

## **Working Group I21, Relaying Practices Subcommittee**

### **IEEE PES Power System Relaying Committee**

#### **Analysis of System Waveforms and Event Data**

**December 2015 (Revised May 11, 2016)**

**Abstract:** The working group for use of disturbance recorders was given the assignment to develop a report to the System Protection subcommittee of the IEEE Power System Relay Committee. The paper discusses the types of recording devices available to capture disturbances on the power system, and the analog and binary inputs that will help an engineer analyze these disturbances.

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## 1.0 Introduction

This report presents a wide range of phenomena that may be observed in recordings of system waveforms. Such recordings are typically made by digital fault recorders and digital relays. Each section illustrates a case study of a particular type of event which may require further analysis. Each event is described in detail, to allow those unfamiliar with that particular phenomenon to better understand the circumstances of the event and correct possible unintended operations. This report aims to provide an illustrative reference of different types of power system events that might be encountered by anyone who is analysing waveform data.

These case studies are defined by power system waveforms and event data in the COMTRADE (IEEE Std C37.111) format.

## 2.0 Circuit Breaker Restrike

Per IEEE 100, The Authoritative Dictionary of IEEE Terms, 7<sup>th</sup> Edition, a restrike is defined as a resumption of current between the contacts of a switching device during an opening operation after an interval of zero current of  $\frac{1}{4}$  cycle of normal frequency or longer. Figure 1 shows the captured event of one restrike although if the deteriorating condition of a circuit breaker is not captured early enough, there may be multiple restrikes in both the positive and negative half cycles.

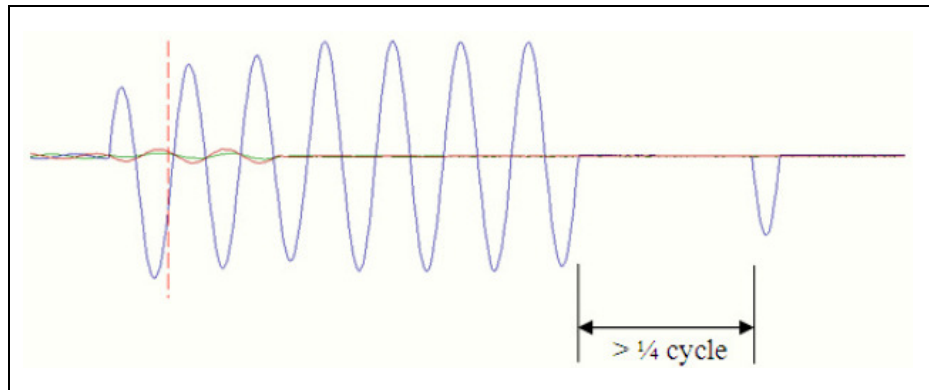


Figure 1. Circuit Breaker Restrike.

## 3.0 Arcing

At a distribution substation, the 27 kV capacitor bank vacuum tube breakers were experiencing failures. The breakers are typically operated twice a day for controlling voltage and reactive power and, over time, they accumulate a significant number of operations. The resulting waveform data (refer to Figure 2) shows both the trip coils of the breakers (DC captures) and the CTs of the capacitor bank feeder (AC captures). The DC captures indicated that the breaker timing was within specification but the AC captures showed considerable transients immediately after the breaker opened.

Further analysis of the transients revealed that the vacuum tube bottles were breaking down. Such breakdowns pose a danger of damage to surrounding equipment and more importantly they pose a safety concern for operations personnel. Removing a failed vacuum circuit breaker from its cell is a serious arc-flash-hazard to operation personnel. Clearly, such potentially life threatening events can be avoided with proper monitoring.

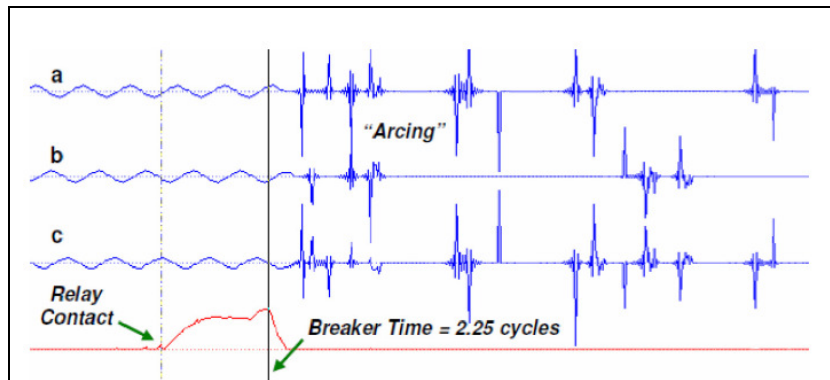


Figure 2. Vacuum bottle breakdown (27 kV capacitor bank breakers).

## 4.0 Fault Magnitude and Time

The measurement of current plays a significant role in determining the nature of a fault and the well-being of a system. This segment will address additional, but not all, uses for current measurements in a power system.

Some utilities find it advantageous to measure the magnitude of current and time duration during fault conditions. This information can be accumulated over a period of time to assess maintenance of breakers. Some microprocessor relays automatically accumulate this information on a per-phase basis. Therefore, if one phase of a breaker accumulates considerably more operations than the other two phases, additional attention can be made to that phase.

Figure 3 depicts a typical fault clearing of three cycles.  $I^2t$  is a damage factor formula that can be used to indicate damage to power equipment, such as for circuit breakers. The case provide in Figure 3 is a 100 A fault lasting .05 seconds. In this case,  $I^2t$  is calculated to be 500 ampere<sup>2</sup>-seconds. Such values accumulated over a period of time can be used to determine when breaker maintenance is required.

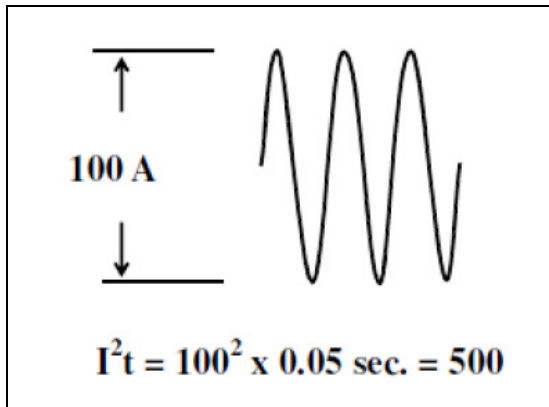


Figure 3. Typical Fault Clearing of Three Cycles.

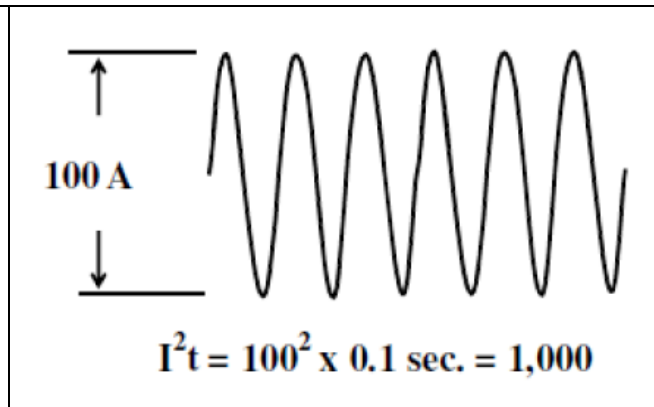


Figure 4. Fault Current Duration is twice that of Figure 3.

Figure 4 depicts the same fault current magnitude but twice the time. Therefore,  $I^2t$  is logically twice the value shown in Figure 3. More significantly, the waveform shown in Figure 4 might indicate a more intrinsic problem of slow breaker clearing. Microprocessor relays can be programmed to detect slow breaker clearing and send alarm signals to evaluate the significance of the delay. It might signify a breaker problem, relay problem, etc.

Figure 5 depicts a waveform that is twice the current value in Figure 4. This is significant because the value of  $I^2t$  increases by a magnitude of four times than that in Figure 4. Some utilities elect to leave breakers in service that have marginal interrupting capacity for close-in faults. This situation would require that utilities take precautionary steps to inspect a marginal breaker for internal damage. The use of overcurrent relays can play a vital role in this process.

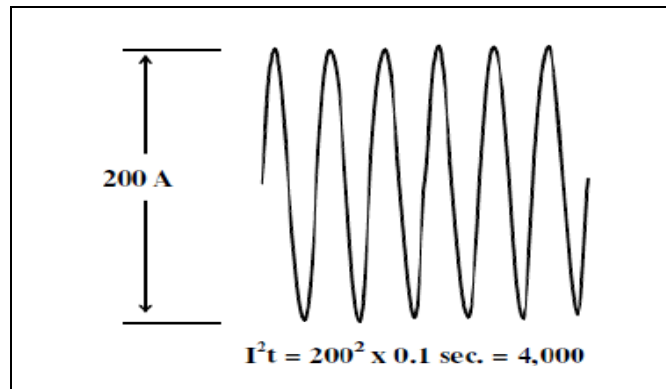


Figure 5. Fault Current Magnitude is twice that in Figure 4.

Figure 6 depicts a condition on a 161 kV system that could adversely affect successful reclosing because of the insufficient "dead time". One utility ran extensive studies to determine that if the dead time exceeded 13 cycles on 161 kV system, reclosing will be 90% successful. The utility also concluded that if the delay time were reduced to 10 cycles, successful reclosing would be reduced to approximately 50%. It was concluded that ionized gasses around an insulator may not have sufficient time to dissipate if the "dead time" were less than 13 cycles. To further clarify the example given in Figure 6, the bottom oscillography trace depicts a six cycle breaker clearing time at one end of the line and a three cycle breaker clearing time at the remote terminal. Under these conditions the 10 cycle dead time did not provide enough time for ionized gasses to dissipate around an insulator and the fault was re-established when the breakers reclosed.

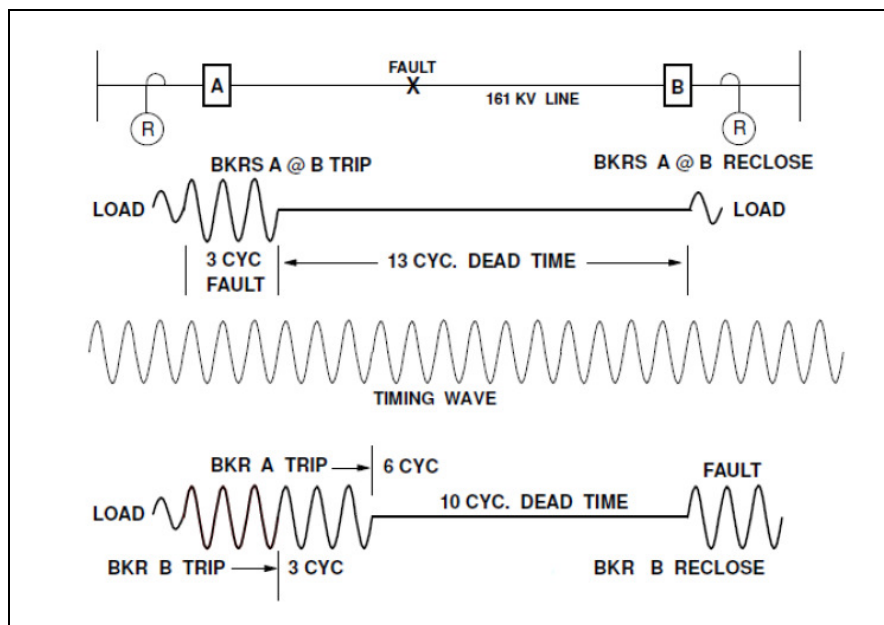


Figure 6. 161kV System with Reclosing "Dead-Time" issue.

The use of overcurrent elements to detect and evaluate this type of condition is invaluable.

The dead time will vary with system voltage. For example, a 500 kV line might have a successful reclosing rate with a dead time of 22 cycles, or longer. Some high-voltage transmission lines require successful reclosures to prevent system instability. Therefore, it is vitally important to have knowledge of a 500 kV transmission line's reclose success rate because some 500 kV breakers are not equipped to handle an additional fast reclosure.

Figure 7 is a good example of an evolving fault. The fault started out as a phase to phase fault involving B and C phases. After four cycles, it evolved into a three-phase fault. The current oscillography elements played a vital role in resolving a problem. The initial phase to phase fault was an external fault on a 23 kV distribution circuit. A "fast bus protection scheme" was employed to differentiate between a line fault and a bus fault.

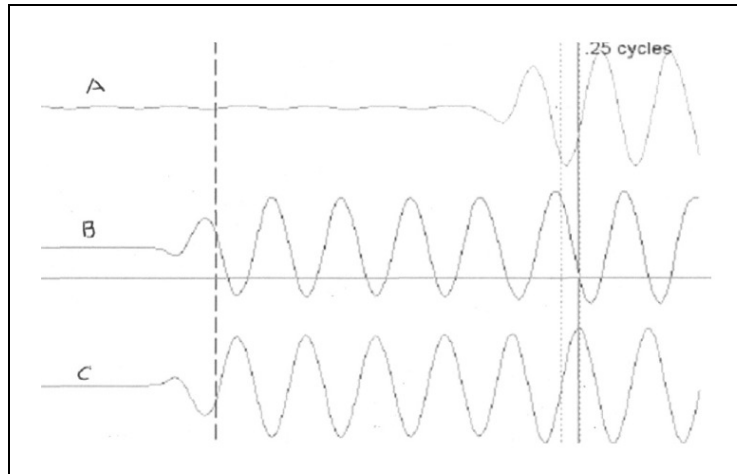


Figure 7. Example of Evolving Fault.

Overcurrent relays were used to assert for feeder faults and send a block tripping signal to a high side breaker. This required feeder breaker relays to initiate a block signal to prevent tripping the high side breaker for external faults. With this arrangement, “no” signal would indicate a bus fault and initiate instantaneous tripping of the high side breaker.

A negative-sequence directional relay was used to detect phase-to-phase and ground faults. For the first four cycles, during a B to C phase-to-phase fault, a negative-sequence directional ground relay picked up to detect an external fault on a feeder breaker. The system was designed in such a way that a positive-sequence directional relay, which was used to detect the ensuing three-phase fault, could not assert until the negative-sequence relay had dropped out. The dropout time was approximately 4 msec. Unfortunately, during the 4msec, the block signal to the high side breaker was interrupted, signifying a bus fault. The significance of this revelation required relay manufacture to install a two-cycle override to provide a continuous block signal while the negative sequence relay dropped out and a positive sequence overcurrent element asserted.

These are just a few examples of how overcurrent oscillography traces can be used to evaluate system conditions.

## 5.0 Carrier System

### 5.1 Carrier System Reviews

Figure 8 depicts a 500 kV/161 kV wye-wye delta transformer. For analysis purposes, a phase-to-ground fault on the 161 kV line between breakers B and C produces a polarizing neutral current (P) and a residual current from breaker B that provides carrier directional characteristics to initiate an unblocking signal between breakers B and C.

Note that an arbitrary setting of 0.5 A is shown to initiate the pickup of all non-directional residual ground blocking elements. The residual ground directional element is also arbitrarily set to pick up at 1 A. It is important to note that the non-directional start elements must always be set more sensitively than the directional element. The directional characteristics are determined by the interaction of a line residual current and the station polarizing current which is made up of the summation of the 161 kV neutral CT and 500 kV neutral CT.

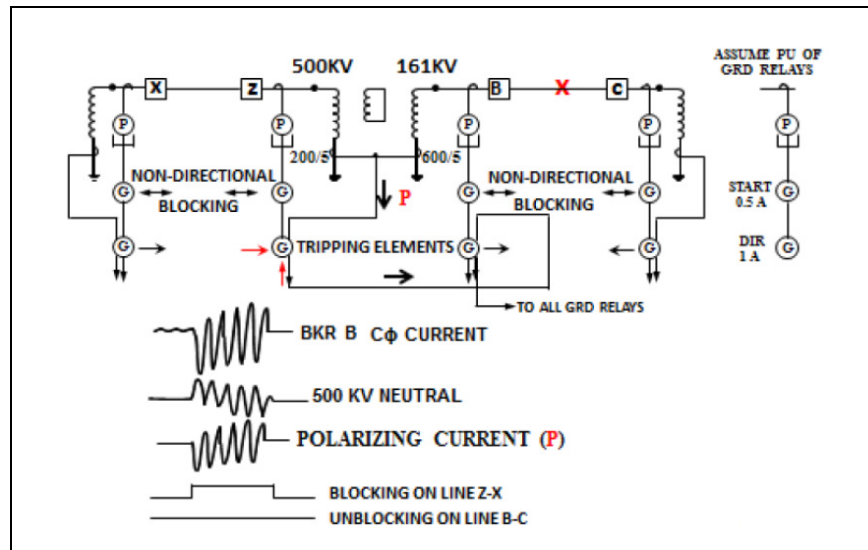


Figure 8. Carrier system with 500 kV/161 kV wye-wye delta transformer.

Thus, a phase-to-ground fault between breakers B and C will be detected as an internal fault by the directional tripping elements at both terminals to stop the transmission of the carrier signal. (unblocking on line B-C). Conversely, the residual current on breaker (Z) together with the station neutral ground polarizing circuit will determine that the fault is external and produce a continuous blocking signal.

It should be noted that the directional tripping element at breaker X will view the 161kV fault as an internal fault unless correctly blocked by the directional ground relay at breaker (Z).

All three currents depicted show significant offset, but no saturation. The C phase current on breaker B is in-phase with the polarizing current and out-of-phase with the 500 kV neutral current. It should be noted that the 161kV neutral CT (600/5) and the 500kV neutral CT (200/5) should be sized so as to produce a current with the same directional polarizing characteristics for all phase-to-ground faults on the 161kV and 500kV circuits.

## 5.2 Carrier Holes and Current Reversals

For the Figure 9 a carrier hole developed during the current reversal caused by the tripping of an adjacent line. Figure 9 depicts a phase-to-ground fault on line 1 adjacent to breaker B. For this condition, the ground relays associated with breaker D are required to block the relays associated with breaker C breaker from tripping breaker C. For this condition, a current of 2000 A flows towards breaker D. The directional characteristics of the ground relay on breaker C is determined by the residual current from the CT on breaker C and the transformer neutral current. It should be noted that both currents are in phase. Conversely, the secondary currents in the ground relay associated with breaker D are 180° out of phase, which indicates that the ground fault current of 2000 A is flowing towards the bus at station Y.

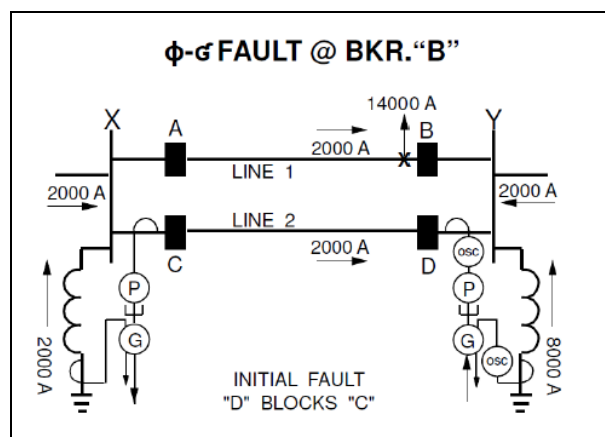


Figure 9. Phase to Ground Fault on Adjacent Line.

The time duration of three cycles is shown in red in Figure 10. Both the phase-to-ground fault current of 2000 A in the residual CT associated with breaker D and the station polarizing current of 8000A in the neutral CT of the transformer at substation Y to produce the proper directional characteristics which provide a continuous carrier blocking signal shown at the bottom of Figure 10.

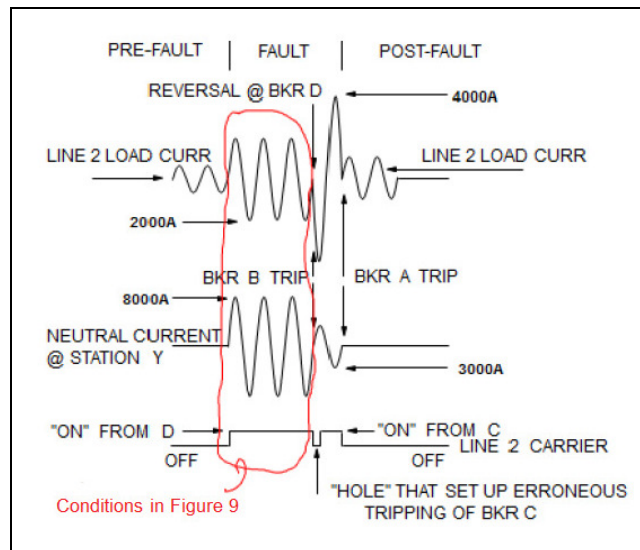


Figure 10. Phase to Ground Fault duration of 3 cycles.

Figure 11 depicts a condition that occurs after breaker B opens in three cycles. At this time, breaker A on line 1 is still closed. It will remain closed for an additional one cycle. During this one cycle time period the current of Line 2 will increase to 4000A and flow in the reversed direction. This instantaneous reversal of current will require that the ground relays on breaker C must assume a blocking mode.

The ground relays on breaker D will be in the trip mode. On occasions, this instantaneous reversal of current may result in the momentary loss of a carrier signal. One cycle of the current reversal is circled in red in Figure 12. The momentary loss of a carrier signal is shown at the bottom of Figure 12. This momentary dip in carrier is referred to as "a carrier hole". When this occurred, breaker C tripped by its carrier ground relay.

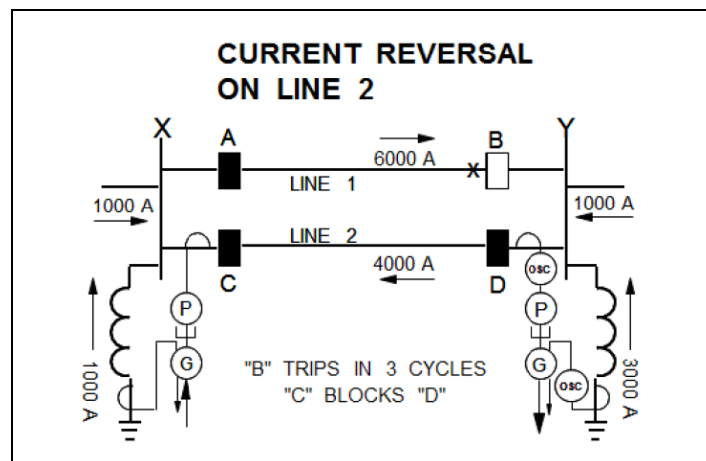


Figure 11. Conditions after Breaker B Opens.

At this point, a trip initiation signal has been sent to breaker C. As soon as breaker A opens one cycle later, a second current reversal took place on line 2. The resultant current flow was load current because the fault had been extinguished on line 1 by the opening of breakers B and A. It is important to note that the fault current in the neutral trace at station Y in Figure 12 is zero when breaker A opened. When this occurred, the carrier trace at the bottom of Figure 12 went from "on" to "off".



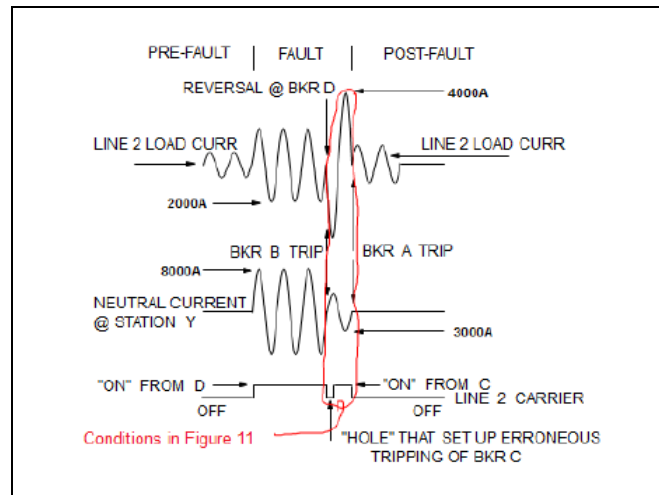


Figure 12. Conditions after Breaker B Opens in 3 cycles.

Figure 13 shows the end result when breaker C trips six cycles after the initial fault. The section circled in red reveals that load current flowed in line 2 approximately 2 cycles after breaker A opened to clear the fault on line 1.

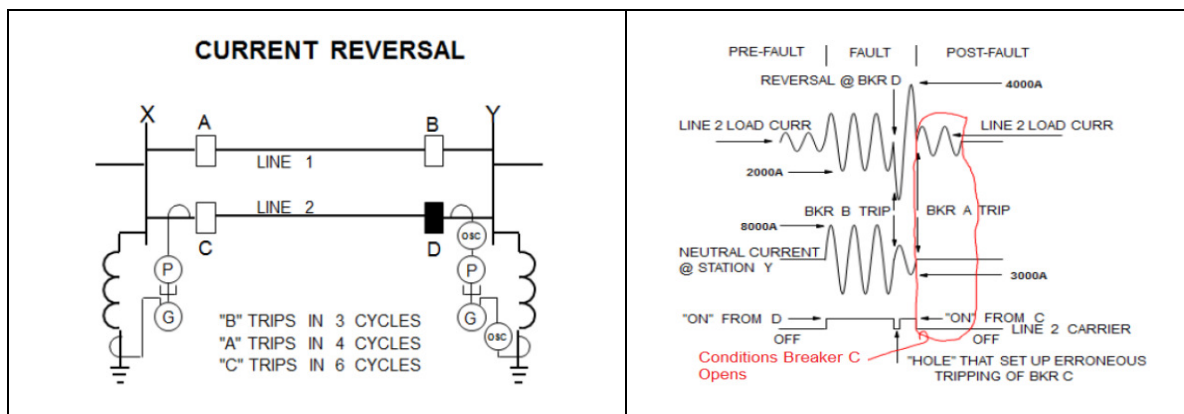


Figure 13. Conditions after Breaker C Opens in 6 cycles subsequent to the initial fault.

### 5.3 Carrier Holes in Directional Comparison Blocking ( DCB ) Scheme.

A directional comparison blocking scheme using on/off power line carrier is commonly used as the communication scheme for transmission line protection. A blocking signal is transmitted to remote line terminals when a reverse fault is detected at a local terminal. Scheme security is dependent on maintaining a continuous blocking signal throughout the external fault clearing. A carrier hole occurs when the blocking signal disappears during a fault on an external transmission line due to something in the PLC system shorting to the ground. There are several culprits of carrier holes in the PLC transmission path. The signal is propagated from the transmitter through a coax or triax cable to the line tuner, through the coupling capacitor to the transmission line itself. Flash-overs of the signal to ground can occur at several of these places in the channel. It is the “weakest link” that causes the issue. As coax ages, the insulation begins to degrade, allowing a path from the center conductor to the grounded shield, allowing a flash-over when stressed. This will result in a loss of signal or carrier hole for the time the flash-over is present.

In the coupling capacitor and line tuner, there are protective units, consisting of protective air gaps (spaced electrodes), gas tube or other limitation devices, and an RF grounding switch. Shown in Figure 14 is a typical Power Line Carrier (PLC) Configuration.

In the coupling capacitor voltage transformer (CCVT), the protective unit is across the drain coil. The line tuner may or may not also have a secondary drain coil in parallel with the protective unit across that as well, but otherwise, the protective unit is still there, along with an RF grounding switch. In any case, the protective unit is still there, along with and RF

grounding switch. The protective gaps serve to provide a low impedance path to ground for surges due to transients, thereby preventing high level surges from getting into the electronics of the PLC channel as well as protecting the drain coil in the CCVT.

The goal of the protective gap is to arc over quickly and “seal-off” or extinguish the arc expediently. The gap should arc and seal-off within 1 to 2 milliseconds, so fast that the transmission line protection relay has not had time to process the fault data and take action for the fault. The flashover point is defined in the ANSI/NEMA C93 standards to be above 2.5 kV RMS at power frequency voltage and below 85% of the BIL rating of the device (10 kV for Line Tuners and CCVTs). Also, these surges are limited by other adjacent lightning arresters.

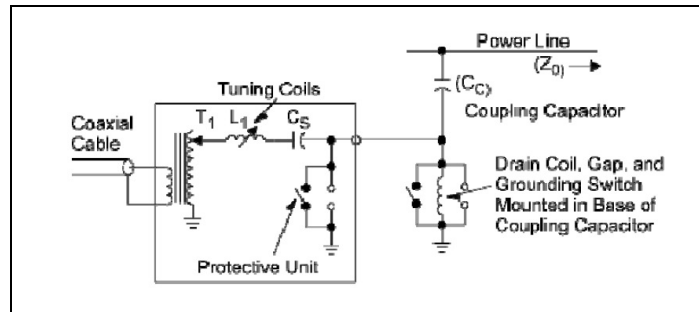


Figure 14. Typical Power Line Carrier (PLC) Configuration.

Maintenance is the key for preventing carrier holes. The protective gaps need to be routinely cleaned and re-adjusted for proper flash-over voltage, and coax cables should be periodically tested and replaced if necessary. Every time there is a transient on the transmission line, the protective gap will more likely flash-over, which in turn builds up carbon, thereby decreasing the flash-over voltage of the gap. This carbon build-up may cause the gap to flash-over sooner than expected the next time and not seal-off in time, thereby creating a carrier hole.

***Maintenance of the gaps will greatly improve the overall security of the channel and the protection system.*** Check-back systems do not detect issues with carrier holes since they are run during non-fault conditions.

It would appear that there is an increase in the occurrence of “carrier holes”, but it is probably more due to the increase of information that is now available with the microprocessor-based devices and the ability to obtain sequence of events out of these devices.

Carrier holes range from around 2 msec to several or more cycles depending on the state of the carrier channel apparatus, protective gaps and the voltage transients produced during faults. Experience shows that carrier holes are more often not less than ½ cycle in duration. Experience also shows that “stuff” happens and much larger carrier holes may occur. The following cases are provided as real-world examples.

## Events 1 and 2.

Figures 15 and 16 show Events 1 and 2, respectively. These events show a very common occurrence of repeated carrier holes in the BLOCK signal of a short duration. The resolution (sampling and/or computation frequency) affects the apparent length of the carrier hole, which may appear slightly longer than what they actually are. In any case, the holes in these two events are less than ½ cycle in duration.

In Event 1, a fault external to the protected line occurs and the carrier holes begin approximately 3 cycles after the fault inception. The FP (67N) signal has been asserted for a while so the relay asserts its TRIP signal immediately with the start of the first carrier hole (BLOCK signal drops out). It is speculated that the remote line’s breaker is opening, thus generating the voltage transients that initiate the insulation breakdown and resulting carrier holes.

In Event 2, the carrier holes begin approximately 2.5 cycles after the fault inception. The FP (67N2) signal has been operated for a while so the relay asserts its TRIP signal immediately with the start of the first carrier hole. It is again speculated that the breaker at the remote end of the line is opening, thus generating the voltage transients that initiate the insulation breakdown and resulting carrier holes. Higher frequency voltage transients cannot be observed in digital fault records recorded with lower sampling frequencies. The carrier holes continue in the BLOCK signal after breaker opening and are most probably the result of breaker opening transients. In this instance, a spark gap in the remote location’s tuner reportedly had “spit” marks, clear evidence of operation. Also, the tuner ground was not very good.

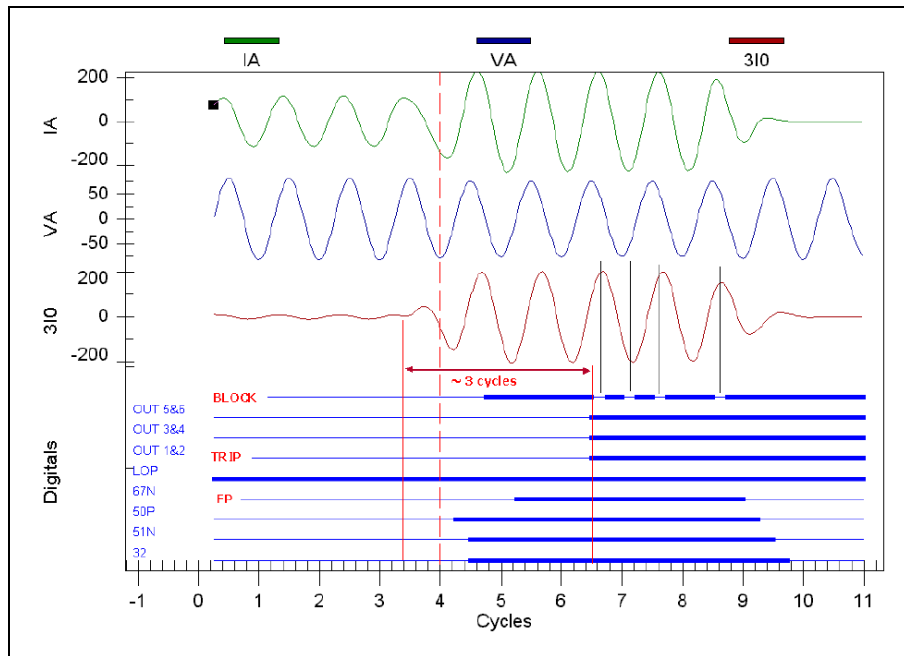


Figure 15. Event 1 fault record of an incorrect trip for a forward external fault.

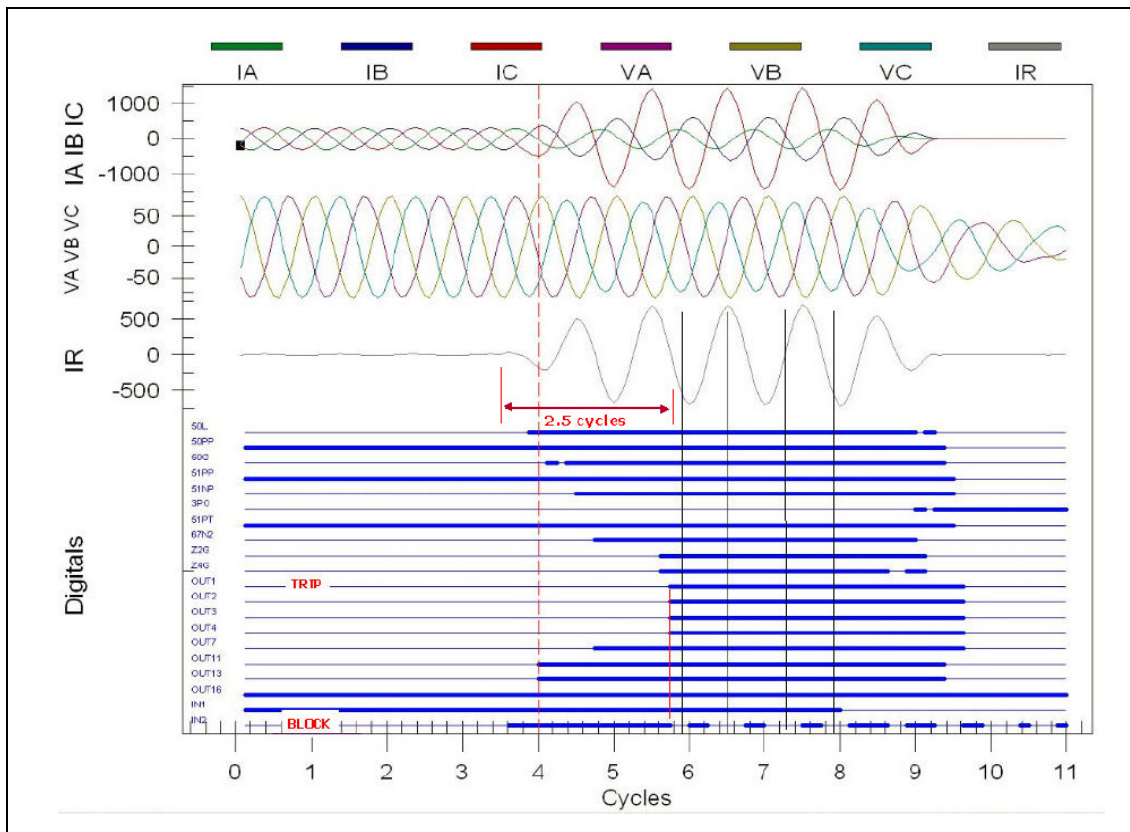


Figure 16. Event 2 fault record of an incorrect trip for a forward remote fault.

## 6.0 Breaker Clearing Times

Circuit breakers are integral parts of electrical power system protection system. In addition to breaking the current under normal load conditions, circuit breakers are also designed and constructed to be able to interrupt fault currents to isolate

faulted power system elements and to protect the rest of the power system. Circuit breakers that fail to interrupt fault currents will trigger breaker failure relays or backup protection systems to open more circuit breakers to isolate the fault. The result of a failed circuit breaker will force the protection system to take out more power system elements and, therefore, increase the possibility of unnecessary outages.

Circuit breakers are electromechanical devices that have multiple components. The interrupter system and the operating mechanism are the main components of circuit breakers. The open and close operations of a circuit breaker often involve the sequenced operation of multiple parts. For example, the open command from relay or manual operation will trigger the circuit breaker opening coil to unleash the stored energy to move the contacts in interrupter system to interrupt the current.

Typical forms of stored energy are hydraulic cylinders and springs. Circuit breakers normally have two contacts: the main contact and the arcing contact. In the process of opening a circuit breaker, the moving speed of the main contact is relatively slow to minimize the necessary mechanical energy for the interrupter operation. The arcing contact starts to separate at much faster rate after the main contact is separated. The high velocity of the arcing contact reduces the arcing time, increases the rate of voltage withstands recovery, and ensures restrike-free capacitive switching capability.

High-voltage circuit breakers manufactured today have the expected lifetime of up to 50 years and maintenance intervals in the order of 2 to 5 years. Over the life cycle of a circuit breaker, the breaker contacts can be worn out depending on the number of operation. A failure of a single component in the operating mechanism can cause the breaker failure. A CIGRE report shows that approximately 25% of the major and minor circuit breaker failures are attributed to the operating mechanism failure.

Monitoring the condition of circuit breaker operation and detecting the early sign of failure are of significant importance to utility maintenance and operation business units. Digital relays generate event records that are triggered by power system faults and circuit breaker operations. These event records capture all the necessary information including primary voltages, currents, and breaker coil status for analyzing the circuit breaker operation conditions.

Utilizing the event records that are triggered by power system faults reduces the needs to regular breaker tests that typically require scheduled outages. Circuit breaker opening time is one of the most important indices of breaker health conditions. The circuit breaker opening time is calculated by taking the time difference between the assertion of trip command and the change of breaker status. The auxiliary contacts of the circuit breaker (52A, 52B) typically give accurate indication of breaker status change. For more accuracy, the line currents can be used to identify the precise timing of breaker status change. The moment that the phase currents have finally gone to zero is the exact moment of circuit interruption and clearly indicates the breaker has opened.

A pair of event record captured in the field has been used to illustrate the concept of calculating the breaker opening time from digital relay event records.

Figure 17 and Figure 18 show the operation of two circuit breakers from both terminals of a 765kV transmission line to isolate a single-phase-to-ground fault. In both figures, the first chart areas show the line terminal currents; the second chart shows the line terminal phase voltages; the third chart shows the trip command issued by the digital relay in brown color and the breaker 52A contact status change in green color. By examining the time difference between the trip signal and the breaker status change, the breaker opening time for the left terminal (Figure 17) is 33 msec (1.98 cycle) and the breaker opening time for the right terminal (Figure 18) is 26 msec (1.56 cycle). Both opening times are within the range of the expected opening time that is 2 cycles.

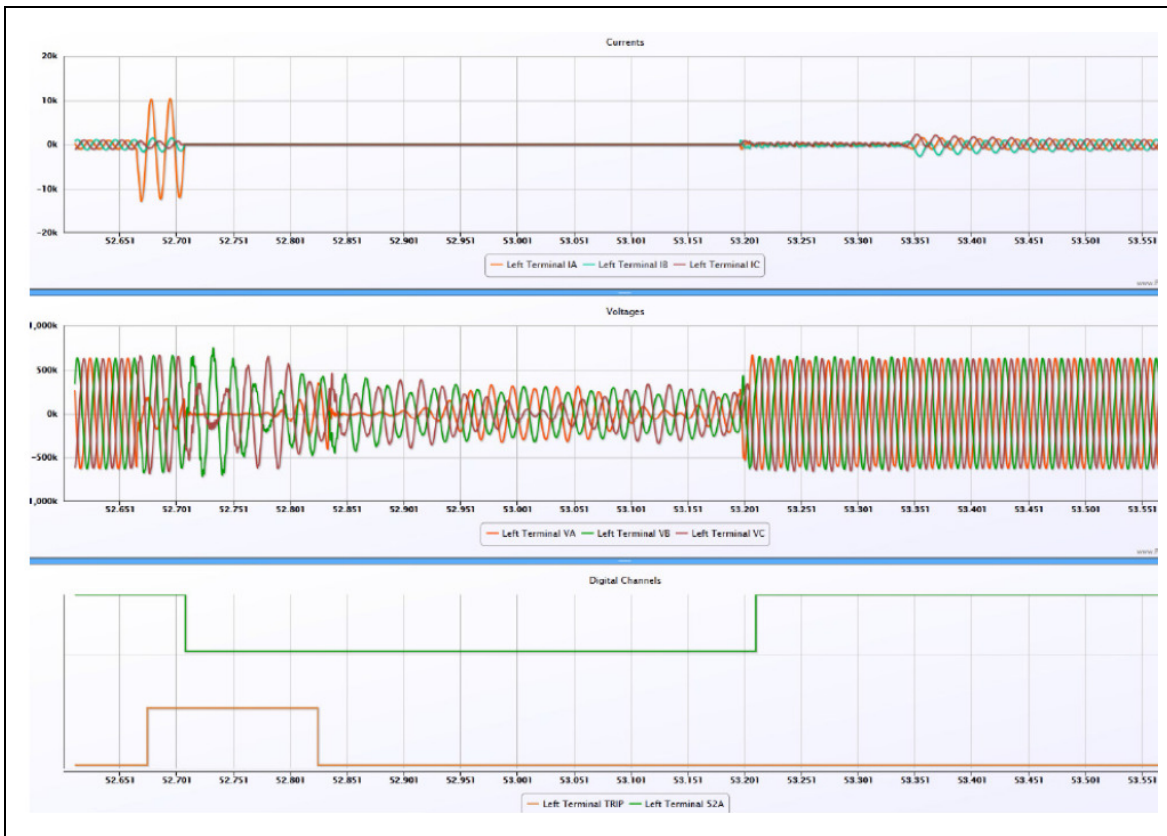


Figure 17. 765kV Line Left terminal relay triggered event record.



Figure 18. 765kV Line Right terminal relay triggered event record.

## 7.0 Transformer Inrush

### 7.1 Characteristics of a Three Phase Transformer Inrush Current Waveforms

Figure 19 below identifies a few of the salient features of a typical three-phase transformer inrush current waveform. Transformer inrush is quite unpredictable, considering that its characteristic depends on several factors including the point on wave when each phase is energized, the remanent core flux from the previous deenergization, the energizing source impedance, and the loading on the transformer when it is energized. The salient features depicted in the figure below are:

- Decaying current peaks: The peak of each current will decrease until the transformer core flux reaches its steady state, at which time the current will consist of the normal excitation current combined with the load current.
- Unipolar and bipolar waveforms: Typically, two of the three- phase currents will initially have a unipolar waveform, while the third phase will exhibit a bipolar waveform. This characteristic will change with time until all three phases have a bipolar sinusoidal wave form.
- Current “flat spots”: There will typically be simultaneous, near-zero current “flat spots” between current pulses. Over time, these flat spots will disappear as the waveforms become more sinusoidal.

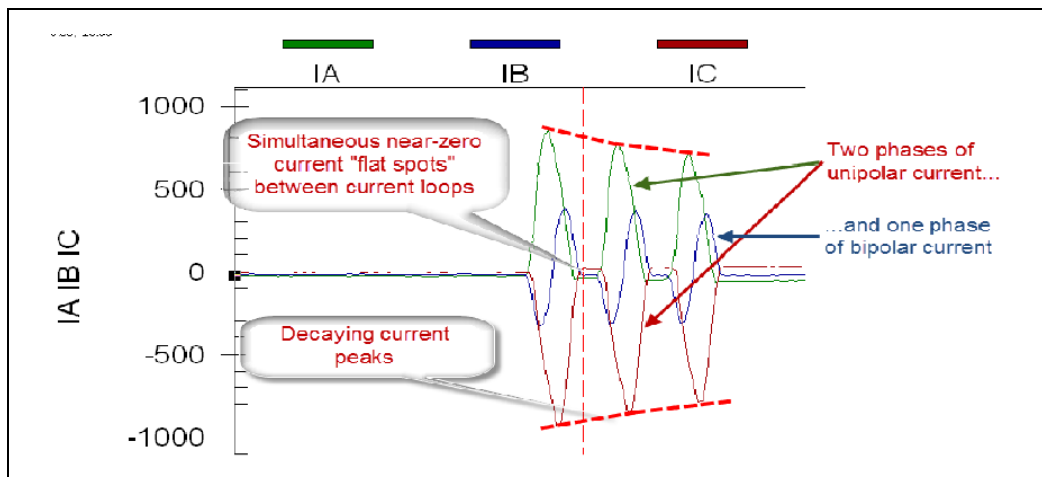


Figure 19. The salient features of a typical three-phase transformer inrush current waveform.

### 7.2 Transformer Inrush Current Waveform

At a generating plant, an attempt was made to energize a generator auxiliary power transformer. When the transformer was energized, it tripped on “A” phase differential relay. The resulting waveform data (refer to Figure 20) shows typical inrush current signature for about 3 cycles subsequently, the inrush current degrades over the next 9 cycles during which the differential relay operates to trip the circuit breaker.

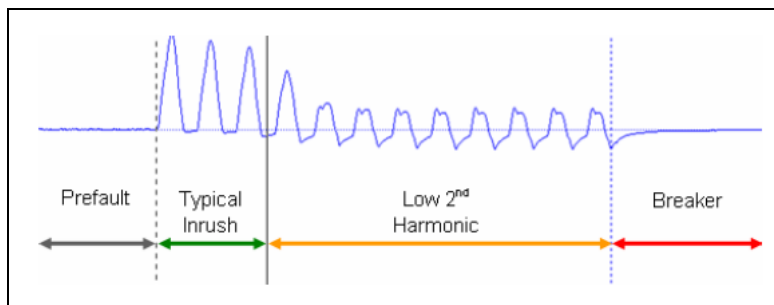


Figure 20. Typical 345kV Transformer Differential relay operation.



Further analysis of the data reveals that the root cause was CT saturation due to remanent flux. The saturated CT failed to provide the 2nd harmonic content required by the differential relay for restraint and, thus the relay operated. Corrective actions were then taken and the transformer was restored to service.

For comparison, Figure 21 shows a typical inrush current waveform from a similar transformer during energization. The shown waveform contains strong 2<sup>nd</sup> harmonic content (above 30% of fundamental) and the magnitude slowly decays towards zero (which could take over 10 seconds to complete).

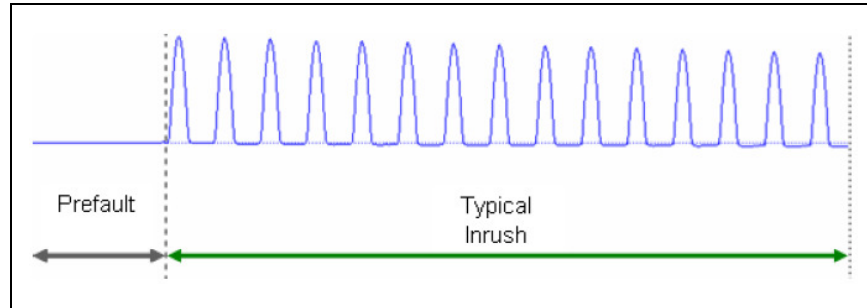


Figure 21. Typical 345kV transformer inrush current waveform.

### 7.3 Comparison of Three-Phase Transformer Inrush Currents for WYE-WYE and DELTA-WYE Transformers

This case study provides a comparison of the inrush signatures for two transformers in a radial configuration, one transformer having a wye winding facing the voltage source and the other transformer having a delta winding facing the voltage source. In both cases, the transformers are energized with the low-side load removed so that the inrush transient is captured.

#### Event 1: Energizing a 115/23/12.47kV 53MVA Wye-Wye-Delta Transformer

This event involves energizing the transformers at Station B from Station A. The initial state of the system shown in Figure 22 is as follows:

- All of the circuit breakers shown in Figure 22 are open so that the 115kV line, the Station B bus, and transformers #3 and #4 are deenergized.
- The high side disconnect switch of transformer #4 is open in addition to the low side switches of both transformers.

From this initial state, the system is positioned to energize an unloaded Station B transformer #3 from Station A.

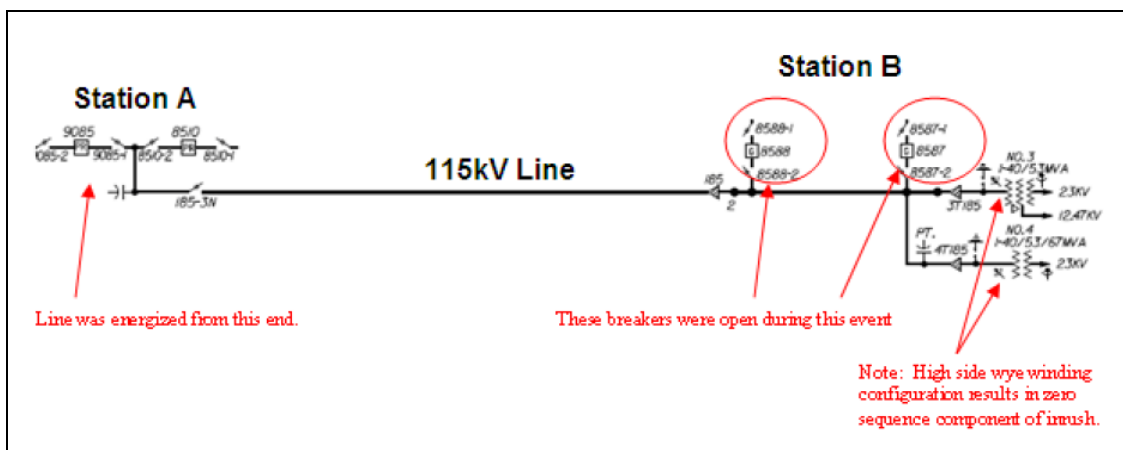


Figure 22. 115kV System One-Line.

Because transformer #3 is unloaded before switching, the only current that Station A relays would see are line charging and transformer #3 inrush and magnetization currents. Therefore, the expected steady-state currents are small.

With a fault recorder at Station A recording the event, Figure 23 illustrates the currents in CT secondary of the 115kV line when the Station A breaker is closed. Although transformer inrush can last a few seconds, this particular event caused a nuisance operation of the 115kV line carrier ground relays at Station A, which cleared the line current in 4 cycles.

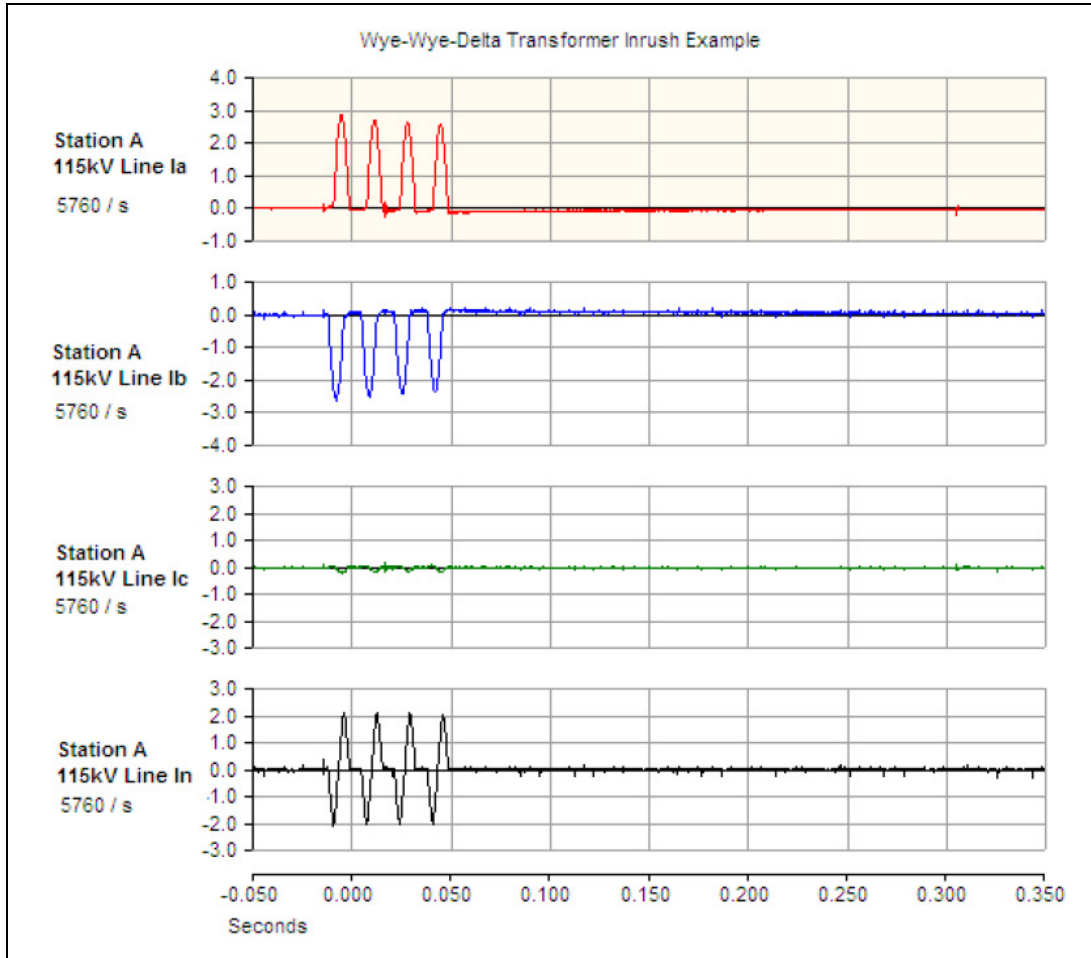


Figure 23. 115kV Line Currents in CT Secondary Amps.

The inrush current on each phase including the DC offset is a function of the phase voltage at the instant of the switch closure. This recording is a typical of transformer inrush current where two phases show a large DC offset and large even harmonic distortion, while one phase shows little or no DC offset and, therefore, little or no harmonic distortion.

The magnitude of  $I_c$  is considerably less than that of  $I_a$  and  $I_b$ . This is to be expected because  $I_a$  and  $I_b$  consist primarily of the large transient AC component of inrush in addition to the large DC component. With no significant transient component,  $I_c$  is reflective of steady-state current consisting only of 115kV line charging and transformer #3 steady-state magnetization current.

The resulting unbalanced current is returned to Station A as  $I_n$ , as indicated in the DFR record because of the wye winding configuration of transformer #3.

## Event 2: Energizing a 11.5/4.16kV 7.5MVA Delta-WYE Transformer

This event involves energizing the #3 transformer shown in Figure 24. The initial state of the system is as follows:

- The 11.5kV 3T11 breaker and the 4.16kV breaker (not shown) are both open so that the #3 transformer is deenergized.

From this initial state, the system is positioned to energize an unloaded #3 transformer from 11.5kV main bus.



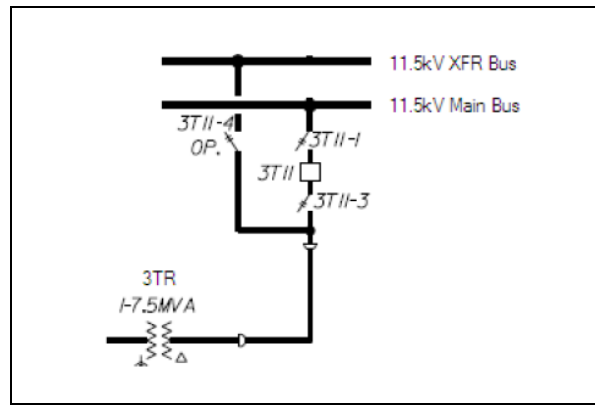


Figure 24. One-line diagram of a 11.5kV System.

From the transformer differential relay event record, Figure 25 illustrates the 11.5kV Side currents (IAW1, IBW1 and ICW1) in CT secondary amps when the 11.5kV breaker is closed. Because the transformer #3 is energized with the 4.16kV side switch open the 11.5kV line currents consists only of transformer #3 inrush and magnetization currents, and there are no 4.16kV side currents (IAW2, IBW2 and ICW2 are not shown).

Similar to the previous event, the inrush current including the DC offset on each phase is a function of the phase voltage at the instant of the switch closure. The reason this event record differs significantly from the previous event is that the delta winding facing the 11.5kV bus represents a break in the zero sequence circuit so there is no neutral return path. Consequently, the three-line currents must sum to zero. Typically, one phase (C phase in this case) shows a peak current that is roughly the sum of the magnitudes of the other two phases and is opposite in direction. This record does show a small nonzero bit of a residual current (IRW1) which can be attributed to CT error.

Although transformer inrush can last a few seconds, this particular event resulted in a nuisance operation of the transformer differential relay because of a logic issue with harmonic restraint logic settings. This relay provides a choice between letting Phase A harmonic blocking to restrain only the Phase A 87R element (and similar for Phases B and C) or letting the OR combination of all three harmonic blocking elements block the 87R elements for all three phases. The former is more dependable, while the latter is more secure. At this station, the former was chosen. The latter may have been the better choice.

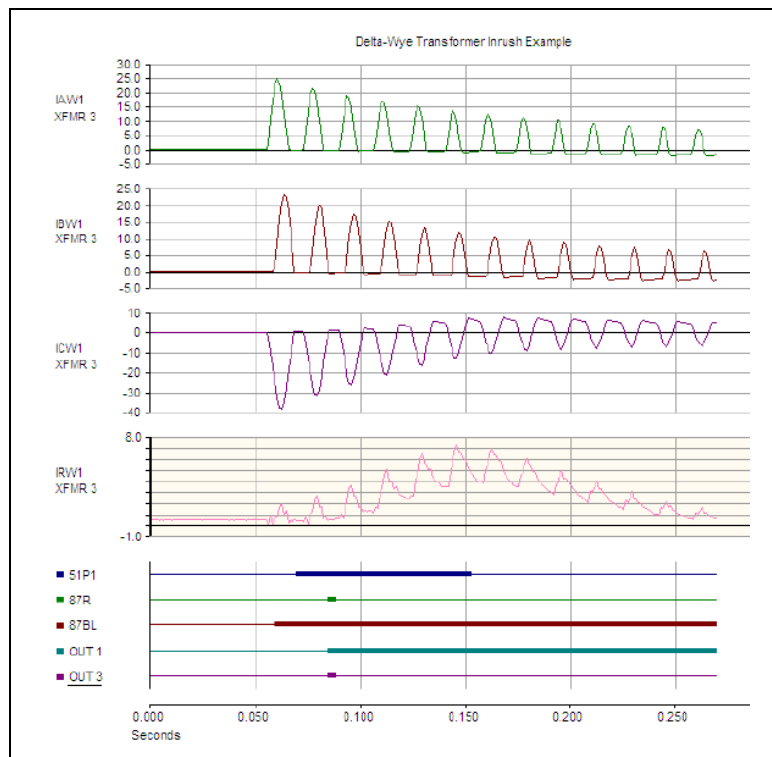


Figure 25. 11.5kV Side 3TR Line Currents in CT Secondary Amps.

## Conclusions and Considerations:

An important application consideration arises from this comparison of inrush signatures with respect to load transformer winding configurations. The majority of load transformers are delta-wye banks, which means that most of the time one could safely ignore tapped load transformer inrush when applying ground overcurrent or ground distance elements on transmission lines such as this. However, when tapped loads are grounded wye-wye banks or autotransformers, inrush currents cannot be ignored.

When analyzing records involving transformer inrush, it is necessary to understand the nature of how the recorded analog data is sampled and processed. DFRs typically provide unfiltered data which is most suited to this analysis. Some relays provide event records with a low sampling rate such as 4 points per cycle. Some relays provide event records with frequencies above 60Hz and DC components removed. These records are useful for analyzing relay performance if the sample rate and/or filtering are reflective of the relay's internal algorithms. However, these types of records do not accurately show what happened outside the relay. Often, both types of records are needed to do a complete analysis of certain events.

## 8.0 Capacitor Bank Ringing.

Power systems designed to function at 50 and 60 Hz are prone to experiencing failures when subjected to voltages and currents that contain high harmonic frequency content. Very often, the operation of electrical equipment may seem normal, but under a certain combination of conditions, the impact of harmonics is enhanced with damaging results. The only means of determining the magnitude and type of harmonics is through “careful monitoring”. Once sufficient data is collected and analysed, then the proper mitigation strategies can be defined and implemented. Here is a good example of careful monitoring:

At a 345 kV switching station, capacitor bank switching was causing damage to solid-state protective relay equipment and the capacitor banks themselves were also experiencing failures. The resulting waveform (refer to Figure 26) show the harmonic content at the time of switching.

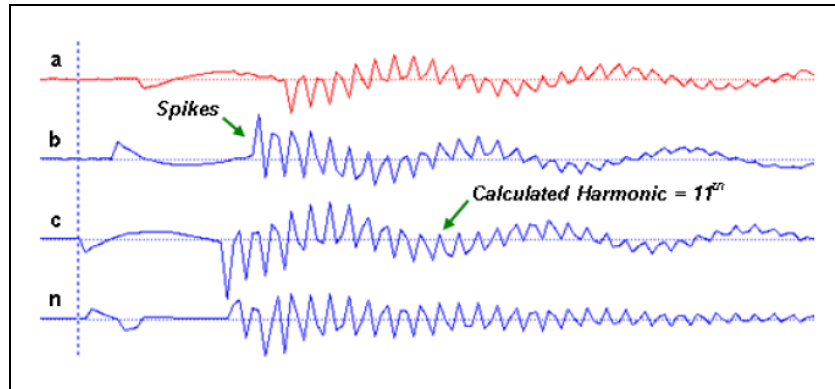


Figure 26. Capacitor Bank cut-in waveform at 32 sample per cycle.

The data revealed the presence of high harmonic spikes with large current magnitudes, during cut-in. This type of phenomenon is called “capacitor bank ringing”. One mitigation strategy is to install zero-crossing detectors and use them to cut-in the capacitor bank when the individual phase voltages are at zero (this prevents the occurrence of large discontinuities in current magnitudes). Other methods to mitigate inrush transients include the use of pre-insertion resistors or inductors on the switching device.

As for “careful monitoring”, the shown spikes are typical signatures of under-sampling. Using a Fourier filter, the calculated frequency of the spikes is 660 Hz (the 11<sup>th</sup> harmonic). Knowing that the installed sensors were being sampled at 32 samples per cycle, and seeing the asymmetric, saw-tooth like signature of these spikes, it is clear that the actual frequency should be a number above the 16<sup>th</sup> harmonic. Figure 27 shows the same cut-in event but with a sampling rate of 320 samples per cycle.

Clearly, the capacitor banks were not ringing at the 11<sup>th</sup> harmonic, they were ringing at the 21<sup>st</sup> harmonic. Careful monitoring requires a solid understanding of the events being observed and of the nature of the waveform signatures being captured.

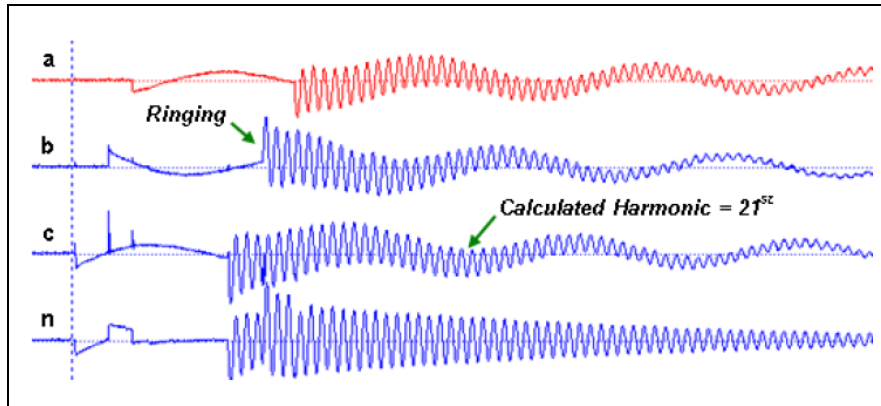


Figure 27. Capacitor Bank cut-in waveform at 320 sample per cycle.

## 9.0 Voltage Transformer Saturation and Ferroresonance

Voltage transformers will saturate when operated at voltages higher than their rating. Such a condition is usually obvious in the voltage waveform measurement. Transformer overvoltages produce a high 5<sup>th</sup> harmonic in the transformer magnetizing current, a quantity often used to block transformer differential relay tripping.

Ferroresonance also involves transformer saturation and occurs in power system circuits containing capacitance and a non-linear transformer magnetizing inductance and is usually initiated with a transient disturbance such as opening a switch. It results in severe transformer saturation and overvoltages and high current spikes that causes dielectric and thermal stresses, which may result in failure as well as subjecting operating personnel to hazardous conditions. Ferroresonance can occur with any transformer – power, instrument or auxiliary. Also, protective relays that measure these quantities are subject to incorrect operations causing unwanted outages.

Transformers by nature of their non-linear characteristics have two possible operating states; a normal state where operation is in the non-saturated region of the transformer's magnetic characteristic and a ferroresonant state where operation is in the saturated region.

Operation in the ferroresonant state is usually initiated by a transient condition and is dependent on a number of factors such as the system voltage magnitude, the initial voltage on the capacitor, the initial state of the magnetic characteristics of the transformer, the total loss in the circuit and the point on wave of initial switching.

Given the right conditions, the transformer can lock into a number of ferroresonant waveform patterns. Common ones are shown in Figures 28, 29, 30, 31 and 32. The one common characteristic among these ferroresonant waveforms is that they all contain the fundamental frequency driving voltage component, which sustains it.

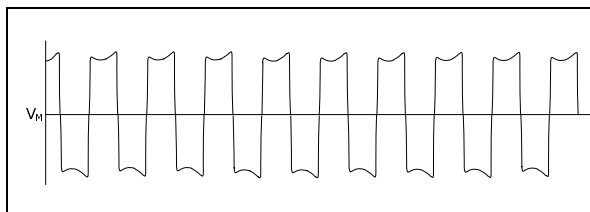


Figure 28. Fundamental – 60 Hz

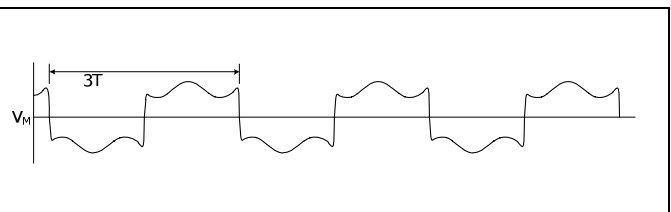


Figure 29. Sub-harmonic – 20 Hz

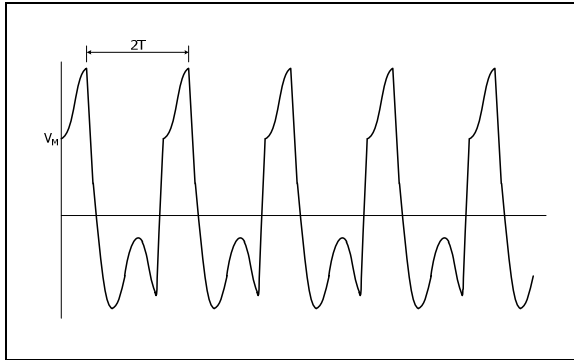


Figure 30. Sub-harmonic – 30 Hz

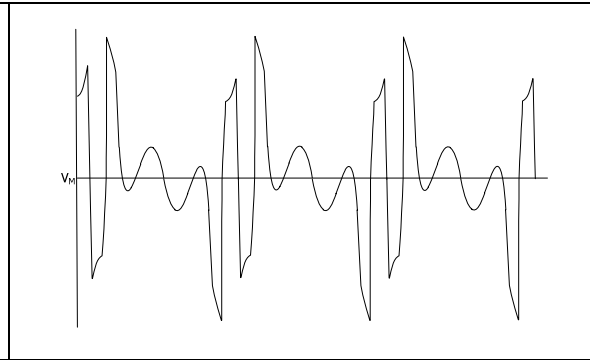


Figure 31. Quasi-periodic (slightly different periods and magnitudes)



Figure 32. Chaotic (hunts for, but does not lock into a pattern)

Figure 33 is a copy of a vintage magnetic strip chart recording (circa 1976) from Voltage Transformer (VT) ferroresonance testing in a 345 kV substation. During the testing, several waveform patterns of ferroresonance were observed with several being captured on this waveform – fundamental, sub-harmonic and chaotic (hunting) to be sure.

Unfortunately, an estimated 2 to 4 seconds of recording were removed [from a long roll of recording paper] between events at  $t_2$  and  $t_3$ . This test was to determine if the calculated damping resistance of 1.9 ohms would eliminate ferroresonance of a specific VT.

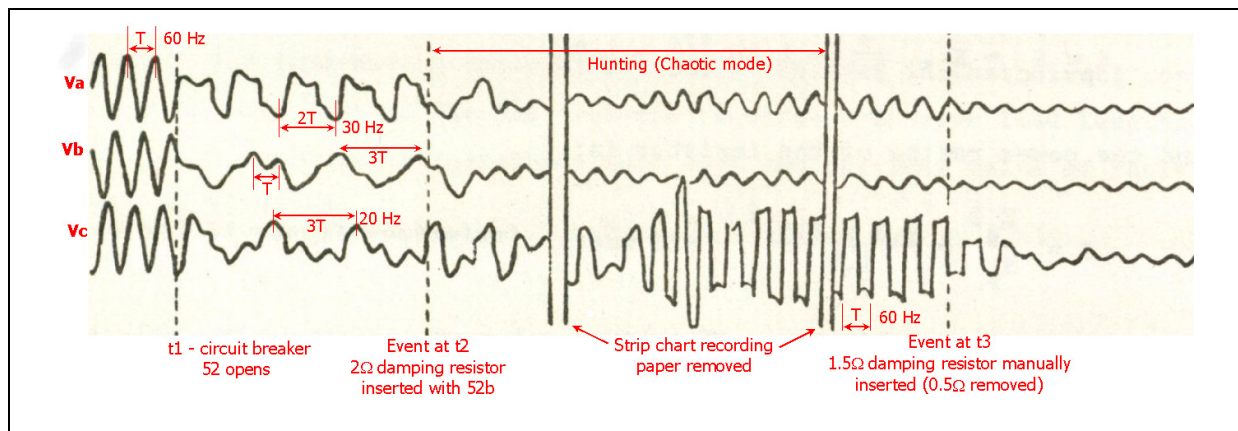


Figure 33. Vintage magnetic strip chart recording (circa 1976) from Voltage Transformer (VT) ferroresonance

## 10.0 Capacitive Voltage Transformer ( CVT ) Transient

A seven mile long 161 kV Line is protected using Phase and Ground Distance elements. The voltage inputs are provided by CVTs. A remote (A-B) bus fault occurs and the local ZAB (A-B Mho Element) asserts, producing a Zone 1 trip. The relay reach is set to 90% of the line impedance.

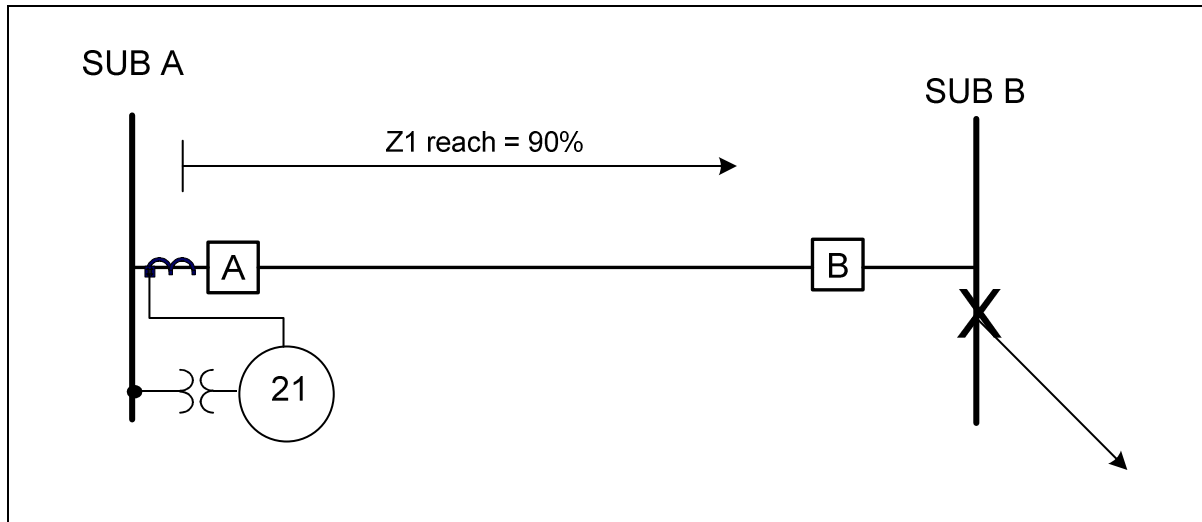


Figure 34. One-Line Diagram Shows Remote Fault

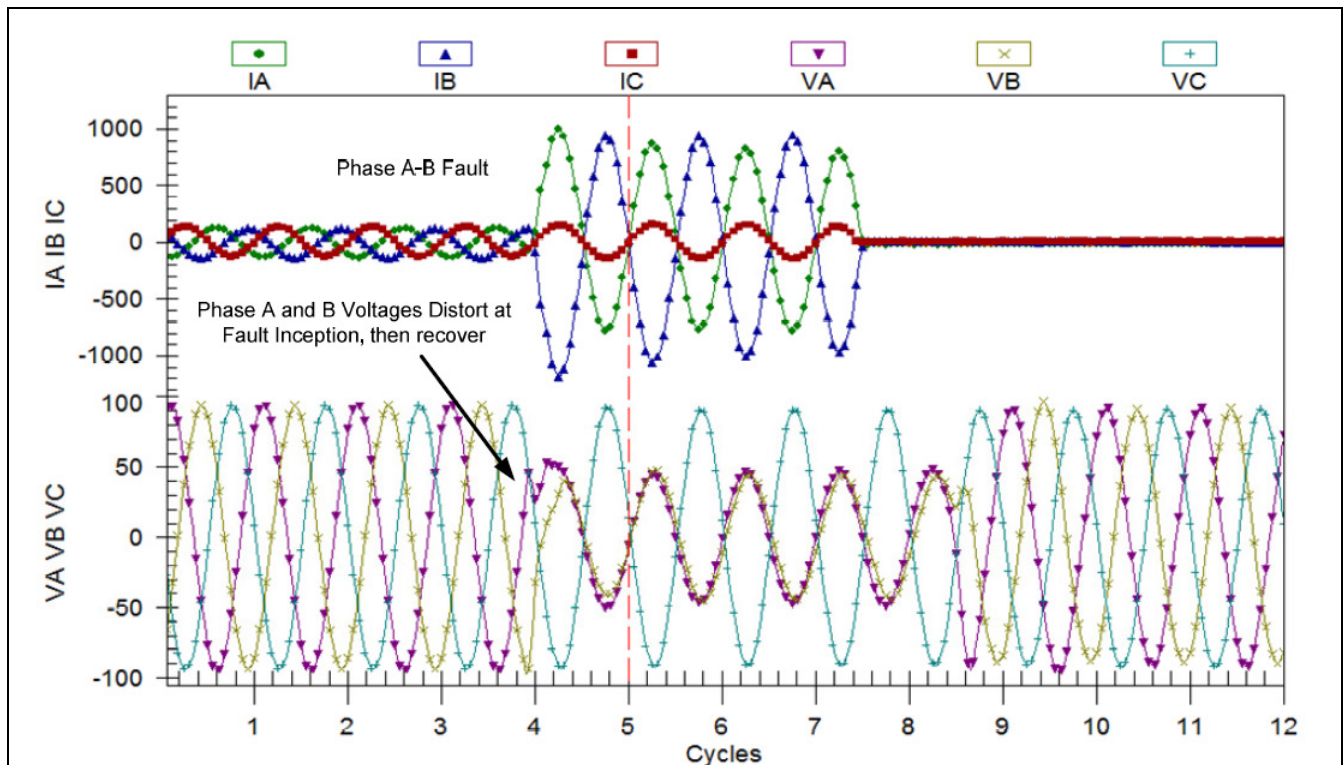


Figure 35. CVT transients for remote A-phase to B-phase Fault

Note that the Phase A voltage is closer to zero crossing and Phase B is near voltage peak at the fault instant. Thus, the Phase A transient is more severe.

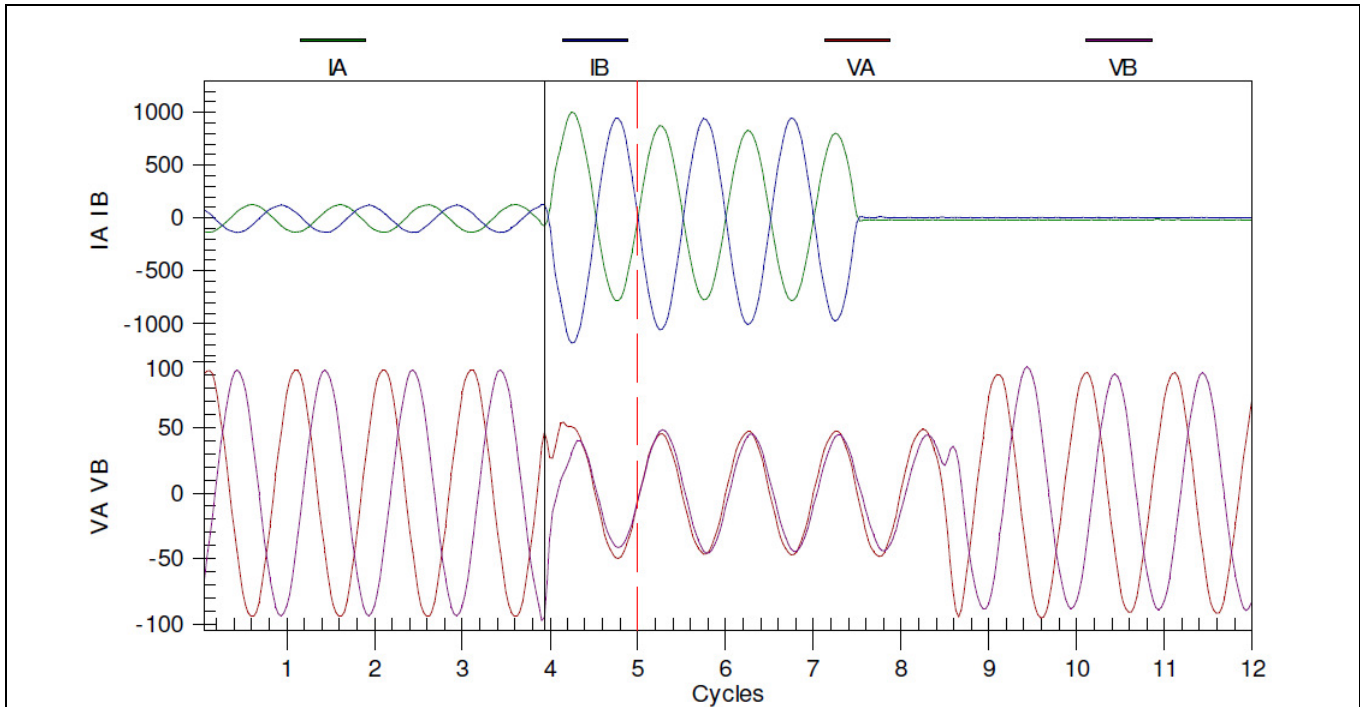


Figure 36. More severe CVT transient on A-phase (fault inception near zero crossing) versus B-phase (fault inception near voltage peak)

There are many factors that contribute to CVT transients, including point on wave when fault occurs, magnitude of stack capacitance, turns ratio and excitation current of intermediate transformer, the type of ferroresonance suppression circuit (active or passive filter), and the composition of burden on the CCVT. Solutions include reducing Zone 1 reach, adding time delay to Zone 1 and applying smoothness detection logic to recognize the transient and dynamically add time delay.

## 11.0 Unbalance Condition and Negative sequence Current

In order to demonstrate the properties of unbalanced current, which could be caused by unbalanced load or unsymmetrical faults, an arbitrary 230 kV line connecting Source 1 and Source 2 is shown in the Figure 37. Five cases have been simulated including unbalanced load, three unsymmetrical faults (AG, ABG, AB), and a symmetrical three-phase fault could represent symmetrical load as well.

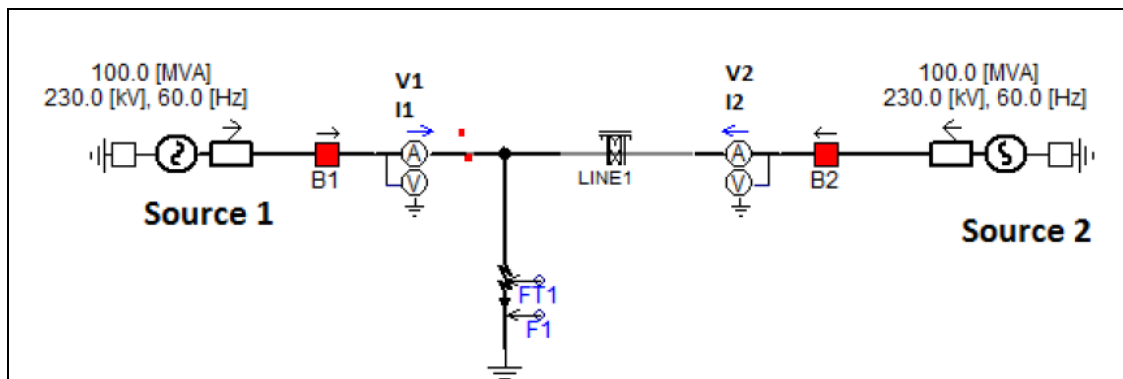


Figure 37. Single line diagram of the case studied

The five simulations are presented Figures 39 through Figure 43. In each plot, the three-phase voltage and current of Source 1, plus the amplitude of symmetrical sequence quantities are extracted from the plotted currents.

I1m = Magnitude of the positive sequence current

$I_{2m}$  = Magnitude of the negative sequence current  
 $I_{zm} = I_{0m}$  = Magnitude of the zero sequence current  
 $I_1$  = Current of Source 1  
 $V_1$  = Voltage of Source 1

**Symmetrical components background note: How to resolve three unsymmetrical phasors into their symmetrical components.**

Followings are mathematical formulation of symmetrical component for quick reference.

$$a = 1 \angle 120^\circ, a^2 = 1 \angle 240^\circ, a^3 = 1 \angle 0^\circ$$

$  \begin{aligned}  I_A &= I_{a0} + I_{a1} + I_{a2} \\  I_B &= I_{b0} + I_{b1} + I_{b2} \\  I_C &= I_{c0} + I_{c1} + I_{c2}  \end{aligned}  $	$  \begin{aligned}  I_A &= I_{a0} + I_{a1} + I_{a2} \\  I_B &= I_{a0} + a^2 I_{a1} + a I_{a2} \\  I_C &= I_{a0} + a I_{a1} + a^2 I_{a2}  \end{aligned}  $
$  \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} I_{a0} \\ I_{a1} \\ I_{a2} \end{bmatrix}  $	$  \begin{bmatrix} I_{a0} \\ I_{a1} \\ I_{a2} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix}  $

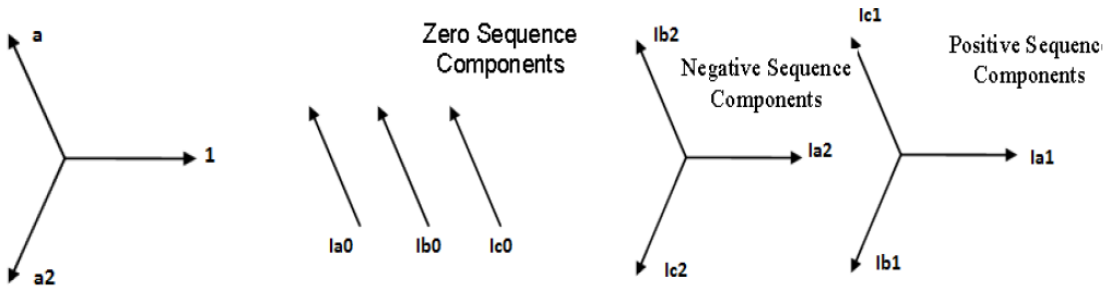
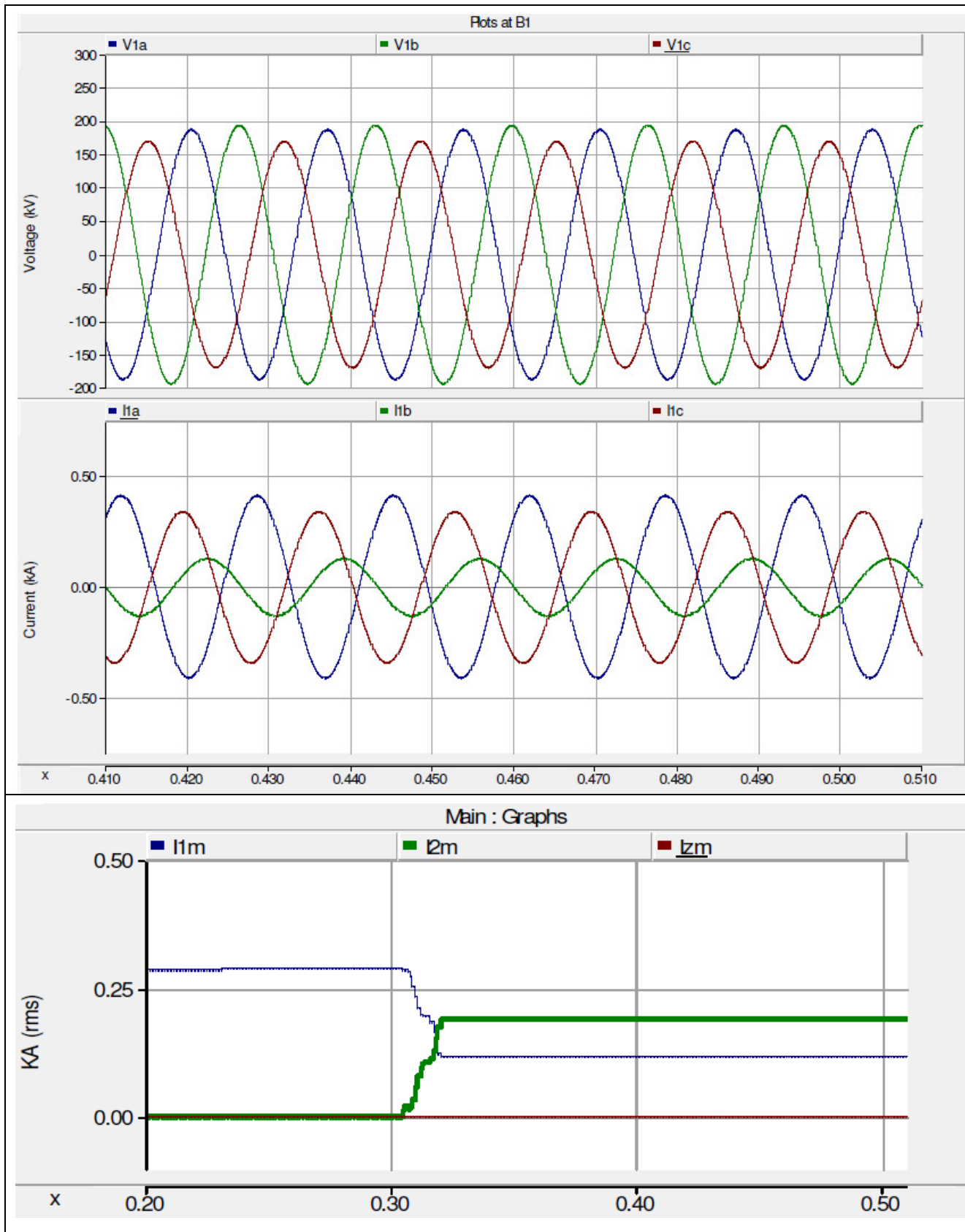


Figure 38. Symmetrical components presentation for three phase system



Figure 39. Unbalanced load @  $t=0.3$  sec



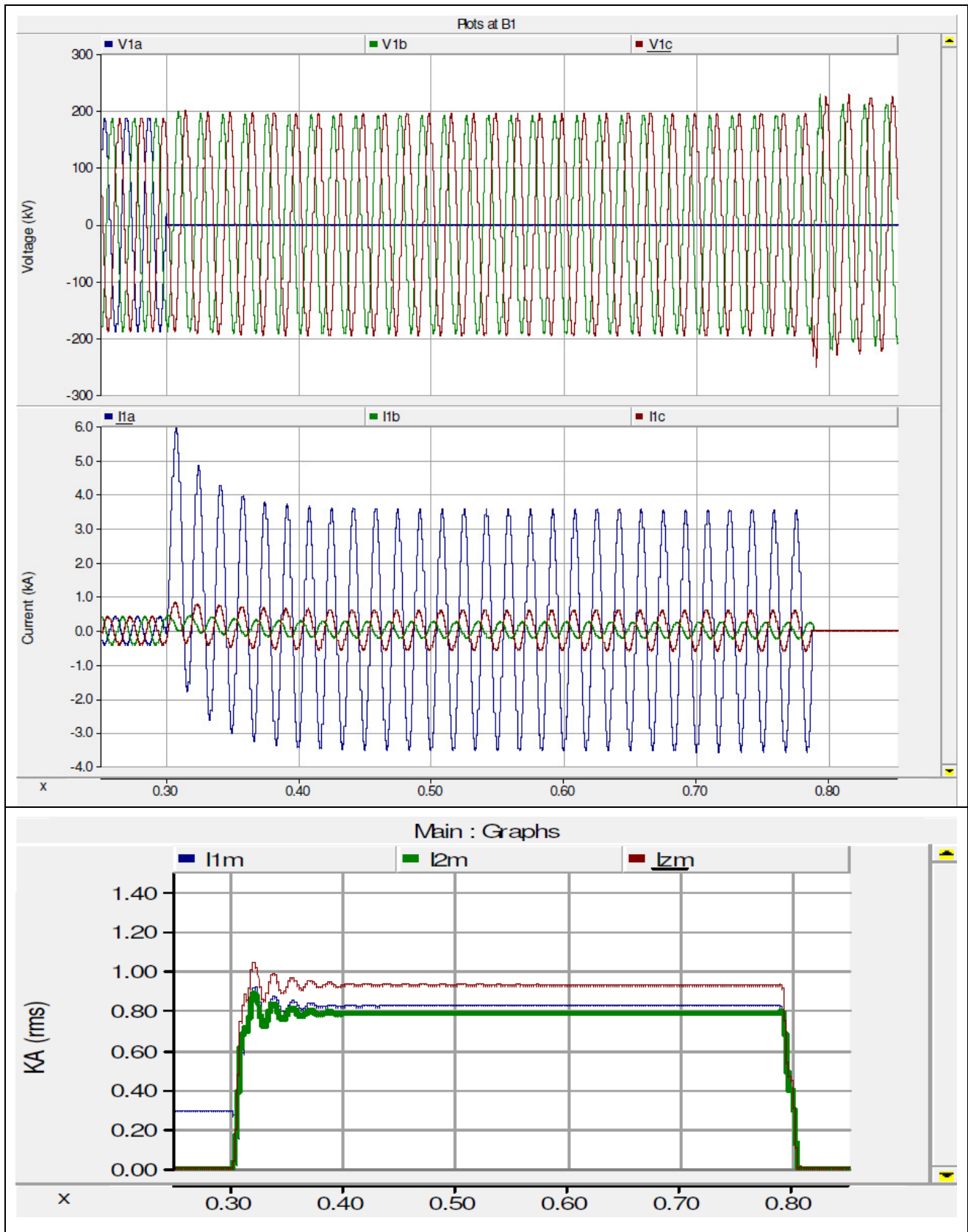


Figure 40. Unbalanced fault @  $t=0.3$  sec, phase to ground (AG)

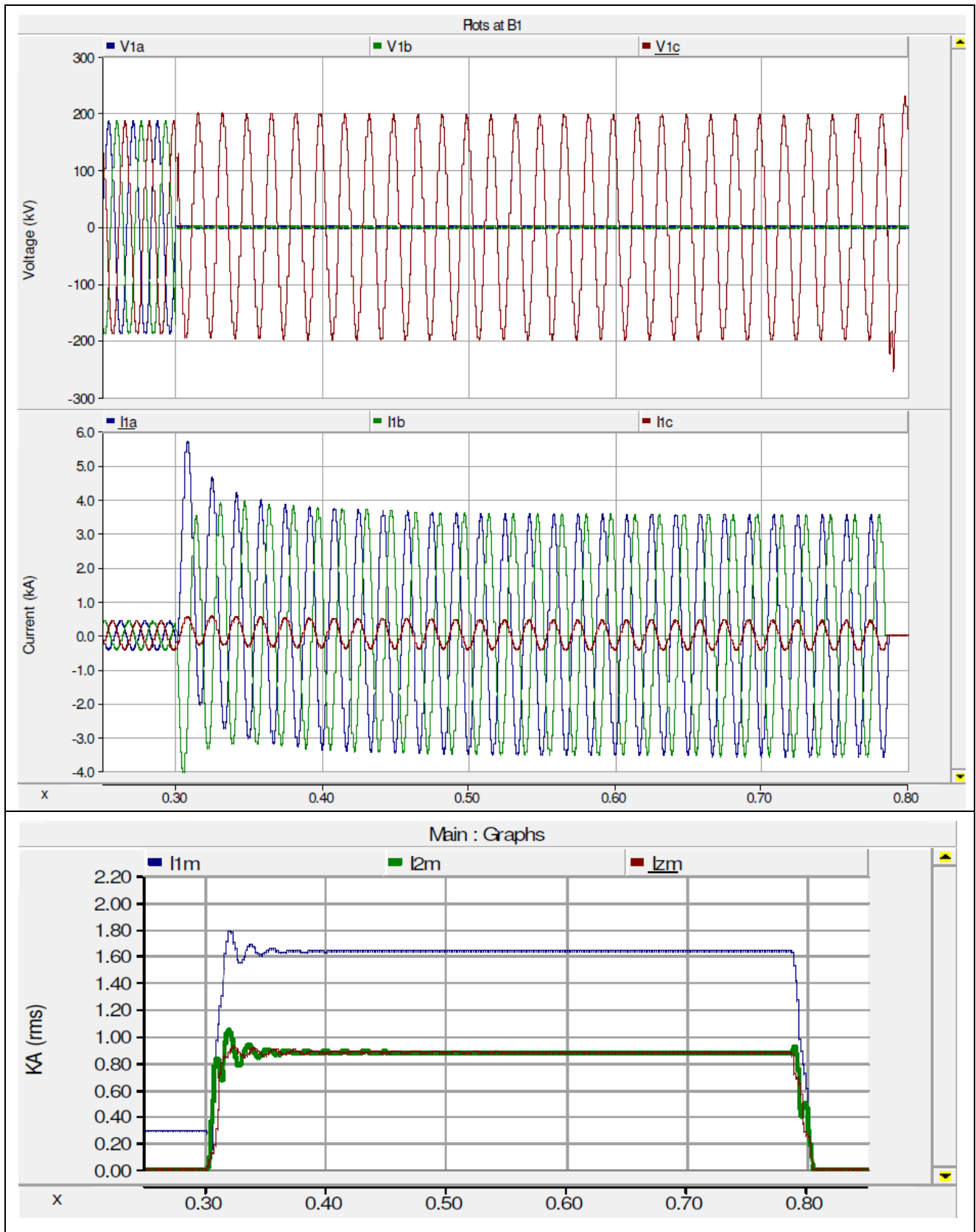


Figure 41. Unbalanced fault @  $t=0.3$  sec, phase to phase to ground (ABG)

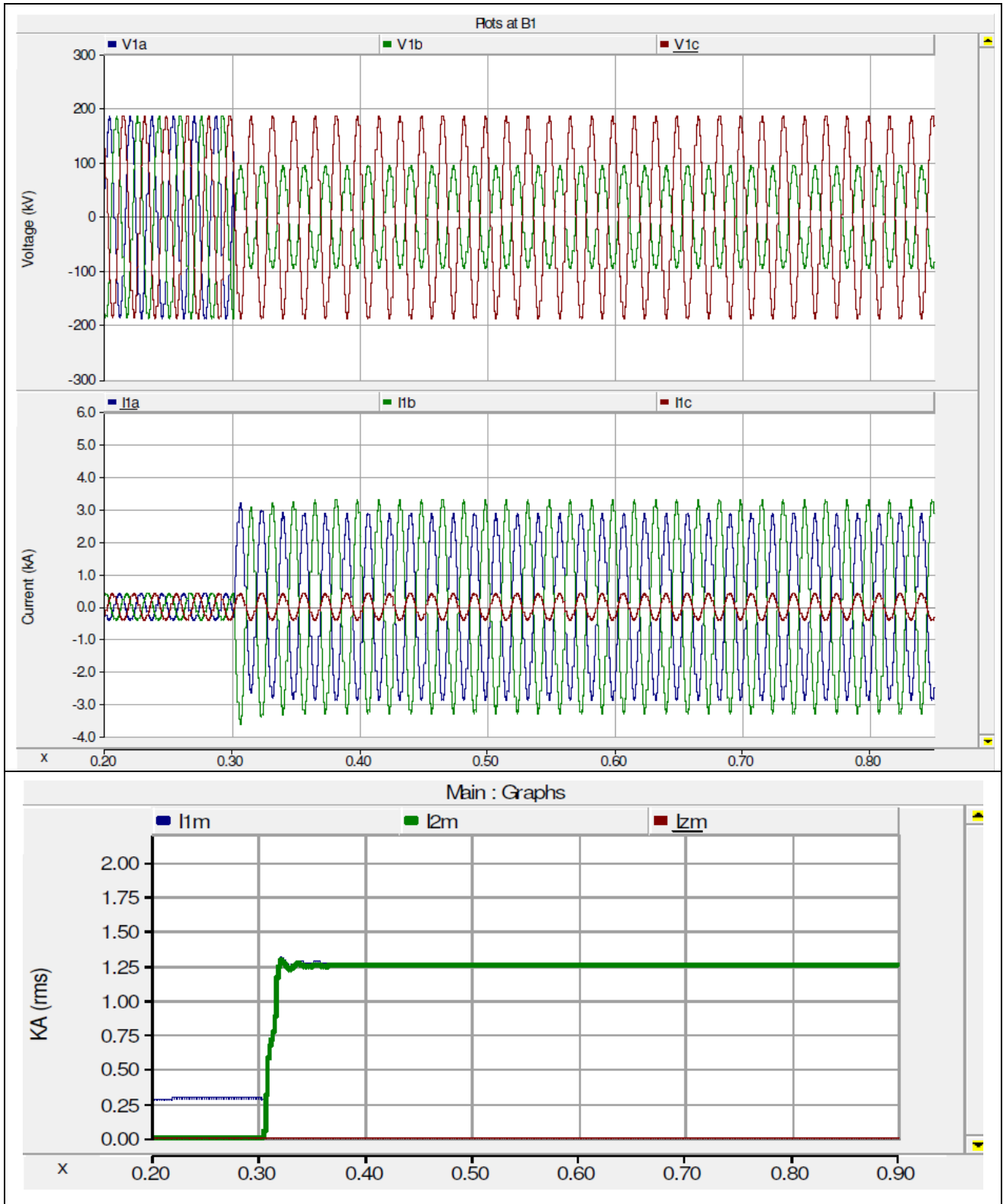


Figure 42. Unbalanced fault @  $t=0.3$  sec, phase to phase (AB)

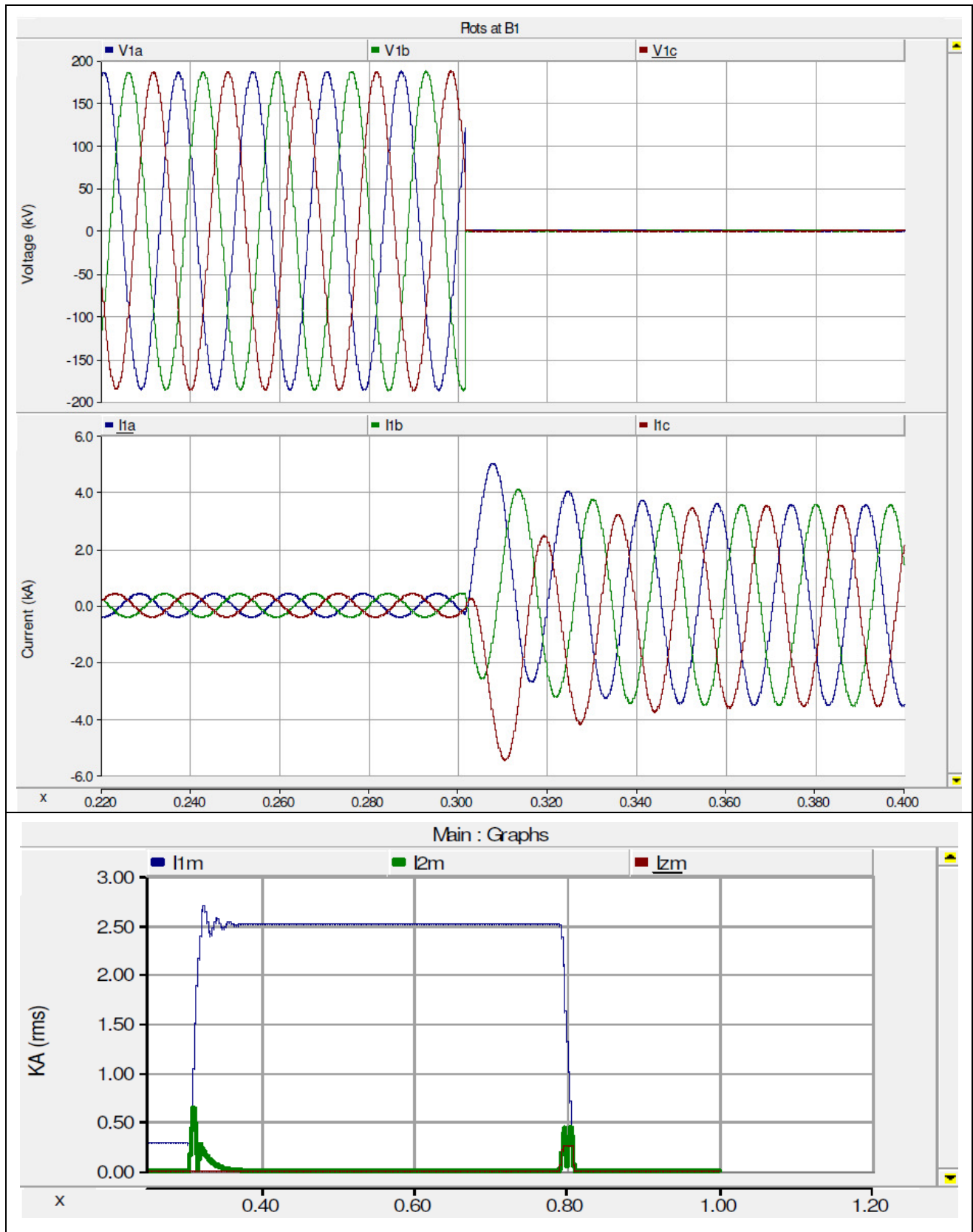


Figure 43. Balanced fault @  $t = 0.3$  sec, three phase (ABC)

## 12.0 Evolving Faults

Example Event 1: A fault that evolves from CG to BCG fault

This fault was a fault that evolved from CG fault to BCG. The cause is a snake contact. The waveforms are shown in Figure 44.

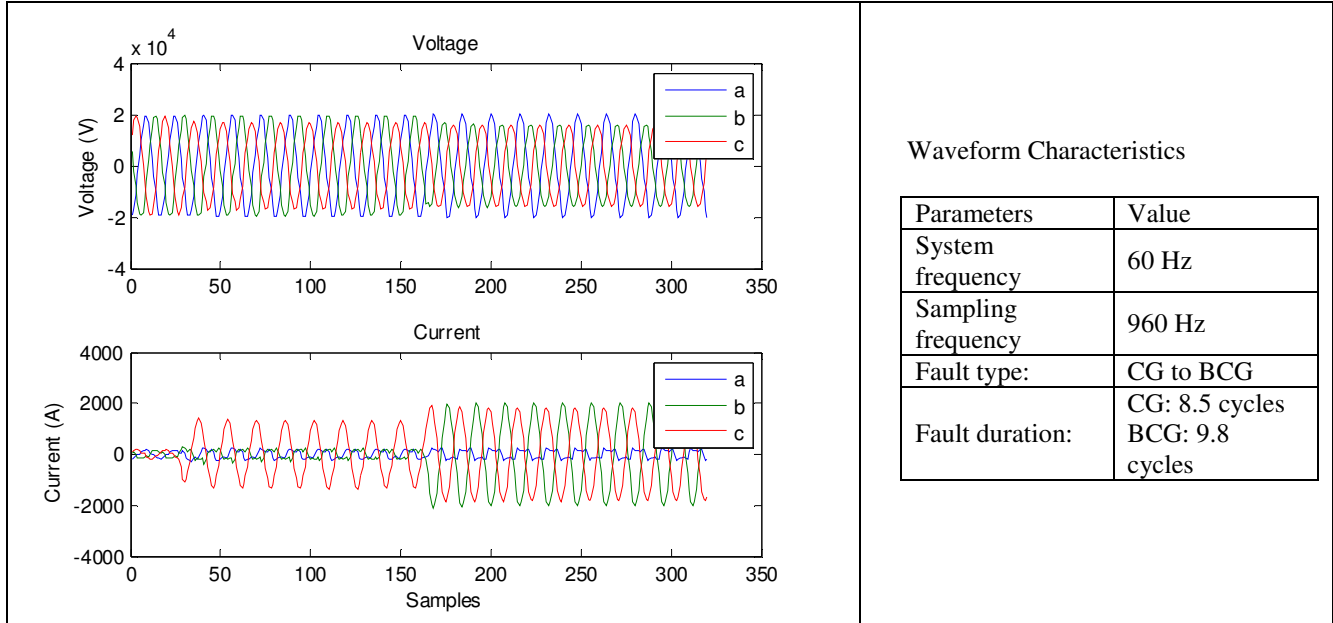


Figure 44. Evolving Fault caused by a snake contact

Example Event 2: A fault that evolves from CG to BG

This fault is evolved from CG to BG. The fault was caused by a dig-in. The waveforms are shown in Figure 45.

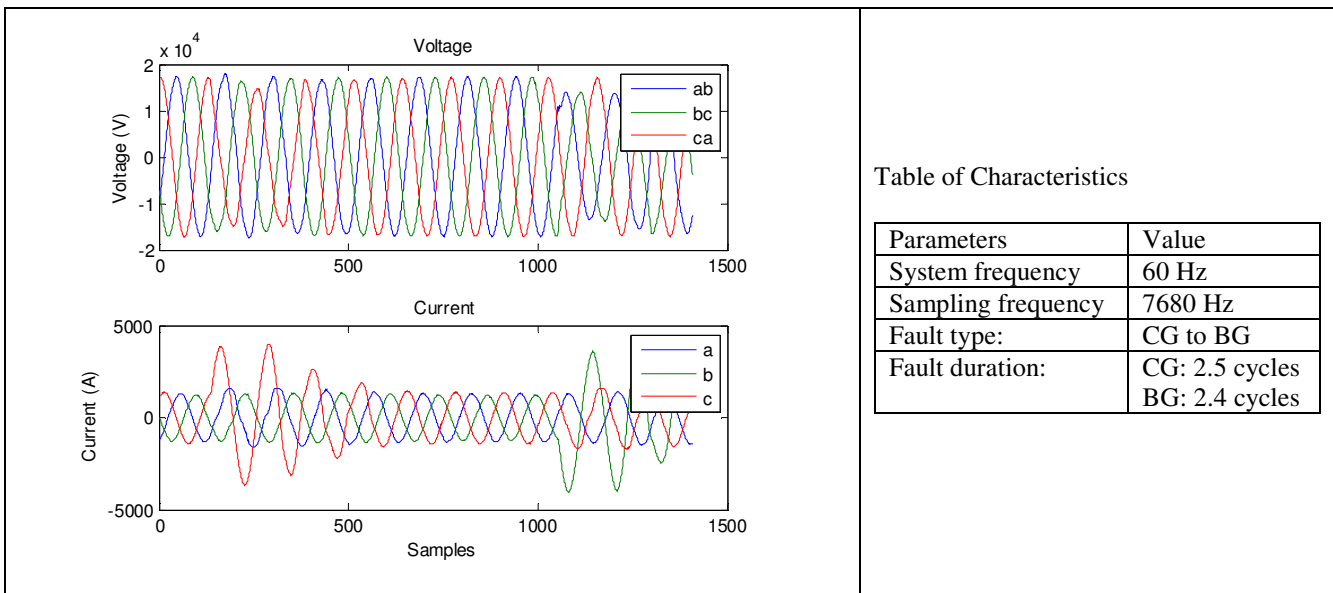


Figure 45. Evolving Fault caused by a dig-in contact

## 13.0 Fault Locations

A line-to-ground fault occurs on a 60Hz, 161 kV transmission system. The total length of the line is 48 miles and the fault is located 30.6 miles from bus 1. Figures 46 and 47 show the voltage and current waveforms measured at both ends of the line, when a sampling frequency of 5760 Hz has been used.

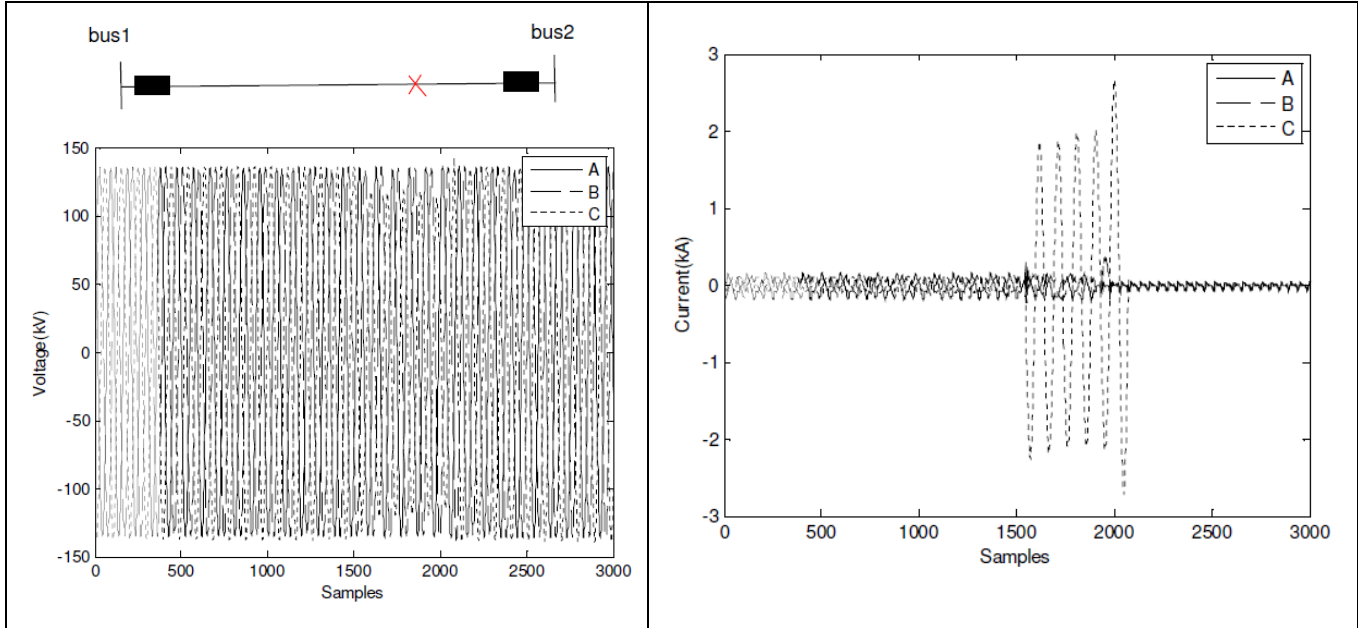


Figure 46. Bus 1 voltage and current waveforms

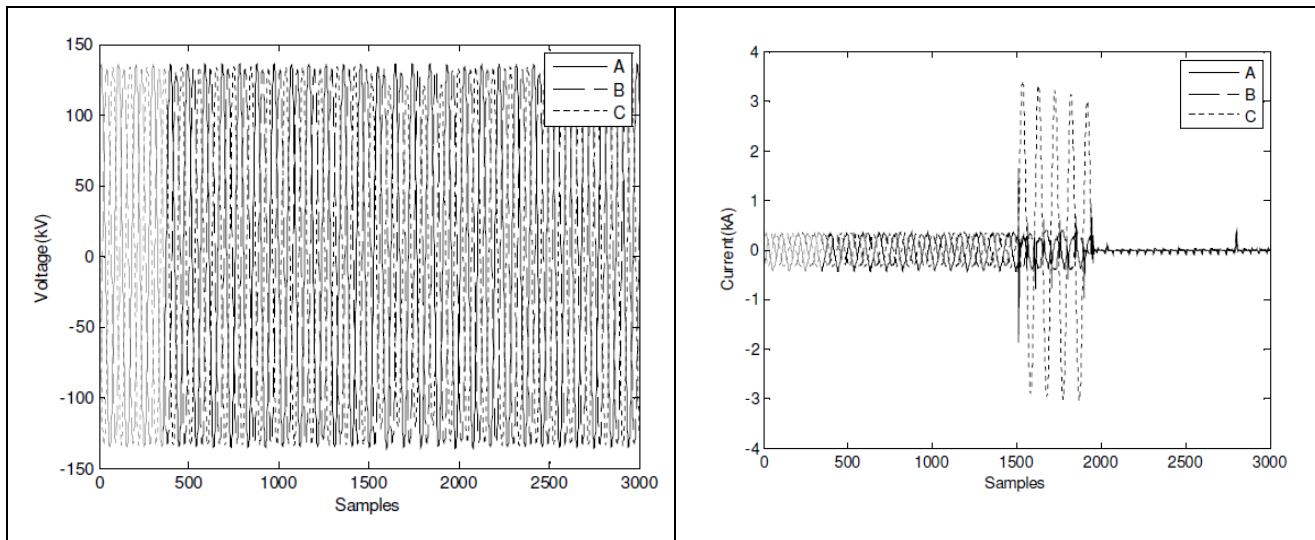


Figure 47. Bus 2 voltage and current waveforms

### Fault location results

Example Event 2 is used to calculate the fault location. The fault location results are as follows:

- Results based on positive sequence voltages and currents: 26.94 miles, error: 3.66 miles, 7.6%
- Results based on negative sequence voltages and currents: 28.28 miles, error: 2.32 miles, 4.8%
- Results based on zero sequence voltages and currents: 28.40 miles, error: 2.2 miles, 4.5%

## 14.0 Breaker Anti-pump Control ( XY Logic ) Defeated

This case illustrates a circuit breaker anti-pump control (also referred to XY or trip-free control) mis-operation.

A close command given to a breaker must be asserted long enough to assure a solid breaker closure. Closing a breaker into a fault presents a conflict to the breaker controls whereby both trip and close controls are asserted simultaneously. Breaker anti-pump logic prevents the breaker from closing immediately after it trips. Without this logic a breaker could conceivably chatter at a rapid rate between open and close states with potentially catastrophic results.

For the station of this example, all of the breaker XY controls had been defeated during a construction project because of a design error. The flaw was discovered during the first line fault for which protections were called upon to trip and reclose.

Circled in Figure 48 are the particular line and breaker that were called upon to trip and reclose for this event.

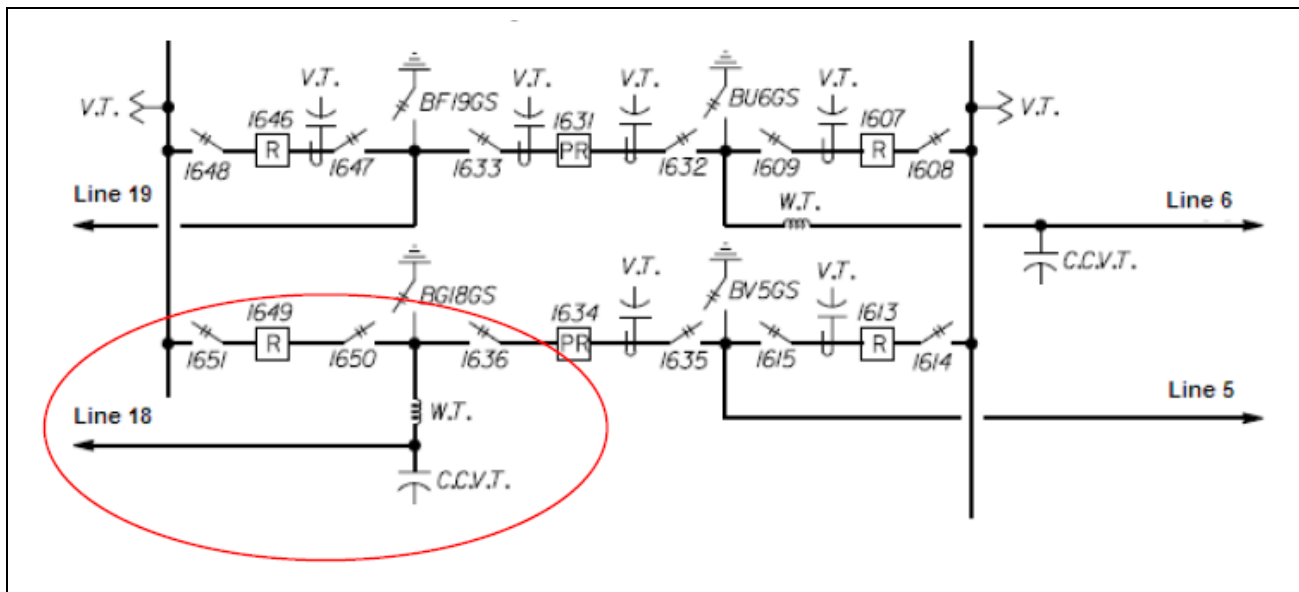


Figure 48. Area Oneline

### First Event Record: Line 18 Trip

Figure 49 provides the voltages and currents in primary volts and amps for the initial trip in response to an AC phase-to-phase fault. Phase A and C voltages are reduced, and currents increased substantially at  $t=0\text{sec}$ . The local breakers are both open 4.5 cycles later. Notice that at this point (approx  $t=0.075\text{sec}$ ), the fault current is interrupted. However, the voltage is not reduced to zero because the remote end of the line doesn't open for another 2 cycles.

The fault current magnitude on phases A and C is about 10.6 kA RMS whereas the current on phase B is about 142 amps RMS. So far, this looks like a normal and correct fault tripping event.



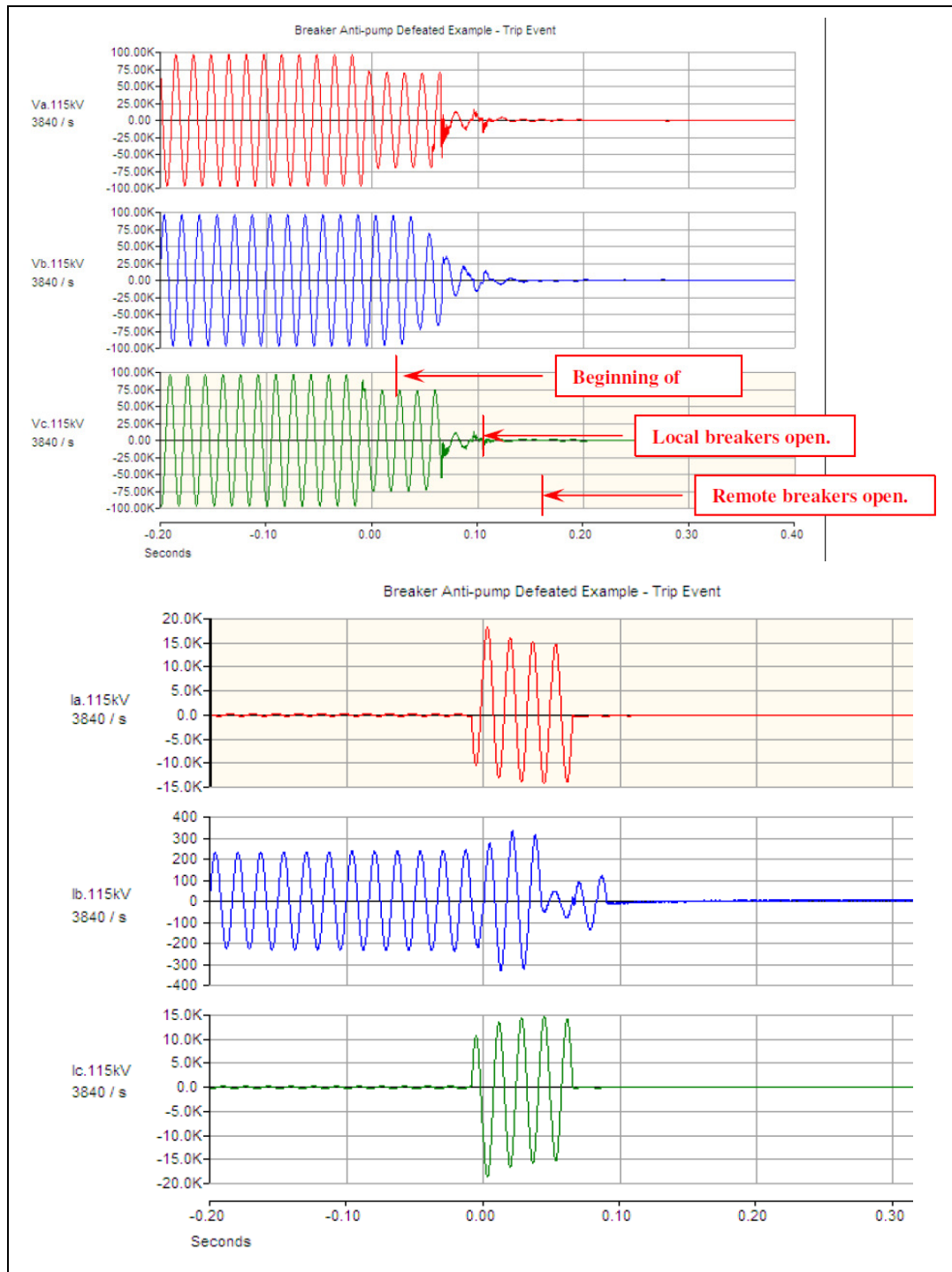


Figure 49. Trip Event with 115kV Line Voltages and Currents in Primary Volts and Amps

### Second Event Record: Line 18 Reclose and Subsequent Breaker Failure Trip

Figure 50 provides the voltages and currents in primary volts and amps for the subsequent bus breaker (1649) reclosure. As the record shows, the fault is now an AB phase-to-phase fault with a current magnitude of about 10.6 kA RMS in both faulted phases. The fault is cleared at the local end in about 3.5 cycles and at both ends in about 6 cycles.

After about 0.2sec, the AB fault once again is present and is subsequently cleared in a similar fashion. We know from the record time stamps (not shown) that the trip and reclosure records are triggered about 5sec apart. This agrees with the recloser relay settings. The second "reclosure" simply happens too fast to be a planned one. Notice that the high frequency prestrike activity on the voltage traces for the true reclosure and the false "reclose" is identical. This suggests that the



breaker actually closed so restrike was ruled out in favour of testing the anti-pump failure assertion. The anti-pump failure was confirmed by field observation that the X-Y seal-in wiring had been removed during the last construction activity. The breaker was then tested to confirm nonoperation of anti-pump logic.

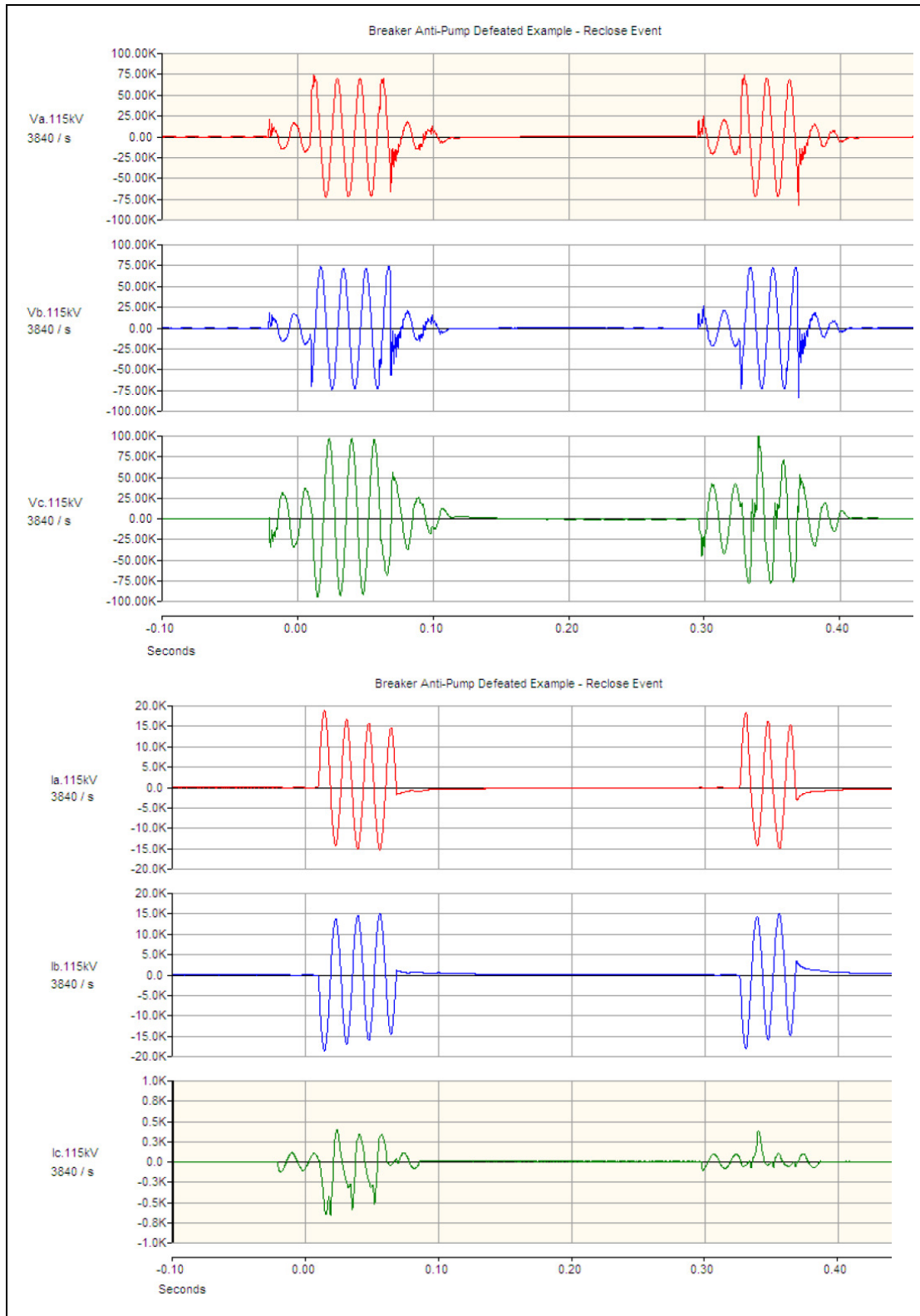


Figure 50. Reclose Event with 115kV Line Voltages and Currents in Primary Volts and Amps

## Conclusions:

Reclosures that do not match up with recloser setting times bear scrutiny. Longer than expected reclosures may be the result of the intervention of supervisory elements. Unusually fast "recloses" are most likely problems if high speed reclosing is not in use. An anti-pump issue is one possible explanation. Restrike is another. This case illustrates the importance of making sure recording instrumentation captures recloses as well as trips.

## 15.0 Wide Area Power System Disturbances and the Time Synchronization of Unsynchronized Recordings

Analysis of a system disturbance invariably includes a study of the available data from dynamic recording devices such as Digital Fault Recorders (DFR). Sometimes, especially for historic events, these dynamic data recordings are not synchronized. However, such data need not be discarded; there exist means of computing the time skew between an unsynchronized DFR clock and the actual GPS time as recorded by the U.S. National Institute of Standards and Technology (NIST), as long as the time of at least one particular event is known precisely. From that one event, many specific times of other events during the disturbance can be precisely determined.

To more accurately determine the time of a particular recording being analyzed, frequency may be calculated from the available data by calculating the time between consecutive rising zero crossings (and also consecutive falling zero crossings) of a voltage or current channel. The calculated frequency information is compared with frequency traces from DFRs at other stations showing events of known NIST-synchronized time. If available, the frequency in a dynamic simulation of the disturbance can also be used to assist in identifying the recording time. Since frequency tends to be relatively uniform over a broad area, comparisons of frequency are possible among DFR recordings from multiple stations. In addition, real and reactive power line flows can be calculated for some recordings using the voltages and phase currents in the DFR data. These power flows, along with the voltage, provide another means to identify the approximate time frame of a recording.

The derived frequency plots from the DFR recordings often show spikes that are found to correspond to discrete events such as line and generation trips. Step changes in voltage and current are also observed in many of the recordings, indicating events. In many cases, a DFR at one end of a line that has tripped recorded the line trip, making it easy to identify the cause of the frequency spike in that recording. This spike can then be identified in DFR recordings from other stations in the area by comparing the frequencies and other quantities. However, in some cases, a line trip is not directly observed by a DFR at either end of the line. In those cases, some deductive reasoning needs to be applied to determine the event that was observed, often using data from multiple DFRs.

The timing of the spikes and accompanying voltage and current changes can be used to establish a precise synchronization between DFR recordings from different stations after performing the general frequency match described above. The time duration between spikes precisely indicates the elapsed time between two events. By finding an event of known NIST time in the DFR recordings, other event times are calculated by measuring the time difference between events. Furthermore, once the time skew of a particular DFR is known, its data can be used as a reference for other data recorders whose skews are not yet known. The number of recorders whose time skew can be calculated by "daisy-chaining" in this fashion is unlimited.

An example of a frequency plot is shown in Figure 51. Frequency is initially at 60 Hz but deviates significantly over the time of the recording, indicating that this recording is at the beginning of a major disturbance. Spikes indicate system events (in this case, line trips) in close proximity to the data recorder.

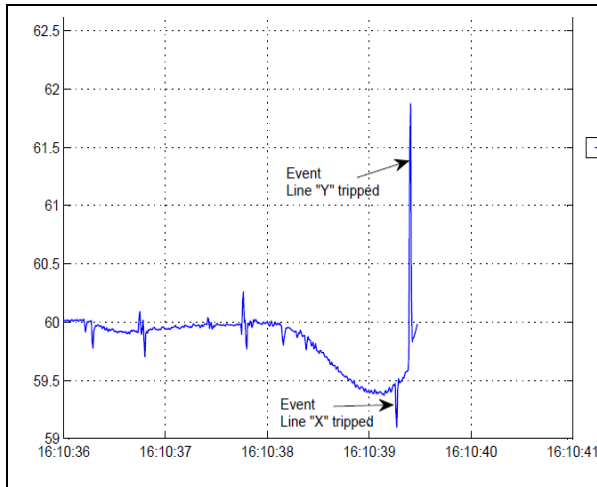


Figure 51. Frequency Plot

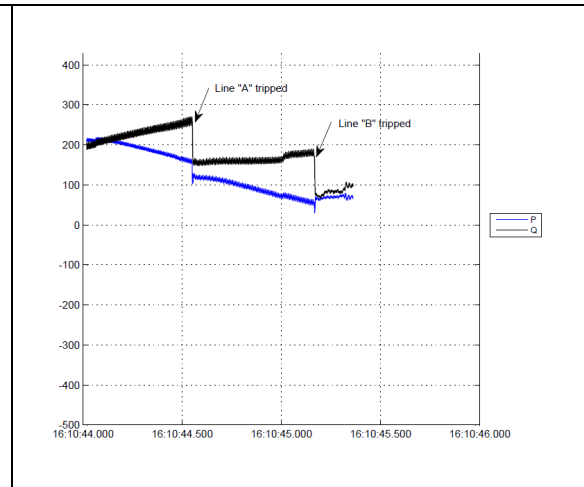


Figure 52. Real and Reactive Power flow on line

Figure 52 shows a recording of real and reactive flow on line “J” from a synchronized disturbance data recorder. Two line trip events, whose approximate times are known from other data sources, are indicated. This data recorder allows us to identify the precise time of these line trips. Figure 53 shows a recording from an unsynchronized disturbance data recorder at the other end of line “J”. Through deductive reasoning, including a comparison of the size of step changes, matched timings of step changes, analysis of system topology, and dynamic simulation, we are able to conclude that the large step change in the recording is the tripping of line “A”. Since the exact time of the trip of line “A” is known, the time skew for this recorder is also known (in this case, 36.826 seconds). Adjusting the recorder data for the time skew results in Figure 54.

The process need not stop here, however. Since the clock skew for one recorder is now known, the precise time for additional events may be determined, and the time skew for additional unsynchronized data recorders may be calculated. There is no limit to this “daisy-chaining” process of computation.

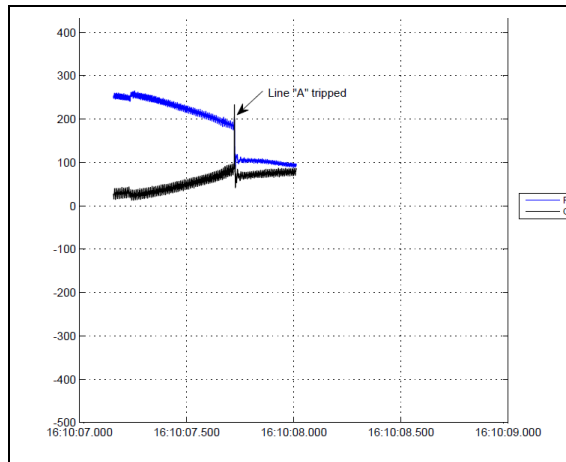


Figure 53. Unsynchronized disturbance data

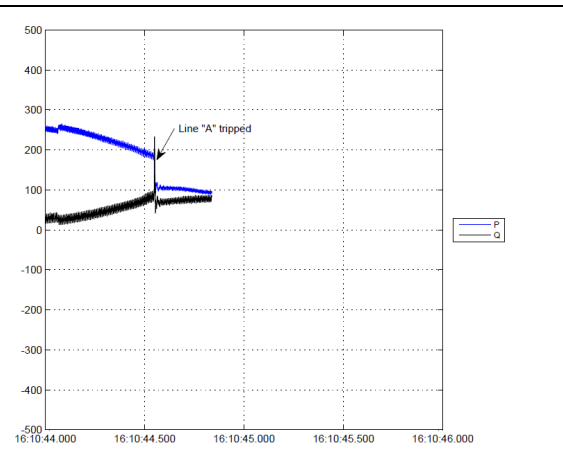


Figure 54. Adjusting the recorder data for the time skew results

The unsynchronized data recording in Figure 55 comes from the same recorder as Figure 53. Therefore, the same time skew (36.826 s) is applicable to this recording; its application to the recorder data results in Figure 56. Through the same type of deductive reasoning described previously, we have concluded that this recording captures the tripping of lines “C”, “D”, and “E”; the times of these trips are now known precisely. Another recorder also observed the trips of lines “C” and “D”, as shown in Figure 57. Although this recorder is not synchronized, the knowledge of the times of these line trips allows us to calculate the time skew for this recorder as well (1.706 s). Replotting with correction for this time skew results in Figure 58. Now, the times that line “F” and transformer “T1” tripped are known precisely.

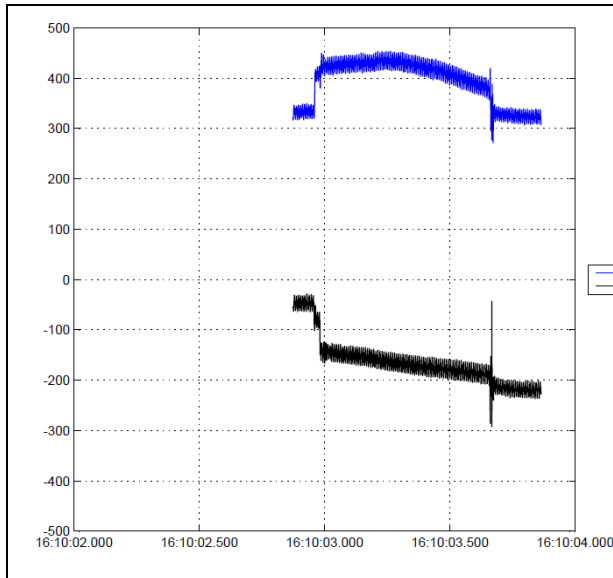


Figure 55. Unsynchronized data P &amp; Q recording

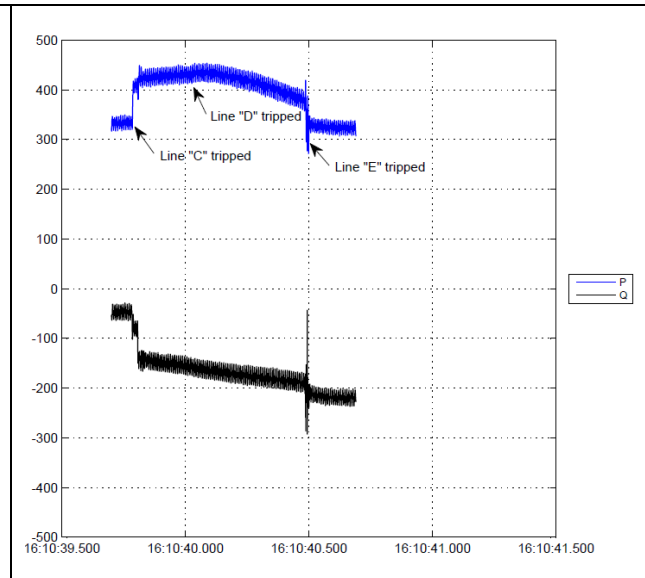


Figure 56. Time Adjusted data P &amp; Q recording

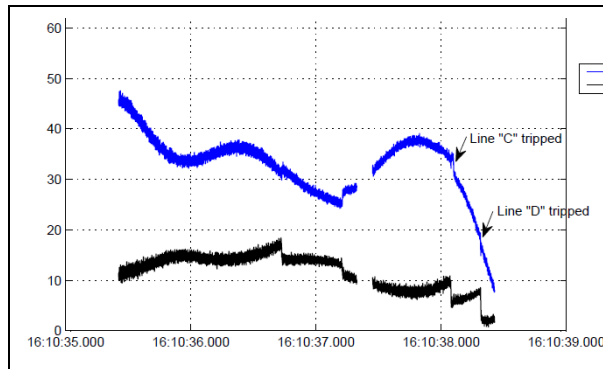


Figure 57. Unsynchronized Line C and D tripped

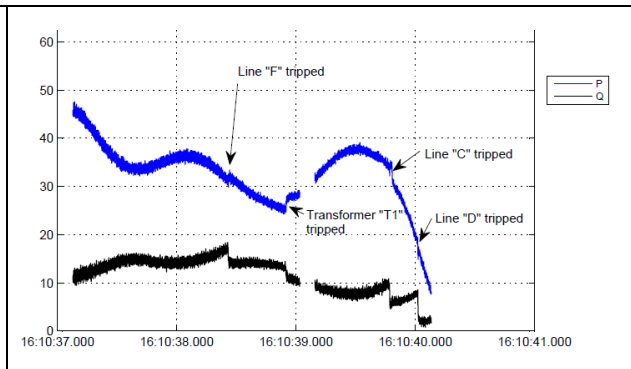


Figure 58. Time Adjusted Line C and D tripped

## 16.0 Power Quality Monitor Case Studies on Disturbances

### Case 1: Three-Cycle Capacitor Switching Transient

The energization of a discharged capacitor bank results in a transient oscillation in the system voltage and current. These capacitor switching transients are common in distribution systems. Due to system damping, typical distribution capacitor switching transients have a peak magnitude in the range of 1.2 -1.7 per unit and a duration of less than one cycle. These transients can be controlled through the use of synchronous closing switches or pre-insertion resistors.

Figure 59 presents an example capacitor energization operation that occurs almost daily on a distribution feeder and produces transients that appear to be about two to three cycles in duration. This measurement was recorded mid-feeder near the capacitor bank. The system is a 4.16 kV distribution feeder which is about 5 km (3 miles) in length. The primary connection is to another 13.8 kV distribution line. The transformer is rated 5 MVA and has a short circuit duty of 62 MVA. The urban load is 100% fed with overhead.

The reason for the duration is that the capacitor bank is energized through three single-phase mechanical oil switches. Thus, there are three distinct transients visible, corresponding to each individual pole closing. Typically, all phases close within 5 cycles.

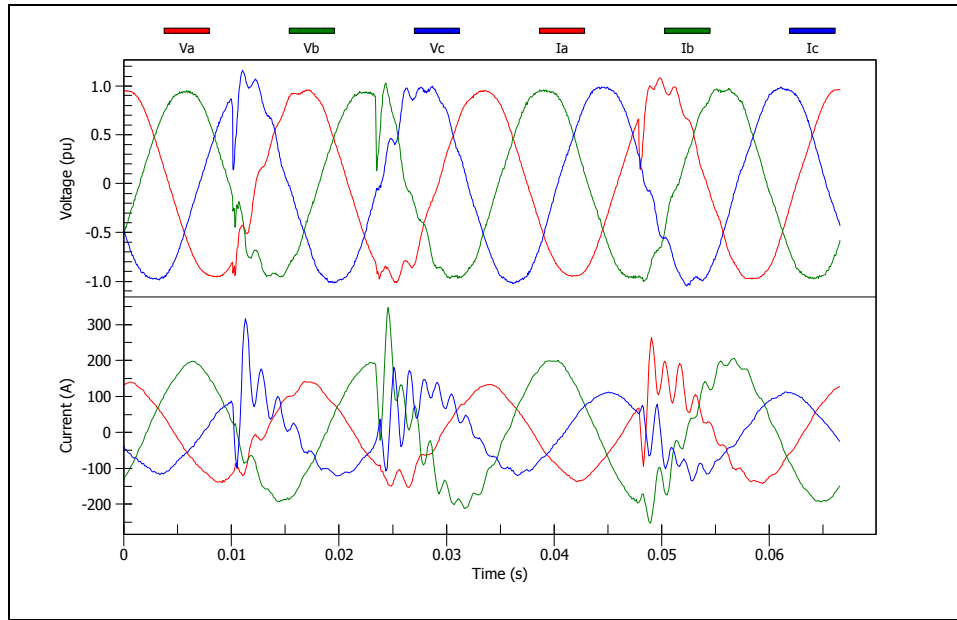


Figure 59. Case 1: Three Cycle Capacitor Switching Transient

Figure 59 shows that a related transient often occurs on the non-closing phases when the contacts of the third phase closes; this is due to coupling through the neutral or induction and is seen in all of the phase voltages and currents.

Figure 60 presents a second example of a three-phase capacitor transient, this time recorded by a power quality monitor at the feeder substation. The transient is less pronounced because there is a larger feeder impedance between the substation and the switched capacitor bank. Figure 61 presents a calculation of the reactive power during the transient in Figure 60. The change in reactive power by phases agrees with the transients seen in each phase.

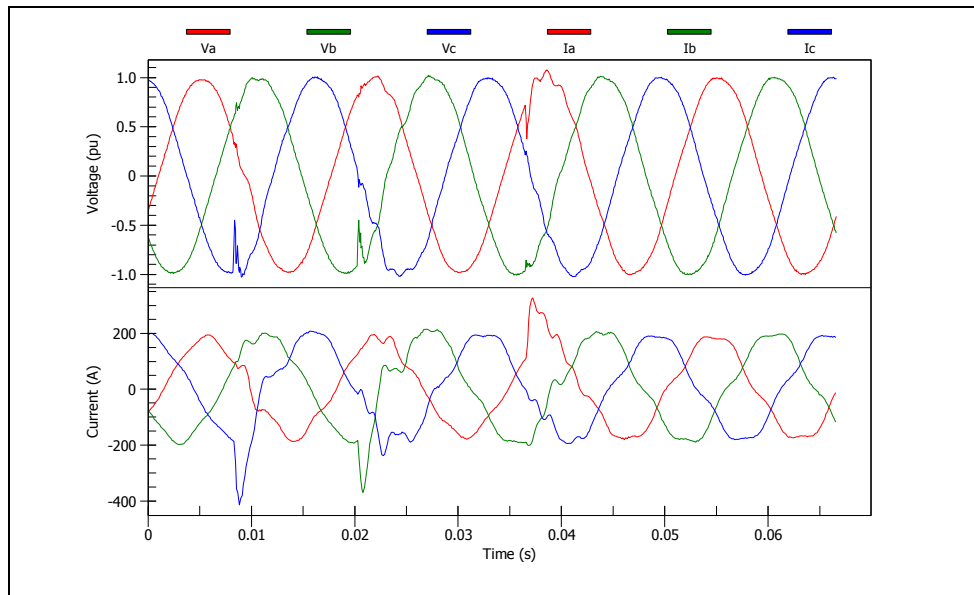


Figure 60. Case 2: Three Cycle Capacitor Switching Transient from feeder substation

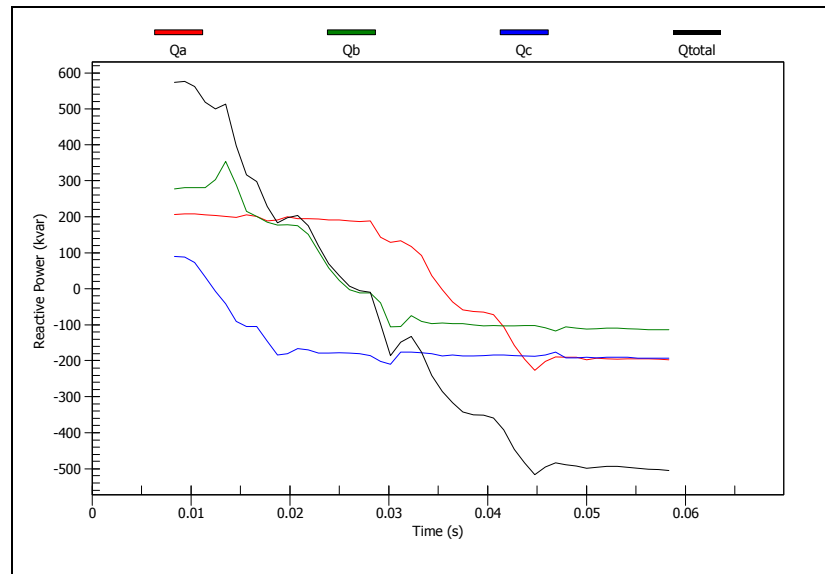


Figure 61. Calculation of Reactive Power from Figure 60

## Case 2: Back-to-Back Capacitor Switching Transient

Energization of an isolated capacitor bank typically produces a voltage and current transient with a frequency in the range of 300 Hz to 1000Hz. The magnitude of the inrush current into the bank is limited by the distribution system's relatively large inductance. However, when a capacitor bank is energized in close proximity to a bank that has already been charged, the inrush into the bank being energized is now limited by the much smaller line inductance separating the two banks, resulting in currents of a much higher magnitude and frequency. This phenomenon is known as back-to-back capacitor switching.

Figure 62 shows a typical back-to-back switching transient current waveform. This waveform was recorded at a mid-feeder monitoring location positioned between two relatively close capacitor banks, which explains the high-frequency and high-magnitude inrush current. Figure 63 presents the harmonic spectrum of the current for Phase A at the moment of energization, showing a peak frequency near 2400 Hz.

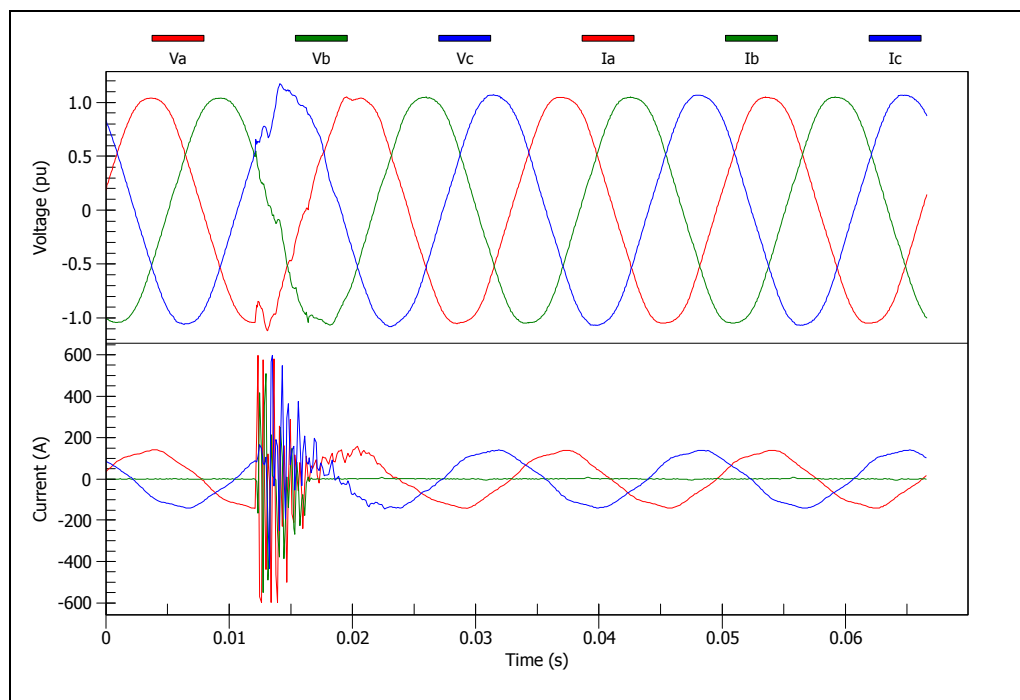


Figure 62. Back-to-Back Capacitor Switching Transient

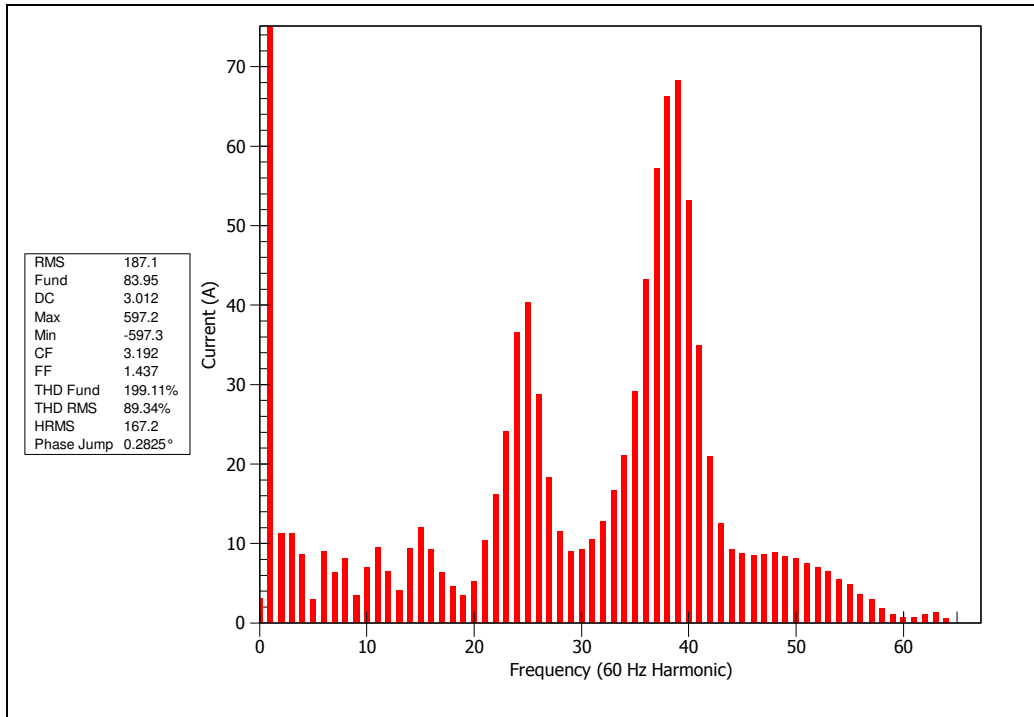


Figure 63. Harmonic Spectrum of Phase A current in Figure 62

### Case 3: Current Limiting Fuse Operation

This event is characterized by the operation of the fuse to limit the energy available to the protective device. At the instant of the fault, the voltage drops dramatically for a few milliseconds during which time the fuse starts to melt prior to going into current limiting mode. Once the fuse element melts, the design of the fuses introduces a high arcing voltage that forces the current towards extinction. The “peak arc voltage” is an important design parameter that must be high enough to cause effective current limitation but must be low enough to avoid damage to power system components when the fuse operates in response to a fault.

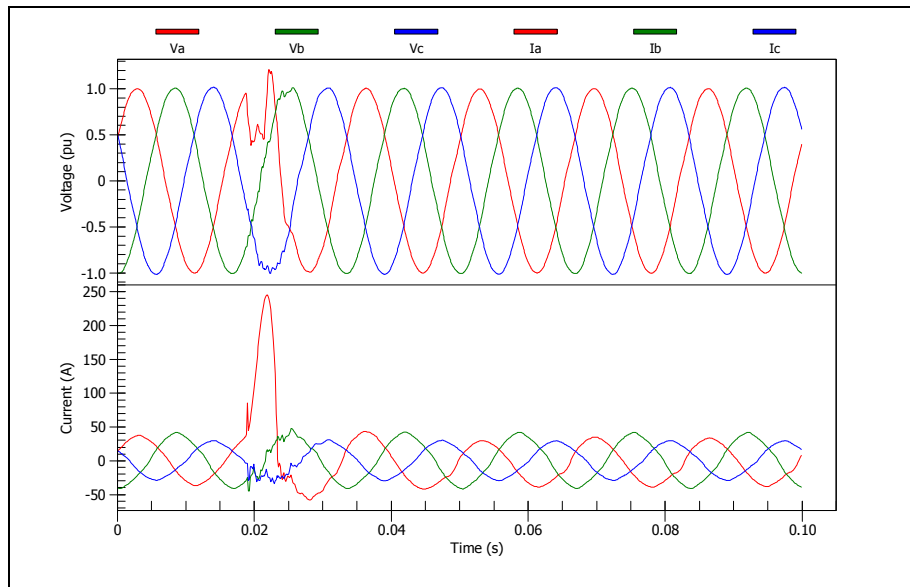


Figure 64. Current Limiting Fuse Operation – Voltage and Current Transients

Figure 64 shows a short quarter cycle duration before the fault is cleared. At the instant of the fault, the voltage dropped to 50 % for about 3 milliseconds. The peak arc voltage reached a maximum value of almost 140 % of normal peak system voltage.

Upon the initiation of the fault, there is an immediate large negative excursion in the current, as seen in Figure 65. This can be due to several factors including the capacitor banks located nearby or load feeding back into the fault.

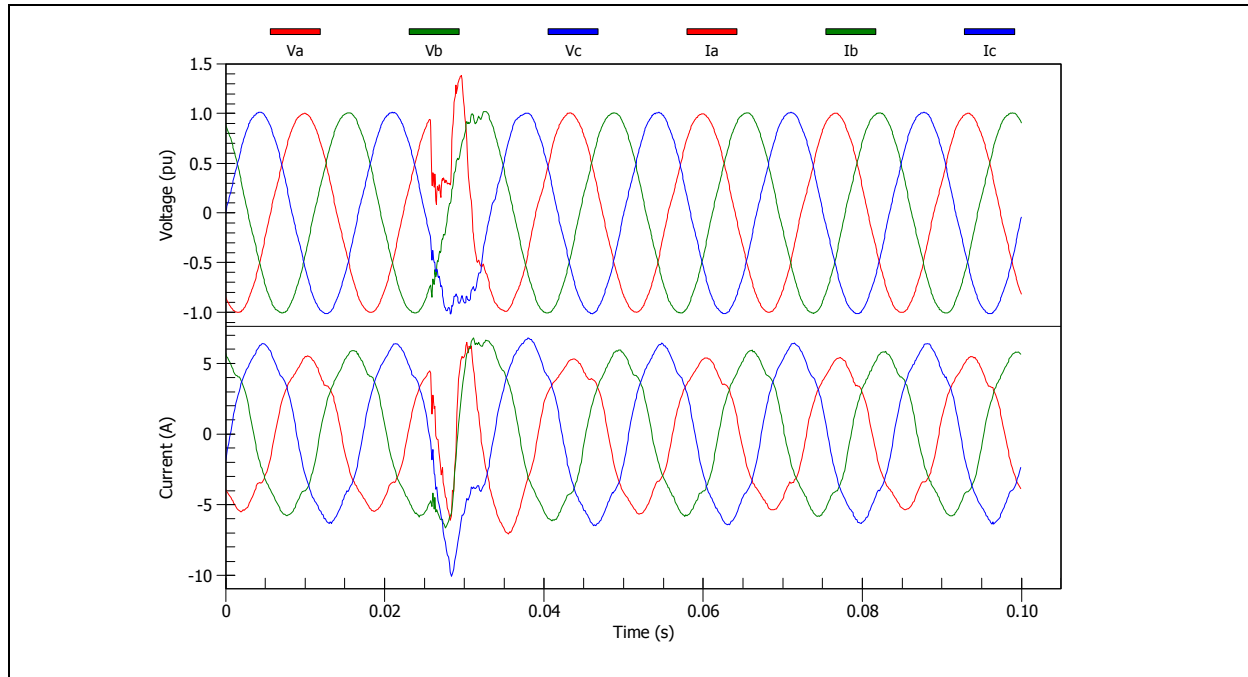


Figure 65. Voltage and Current Transients Recorder Downline from Tap with Current Limiting Fuse operation

#### Case 4: Arcing Fault on Distribution and Transmission Feeders

Arcing faults are common on distribution and transmission feeders. They can be caused by storms, contacts of limb trees with the line, or contacts of animals. The example arcing fault in Figure 66 involved all three phases and occurred during a light loading period. This fault was characterized by a sudden shift in system voltage on the feeder's capacitors resulting in the initial current peak. The ringing continues for the full duration of the sag rather than for a single cycle because the voltage due to an arcing fault closely resembles a square wave. With each reversal of polarity of the voltage, a new transient begins. However, the magnitude of each successive transient is being damped, which is evident as the current waveform seems to fit inside the envelope.

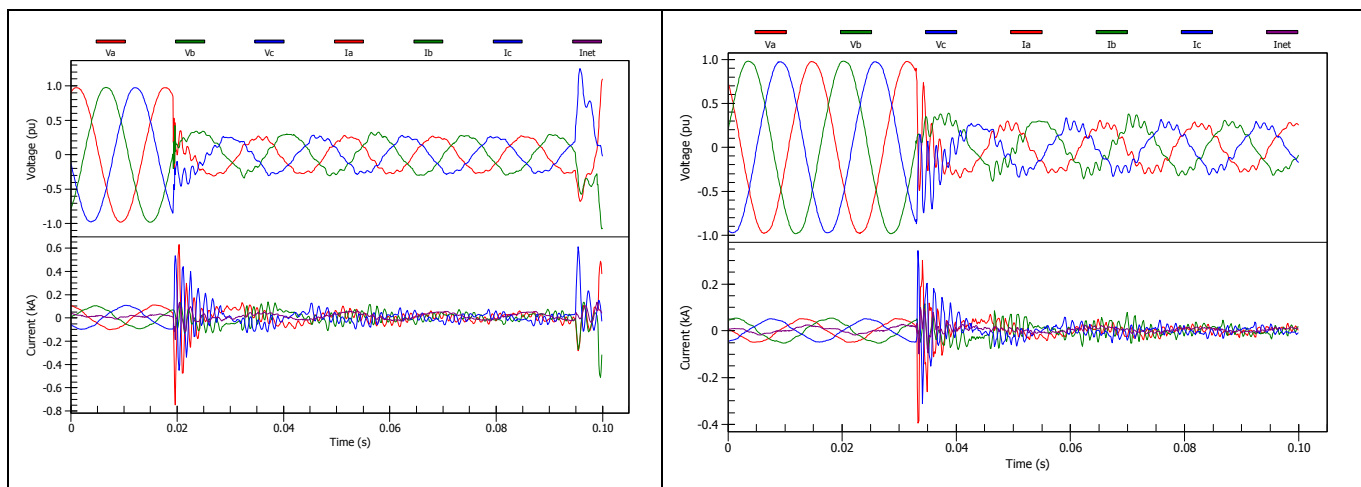


Figure 66. Voltage and Current Transients at Feeder Substation      Waveforms captured by Mid-Feeder PQ Monitor

The fault is three-phase and causes a sag to about 0.25 per unit magnitude in the middle of the feeder. The waveform recording shows an oscillatory transient during the fault with a frequency of about 700 Hz. The oscillations are due to the



combination of inductance and resistance of the feeder with two 600 kvar capacitor banks at the beginning and end of the feeder.

## 17.0 Harmonic Analysis

Harmonics are caused by non-linear loads and may lead to, among other things, misoperation of protective relay systems and/or overheating of major equipment (transformers, motors, generators). Examples of non-linear loads are switch-mode supplies, motor drives, static VAR compensators, and inverters. Harmonics are most undesirable under resonance conditions which occur when natural frequencies of capacitive and inductive elements approach an integer multiple of the system frequency. Such resonant conditions amplify harmonic currents and lead to equipment damage.

Modern protection, monitoring, and metering equipment measure harmonics continuously and are, in many cases, configured to trigger upon occurrence of specific harmonics above certain magnitudes. The resulting reports are used by technicians and engineers to discover root causes and deploy corrective measures including compensators and harmonic filters. IEEE Std. 519-1992, "Requirements for Harmonic Control in Electric Power Systems", provides a good tutorial on harmonics.

As for the practice of fault analysis, the ability to recognize and study harmonic content is an invaluable component of the practice. For example:

- DC components can be measured by observing the 0<sup>th</sup> harmonic.
- CT saturation can be measured by observing the 0<sup>th</sup> and 2<sup>nd</sup> harmonics.
- Inrush signatures can be measured by observing the 2<sup>nd</sup> harmonic.
- Generator health can be measured by observing the 3<sup>rd</sup> harmonic.
- Cap bank ringing can be measured by observing the occurrence of a dominant, decaying harmonic (could be even larger than the 21<sup>st</sup> harmonic).
- Transformer overexcitation can be identified by measuring 5<sup>th</sup> harmonic.

Graphic examples of observing the 0<sup>th</sup>, 2<sup>nd</sup>, and 3<sup>rd</sup> harmonics are shown in Figures 67 thru 70.

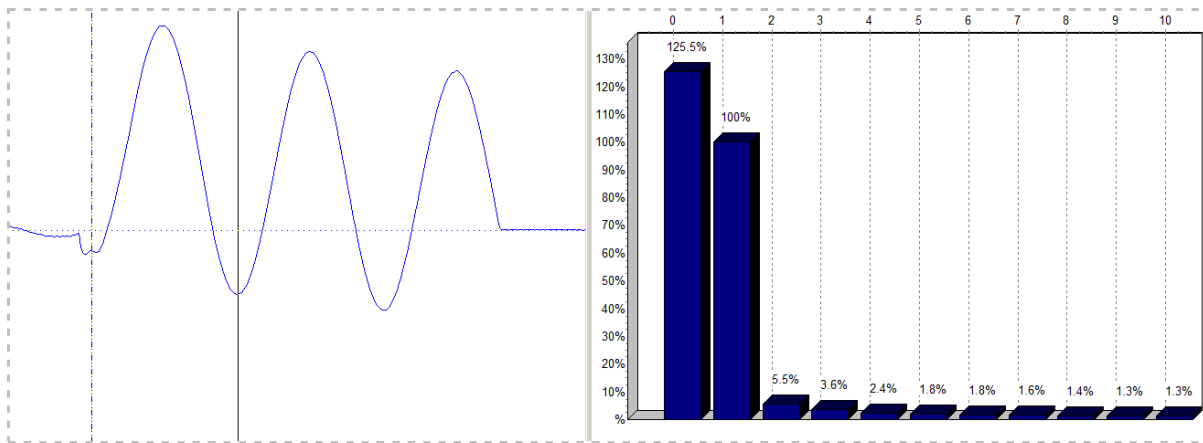


Figure 67. The DC component is the 0<sup>th</sup> harmonic (the 1<sup>st</sup> harmonic is the fundamental).

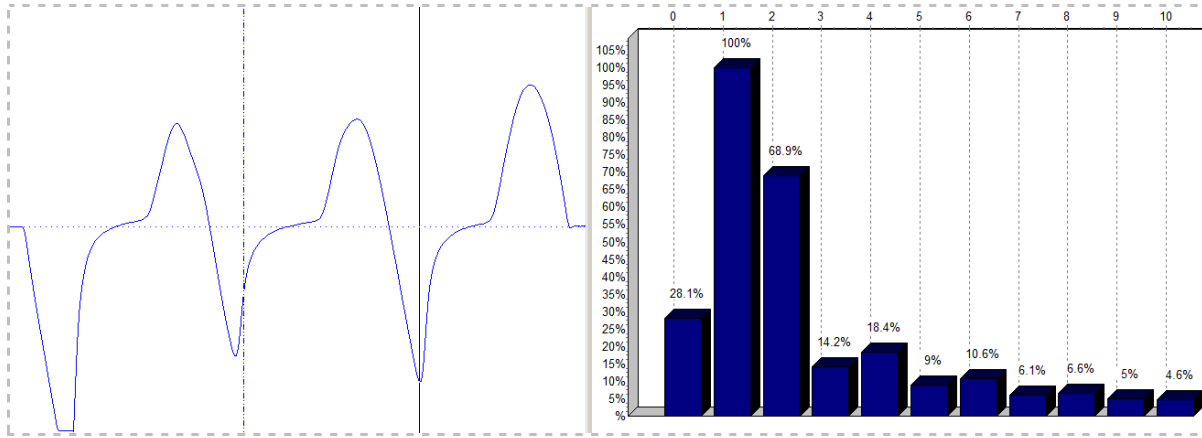


Figure 68. CT saturation has a dominant 2<sup>nd</sup> harmonic with significant DC.

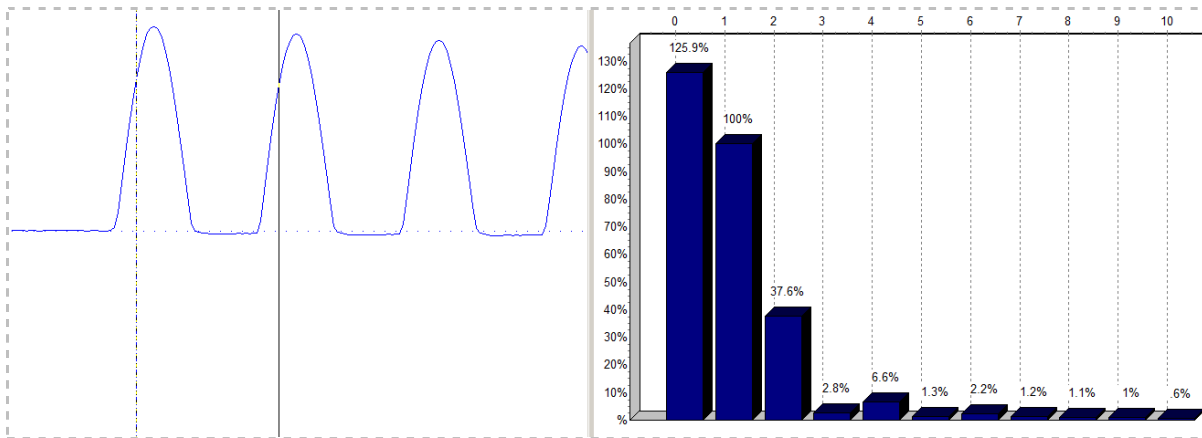


Figure 69. Inrush has a dominant DC component with significant 2<sup>nd</sup> harmonic.

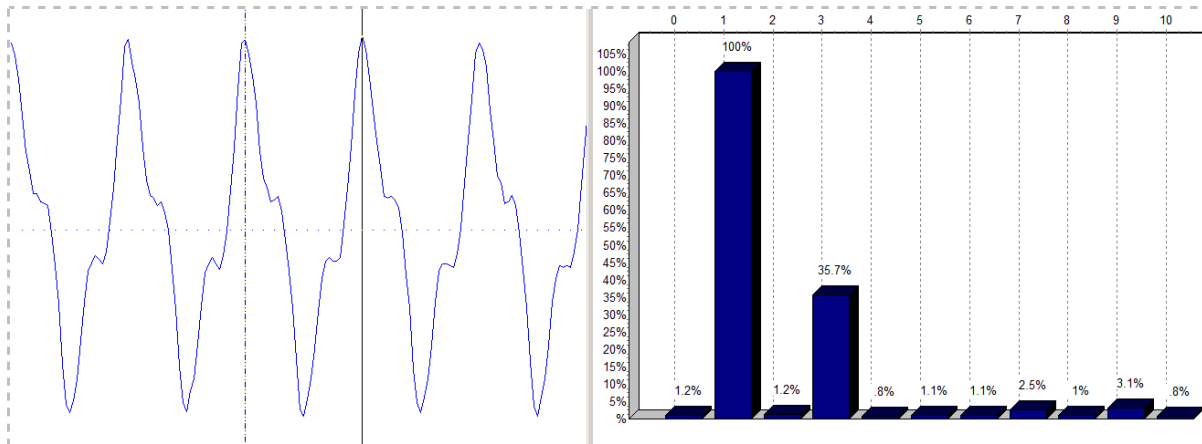


Figure 70. Generator operation produces 3<sup>rd</sup> harmonic content (level indicates health).

## Appendix A

The following process is handy when analysing event report data from relays.

### **Step 1: Understand what is expected to happen for given conditions**

To understand what you can expect, you must look at settings, installation drawings, reference texts, and instruction manuals.

### **Step 2: Collect all relevant information**

Including eyewitness testimony, any available information about the fault, sequence- of-events records, trip targets, and relay event data.

### **Step 3: Gather available analysis tools**

Such as instruction manuals, reference texts, and event analysis software.

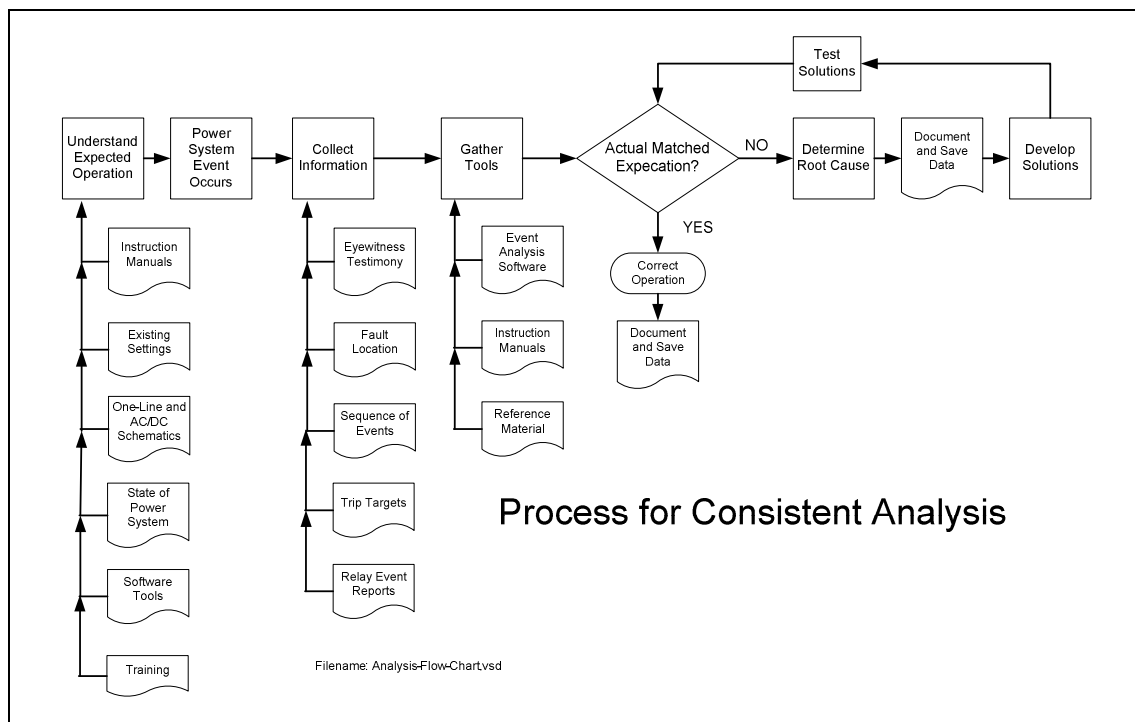
### **Step 4: Compare the actual operation to expectations**

If there are any differences, resolve these differences by determining root cause. Do not waste time analysing unused elements or settings. Focus, instead, on trip logic and output contact programming. Do not forget to look at pre-fault information, and use data from pre-fault information to perform an “offline” commissioning test to prove that system installation is correct. Before and during the analysis process, save data intelligently, naming files in a coherent way.

### **Step 5: Document your findings, proposed solutions, and test result**

When you have validated a correct operation, or determined root cause and developed a proven solution for an incorrect operation, you are done.

Refer to the flowchart below for a graphical demonstration of these steps:



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