Advancing Power Equipment and Line Protection with Practical Solutions

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Degree

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DEDICATION

To my wife and best friend, Lilah, whose unwavering support, love, and understanding sustained me throughout this journey. Your patience and encouragement were my guiding light.

To my esteemed advisor, Dr. Yilu Liu, for your mentorship, guidance, and wisdom that has supported me and pushed me to this goal. Your dedication to the pursuit of knowledge is truly inspiring and I have not known a more supportive, dedicated teacher. I'll forever be grateful to you.

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I offer my humble gratitude to my Lord and Savior, for His grace, strength, and guidance throughout my life. With the faith He placed in my heart as my foundation, I have hope and found the resilience to persevere to this milestone.

Lastly, to my children, Paiton and Garner, your love and presence in my life is a joy to me and you are my greatest source of pride.

This dissertation is dedicated to all of you, with heartfelt gratitude for your support and belief in me.

ABSTRACT

This dissertation is the culmination of an academic and professional career dedicated to power system protection. It begins with an emphasis on the need for excellence in analysis of power system fault events with the goal of improving system protection and reliability. The bulk of this work describes the detailed analysis of various misoperations of protective relays and the solutions that those analysis led to. The last chapters round out the manuscript with two improvements that the author advanced, and which are now becoming part of the state of the art in generator protection being incorporated into Institute of Electrical and Electronics Engineers (IEEE) standards for generator protection.

In conclusion, this dissertation contributes to the field of power system protection by providing in-depth analyses of protection challenges and offering practical solutions to improve system protection and reliability. The research outcomes are contributions to enhancing the security and performance of power grids, ultimately benefiting both utilities and consumers.

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INTRODUCTION

Chapter one of this dissertation discusses the importance of and the need for good analysis of all protective system operations. The chapter discusses how important diagnostic information is being left on the table after "normal" operations and opportunities for improvement to protective relay settings or signatures of equipment anomalies are missed. Examples are given of valuable information that can be gleaned with a small-time investment by analysis engineers.

Chapter two evaluates various methods used to prevent transformer differential relays from misoperation on inrush currents at energization. The tradeoff between protection security and dependability is examined in relation to properly restraining on inrush currents while remaining sensitive for energization of faulted transformer banks. Several actual digitally captured inrush waveforms and relay event reports for bank energizing cases are analyzed. This chapter lays the important groundwork for the analysis developed in chapter three.

Chapter three describes the analysis of a transformer bank differential misoperation. The only information available was local differential relay target indication and a digital fault recording from a remote DFR (digital fault recorder). The subsequent analysis used the MATLAB (software by The MathWorks, Inc.) environment to plot total harmonic distortion (THD) with operating fundamental to show why the single-phase differential (GE STD) operated. The MATLAB analysis technique is presented as a means of determining the various operating quantities (e.g. 2nd, 5th, or total harmonic content) and how the various restraint techniques respond. The analysis points out the vulnerability of transformer differential relay schemes that use independent fixed percentage harmonic restraint to block false operation on bank energization. A corollary presented is the possibility of "cross-blocking" schemes improperly restraining on energization of a faulted transformer bank.

Chapter four discusses the saturation of a 500 kV neutral CT (current transformer) upon energization of a 1,300 MVA transformer bank. The event resulted in the misoperation of a restricted earth fault element protecting the bank and capacitor bank protection on grounded wye capacitor banks in the surrounding system remote from this station. The merits of the simple directional overcurrent restricted earth fault scheme will be discussed as well as the analysis of the capacitor bank protection misoperations.

Chapter five describes the analysis of a 161 kV capacitor bank residual overcurrent scheme misoperation. Information available included local relay target indication, a digital fault recording from the local DFR, and system dispatcher logs. The dispatcher logs indicated that a 500 kV intertie transformer bank one station away had been briefly energized with one phase on the wrong voltage tap. This occurred simultaneous with the 161 kV capacitor bank misoperation. The Mathcad (software by PTC Inc.) environment was used to help determine why the zero-sequence voltage supervised residual overcurrent (GE SFC) operated. The analysis and subsequent field-testing point out the vulnerability of this protection scheme to harmonic energy and therefore its misapplication to capacitor bank protection. Six months later this same scheme installed at five different substations (separated by hundreds of miles) operated on harmonic energy produced by a different mechanism, geomagnetically induced current.

Chapter six discusses the effect tapped motors have on transmission line reclosing and the effect reclosing has on tapped motor loads. An analysis is described to determine how long a delay is required before reclosing may safely and successfully occur. Actual captured events on the Tennessee Valley Authority (TVA) power system are used in the discussion.

Chapter seven goes through the event analysis of an undesired trip of a line-distance relay applied near a large 522 MVA wye-grounded/delta generator step-up transformer. The generator was off-line, setting up a large remote zero-sequence source (without positive or negative sequence currents) that undesirably affected the relay operation. This paper utilizes the recorded fault data and symmetrical component sequence networks to analyze the fault. Detailed lists of observations of the relays' analog (currents and voltages) and digital logic signals are developed from which a cause and solution are quickly determined. In addition, other relay application problems are identified.

Chapter eight discusses the phenomenon of zero-sequence voltage coupling from the high-voltage system to the high-impedance grounded low-voltage bus for a synchronous generator and a simple improvement to accelerate stator ground fault protection (59G) using negative sequence current. This improvement, developed by the author, is being incorporated into the latest revision of the IEEE standard C37.101 – "IEEE Guide for Generator Ground Protection".

Chapter nine describes generator inadvertent energization protection and then explains the author's supplemental protection to cover a gap in the existing practice. The supplemental protection detects an inadvertent energization that may occur just prior to a generator is tied to the grid or just after it is disconnected. This new method is being incorporated into the latest revision of the IEEE standard C37.102 – "IEEE Guide for AC Generator Protection".

CHAPTER 1

THE IMPORTANCE OF POWER SYSTEM EVENT ANALYSIS

A version of this chapter was originally presented to the 8th Annual Fault and Disturbance Analysis Conference April 25-26, 2005:

Russell W. Patterson. “The Importance of Power System Event Analysis.” 8th Annual Fault and Disturbance Analysis Conference, April 25-26, 2005, Atlanta, GA.

Abstract

This chapter discusses the importance of and the need for good analysis of all protective system operations and how important diagnostic information is being left on the table after “normal” operations and opportunities for improvement to protective relay settings or signatures of equipment anomalies are missed. Examples are given of valuable information that can be gleaned with a small-time investment by analysis engineers.

Introduction

There are basically two levels of analysis being performed at utilities: Minimal and Good. At the minimal level the reviewers look at easily obtained information and determine whether the operation was proper. For example, a lightning strike causes a phase-ground fault on a 230 kV transmission line. SCADA reports that both end breakers tripped and reclosed successfully. Both ends have zone 1 ground instantaneous targets. Case closed. The major problem with this approach is that there are frequently incipient problems that can be identified by simply taking the time to review data that is readily available.

It is this author's opinion that every operation on the bulk transmission system (100 kV and above) should be reviewed in greater detail than the scenario outlined above. Any relay engineer worth their salt knows the importance of good analysis on all operations, not just post-mortem on obvious system failures. Many incipient problems can be diagnosed and nipped in the bud.

If DFR (digital fault recorder) or microprocessor protective relay event data is available for an operation it should be reviewed. For a normal operation an analysis engineer can quickly review oscillography data to check the health of the protection system.

Example Events

The following events underscore the importance of analysis and what is being left on the table by neglecting to do this analysis except on obvious misoperations.

CASE 1: Restrike on 161kV breaker - successful fault clearing.

October 20, 2004 - System Protection & Analysis engineers reviewed the DFR shot for a "routine" line operation with apparently "normal" clearing and relay targets at both ends. It was quickly apparent that a breaker restrike had occurred on C-phase. The recommendation was made to bypass the breaker for maintenance. The likely result of not doing this analysis would have been catastrophic failure of the breaker. See Figure 1-1.

CASE 2: Normal 500 kV CCVT energization event - improperly diagnosed as Ferroresonance.

March 23, 2005 - Engineers reviewed the DFR shot for a routine 500 kV line energization. Ferroresonance was quickly identified, and the maintenance organization notified. This improper diagnosis resulted in undue alarm over an event that occurs regularly and is of no harm. The trapped flux in the voltage transformer in the CCVT (capacitive coupled voltage transformer) was in the same direction as the flux created by the applied voltage. The result was ac core saturation in the base of the CCVT (J. Chadwick). Regular experience reviewing oscillography will "educate" the analysis engineers so that they can quickly identify characteristic signatures of equipment under various conditions. See Figures 1-2 and 1-3.

CASE 3: "Normal" ground fault clearing – breaker pole on unfaulted phase fails to open.

February 24, 2005 – An analysis engineer reviewed the DFR shot for a routine 161 kV line fault event. An A-phase to ground fault had occurred and was seemingly cleared properly by the protection system. However, further review of the oscillography revealed that the B-phase pole on the breaker had failed to open during the event. See Figure 1-4.

CASE 4: Memory polarizing misoperation needle in haystack of operations

June 15, 2010 – In the midst of significant system disturbances due to a major flooding storm event a misoperation of a positive sequence memory [7] polarized digital relay occurred. Diligent protection engineers at the utility reviewed each event that occurred, and this event revealed a vulnerability in the relay's memory polarizing. During the storm many transmission lines had tripped out, leaving this relay terminal connected radially to the utility system with a large pocket of industrial motor load behind it.

A fault occurred in the utility system beyond the remote end of this transmission line. When that remote fault was cleared it opened the last path connecting this line to the utility system. As the large motor load spun down, this relay misoperated as shown in Figure 1-5. When the phase voltages are a balanced set, the positive-sequence voltage equals the A-phase voltage since $3\mathrm{V}_1 = \mathrm{V}_\mathrm{A} + \mathrm{aV}_\mathrm{B} + \mathrm{a}^2\mathrm{V}_\mathrm{C}$ in an A-B-C rotation system ($a = 1\angle 120°$). As such, for this event we can plot the A-phase voltage (proxy for V_1) along with the memory voltage (actual $V_{1_{memory}}$) to have an acceptably accurate comparison of the actual positive-sequence voltage during the event to the memory voltage. In the third plot of Figure 1-5 the two are coincident until just after the -50 ms point in the shot. At this point they start moving out-of-phase since the memory voltage was predominately comprised of voltage measured earlier when the system was at 60.02 Hz. The time between zero crossings of the A-phase voltage (green trace) near the 0 ms mark is approximately 10.3 ms, equivalent to a frequency of $\frac{1}{2\times 10.3\mathrm{E}-3} = 48.5$ Hz. This represents a rate-of-change-of-frequency (ROCOF) of approximately 230 Hz/s, well above the capability of this or any other commercially available phasor-based distance relay to track. A similar calculation for the memory voltage estimates it at around 54.5 Hz in this region. At the 0 ms point the two waveforms are about 90° out-of-phase and this is where the distance elements misoperate.

This relay had a phase-phase current detector supervising the distance element. It was fixed in the relay (not changeable) at 10% of nominal and with nominal being 5 A it provided a minimum current requirement of 0.5 A secondary phase-phase current. At the time of trip, the relay was measuring around 0.7 A, sufficient to allow the operation. Analysis engineers recognized that the B set relay did not misoperate for this event even though it was also a positive-sequence memory polarized relay. However, the B set relay had settable phase-phase overcurrent supervision that was set, based on fault studies, well above the 0.7 A present during the fault. The relay manufacturer eventually introduced settable phase-phase overcurrent supervisors into the A set relay logic.

Summary

Tell any “old timer” analysis engineer that your utility takes the minimal approach to analysis, and they will likely insult you - as they did me. They can’t understand the mindset that discounts the importance of thorough analysis. They were accustomed to doing analysis when it required developing the old paper oscillograph shots and using rulers to determine fault current levels. And they were much more thorough than we are today.

The typical relay engineer performs only pre-fault analysis: Performing fault studies, checking system impedances, and specifying relay settings. This is only half of a complete job. Post-fault analysis completes the loop, providing feedback on how the protective system operated, if the intended elements operated. This allows the engineer to make any necessary adjustments in relay settings or in overall scheme philosophy as well as find the occasional issue with digital relay firmware that allows the manufacturer to improve their design.

We now have modern microprocessor relays and digital fault recorders that allow us to quickly display the oscillography on a computer screen. By simply making a small investment in time we can avoid possibly catastrophic and costly equipment failure and interruption to the bulk transmission system and/or end-use customers.

One estimate puts the cost of the August 14, 2003, blackout in the U.S. at between $7 and $10 billion. It is astonishing that there has been no significant increased emphasis placed on improving analysis of the data that is captured daily from digital fault recording devices and protective relays.

To only review oscillographic data after obvious misoperations is analogous to a doctor ignoring your reports of anxiety, tightness in chest, nausea and shortness of breath and only treating you for a heart attack if you experience cardiac arrest.

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Appendix

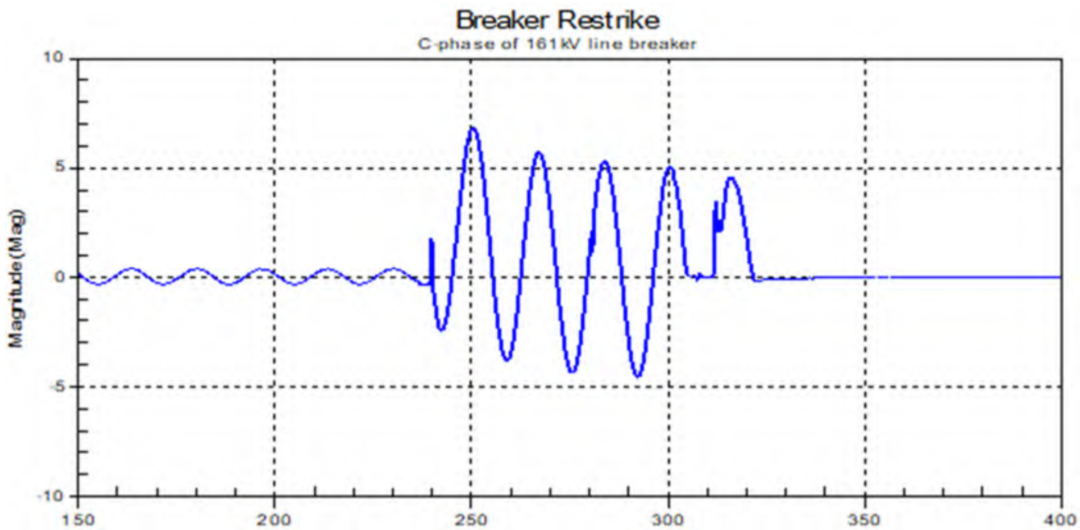

Figure 1-1 Breaker Restrike on "Normal" Operation

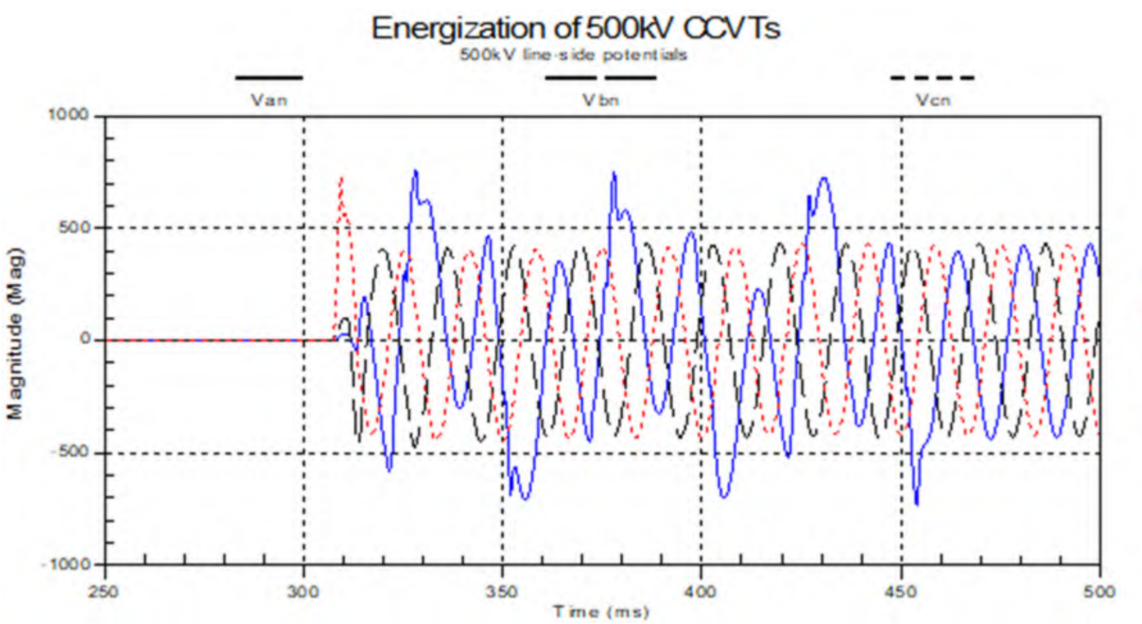

Figure 1-2 Energizing a Set of 500 kV CCVTs (Three-Phases Plotted)

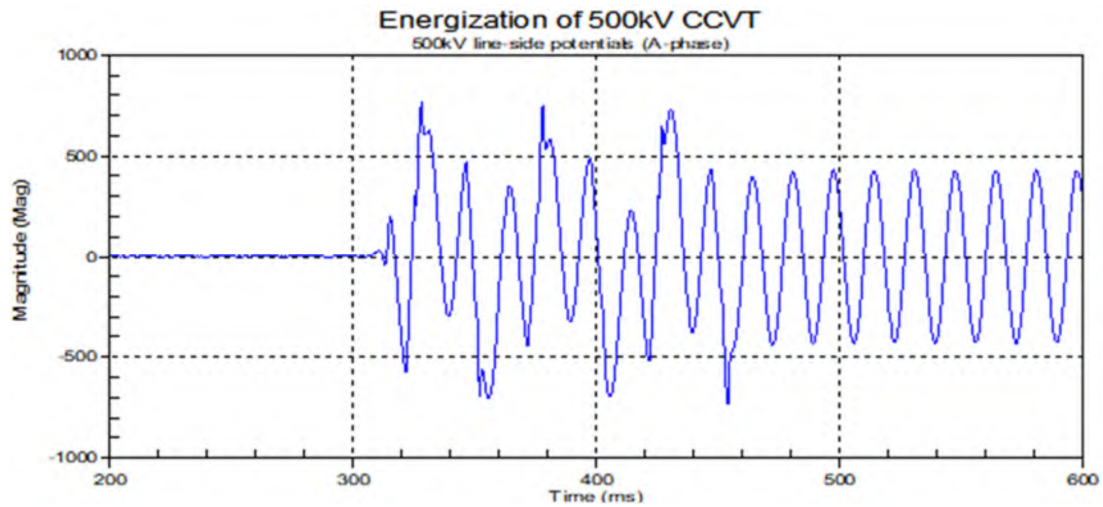

Figure 1-3 Energizing a Set of 500 kV CCVTs (A-Phase Only Plotted)

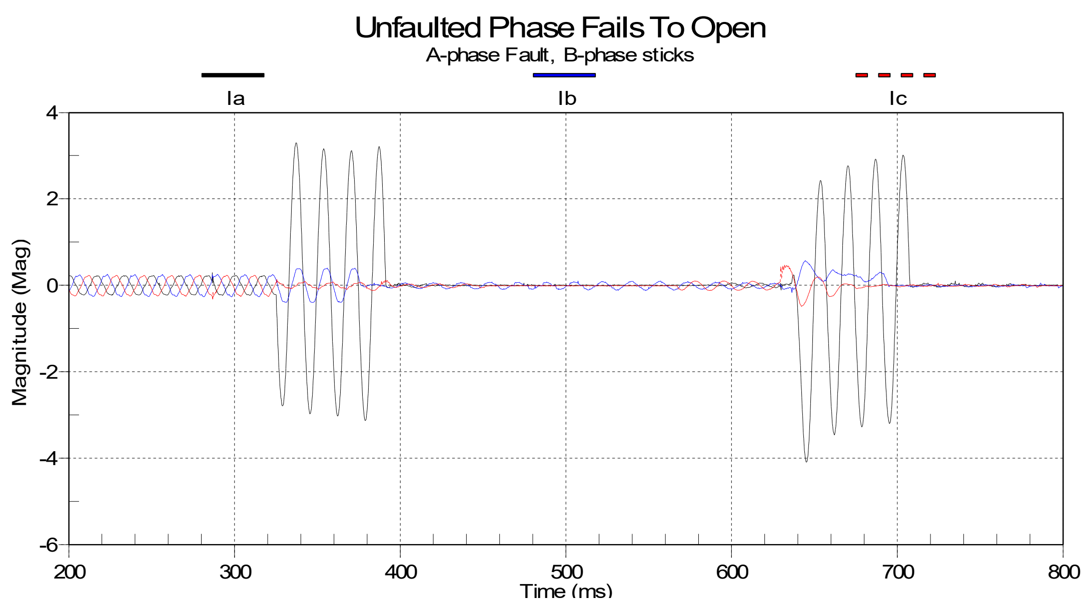

Figure 1-4 A-Phase Ground Fault Cleared, Unfaulted B-Phase Remains Closed.

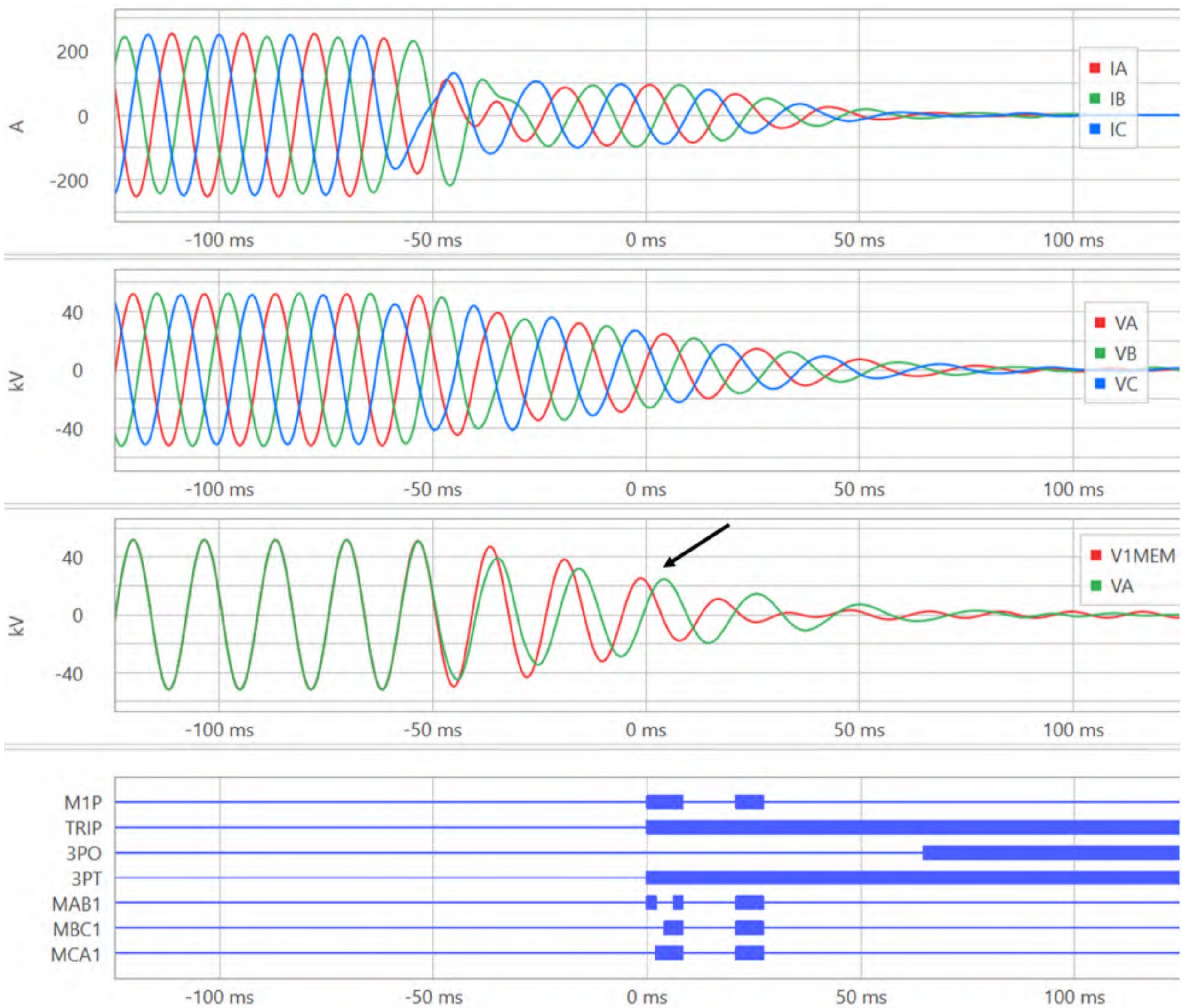

Figure 1-5 Positive-sequence memory polarization misoperation.

CHAPTER 2

A CONSIDERATION OF INRUSH RESTRAINT METHODS IN TRANSFORMER DIFFERENTIAL RELAYS

A version of this chapter was originally presented to the 54th Annual Georgia Tech Protective Relaying Conference May 3-5, 2000:

Walter P. McCannon, Russell W. Patterson, Gary L. Kobet. “A Consideration of Inrush Restraint Methods in Transformer Differential Relays.” 54th Annual Georgia Tech Protective Relaying Conference May 3-5, 2000, Atlanta, GA.

Abstract

This chapter evaluates various methods used to prevent transformer differential relays from misoperation on inrush currents at energization. The tradeoff between protection security and dependability is examined in relation to properly restraining on inrush currents while remaining sensitive for energization of faulted transformer banks. Several actual digitally captured inrush waveforms and relay event reports for bank energizing cases are analyzed, laying the groundwork for the analysis developed in chapter three.

Introduction

Background Information

On March 19, 1999, a Tennessee Valley Authority (TVA) substation experienced a transformer bank differential misoperation on inrush (for details see Chapter 3 and [1]). A digitally captured waveform of the inrush currents was analyzed and indicated that the 2nd harmonic restraining quantity in one of the single-phase transformer differential relays was lower than the threshold of the relay. This event and subsequent analysis motivated the authors to further investigate the various methods in use at that time on our system for properly restraining during inrush events. Properly restraining means to reliably recognize and restrain on inrush events while being capable of tripping when energizing a faulted transformer bank. Our purpose in writing this chapter was to present our method for analyzing inrush currents and to further educate ourselves and stimulate discussion on this topic. The following is a description of our efforts.

Differential Protection Applied to Power Transformers

The IEEE standard for the protection of power transformers states that current differential protection is "…the most commonly used practice for protecting transformers that are rated approximately 10 MVA (three-phase, self-cooled rating) or more…" [2]. The differential principle is simple and provides the best protection for phase and ground faults (grounded-wye windings with neutral impedance may also require restricted-earth-fault protection).

Although differential protection is relatively simple to apply, it does have its challenges. The problem of the differential relay operating on transformer magnetizing current inrush is well known. This is mainly a consideration during bank energization, although it can also be a problem during an overvoltage or overexcitation condition. Inrush occurs when the voltage suddenly applied to the bank would tend to produce a magnetic flux in the core that differs from that present in the core [3]. The resulting current can be many multiples of rated current. This current appears on only one input to the differential (from the side of energization), thus presenting as an internal fault. Figure 2-1 illustrates the typical current waveforms present during a three-phase transformer bank energization.

Transformer Differential Basics

To facilitate understanding, an example of a complete secondary wiring diagram is shown in Figure 2-2 for the transformer differential protection of a delta-wye (Dy1) transformer. When electromechanical relays are used, the current transformers (CTs) on the wye power side are connected in delta. This is necessary to align the secondary currents entering the restraint winding for the VL side with the secondary currents entering the restraint winding on the VH side. For balanced currents (balanced phase, positive-sequence, negative-sequence) this results in a 30° phase shift in the secondary, compensating for the 30° phase shift across the delta-wye power connections. In digital relays this compensation can be handled mathematically inside the relay such that the CTs may be connected in wye on both sides of the transformer. This is beneficial both for analysis purposes (retaining zero-sequence) but it also reduces the burden

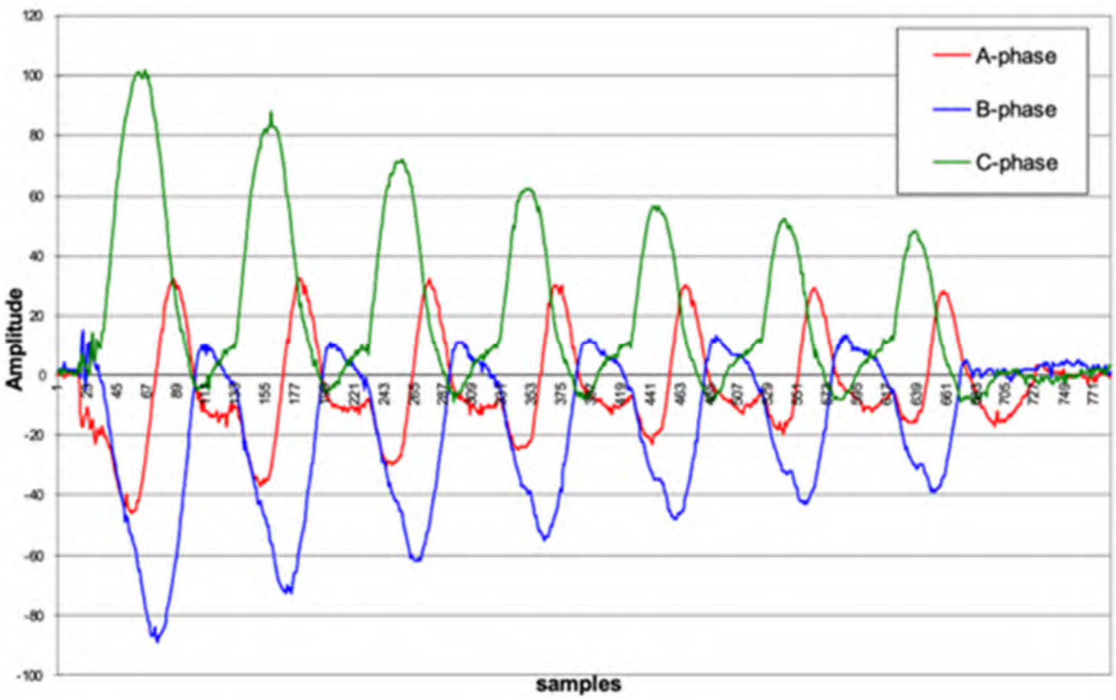

Figure 2-1 Inrush Currents During Transformer Energization.

impressed across the CT. Under balanced currents, the wye connected CT experiences $\sqrt{3}$ lower burden than the delta connected CT.

Not shown on the drawing in Figure 2-2 are the relay taps. The current entering the differential restraint coil on the VH side gets divided by relay setting TAP1. The current entering the differential restraint coil on the VL side gets divided by relay setting TAP2. This serves to balance the two currents in per-unit of tap. The resulting two phasor quantities combine at the node to create the operate current (op), which is in per-unit of tap. It is this quantity, the operate current, that is used for the harmonic restraint calculation. It is also the RMS value of the operate current that is used in the restrained differential element and the unrestrained differential element. The later operates as a simple overcurrent on this magnitude.

Methods of Preventing Misoperation of Transformer Differential Relays on Inrush

Undoubtedly every utility has experienced false operation of differential protection when energizing a transformer bank. Over the years, many different methods of preventing differential relay operation on inrush have been implemented or proposed.

1. <u>Ignore</u> the issue: That is, if it can be verified that there was no fault (via visual inspection, no sudden pressure relay operation, no oscillograph operations in the area, etc.) in the transformer, the bank is simply reenergized. This may be accepted practice in the case of a generating plant, especially nuclear, where each relay must be removed from service and exhaustively tested to make sure the relay itself is not the problem. Should the bank trip again, in some cases it has been reported that the differential trip cutout switch would be opened, the bank energized, the differential relay contacts verified to be open, and the

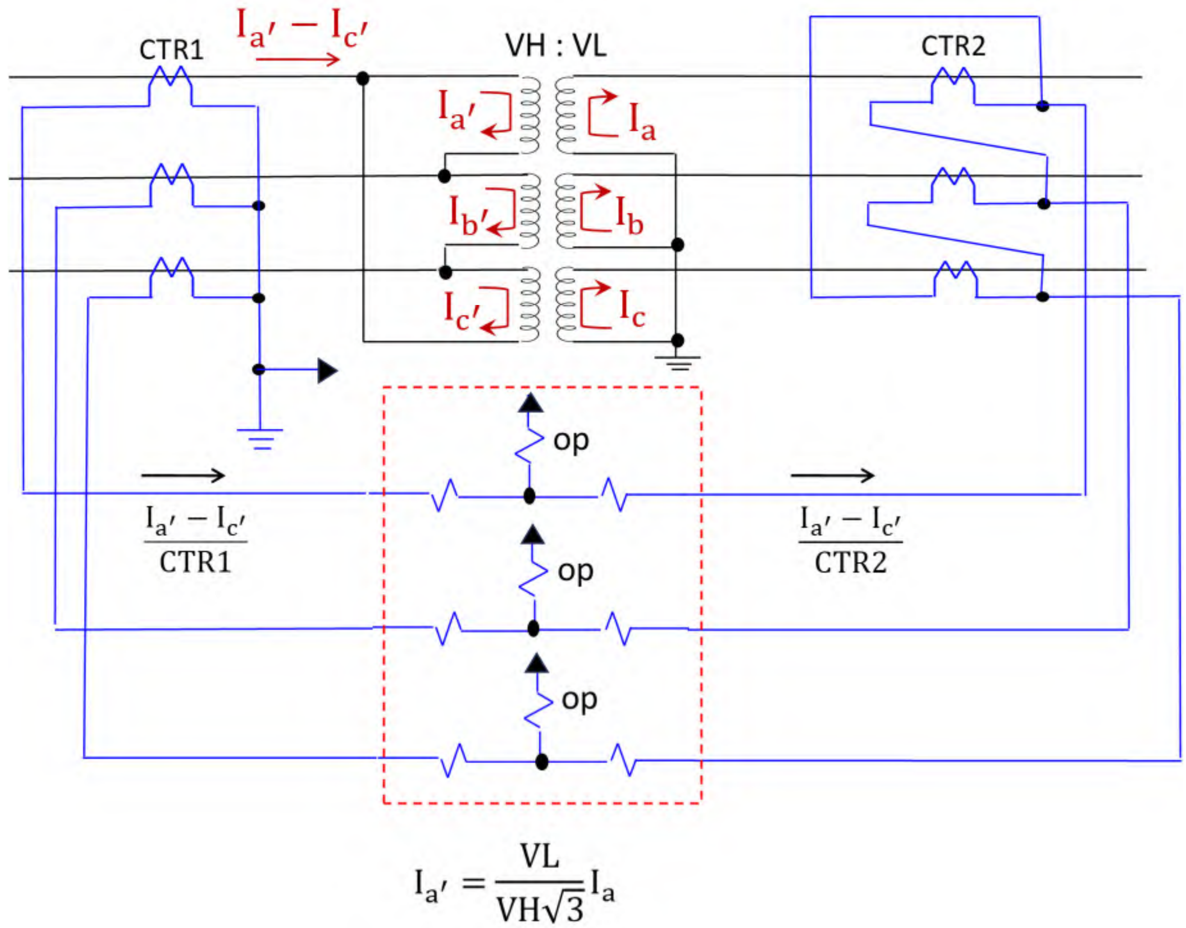

Figure 2-2 Wiring diagram for transformer differential.

cutout switch closed.

2. <u>Desensitize</u> the relay by:
    a. Raising the minimum pickup.
    b. Using an auxiliary relay measuring bus voltage to determine whether a fault is present on energization. On energization, with this method it is assumed that the bus voltage will not drop appreciably, and the auxiliary relay will be picked up, restraining the differential element from operating. If a fault exists, the voltage will drop, the auxiliary relay drops out, allowing the differential element to operate.
3. Use <u>slow-speed</u> electromechanical induction-type relays with relatively long operating time and high current settings.
4. <u>Power differential method:</u> This method is based on the idea that the average power drawn by a power transformer is almost zero on inrush, while during a fault the average power is significantly higher [4].
5. <u>Rectifier relay</u>: This method takes advantage of the fact that magnetizing inrush current is in effect a half-sinusoidal wave. Relays based on this method use rectifiers and have one element functioning on positive current and one on negative current. Both elements must operate to produce a trip. On inrush, the expectation is that one element only will operate, while on an internal fault, the waveform will be sinusoidal, and both elements will operate [5].
6. A variation of method 5 is the method of measuring “dwell-time” of the current waveform, that is, how long it stays close to zero, indicating a full dc-offset, which it then

uses to declare an inrush condition [6]. Such relays typically expect the dwell time to be at least ¼ of a cycle and will restrain tripping if this is detected.

7. One unique method proposed using the flux-current relationship of the transformer to provide restraint [7].
8. Harmonic current restraint (blocking): This is one of the most common methods and is discussed in more detail below.

An important feature of this inrush current is that it is evident that the currents are not pure fundamental frequency waveforms. Past research has shown that magnetizing inrush produces currents with a relatively high 2nd harmonic content [8], with relatively low third harmonic content [9]. Relay designers have taken advantage of this fact, along with the fact that internal fault currents have relatively low harmonic content. Relays have been designed with fixed or settable 2nd harmonic restraint thresholds that will restrain tripping if the input currents have a certain level of harmonic current and allow tripping if the second harmonic content is below that threshold. Different manufacturers chose different thresholds in fixed relays and for settable digital relays they provide a wide setting range. Table 2-1 lists the harmonic thresholds of three different types of electromechanical and solid-state transformer differential relays.

It should be noted that this chapter focuses on logic that blocks the differential from operating based on harmonic levels in the operate coil. This is not to be confused with methods [11, 12] that add the harmonic content to the fundamental frequency restraint quantity used in the restrained differential. In the former the harmonic content is used to block the relays operation. In the later the harmonic content is added into the percent differential restraint quantity to increase the restraint quantity. The term “restraint” as used in this chapter is in the context of blocking the relay from operating utilizing harmonics. It should also be noted that fifth harmonic energy, which is present during transformer overexcitation, may also be used in blocking logic (or in restrained differential restraint quantity) but is not discussed in this chapter which is focused on preventing misoperation on inrush.

Potential Problems with Fixed Second Harmonic Restraint

Conventional differential protection of a wye-wye-delta connected power transformer using electromechanical or solid-state relays required the CTs on the wye-connected windings to be connected in delta, to avoid misoperation on external ground faults due to zero-sequence currents (see Figure 2-3). However, it is possible for the subtraction effect of the delta connection to reduce the amount of 2nd harmonic in the differential currents seen by the relay, even if the phase currents have ample 2nd harmonic [1, 10]. This phenomenon has resulted in false tripping.

One study reported the minimum possible level of 2nd harmonic content in magnetizing inrush current was about 17% [9]. That being posited, a reasonable setting would be a 15% threshold. However, newer transformer designs are producing transformers that can have inrush current with 2nd harmonic levels as low as 7% [3]. In that case, the above-described fixed threshold relays would not be able to distinguish between fault and inrush. Other methods will need to be considered to provide secure, dependable transformer differential protection. Some of those are considered in the next section.

Table 2-1 Harmonic Restraint Thresholds for Sample of Transformer Differential Relays.

Relay	Harmonic Threshold
Westinghouse HU-1	15%[5] 2nd[7]
General Electric BDD	35% 2nd, 20-25% 3rd and above[8]
General Electric STD16C	20%[9] 2nd
Asea RADSE	32% 2nd
SEL 387, 487	5 to 100% 2nd[11,12]
General Electric 745	0.1 to 65% 2nd, 2nd+5th[13]
Schneider Electric MiCOM P633	10 to 50% 2nd[14]

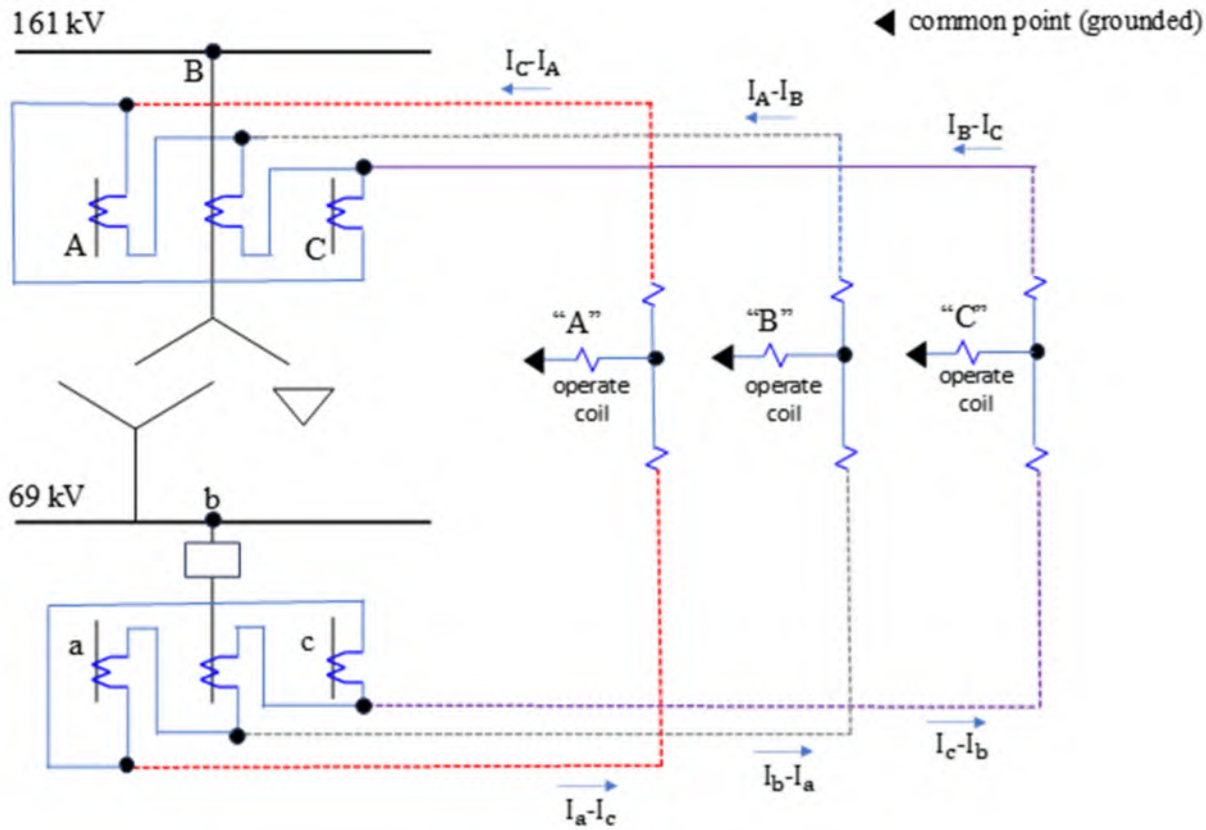

Figure 2-3 CT Connections to Differential Relays on Wye-Wye-Delta Transformer Bank.

Harmonic Restraint Methods Analyzed in this Chapter

Four methods were selected for review for blocking (restraining) operation on inrush currents, they are described below.

Simple 2nd Harmonic Restraint

This method has been in use for many years and simply looks for a percentage level of 2nd harmonic content (or THD in some relays) in the differential current. If the 2nd harmonic content present in the waveform is above a set threshold (typical thresholds used are between 15 and 35% of fundamental) the relay is blocked from operation. This is simply a per-phase calculation of 2nd harmonic current (in Amps or in per unit of tap) divided by fundamental current (in Amps or per unit of tap) in the operate coil. E.g. If the waveform has 4 A of 2nd harmonic and 10 A of fundamental it has a 2nd harmonic level of 40%. This method is titled Method A in this chapter.

Shared 2nd Harmonic Restraint

This method follows the same process as the Simple 2nd harmonic restraint method described above with the exception that the numerator is the sum of the 2nd harmonic current (in Amperes) all three differential currents. e.g. If the sum of 2nd harmonic current from all three differential operate currents is 9 A and the one differential of interest (this calculation is performed for each differential operate coil) has 10 A of fundamental, its restraining quantity is thus 90%. This sharing method attempts to avoid misoperating on the deficiency of 2nd harmonic content in one differential that commonly occurs on bank energization with delta CTs. This method is titled Method B in this chapter.

Cross-Blocking

Cross-blocking is described in a subsequent section. It is not a “method” of detecting inrush, but a choice made to block all tripping if any relay detects inrush. Any of the relays that use single-phase inrush detection methods can utilize cross-blocking. It is referred to as Method C in this chapter.

Waveform Recognition

Like the simple 2nd harmonic restraint, this method has been around for many years. This method takes advantage of the characteristic shape of inrush current waveforms. This method looks for ¼ cycle nulls (near zero values) that are common in the waveforms. Once these nulls are detected a restraint condition is declared. This method is titled Method D in this chapter.

More on Cross-blocking

Prior to the 1990’s, most transformer differential relays were packaged as single-phase devices. These relays were primarily electromechanical devices that were applied as a group of three relays for each protected three-phase transformer bank.

Most protective relay manufacturers are now marketing differential relays that, while emulating many of the features and philosophies of these earlier electromechanical designs, are different in their packaging and operation. Most of these modern designs are microprocessor based and incorporate the sensing and differential comparison of all three phases of each winding in a single package.

An important aspect of the newer relay's operation, that the protection engineer should carefully evaluate, is the capability of the relay algorithms and logic to compare the conditions sensed in all three differential phases. One aspect of this logic is the cross-blocking feature.

An example of applying cross-blocking logic begins with imagining a differential relay protecting a transformer that is now being energized. The relay typically senses the harmonic content of the current flowing into each differential operate coil and "blocks" the probable tendency of that differential element to operate. Cross-blocking logic blocks all three differential elements from operating if sufficient harmonic content is measured in any of the differential elements. The alternative is to allow the three differential elements to operate independently.

This cross-blocking logic was not typically available in single-phase electromechanical relaying. While this security feature seems to be a worthwhile benefit derived from packaging all the protective elements together in one box, there are relay dependability concerns to be considered.

Building on the example above, now add a few unfortunate details. First, assume the protected transformer bank consists of three single-phase tanks that comprise a large capacity, expensive, 500/230 kV autotransformer bank. Second, the phase one tank of this bank has an internal fault.

Now, with the differential relay's cross-blocking logic in place, the transformer bank is energized. The two unfaulted tanks exhibit normal levels of 2nd harmonic content in the energizing current flowing into the two tanks. The harmonic blocking in two of the three differentials activate the relay's cross-blocking feature. The tremendous fault current flowing into the faulted tank leaves the differential relay unimpressed. No trip output is issued from the relay until the harmonic content of the unfaulted tanks' energizing currents decline to levels below the threshold of the element's harmonic blocking algorithm or until the fault becomes severe enough to pick up the relay's high-set unrestrained element (this element is not blocked by harmonic blocking/restraint logic). The cross-blocking feature is then defeated, and a trip output is allowed to be issued.

This method is titled Method C in this chapter and is omitted from analysis to avoid complication. It is a simple step to review Method A and Method D and decide if any of the three single-phase relays would have declared a restraint condition. If any phase declares a restraint condition, the relay is cross blocked preventing any of the three differentials from operating.

Applying Actual Currents to the Various Methods

Appendix A is a concise summary of the inrush restraint methods analyzed in this chapter. It gives numerical examples to solidify understanding of how each method operates.

Braytown Event

Analysis of the Braytown Event indicates that Method A would allow a misoperation on inrush (Chapter 3). Method B would properly restrain as would Method D. It should be noted that the interpretation of Method D is simplified without detailed knowledge of an actual implementation from a manufacturer using this method.

Care must be used when applying a threshold level to Method B (shared 2nd harmonic method). By selecting too low a threshold the relay becomes extremely resistant to misoperating on inrush current while simultaneously becoming more insensitive to the low-magnitude faults that pose problems for the cross-blocking method. Good inrush restraint can be achieved without sacrificing too much coverage of the lower magnitude energization faults.

Summary

In summary we can say that using the simple 2nd harmonic restraint method with too high restraint levels invites misoperations on inrush. Likewise, using cross-blocking increases the odds of allowing a faulted transformer to remain energized for a lengthened amount of time increasing the possibility of damage.

The shared 2nd harmonic method appears very robust if the threshold is not too high making it insensitive to the low-magnitude fault at energization. Protection engineers are required to weigh the tradeoffs and benefits of the various methods and to decide which works best for various configurations.

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Appendix

Description of Inrush Restraint Methods used in this chapter.

METHOD A

This method is a per phase only method. It compares the ratio of 2nd harmonic operate current to fundamental operate current to the restraint quantity threshold.

Example: 2nd harmonic restraint setting = 15.0% (default)

Coil 1 has a fundamental current of 425 A, a 2nd harmonic current of 180 A. Coil 2 has a fundamental current of 670 A, a 2nd harmonic current of 125 A. Coil 3 has a fundamental current of 435 A, a 2nd harmonic current of 230 A.

Thus, the restraint quantity measured for each operate coil is as follows.

Coil 1 percent 2nd = $\frac{180\,A}{425\,A} \times 100\% = 42.3\ \%$

Coil 2 percent 2nd = $\frac{125\,A}{670\,A} \times 100\% = 18.6\ \%$

Coil 3 percent 2nd = $\frac{230\,A}{435\,A} \times 100\% = 52.9\ \%$

Note: Relay operate time is around 1 60Hz cycle.

METHOD B

This method uses 2nd harmonic "sharing". The magnitude (in per unit of tap) of the 2nd harmonic operating current is summed from all three operate coils. This resulting magnitude is then compared to the fundamental operating coil current on a per element basis (as opposed to each phase comparing its own 2nd harmonic content to its fundamental).

Example: TAP = 2.0 A and 2nd harmonic restraint setting = 18.0% (default)

Assuming the following currents into the three relay "operate" coils:

Coil 1 has a fundamental current of 425 A, a 2nd harmonic current of 180A. Coil 2 has a fundamental current of 670 A, a 2nd harmonic current of 125 A. Coil 3 has a fundamental current of 435 A, a 2nd harmonic current of 230 A.

The "shared" 2nd harmonic quantity = (180 A + 125 A + 230 A) / TAP = 267.5 A Thus, the restraint quantity measured for each operate coil is as follows.

Coil 1 restraint quantity = $\frac{267.5\,A}{425\,A} \times 100\% = 62.9\ \%$

Coil 2 restraint quantity = $\frac{267.5\,A}{670\,A} \times 100\% = 39.9\ \%$

Coil 3 restraint quantity = $\frac{267.5\,A}{435\,A} \times 100\% = 61.5\ \%$

For comparison, below are the per element percentages of 2nd harmonic content in each operate coil.

Coil 1 percent 2nd = $\frac{180\,A}{425\,A} \times 100\% = 42.3\ \%$

Coil 2 percent 2nd = $\frac{125\,A}{670\,A} \times 100\% = 18.6\ \%$

Coil 3 percent 2nd = $\frac{230\,A}{435\,A} \times 100\% = 52.9\ \%$

METHOD C

This method is a “common block” method. A restraint quantity is calculated for each phase (as above for METHOD B) and if at least one of those three quantities is above the threshold all three differential elements are restrained from operation.

Example: 2nd harmonic restraint setting = 20.0% (default = 15%)

Using the values calculated at the end of Method B above, we see that even though Coil 2 has less restraint quantity than the threshold (18.6% compared to 20% threshold) it would be restrained from tripping because Coil 1 and/or Coil 2 have greater than the threshold level.

METHOD D

This method is a waveform recognition method. This method full wave rectifies the differential current and then times the resulting null gaps (a null is a point on the rectified waveform whose magnitude is 1/3 of the waveforms peak) to detect null gaps that last longer than ¼ of a cycle. If gaps longer than ¼ cycle are detected an inrush event is declared.

CHAPTER 3

MATLAB ANALYSIS OF BRAYTOWN TRANSFORMER DIFFERENTIAL INRUSH MISOPERATION

A version of this chapter was originally presented to the 3rd Annual Georgia Tech Fault and Disturbance Conference May 1-2, 2000:

Russell W. Patterson, Gary L. Kobet. “MATLAB Analysis of Braytown Transformer Differential Inrush Misoperation” 3rd Annual Georgia Tech Fault and Disturbance Conference May 1-2, 2000, Atlanta, GA.

Abstract

This chapter describes the analysis of a transformer bank differential misoperation. The only information available was local differential relay target indication and a digital fault recording from a remote DFR. The subsequent analysis used the MATLAB (software by The MathWorks, Inc.) environment to plot total harmonic distortion (THD) with operating fundamental to show why the single-phase differential (GE STD) operated. The MATLAB analysis technique is presented as a means of determining the various operating quantities (e.g. 2nd, 5th, or total harmonic content) and how the various restraint techniques respond. The analysis points out the vulnerability of transformer differential relay schemes that use independent fixed percentage harmonic restraint to block false operation on bank energization.

Introduction

Background Information

On March 19, 1999, at 0752 system time, an overhead static wire on TVA's Elza-Braytown-Huntsville 161 kV line fell into and faulted the transmission line which was subsequently tripped by relay action. The auto-sectionalizing scheme at Braytown operated, and the Huntsville terminal attempted to radially pick up the two Braytown transformers and load by time-delay dead-line reclosing. When the Braytown substation was re-energized, the "C" transformer differential relay operated to trip and lock out the transformer banks. Total load on the transformer banks just before the trip (according to metering data) was (14.8 + j1.2) MVA.

The Braytown station is tapped 23 miles from the Huntsville terminal of the Huntsville - Elza 161-kV line (Figure 3.1). It is comprised of two banks in parallel, each rated 25/33.3/41.7 MVA and 161 kV wye-grounded to 69 kV wye-grounded with a 13 kV delta connected tertiary (Yy0d11). Each bank has an 85 Ω reactor in the 161 kV neutral.

Analysis

The differential relays used in this case are intended to be resistant to misoperation on inrush while maintaining their ability to properly detect and operate for an actual transformer fault that may present simultaneous with the inrush event (energizing a faulted transformer). However, harmonic inrush was the suspected culprit, and relay tap settings were initially raised to decrease the relays sensitivity to inrush, although it was not actually proven that inrush was the cause.

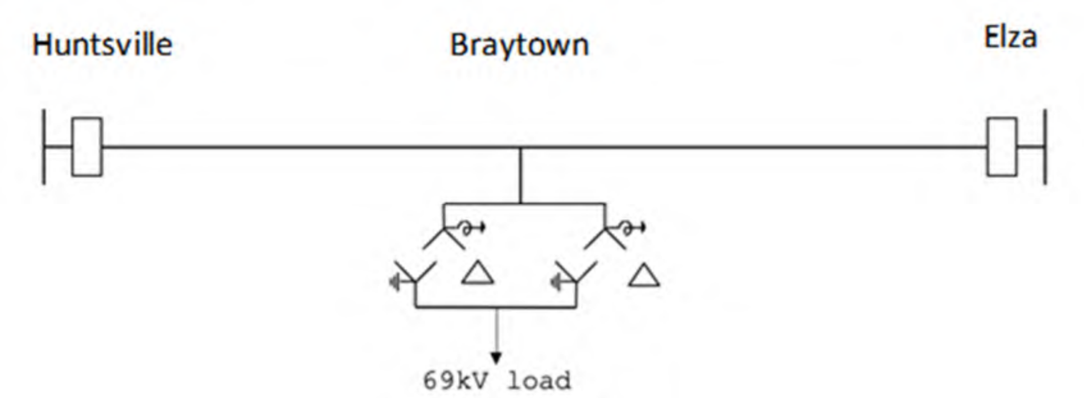

Figure 3-1 Huntsville-Braytown-Elza System One-line.

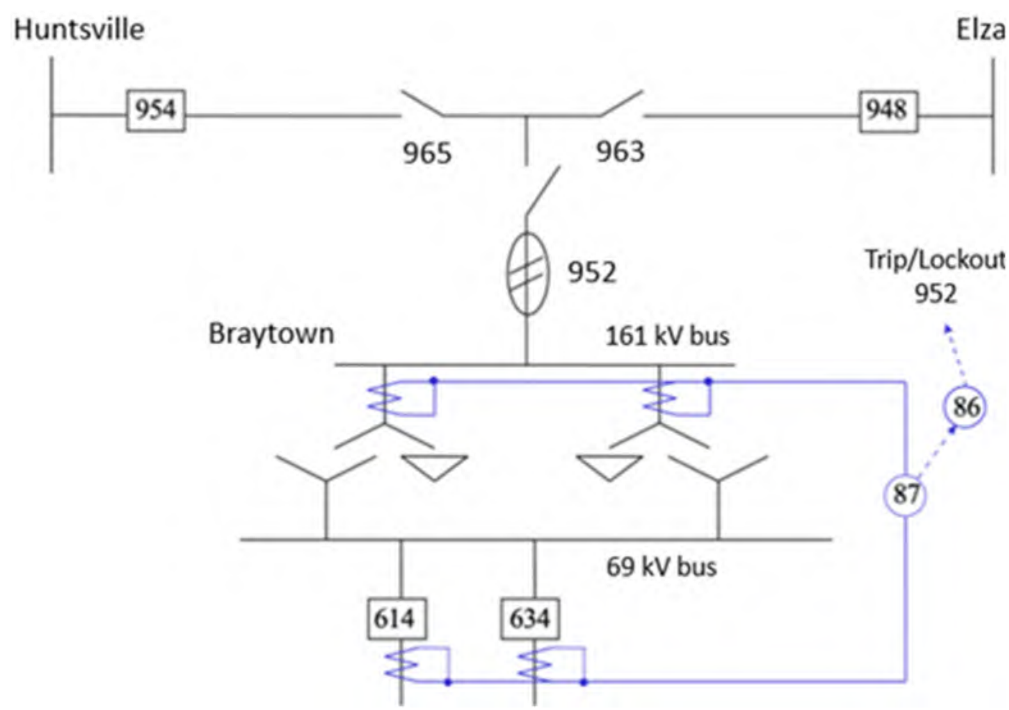

Figure 3-2 Braytown 161-69 kV Substation Protection One-line.

The instruction manual for the STD16C relay states that the relay should “restrain with greater than twenty percent second harmonic but will operate with second harmonic equal to twenty percent or lower” [1].

The missing piece of information was the actual currents seen by the differential relays. Since electromechanical relays do not capture event (waveform) data, and with no oscillography at the Braytown substation, there was no way locally to determine why the differential relay operated. However, the Huntsville terminal station did have a digital fault recorder, and fortunately it did record an event at the exact time that the Huntsville terminal breaker reclosed to energize the Braytown station (see Figure 3-3).

The raw DFR data was exported into a data file, and MATLAB was used to analyze the waveforms. A sliding window discrete Fourier transform (DFT) algorithm was used to calculate the second harmonic content of each Huntsville phase current (see Figure 3-4).

Note that all three phase currents had around 20% or greater second harmonic during the length of the event (Figure 3-4). It was then suggested that the harmonic restraint characteristic of the “C” relay may have been somewhat higher than 20%.

However, this initial theory proved to be erroneous when the “C” differential relay was bench tested with no problems found and within calibration limits. It was then recognized that the currents at the Huntsville terminal were the phase currents, while the currents measured by the differential relays at Braytown were provided by delta connected CTs. The actual high-side currents going into the differential current transformers (CTs) were the delta combinations of the three Huntsville phase currents. A common phenomenon in this

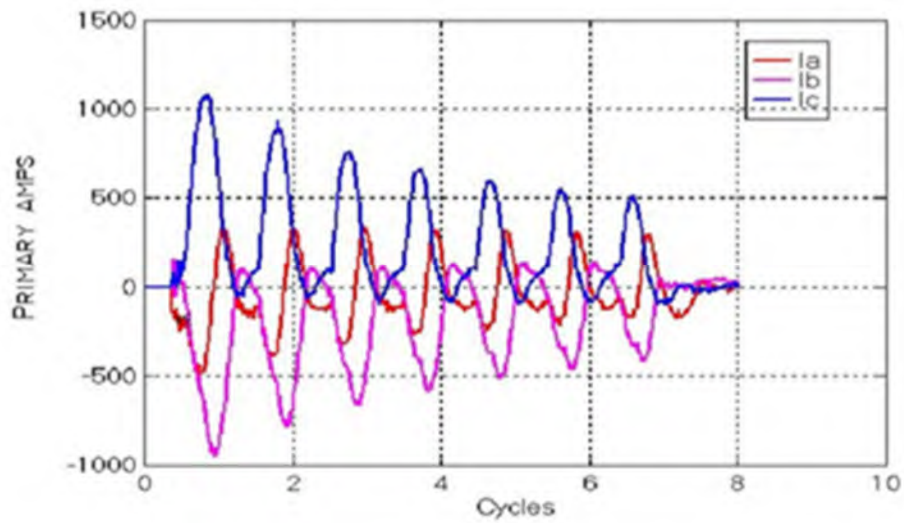

Figure 3-3 Phase Currents at Huntsville Terminal for Braytown Inrush.

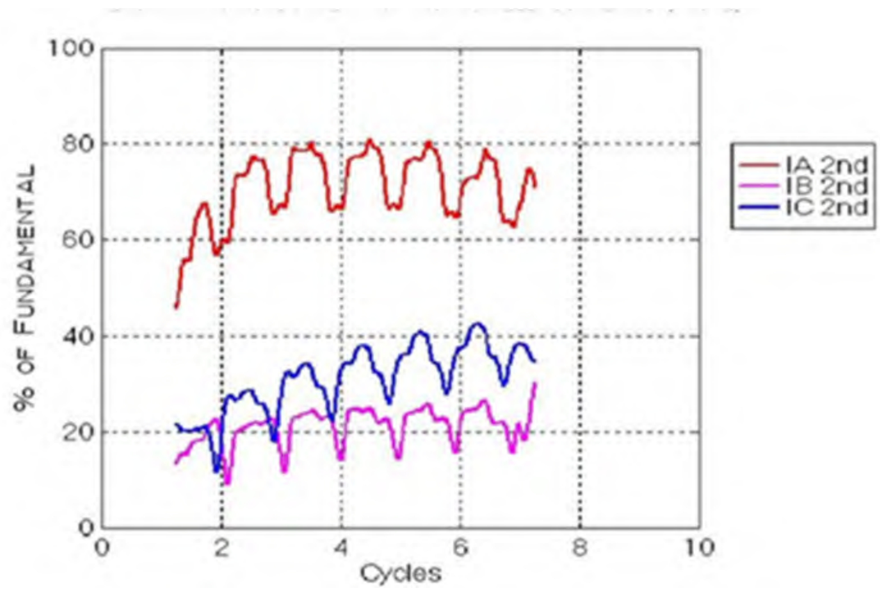

Figure 3-4 Percent 2nd Harmonic content in Huntsville Phase Currents.

transformer bank configuration (unknown to the authors at the time of this event) is that the differential currents in one of the three operate coils will have a very small percentage of 2nd harmonic content even though the phase currents have ample 2nd harmonic.

Figure 3-5 illustrates in more detail the delta CT connection of the currents to the differential relays at Braytown. The relay labeled "C" is measuring the difference between the C-phase and B-phase Huntsville phase current (I_{CB}).

The delta currents seen by each relay were then calculated by simple sample-by- sample subtraction of the currents. Figure 3-6 illustrates the results where MATLAB was again used to compute the 2nd harmonic content of each differential relay current (Figure 3.6).

Referring to Figure 3-6, note that while the $I_A - I_B$ and $I_C - I_A$ currents both had greater than 45% 2nd harmonic, the $I_B - I_C$ current had less than 15% for around 1 cycle and less than 20% for 2 or more cycles. This is due to the subtraction effect of the delta connection canceling second harmonic content ($I_{BC} = I_B - I_C$) in the phase currents.

Figure 3-7 shows the harmonic analysis of the "C" relay differential current (I_{BC} current). The total harmonic distortion calculation (THD) added little to the 2nd harmonic content and would basically have a smoothing effect on the 2nd harmonic content. There was not enough total harmonic content to restrain the relay.

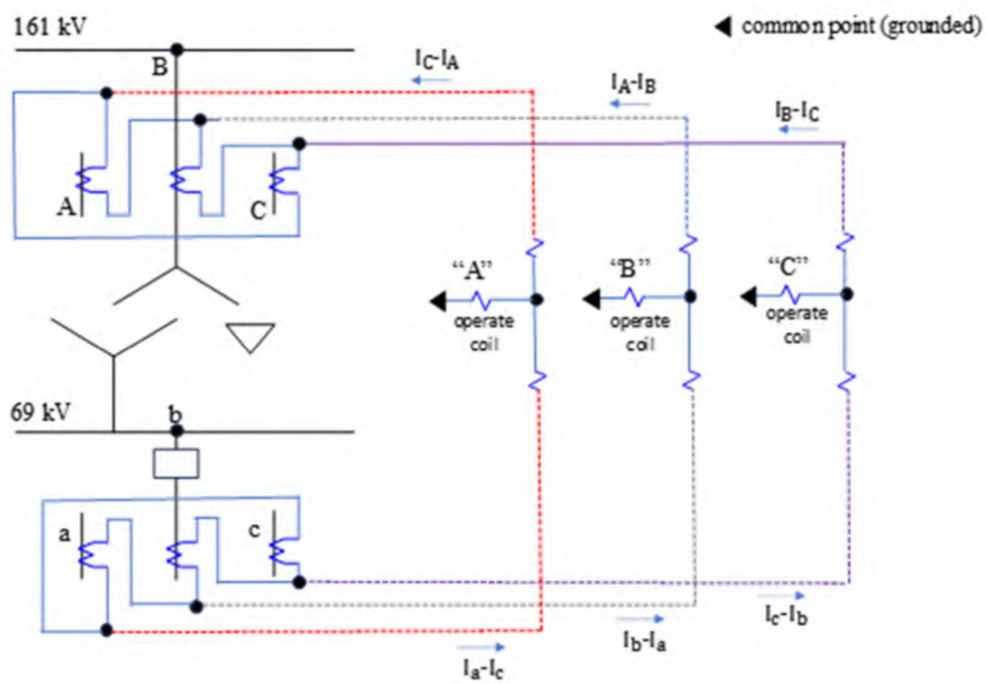

Figure 3-5 Delta connected CTs feeding the Braytown Differential Relays.

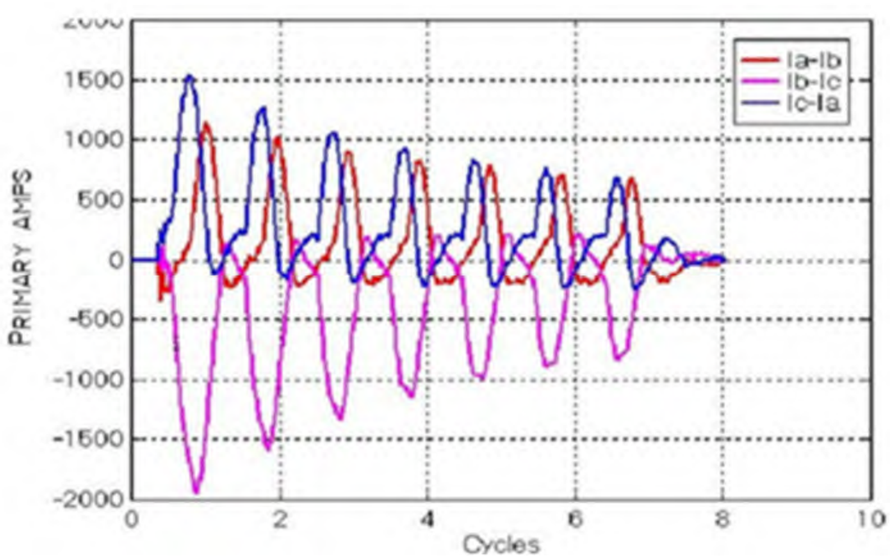

Figure 3-6 Computed Delta currents at Braytown.

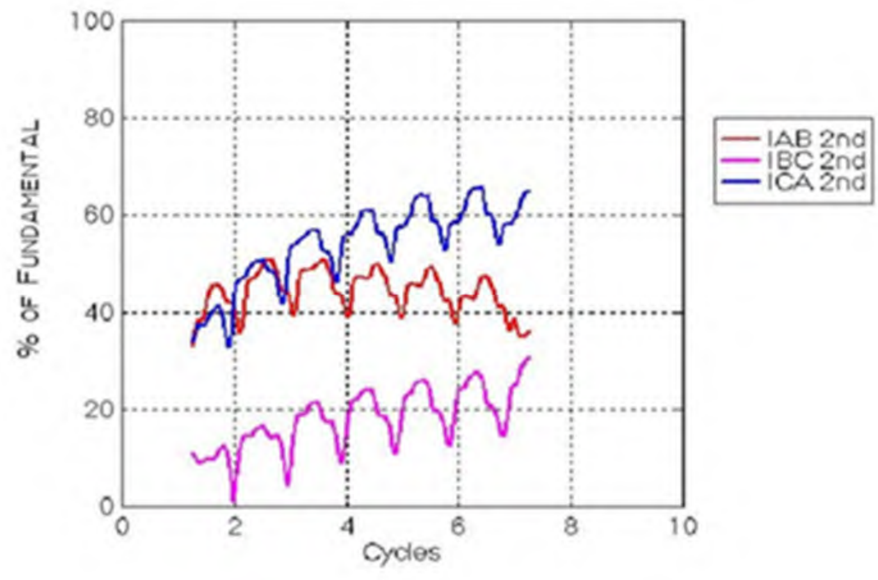

Figure 3-7 Percent 2nd Harmonic in 161 kV Delta Currents.

Further, Figure 3-8 shows the amount of fundamental current in the I_{BC} current. Ample 60 Hz content was available in the inrush waveform to operate the relay. Without digital oscillographic data from Braytown, we were unable to analyze and account for the 69 kV currents that would have been present in some distorted form due to connection of load.

To complete the analysis, since the STD uses total harmonic energy to restrain, the total harmonic energy (for the significant harmonics) is shown in Figure 3-9.

The lower plot in Fig 3-9 shows the amplitude of the fundamental component (in red) in the "C" differential operate coil current waveform. With no current in the low-side restraint coil the STD16C relay differential element operates with 30% (±10%) times tap. So, with a high-side tap setting of 3.2 A the relay would have picked up with current in the range of 0.64 A to 1.28 A with the midpoint being 0.96 A. Taking the high-side current transformer ratio (effective ratio to the relay) of 400:8.66 and picking an average value of fundamental amplitude from the above plot the operate coil current can be calculated as:

$$I_{OP} = \frac{\frac{75\ A}{\sqrt{2}}}{\frac{400}{8.66}} = 1.15\ A$$

As the "C" differential operated for this event it is obvious that this relay pickup was closer to the mean. From this analysis the "C" differential current presents less than 20% harmonic for over the 2.2 cycle operate time of the relays differential element resulting in the misoperation on inrush. Thus, the differential relay trip at re-energization was determined to be a misoperation due to lack of harmonic restraint on inrush currents, a vulnerability in this relay design.

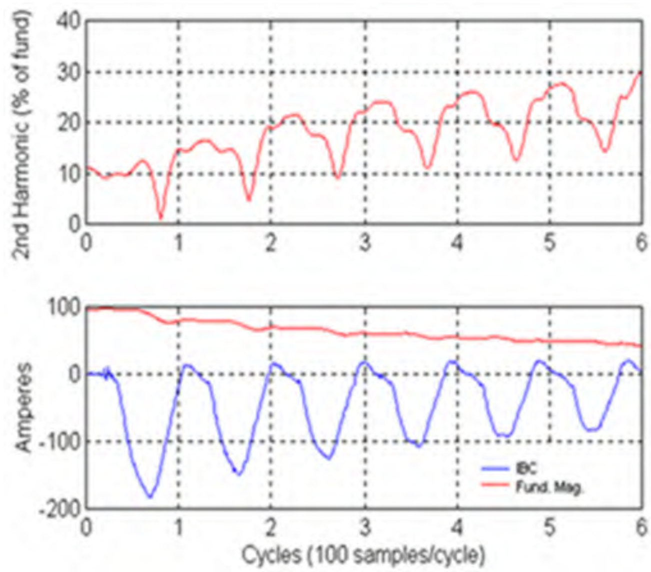

Figure 3-8 Harmonic Analysis of BC Current feeding the "C" differential relay.

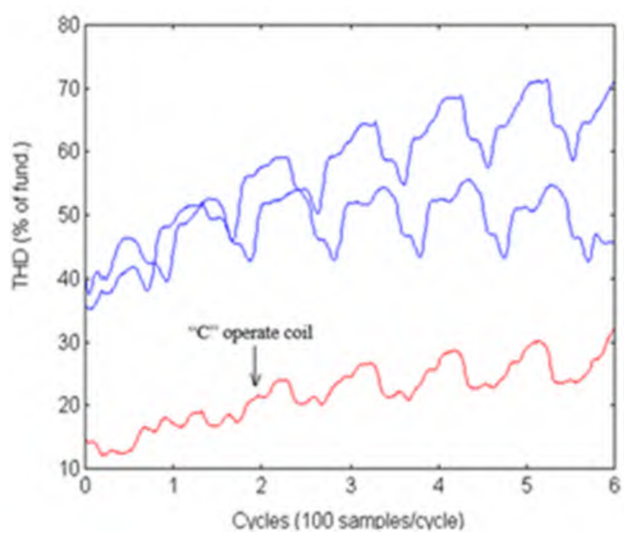

Figure 3-9 Total Harmonic Content of Each Operate Coil (differential "C" in red)

Solutions

With the cause of operation determined, a few different solutions were considered. Having already considered the method of raising taps (which only provides a very small increase in security while decreasing sensitivity to actual faults), the next approach was to determine if the harmonic restraint setting of the existing GE STD16C could be lowered. It is known that other electromechanical transformer differential relays with harmonic restraint have different 2nd harmonic thresholds. For example, the Westinghouse HU-1 is factory set for 15% 2nd harmonic, and it can be lowered to 7.5% [2]. The BDD relay, also made by GE, has a 2nd harmonic threshold of 35%. The manufacturer was contacted concerning the STD16C relay, and it was discovered some versions of the relay, such as the STD25D, can be modified but that it is not possible to modify the second harmonic restraint threshold of the STD16C by more than 1-2%.

With the relay harmonic restraint setting fixed at 20%, the only other realistic option to avoid misoperation on inrush considered was to replace the relay with a relay using a more secure method of harmonic restraint, this was the option chosen.

One method being used by manufacturers of three-phase microprocessor transformer differential relays is known as "cross-blocking." Cross-blocking is simply blocking all three differential elements from operating if any one of them detects an inrush condition. The obvious pitfall to this technique occurs when energizing a transformer bank with one phase faulted. If either of the other two phases differential relays detects inrush and declares a "restrain" then all relays are blocked from operating until the inrush currents have subsided. Many of the newer relays have a high-set overcurrent element that is not restrained by the inrush detection logic.

This “unrestrained” element would provide protection for energization of the faulted transformer in the event the fault current was high enough.

This still provides no protection for the lower magnitude currents that may be present upon energizing a faulted transformer. Our goal is to de-energize the transformer bank before those lower magnitude fault currents become higher magnitude fault currents possibly moving us from a minimally damaged transformer to a severely damaged transformer. The obvious benefit to this method is that misoperations on inrush when one phase has low levels of restraint quantity is avoided. However, as in all facets of power system protection, tradeoffs between dependability and security are necessary.

Conclusions

From this chapter several very important points should be taken. First, it can be seen how important digital fault recorders are to the analysis of system disturbances, especially for those events where relays are suspected to have misoperated. One event report from a remote digital fault recorder provided the key to analyzing this event and led the utility to reevaluate its transformer protection standard. Without digitally captured waveforms, analysis of this detailed nature is nearly impossible.

Second, the phenomenon of 2nd harmonic subtraction when delta connected CTs are used on wye connected transformer windings (on the winding normally energized to pick up the bank) was not widely known to practicing protection engineers, at least for this author, prior to this event. This phenomenon, along with newer power transformers with lower 2nd harmonic requirements, suggest that the shared 2nd harmonic method described in Chapter 2 may be more suitable in this case. The newer approaches that include harmonic energy in the restrained differential restraint quantity (along with lower levels of simple 2nd harmonic blocking) may also be necessary depending on the protection available. It is also possible to include a requirement in transformer specifications to have the manufacturer specify the harmonic content (in percent of fundamental) expected at energization to aid in evaluation of methods and setting levels.

Finally, the power of tools like MATLAB (code used in this chapter is given in the appendix) is evident in its ability to allow us to analyze and present results in this fashion. Sliding DFT algorithms like those used by the relay manufacturers in newer microprocessor relays can be modeled and their performance evaluated with actual captured waveform data. This gives us the ability to determine with confidence how and why our protective relays operate (or fail to operate) under fault or other transient conditions.

References

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Appendix

MATLAB code script file used in the analysis:

```
% DFT sliding window to plot 2nd harmonic content of Braytown
% differential currents.
%
% Input signal as IA, IB & IC from the file bray.m
%
%
clear % clear all variables
bray;
% this loads the 3 current waveforms and creates delta currents
IAB = Ia-Ib;
IBC = Ib-Ic;
ICA = Ic-Ia;
N = 100;     % samples per cycle of dfr
P = 600;     % number of points desired for plot output (6 cycles)

M = length(IAB)-N; % number points for the output vectors
for i = 1:M
t(i) = i;    % fill vector t to simplify plotting
end
for i = 1:M
 for j = 1:N
 WINDOW_of_IAB(j) = IAB(i+j-1);  % fills the current 100 sample window
 WINDOW_of_IBC(j) = IBC(i+j-1);
 WINDOW_of_ICA(j) = ICA(i+j-1);
 end
 % 2nd harmonic calc.
 FFT_of_WINDOW_IAB = fft(WINDOW_of_IAB); IAB MAG_of_FFT_IAB = abs(FFT_of_WINDOW_IAB);
 mysecond_IAB(i) = MAG_of_FFT_IAB(3)/MAG_of_FFT_IAB(2)*100;

 FFT_of_WINDOW_IBC = fft(WINDOW_of_IBC); MAG_of_FFT_IBC = abs(FFT_of_WINDOW_IBC);
 mysecond_IBC(i) = MAG_of_FFT_IBC(3)/MAG_of_FFT_IBC(2)*100;

 FFT_of_WINDOW_ICA = fft(WINDOW_of_ICA); MAG_of_FFT_ICA = abs(FFT_of_WINDOW_ICA);
 mysecond_ICA(i) = MAG_of_FFT_ICA(3)/MAG_of_FFT_ICA(2)*100;
```

```
end

% plot resulting 2nd harmonic points with each waveform
figure
subplot(3,1,1);
plot(t(1:P),mysecond_IAB(1:P),t(1:P),IAB(1:P));
ylabel('IAB');
title('Braytown GE STD Differential Inrush Trip - Second Harmonic Content');

subplot(3,1,2);
plot(t(1:P),mysecond_IBC(1:P),t(1:P),IBC(1:P));
ylabel('IBC');
subplot(3,1,3);
plot(t(1:P),mysecond_ICA(1:P),t(1:P),ICA(1:P));
ylabel('ICA');
xlabel('Data Points at 100 samples/cycle');

% now plot each separately figure
plot(t(1:P),mysecond_IAB(1:P),t(1:P),IAB(1:P)); xlabel('Data Points at 100
samples/cycle');
ylabel('IAB'); title('Braytown GE STD Differential Inrush Trip - Second Harmonic
Content');
figure plot(t(1:P),mysecond_IBC(1:P),t(1:P),IBC(1:P)); xlabel('Data Points at 100
samples/cycle');
ylabel('IBC'); title('Braytown GE STD Differential Inrush Trip - Second Harmonic
Content');
figure plot(t(1:P),mysecond_ICA(1:P),t(1:P),ICA(1:P)); xlabel('Data Points at 100
samples/cycle');
ylabel('ICA'); title('Braytown GE STD Differential Inrush Trip - Second Harmonic
Content');
t=t/100; % to put x-axis in fundamental frequency cycles
% now plot the three 2nd harmonic plots together vs. cycles figure
plot(t(1:P),mysecond_IAB(1:P),'b',t(1:P),mysecond_IBC(1:P),'r',t(1:P),mys
econd_ICA(1:P),'b');
xlabel('Cycles'); ylabel('2nd harmonic in % of fundamental per-phase');
title('Braytown GE STD Differential Inrush Trip - Second Harmonic Content');
```

CHAPTER 4

PINHOOK 500KV TRANSFORMER NEUTRAL CT SATURATION

A version of this chapter was originally presented at the 9th Annual Fault and Disturbance Analysis Conference May 1-2, 2006:

Russell W. Patterson. "Pinhook 500kV Transformer Neutral CT Saturation." 9th Annual Fault and Disturbance Analysis Conference, May 1-2, 2006. Atlanta, GA.

Abstract

This chapter discusses the saturation of a 500 kV neutral CT upon energization of a 1,300 MVA transformer bank. The event resulted in the misoperation of a restricted earth fault element protecting the bank and capacitor bank protection on grounded wye capacitor banks in the surrounding system remote from this station. The merits of the simple directional overcurrent restricted earth fault scheme will be discussed as well as the analysis of the capacitor bank protection misoperations.

Introduction

On May 31, 2003, TVA energized the 1300 MVA Pinhook bank from the 500 kV side with the 161 kV breakers open and 13 kV tertiary winding unloaded. The bank tripped by 500 kV winding restricted earth fault (REF) protection located in the B set microprocessor transformer protection relay. On a subsequent energization of the bank, 161 kV capacitor banks remote from this station misoperated by solid-state residual overcurrent protection (GE SFC relays).

Figure 4-1 below shows the transformer bank configuration and the secondary CT wiring to one of the microprocessor bank protection relays. Dual primary bank protection relays are used, and both A and B set relays are wired identical but from different CT windings except for the neutral CTs (one per neutral).

Neutral CT Saturation

Figure 4-2 shows the 500 kV currents during the May 31, 2003, energization of the Pinhook bank. B phase has a large dc offset and the CT experiences a degree of saturation as can be seen by the inrush current waveform transitioning below the axis. The 500 kV neutral CT experiences significant saturation around 200 ms into the event.

Figure 4-3 shows the 500 kV neutral current along with the 500kV residual of the phase currents. Initially all CTs reproduce well but around the 200 ms point the neutral CT experiences heavy dc saturation. The 500 kV neutral CT is a 25 kV, 200/400:5 (set on 400:5 ratio), T200 when on full winding, T90 when set on 200:5 tap, type KOR- 15.

Figure 4-4 shows the ground (REF) differential current resulting between the 500 kV residual and 500 kV neutral CT currents.

Effect on a Restricted Earth Fault Protection Element

The B set transformer differential relay has a REF element that is implemented as a traditional differential element with slope. When the 500 kV neutral CT saturated it produced a large REF differential current (Figure 4-4) causing this differential element to pick up. After a 6 cycle delay it tripped. The 500 kV breaker disconnects the transformer bank 2 cycles later. Figure 4-5 is a combination plot showing the analog REF differential current (black trace) and the two digital traces showing the REF element pick up (blue) and then the REF trip (red) after the 6-cycle delay.

The B set relay was running an early version of the relay vendor's firmware which included a default slope setting of 10%. Subsequent versions of the firmware had a default slope of 40% as well as other enhancements to make the REF element more secure. The A set relay implemented REF protection using a simple directional overcurrent principle [2] that is simple, secure, and reliable. This method compares an operate quantity (residual of 500 kV phase currents) with a polarizing quantity (500 kV neutral current). The element won't allow operation unless the two currents are within 90º of each other and are of sufficient magnitude. The CT currents are wired to the relay such that normally these two currents are 180º out-of-phase with each other. When CTs saturate their output is reduced in magnitude and goes leading in phase but cannot move more than 90º. Even under heavy saturation the two currents cannot move to within 90º of each other to satisfy a directional forward decision (internal fault).

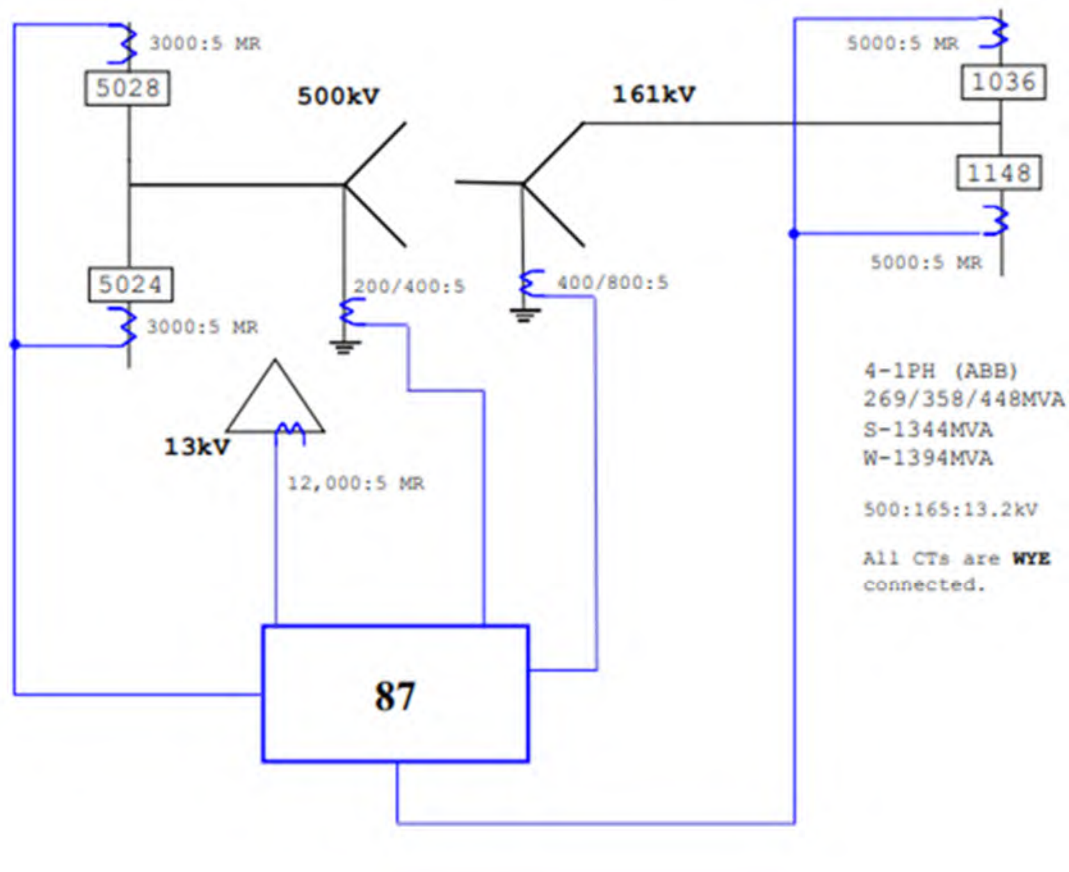

Figure 4-1 One-line of Pinhook Bank Differential Protection Circuit.

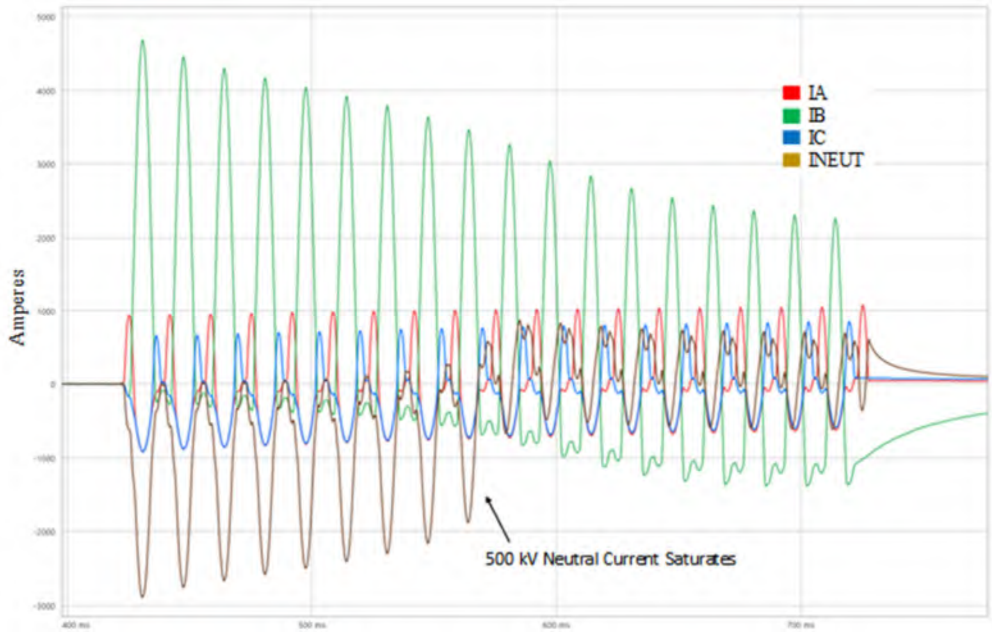

Figure 4-2 500 kV Phase Currents and 500 kV Neutral Current

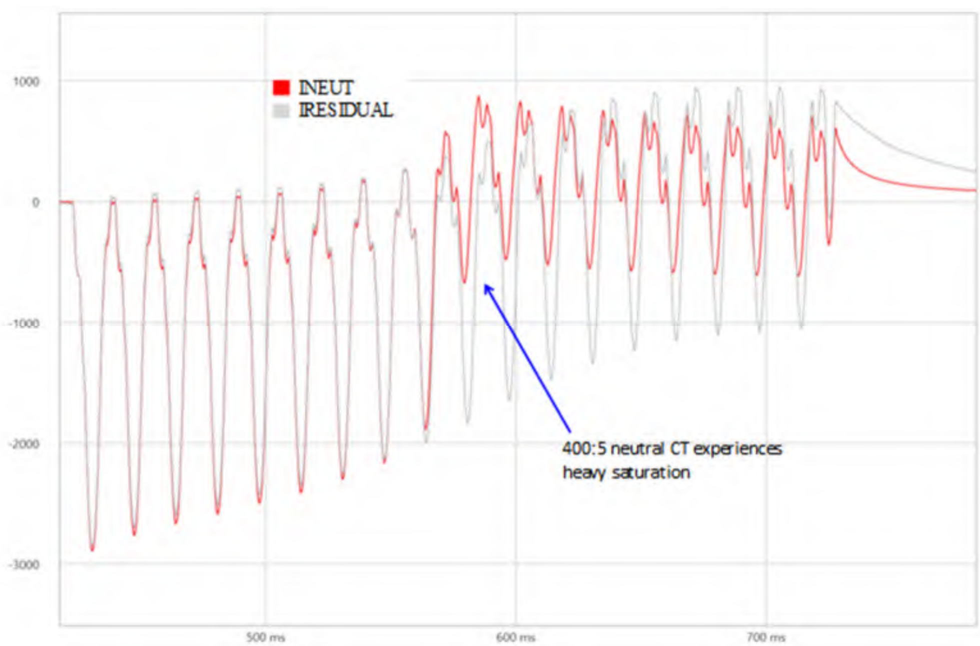

Figure 4-3 500 kV Neutral CT Saturation

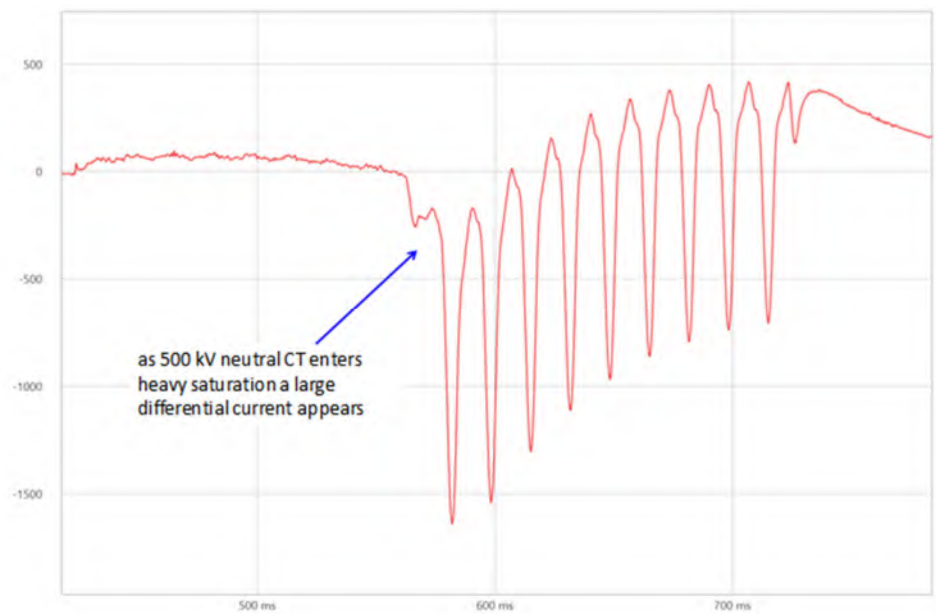

Figure 4-4 500 kV Ground Differential Current

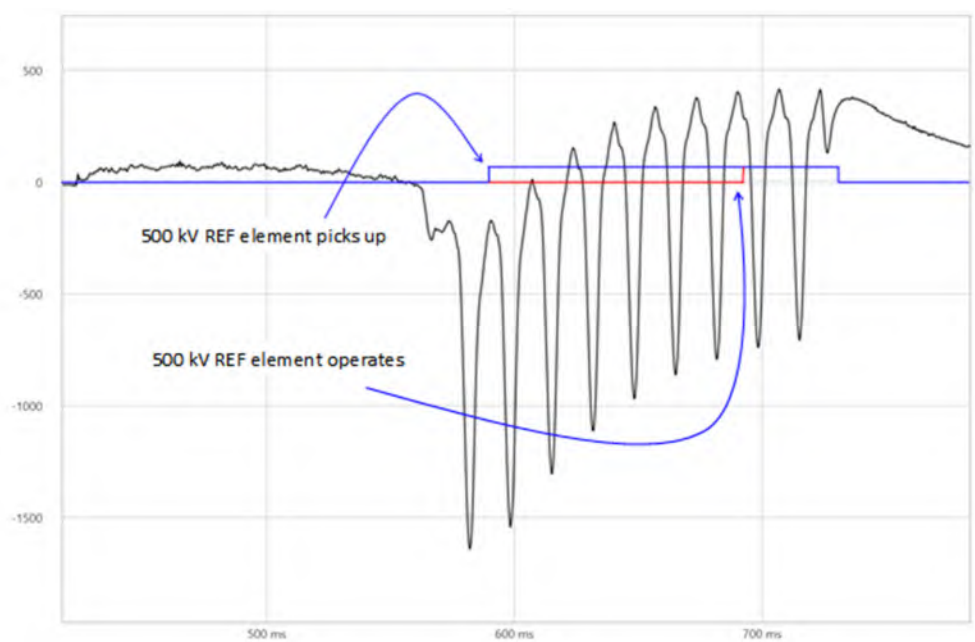

Figure 4-5 B set Transformer Relay Initiates a Trip.

Figure 4-6 shows a phasor plot of the two currents fundamental components before and after the 200 ms point where heavy saturation starts. The neutral CT phasor reduces in magnitude and proceeds in the leading direction by just under 45º, still well away from within 90º of the residual current phasor. An animation was generated as well and shows the Figure 4-6 plots as time is progressed across the event. The animation file is (Patterson) "pinhook_phasors_and_waveform.mp4" and is an attachment to this dissertation.

Misoperation of Area Capacitor Banks

The May 31, 2003, bank energization only lasted about 16 cycles before the REF misoperation tripped off the bank. On June 11, 2003, the bank was energized for a second time (see Figure 4-7). This time the REF problems in the B set relay had been overcome and the bank remained energized. After this bank energization three area 161 kV capacitor banks misoperated by SFC (obsolete static type) residual overcurrent relays.

The energization of the large Pinhook transformer bank was a significant unbalanced condition applied to the power system. The large currents in the transformer neutral were reflected in area 161 kV capacitor bank neutrals as they are configured solid grounded wye. The sensitive SFC residual overcurrent relay applied on these capacitor banks misoperated for these currents. The SFC relay is a solid- state relay that operates on a true RMS value. TVA field test personnel tested an SFC relay to ascertain its frequency performance [1]. The relay was tested up to the 14th harmonic and was shown to have a flat frequency response (i.e., the relay operates equally well for 5 A at 840 Hz as it does for 5 A at 60 Hz).

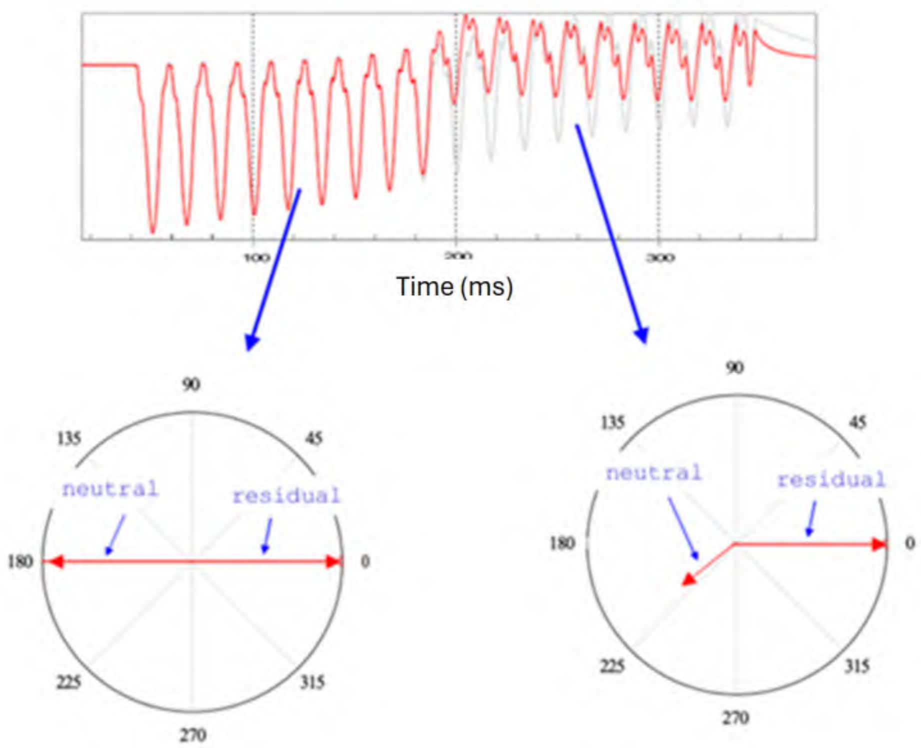

Figure 4-6 Fundamental Frequency Phasors Before and During Saturation

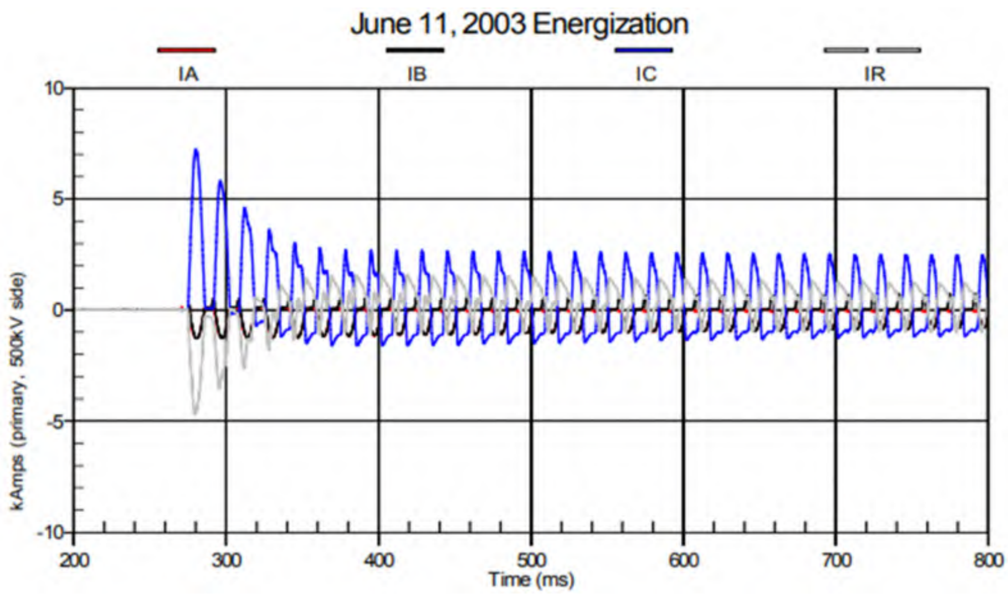

Figure 4-7 June 11th Energization of Pinhook Bank.

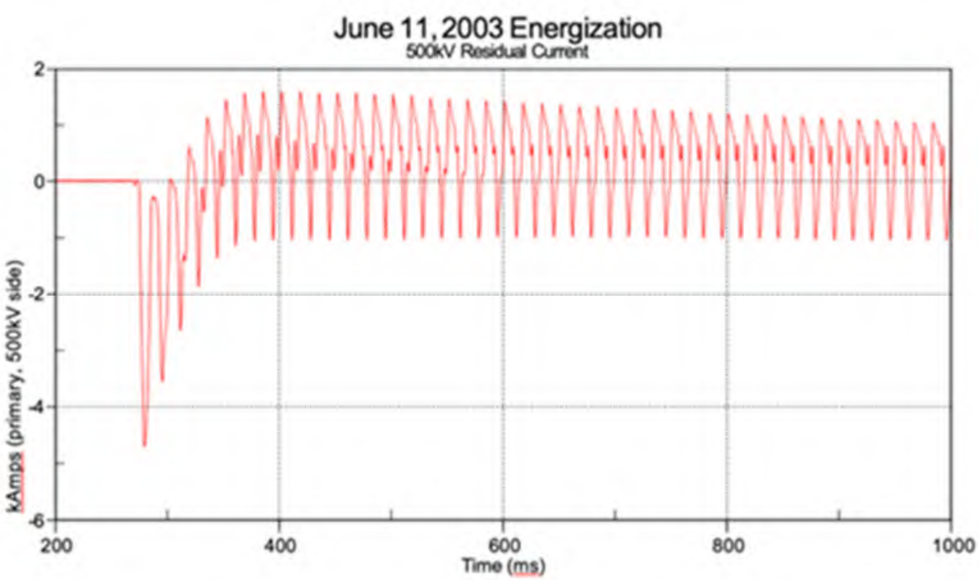

Figure 4-8 Residual Current Present During June 11th Energization.

The SFC was wired to measure capacitor bank residual current and was set low (20-30 A primary). It was supervised by a zero-sequence (3V0) relay designed to block its operation during normal system ground faults while allowing its operation for capacitor bank unbalance. The capacitor banks were excellent sinks for the inrush neutral current and the supervising relays were set based on system fault studies such that they did not pick up during this event. Note that these currents flowing in the capacitor bank neutrals would have been predominately 2nd harmonic. This is contrary to what we usually think flows in neutrals. For balanced harmonics (symmetrically created across all three phases) only triplen (3rd, 6th, 9th etc.) harmonics flow in the capacitor bank neutrals [3]. However, transformer energization is not a symmetrical event as is clearly seen by the 500 kV residual current present during energization (Figure 4-8).

Below is the SCADA (supervisory control and data acquisition) Sequence of Event data recorded during the June 11 Energization:

1. 13:39:11 Pinhook 500/161 kV intertie bank energized at 500 kV
2. 13:39:13 Smyrna 161 kV cap bank trips by SFC ground relay
3. 13:39:17 McMinnville 161 kV cap bank trips by SFC ground relay
4. 13:39:18 Murfreesboro 161 kV cap bank trips by SFC ground relay

Note: Wilson 161 kV cap bank did not trip because it was tagged out.

The bank was energized a third time on June 12, 2003, with a similar result. The bank stayed energized and, once again, three area 161 kV capacitor banks (two new ones this time) misoperated by SFC relay. The following is a quote from our Transmission Operator disturbance log: “1819: The Franklin 161-kV, Smyrna 161-kV and Murfreesboro 161-kV capacitor banks were interrupted by ground relay action. This interruption coincides with energizing the Pin Hook 500/161/13-kV transformer. Cause is under investigation."

The SFC relay is poorly suited to protection of a capacitor bank for 60 Hz protection duty. Capacitor banks are excellent sinks for harmonic energy. TVA has experienced significant simultaneous loss of 161 kV capacitor banks (up to 800 MVAR) due to misoperations of SFC relays during geomagnetic events [1]. The geomagnetically induced currents (GIC) caused half-cycle saturation of 500 kV transformers with the resulting harmonic currents finding a path in the capacitor bank neutrals. TVA has also experienced misoperation of an SFC residually connected relay protecting a 161 kV capacitor bank when an electrically nearby 500 kV transformer bank was energized with one phase on the wrong tap.

To preclude the chances of significant loss of 161 kV capacitor banks these relays have been replaced with microprocessor relays that operate on the fundamental (60 Hz) component only.

Summary

The simple directional overcurrent approach to Restricted Earth Fault (REF) protection provides excellent security during neutral CT saturation. Harmonic currents other than the zero-sequence triplen (3rd, 6th, 9th, etc.) can flow in capacitor bank neutrals if they are generated asymmetrically in the power system, such as during a transformer energization. History repeats, the GIC events of July 15, 2000, uncovered a susceptibility to misoperation of SFC relays that resurfaced when the large Pinhook transformer bank was energized.

References

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2. IEEE Standard C37.91-2000, "IEEE Guide for Protective Relay Applications to Power Transformers."
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CHAPTER 5

MATHCAD ANALYSIS OF DAVIDSON CAPACITOR BANK MISOPERATION

A version of this chapter was originally presented to the Georgia Tech 2001 Fault and Disturbance Analysis Conference May 1-2, 2001:

Russell W. Patterson. “Mathcad Analysis of Davidson Capacitor Bank Misoperation.” Georgia Tech 2001 Fault and Disturbance Analysis Conference, May 1-2, 2001.

Abstract

This chapter describes the analysis of a 161 kV capacitor bank residual overcurrent scheme misoperation. Information available included local relay target indication, a digital fault recording from the local DFR, and system dispatcher logs. The dispatcher logs indicated that a 500 kV intertie transformer bank one station away had been briefly energized with one phase on the wrong voltage tap. This occurred simultaneous with the 161 kV capacitor bank misoperation. The Mathcad (software by PTC Inc.) environment was used to help determine why the zero-sequence voltage supervised residual overcurrent (GE SFC) operated. The analysis and subsequent field-testing point out the vulnerability of this protection scheme to harmonic energy and therefore its misapplication to capacitor bank protection. Six months later this same scheme installed at five different substations (separated by hundreds of miles) operated on harmonic energy produced by a different mechanism, geomagnetically induced current.

Introduction

On October 27, 1999, at 7:02AM (CST) TVA's Johnsonville Steam Plant 500 kV to 161 kV intertie transformer bank was energized with one phase on the wrong tap (Figure 5-1). Simultaneous with this energization the 161 kV capacitor bank at the neighboring Davidson 500 kV substation tripped by residual overcurrent relay (GE SFC). The residual overcurrent relay is supervised by a zero-sequence voltage relay (Westinghouse SV).

The Johnsonville Steam Plant 500 kV intertie bank is comprised of single-phase three-winding units rated 240/320/400 MVA connected Yn-yr-d. The Davidson 500 kV substation is electrically connected to Johnsonville via a 57-mile 500 kV transmission line. There are two 500 kV to 161 kV intertie banks at Davidson (single-phase units) also connected Yn-yr-d. One rated 180/360/400 MVA, the second rated 268.8/358.4/448 MVA. Both Davidson banks and the Johnsonville bank have 4.5-ohm reactors in their 161 kV neutrals. The Davidson 161 kV capacitor bank is comprised of two 84 MVAR capacitor banks with seven series groups per phase. Each series group is made up of 20 – 13.2 kV, 200 kvar capacitor units. Figure 5-1 below shows the simplified single line.

Part of the Davidson 161 kV capacitor bank protection consists of the SFC (obsolete static type) overcurrent relay supervised by an SV (electromechanical plunger type) voltage relay. The SFC relay operates on the residual current from the capacitor bank breaker (Figure 5-2). This relay has a primary pickup of 38.4 A with a time lever setting of 2 which results in the following characteristic curve:

% of pickup:	150%	200%	300%	500%	1000%
trip time:	90~	63~	43~	32~	25~

The SV relay, an electromechanical voltage relay, operates on zero-sequence voltage from the broken delta connection of the 161 kV bus voltage transformers (VTs). Its pickup is 7,200 V primary 3V0 at 60Hz. Figure 5-2 shows this relaying in single line form.

This scheme is designed to be a backup to capacitor unbalance protection and its overcurrent pickup is only marginally below the residual current that would flow due to the loss of one complete series group (seven groups parallel per phase, one group having 43 A normal load current). The SFC is supervised by the SV zero-sequence overvoltage relay to prevent its operation on normal zero-sequence current from the capacitor bank that flows when 161 kV system ground faults occur. The zero-sequence voltage that is produced by system ground faults is significantly higher than the zero-sequence voltage present due to capacitor bank unbalances, thus allowing discrimination between the two. The zero-sequence voltage on the bus due to unbalance in the grounded wye capacitor bank can be simply calculated to an acceptable accuracy by taking the zero-sequence current from the bank and multiplying times the zero-sequence Thévenin equivalent at the bus. For example, if there is 10 A in the capacitor bank neutral and the zero-sequence Thévenin at the bus is 9 ohms, then the zero-sequence voltage will be ${}^{10}/_{3} \times 9 = 30$ V). Alternatively, you can solve a networks problem with the sequence equivalent of the unbalanced capacitor bank which produces the same result [2].

The SV relays voltage pickup is typically set 150% below the lowest zero-sequence voltage present for line end ground faults. In general, this is significantly above the unbalance present for one complete phase open on the capacitor banks. This supervision allows a low residual overcurrent pickup setting while providing security against misoperation on 161 kV

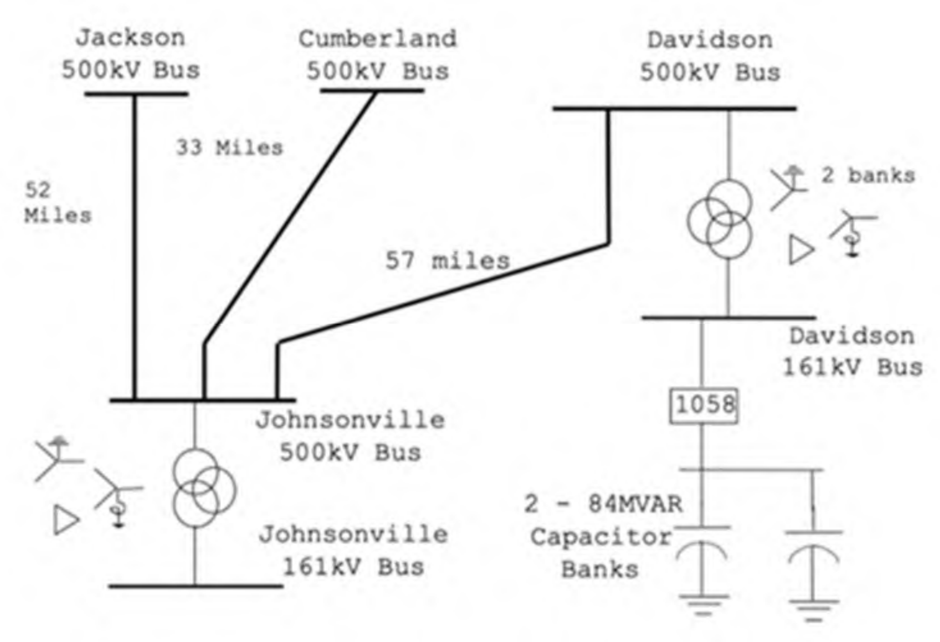

Figure 5-1 Single Line of the TVA Network between Davidson and Johnsonville

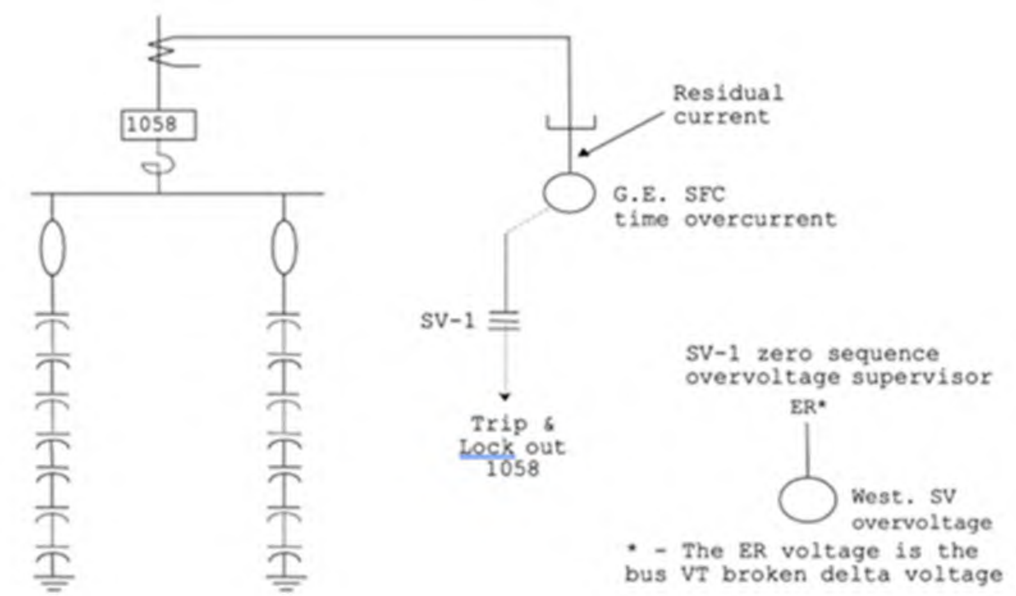

Figure 5-2 Single Line of Davidson 161kV Capacitor Bank Residual O.C. Protection.

ground faults. This scheme operated at Davidson when the Johnsonville Steam Plant 500 kV intertie bank was energized with A phase on the wrong voltage tap.

Analysis

The only clues to this misoperation where the dispatcher logs indicating that the Davidson 161 kV capacitor bank tripped by SFC relay simultaneous with the energization of the Johnsonville Steam Plant 500 kV intertie bank. Subsequent information from the field indicated that the A phase transformer had been on 20.7:1 tap and the B and C phase transformers had been on 22.7:1. Since the 500 kV and 161 kV windings have taps, these ratios are given with respect to the 13 kV winding (it has no taps so can be a fixed reference). A 20.7:1 ratio indicates a tap of 20.7 x 13 kV = 269.1 kV. A 22.7 tap would be 295 kV.

The actual DFR shot for the misoperation was not available. The following several pages use a different event record to graphically show the approach used in Mathcad for this analysis. The actual shot being analyzed occurred for a 161 kV ground fault several buses away that was cleared by instantaneous ground relay.

The capacitor bank currents were not available so only the 161 kV voltages were analyzed. The three phase-neutral voltages were converted to COMTRADE file format and imported into Mathcad for analysis. Below, in Figure 5-3, is a plot of the three 161 kV bus voltages. A noticeable dip in A phase can be seen around the 2000 sample mark.

Figure 5-4 shows the sum of the three phase-neutral voltages ($V_A + V_B + V_C = 3V0$). The horizontal line is the 7,200 V line marking the RMS level of zero-sequence voltage required to operate the SV voltage relay at 60 Hz. The trace that travels just below this 7200 V threshold during the event is the RMS value of the fundamental component of the 3V0 voltage.

The instruction manual for the SV relay indicates that this relay's pickup is proportional to frequency. In other words, if the frequency goes up by a factor of 1.25 the pickup voltage increases by that same factor. So, if the relay is set to pick up at 7,200 V at 60 Hz it will pick up at 14,400 V at 120 Hz. In Figure 5.5 a plot of the first 15 harmonics of the 3V0 voltage are shown. Figure 5.6 shows the harmonics that are most significant in magnitude during the 5 cycles of the event.

An approach to estimate the neutral current in the capacitor banks is to take the 3V0 voltage at each harmonic and divide by the harmonic impedance of the banks (assuming 150-ohm impedance at 60 Hz). At the higher harmonics the outrush suppression reactance would have to be considered (1,600 µH phase reactors).

$$\mathrm{I}_1 = \frac{7200\ \mathrm{V}}{150\ \Omega} = 48\ \mathrm{A}\ \ (60\ \mathrm{Hz\ current})$$

$$\mathrm{I}_3 = \frac{600\ \mathrm{V}}{50\ \Omega} = 12\ \mathrm{A}\ \ (180\ \mathrm{Hz\ current})$$

$$\mathrm{I}_5 = \frac{400\ \mathrm{V}}{30\ \Omega} = 13.5\ \mathrm{A}\ \ (300\ \mathrm{Hz\ current})$$

$$\mathrm{I}_5 = \frac{200\ \mathrm{V}}{21\ \Omega} = 9.5\ \mathrm{A}\ \ (420\ \mathrm{Hz\ current})$$

Since the RMS values from different frequencies in the same signal add according to squares, we get the following RMS total current.

$$\mathrm{I}_{\mathrm{RMS}} = \sqrt{48^2 + 12^2 + 13.5^2 + 9.5^2} = 52.2\ \mathrm{A}$$

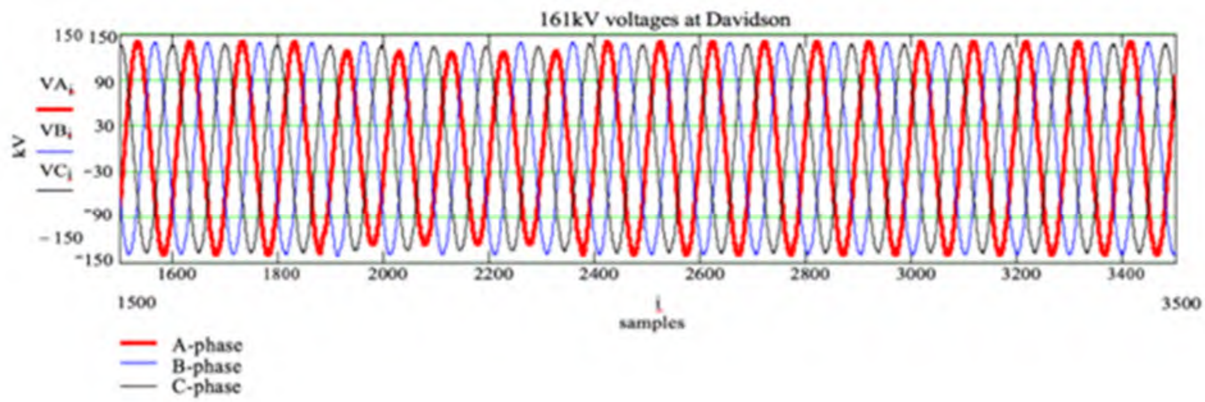

Figure 5-3 A-Phase Voltage Dips During Ground Fault Event (Heavy Trace).

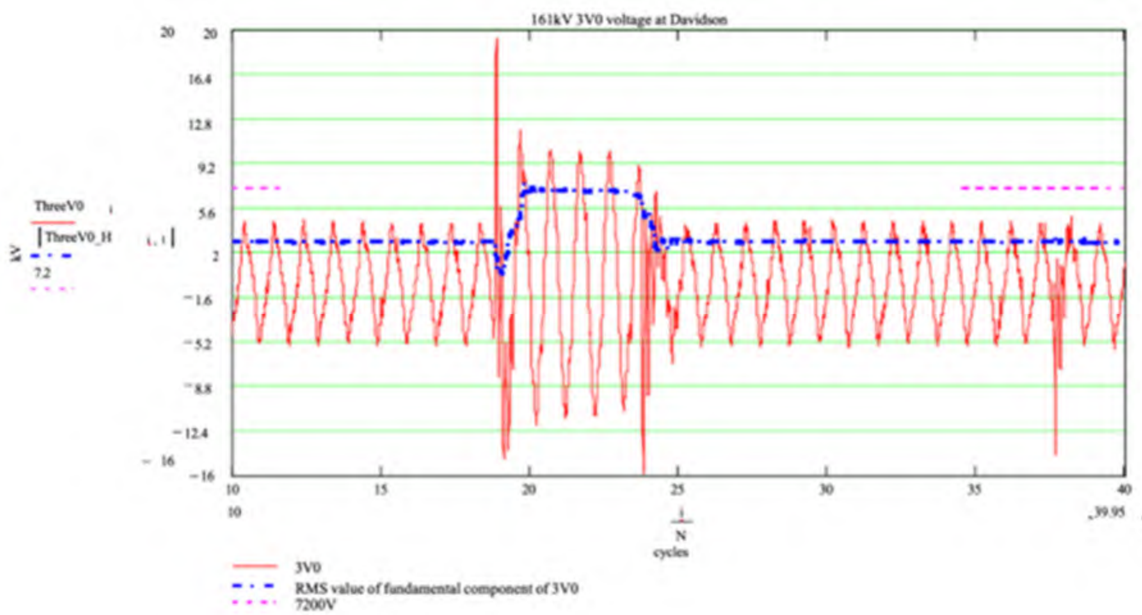

Figure 5-4 Graph of 3V0, RMS Fundamental component, and SV Pickup (blue dash).

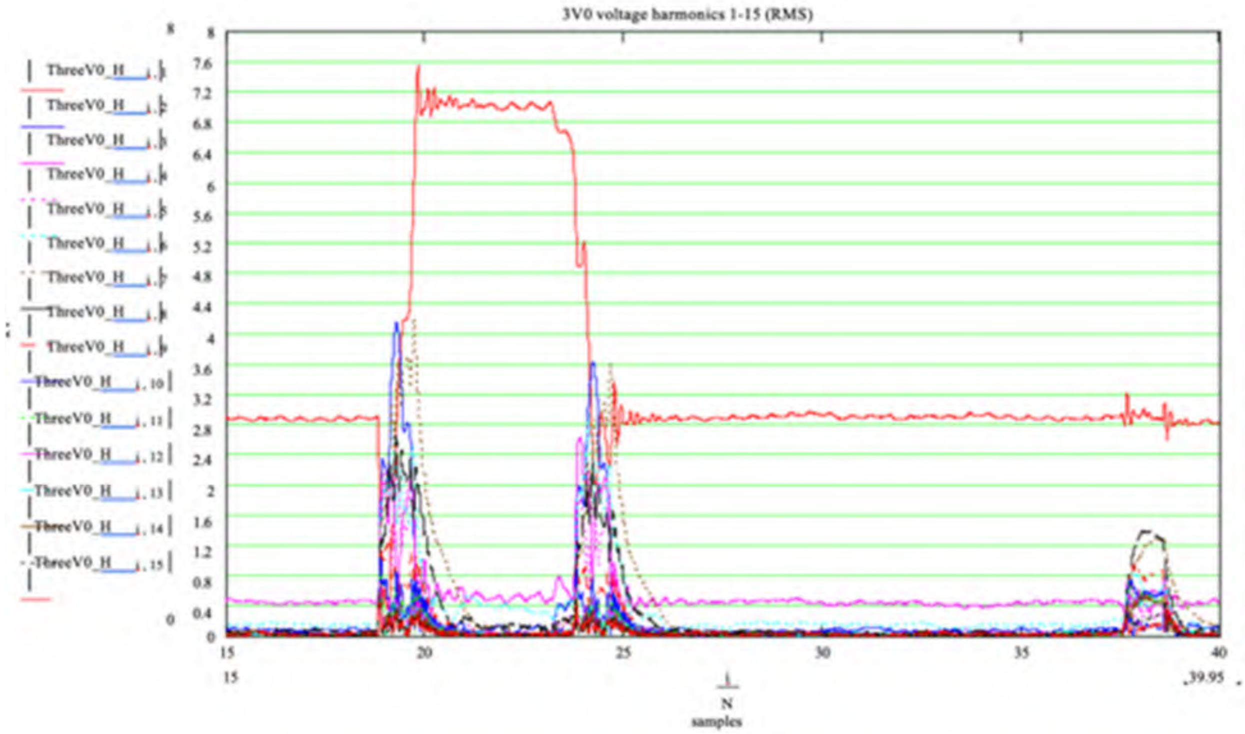

Figure 5-5 Harmonics 1 through 15 of the 3V0 Voltage (RMS Values).

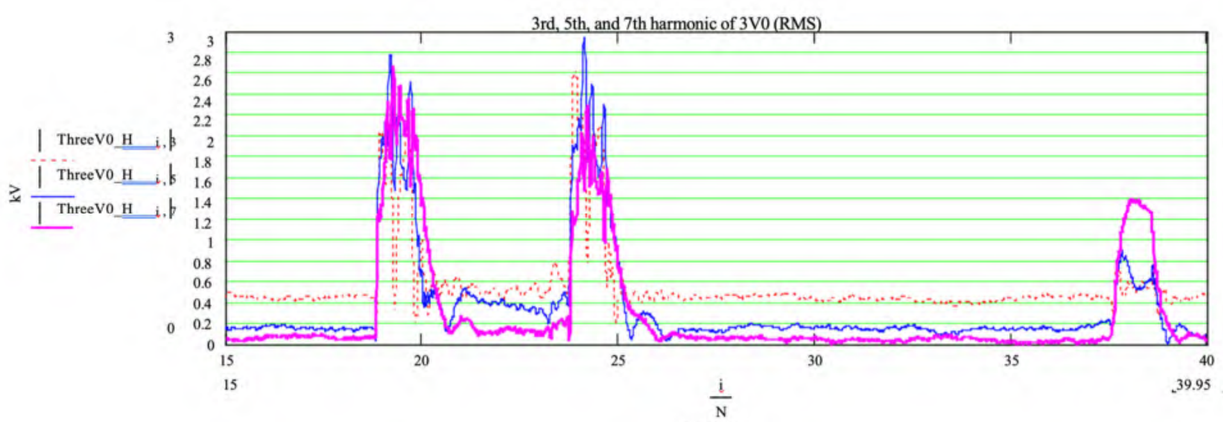

Figure 5-6 3rd, 5th, and 7th Harmonics of the 3V0 Voltage (RMS).

Had this been the DFR shot for the actual misoperation event this 52.2 A would be the current seen by the relay (just under 140% of pickup) between the large perturbations or between the 20 and 25 cycle mark shown in Figure 5-6. The DFR record would have shown the 60 Hz component of the 3V0 voltage below the 7200 V pickup of the SV relay and enough harmonic current possible to have operated the SFC relay. Reports indicate that a large standing neutral current was noticed after energizing the Johnsonville bank, and they were quickly de-energized.

Testing

TVA field test personnel (see Appendix A for actual test report) bench tested the SFC relay to ascertain its frequency performance. The relay was tested up to the 14th harmonic and was shown to have a flat frequency response (i.e., The relay operates the same when it measures 5 A at 480 Hz as it does for 5 A at 60 Hz).

Additional Ramifications

The above analysis of the unrelated DFR shot at Davidson did result in a test of the relay that shows us its frequency characteristic. This was useful information when analyzing the simultaneous operation of SFC relays all over the TVA region on July 15 during a geomagnetic event.

Table 5-1 summarizes the tripping of capacitor banks across the TVA region on Saturday, July 15, 2000. Appendix C shows one page of a report from 1991 identifying this same problem during the previous solar cycle. Predictive “early warning” services are now available to predict these GIC events [3].

Several of these capacitor bank trips at different locations occurred simultaneously. These locations are separated by hundreds of miles (see Figure 5.7) as calculated from longitude and latitude [4]. This was a total of around 800 Mvar of reactive support lost near simultaneously across the TVA system.

A quick look at the NASA space weather website [4] showed that one of the largest solar storms in a decade had occurred prior to this event and was the most likely candidate for the subsequent geomagnetic activity. During a geomagnetic event, quasi-dc currents are induced in the earth. These currents find a path up the neutrals of transformer banks and over the transmission lines of our transmission systems. When these dc currents flow in transformers they can produce varying degrees of half-wave saturation.

The saturation produces harmonics that find a convenient path to ground through the capacitor banks. This is a problem for the capacitor banks because they are absorbing harmonic energy. The following is an excerpt from a working group draft of IEEE 1036 (as of July 2000):

The effect of the harmonic components on the capacitor bank is to cause additional heating and higher dielectric stress. IEEE Std 18 gives limitations on voltage, current, and reactive power for capacitor banks, which can be used to determine the maximum allowable harmonic levels. IEEE Std 18 indicates that the capacitor can be applied continuously within the following limitations, including harmonic components:

Table 5-1 List of July 15th Capacitor Bank Operation Times from Dispatching Logs.

Trip Time (CST)	Location	Tripping relay
0939:01	Madison, AL 161kV	GE SFC
0939:01	New Albany, MS 161kV	GE SFC
1203:34	Philadelphia, MS	GE SFC
1328:00	"	"
1500:24	"	"
1633:00	"	"
1652:37	"	"
1656:00	"	"
1749:06	"	"
1757:00	"	"
1541:00	Davidson, TN 161kV	GE SFC
1203:35	Freeport, TN 161kV	S&C UP
1329:00	"	"
1545:00	"	"
1633:00	"	"
1541:00	Jackson, TN 161kV	GE SFC and S&C GPS

Figure 5-7 Geographic Dispersal of Simultaneous Capacitor Bank Trips by SFC Relay.

110% of rated rms voltage

120% of rated peak voltage

135% of nominal rms current, based on rated kvar and rated voltage.

135% of rated reactive power

The point is that, even though the SFC relays misoperated, it may have been beneficial from the capacitor bank's perspective. This point was brought up during internal TVA discussions pertaining to the replacement of the SFC relays. It was this author's position that the SFC should be replaced because its function is for 60 Hz protection of the capacitor bank. The SFC is not well suited to protecting the capacitors from harmonic energy because it only sees those harmonics that add in the neutral or are present due to asymmetrically generated harmonics. It does not see positive or negative sequence harmonics that are balanced across the three phases of the grid (see Appendix D).

Conclusion

Analyzing every unexplained relay operation (even when the cause seems apparent) builds a knowledge base and insight into the operation of the protective schemes that can pay off in the future. The SFC relay was shown to be a poor choice for 60 Hz protection of a capacitor bank due to its flat harmonic response. Similarly, it is not well suited to protecting the capacitor banks from harmonic energy since it only sees triplen (zero-sequence harmonics e.g. 3, 6, 9, 12, etc.) and asymmetrical harmonic current. A more significant consideration is the susceptibility of this scheme to the harmonic energy that occurs during power transformer half-wave saturation during geomagnetic events. On Saturday, July 15, 2000, TVA experienced the loss of over 800

Mvar of capacitor banks. This loss during peak hours on a weekday would have likely been catastrophic not excluding the possibility of grid collapse.

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Appendix

Appendix A - Field test report on GE SFC relay frequency response.

The relay settings show a critical pickup at 500% (5 times pickup) of 32 cycles. This was the test point used with only the frequency being varied between tests. This important test was done courtesy Kirk Woodard and Jimmy Scarborough and others.

Test: TIMEI PASS CRITICAL PU CHECK PICKUP @ CRITICAL

Source Amplitude Phase Freq
I1 ACTION 0 VARIOUS

ProTesT v.1.61 Test Results 02/03/00

Location 1: DAVIDSON 500 KV SUB. Terminal 24: CAPACITOR BANK RELAYS

Relay 4: 12SFC151D1A S/N: 8837 Fct: RESIDUAL GROUND

FREQ	Actual CYCLE	Expect	Error	P/F	Date	Time	Operator
840	31.243	32.000	-2.4	P	02/03/00	12:00:09	JDS
780	31.262	32.000	-2.3	P	02/03/00	11:59:36	JDS
720	31.283	32.000	-2.2	P	02/03/00	11:59:14	JDS
660	31.302	32.000	-2.2	P	02/03/00	11:58:53	JDS
600	31.323	32.000	-2.1	P	02/03/00	11:58:36	JDS
540	31.354	32.000	-2.0	P	02/03/00	11:58:18	JDS
480	31.381	32.000	-1.9	P	02/03/00	11:57:53	JDS
420	31.413	32.000	-1.8	P	02/03/00	11:57:38	JDS
360	31.459	32.000	-1.7	P	02/03/00	11:57:15	JDS
300	31.507	32.000	-1.5	P	02/03/00	11:57:00	JDS
240	31.560	32.000	-1.4	P	02/03/00	11:56:38	JDS
180	31.569	32.000	-1.3	P	02/03/00	11:56:09	JDS
120	31.654	32.000	-1.1	P	02/03/00	11:55:39	JDS
60	31.836	32.000	-0.5	P	02/03/00	11:55:07	JDS

Figure 5-A-1 SFC Field Test Report.

Appendix B – Positive, negative, and zero-sequence harmonics.

The harmonics of 60 Hz that behave as positive sequence are 1, 4, 7, 10, 13, etc. Those that behave as negative sequence are 2, 5, 8, 11, 14 etc. Those that behave as zero-sequence (sum in the neutral) are 3, 6, 9, 12, 15 etc. and are also referred to as "triplen" harmonics. This behavior depends on the harmonics being generated symmetrically across the three phases (magnitude and relative phase angle).

Figure 5-B-1 shows 3 cycle plots of A, B, and C 60 Hz phase currents along with a 20% 2nd harmonic that might be superimposed on these currents. The 2nd harmonic is a negative sequence harmonic so the three components in each phase sum to zero at the neutral. Note that the harmonic energy is symmetrical across the phases because they have the same magnitude and phase angle relative to each 60 Hz phase current.

Figure 5-B-2 shows 3 cycle plots of A, B, and C 60 Hz phase currents along with a 20% 3rd harmonic that might be superimposed on these waveforms. The 3rd harmonic is a zero-sequence (triplen) harmonic so the components in each of the three phases sum to three times in the neutral.

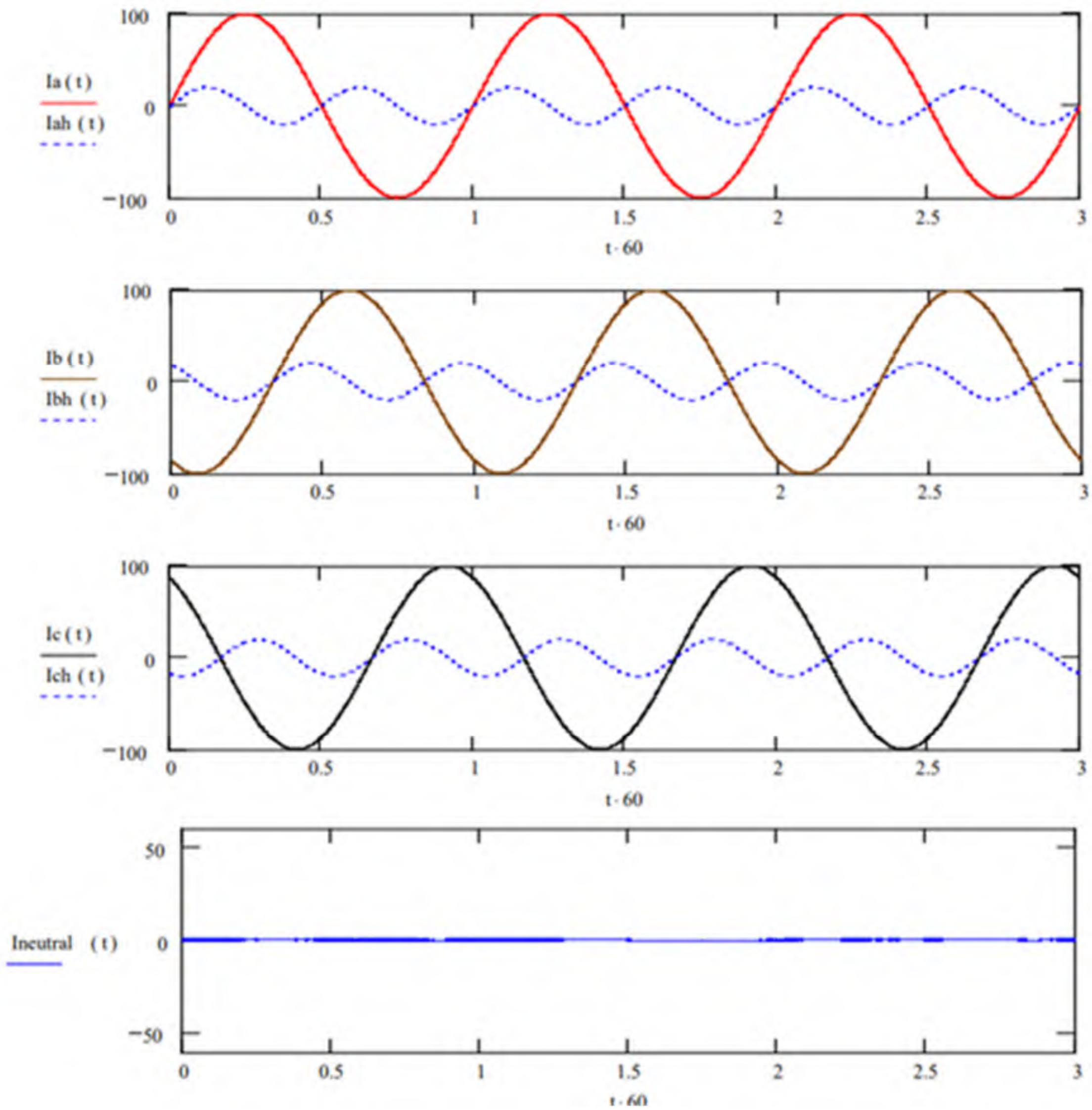

Figure 5-B-1 Symmetrically Generated 20% 2nd Harmonic.

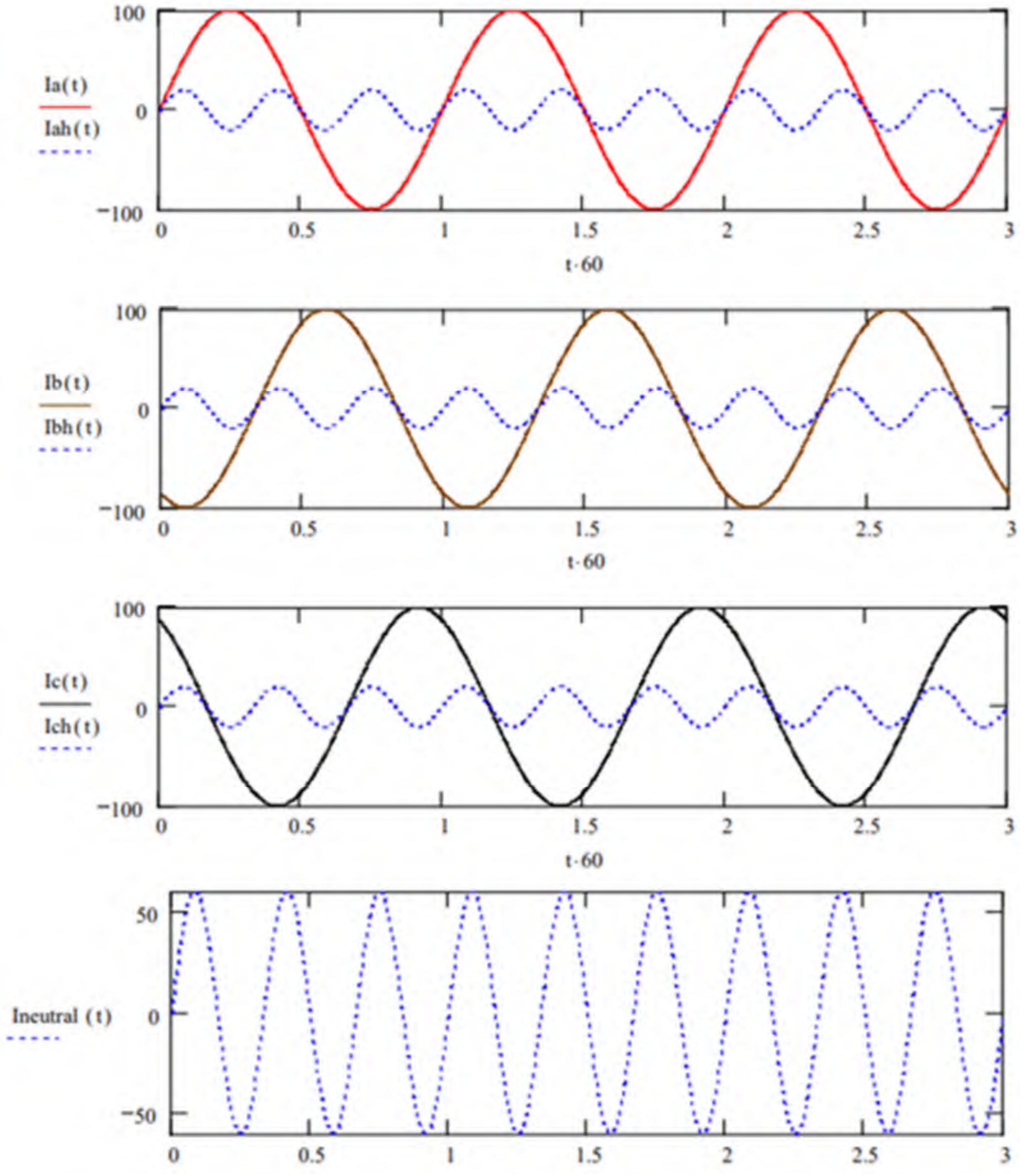

Figure 5-B-2 Symmetrically Generated 20% 3rd Harmonic

Appendix C - Excerpt from system event review report in November 1991.

J05 On October 28, a solar magnetic disturbance (SMD) of K-9 intensity resulted in three reported unusual events on the TVA system. A 161-kV capacitor bank tripped by backup ground relay operation at West Point 500-kV Substation. A low voltage alarm came into the Nashville ADCC from the Maury 500-kV Substation. The Wilson 500-kV Substation experienced a noticeable increase in the audible noise generated by the 500/161/13-kV transformer bank and the oscillograph recorded detectible harmonics in the 500-kV voltage for more than 20 seconds. All three events happened simultaneously. There were no interruptions or known equipment damage as a result of these incidents. The K-9 level SMD was reported to TOD two days later.

1. What method is used to quickly inform the ADCC offices that a potentially significant SMD is underway so that appropriate actions/responses can be made? Is there any quicker source of information? JJB/JBG

2. Was there a correlation between the reported SMD, the above events, and the magnetic and GIC monitoring stations maintain by Energy Research? Could alarms or SMD status indicators be conveniently developed from these installations to more quickly inform us of impending SMD events? JBG

3. Can the ground relay characteristic or setting on the 161-kV capacitor bank at West Point be changed to make it less sensitive to the harmonic currents associated with SMDs? BWS/DMA

4. Has the Wilson 500-kV bank been tested after this reported incident? Should it be? JWC/MBG

This agenda was prepared by Gary Bullock, Customer Group (6002-C)

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Appendix D - Mathcad 2001 Professional data files.

Note: The methods used can be implemented in older versions of Mathcad as well. The first file below calculates the RMS values of the harmonics of the 3V0 voltage from fundamental to 15th harmonic.

$\mathrm{Input} := \mathrm{READPRN}(\text{"e:\textbackslash davidson\textbackslash data1011.dat"})$ <-- input data from COMTRADE data file.

$VA := (0.145064 \cdot \mathrm{Input})^{\langle 2 \rangle}$ $VB := (0.145064 \cdot \mathrm{Input})^{\langle 3 \rangle}$ $VC := (0.145064 \cdot \mathrm{Input})^{\langle 4 \rangle}$ <-- Scale the 3rd, 4th and 5th data columns as per C37.111-1991 (a newer COMTRADE standard is now out.)

$N := 100$ samples/cycle $nmax := \mathrm{rows}(\mathrm{Input})$ $nmax = 4096$

$n := 0, 1 .. nmax - 1$ $i := 0 .. (nmax - N - 1)$ $k := N .. nmax - 1$ $h := 1 .. 15$

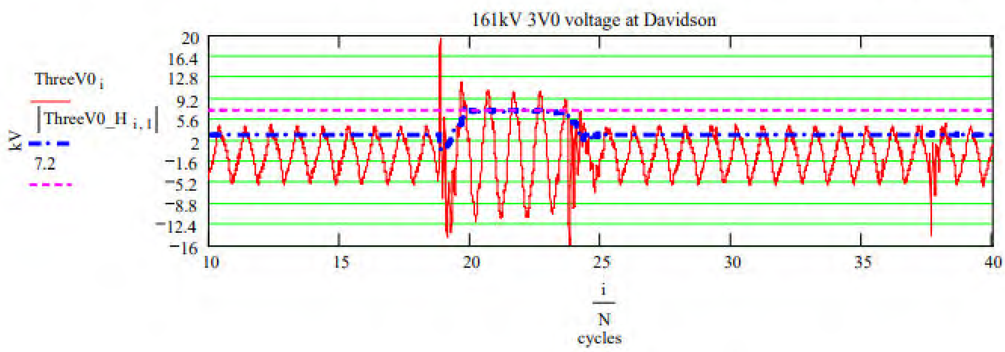
<-- The EMAX recorder that took the shot samples at 100 samples/cycle. The variable nmax is the number of data points in the event. The variable h is the number of harmonics to analyze.

$\mathrm{ThreeV0}_n := VA_n + VB_n + VC_n$ <-- the ThreeV0 vector is just the sum of the phase voltages.

Harmonic analysis

$$\mathrm{ThreeV0\_H}_{k,h} := \frac{2}{N} \cdot \sum_{n = k-N+1}^{k} \mathrm{ThreeV0}_n \cdot e^{-j \cdot n \cdot \frac{h \cdot 2 \cdot \pi}{N}} \qquad \mathrm{ThreeV0\_H}_{k,h} := \frac{\mathrm{ThreeV0\_H}_{k,h}}{\sqrt{2}}$$

<-- The equation with the summation symbol is where the work is being done. This formula performs the discrete Fourier transform using a "sliding" window of 100 data points. This is done for fundamental through the "h" harmonic. Since the results of this are in peak magnitudes the RMS values are obtained by dividing by root 2.



Note: Importing ASCII COMTRADE data is as easy as reading comma separated data. There are several methods of reading data into Mathcad. The path chosen in this data file (see "VA:=" input equation at top) references the first column of data as column 0. The A-phase voltage is at column 3 so it is referenced as 2. The data is scaled as per C37.111 by the "a" constant of "0.145064" from the associated CFG file. This satisfies the equation ax + b with b = 0 in the present CFG file.

Some explanation for the “sliding DFT” being used is in order. The digital Fourier transform is meaningful when you have enough samples to create one complete cycle of the fundamental waveform. In this case we require 100 samples to make one waveform since the fundamental is 60 Hz. The “sliding” comes in because this routine takes the first 100 data points and spits out the harmonic content, then it drops off the first data point and adds in the 101st data point. In this manner the window “slides” down the waveform outputting harmonic content values with a 100 data point wide window.

This following Mathcad file creates the harmonic plots to demonstrate the positive, negative, and zero-sequence behavior of symmetrical harmonics. “A” is the magnitude of the fundamental used, “H” is the magnitude of the harmonic used, and “h” is the harmonic number (3rd harmonic in this case).

$A := 100 \qquad t := 0, .00001 .. .05 \qquad H := 20 \qquad h := 3$

$Ia(t) := A \cdot \sin(2 \cdot \pi 60 \cdot t) \qquad Ib(t) := A \cdot \sin\left(2 \cdot \pi 60 \cdot t - 2\frac{\pi}{3}\right) \qquad Ic(t) := A \cdot \sin\left(2 \cdot \pi 60 \cdot t + \frac{2\pi}{3}\right)$

$Iah(t) := H \cdot \sin(2 \cdot h \cdot \pi \cdot 60 \cdot t) \qquad Ibh(t) := H \cdot \sin\left(2 \cdot h \cdot \pi \cdot 60 \cdot t - \frac{2 \cdot h \pi}{3}\right) \qquad Ich(t) := H \cdot \sin\left(2 \cdot h \cdot \pi \cdot 60 \cdot t + \frac{2h \cdot \pi}{3}\right)$

$Iasum(t) := Ia(t) + Iah(t) \qquad Ibsum(t) := Ib(t) + Ibh(t) \qquad Icsum(t) := Ic(t) + Ich(t)$

$Ineutral(t) := Iasum(t) + Ibsum(t) + Icsum(t)$

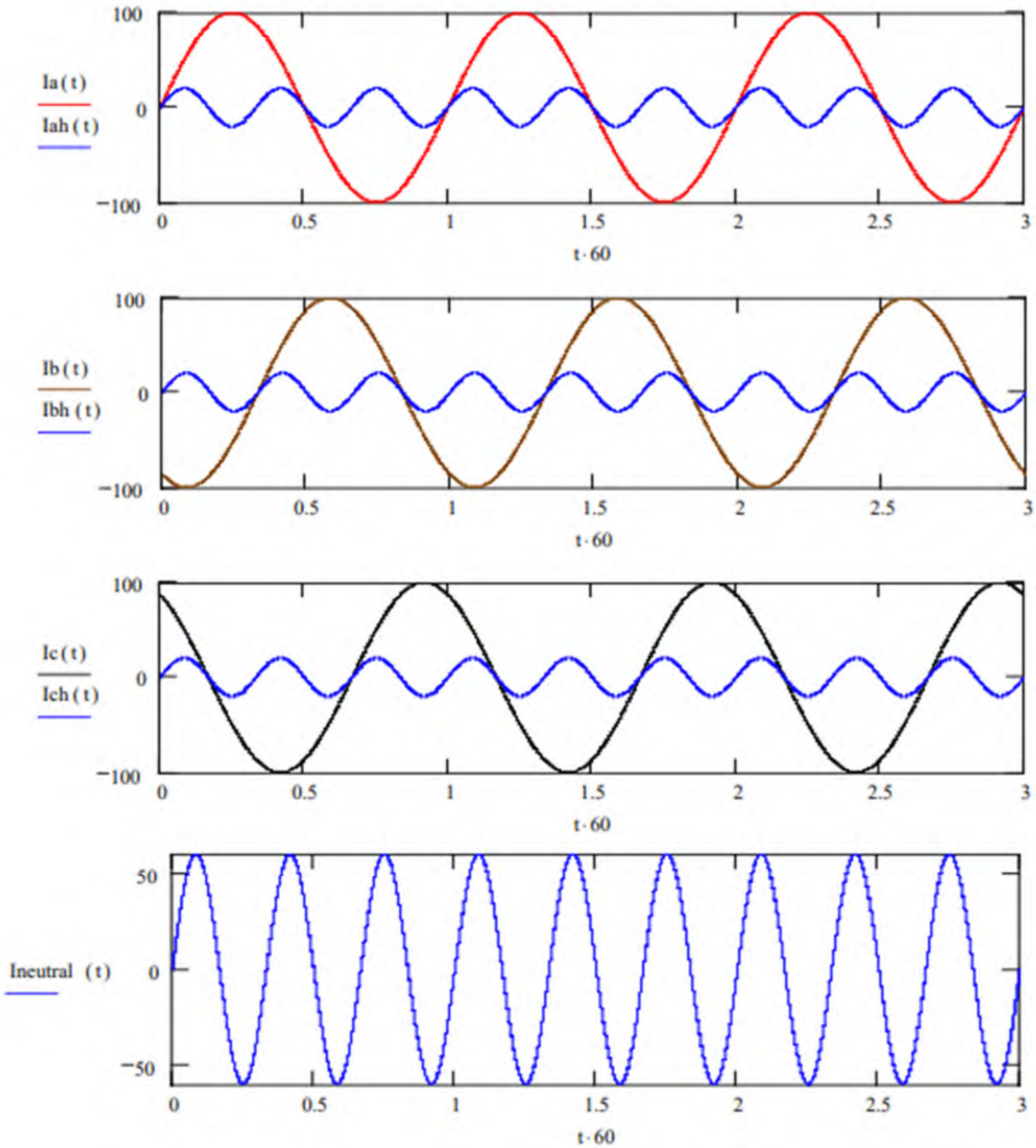


Figure 5-D-1 Symmetrical Component Nature of Balance Generated Harmonics

CHAPTER 6

RECLOSING AND TAPPED MOTOR LOAD

A version of this chapter was originally presented to the 61st Annual Georgia Tech Protective Relaying Conference May 2-4, 2007:

Russell W. Patterson and George T. Pitts, “Reclosing and Tapped Motor Load.” 61st Annual Georgia Tech Protective Relaying Conference, May 2-4, 2007.

Abstract

This chapter discusses the effect tapped motors have on transmission line reclosing and the effect reclosing has on tapped motor loads. An analysis is described to determine how long a delay is required before reclosing may safely and successfully occur. Actual captured events on the Tennessee Valley Authority (TVA) power system are used in the discussion. It is shown that high-speed reclosing on transmission lines with significant tapped motor load will be unsuccessful, stressing system components and motors for no benefit.

Introduction

When supply voltage is removed from an induction machine, flux is trapped in its rotor. This flux decays with time and produces a residual voltage in the machine windings until shaft rotation ceases. This residual voltage can decay in a few cycles in small machines but may require up to five seconds in larger machines. The rate of decay for high-speed machines is generally less than that for slow-speed motors [1]. Higher inertia machines will tend to act as generators feeding the lower inertia machines on the bus such that the entire group decays together. Synchronous machines have the added complication of having their own field excitation to maintain healthy internal voltage during the brief dead-time before utility high-speed reclosing occurs, putting them at increased risk over induction machines.

The problem that is encountered by these disconnected machines maintaining a residual voltage is that when reclosing occurs, the utility system voltage and machine residual voltage are likely out-of-phase. Reclosing by the utility can apply voltages across the motor that is above the motor design limits and result in high transient currents and torques. The motor may not immediately fail, but the resulting high shaft torque and torque on the coils can produce cumulative damage and eventually result in “unexplained” failures of the machines. The phasor difference between the system voltage per Hertz and the motor residual voltage per Hertz should not exceed 1.33 per unit volts/Hertz at closing [2]. An historical “rule-of-thumb” for unsupervised reclosing on motor loads has been to delay until the motors residual voltage magnitude has dropped below 25% of rated. Many designers set 125% as a desirable limit of maximum momentary voltage applied across a motor [1, 14].

Additionally, the back feeding motor loads can keep ionized fault paths intact during the reclosing dead time meaning that a high-speed reclose has a low probability of success. The result is unnecessary wear and stress on all the interposing equipment (utility breakers, transformers, motors).

For purposes of this chapter, high-speed reclosing is a blind reclose (not supervised by voltage conditions or synchronism check relays) that occurs within 30 cycles of initial circuit interruption. A common high-speed reclose setting on the TVA system is between 13 and 20 cycles from the time the breaker contacts part (initially interruption the circuit current) until the contact recloses to reestablish the circuit. The faster time of 13 cycles is applied on oil circuit breakers having pneumatic mechanisms and the 20 cycles is applied on SF6 breakers having spring mechanisms.

The topics covered in this chapter may be applicable at the distribution level as well, on feeders that supply power to industries with heavy motor load or distributed generation that utilize high-speed or "instantaneous" unsupervised reclosing. Also, the IEEE Power System Relaying Committee's Rotating Machinery Subcommittee (J) has an active working group "J15 – Investigation of the Criteria for the Transfer of Motor Buses", chaired by Wayne Hartmann, addressing issues related to transfer of generating plant auxiliary boards with motor load.

Actual Event

On August 24, 2006, after successfully clearing a ground fault on the TVA Monsanto to Johnsonville Fossil Plant #1 161kV line, an unsuccessful high-speed reclose attempt occurred. Subsequent analysis of the event revealed that the high-speed reclose attempt was unsuccessful because of significant tapped motor load. The system one-line is shown in Figure 6-1.

When the high-speed reclose attempt occurred (approximately 20 cycles after the line breakers tripped) the motor load at the pulp and paper mill was still holding the line voltage up (roughly 60% of nominal at time of reclose). This kept the fault path ionized resulting in a reignition of the fault when the reclose occurred. It also resulted in an out-of-phase reclose between the mill motors and the TVA power system. A power quality monitor on the low-voltage bus (4,160 V) of the mill captured the event (Figure 6-2). The data is RMS voltage recorded for each cycle (on 60 Hz basis).

An earlier event analysis showed similar results for an event that occurred on August 6, 2005, and is fully described in [3]. Figure 6-3 shows the motor bus voltages during that event and Figure 6.4 shows an estimation of power system voltage and islanded motor voltage during the period after separation, just prior to reclosing. The VA data shown in Figure 6-4 was captured at a rate of 128 samples/cycle.

No successful high-speed reclose has been found in historical records on this transmission line. Over a half-dozen unsuccessful attempts, like the above-described events, have been recorded in the previous several years.

Fault Arc Path

When lightning strikes a transmission line the field intensity stressing the insulation may exceed the ionization field intensity level (around 30 kV/cm) and create an arc from the line to ground. A path now exists for current flow. The resulting discharge current flow from the lightning stroke is usually over within a few milliseconds but the ionized path has been

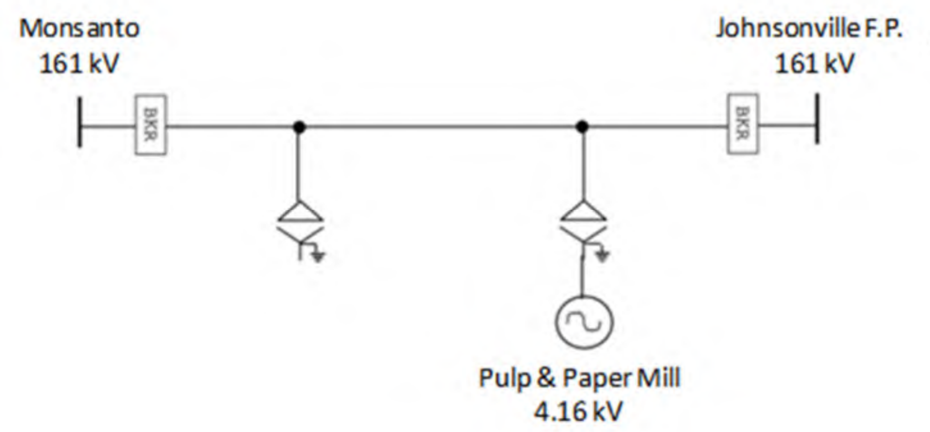


Figure 6-1 One-line of Monsanto-Johnsonville #1 161kV line.

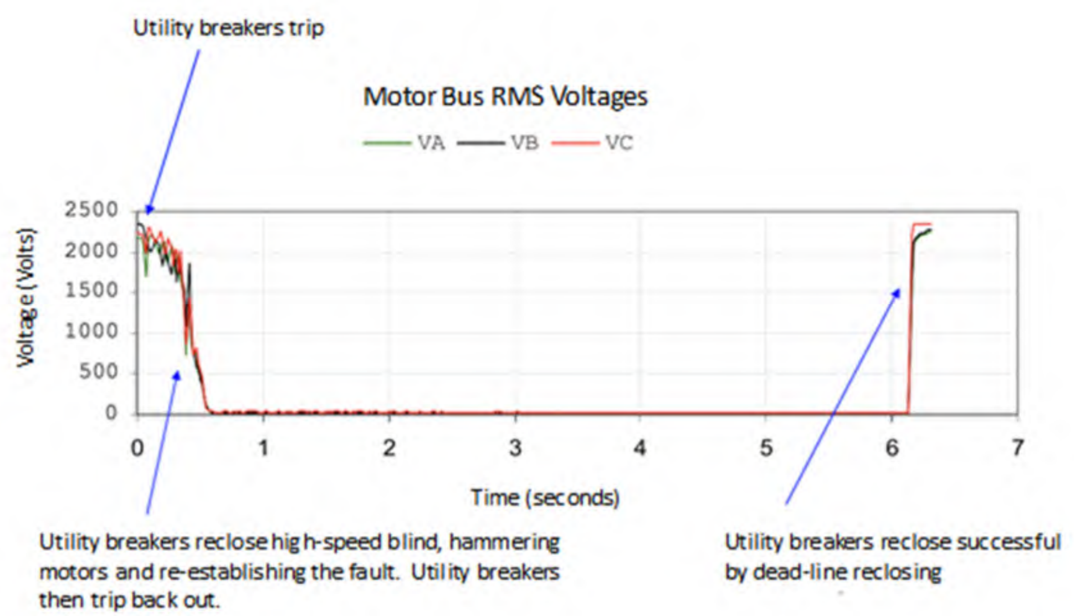


Figure 6-2 Power Quality data captured during unsuccessful high-speed reclose.

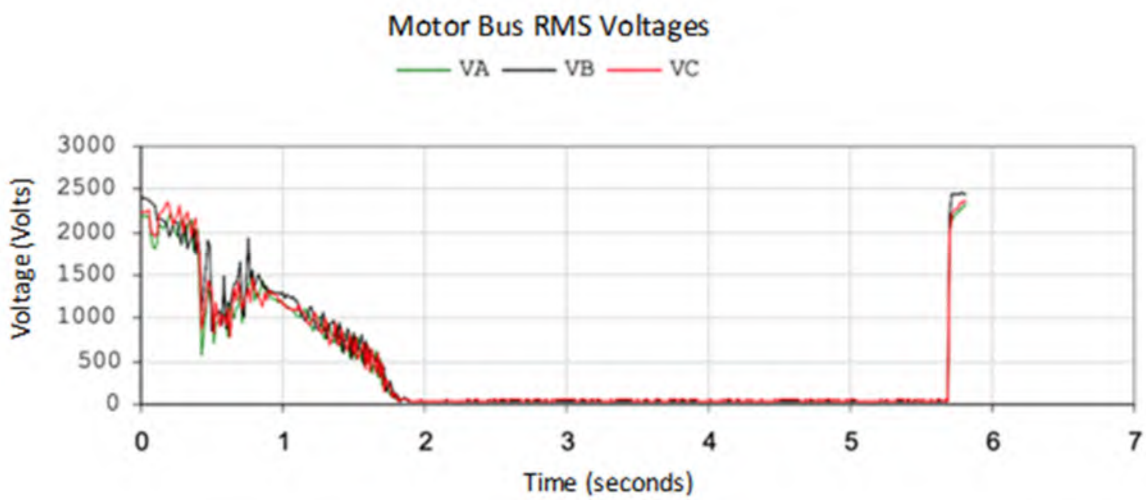


Figure 6-3 Power Quality data captured during August 6, 2005, event [3].

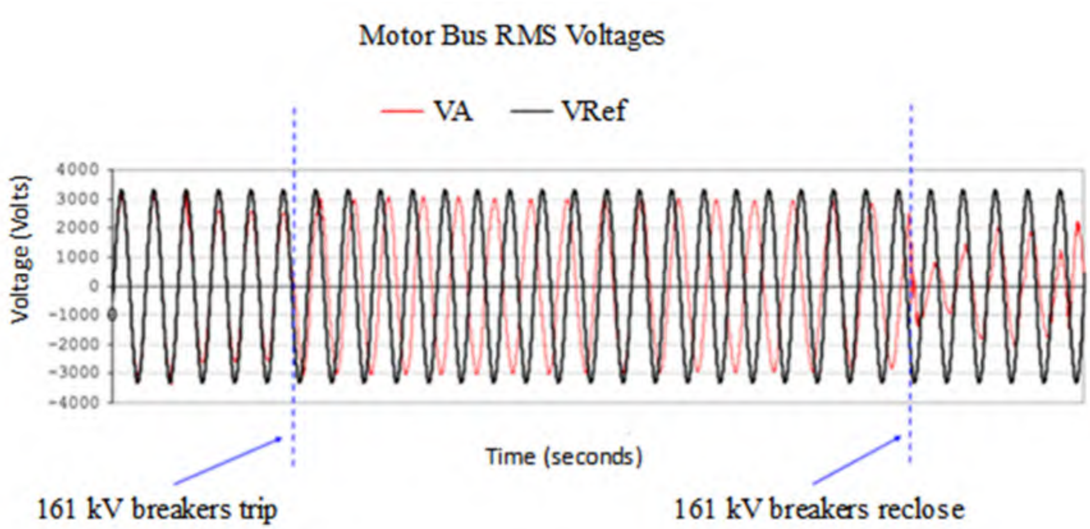


Figure 6-4 Oscillography of August 6, 2005, event with utility reference [3].

established and a 60 Hz “follow” current now flows. This current must be detected and interrupted by de-energizing the line with circuit breakers. For the ionization path to dissipate, the voltage must be absent for a sufficient duration. The time during which the voltage is absent is commonly called “dead” time.

For transient faults to be successfully cleared, an adequate dead time for deionization must be afforded. Table 6.1 shows the minimum time required by voltage level and by probability of successfully reclosing and energizing the line according to [4].

If sufficient motor load is still connected during the dead time the ionization path can/will be kept intact and a fault reignition will result when the utility breakers reclose. This occurs even though the fault is phase-ground and there is an interposing delta winding between the motor load and the fault, as in Figure 6-1. As can be seen in Figure 6-2, the tapped motor load holds up the voltage as it decays. At the time of the reclose the voltage is roughly 50% of nominal.

Effect on Motors

Unsupervised high-speed reclosing on islanded motors (induction or synchronous machines) before their residual voltage has subsided below 25% may subject the motors and other equipment to cumulative damage and failure. Reference [2] indicates that the motor should not be subjected to a reclose when the phasor difference between the source volts/Hz and the motor residual volts/Hz exceeds 1.33 per unit volts/Hz. The available literature clearly indicates that reclosing on motor load should be delayed long enough for their residual voltage to decay to acceptable levels (or their contactors drop out) to prevent damage which may be immediate or cumulative.

Table 6-1 Minimum De-Ionization Time for Reclosing Breakers [4, page 491].

System Voltage	Cycles on 60 Hz basis	
Line-line kV	95% probability	75% probability
23	4	
46	5	3.5
69	6	4
115	8.5	6
138	10	7.5
161	**13**	**10**
230	18	14

Alternatively, some means to ensure the two voltages are in-phase at time of reclose would be needed [2, 5]. Damage may include shifting of stator coils, loosening of rotor bars, distortion of coil ends, shaft damage etc. In some cases, torsional resonance can be established with resulting torques as high as 20 times normal [2, 5, and 6].

When a motor is disconnected from its power supply it starts to slow down depending on its inertia and the characteristics of its connected load. For an open circuited induction (asynchronous) motor the voltage at its terminals will be a product of its speed, open circuit time constant, and its trapped rotor flux. For a synchronous machine with field forcing applied it may take much longer for its voltage to decay. If not open circuited, the motors will experience an electrical interaction with other motors bussed with them as well (an electrical "to-and-fro" energy flow).

From the moment the motors are disconnected from the power system they begin to slip out-of-phase with the power system and their voltage magnitude begins to decay. The voltage impressed across them at reclose will be a function of this internal residual voltage and the power system voltage at time of reclosing. If the two voltages were equal in magnitude and 180° out-of-phase the resulting voltage difference would be 2 per unit.

Calculations of Out-Of-Phase Reclose

The simple circuit shown in Figure 6-5 can be used to calculate the initial currents that result from an out-of-phase reclose between the utility system and a single machine or equivalent group of machines.

This is no different than typical circuits used for calculating fault currents. The voltage E_S and reactance X_S represent the utility system equivalent. The voltage E_M and reactance X_M

represent the motor load equivalent. For purposes of this calculation the utility system voltage can be assumed to be constant (60 Hz) while the motor load will be slowing down and pulling out-of-phase during the time it is disconnected from the utility.

The current, I, that flows is the phasor difference between the two voltages divided by the series reactance between them.

$$\bar{\mathrm{I}} = \frac{\bar{\mathrm{E}}_{\mathrm{s}} - \bar{\mathrm{E}}_{\mathrm{M}}}{\bar{\mathrm{X}}_{\mathrm{s}} + \bar{\mathrm{X}}_{\mathrm{M}}}$$

From this equation it is easy to see that no current will flow if no difference in magnitude and/or phase exists between the two systems. Also, the maximum current possible will occur when the two systems are exactly 180° out-of-phase, and both voltages are at their highest magnitudes. It is possible for the system voltage to have risen upon breaker opening (e.g. to 1.05 per unit) and the open circuited motors may initially have as high as 1.45 per unit voltage [8] or higher (depending on the excitation method for synchronous machines). Note that under this condition the current experienced by some elements in the system can exceed those due to short circuits [7].

Figure 6-6 is oscillographic data of motor voltage decay on the customer bus described in Figure 6-1 for the first 2 seconds of disconnect without subsequent high-speed reclose. It reveals the natural decay of the motor system (mix of small and large induction and synchronous machines) without the influence of a high-speed reclose. In this case, it takes the rotating system just over 1 second to decay to 25% voltage and just over 1.2 seconds to reach zero. Phase to ground voltage is $\frac{4{,}160\ \mathrm{V}}{\sqrt{3}} = 2{,}402\ \mathrm{V}$ so 25% would be 600 V.

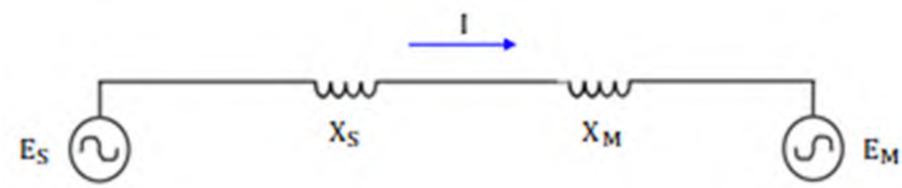


Figure 6-5 Simple System Equivalent for Current Calculation [6].

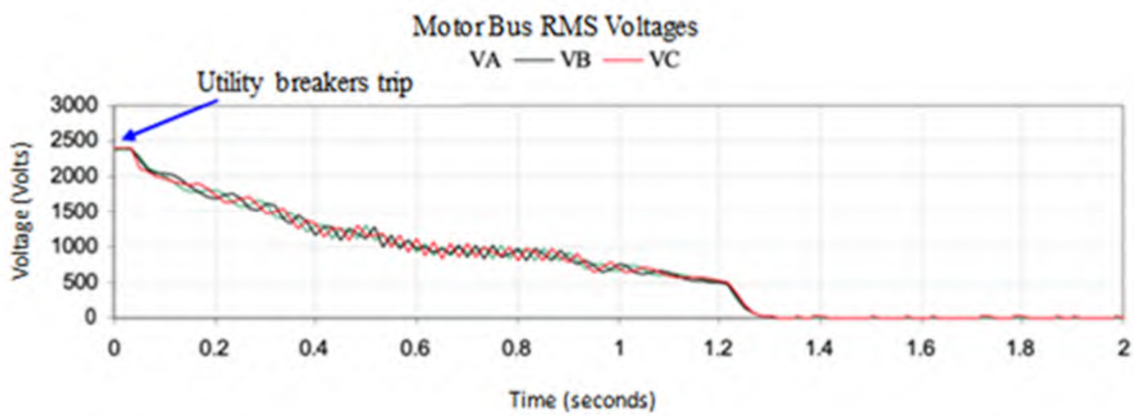


Figure 6-6 Power Quality data captured during disconnect of motor load.

Equipment Current Limits

TRANSFORMERS: IEEE Standards stipulate that power transformers are to be braced to withstand the maximum current experienced for a three-phase bolted fault on their secondary with full primary voltage applied, or 25 times nominal, whichever is less, for up to 2 seconds [6,9]. In other words, transformers must be built to withstand a per unit current of,

$$\mathrm{I} = \frac{1.0}{\mathrm{X_T}}$$

where X_T is the transformer reactance or a reactance of 4.0%, whichever results in higher fault current. Figure 6-7 shows a power transformer connected between the utility system and the motor load. The value of fault current, I, that flows when the two systems are reconnected is,

$$\bar{\mathrm{I}} = \frac{\bar{\mathrm{E}}_s - \bar{\mathrm{E}}_M}{\bar{\mathrm{X}}_s + \bar{\mathrm{X}}_T + \bar{\mathrm{X}}_M}$$

which should not be allowed to exceed the transformer withstand current as discussed above.

For example, the following system values will be assumed:

X_S = j3% on 100 MVA base, 161 kV

X_T = j4% on 30 MVA base, 161 kV

X_M = j15% on 7.5 MVA base, 4.16 kV (10,000 HP induction motor)

After converting to 100 MVA, 161 kV base:

E_S = 1.0, E_M = 0.9 @ -180°, X_S = j3%, X_T = j13.33%, and X_M = j200.0%.

$$\bar{\mathrm{I}} = \frac{\bar{\mathrm{E}}_s - \bar{\mathrm{E}}_M}{\bar{\mathrm{X}}_s + \bar{\mathrm{X}}_T + \bar{\mathrm{X}}_M} = -\mathrm{j}0.88 \text{ pu}$$

So, for the example circuit values above the transformer experiences just under 1 per unit current flow when the two systems are initially tied back together. In contrast, the most current it would see for a bolted low-side three-phase fault would be 6.1 per unit.

$$\bar{I} = \frac{1.0}{\bar{X}_s + \bar{X}_T} = -j6.1 \text{ pu}$$

It isn't very likely that the transformer will experience higher current when the two system are re-synchronized than it would for a bolted three-phase fault, but it should be considered and recognized that the likelihood increases with the size of the connected motor load and the phase angle between the two systems at time of reclosing. The above example is with a single 10,000 HP motor. It is easy to see that increasing the size or number of motors drives the 2.0 reactance down in the denominator, increasing the current I.

<u>ROTATING MACHINES</u>: Reference [2] says that the maximum current that rotating machine windings are built to withstand is,

$$I = \frac{1.0}{X''}$$

where 1.0 is the machines rated voltage in per unit. For asynchronous (induction) machines X" is the locked rotor reactance. A reasonable estimate of the inductance of an induction motor is to assume the locked rotor (starting) current is 6 times the rated current. This is equivalent to using a 1/6 per unit impedance in the following equation [7].

$$L = \frac{X_{pu} \times kV^2}{\omega \times MVA}$$

For synchronous machines, X" is the direct axis sub-transient reactance. Table 5 [9] gives estimates of sub-transient reactance of three-phase synchronous machines.

Typically, the reactance of the largest machine in a plant will be much larger than the reactance of the utility Thévenin equivalent and the interconnecting power transformer [8]. This means that the motor load is typically at higher risk than the utility equipment during out-of-phase reclosing. Using the numbers from above, the maximum current the equivalent motor load is designed for would be,

$$\mathrm{I} = \frac{1.0}{0.15\ \mathrm{pu}} = 6.7\ \mathrm{pu}$$

Reference [1] indicates that reclosing on induction motors with residual voltage on the order of 0.9 to 1.0 per unit may produce peak electrical torque as high as 10 to 20 times normal. The paper explains that a simplified torque equation can be separated into two components, a unidirectional torque, and a fundamental frequency oscillatory torque. The maximum value of the unidirectional torque occurs when the reclosing angle is 90°. The maximum value of the oscillatory torque occurs when the reclosing angle is 180°. The maximum values of these components are given by the following equations,

$$\text{Torque unidirectional} = \frac{\mathrm{E_S E_M}}{\mathrm{X}}$$

$$\text{Torque oscillatory} = \frac{(\Delta \mathrm{E})\mathrm{E_M}}{\mathrm{X}}$$

where ΔE is the magnitude of the phasor difference between E_S and E_M (refer to Figure 6-5), and X is the total equivalent reactance between the voltage sources.

For values of residual motor voltage, E_M, below approximately 30% of the system voltage, E_S, the maximum torque is predominately unidirectional and occurs near the 90° out-of-phase point.

For values of residual motor voltage near 1.0 per unit, the largest torque occurs when reclosing near 120° out-of-phase. The reference indicates that this maximum torque would be,

$$\text{Torque maximum} = \frac{2.6\Delta \mathrm{E}^2}{\mathrm{X}}$$

For synchronous machines the issue of field forcing can dominate. If the dc field excitation is maintained when a synchronous machine is tripped, then its generated voltage can be quite high. A typical rated field produces internal EMF as high as 1.4 per unit for 0.8 power factor machines and 1.2 per unit for 1.0 power factor machines. The generated voltage at the machine terminals will decrease as the speed decreases, the rate of speed decrease being a function of the shaft inertial system (loads etc.) and the electrical load on the bus. It may take many seconds for a machine to stop.

Reference [1] says that high-speed reclosing (15 to 30 cycles) will result in high transient torques on the connected synchronous machine with field forcing present. It provides several analytically created charts for estimation of the torque shock experienced at time of reclosing for a synchronous machine. Closing angle, motor generated voltage, and system voltage are known quantities that are used together with machine data (reactances) to estimate the maximum torque to be expected.

CIRCUIT BREAKERS: The IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers, IEEE C37.04-1999, describes an out-of-phase event as an abnormal circuit condition of loss or lack of synchronism between parts of an electrical system on either side of a circuit breaker and it is not considered necessary to include this as a standard rating for general purpose circuit breakers. An out-of-phase switching current rating applies to circuit breakers intended to be used for switching the connection between two parts of a three-phase system during out-of-phase conditions. For circuit breakers with an assigned out-of-phase switching current rating IEEE states the preferred rating shall be 25% of the rated symmetrical short circuit current, expressed in kA, at a phase separation angle up to 180°, unless otherwise noted by the manufacturer [11]. Relaying engineers should also be aware that the interrupting time for out-of-phase switching is permitted to exceed the rated interrupting time by 1) 50% for five or more cycle circuit breakers and 2) one cycle for three or fewer cycle circuit breakers.

The IEEE Standard for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis, IEEE C37.013-1997, states that only generator circuit breakers having full interrupting capability (to clear short-circuit currents on either side of the circuit breaker) could have an assigned out-of-phase current switching rating. The rating is limited to 50% of the symmetrical system-source short-circuit current at a 90° angle at maximum system voltage [11]. The standard states most generator circuit breakers are expected to close but not to interrupt under full phase opposition conditions because the latter task could be solved more conveniently by the circuit breaker on the high-voltage side of the transformer.

These ratings are considered in the design and setting of out-of-step tripping schemes but may have applicability to this issue of reclosing in some circumstances.

Open Circuit Time Constant

Figure 6-8 shows the Steinmetz equivalent circuit of an induction motor where,

E_0 - residual voltage at terminals of opened motor

R_1 - stator resistance

R_2 - rotor resistance (on stator basis)

X_1 - stator reactance

X_2 - rotor reactance (on stator basis)

X_M - magnetizing reactance (on stator basis)

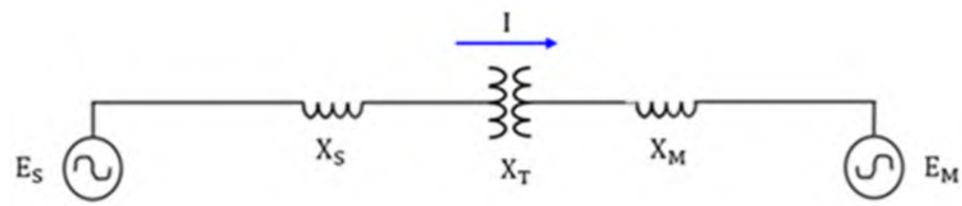


Figure 6-7 Transformer between out-of-phase systems.

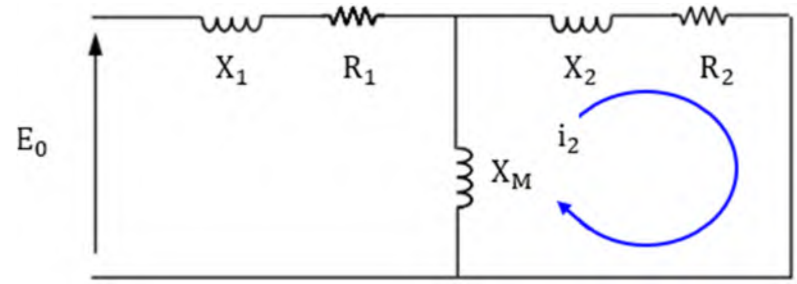


Figure 6-8 Steinmetz model of induction motor.

At the instant the motor is disconnected the supply current goes to zero. However, the current in the closed rotor loop will not immediately go to zero, it will change to match the motor flux present at that instant [12]. This flux is the "trapped" flux at the instant of disconnection. This flux decays with time and induces a voltage to sustain the slowly decaying rotor current. The following equations dictate the physics of the circuit in Figure 6-8 and are used to arrive at a formula for the open circuit time constant of the motor.

$$L_2 \frac{di_2}{dt} + L_M \frac{di_2}{dt} + R_2 i_2 = 0$$

$$i_2 = Ae^{\frac{-R_2 t}{L_M + L_2}}$$

The inductance is in henrys per phase and resistance in ohms on the stator basis, i_2 is the instantaneous rotor current (dc), t is in seconds, and A is the initial rotor current at the moment of disconnection.

The open circuit time constant, T_0, of the decaying rotor current is,

$$T_0 = \frac{L_M + L_2}{R_2}$$

this is also the time constant of the decaying residual voltage induced in the opened stator winding, E_0. The equation for the decaying residual voltage can be written as,

$$E_0 = Ee^{\frac{-t}{T_0}}$$

where E is the voltage at the motor terminals at instant of disconnection. It takes T_0 seconds for this residual voltage, E_0, to decay to 36.8% of the initial voltage E.

The model used in Figure 6-8 is acceptable if the frequency doesn't drop too low (roughly 30-40Hz range or below). If the frequency deviates too far from nominal the skin effect on rotor resistance and inductance must be considered.

Below is an example calculation of open-circuit time constant [12] for a 250 hp, 350 rpm, 440 V, three-phase, 60 Hz squirrel cage motor of typical design.

R_2 - 0.023 ohms

X_2 - 0.0637 ohms (L_2 = 0.169 mH)

X_M - 1.17 ohms (L_M = 3.104 mH)

For these values T_0 = (0.169 mH + 3.104 mH)/0.023 ohm = 0.142 seconds (8.54 cycles on 60 Hz basis). This motor would take 8.54 cycles for its voltage to decay to 36.8% of rated value, assuming it was at rated voltage when disconnected. To reach 25% of rated voltage would require 11.80 cycles.

This approach, of course, doesn't include the effects of load inertia or of connected electrical load, it assumes the stator winding is opened. But it can provide a basis for a good engineering estimate of how long is required to wait before reclosing. For instance, if the plant has one or two very large motors that make up the largest portion of its motor load, the conservative estimate based on open-circuit time constant should provide a good basis when deciding the minimum reclosing dead time. The presence of heavy mechanical load on the motors and the electrical connection to other smaller inertia motors (which will tend to be driven by these large motors upon disconnection) will tend to help accelerate residual voltage decay.

Reference [8] notes that the larger the motor's horsepower, the longer the open-circuit time constant, T_0, if other rating characteristics such as voltage and rpm are equal. Also, the higher a motor's rated speed, the longer its time constant will be with other rating factors being equal. So, because of their speed, 2-pole motors have longer open-circuit time constants than comparable motors with more poles. Motors in the 200 to 2000 hp range typically have open-circuit time constants in the range of 0.25 to 2 seconds [13, 14].

Reference [8] also points out that designers have some degree of control over the open circuit time constant. The most effective means for controlling T_0 (with least adverse affect on machine performance) is to control the magnetizing reactance. The magnetizing reactance is largely controlled by the air gap dimensions. An increase in air gap will increase magnetizing current, decreasing X_M and subsequently T_0. This approach also has the adverse effect of reducing power factor.

Synchronous motors and generators have much larger time constants due to their independent field excitation, making them more vulnerable to damage from high-speed reclosing than comparable induction machines. Reference [14] indicates that typical open-circuit time constants for large salient-pole synchronous motors range from 1.5 to 10 seconds with an average value of about 4 seconds.

Page 188 of [4] shows charts of open-circuit time constants for machines up to 150 kVA and 1200 rpm. Page 189 shows a very thorough table of typical constants for three-phase synchronous machines of various construction.

PRESENCE OF CAPACITORS: If a bank of capacitors is connected to the motor while disconnected from the supply system the time constant will be affected. The capacitors may be power factor correction capacitors, surge protection capacitors, or capacitors that supply excitation current to asynchronous generators like wind turbines (see Figure 6-9).

If capacitors remain in parallel with the motor load during the time of disconnection from the power system, they will help maintain residual winding magnetism by storing energy during half of each voltage cycle and returning it to the winding during the other half [6].

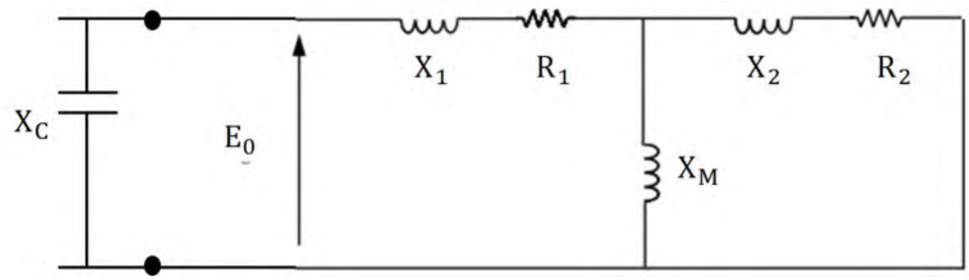


Figure 6-9 Capacitance located near terminals of motor.

Capacitors that are large enough will cause the residual voltage to rise when initially opened. Losses will still reduce the energy in the circuit, but the time of decay will be extended, in some cases greatly. For example, the open-circuit time constant of a typical 400 hp, 460V, 6-pole motor without capacitors present is 0.35 seconds (21 cycles). With a terminal capacitance of 110 kvar the open-circuit time constant goes to 5.8 seconds - an increase of a factor of more than 15 [6]. Additionally, switching an excessive amount of capacitance near a motor may well expose the motor to large overvoltage.

Options

The simplest solution for the utility is to disable the high-speed reclose and rely on dead-line reclosing. If studies support this option (to ensure no stability problems or transient voltage issues) then it is simple and no cost. On highly interconnected transmission systems the loss of one line is unlikely to cause the two parts of the system to lose synchronism. In this case delayed reclosing is acceptable.

Another option that is commonly used is direct transfer-trip from one utility terminal to trip the tapped motor load. This would allow high-speed reclosing to remain, restoring the transmission tie quickly. Delayed voltage check reclosing could be used at the tapped station with appropriate delay to restore service to the plant.

Summary

Reclosing must be delayed long enough to allow the fault arc ionization path to dissipate. High-speed transmission line reclosing before tapped motor load can be disconnected or their voltage allowed is to decay (plus delay to allow the fault arc ionization path to dissipate) should be avoided to prevent damage/undue wear to utility breakers and transformers. To limit transient motor currents and torques to acceptable values motor residual voltage should be allowed to decay below 25% before reclosing the line. This may take as long as 5 seconds for some large motor loads. An alternative is to use direct transfer trip. The phasor differences between the source voltage/Hertz and the motor bus voltage/Hertz should not exceed 1.33 per unit volts/Hertz at instant of closing. The largest torque perturbations for the motors may occur at reclosing angles between 90° and 120°. Good oscillographic capture devices (digital fault recorders or power quality monitors etc.) are essential to proper monitoring and analysis of power system operation. Thorough event analysis is essential as described in Chapter 1.

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CHAPTER 7

PROTECTION APPLICATION ISSUES NEAR STRONG GROUNDING PATHS

A version of this chapter was originally presented to the 29th Annual Western Protective Relaying Conference October 22-24, 2002:

Russell W. Patterson, Elmo Price. "Protection Application Issues Near Strong Grounding Paths." 29th Annual Western Protective Relaying Conference October 22-24, 2002.

Abstract

This chapter goes through the event analysis of an undesired trip of a line-distance relay applied near a large 522 MVA wye-grounded/delta generator step-up transformer. The generator was off-line, setting up a large remote zero-sequence source (without positive or negative sequence currents) that undesirably affected the relay operation. This paper utilizes the recorded fault data and symmetrical component sequence networks to analyze the fault. Detailed lists of observations of the relays' analog (currents and voltages) and digital logic signals are developed from which a cause and solution are quickly determined. In addition, other relay application problems are identified.

Introduction

The single line diagram in Figure 7-1 shows the general arrangement of a portion of the TVA system around Sturgis, Mississippi. The Red Hills generating plant is connected to the TVA system through two 161kV lines from Sturgis. One of the lines is tapped in the middle with two autotransformers at Ackerman. Also, there is no generation (positive sequence source) on the Ackerman 69 kV. There are, however, motors at Ackerman 69 kV that have a small sub-transient contribution to faults on the 161 kV system.

With the generation off-line at Red Hills and the 522 MVA step-up transformer still tied to the Red Hills bus, the only sequence current that can flow from Red Hills in the two lines to Sturgis is zero-sequence. Due to the size of the solid grounded delta-wye transformer at Red Hills and the autotransformers at Ackerman considerable ground current is available to flow into ground faults around Sturgis. This system configuration, coupled with deficiencies in some of the applied line protection relays, sets up several protection application issues that resulted in incorrect operations.

Figure 7-2 is the symmetrical component sequence network connection model for the system of Figure 7-1 with a reverse two phase-to-ground fault connection. It also shows the single phase-to-ground connection option. The gray area is the part of the circuit where no positive or negative sequence current flows because the generator (positive sequence source) is disconnected from the system through the open switch SW. As can be clearly seen the positive sequence system source at Sturgis has a [ground] path through the Ackerman (Z_{0A}) and Red Hills (Z_T) transformers whose winding connections allow zero-sequence current to flow in the Red Hills to Sturgis lines.

Also, there are two POTT (Permissive Overreaching Transfer Trip) pilot protection schemes of different manufacturers associated with each line, referred to as "A set" and "B set".

Incident 1 (2/16/2001 at 11:08)

This event was precipitated by a double-phase-to-ground fault on one of the adjacent lines out of Sturgis as shown in Figure 7-3. When this fault occurred, the Red Hills generator was off-line so that only zero-sequence current could flow from the Red Hills lines into the Sturgis bus. The A set protection for both lines incorrectly tripped. The B set relays correctly restrained from operation.

Digital fault records were collected from both the A set and B set protective relays and analyzed. Analog and digital quantities recorded by both relays are shown in Figures 7-4 to 7-8. The phase voltages are plotted in each as a common reference.

Review of the Analog Data

Figures 7-4 and 7-5 show the analog quantities for B set and A set relays, respectively. Different formats are used because different analysis programs are required for the different relay manufacturers. As expected, the phase analog data is nearly identical. Figures 7-5 and 7-6 show the primary rms values of the sequence currents and voltages for the A set relay. Some observations with respect to the analog data are as follows.

1. The data of Figures 7-4 and 7-5 show that the currents IA, IB, and IC are in phase. From this it can be inferred that the forward (looking into line # 1 from Sturgis) system zero-sequence equivalent impedance is much smaller than the forward positive and negative equivalent impedance. The sequence network of Figure 7-2 shows the zero-sequence path

(Z_T) of the large wye-delta generator step-up transformer and supports these results.

2. The data of Figures 7-4 and 7-8 show no appreciable negative sequence current (Figure 7-4 shows 3I2, Figure 7-8 shows I2) flowing to the fault through breaker 998. Note that this is consistent with observation #1. The symmetrical component sequence network also readily reveals this. With the switch SW open to show that the generator is out of service, it is observed that there is no path for positive or negative sequence current to flow through breaker 998. The small amount of measured negative sequence current may be explained as motor contribution from Ackerman or possibly some small impedance unbalance or mutual on the parallel lines from Red Hills. It is, however, inconsequential. There is negative sequence voltage (Figure 7-4 shows 3V2, Figures 7-7 and 7-8 show V2). This indicates that negative sequence current is flowing to the reverse fault, but not through breaker 998.
3. The decision to trip was made in about 2 ½ cycles followed with breaker F clearing in about 2 to 3 cycles. This indicates high-speed (pilot time) clearing. Breaker F in Figure 7-2 corresponds to breaker 954 in Figure 7-1.

Most of these observations will have some bearing on defining and solving the problem. Some may not, but they should be listed and rationalized with the symmetrical component sequence network as a matter of good habit. This will help hone the intuitive skills required for fault analysis as discussed in Chapter 1.

Review of Digital Data

Figures 7-4 and 7-8 show some of the digital signals that operated for the B set and A set relays. These signals include the appropriate measuring unit and key logic signal operations.

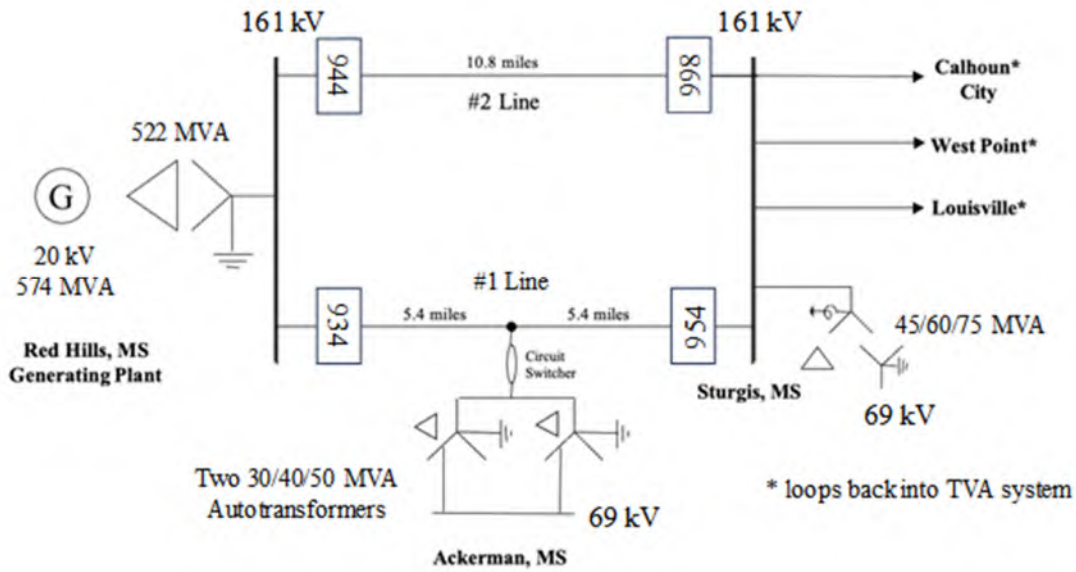

Figure 7-1 System Single Line.

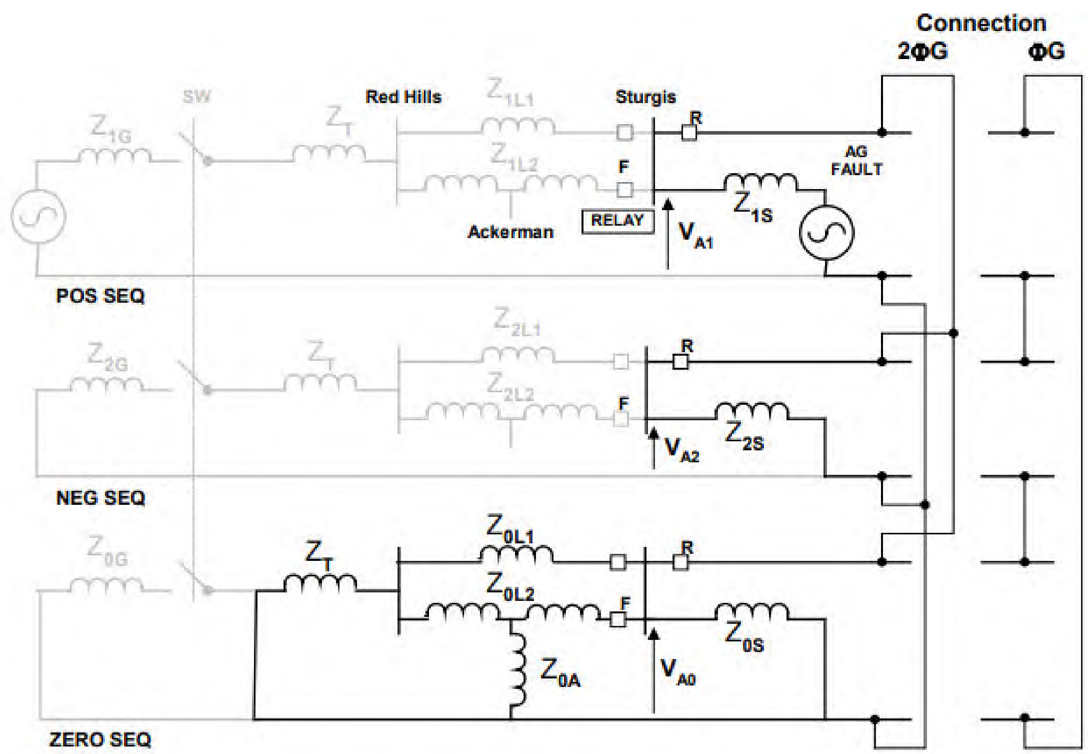

Figure 7-2 Sequence Connections for Single and Two Phase-to-ground Faults.

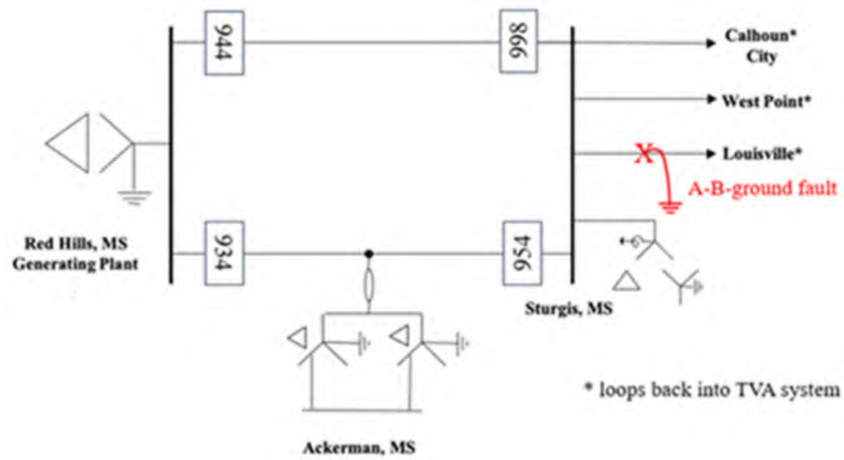

Figure 7-3 Location of A-B-ground fault.

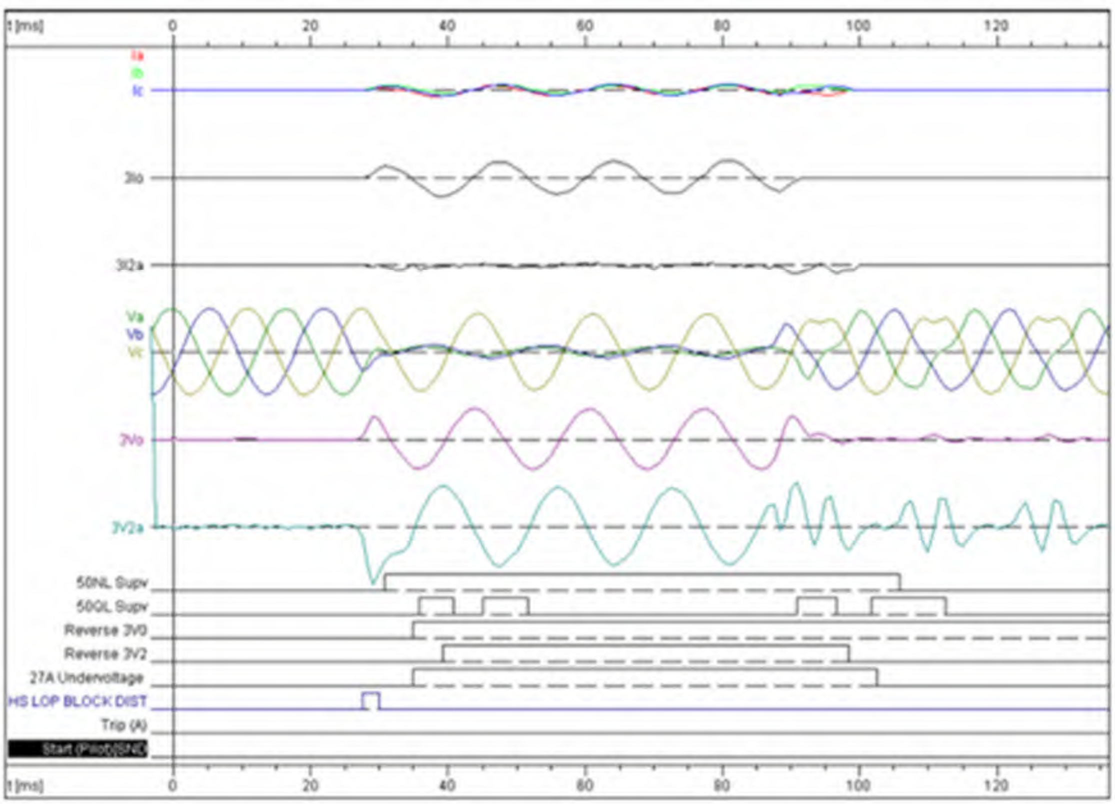

Figure 7-4 Current, Voltage, and Digital traces in 998 B set relays during Incident 1.

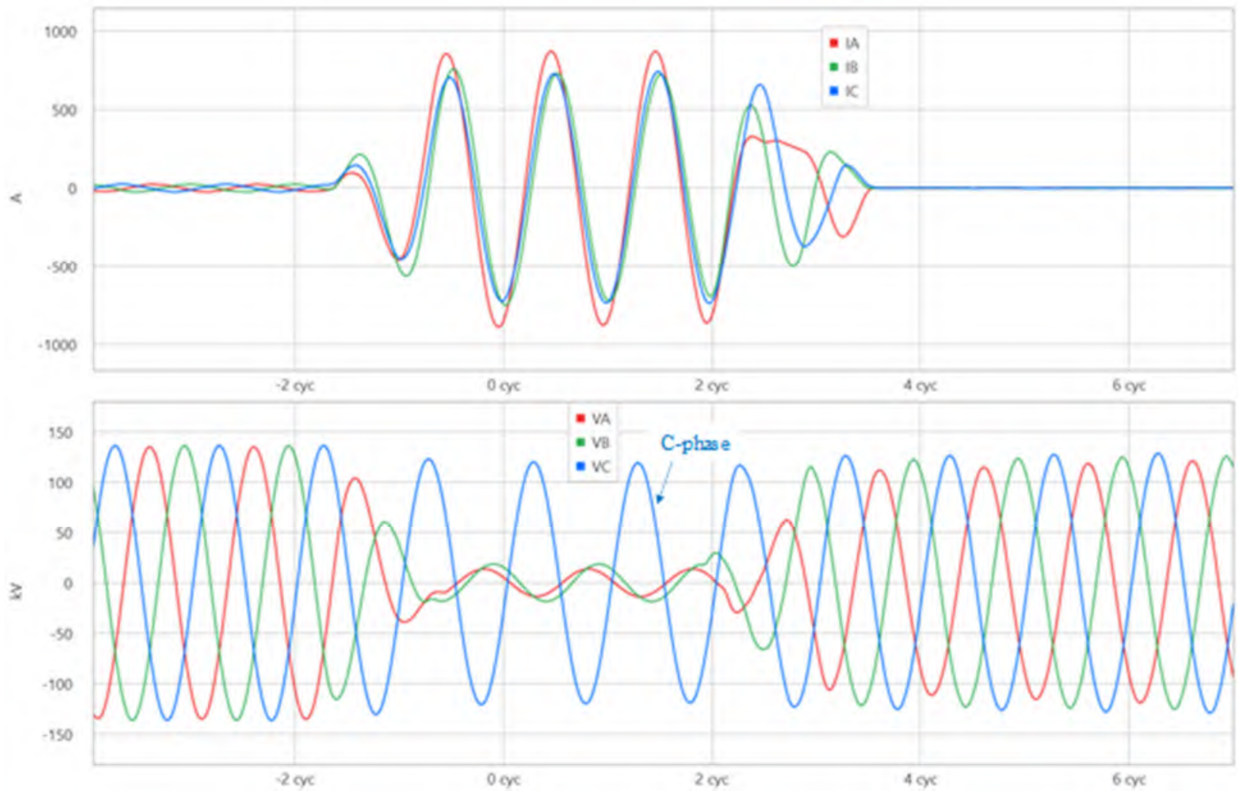

Figure 7-5 Currents and Voltages in 998 A set Relays During Incident 1

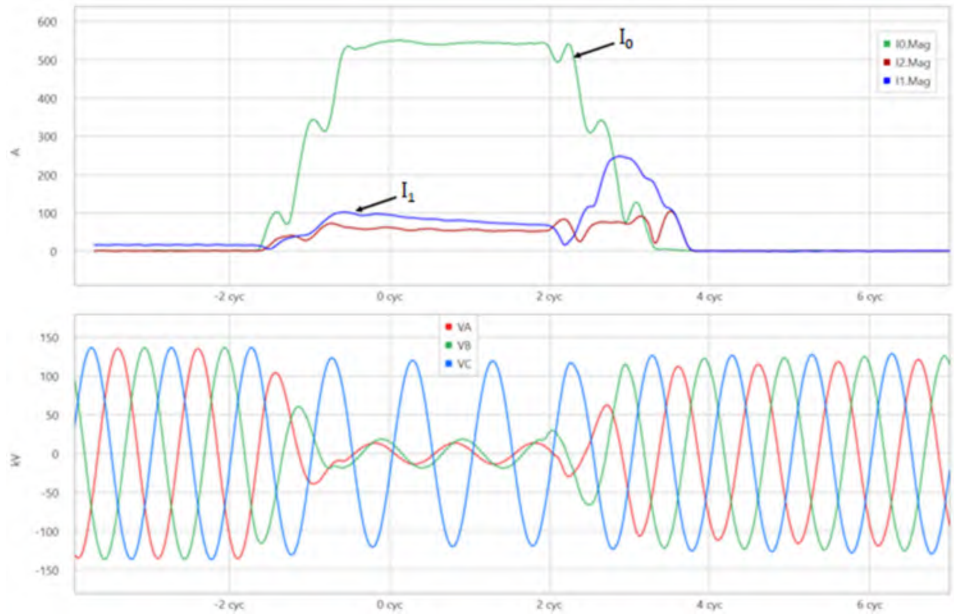

Figure 7-6 Sequence Current RMS magnitudes in 998 A set Relay During Incident 1.

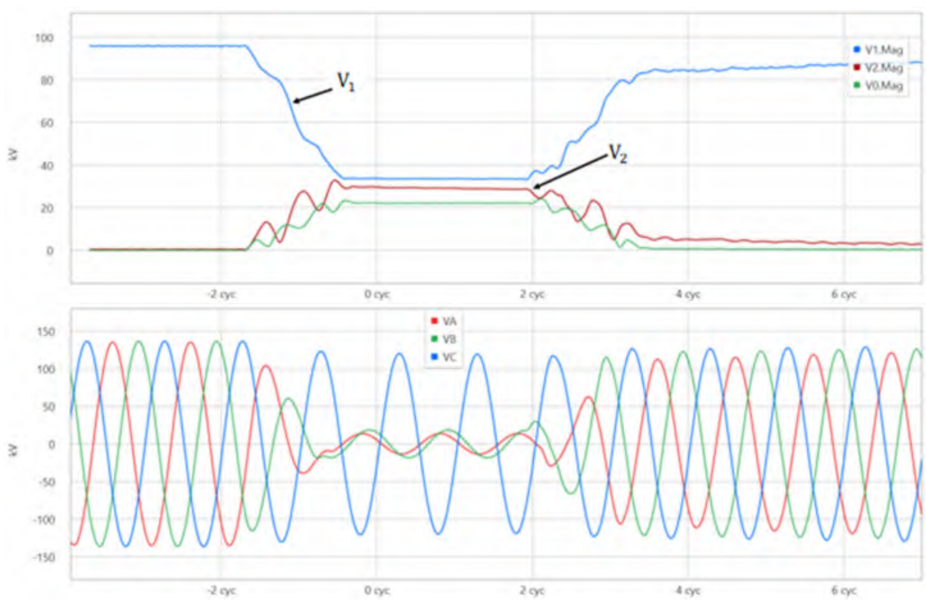

Figure 7-7 Sequence Voltage RMS magnitudes at 998 A set Relay During Incident 1.

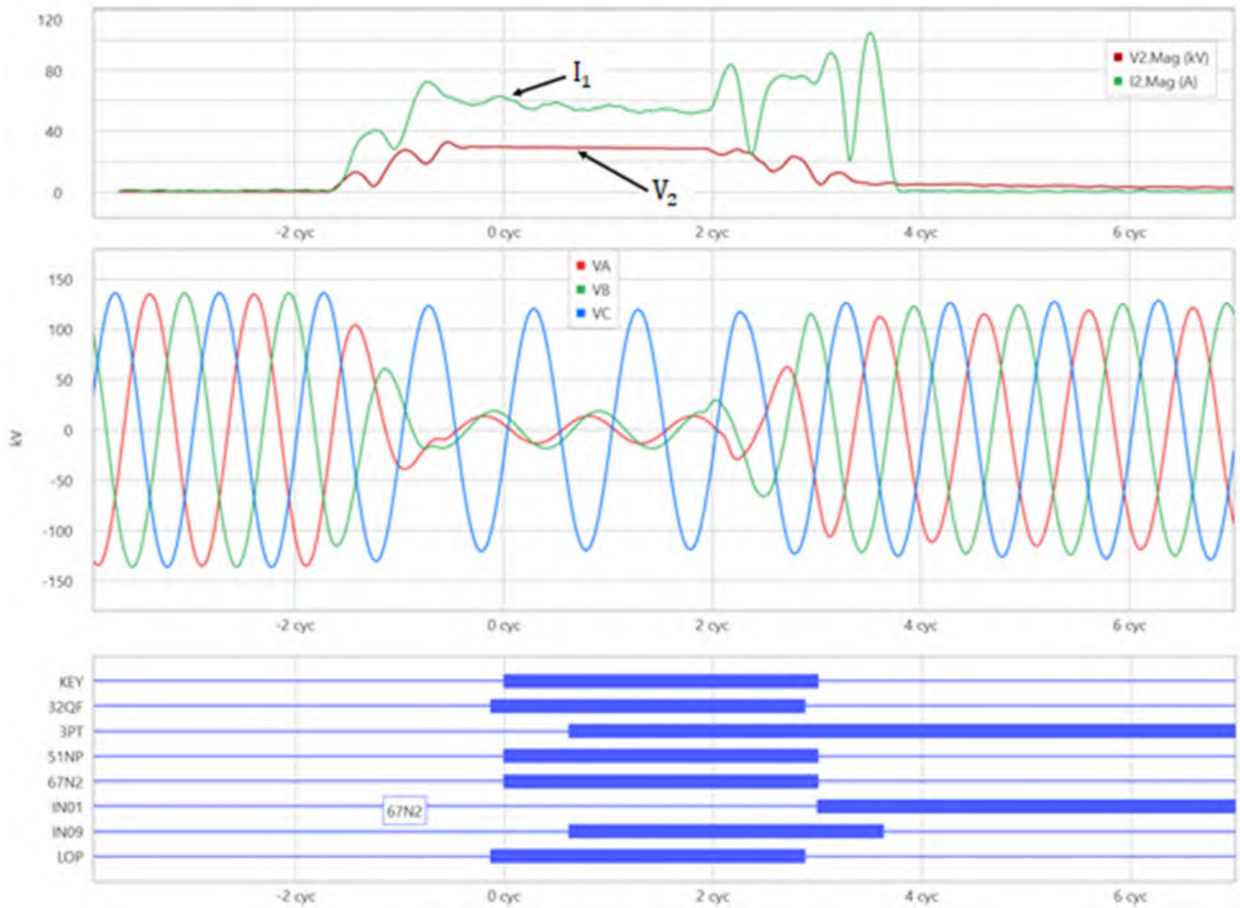

Figure 7-8 V2 and I2 RMS and digital traces in 998 A set Relay During Incident 1.

Some observations are:

1. The reverse directional zero-sequence and negative sequence units of the B set relay (Figure 7-4 - Reverse 3V0 and Reverse 3V2) asserted agreeing with the correct fault direction.
2. The forward directional negative sequence unit of the A set relay (Figure 7-8 – 32QF) operated for the reverse fault. This was a misoperation of the element.
3. On the B set relay (Figure 7-4) the low-set ground (3I0) instantaneous overcurrent unit (50NL) operated while the low-set negative sequence (3I2) instantaneous unit (50QL) operated on and off indicating it is very close to pickup (200 A primary). This agrees with the analog data where I2 rises above and falls below 67 A.
4. On the B set relay (Figure 7-4) there is also a low phase voltage (27A Undervoltage). The loss-of-potential block function (HS LOP BLOCK DIST) momentarily operates but does not sustain. The event ends without the B set relay tripping.
5. On the A set relay the loss-of potential function (LOP) operated simultaneously with the 32QF. This was followed closely by the simultaneous pickup of the ground time overcurrent element (51NP), the overreaching [forward] directional ground overcurrent (67N2) element, and the pilot KEY signal. One-half cycle later a pilot permissive signal is received on input IN9 and the relay trips. This is a misoperation of the A set relay.

Knowing the direction to the fault is reverse, which is also indicated by the B set relay performance, the key question is why the A set relay determined the fault was in the forward direction, resulting in the pilot trip. The other key question is why the A set relay loss-of-potential (LOP) element operated, in disagreement with the B set relay. This A set relay LOP was a misoperation due to a deficiency in the logic.

LOP Logic

The above results indicate that a look at the loss-of-potential (LOP) and directional (32QF) logic is probably the first step to resolve the issue. LOP logic is used to detect when one or more of the ac potentials provided to the relay are missing such as due to a blown fuse etc. Losing one or more potentials results in an inability of voltage dependent elements (polarized directional elements or distance elements etc.) to work correctly. The relay must detect this LOP condition so that voltage supervised/dependent elements can be disabled or made non-directional.

The A set microprocessor relays on these four breakers used an older version of the manufacturer's LOP logic. The older logic declares a LOP condition when it sees the presence of negative sequence voltage without accompanying negative sequence current (there is additional logic to detect loss of all three potentials). The logic being that negative sequence voltage would not be present without negative sequence current unless one or two potential fuses were blown. Figure 7-9 is a simplified logic diagram showing this concept.

When the negative sequence voltage measured at the relay exceeds the 59Q setting without the negative sequence current exceeding the 50Q setting the logic is satisfied and after a short delay, T_D, an LOP condition is declared.

The settings engineer chooses whether to block the distance elements and force the directional elements to a forward decision when a LOP condition occurs. The protective relays under investigation in this chapter were set with a T_D of 1 cycle (minimum) and were set to block distance element operation and force directional elements to a forward decision.

The B set microprocessor relays used a similar logic except it also looks for zero-sequence voltage without zero-sequence or negative sequence current. As such, the B set relay was secure.

Resolution

The cause of the operation is now quickly resolved based on what we have learned in our analysis of the event reports and review of LOP logic. Figure 7-8 above shows the magnitude of negative sequence current being over 50 A primary and that of negative sequence voltage being around 30 kV. This value of current would be zero except for the possible motor contribution or unbalance line impedance effects as discussed in the previous section. In the logic diagram of Figure 7-9 the LOP logic looked for negative sequence voltage (59Q) in the absence of negative sequence current (50Q). The 50Q element had a pickup of 67 A of I_2 (the actual pickup setting was 200 A as this element operates on $3I_2$, but for purposes of comparison with Figure 7-8 the pickup will be shown in I_2 amps). The 59Q element had a pickup of 15 kV, and it operates on V_2. From Figure 7-8 we see the V2 present is well above the 59Q setting and the I_2 present is below the 50Q setting. In this case LOP was asserted, resulting in misoperation. See Appendix A for background discussion on these settings.

The following sequence is noted from our previous observations of the digital signals. LOP asserts and simultaneously forces the overcurrent directional supervising element 32QF to forward. The 51NP (ground time overcurrent) element then begins timing, the 67N2 (over-

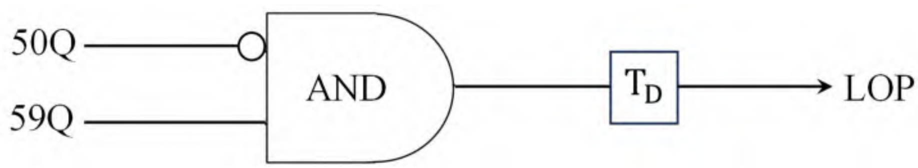

Figure 7-9 Simplified Relevant Portion of the LOP Logic

-reaching directional ground overcurrent) asserts which in turn keys permission via the POTT logic. A short time later (1/2 cycle) permission from the remote end is received (IN9) as it made an incorrect LOP declaration as well and a POTT trip occurs (3PT indicates three-pole trip). The breaker is open less than three cycles later (IN1 is a b-finger). In summary, the line was tripped in pilot time by the A set relay due to the large ground current and insecure LOP logic.

Incident 2 (2/16/2001 at 13:19)

This incident is like the one previously described except that the fault is an A-ground fault this time and the zero-sequence current from Red Hills is less. The system configuration is shown in Figure 7-10 and the related fault recordings are shown in Figures 7-11 and 7-12.

For the A set relay note that when the LOP logic asserts the relay forces directional elements forward as before. In this case, with a POTT scheme, this allowed a pilot trip to occur because the reverse looking residual overcurrent (67N3, that blocks the sending of permission) could not assert even though the residual current present exceeded its 50N3 pickup. It could not assert because its directional supervisor (32QR) is a reverse directional and LOP has forced all directional decisions forward.

The B set relays at Sturgis again correctly restrained from tripping and provided useful fault data for this case. Analog and digital data are provided in Figure 7-12.

Resolution

The correct LOP logic is like that of Figure 7-9 except it also utilizes zero-sequence, 50N and 59N. Until the A set relays could be upgraded to a newer version of firmware with adequate LOP logic the relay was set so a LOP condition would not block distance element operation or force overcurrent directional decisions forward. The reasoning being that ground faults out of Sturgis were much more likely than a blown fuse condition. With the LOP logic corrected we are still left with a lingering application decision to make as to what we allow to occur during a real LOP condition. We have the following options.

1. Set LOP and have a pilot trip for any unbalanced fault within the sensitivity of the remote 67N2.
2. Block all tripping and rely on remote backup.
3. Do not use LOP and risk incorrect impedance or voltage directional element operation.

This issue is worthy of a different discussion specific to loss of potential operations and the application and is not further addressed here.

Other Issues

Directional Supervision

Since Sturgis has individual breaker failure relays and a local backup ground relay (in the 161 kV transformer neutral), it is not a requirement for the relays at Red Hills (looking into lines 1 & 2) to backup for stuck breakers at Sturgis. However, in the absence of adequate Sturgis backup protection, it would be desirable for the relays at Red Hills to operate and remove the large ground source of the Red Hills GSU (generator step up transformer). This would allow the other positive sequence source lines into Red Hills to see a large increase in ground current from their end to backup clear a ground fault with a stuck breaker at Sturgis. Since the negative sequence directionally supervised

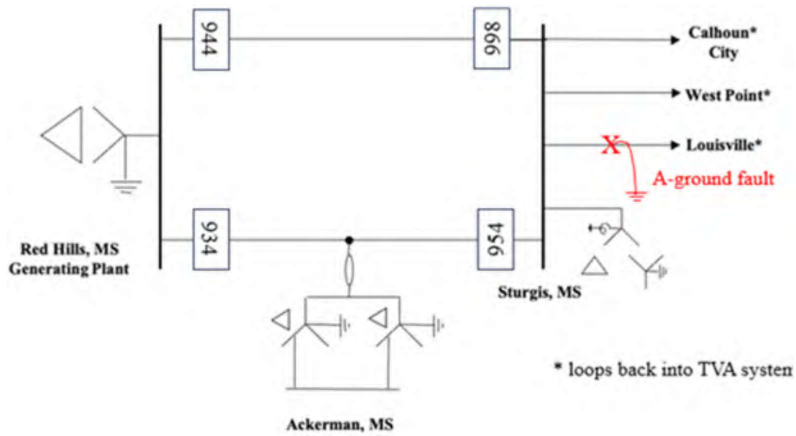

Figure 7-10 Location of A-ground fault for Incident 2.

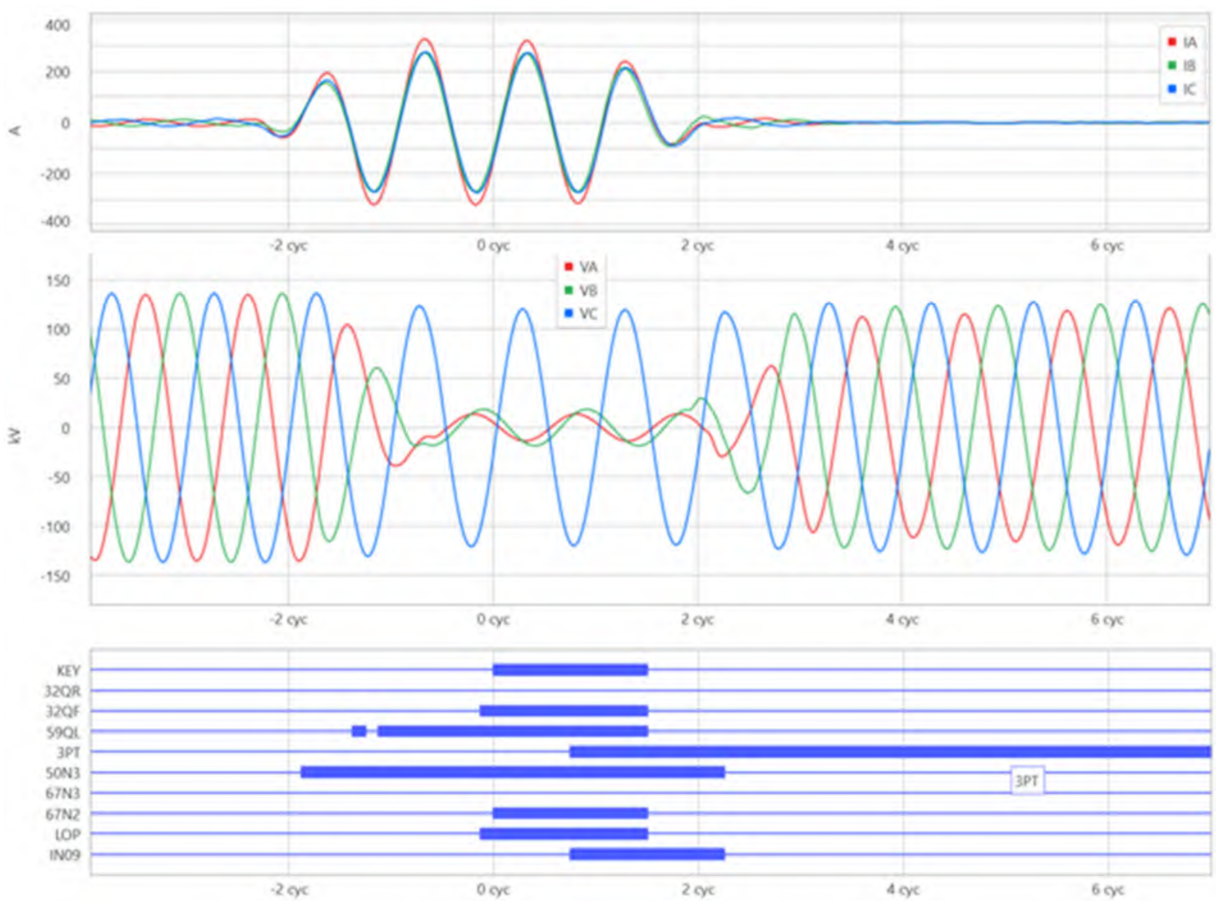

Figure 7-11 Currents, Voltages, and Digital Traces in 998 A-set Relay During Incident 2.

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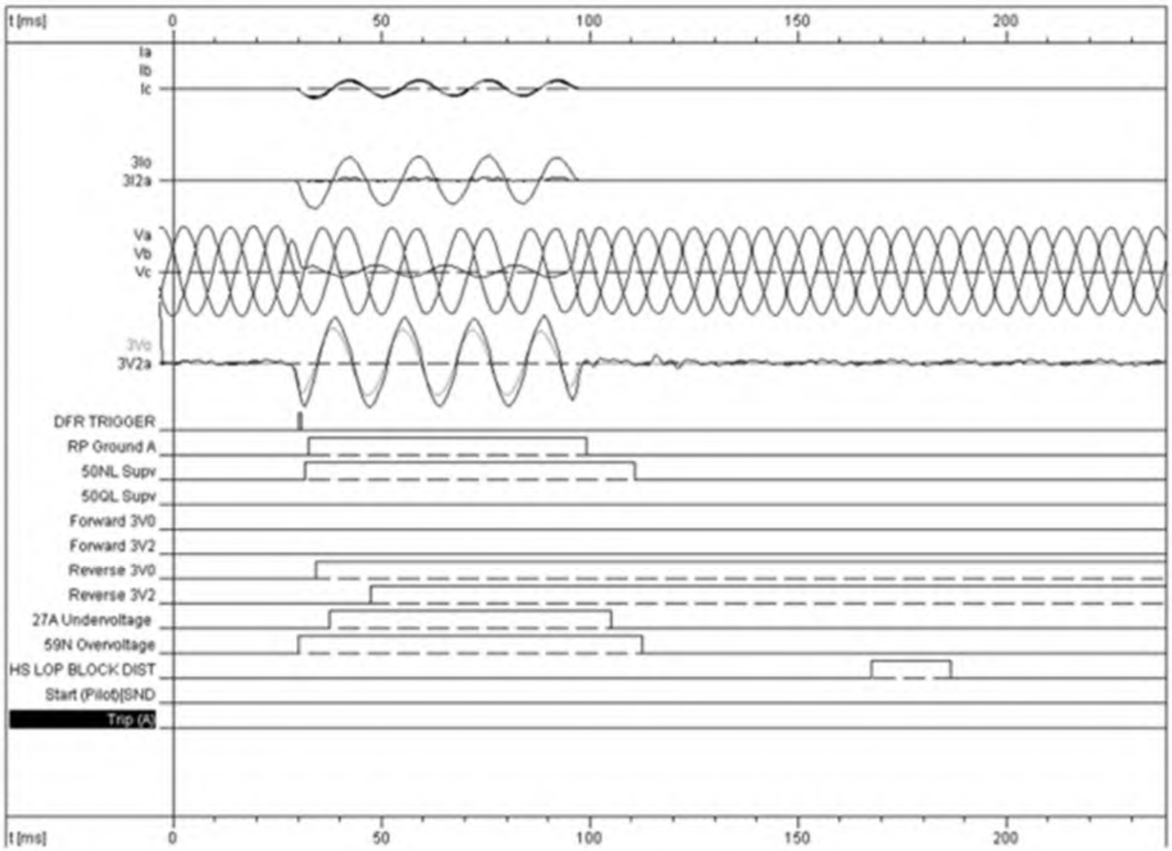


Figure 7-12 Currents, Voltages, and Digital Traces in 998 B set Relay During Incident 2.

A set relays cannot operate without a negative sequence source behind them, they could not provide backup protection for the above scenario. A backup ground time-overcurrent relay is located on the neutral of the Red Hills GSU transformer, but it is set slow to ensure it coordinates with the line relays. It will eventually trip but much slower than the line relays could. Using zero-sequence polarization, as available in the B set relay, may be the more practical solution provided the zero-sequence mutual coupling problems with the parallel lines can be handled. The use of non-directional time-delayed overcurrent may also be considered.

Ground Impedance Reach Settings

The tapped ground path at Ackerman will affect the measured ground impedance reaches at breakers 934 and 954 (see figure 7-1). This should be considered when setting under and overreaching distance units. This will be particularly important if a transformer is removed from service, affecting the ground path impedance.

Summary

Modern microprocessor relays provide valuable data that help in understanding the performance of the power system and assist in analyzing relay operations for system disturbances. In this case we had data from two relays that let us clearly see the effect of the large ground path when the Red Hills generator was removed from service. Noting the analog values and digital targets that were recorded for the event by both relays, and observing differences pointed directly to the cause of the misoperation.

To aid in the analysis, there is no substitute for a relay engineer well-grounded in symmetrical component analysis. A good symmetrical component understanding of how the system will behave under various configurations and faults is invaluable for setting protective relays and analyzing their operations. This coupled with the wealth of information provided by most microprocessor relays makes difficult analysis relatively simple.

Appendix

50Q and 59Q Setting Calculations

The 50Q elements were set on minimum = 0.5 A secondary = 200 A primary 3I2. This setting need only be above normal expected unbalance to avoid forcing a forward directional decision in the absence of an unbalanced fault.

The 59QL setting is used to detect the resulting negative sequence voltage (V2) due to the loss of 1 or 2 fuses. It should be set above the normal expected system unbalance voltage. In the equations below, $a = 1\angle 120°$.

$$V_2 = \frac{1}{3} \times (V_A + a^2 V_B + aV_C)$$

For one blown fuse (assuming 66.0V secondary phase-neutral nominal on the relay),

$$V_2 = \frac{1}{3} \times (V_A + a^2 V_B + 0)$$

$$V_2 = \frac{1}{3} \times (66\angle 0° + (1\angle 240°)(66\angle 240°) + 0) = 22\angle 60° \text{ Volts}$$

Set 59QL = 22 V / 2 = 11 V secondary = 15.4 kV primary

Check case of two blown fuses,

$$V_2 = \frac{1}{3} \times (V_A + 0 + 0)$$

$$V_2 = \frac{1}{3} \times (66\angle 0° + 0 + 0) = 22\angle 0° \text{ Volts}$$

$V_2 = 22\ V$ secondary (same as for 1 blown fuse) Note: In both cases the result was 0.333V per unit.

CHAPTER 8

A PRACTICAL IMPROVEMENT TO STATOR GROUND FAULT PROTECTION USING NEGATIVE SEQUENCE CURRENT

A version of this chapter was originally presented at the 2013 IEEE PES General Meeting, July 21-25, 2013. Vancouver, BC Canada.

R. W. Patterson and A. Eltom, "A practical improvement to stator ground fault protection using negative sequence current," 2013 IEEE Power & Energy Society General Meeting, Vancouver, BC, Canada, 2013, pp. 1-4, doi: 10.1109/PESMG.2013.6672076.

Abstract

This chapters describes the phenomenon of zero-sequence voltage coupling from the high-voltage system to the high-impedance grounded low-voltage bus for a synchronous generator and a simple improvement to accelerate stator ground fault protection (59G) using negative sequence current. This improvement, developed by the author, is being incorporated into the latest revision of the IEEE standard C37.101 – “IEEE Guide for Generator Ground Protection”.

Introduction

Figure 8-1 shows a typical one-line diagram for a unit connected synchronous generator. The machine is high- resistance grounded via a neutral transformer and secondary resistance [1]. The step-up transformer is delta connected on the generator side and wye connected on the high-voltage (HV) system side. Likewise, the unit station service transformer (USST) is also connected delta on the generator side.

An almost universally used method of detecting phase to ground faults in the generator stator winding is to use a voltage relay (59G) to measure the fundamental frequency voltage across the grounding resistance as shown in Figure 8-1. This relay will typically be set to detect ground faults in the upper 90-95% of the stator winding as described in section 7.18.1 of [1]. This relay will be complemented with other protection (e.g. third-harmonic neutral undervoltage, 27TH) to provide for 100% coverage of the stator for ground faults.

Due to the sensitive setting of the 59G (around 5% of generator rated phase-ground voltage) this relay is susceptible to operation during phase-ground faults on the HV side of the step-up transformer. When ground faults occur on the HV system a zero-sequence voltage will be present as shown in Figure 3.40 of [2]. Due to the inherent interwinding capacitance between the HV and LV windings of the step-up transformer, a portion of this HV zero-sequence voltage will be impressed across the neutral grounding transformer. This phenomenon happens for ground faults on the low-voltage side of the USST as well but typically to a negligible degree. This chapter recommends a new simple approach to prevent operation of the 59G for HV system phase-ground faults that securely allows for much faster operation of the 59G for stator ground faults in the machine, thus offering improved protection.

Generator Neutral Voltage During HV System Ground Faults

The circuit to determine this voltage is a simple series voltage drop circuit comprised of the interwinding capacitance in series with the parallel combination of the generator neutral resistance and the phase-ground capacitance of the generator bus system (usually dominated by the stator phase-ground capacitance). This circuit is shown in Figure 8-2. V_0 is the zero-sequence voltage at the HV terminals of the step-up transformer during the HV system ground fault, X_{CT} is the capacitive reactance of the HV to LV interwinding capacitance, $3R_N$ is the effective resistance in the zero-sequence of the high-impedance resistor grounding, and X_{C0} is the total zero-sequence phase-ground capacitive reactance of the generator bus system (includes stator phase-ground capacitance, any TRV capacitors, etc.). This circuit is easily arrived at by applying symmetrical component theory and neglecting insignificant impedances.

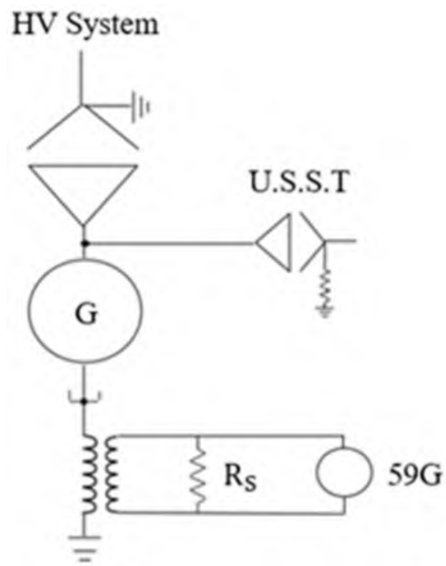


Figure 8-1 Typical High-Impedance Grounded Synchronous Generator.

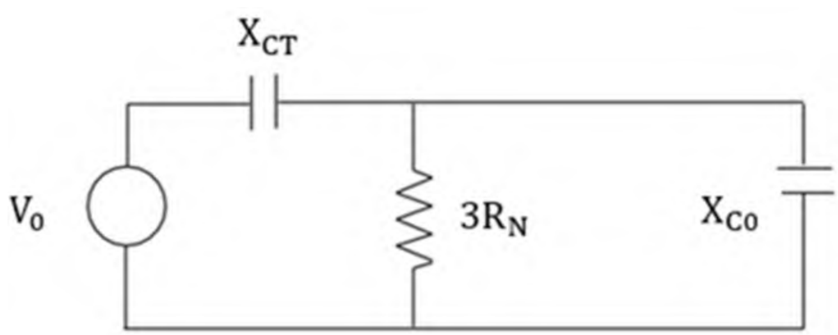


Figure 8-2 Equivalent Zero-sequence circuit.

The interwinding capacitance, X_{CT}, is typically much larger than the parallel combination of $3R_N$ and X_{C0}. However, a small percentage of the V_0 voltage will be impressed across $3R_N$ nonetheless. Due to the sensitive setting of the 59G it can operate during this HV phase-ground fault. The typical practice to prevent this protection from misoperating for this fault is to simply time delay its operation (delays of 1 to 5 seconds being common). A common belief is that since the phase-ground fault current in the generator is relatively small (10 to 25 A) that damage is not occurring during this long delay. That may not always be the case and if the core of the generator is damaged significant down-time may be required for repairs, resulting in loss of opportunity as well as repair costs. Further, if a second ground occurs on one of the unfaulted phases during elevated voltage the resulting phase-phase-ground fault would most likely be catastrophic to the machine. The sooner the first ground fault can securely be cleared the better.

Actual data from [3] can be used to calculate the voltage (V_N) impressed across the neutral grounding transformer of a real machine during an actual HV system ground fault as follows with Z_0 being the parallel combination of $3R_N$ with X_{C0}. Reactances assume 60 Hz.

$$V_0 = 147 \text{ kV}$$

$$X_{CT} = 0.012 \text{ µF} = 221.0 \text{ k}\Omega$$

$$X_{C0} = 0.254 \text{ µF} = 10.4 \text{ k}\Omega$$

$$3R_N = 8.4 \text{ k}\Omega$$

$$Z_0 = \frac{3R_N \times X_{C0}}{3R_N + X_{C0}} = 6.5\angle -39° \text{ k}\Omega$$

$$V_N = \frac{V_0 \times Z_0}{Z_0 + X_{CT}} = 4.2 \text{ kV}$$

With a neutral VT ratio of 120:1 this would impress 35.0 V across the 59G relay (normally set around 6.0 V secondary).

This same phenomenon occurs for ground faults on the low-voltage side of the USST but the driving zero-sequence voltage on the low-voltage side of the USST is much smaller than the zero-sequence voltage available on the HV side of the generator step-up transformer during close-in transmission ground faults. For example, a typical auxiliary board voltage might be 6.9 kV or less. Since the USST low-voltage side is commonly wye-grounded through a resistor the maximum available V_0 during a 6.9 kV board ground fault might be $\frac{6.9 \text{ kV}}{\sqrt{3}} \approx 4$ kV. This result is obvious from the symmetrical component network driven by a 1.0 per unit source. It can also be found by recognizing that the two unfaulted phase-ground voltages in an ineffectively grounded system go up in amplitude by $\sqrt{3}$ and move in phase position by 30° (one forward and one reverse) as shown in Figure 8-3. $V_C = \sqrt{3}\angle 150°$ pu and $V_B = \sqrt{3}\angle\text{-}150°$ pu during the A-ground fault. From the symmetrical component zero-sequence analysis equation we can find V_0 from these known phase voltages, the result being 1.0 per unit.

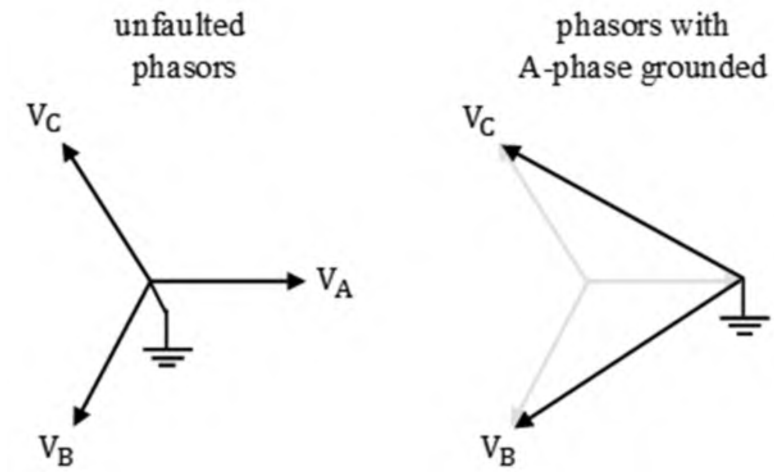


Figure 8-3 Unfaulted Phase-ground phasors shifting during ground fault.

$$3V_0 = V_A + V_B + V_C$$

$$3V_0 = 0 + \sqrt{3}\angle\text{-}150° + \sqrt{3}\angle 150° = -3$$

$$|V_0| = 1$$

One USST familiar to the author has an interwinding capacitance of 9,400 pF resulting in an X_{CT} of 282 kΩ at 60 Hz. The worst case V_N impressed on the generator neutral for a USST low-side ground fault would thus be less than 100 V primary, well below the typical 59G pickup. The interwinding capacitance can be obtained from USST test data and evaluated easily as described above. In the unlikely event that the USST interwinding capacitance is large enough to allow low-voltage bus faults to produce generator neutral voltage above the 59G set point then the approach described as follows in this chapter would need to be modified or simply not used.

Generator Negative Sequence Current During HV System Ground Faults

When phase-ground faults occur in the HV system the generator will feed fault current to the fault. This fault current from the machine will be comprised of positive and negative sequence current as can be seen from the symmetrical component network for this fault shown in Figure 8-4 where,

E_G = generator emf behind reactance

E_S = system positive sequence voltage

ZG_1 = generator positive sequence impedance

ZG_2 = generator negative sequence impedance

ZG_0 = generator zero-sequence impedance

Z_T = step-up transformer positive sequence impedance

Z_{T0} = step-up transformer zero-sequence impedance

ZS_1 = system Thévenin positive sequence impedance

ZS_2 = system Thévenin negative sequence impedance

ZS_0 = system Thévenin zero-sequence impedance

In this case the interwinding capacitance and the stator phase-ground capacitance can be neglected, and the sequence networks connected in series as shown. During this fault significant negative sequence current will flow through the left-hand side of the negative sequence network through the generator (ZG_2). This quantity can be used as a "torque control" to block fast operation of the 59G when the operating voltage it measures is due to the zero-sequence voltage coupled across the interwinding capacitance of the step-up transformer during an HV system ground fault. If the 59G experiences operating quantity above its pickup in the absence of this negative sequence current, it can be allowed to operate significantly faster than the typical 1 to 5 seconds. It can securely operate in as fast as 5-10 cycles depending on a few other aspects that are discussed in the following section.

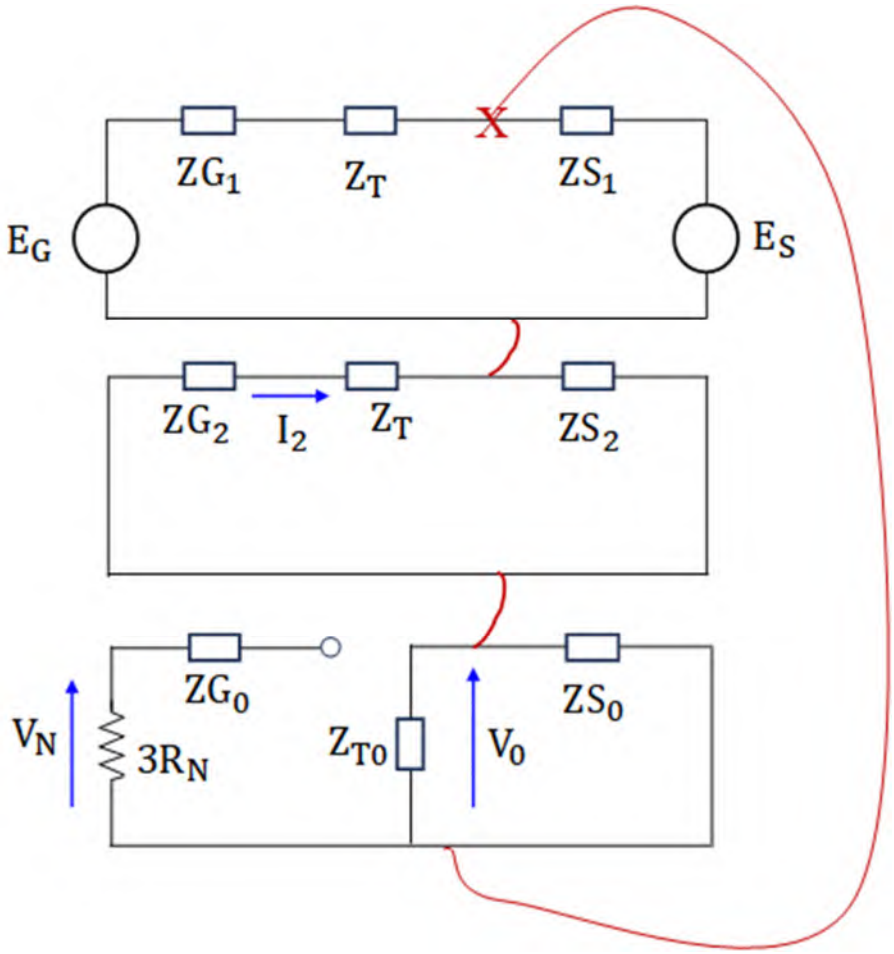


Figure 8-4 Sequence circuit to calculate I2 During HV Ground Fault.

Figure 8-5 shows the negative sequence current from the Cumberland Fossil Plant 1A generator (1,200 MVA cross-compound arrangement) during a remote ground fault in the TVA 500 kV system. It shows ample negative sequence current present.

Factors Effecting Speed of 59G

A minor complication for 59G protection is the use of VTs on the generator bus that are connected wye-grounded on both the primary and secondary windings as shown in Figure 8-6. This allows zero-sequence current to flow through the VTs during secondary ground faults.

In this configuration VT secondary phase-ground faults (aka "screwdriver faults") will be detected by the generator 59G. As such, the 59G must be coordinated with the VT primary and secondary fuses to prevent erroneous tripping of the generator for secondary wiring ground faults. Figure 8-7 shows coordination curves for two commonly used primary (EJO-1, 0.5E current limiting) and secondary (NON-30A) VT fuses in this configuration with the secondary fuse curve reflected to a primary ampere base and adjusted since the total fuse current is a combination of current from the generator neutral and from the phase-ground capacitance. A typical approach to sizing the neutral resistance is to size it such that the kW drop in the resistor equals the kvar drop in the phase-ground capacitance of the generator system. This approach results in $3R_N$ being equal in magnitude to X_{C0}. Since they are in parallel (Figure 8-2) in the zero-sequence it

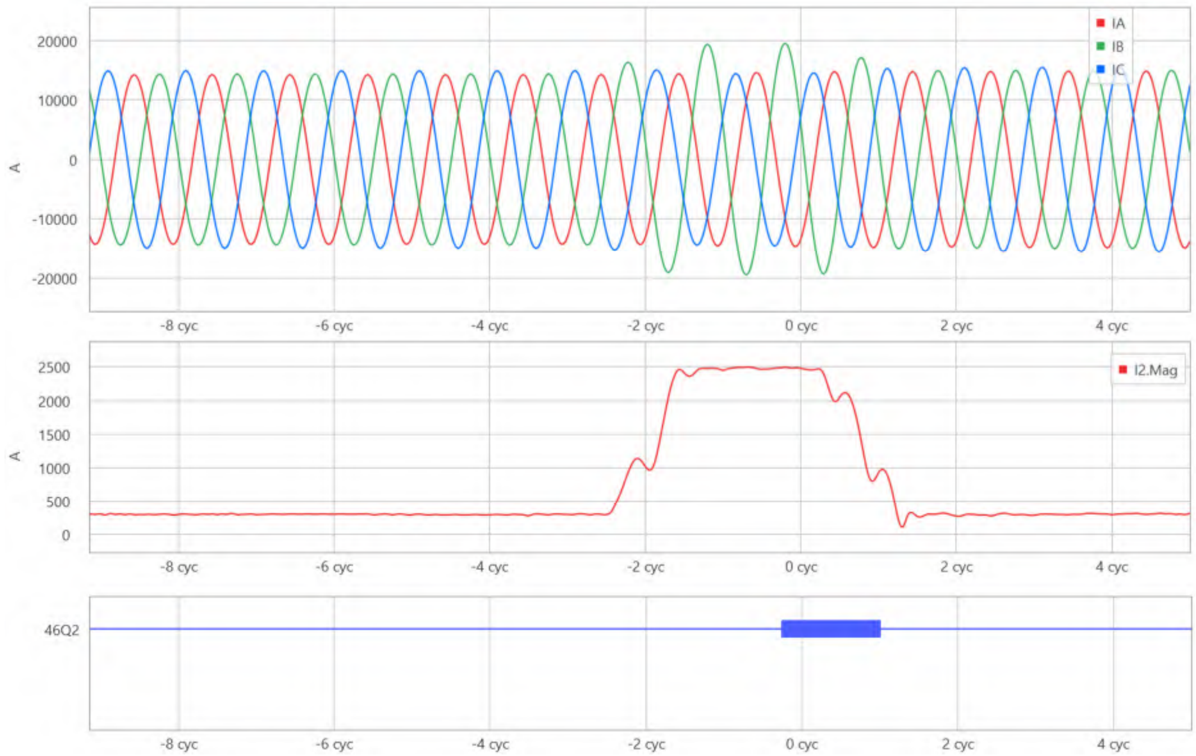


Figure 8-5 Negative sequence current from generator for system ground fault.

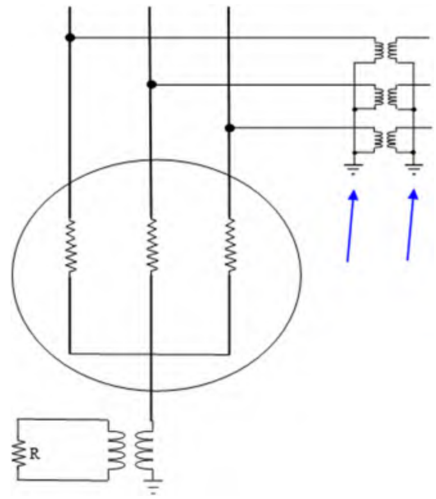


Figure 8-6 Wye-grounded/wye-grounded Generator VTs.

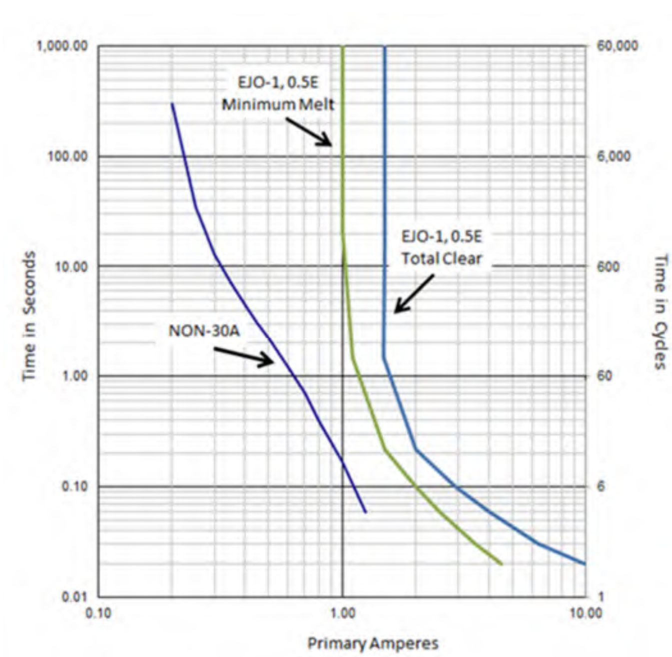


Figure 8-7 VT Primary Fuse (EJO-1) and Secondary Fuse (NON-30A).

is obvious that the current flowing through each will have the same amplitude and be in quadrature (90° separated in phase). Thus, they combine to produce a current that is $\sqrt{2}$ larger than each of them. This is the current that would be flowing through the VT fuses for a secondary ground fault and as such it results in an additional shifting factor of $\sqrt{2}$ when aligning the fuse curves with the 59G characteristic.

In the range of normal ground fault current resulting from a high-resistance grounding method (10 to 25 A typical) the fuses operate relatively fast (faster than 6 cycles at 60 Hz). Note that the presence of current limiting resistors in series with the VT primary fuses (used when the available multiphase fault current exceeds the capability of the current limiting fuses) have a negligible effect on the phase-ground fault current as they are swamped by the other circuit parameters (e.g. 65 Ω is used for current limiting resistance in one installation and as such is negligible compared to $3R_N$ and X_{C0}).

It is recommended to break the zero-sequence path of the wye-grounded primary and wye-grounded secondary by simply removing the ground connection on the secondary wye point and placing it on one of the phase conductors (typically b-phase). This breaks the zero-sequence path through the VTs while maintaining a ground reference for safety as shown in Figure 8-8. By removing the ground on the neutral and by not running a neutral conductor out with the phase conductors the chances of a phase-neutral fault occurring and risking a unit trip are eliminated. Placing the safety ground on a phase conductor (e.g. b-phase) is an acceptable and preferable approach if the protection and control devices fed from the secondary of the VTs do not require

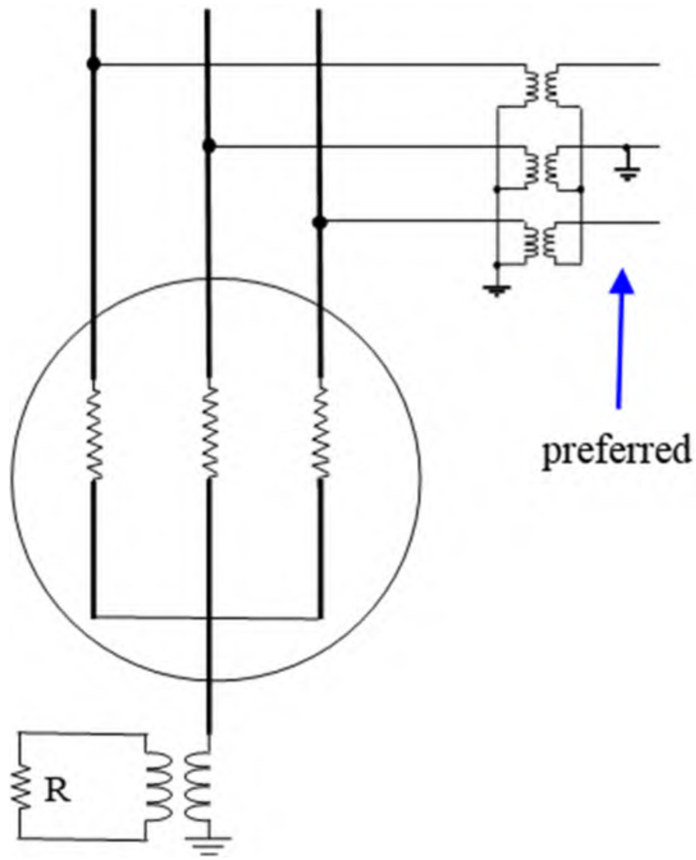


Figure 8-8 Wye-Grounded Generator VTs with B-Phase on Secondary Grounded.

zero-sequence quantities for operation (such as a 3rd harmonic voltage differential). Note that it is still possible to ground a phase conductor and run a conductor from the secondary neutral point to relays that require zero-sequence quantities allowing them to properly operate (such as 3rd harmonic voltage differential). Doing so simply reduces some of the benefit of b-phase grounding due to the neutral conductor being exposed with the phase conductors along the run and available to allow a secondary phase-neutral fault which will appear as a phase-ground fault to the 59G protection.

It should be mentioned that it is commonplace to use open-delta generator VTs to provide the phase-phase voltages required by protection and control devices. This approach requires only 2 VTs and is an open-circuit in the zero-sequence.

In configurations with VTs being wye-grounded on both primary and secondary there will be only minute negative sequence generator current during the secondary phase-ground faults. As such, coordination with the VT fuses must be ensured. This has been shown to be a minor point only requiring minimal delay for the 59G since the secondary NON-30A fuse is relatively fast. It is also acceptable to ignore coordination with the primary EJO-1 fuse. The small additional delay to coordinate with the NON-30 is an acceptable delay as it is also required if it is desired to prevent operation of the 59G for stator turn-turn faults that produce brief neutral shifts detected by this relay.

Figure 8-9 shows tripping logic to implement this negative-sequence torque-control. It allows accelerated tripping unless a system ground fault is detected (50Q). It also has an unsupervised trip path with a long delay to ensure operation. The low set 59N is typically set on 5-10% of the generator phase-neutral voltage. The high set is typically set on 50% or higher such that it is above the level that can be impressed upon the neutral for an HV side ground fault. The negative sequence current supervisor, 50Q, is typically set around 5 to 10% of generator full load current.

Additionally, to accommodate arcing ground faults [4] in this logic a dropout timer may be added in the 59N low set tripping path as shown in Figure 8-10.

Summary

This chapter outlines a simple method to allow accelerated tripping of the 59G for stator ground faults in the absence of negative sequence current as would be present in the generator during HV system phase-ground faults. This method is simple and secure and easily implemented in most modern digital protection relays. One approach used by the author is to simply use the pickup of the negative sequence unbalance protection (46Q) as the torque control used to prevent accelerated tripping of the 59G. The 46Q is typically set in the range of 5-10% of the generators full load current providing good sensitivity when used in this additional role. Fast tripping (e.g. 5 to 15 cycles) can be achieved securely with the negative sequence torque control suggested in this chapter.

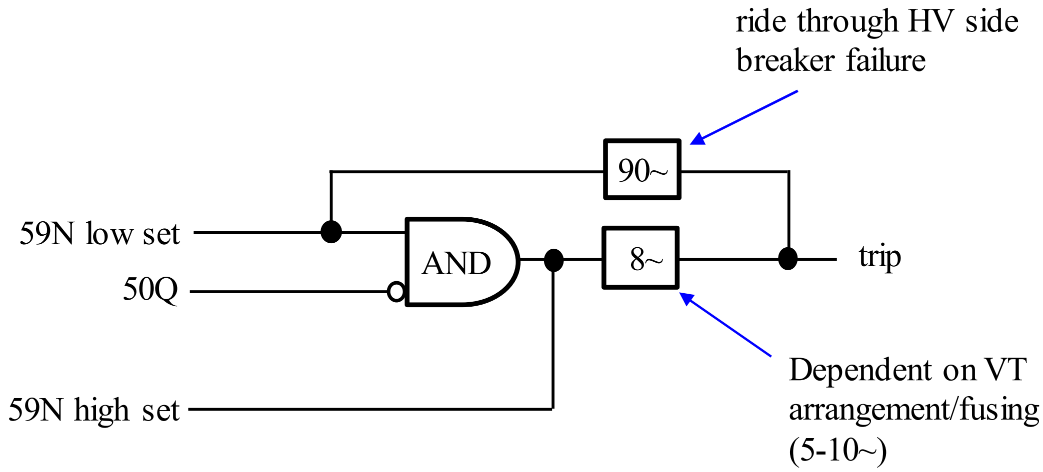
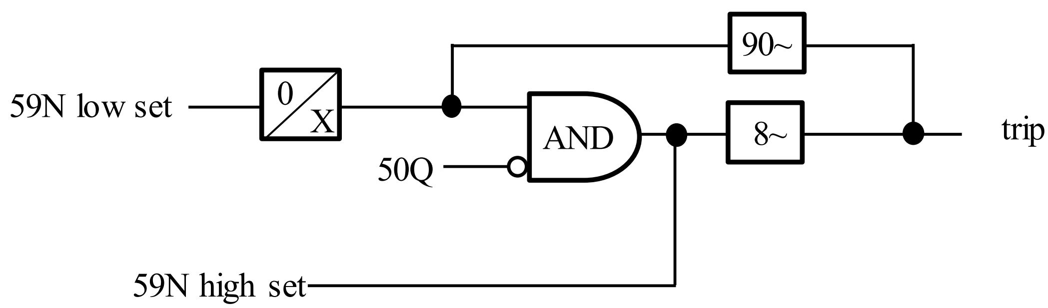


Figure 8-9 Stator 59N ground fault protection with I2 acceleration.



Letting X = 5 cycles will ride through 5 cycle nulls between arc strikes

Figure 8-10 Addition of a timer to accommodate arcing ground faults.

This new method is being incorporated into the latest revision of [1], the IEEE standard "C37.101 – IEEE Guide for Generator Ground Protection".

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CHAPTER 9

SUPPLEMENTAL INADVERTENT ENERGIZATION PROTECTION

Abstract

This chapter describes generator inadvertent energization protection and then explains the author's supplemental protection to cover a gap in the existing practice. The supplemental protection detects an inadvertent energization that may occur just prior to a generator being tied to the grid or just after it is disconnected. This new method is being incorporated into the latest revision of the IEEE standard C37.102 – "IEEE Guide for AC Generator Protection".

Introduction

An inadvertent energization occurs to a generator when the machine is accidentally energized while disconnected from the system. For large steam machines this may occur while the machine is on turning gear (when offline the rotor is slowly turned to avoid deformation due to its immense weight).

Inadvertent energization may occur when the generator is at stand still, just prior to synchronization to the grid, or just after disconnection from the grid. When a machine is energized while its rotor is not spinning, it will accelerate as an induction motor. High currents will be induced in the rotor and may result in significant damage in a matter of seconds. If the machine is inadvertently energized from an auxiliary transformer the resulting current may be much lower (e.g. 10 to 20 % of rated) than when energized from the grid.

Note that inadvertent energization protection must trip (possibly via breaker failure logic) upstream breakers under the assumption that the generator breaker is not reliable if it has flashed over or otherwise failed.

Some Conventional Inadvertent Energization Detection Methods

Directional Overcurrent

With this approach three inverse directional time-overcurrent elements are set directional into the machine from the machine terminals. This approach requires the generator bus VTs be in service, which may not always be the case for an offline generator.

Frequency Supervised Instantaneous Overcurrent

This approach uses an instantaneous overcurrent element typically set on 50% of the current present for an inadvertent energization. This overcurrent is supervised with frequency below a certain setpoint (e.g. 48 to 55 Hz for a 60 Hz generator). This requires coordination between the pickup and dropout of the frequency element and the overcurrent. It also requires an underfrequency element that closes its contacts when its ac voltage is removed such as would occur when the generator bus VTs are deenergized along with the machine.

Distance Relay

Some schemes use a distance relay on the HV side of the generator step-up transformer (GSU) looking into the GSU reactance and the negative sequence reactance of the machine. This approach needs supplemental protection for single-phase inadvertent energization since it relies on phase distance elements. As such it may also operate on stable power swings so it may require tripping delay (e.g. 0.1 to 0.25 s).

Voltage Supervised Overcurrent

Another common approach uses over (59) and under (27) voltage relays with pickup and dropout delays to supervise instantaneous overcurrent tripping. The 27 element enables the protection when the machine is taken offline, and the 59 element disables the protection when the machine is put back online. Figure 9-1 shows the protection logic for this method [1]. This scheme uses phase-phase voltages for the 27 element and may require all 3 phase-phase voltages be below the 27 elements pickup to assert.

This method is susceptible to misoperation when applied to cross-compound machines if one machine has its field applied sooner than the other.

Auxiliary Contact-Enabled Overcurrent

This approach uses auxiliary contacts from the field breaker to enable instantaneous overcurrent elements when the field breaker is open or “racked out”. The instantaneous overcurrent elements are typically set to 50% of the minimum expected inadvertent energization current. This method requires coordination delays to prevent race conditions and misoperations.

GSU Neutral Current

This method measures the current in the neutral of the wye-connected HV winding of the GSU and uses a breaker a-finger to supervise operation. The logic to operate is simply the overcurrent condition while the a-finger is de-asserted (indicating the breaker is open). After a short security time delay (e.g. 5 cycles) a trip is initiated.

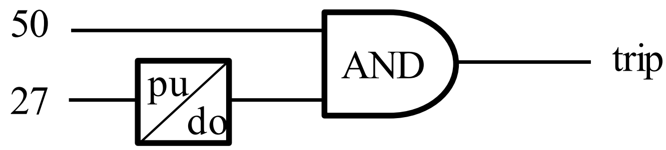

Figure 9-1 Voltage supervised overcurrent scheme.

Supplemental Inadvertent Energization Logic

A "supplemental" scheme has been developed by this author to cover the gap where the traditional 50/27 is inactive while the generator voltage is above the undervoltage (27) element threshold. This supplemental scheme is intended to operate when the generator breaker is open, and both sides of the breaker are near rated voltage. This condition occurs just after the generator is disconnected from the system or just prior to its being synchronized to the system.

When the two voltages are 180° out-of-phase the voltage stress across the generator breaker is 2 pu. The overcurrent element only needs to be set higher than the current expected for a normal synchronization to the system. The logic is shown in Figure 9-2 where 52a is an a-finger from the generator breaker, 50P is the phase overcurrent element, and the pickup/dropout delays are ¼ second (15 cycles at 60 Hz). Note that an a-finger is an auxiliary contact whose binary status follows the position of the breaker (breaker closed = 1, breaker open = 0). Conversely, a breaker b-finger has the opposite property (breaker closed = 0, breaker open = 1) and may be used instead, if logically inverted. It is also possible to use both an a-finger and b-finger together to increase scheme security.

The phase overcurrent pickup, 50P, can be set above the expected synchronizing current, I_{sync}, at the limits specified in [2] as given in Table 9-1 in a simple calculation using the transient reactance of the generator and the Thévenin impedance of the system.

Figure 9-2 Supplemental Inadvertent Energization Protection.

Table 9-1 Synchronizing limits per IEEE Std C50.13-2014

Breaker closing angle	± 10°
Generator side voltage difference relative to system	0% to +5%
Frequency difference	± 0.067 Hz

$$I_{sync} = \frac{1 - 0.05\angle 10° \text{ pu V}}{X'_d + X_1}$$

This provides a lower limit of current that would flow for an acceptable synchronizing event. A synchronization outside the limits shown in Table 9-1 is considered a "faulty synchronization" as per [2] which may result in damage to the machine.

An example is now given to show these calculations for an actual 217 MVA synchronous machine. The values have been converted to 100 MVA and the system voltage is 161 kV nominal with generator bus being 19 kV.

X'_d = j0.1 pu generator sub-transient reactance

X_1 = j0.02 pu system positive sequence impedance (includes GSU)

$$I_{sync} = \left|\frac{1 - 1.05\angle 10°}{j0.12}\right| = 1.55 \text{ pu A}$$

This per unit current multiplied by the generator current base, $I_{BASE} = \frac{100 \times 1{,}000}{19\sqrt{3}} = 3{,}039\text{A}$ results in a generator current of 4,710 A for a synchronization at the voltage and angle limits prescribed in [2]. Full load current for this machine being 6,595 A. It is possible to set the 50P below the machine full load current as this element only becomes active 15 cycles after the generator breaker opens, remaining active until after the generator breaker has been closed for 15 cycles (see Figure 9-2).

An upper limit can be found from assuming an inadvertent three-phase energization when the generator and system are 180° out of phase and at nominal voltage.

$$I_{INAD} = \left|\frac{2.0}{j0.12}\right| = 16.67 \text{ pu A}$$

This is just over 50 kA of generator phase current for this event. Now, assuming the two systems are still at 1 pu voltage but only 60° out-of-phase we find the following.

$$I_{INAD} = \left|\frac{1 - 1\angle 60°}{j0.12}\right| = 8.33 \text{ pu A}$$

This is just over 25 kA of generator phase current. As such, a 50P setting of 150% of generator full load current has been used in practice. For this example, that would be a 50P pickup of approximately 10 kA.

An actual bad synchronization event is shown in Figure 9-3 that resulted in a trip of this supplemental inadvertent energization protection. The wrong synchronizing voltage was wired to the relay and resulted in closing the generator breaker when the machine was approximately 60° out-of-phase. In this event, the A and B-phase neutral side generator CTs saturated, resulting in a phase differential trip. The system side generator differential A-phase current is labeled “IA” and the neutral side generator differential A-phase current is labeled “Ia_neut” in Figure 9-3. The third trace in the figure is the differential between these two currents. The digital signal “IN9” is the generator breaker a-finger and “OUT10” is the trip output on the relay asserting.

The supplemental inadvertent energization logic also operated for this event and would have been the only protection to operate had the generator differential CTs not saturated.

For the case of a single-phase inadvertent energization (e.g. breaker head flashover) with the generator breaker on the low-voltage, delta side of the delta-wye GSU, no current will flow. However, for the case where the generator breaker is on the high-voltage side of the GSU this single-phase energization would result in inadvertent energization. As per [3] the positive and negative sequence current on the high-side of the GSU for this event, assuming the generator and system are 180° out-of-phase and at nominal voltage would be calculated as follows, where,

X_{G1} = j0.1 pu generator sub-transient reactance

X_{G2}= j0.0475 pu generator negative sequence reactance

X_{T1} = j0.057 pu GSU positive and negative sequence reactance

X_{T0} = j0.176 GSU zero sequence reactance (includes a j10.3Ω neutral reactance)

X_{S1} = j0.02 pu system positive sequence Thévenin impedance

X_{S2} = j0.02 pu system negative sequence Thévenin impedance

X_{S0} = j0.02 pu system zero sequence Thévenin impedance

$$I_{INAD_{sequence}} = \left| \frac{E_S\angle 0° - E_G\angle 180°}{X_{G1} + X_{T1} + X_{S2} + X_{G2} + X_{T1} + X_{S0} + X_{T0} + X_{S1}} \right| \approx 4 \text{ pu A}$$

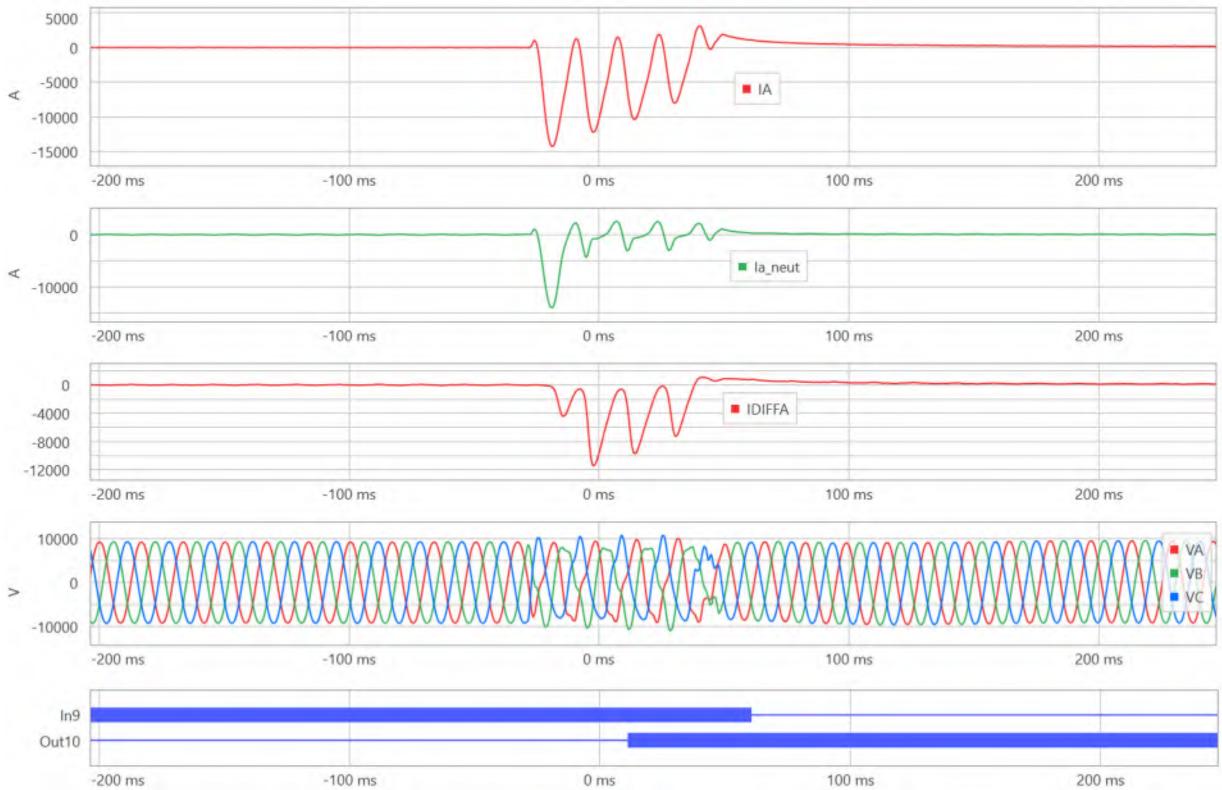

Figure 9-3 Bad generator synchronization event

So, the generator $I_1 = 4\angle\text{-}30°$ and $I_2 = 4\angle 30°$ with the ±30° phase shifts due to the delta-wye GSU. This results in a generator phase current in two phases of 6.9 pu or just under 21 kA. If the single-phase flashover occurred when the generator and the system where 60° out-of-phase this drops to just over 10 kA. In this case, a 50P pickup lower than 10 kA would be required. However, an alternative approach would be to use the neutral current [4] from the wye GSU winding with additional logic to complement this supplemental inadvertent energization logic.

For black start units that energize their GSU from the low-voltage side by closing the generator breaker, this supplemental scheme may misoperate due to GSU energization inrush. To accommodate this configuration, an overvoltage element can be added on the GSU (system) side of the generator breaker. This overvoltage element is then used as an additional supervision along with the generator breaker status. This addition input (HV 59) to the supplemental inadvertent energization logic is shown in Figure 9-4.

Summary

The supplemental inadvertent energization logic described in this chapter covers a gap in the existing approaches when the generator is inadvertently energized while the generator breaker is open. When the two systems (the generator and the grid) on either side of the open breaker are out of phase with one another a voltage is developed across the open breaker, reaching 2 per unit when the two systems are 180° out-of-phase.

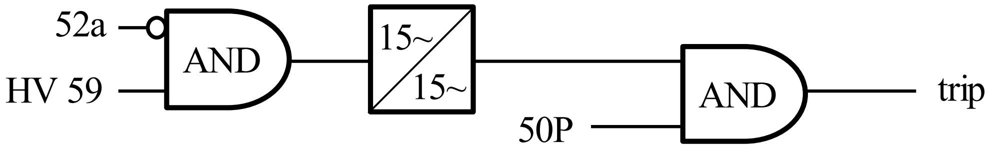

Figure 9-4 Addition of HV side voltage supervision for black start units.

This chapter provided reasoning behind the new methodology as well as a calculation approach to support its application.

This method is being incorporated into the latest revision of [1], the IEEE standard "C37.102 – IEEE Guide for AC Generator Protection".

References

1. "IEEE Guide for AC Generator Protection," IEEE Std C37.102-2006, pp. 1-177, 2006, doi: 10.1109/IEEESTD.2006.320495.
2. "IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above," IEEE Std C50.13-2014 (Revision of IEEE Std C50.13-2005) , vol., no., pp.1-63, 9 May 2014, doi: 10.1109/IEEESTD.2014.6811137.
3. C. J. Mozina et al., "Inadvertant energizing protection of synchronous generators," *in IEEE Transactions on Power Delivery*, vol. 4, no. 2, pp. 965-977, April 1989, doi: 10.1109/61.25577.
4. Schweitzer Engineering Laboratories, "SEL-300G Multifunction Generator Relay Instruction Manual," [Online]. Available: https://selinc.com/products/300G/docs/.
5. P. M. Anderson, "Analysis of Faulted Power Systems," 1st ed. Piscataway, NJ: IEEE Press, 1995. [ISBN: 0780311450]

Appendix

Derivation of Fault Current Equations

Inadvertent energization for the three-phase event is a trivial calculation. One and two-phase inadvertent energization require 2-port theory in the sequence networks. Figure 9-A-1 shows the two locations of generator breakers that will be considered. The generator breaker(s) can be on the high-side (system side) of the GSU or on the low-side (generator side).

Low-side Breaker Inadvertent Energization

Figure 9-A-2 shows the sequence networks for the series unbalance at the low-side generator breaker with the two ports, F_1 and F_1', shown. Using impedance parameters, we find the 2-port equivalent sequence networks are as shown in Figure 9-A-3. Note that when the two ports are uncoupled, each port's driving point impedance can be found to bet the one-port Thévenin impedance at that port with the series connection between the two ports open.

To determine how these equivalents are to be connected we analyze the series unbalance network of Figure 9-A-4 where A-phase impedance is Z_A and the B-phase and C-phase impedances are equal and represented by Z_B. The voltage drop across these impedances are as follows.

$$V_{aa'} = V_a - V_{a'} = Z_A I_a$$

$$V_{bb'} = V_b - V_{b'} = Z_B I_b$$

$$V_{cc'} = V_c - V_{c'} = Z_B I_c$$

Written in matrix format the voltage drop is as below.

$$V_{abc} - V_{a'b'c'} = Z_{ABC} I_{abc}$$

Applying the similarity transformer, $Z_{012} = A^{-1} Z_{ABC} A$, we can convert this to the sequence domain.

$$V_{aa'_{012}} = Z_{012} I_{012}$$

Where we find the following for Z_{012}.

$$Z_{012} = \frac{1}{3}\begin{pmatrix} 1 & 1 & 1 \\ 1 & \alpha & \alpha^2 \\ 1 & \alpha^2 & \alpha \end{pmatrix}\begin{pmatrix} Z_A & 0 & 0 \\ 0 & Z_B & 0 \\ 0 & 0 & Z_B \end{pmatrix}\begin{pmatrix} 1 & 1 & 1 \\ 1 & \alpha^2 & \alpha \\ 1 & \alpha & \alpha^2 \end{pmatrix}$$

$$Z_{012} = \frac{1}{3}\begin{pmatrix} Z_A + 2Z_B & 0 & 0 \\ 0 & Z_A + 2Z_B & 0 \\ 0 & 0 & Z_A + 2Z_B \end{pmatrix}$$

Now, we can expand the voltage drop equation into the positive, negative, and zero-sequence equations.

$$V_{aa'_0} = \frac{1}{3}[(Z_A + 2Z_B)I_0 + (Z_A - Z_B)I_1 + (Z_A - Z_B)I_2]$$

$$V_{aa'_1} = \frac{1}{3}[(Z_A - Z_B)I_0 + (Z_A + 2Z_B)I_1 + (Z_A - Z_B)I_2]$$

$$V_{aa'_2} = \frac{1}{3}[(Z_A - Z_B)I_0 + (Z_A - Z_B)I_1 + (Z_A + 2Z_B)I_2]$$

Subtracting the second equation from the first we find an equation relating the zero sequence to the positive sequence.

$$V_{aa'_0} - Z_B I_0 = V_{aa'_1} - Z_B I_1$$

Subtracting the third equation from the second we find an equation relating the positive sequence to the negative sequence.

$$V_{aa'_1} - Z_B I_1 = V_{aa'_2} - Z_B I_2$$

From these results we can see that the positive, negative, and zero-sequence networks have common parallel connections.

$$V_{aa'_0} - Z_B I_0 = V_{aa'_1} - Z_B I_1 = V_{aa'_2} - Z_B I_2$$

Now, taking the first equation plus the second equation and substituting $V_{aa'_0} = V_{aa'_1} - Z_B I_1 + Z_B I_0$ we find the following.

$$V_{aa'_1} - Z_B I_1 + Z_B I_0 + V_{aa'_1} = \frac{1}{3}(2Z_A + Z_B)(I_0 + I_1) + \frac{1}{3}(2Z_A - 2Z_B)I_2$$

The above can be algebraically reduced to the following which completes the connection information needed, the three sequence 2-port equivalents are thus connected as shown in Figure 9-A-5.

$$V_{aa'_1} - Z_B I_1 = \frac{1}{3}(Z_A - Z_B)(I_0 + I_1 + I_2)$$

We can simplify this result since the zero-sequence port F' impedance is infinite due to the delta winding, and we will let $Z_A = \infty$ and $Z_B = 0$ for the two-phase inadvertent energization case. The final model for this case is shown in Figure 9-A-6. We can now find the resulting positive and negative sequence currents that flow when the low-side generator breaker has two phases inadvertently energized.

$$I_1 = -I_2 = \frac{V_G - V_S}{X_{G1} + X_{T1} + X_{S1} + X_{T2} + X_{S2} + X_{G2}}$$

Notice that a one-phase inadvertent energization with the low-side breaker would not result in current flow due to the delta winding producing the open in the zero-sequence equivalent.

High-side Breaker Inadvertent Energization

Figure 9-A-7 shows the sequence networks for the series unbalance at the high-side generator breaker with the two ports, $\mathrm{F_1}$ and $\mathrm{F_1'}$, shown. Using impedance parameters, we find the 2-port equivalent sequence networks are as shown in Figure 9-A-8. To determine how the equivalents are to be connected we analyze the series unbalance network of Figure 9-A-9 where A-phase impedance is $\mathrm{Z_A}$ and the B-phase and C-phase impedances are infinite. We find the following equations in the phase domain describing this network.

$$\mathrm{V_{aa'} = V_a - V_{a'} = Z_A I_a}$$

$$\mathrm{I_b = I_c = 0}$$

These can be transformed to the sequence domain where we find the following results which suggest the sequence networks are connected in series with an impedance $3Z_A$ closing the loop as shown in Figure 9-A-10.

$$\mathrm{V_{aa_0'} + V_{aa_1'} + V_{aa_2'} = Z_A(I_0 + I_1 + I_2)}$$

$$\mathrm{I_{012} = I_a} \begin{pmatrix} 1 \\ 1 \\ 1 \end{pmatrix}$$

The resulting sequence currents can thus be found from the following.

$$\mathrm{I_0 = I_1 = I_2 = \frac{V_G - V_S}{j(X_{G1} + X_{T1} + X_{S1} + X_{G2} + X_{T2} + X_{S2} + X_{T0} + X_N + X_{S0})}}$$

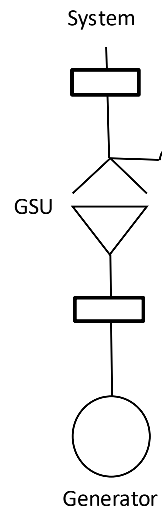

Figure 9-A-1 Typical Generator Configuration

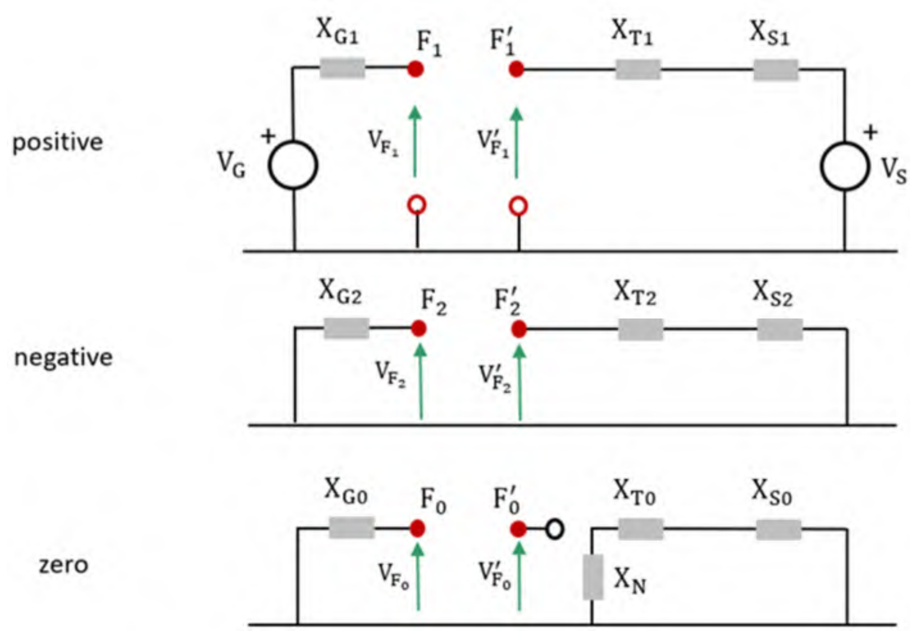

Figure 9-A-2 Sequence Networks with ports for low-side breaker

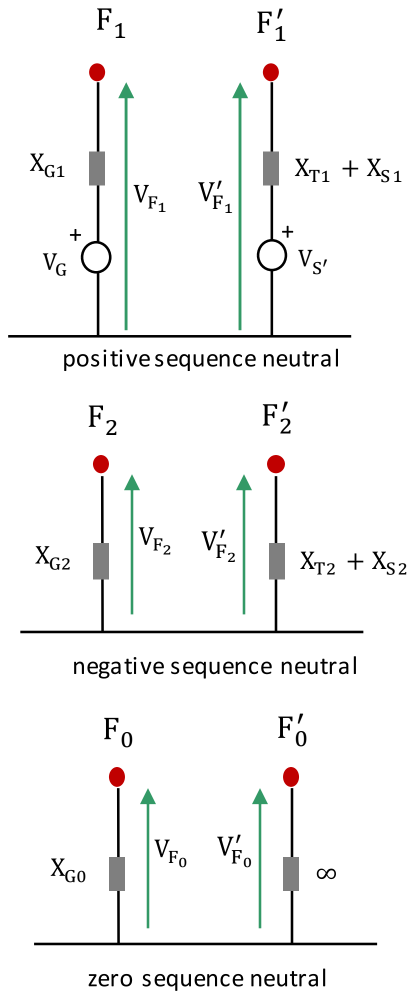

Figure 9-A-3 Two-port sequence equivalents for low-side breaker

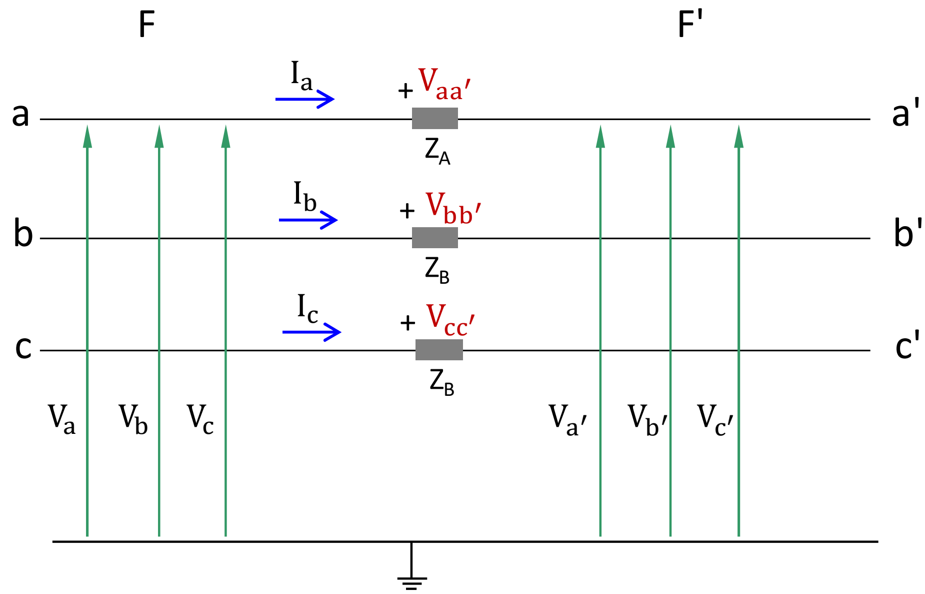

Figure 9-A-4 Series imbalance for analysis between point F and F' on low-side

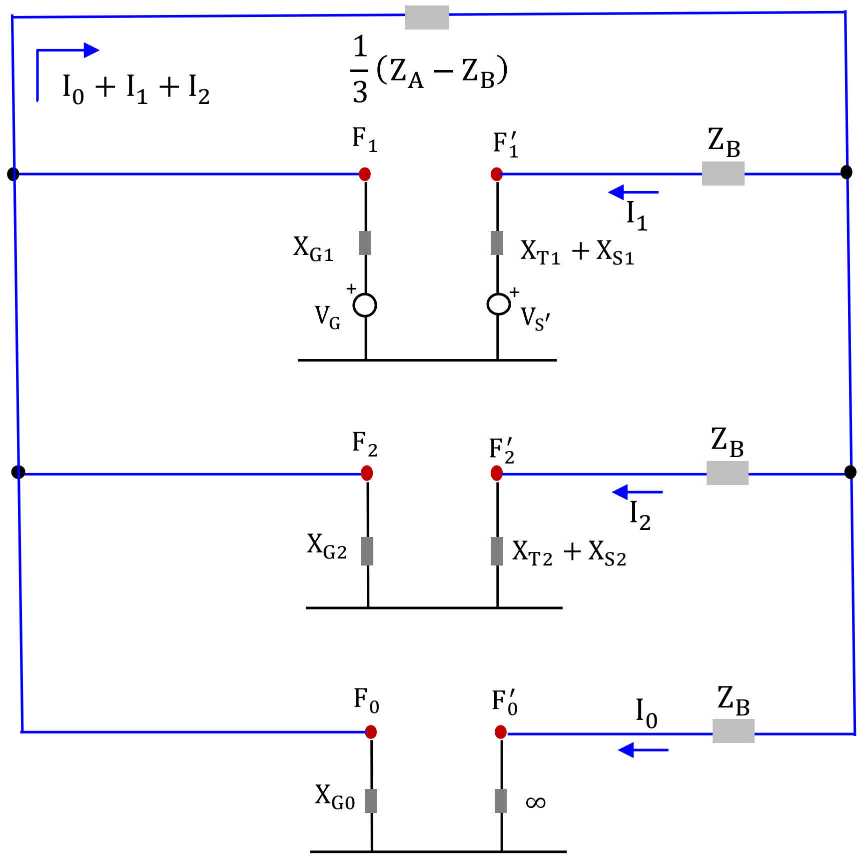

Figure 9-A-5 Port connections for analysis between point F and F' on low-side

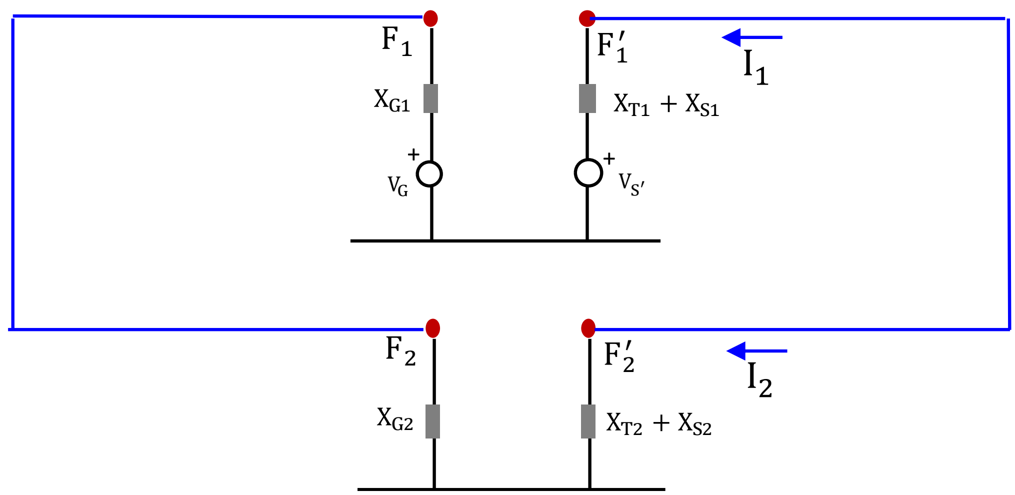

Figure 9-A-6 Simplified port connections for low-side imbalance

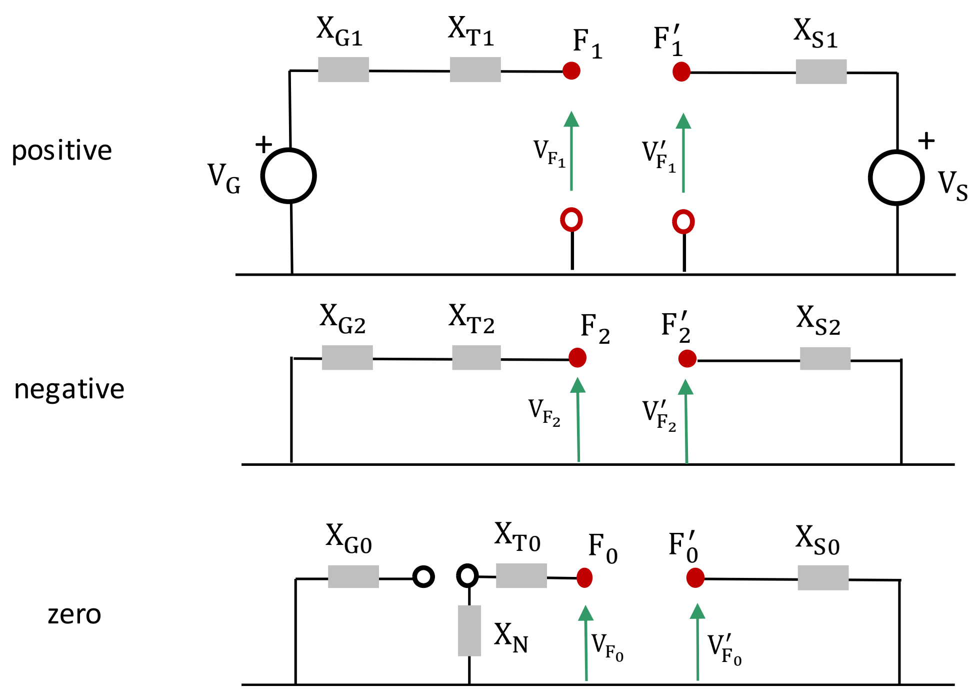

Figure 9-A-7 Sequence networks with ports for high-side breaker

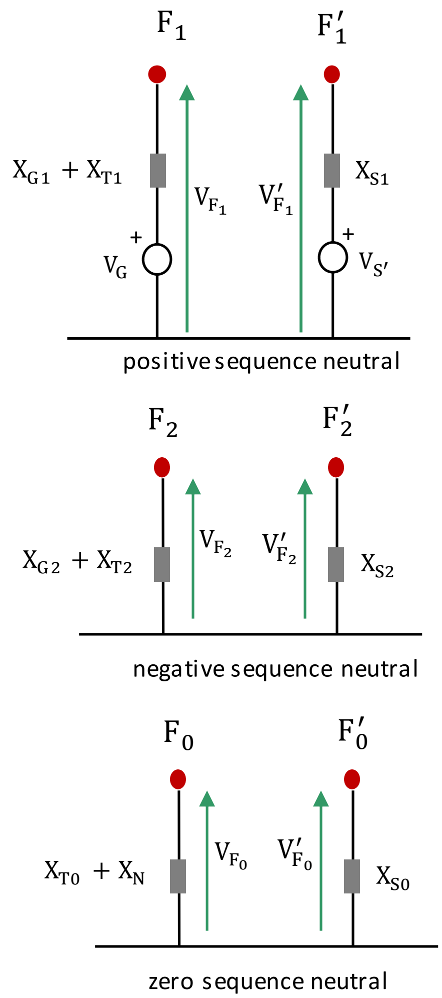

Figure 9-A-8 Two-port sequence equivalents for low-side breaker

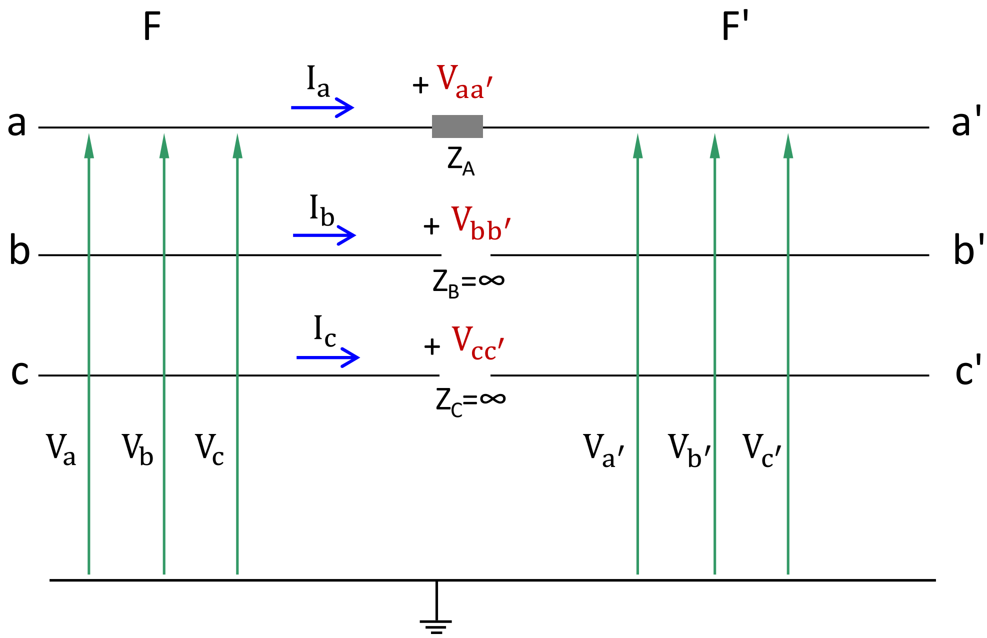

Figure 9-A-9 Series imbalance for analysis between F and F' on high-side

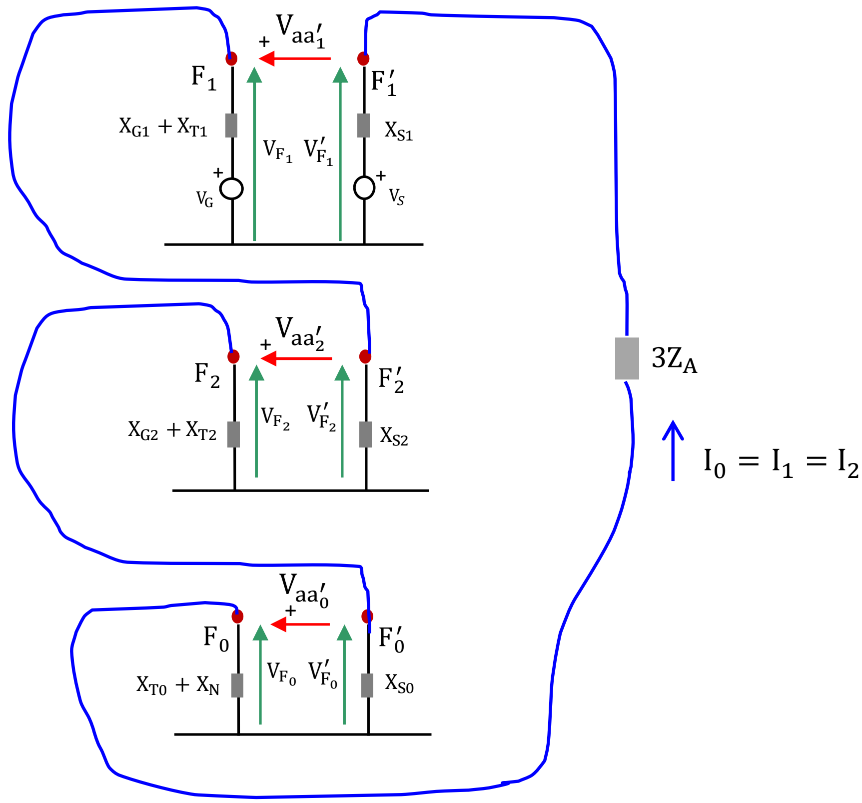

Figure 9-A-10 Series imbalance for analysis between point F and F' on high-side

VITA

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Russell began his career as a field test engineer for TVA in 1991 and has over 30 years' experience in utility protection for generation, transmission, and distribution. He managed the system protection department for TVA until his retirement in 2008 to enter full time consulting. Russell served rotations as TVA's Manager of Power Quality and Manager of Advanced Power Applications.

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Russell is the chair of the IEEE Joint Technical Committee Meeting (JTCM) and is a member of the IEEE Power System Relaying and Control Committee (PSRC) where he is past chairman of the committee, past chairman of the Line Protection subcommittee and a member of the Rotating Machinery subcommittee. He is a senior member of IEEE, a member of IET (MIET), a member of CIGRÉ, and a registered professional engineer in multiple states. He is also an adjunct lecturer at the University of Tennessee at Chattanooga in the electrical engineering department where he teaches graduate classes and short courses on power system protection.

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