Event Analysis: Innovative Tools and Strategies for Protection Engineers

Daniel Zhang
Pacific Gas & Electric, San Ramon CA

I. Abstract

Protection engineers are generally familiar with different faults and events in power systems. While some events are straightforward, others present challenges and demand unique approaches for analysis, especially when protection schemes fail to operate correctly. In such instances, it is crucial to identify root causes and implement corrective actions. Event analysis can be very challenging and encounter many obstacles, making it essential for protection engineers to develop a deep understanding of power system fault characteristics, primary equipment behaviors, CTs and PT/CCVT behaviors, the design and algorithms of various relays, among other factors.

When faced with unusual events where conventional analytic tools fall short, protection engineers must adopt unique and creative strategies. This paper discusses a few distinct and initially puzzling events, most of which caused protection schemes to misoperate. Through the application of novel and unconventional analytical tools, protection engineers were able to identify the root causes and implement proper corrective actions accordingly.

II. Introduction:

This section provides a brief overview of several real-world events. The following section will discuss them in detail and highlight the tools and strategies adopted for their analysis, as well as corrective actions implemented when necessary.

1. Transformer REF Misoperation Due to Incorrect CT Shorting:

A transformer restricted earth fault (REF) protection misoperated during an external ground fault, initially suspected due to wrong neutral CT polarity. A detailed analysis revealed the root cause as an incorrect shorting and grounding of a problematic CT, leading to inadvertent second ground in the transformer neutral CT circuit. Ground potential difference between two CT ground points caused current to flow. Part of the current reached to the relay circuit and led to REF misoperation. Current induced by ground potential difference revealed the initially confusing relationship between $3I_0$ and I_N.

2. Transformer REF Misoperation Due to CT Saturation:

CT saturation poses challenges for protection relays. Some types of protection can tolerate CT saturation to a great extent, while other types can misoperate on minor CT saturation. This event illustrates how minor CT saturation led to transformer REF misoperation during an external phase-to-phase fault. Analysis will demonstrate how to identify CT saturation and attribute it to the root cause of REF misoperation.

3. Shunt Reactor Negative Sequence Overcurrent Misoperation Due to CT Saturation:

Similar to Event 2, CT saturation caused negative sequence overcurrent of 13.8kV shunt reactor to misoperate. The negative sequence definite-time overcurrent misoperated upon the shunt reactor

energization. The challenge is how to determine CT has saturated when the current waveforms appeared very normal. A novel approach was employed to prove CT saturation and link it to protection overtrip.

4. Variations of Inverter Fault Current Contributions:

With the increasing integration of Inverter-based Resources (IBRs) into utility grids, IBR modeling for fault studies and protection coordination becomes challenging. Despite the efforts to establish proper IBR models, wide variations of fault currents of inverters from different vendors and even within same inverters during similar faults showcases that the gaps still exist. These events emphasize the importance of mandatory standards be developed and adhered by inverter vendors rather than relying on individual vendor proprietary designs.

5. IBR Sudden Frequency Change Causing Phase Overvoltage Scheme Failure to Operate:

IBRs behave differently from traditional synchronous generators, not only in fault current contribution, but also in the inertia and rate of frequency change, which introduces other challenges to protection relays. Event 5 demonstrates a sudden frequency shift (from 60Hz to 55Hz almost instantaneously) upon IBRs islanding from the grid. The relay traditional frequency tracking algorithm, designed for slow frequency changes due to the inertia of traditional synchronous generators, failed to track the rapid frequency drop. The relay continued to estimate the voltage magnitudes based on 60Hz signals, rather than the actual 55Hz, leading to oscillations in estimated voltage magnitudes and protection scheme failure to operate. A new technique is applied to determine the frequency shift during IBR islanding mode and attribute it to the root cause of the failure of protection scheme.

In conclusion, the paper provides insight into protection engineers' toolbox of event analysis, through the discussions of five selective events. It emphasizes the importance of employing innovative tools and strategies for effective event analysis when faced with puzzling events where conventional analytical tools fall short. It is important that root causes of misoperation be identified because it is the basis of subsequent corrective actions.

III. Real-World Events and Analytic Strategies:

Event 1: Transformer REF Misoperation Due to Incorrect CT Shorting and Grounding

Restricted earth fault (REF) protection provides increased sensitivity for internal ground faults in transformers, particularly near the neutral points. REF protection, though implemented differently across various relays, compares zero-sequence current $3I_0$ (sum of phase currents $I_A+I_B+I_C$) with neutral current I_N to distinguish between internal and external ground faults. If $3I_0$ and I_N are equal in magnitude and opposite in phase, it indicates an external fault. Otherwise, it might be indicative an internal fault.

Even though it is generally simple and straightforward in principle, there are many cases that REFs misoperated for external faults, often due to incorrect neutral CT connections.

As shown in Fig. 1, a 115/12.5/7.2kV transformer tripped during an external B-G fault on a feeder. Review of relay event files reveals that the 12kV side REF2 element issued the trip. Fig. 2 (a) shows the transformer 115kV and 12kV phase currents, and (b) shows the 115kV and 12kV $3I_0$ and neutral currents I_N. 115kV $3I_0$ and I_N are and equal in magnitude and opposite in phase, indicating no internal fault on 115kV winding. However, 12kV $3I_0$ and I_N appear to be in phase and different in magnitude, which

indicates an internal ground fault on 12kV winding. If we analyze the 115kV and 12kV currents, and the differential currents, we can notice that there is almost no differential current. We can conclude that there was no internal fault. The REF2 trip was an incorrect operation.

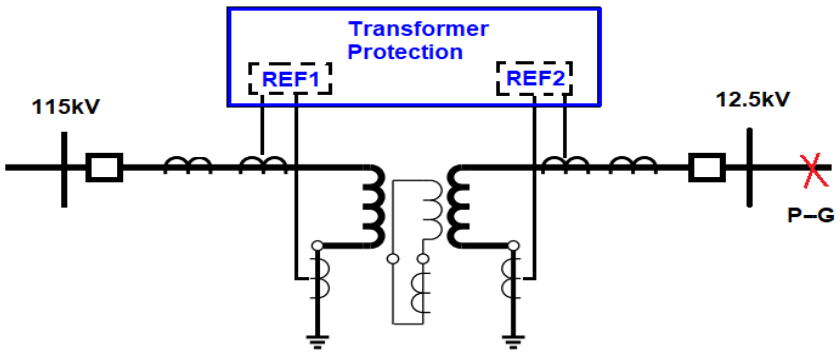
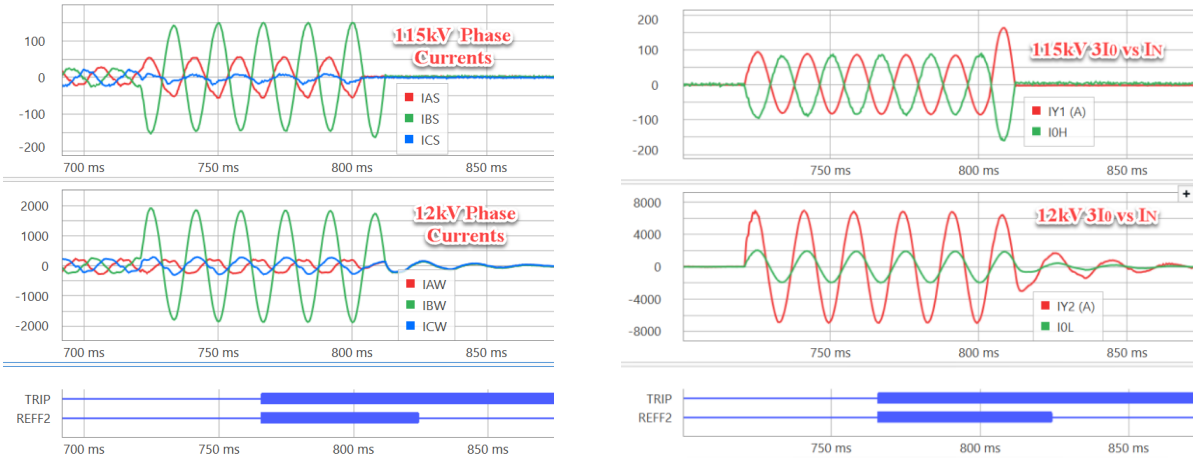


Fig. 1 Diagram of 115/12/7.2kV transformer REF misoperation for external SLG fault



(a) 115kV and 12kV phase currents (b) 115kV and 12kV $3I_0$ vs I_N

Fig. 2 Phase and neutral currents during REF misoperation

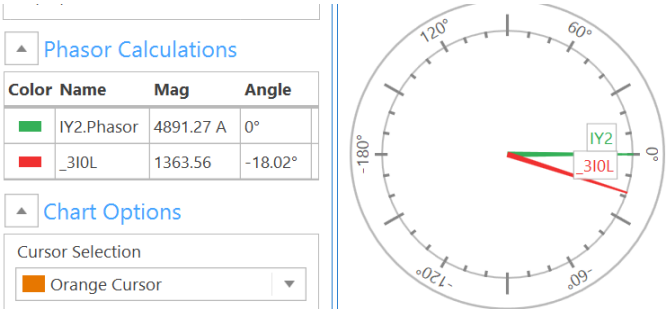


Fig. 3 $3I_0$ and I_N Phasors of transformer 12kV side

From 12kV side $3I_0$ and I_N, it seems that the neutral CT has wrong polarity and ratio, which is one of the common causes for REF misoperation. Further review of 12kV side $3I_0$ and I_N phasors as in illustrated in Fig. 3 shows $3I_0$ and I_N were not equal in magnitude and not exactly 180 deg out of phase, as would be expected for an external ground fault. This suggested there could be some issue with neutral CT or

secondary wiring. The field technicians were contacted to check the neutral CT for possible problems. Technicians confirmed that the CT did have some problem, as it failed the megger test during the commissioning. Technicians decided to short and ground the CT at the transformer cabinet, as depicted in Fig 4, so that the questionable CT will not contribute current to the transformer diff relay.

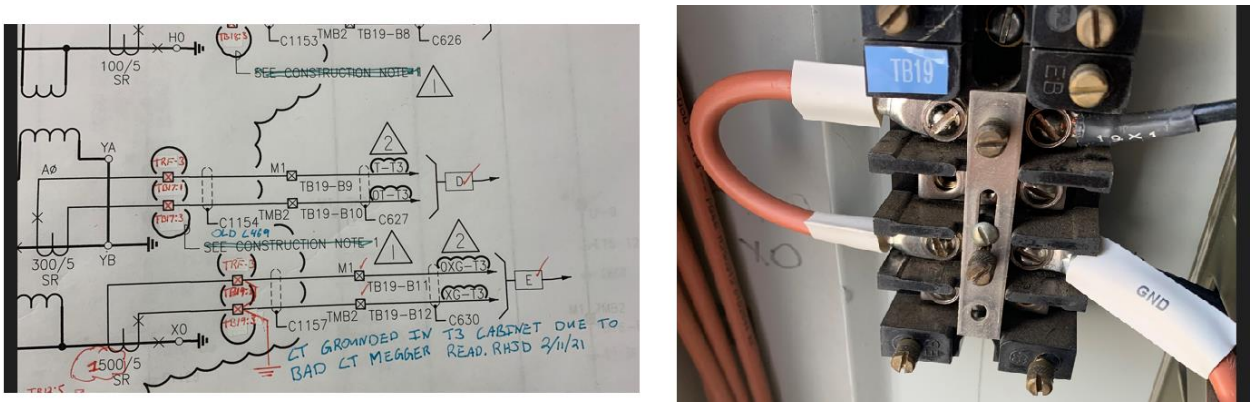


Fig. 4 12kV side neutral CT shorted and grounded after the bad megger test

The question arises as to why there is still current flowing into the relay even after the CT is shorted and grounded. Upon tracing down the neutral CT secondary circuit, another ground inside the control building was noticed. During the external feeder SLG fault, ground current will create ground potential difference between the two ground points, which can induce current into the relay. The induced current I_N was nearly in phase with $3I_0$, causing the relay to interpret it as an internal fault.

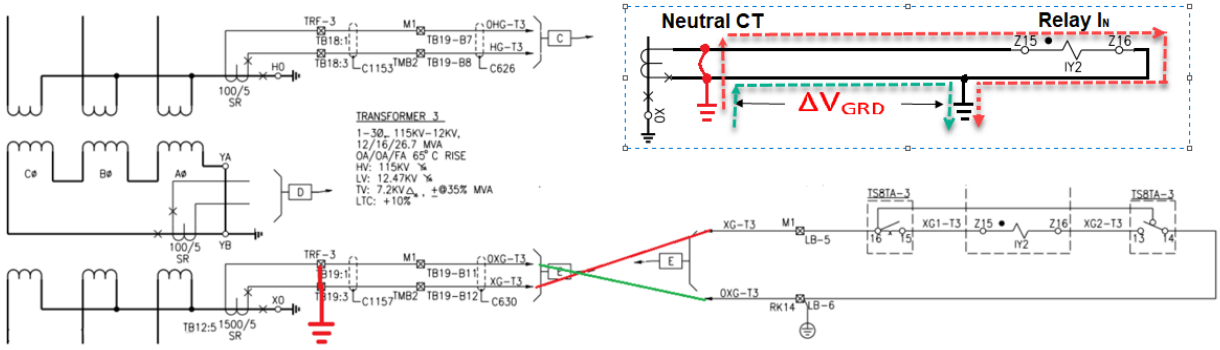


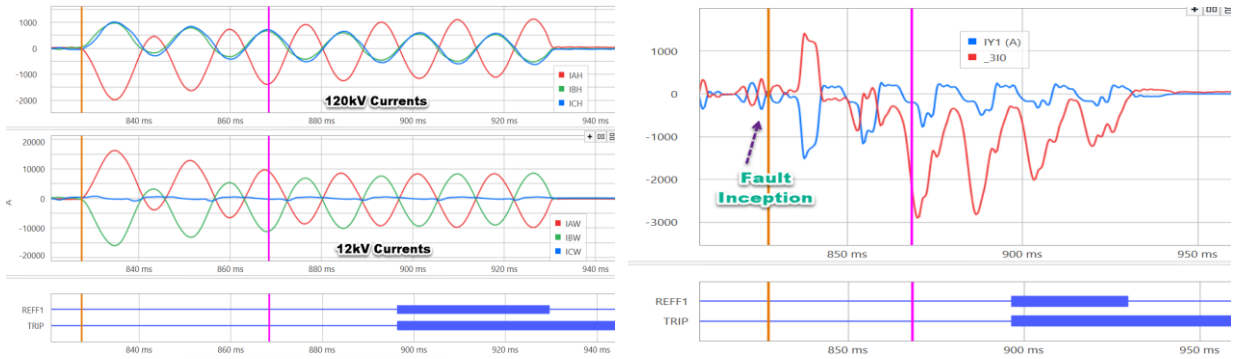
Fig. 5 False current I_N (IY_2) induced by potential difference due to two CT grounds

The corrective action is to remove the additional ground at the transformer cabinet, ensuring that there is only a single ground in the CT circuit.

Event 2: Transformer REF Misoperation due to CT Saturation

A 120/13kV transformer REF misoperated during an external A-B fault on 13kV side. The transformer has a delta connection at 120kV side and grounded wye at 13kV side. REF protection utilizes 13kV $3I_0$ and I_N, and is intended to operate only for internal ground fault. However, it incorrectly tripped on external ungrounded phase-phase fault.

The phase currents of 120kV and 13kV are plotted in Fig. 6 (a), and $3I_0$ and neutral current I_N (denoted as IY1) of 13kV are plotted in Fig. 6 (b). From Fig. 6 (a), it is evident that a phase-phase fault occurred on the 13kV feeders outside the transformer.



(a) 120kV and 13kV phase currents (b) 13kV side $3I_0$ and I_N (IY1)

Fig. 6 Transformer REF misoperated for external phase-phase fault

From Fig. 6 (b), it was observed that both $3I_0$ and I_N had small magnitude and were out of phase in the first two cycles after fault inception. The REF did not operate because the fault appeared external. However, after 2 cycles, $3I_0$ started to increase and became somewhat in phase with I_N, while I_N remained unchanged. This change caused the fault to be perceived as internal, leading to REF operation.

The question arises as to why magnitude and angle of $3I_0$ changed after two cycles? If we reverse I_A ($-I_A$) and plot it over I_B as shown in Fig. 7, $-I_A$ and I_B almost overlap in the first two cycles. After two cycles, $-I_A$ and I_B start to drift apart, and Phase A CT shows sign of saturation. As result, $3I_0$ starts to increase in magnitude, eventually aligned with I_N, which indicates a transformer internal fault. REF misoperated as the result.

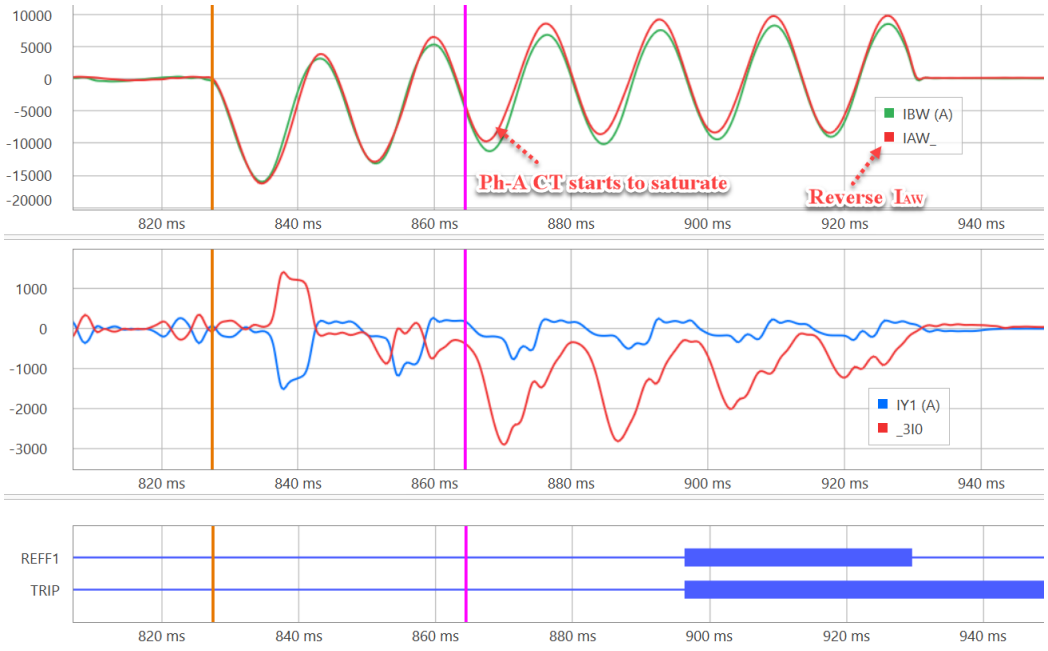


Fig. 7 Phase-A CT starting to saturate after two cycles

The relay misoperation calls for firmware upgrade as the corrective action. The new firmware includes logic to correct the REF misoperation under similar CT saturation condition [1].

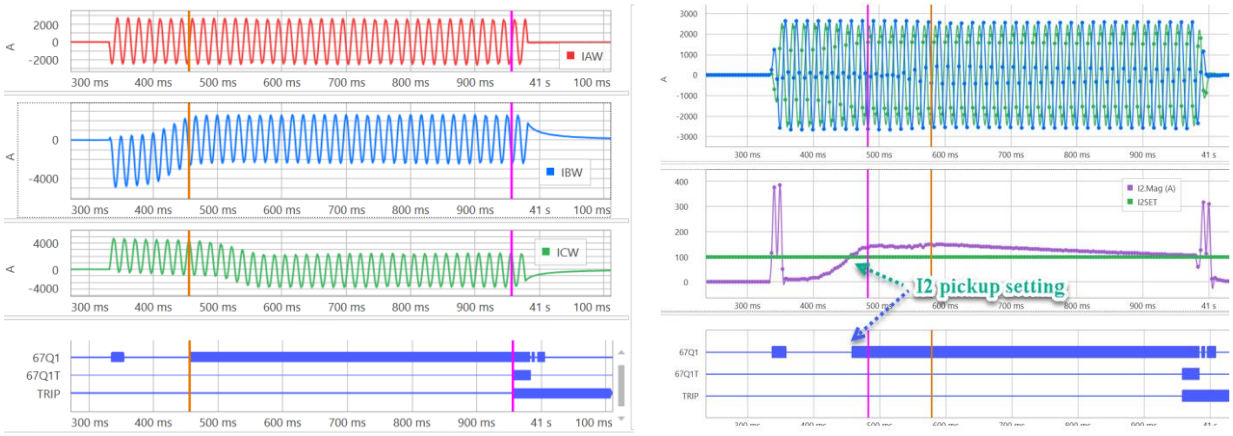
Event 3: Shunt Reactor Negative Sequence Misoperation Upon Energization

Four steps of 13.8kV 45MVA Shunt reactors are connected to 525/230/13.8kV tertiary side to provide the reactive power support. Each step of reactor is protected by negative sequence overcurrent 50/51Q, which protects against phase to ground, phase to phase and turn-to-turn faults.

Upon energizing one of the shunt reactors, the negative sequence overcurrent operated. Inspection of the reactor found no sign of fault. Therefore, the operation was determined incorrect.

The relay event was downloaded for review. As shown in Fig. 8 (a) below, about 7 cycles after breaker closing, the negative sequence overcurrent element started to pick up, and eventually timed out and issued the trip.

Fig. 8 (b) shows the filtered phase currents and magnitude of negative sequence current along with the negative sequence current pickup level. The negative sequence current was initially near zero upon breaker closing. It then started to increase and surpassed the pickup level. After peaking, it started to decrease. It stayed above the pickup just slightly longer than the timer of negative overcurrent element, leading to the incorrect trip.



(a) Comtrade (unfiltered) phase currents (b) Filtered phase and negative sequence currents

Fig. 8 Shunt reactor phase current for protection trip

Based on the pattern of negative sequence current and high DC component in the phase current, CT saturation was suspected as the cause of erroneous negative sequence current. The challenge is how to prove if CT saturation was indeed the root cause. If CT saturation was ruled out, further troubleshooting will be necessary until the true root cause is identified.

It is well known that the reactor energization current comprises a fundamental frequency component along with transient, decaying DC offset, as in Equation (1). The initial magnitude of DC offset depends on the closing angle. The decaying rate of the DC offset depends on time constant τ (or X/R ratio).

$$i(t) = I_m * cos(wt + A_0) - I_m * cos(A_0) * e^{-\frac{t}{\tau}} \qquad (1)$$

Where I_m is the magnitude (peak) of sinusoidal component; A_0 is the closing angle; τ is the time constant.

The first part of Equation (1) represents the AC component, and the second part represents the DC component. We can open the Comtrade data file (.dat) and refer to configuration file (.cfg) to plot the recorded current in Excel. We can then construct a theoretical current waveform based on format in Equation (1) to match the recorded current waveforms. The comparison of recorded and constructed waveforms will help in identifying CT saturation.

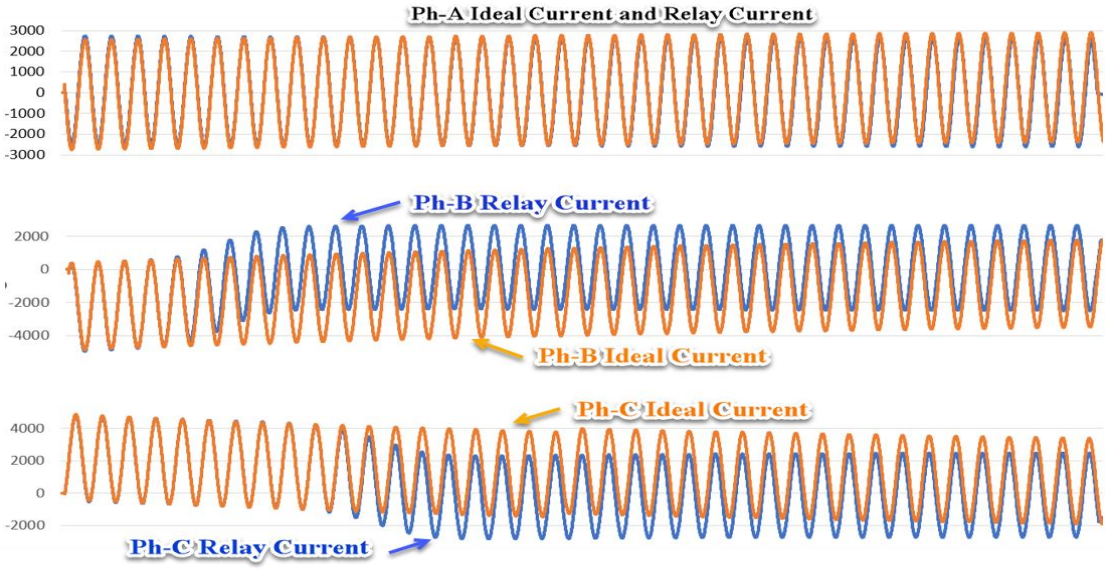


Fig. 9 Relay recorded currents and reconstructed ideal currents

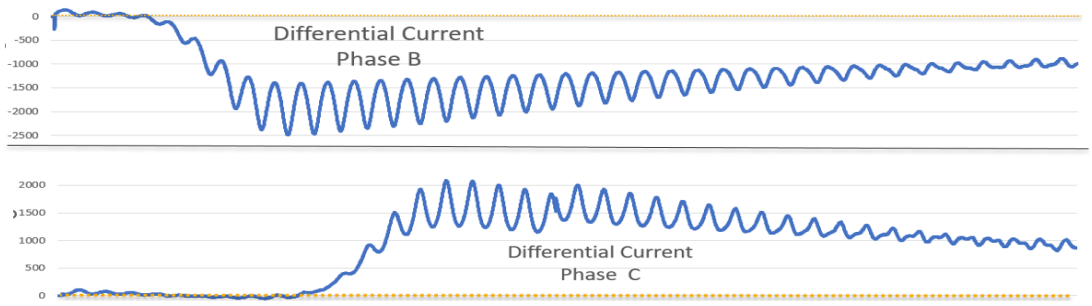


Fig. 10 Missing currents in Phase B and C due to CT saturation

From Fig. 9, the relay current and ideal current overlapped closely for Phase A during the entire event. However, the situation is different for Phase B and C. The relay actual current and ideal current overlapped only in the first a few cycles. After about 5 cycles for Phase B and 11 cycles for Phase C, the two currents began to drift apart. The divergence was clearly caused by CT saturation.

As result of CT saturation, erroneous negative sequence current started to appear, exceeded the pickup threshold of negative sequence overcurrent, eventually timed out and resulted in a trip.

Circling back to Equation (1), the parameters of currents are as follows:

$$I_m = \sqrt{2} * 1880\ amps; \qquad X/R = 200;$$

As shown in Fig. 11, the closing angles of three phases on the voltage waveforms are as following:

Ph-A: 277°; Ph-B: 156°; Ph-C: 36°.

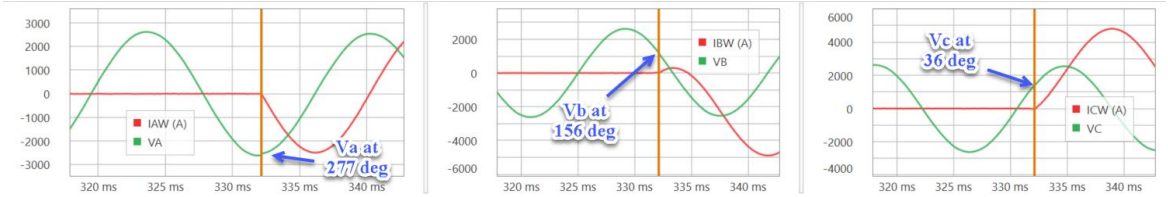


Fig. 11 Three-phase closing angles on voltage waveforms (voltage magnitude re-scaled)

Due to the different closing angles, DC offsets of varying magnitudes were generated on top of AC currents. DC offset with large time constant presents a significant challenge for CTs and can easily drive them into saturation, even though the reactor energization current was not as high as typical fault currents.

According to the IEEE standard [2], to avoid saturation with a DC component in the primary waveform and with a pure resistive burden, the required saturation voltage is given by (2):

$$V_x > Is * Zs * (1 + X/R) \qquad (2)$$

The CT in question has ratio of 2000:5 and accuracy class of C400. The AC component of energization current was about 1,880 amps. Different phases had different DC magnitudes. Phase B breaker was closed at 156 deg, and had highest DC offset. Therefore, Phase B CT experienced worst saturation.

Fig. 12 below shows the CT equivalent model [2], together with the constructed (ideal) primary current, relay recorded actual current, and differential current (flowing in CT excitation circuit) of phase B. The differential current is the missing current due to CT saturation, and cause of erroneous negative sequence current. The higher differential current indicates worse CT saturation.

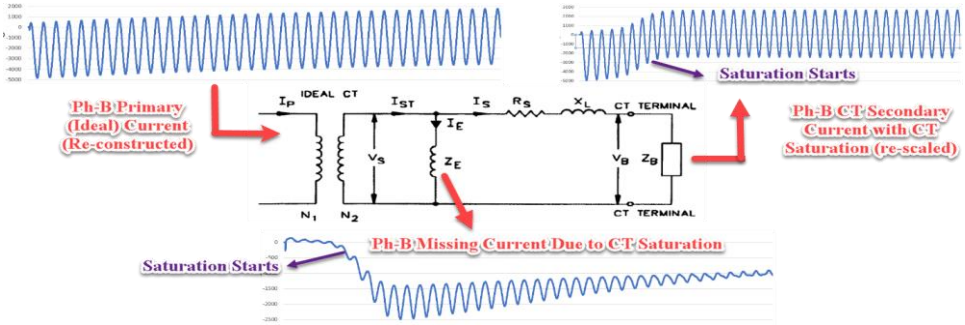


Fig. 12 CT model and Saturation Current

CT performance was analyzed using the IEEEE saturation calculator [3]. The analysis, shown below in Fig. 13, indicates that the CT class has significant impact on the likelihood of CT saturation. When C600 or higher-rated CTs are used, the potential for saturation is largely avoided. PG&E will specify C600 or better CT for future installation. For existing CTs, to address the risk of CT saturation, the negative sequence overcurrent protection will have its operation delayed for 60 cycles upon breaker closing. The delay is intended to allow the relay to ride thru CT saturation, thereby reducing or eliminating the likelihood of incorrect trips. The modified logic is shown in Fig. 14 below.

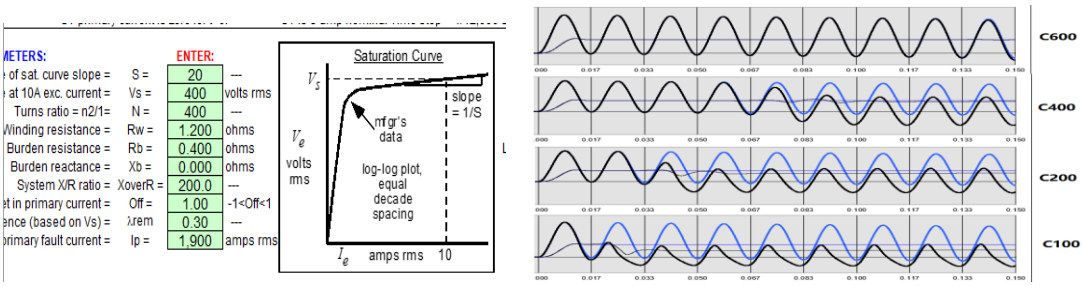


Fig. 13 CT performance analysis using IEEE saturation calculator

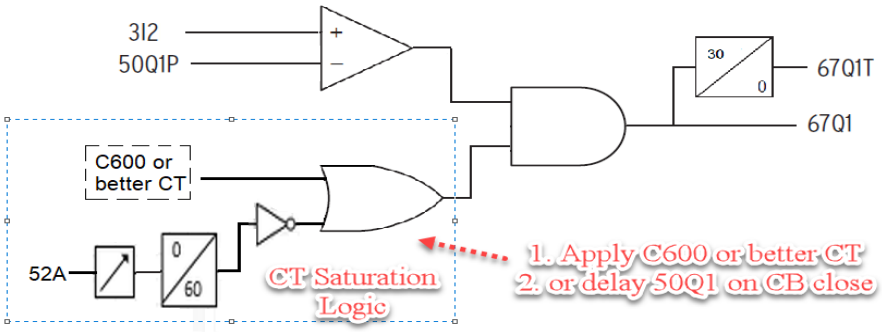


Fig. 14 Corrective actions for negative sequence overcurrent misoperation

A widely accepted guideline is that CT should perform satisfactorily if its accuracy class is equal to or greater than 200% of maximum symmetrical AC voltage. This margin is used to account for the DC offset in primary current and any remanent flux. While guideline works well in most cases, there are exceptions.

In Event 2 (REF) and 3 (shunt reactor), both CTs are rated at C400 and have margin well above 200% of the symmetrical AC voltage. However, CT saturation still occurred, leading to protection misoperation in both instances. Therefore, performance of a CT should be evaluated very carefully, especially for high X/R ratio, and for certain types of protection schemes (such as negative or zero sequence overcurrent, current differential without restraint, REF, etc.). For other types of protection schemes, such as phase overcurrent, distance protection, current differential with restraint, etc., they are generally more capable of riding thru CT saturation.

In event 2, the symmetrical AC fault current is approximately 6,200 amps, CT has accuracy class of C400 and ratio of 3000: 5 or 600. The total secondary burden is less than 3 ohms. The symmetrical secondary voltage is no more than 30 volts or 7.5% of CT class rating.

In event 3, the symmetrical AC energization current is around 1,880 amps. CT has accuracy class of C400 and ratio of 2000:5 or 400. The total secondary burden is less than 2.5 ohms. The symmetrical secondary voltage is no more than 15 volts or 3.75% CT class rating.

In both events, the symmetrical voltages at CT secondary terminals are far below 50% of the CT accuracy rating. However, due to the high DC components with large X/R ratios, and likely high remanent flux, the CTs saturated and resulted in protection schemes to overtrip. This highlights the need for careful assessment of CT performance where high DC offset and large X/R ratio are present.

Event 4: Variations of Inverter Fault Current Contributions:

With increasing adoption of inverter-based resources (IBR), new challenges have emerged in existing protection practices, one of which is modeling IBRs for fault and coordination studies, equipment rating, etc. IBRs typically produce less fault currents than synchronous generators, usually in range of 1.1 to 1.4 times of the rated load current, following a brief uncontrolled response. Different methodologies have been proposed to model IBRs, including treating them as synchronous machines, current-limited machines, using Converter-Interfaced Resource Model (CIR), Voltage Controlled Current Source (VCCS), dynamic link library (DLL), among others. Some suggest using transient models such as EMTP or PSCAD. Each modeling approach has its pros and cons. The detailed discussion is beyond this paper.

However, accurately modeling IBRs remains challenging due to variability in their behaviors. Inverters from different vendors can behave very differently under same fault conditions. Even the same inverters may behave differently during similar faults. The same inverters may even behave differently with time progression during the same fault. These uncertainties make accurate IBR modeling very difficult if not impossible.

Fig. 15 illustrates the diagram of 400MW battery energy storage system (BESS) connected to PG&E's 500kV system via a 0.25-mile gen-tie. There are five 34kV collection feeders on secondary side of generator step-up (GSU) transformer, with inverters from two different vendors. In ASPEN Oneliner, the IBRs were modeled as current-limiting sources, with a 1.2pu fault contribution of rated current.

The gen-tie experienced two SLG faults: a C-G fault in 2021 and a B-G fault in 2023. Relay event data were downloaded for analysis. These events provide valuable insights for evaluating the relay operation, and more importantly, for validating the IBR model. The analysis of these faults helps assess the accuracy of the IBR models in representing their actual behaviors during fault conditions, highlighting the complexities and limitations of current IBR modeling methodologies.

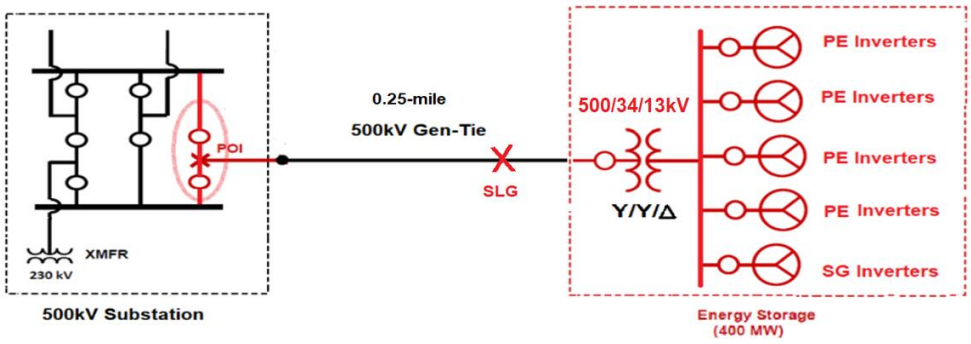


Fig. 15 Diagram of 400MW BESS connected to 500kV system

Fig. 16 shows the relay events for the C-G fault occurred in 2021. The top left graph displays the GSU 500kV side current, which is predominantly zero-sequence current from the contribution of the transformer neutral. The top right graph shows the GSU 34kV side current, which directly reflects the IBR currents. The bottom graphs show individual phase currents at 34kV side of three collection feeders, connected to three inputs of the transformer differential relay.

The feeder with SG inverters (to relay input W) was not in service at the time of fault. Feeders with PE inverters (to relay input U and T) were in service. Upon fault occurrence, the 34kV side current

experienced a short spike, which was caused by the uncontrolled inverter response. Following the short spike, the current started to oscillate at higher frequency and quickly decay to zero. This behavior suggests that the PE inverters might have entered the cessation mode shortly after the fault, effectively ceasing to produce any fault currents. This cessation mode is not modeled in ASPEN Oneliner and similar software.

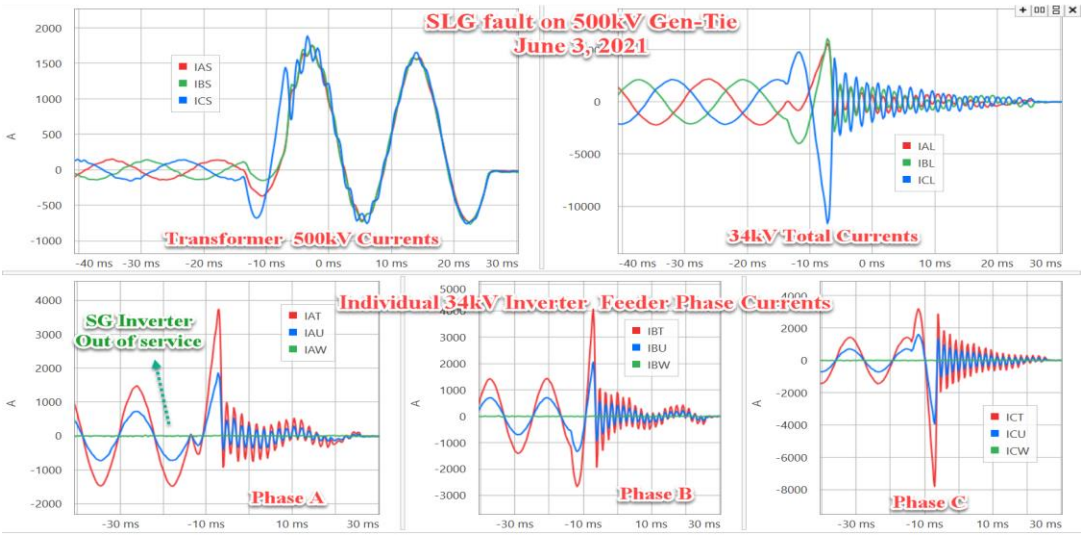


Fig. 16 IBR currents for a SLG fault on 500kV Gen-tie

Fig. 17 shows the comparison of 34kV fault currents recorded in 2021 C-G fault and 2023 B-G fault. SG inverters were in service during the fault in 2023. They produced about 1.1pu fault current as shown on the right side of Fig. 17, which was close to the assumed value.

On the left side, the fault currents from feeders with PE inverters were displayed. Similar to the fault in 2021, the fault current was very limited and quickly decayed to zero. However, unlike the 2021 fault, fault current did not oscillate at high frequency during the 2023 fault.

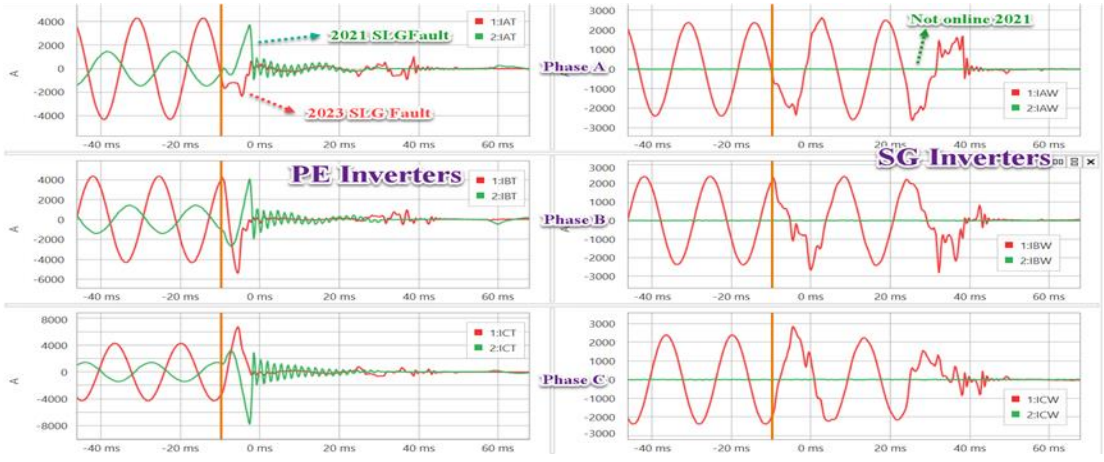


Fig. 17 Comparison of IBR currents of similar SLG fault and different IBR types

It is evident that PE inverter fault currents in both faults were significantly lower than the 1.2pu rated current, which was the assumed value in ASPEN Oneliner model. The discrepancy highlights potential problems of modeling IBRs properly for fault and protection coordination studies, etc.

It is not just that different inverters behave differently, or the same inverters respond differently to similar faults; even fault current from the same inverters can vary during the duration of a single fault as situation evolves. This kind of inverter behaviors adds another layer of complexity, making it more challenging to predict the inverter responses accurately.

As shown in Fig. 18, a 148MW BESS was connected to 115kV and 230kV system via a 0.2-mile 115kV gen-tie. When a C-G fault occurred on an adjacent 115kV line, the DFR currents for faulted line and gen-tie were analyzed.

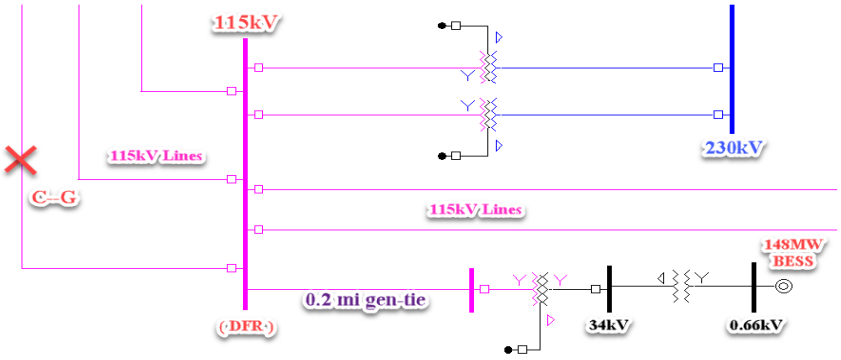


Fig. 18 Diagram of 148MW BESS connected to 115/230kV system

As shown in Fig. 19, the top curves are the current of the faulted 115kV line, and the bottom are the current of 115kV Gen-tie.

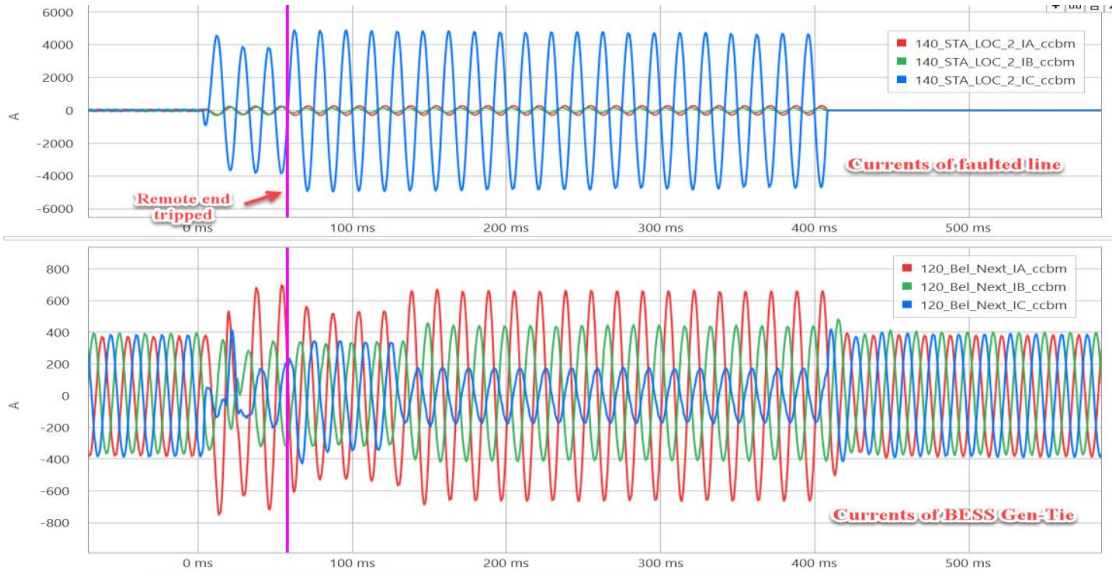


Fig. 19 Currents of faulted 115kV line and gen-tie during a SLG fault

The current of faulted line indicates that the remote end tripped in about 3 cycles, while the local end tripped in 24 cycles. Interestingly, the BESS gen-tie current experienced three consecutive and distinctive

stages during the 24-cycle fault period: the first 3 cycle, the following 4 cycles and the final 17 cycles. The 115kV gen-tie current contained zero-sequence current, which was contributed by the 115/34/12kV transformer neutral and did not exist at 34kV side. After removing the zero-sequence current from the 115kV gen-tie phase current, the resulting current, as shown in Fig. 20, will reflect the 34kV currents except different magnitude due to transformer ratio. This removal provides a clearer picture of actual currents on 34kV side during the fault.

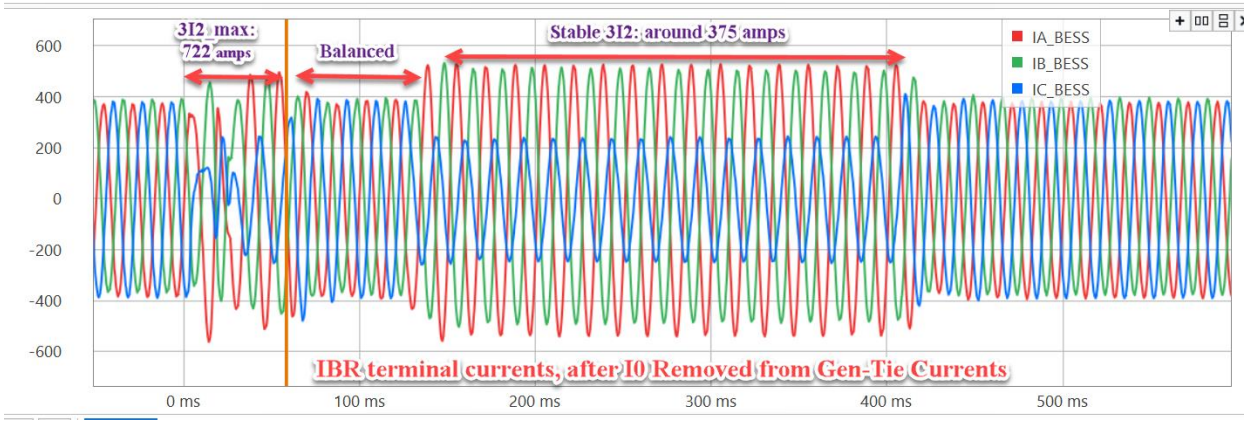


Fig. 20 115kV phase current after remove I_0 (same pattern as 34kV current expect different magnitude)

Some interesting phenomena can be observed from gent-tie current in Fig. 20:

- The first 3 cycles after fault inception:
  1. The faulted phase (Ph-C) had distorted and reduced current.
  2. The unfaulted phases (Ph-A & B) experienced increased currents.
  3. There was significant amount of unstable negative sequence current.
- The following 4 cycles:
  1. Three phase currents became somewhat balanced.
  2. The currents were similar in magnitude as pre-fault load currents.
- The last 17 cycles:
  1. Faulted phase had stable and decreased current.
  2. Unfaulted phases maintained stable and increased currents.
  3. There was significant amount of stable negative sequence current.

Pinpointing the exact causes of such current pattern is challenging and requires a deep dive into inverter proprietary design. One possible explanation is the changes of 115kV and 34kV bus voltage when remote end tripped in about 3 cycles, as shown in Fig. 21. The voltage changes likely triggered IBR controllers to take actions that changed the current output. There was not recording of 34kV voltage. But it is reasonable to assume that it experienced similar changes as 115kV bus voltage.

Unlike synchronous generators, the fault currents from IBRs depend on the internal controllers, which are proprietary designs and can be modified for various reasons. This variability makes it technically impossible to model IBRs accurately, especially when the current exhibits the pattern as in Fig. 20.

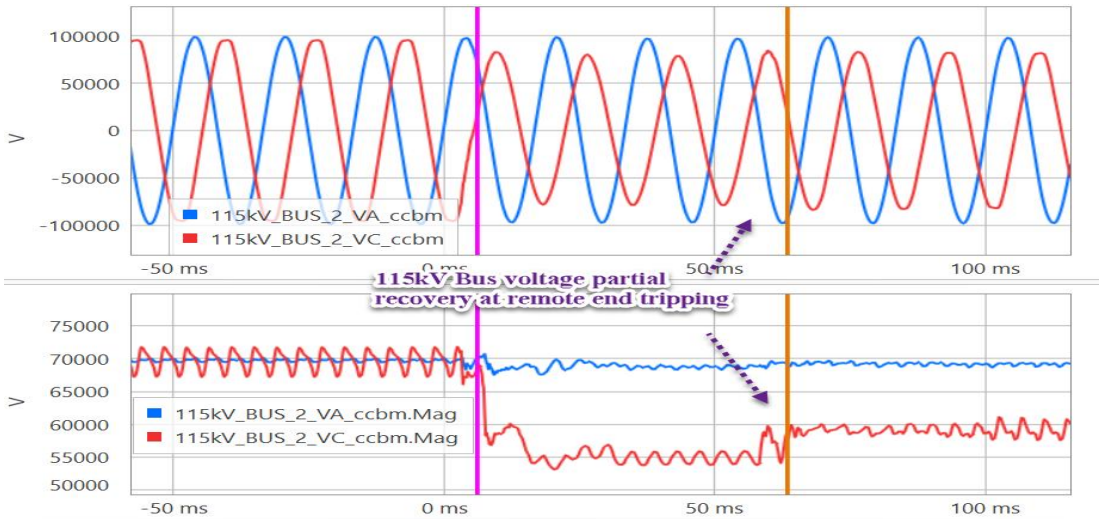


Fig. 21 115kV Bus voltage change upon remote end tripping

Event 5: IBR Sudden Frequency Change Causing Phase Overvoltage Scheme Failure to Operate

As shown in Fig. 22, IBRs for a 6MVA Photovoltaics (PV) were connected to 70kV tapped bus through a 70/12/2.3kV transformer. The transformer 70kV side is ungrounded. When there is a SLG fault on 70kV line and both ends tripped to clear the fault, the line remains energized by the tapped IBR source. Although the tapped IBRs provide very little fault current, the energized line still poses wildfire and safety hazards. The unfaulted phases will experience voltage rise and put dielectric stress on the equipment. It may also lead to unsuccessful reclose. Therefore, it is necessary to trip off the tapped transformer and IBRs in such scenarios.

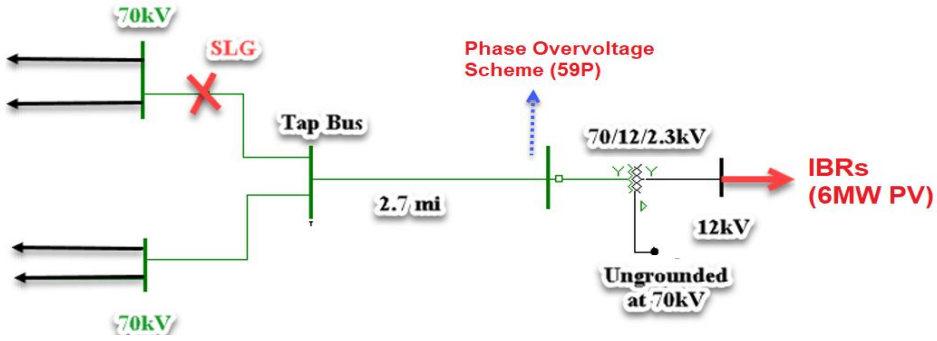


Fig. 22 Diagram of IBR connection to 70kV tapped bus

One approach to addressing this issue is to implement a DTT scheme to trip the tapped IBRs. However, the high cost of such a DTT scheme often prevents its implementation. Another option is to employ a phase overvoltage protection scheme. Because the transformer is ungrounded at 70kV side, the ungrounded phases of 70kV line will experience a voltage rise to about 1.732 (or $\sqrt{3}$) times the nominal voltage during a SLG fault after line breakers trip.

Based on the projected voltage rise of ungrounded phases, a phase overvoltage protection scheme was implemented to trip the 70kV transformer and isolate the IBRs. Two levels of overvoltage settings with different time delays were utilized as follows:

- Level 1 (59A1, 59B1 and 59C1): 150% of nominal voltage with 4-cycle delay
- Level 2 (59A2, 59B2 and 59C2): 120% of nominal voltage with 20-cycle delay

On the surface, the overvoltage settings should provide sufficient sensitivity. However, during an actual SLG fault on 70kV line, the overvoltage protection scheme failed to operate as expected, even though the phase voltage appeared to have reached or exceeded the thresholds after the line breakers were tripped. As shown in Fig. 23, the peak voltages of V_A and V_B increased to 81kV and 92.7kV (1.42pu and 1.62pu) respectively. Despite this, the overvoltage protection did not operate as expected, indicating a need for further investigation of the root cause.

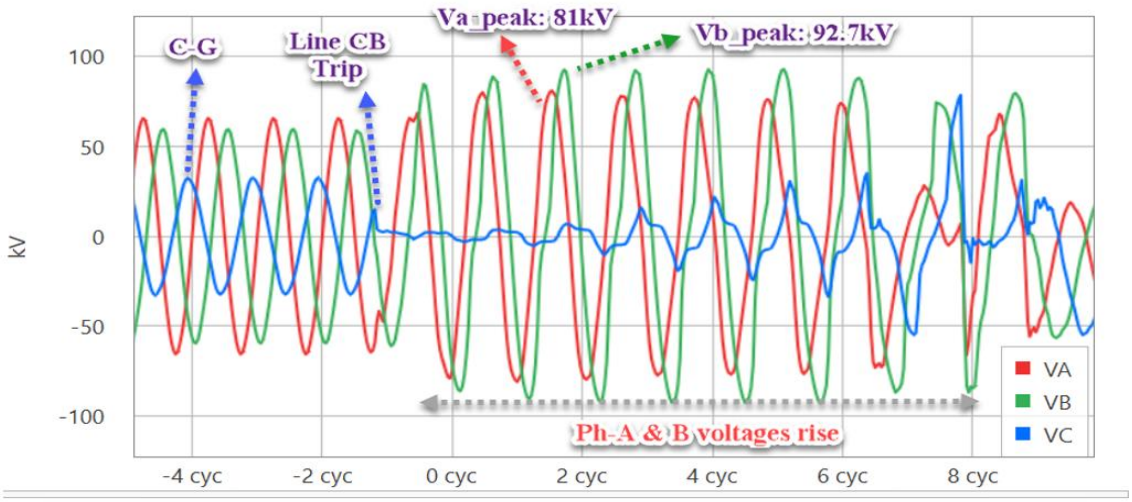


Fig. 23 Relay event of phase overvoltage scheme

Table 1 lists the calculated voltages and the corresponding overvoltage pickup settings. Based on the calculated voltages, 59A2 and 59B1 should have reliably picked up, and 59B1 element should have issued the trip in 4 cycles. However, the relay event indicates these overvoltage elements alternated between ON and OFF, and did not get a chance to time out, as shown in Fig. 24. The reason for this is because the relay-measured voltage magnitudes oscillated, fluctuating above and below the pickup settings. It is also noteworthy that the voltage magnitudes were stable without any oscillation prior to the tripping of line breakers. It becomes evident that the oscillation of relay-measured voltages led to the failure of the overvoltage protection scheme to operate as intended.

Table 1 Apparent voltage as compared to overvoltage settings

Measured Voltage (Primary peak)	Calculated RMS (secondary)	Protection Element	Pickup Setting	Time Delay	Pickup or not
Va: 81 kV	95 V	59A1	101.04 V	4 cyc	No
		59A2	80.83 V	20 cyc	On & OFF
Vb: 92.7 kV	109 V	59B1	101.04 V	4 cyc	On & OFF
		59B2	80.83 V	20 cyc	Yes

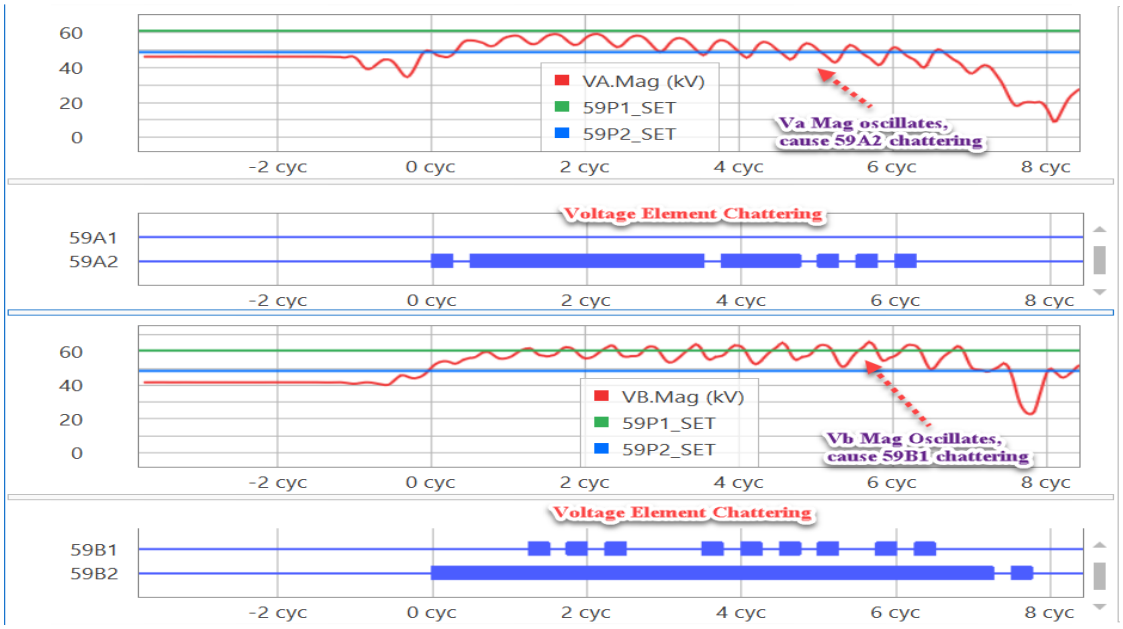


Fig. 24 V_A and V_B magnitudes as compared to the overvoltage settings

To investigate the root cause of voltage oscillations, the relay event file was exported to Excel for further analysis. An ideal 60Hz signal with similar magnitude and phase angle was generated in Excel as shown in Fig. 25. It is interesting to notice that the frequency of system voltage suddenly dropped from 60Hz. The new frequency matched closely with 54.8Hz signal. However, the relay still estimates the signal frequency of 60Hz.

System frequency may deviate from the nominal frequency due to generation and load imbalance. Generally, digital relays employ techniques to track the change of source frequency, and adjust the phasor estimate filtering based on the actual voltage and current frequency. According to the relay instruction manual [4], the relay can track frequency changes at a rate of up to approximately 20Hz/s. The relay will not measure faster-changing frequencies, and will revert to nominal frequency if the condition is maintained for more than 0.25 seconds.

In this case, the voltage frequency dropped from 60Hz to 54.8Hz almost instantaneously. This rate of frequency change exceeded the relay's tracking capability, leading to its failure to accurately follow the frequency drop. As a result, the relay could not adjust its digital filtering for phasor measurement, leading to the oscillation of measured voltage magnitudes and subsequent failure of the overvoltage protection scheme to operate correctly.

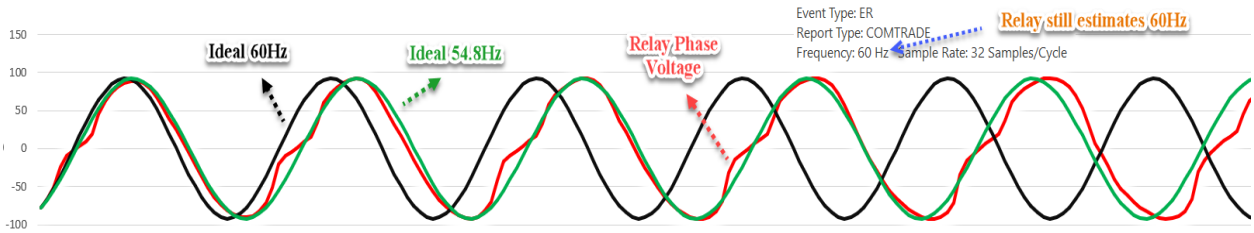


Fig. 25 Relay voltage matching with ideal 60Hz and 54.8Hz signals

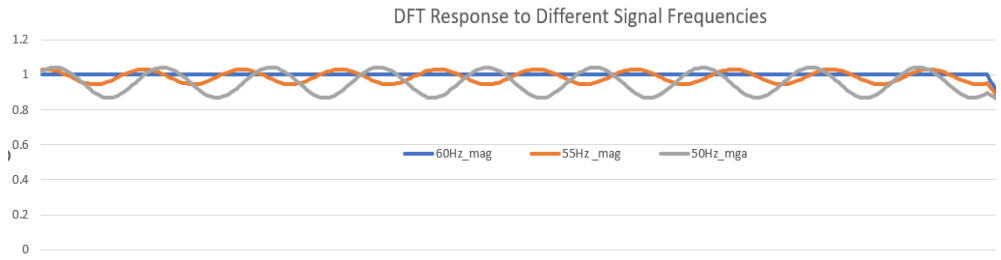


Fig. 26 DFT responses to different frequencies (60Hz fundamental frequency)

Fig. 26 illustrates how Discrete Fourier Transforms (DFT) with 60Hz fundamental frequency responds to signals with frequencies of 60Hz, 55Hz and 50Hz. For a 60Hz signal, the DFT has a stable output of 1pu. However, if the signal frequency deviates from fundamental frequency or its integer multiples, the DFT output will begin to oscillate. Although the relay may use a different digital filtering algorithm than DFT, its performance would be similar in this aspect.

The frequency tracking of a digital relay has been designed based on the synchronous machine-based sources, where the inertia of machines will prevent the frequency from rapid change. However, IBRs output frequency can change so rapidly, exceeding tracking capability of many existing digital relays. This is one of the challenges IBRs introduced to protection engineers. Relay manufacturers will need to develop new techniques to handle frequency tracking issue in era of IBRs.

IV. Conclusions:

Faults and disturbances are inevitable in electric power systems. Analyzing these events are important for protection engineers to develop a deeper understanding of system faults, abnormal conditions and relay performances. It is particularly important when the protection schemes did not operate as expected. Analysis of these events helps identify the root cause of protection misoperation and implement corrective actions.

This paper discusses a few relay events to illustrate how different strategies can be utilized to analyze these events. Many of these events appeared to be confusing and hard to understanding initially. However, when the proper tools and strategies are employed, protection engineers can effectively troubleshoot the incorrect protection operation, identify the root causes and apply the corrective actions to prevent future misoperation.

V. References:

[1] SEL-487E Transformer Protection Relay Instruction Manual, www.selinc.com

[2] IEEE C37.110-2007, Guide for the Application of Current Transformers Used for Protective Relaying Purposes, IEEE Standard Association

[3] IEEE CT Saturation Calculator, www.pes-psrc.org

[4] SEL-351 Protection System Instruction Manual, www.selinc.com

Daniel Zhang is currently an Expert Protection Engineer with Pacific Gas and Electric based in San Ramon, CA. He supports PG&E's 500kV System Protection, Remedial Action Scheme, Phasor Measurement Units, etc. He received his BSc and MSc degrees in 1993 and 1996 respectively from Xi'an Jiaotong University, Xi'an China, and MESc in 2003 from University of Western Ontario, London, Ontario, Canada. He has been working in the field of power system protection and control for over 20 years with utilities and engineering firms. He is a registered professional engineer in NY State.