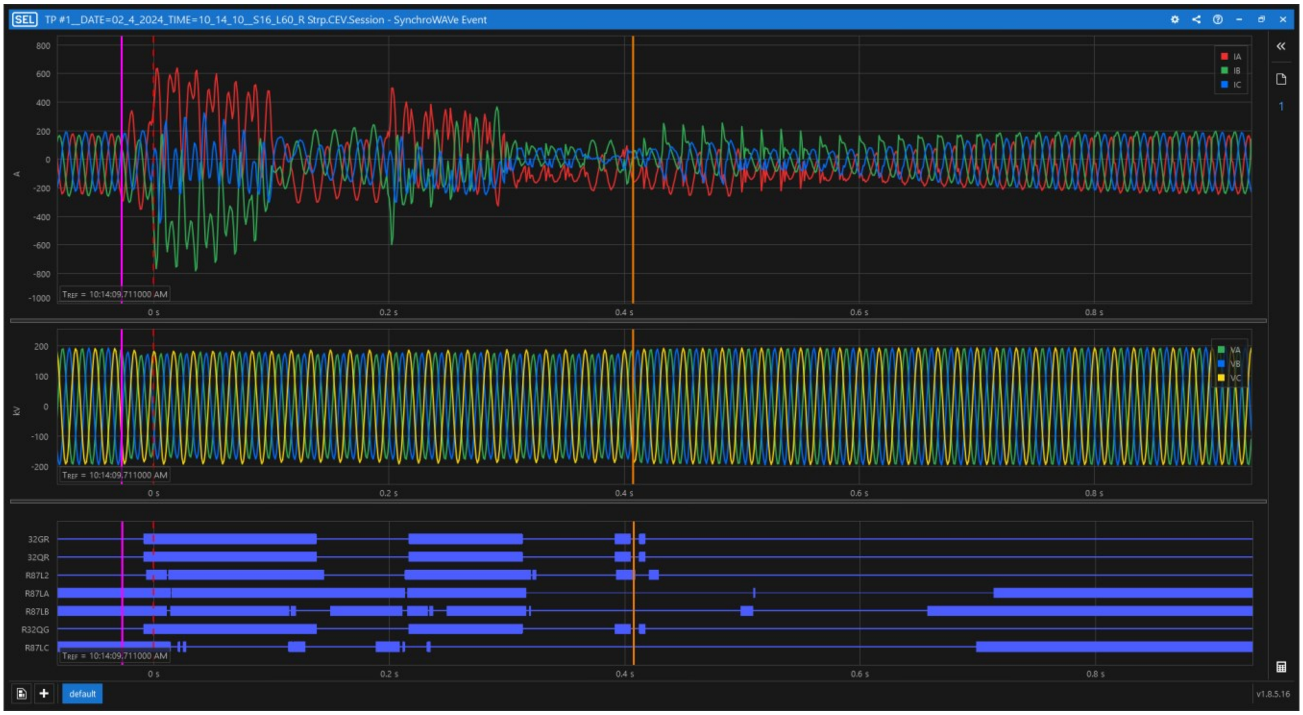


Figure 18. Oscillography showing fault response of a 225 MW solar facility connected to a 230 kV transmission line for an out-of-section (external) fault

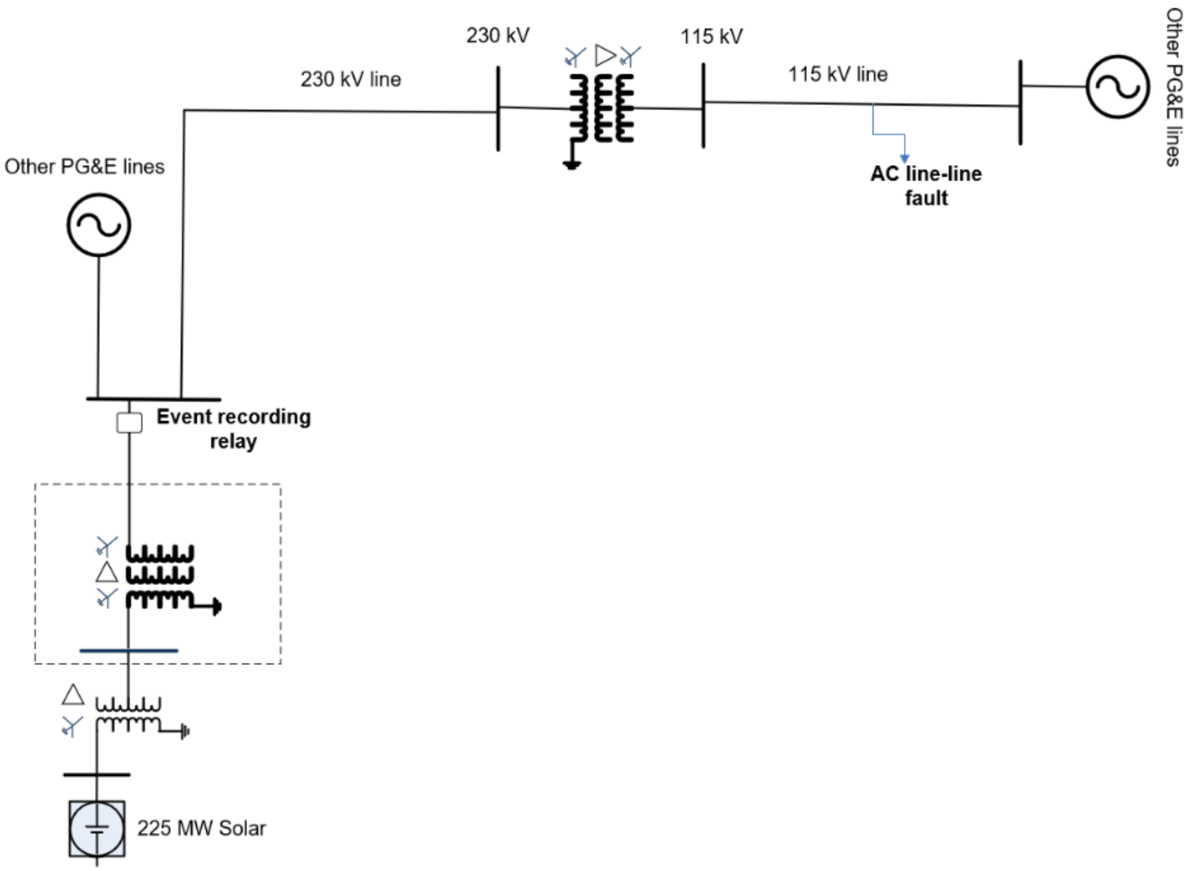
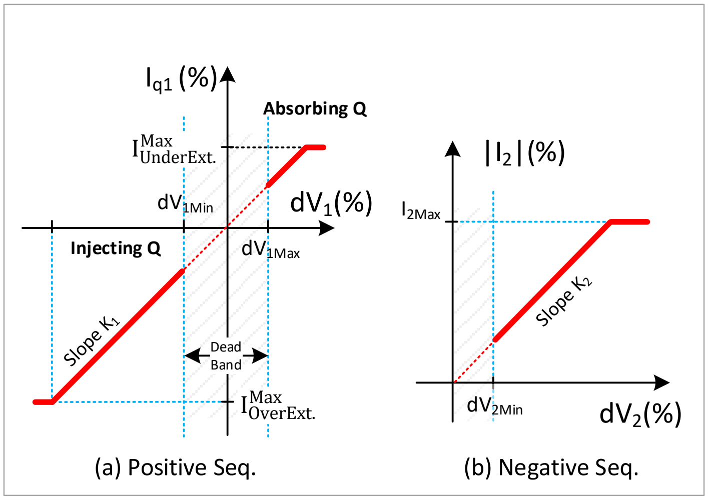


Figure 19. Single line diagram of the system in Event 7

The fault response observed in Figure 18 can be due to the modeling of the reactive power support during the fault as specified by the WECC requirement. According to the WECC model for reactive power support, the curve is not continuous by nature as shown in Figure 20. This can cause a sudden reactive current injection beyond the dead band shown in Figure 20.



(a) Positive Seq.

(b) Negative Seq.

Figure 20. Reactive power support as per WECC model

As an example, for K = 2 (where, K = dI / dV) and dV1max = (0.1 + e) pu, there will be a sudden 0.2 pu current injection. This causes a non-uniform response. Such behavior can be modeled in dynamic response simulations with oscillations showing DC offset and second harmonics.

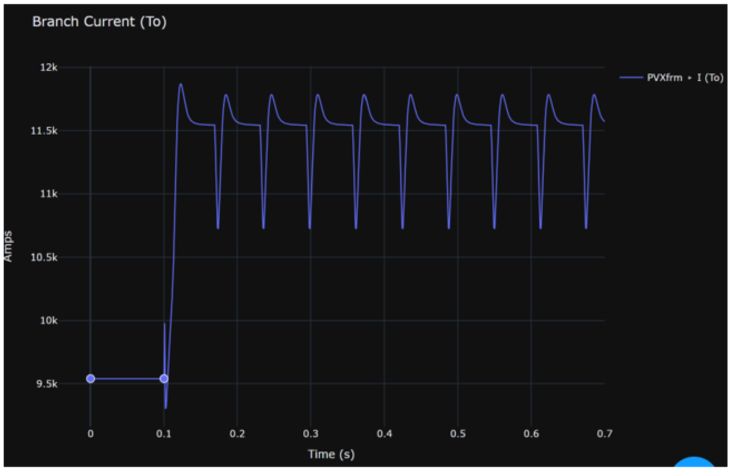
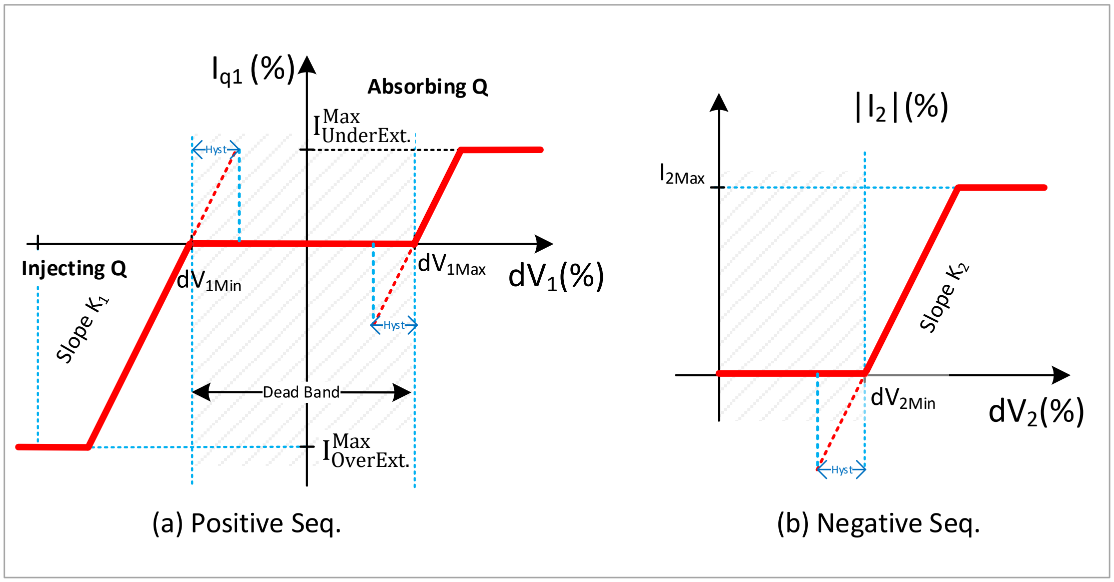


Figure 21. Dynamic response simulations (RMS value of positive sequence current)

Some manufacturers have implemented the dead band in the reactive power support during fault as shown below:



(a) Positive Seq.
(b) Negative Seq.

Figure 22. Reactive power support with dead band implementation

This dead band prevents sudden current injection of 0.2 pu and will prevent the oscillatory response of IBRs. Simulated fault response after implementing a dead band results in non-oscillatory behavior as shown in Figure 23 below.

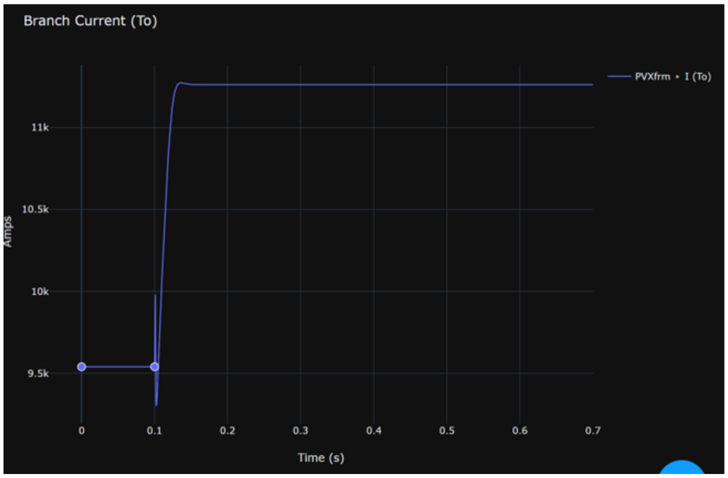
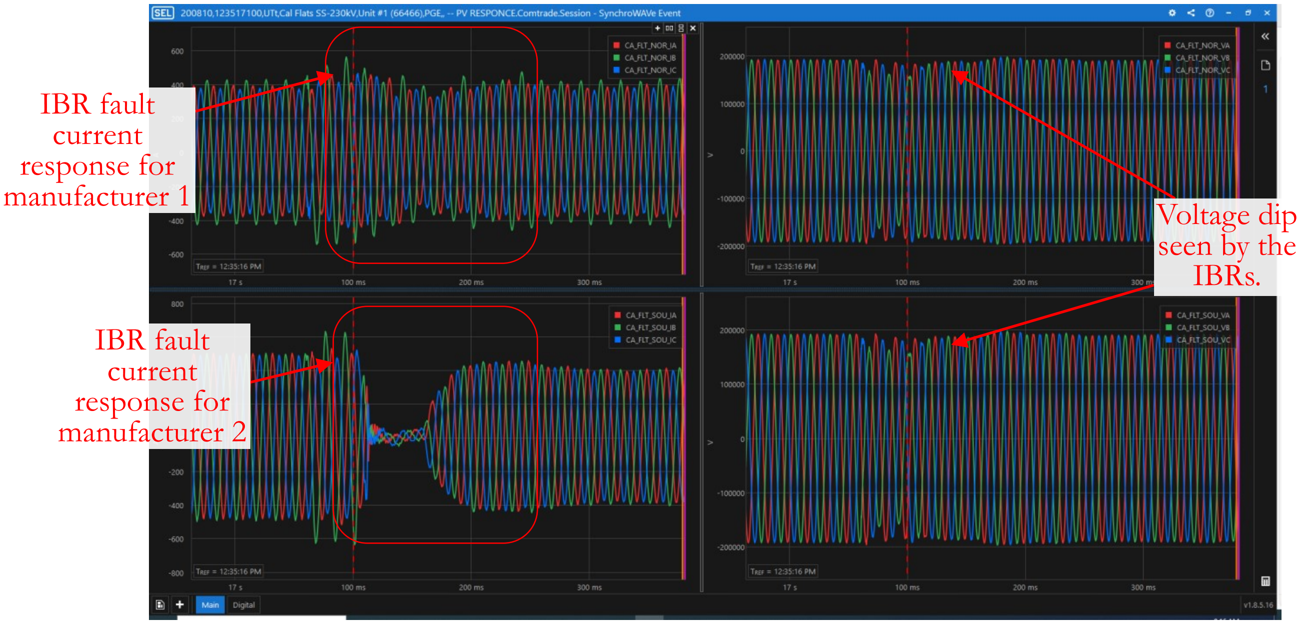


Figure 23. Simulated fault response with a dead band (RMS value of positive sequence current)

4.8. Event 8: Solar plants with inverters from two manufacturers (with momentary cessation from the IBRs of one manufacturer).

IBRs from different manufacturers connected to the same transmission bus may behave differently in response to a fault. In Event 8, the inverters from one manufacturer exhibited momentary cessation while the other manufacturer's inverter did not. Figure 23 shows the oscillography for Manufacturer 2 indicating momentary cessation, while the oscillography for Manufacturer 1 shows that the inverter rides through the disturbance for the same event. It should be noted that the inverter from Manufacturer 2 came back from momentary cessation quickly.



IBR fault current response for manufacturer 1

IBR fault current response for manufacturer 2

Voltage dip seen by the IBRs.

Figure 23. Relay oscillography for two IBRs connected to the same transmission bus and experiencing voltage dip from an external fault.

Single line diagram of the system for this event is shown below.

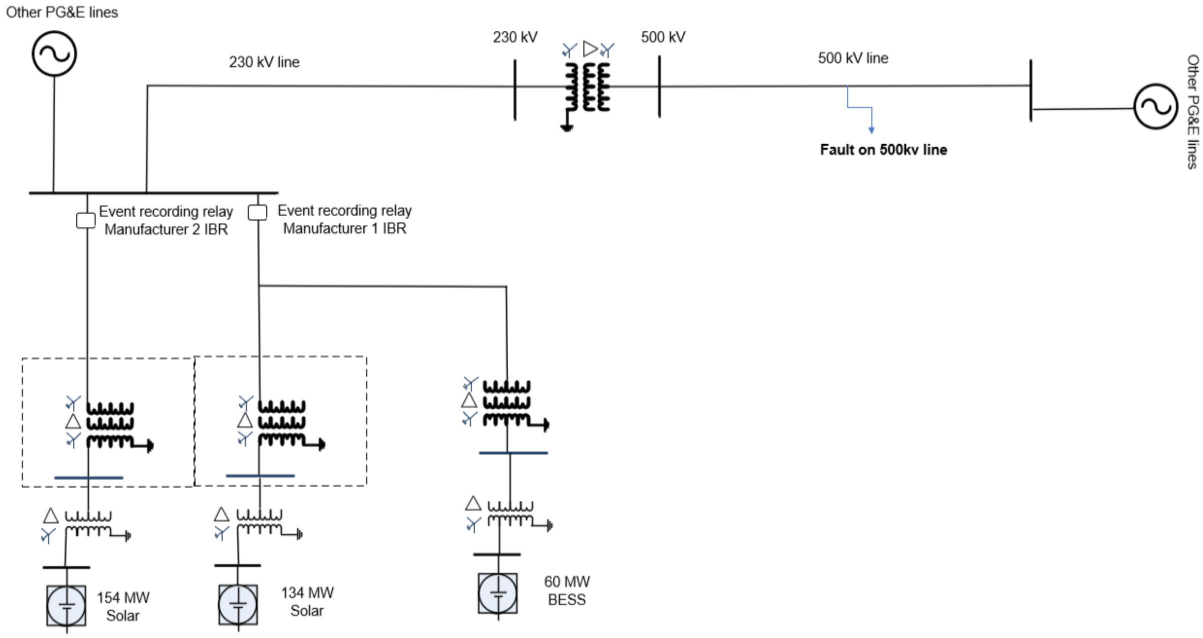


Figure 24. Single line diagram of the system in Event 8

4.9. Event 9: DERs back feeding into Transmission

For an event on PG&E’s 70 kV substation, a microprocessor relay programmed to detect ground fault over-voltages failed to trip because of the sudden frequency shift (from 60 Hz to 55 Hz in a very short time).

For a fault on the 70 kV system, the transmission relays operated to clear the LG fault on the transmission line (shown in Figure 25 below). Subsequent to the fault clearing, DERs from the distribution system were still generating which caused overvoltage on an ungrounded 70 kV transmission substation. PG&E has microprocessor relays on the high side of the distribution bank to detect the overvoltage and trip the feeder breaker.

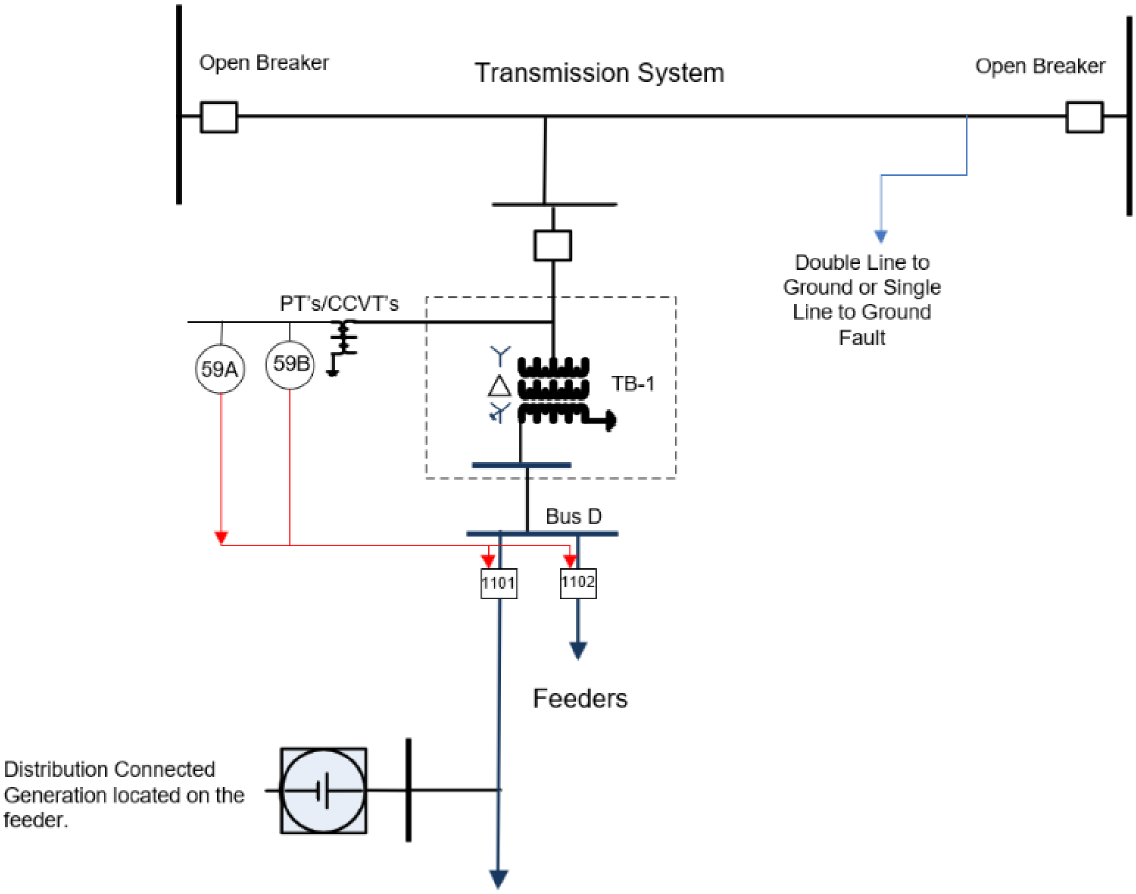
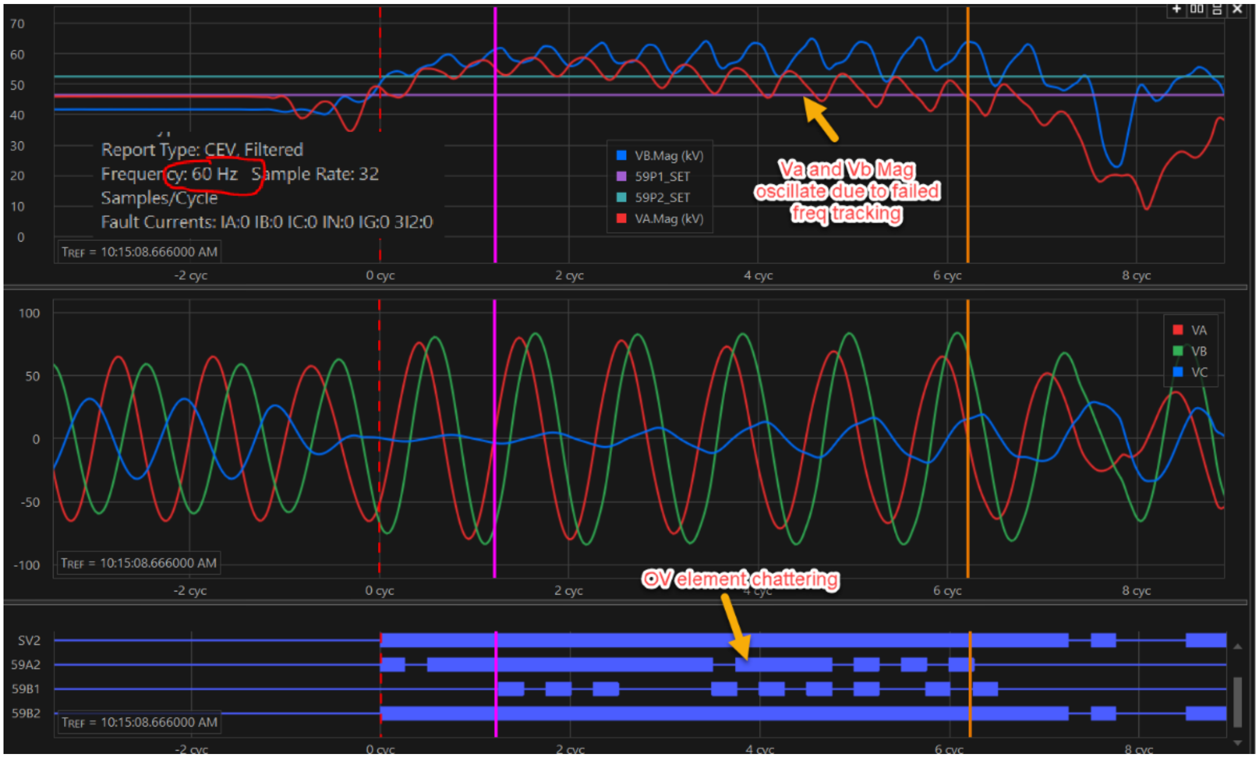


Figure 25. Ground Fault overvoltage caused by DERs back feeding into transmission

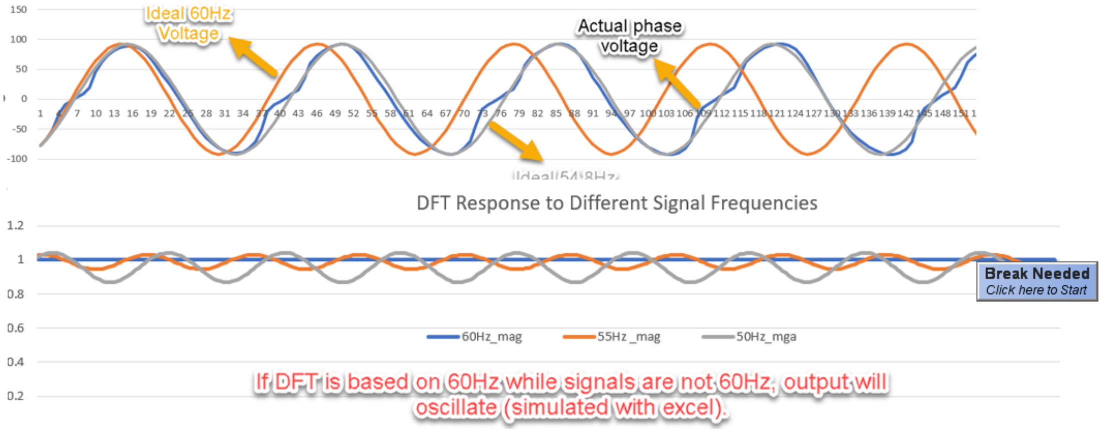
With the loss of transmission, DERs could not keep the frequency stable, and the frequency of the islanded area dropped from 60 Hz to 55 Hz very quickly. This sudden frequency shift exceeded the relay's frequency tracking limit. As such, the relay showed oscillating voltage magnitude caused by the inability of the relays to track frequency which led to the relay failure to operate.



Report Type: CEV, Filtered
Frequency: 60 Hz Sample Rate: 32 Samples/Cycle
Fault Currents: IA:0 IB:0 IC:0 IN:0 IG:0 3I2:0

Figure 26. Oscillography from the relay showing overvoltage on the distribution transformer when the transmission system separates.

Event at 70kV PG&E substation, where microprocessor relay failed to trip, because of the inverter sudden frequency shift (from 60Hz to 55Hz in very short time). This sudden frequency shift exceeded relay's frequency tracking limit. The voltage magnitude oscillated, which led to the relay failure to operate.



If DFT is based on 60Hz while signals are not 60Hz, output will oscillate (simulated with excel).

Figure 27. DFT analysis of phase voltage event recorded by the relay

5. CONCLUSIONS

PG&E and other utilities are observing a rapid increase in renewable resources being added to the generation mix. Most of the renewable resources use power conversion systems (inverters) to connect to the electric grid. These Inverter-Based Resources (IBRs) present unique challenges to conventional protection schemes, and higher contribution of IBRs can result in degradation of reliability if these challenges are not addressed.

This report identifies the protection challenges due to IBRs, gathers data from field protection events, and summarizes questionnaire responses from industry experts.

Commercialized short-circuit software such as CAPE and ASPEN, commonly used in utilities for protection coordination and breaker rating studies, lack a comprehensive IBR model. This deficiency introduces several uncertainties in grid operation and planning. Fault currents produced by IBRs exhibit significant differences compared to fault currents by synchronous machines. Low fault current, lack of negative-sequence currents, and fast-changing frequency contribute to various protection issues.

The power industry is already experiencing the protection issues posed by the growing penetration of IBRs, and this report highlights these protection issues by showcasing field events that demonstrate the complications. The report references various studies, industry working groups, and NERC reports to shed light on high-profile IBR-related events. The responses to a survey of subject matter experts (SMEs) from various utilities reveal widespread concern about these challenges and a strong desire to develop solutions that ensure grid stability and reliability. These solutions should include developing accurate and efficient short-circuit models, improving protection schemes, advancing research into grid-forming inverters, and developing tools to automate protection analysis in an IBR-dominated generation mix.

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