

Considerations for Using Harmonic Blocking and Harmonic Restraint Techniques on Transformer Differential Relays

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Published in
SEL *Journal of Reliable Power*, Volume 2, Number 3, September 2011

Previously presented at the
43rd Annual Minnesota Power Systems Conference, November 2007

Originally presented at the
33rd Annual Western Protective Relay Conference, October 2006

Considerations for Using Harmonic Blocking and Harmonic Restraint Techniques on Transformer Differential Relays

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Abstract—The terms “harmonic restraint” and “harmonic blocking” are sometimes used interchangeably when talking about transformer differential protection. This paper explores the meanings of these terms and how these techniques are individually applied in modern transformer differential relays, including how these techniques affect the speed and security of transformer differential protection. The paper further compares these techniques using examples to show their response to several transformer inrush examples.

Editorial Note—Guzmán, Benmouyal, Zocholl, and Altuve prepared and presented a paper titled “Performance Analysis of Traditional and Improved Transformer Differential Protective Relays” [1] that provides a thorough discussion about percentage restraint current differential relays and the history and background surrounding the use of harmonics in these relays. Portions of that paper covering selected historical and fundamental background issues are used in this paper to reintroduce this subject for the reader’s convenience.

I. INTRODUCTION

Transformer differential relays are prone to undesired operation in the presence of transformer inrush currents. Transformer energization is a typical cause of inrush currents, but any transient in the transformer circuit may generate these currents. Other causes include voltage recovery after the clearance of an external fault or the energization of a transformer in parallel with a transformer that is already in service.

Inrush currents result from transients in transformer magnetic flux before the flux reaches its steady-state value. Early attempts to prevent differential relay operations caused by inrush include the following:

- Introducing an intentional time delay in the differential relay [2] [3].
- Desensitizing the relay for a given time to override the inrush condition [3] [4].
- Adding a voltage signal to restrain [2] or to supervise the differential relay [5].

Ultimately, researchers recognized that the harmonic content of the inrush current provided information that helped differentiate internal faults from inrush conditions. Kennedy and Hayward proposed a differential relay with only harmonic restraint for bus protection [6]. Hayward [7] and Mathews [8] further developed this method by adding percentage differential restraint for transformer protection. These early relays used all the harmonics to restrain. Sharp and Glassburn

introduced the idea of harmonic blocking instead of restraining [9] with a relay that used only the second harmonic to block.

Many modern transformer differential relays employ either harmonic restraint or blocking methods. These methods ensure relay security for a very high percentage of inrush cases. However, these methods do not work in all cases, especially with very low harmonic content in the inrush current on one or two phases. Common harmonic restraint or blocking, introduced by Einval and Linders [10], increased relay security for inrush but could delay operation for internal faults combined with inrush in the nonfaulted phases.

Transformer overexcitation is another possible cause of differential relay undesired operation. Einval and Linders proposed the use of an additional fifth-harmonic restraint to prevent such operations [10]. Others have proposed several methods based on waveshape recognition to distinguish faults from inrush and have applied these methods in transformer relays [11] [12] [13] [14]. However, these techniques generally do not identify transformer overexcitation conditions.

Guzmán, Benmouyal, Zocholl, and Altuve proposed a new approach for transformer differential protection using current-only inputs that combine harmonic restraint and blocking methods with a waveshape recognition technique [1]. This method uses even harmonics for restraint and also blocks operation using the dc component and the fifth harmonic.

II. TRANSFORMER DIFFERENTIAL PROTECTION

Percentage restraint differential protective relays have been in service for many years. Fig. 1 shows a typical differential relay connection diagram. Differential relays sum the currents on each source or outlet associated with the device to determine the difference between the current entering and leaving the device. A substantial difference indicates a fault in the device or between the current transformers (CTs) located around the device. A simple overcurrent relay element could provide basic differential protection, provided the CTs could be sized and connected to perfectly match the secondary current presented to the relay. Complexities associated with transformer differential protection, such as tap changers, power transformer phase shift, and mismatched CT ratios, make it nearly impossible to perfectly balance the CT secondary currents into the relay. For this reason, transformer

differential relays use a percentage restraint characteristic that compares an operating current with a restraining current. The operating current (also called differential current), I_{OP} , can be obtained as the phasor sum of the currents entering the protected element:

$$I_{OP} = \left| \vec{I}_{W1} + \vec{I}_{W2} \right| \quad (1)$$

I_{OP} is proportional to the fault current for internal faults and ideally approaches zero for any other operating conditions, provided the “tap” settings for the relay current inputs are properly selected to match the relative current measured by the relay on each current input for the normal, nonfault condition.

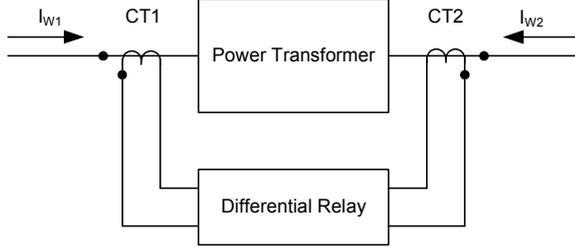


Fig. 1. Typical Differential Relay Connection Diagram

Following are the most common ways to obtain the restraining current:

$$I_{RT} = k \left| \vec{I}_{W1} - \vec{I}_{W2} \right| \quad (2)$$

$$I_{RT} = k \left(\left| \vec{I}_{W1} \right| + \left| \vec{I}_{W2} \right| \right) \quad (3)$$

$$I_{RT} = \text{Max} \left(\left| \vec{I}_{W1} \right|, \left| \vec{I}_{W2} \right| \right) \quad (4)$$

Where: k is a compensation factor usually taken as 1 or 0.5.

More specifically, operate and restraint quantities are generated in a typical two-winding relay as shown in Fig. 2, where $k = 1/2$.

In Fig. 2, I_{WDG1} and I_{WDG2} are CT secondary currents measured by the relay from associated phases on the high and low side of the transformer. The TAP1 and TAP2 relay settings are used to establish a per unit secondary current in the relay, equalized to compensate for the power transformer winding voltage ratio, and associated high- and low-side CT ratios. Transformer/CT Connection Compensation provides the necessary angle and magnitude shift for delta- and wye-connected transformer windings and CTs. The resulting I_{OP} and I_{RT} values are in multiples of TAP setting so they can be referenced to either current winding input.

Three single-phase relays with independent percentage current differential elements can be used to protect a three-phase transformer, or a single three-phase relay can be used. The advantages in using a three-phase relay are 1) wye-connected CTs may be used, and the relay performs the necessary delta current simulation on wye-wye and wye-delta transformers, and 2) the percentage current differential calculations can be performed independently, or they may be

interrelated, which offers some unique advantages. The latter concept will be discussed later in the paper.

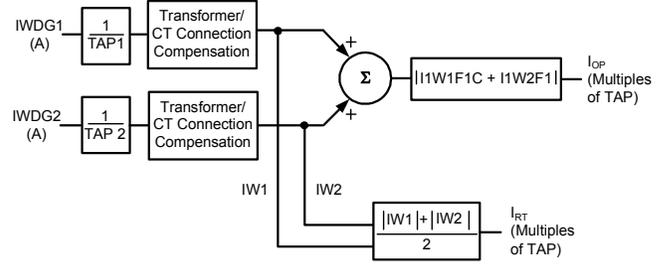


Fig. 2. Percentage Current Differential Operate and Restraint Current Measurements

Equations (3) and (4) offer the advantage of being applicable to differential relays with more than two restraint elements. The differential relay generates a tripping signal if the operating current, I_{OP} , is greater than a percentage, defined by a slope setting, SLP , of the restraining current, I_{RT} , as expressed by the following equation:

$$I_{OP} > SLP \cdot I_{RT} \quad (5)$$

Another way to express this is:

$$I_{OP} / I_{RT} > SLP$$

Fig. 3 shows a typical percentage restraint current differential relay operating characteristic. This characteristic consists of a straight line having a slope equal to SLP and a horizontal straight line defining the relay minimum pickup current, I_{PU} . The slope setting, SLP , is typically defined as a percentage, which is the basis for the term “percentage restraint current differential” relay. The minimum pickup setting, I_{PU} , is typically defined as per unit of operate current.

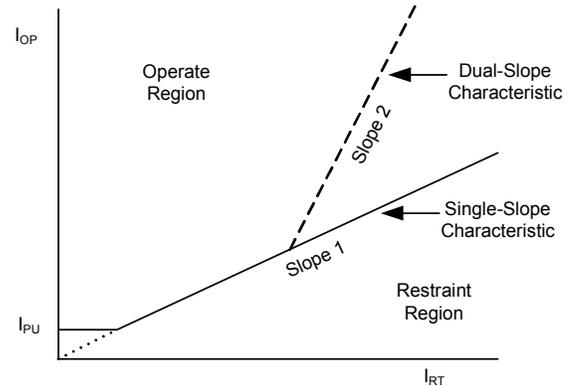


Fig. 3. Differential Relay With Dual-Slope Characteristic

While the slope line typically extends to the origin, where I_{OP} and I_{RT} are both zero, the minimum pickup current, I_{PU} , secures the relay against tripping for normal transformer excitation current, low magnitude transformer inrush, and any CT performance differences at very low load currents. In addition, the slope characteristic of the percentage differential relay provides further security for high current external faults with CT saturation. A variable-percentage or dual-slope characteristic further increases relay security for heavy CT saturation. Fig. 3 shows this characteristic as a dotted line. For single- or dual-slope characteristics, the relay operate (trip)

region is located above and to the left of the slope characteristic, and the restraint region is below and to the right of the slope characteristic.

Fig. 4 shows the logic used to derive the dual-slope characteristic shown in Fig. 3.

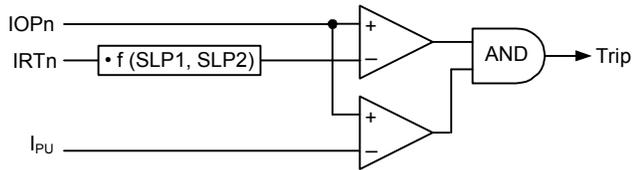


Fig. 4. Simplified Percentage Current Differential Decision Logic

Differential relays perform well for external faults as long as the CTs reproduce the primary currents correctly. When one of the CTs saturates, or if both CTs saturate at different levels, false operating current appears in the differential relay and could cause an undesired relay operation. Some differential relays use the harmonics caused by CT saturation for added restraint and to avoid operations [6]. CT saturation is only one of the causes of false operating current in differential relays. In the case of power transformer applications, other possible sources of error are as follows:

- Mismatch between the CT and power transformer ratios are not properly compensated by the relay TAP settings.
- Variable ratio of the power transformer caused by a tap changer.
- Phase shift between the power transformer primary and secondary currents for delta-wye connections.
- Magnetizing inrush currents created by transformer transients because of energization, voltage recovery after the clearance of an external fault, or energization of a parallel transformer.
- High exciting currents caused by transformer overexcitation.

The relay percentage restraint characteristic typically solves the first two problems. Proper connection of the CTs or emulation of such a connection in a digital relay (auxiliary CTs historically provided this function) addresses the phase-shift problem. A very complex problem is that of discriminating internal fault currents from the false differential currents caused by magnetizing inrush and transformer overexcitation. The vast majority of percentage restraint current differential relays employ some form of harmonic detection to discern this difference.

III. HARMONIC SOURCES: MAGNETIZING INRUSH, OVEREXCITATION, AND CT SATURATION

Inrush or overexcitation conditions of a power transformer produce false differential currents that could cause undesired relay operation. Both conditions produce distorted currents because they are related to transformer core saturation. The

distorted waveforms provide information that helps to discriminate inrush and overexcitation conditions from internal faults. However, this discrimination can be complicated by other sources of distortion, such as CT saturation, nonlinear fault resistance, or system resonant conditions.

A. Inrush Currents

The study of transformer magnetization inrush phenomena has spanned many years. Magnetizing inrush occurs in a transformer whenever the polarity and magnitude of the residual flux do not agree with the polarity and magnitude of the ideal instantaneous value of steady-state flux. Transformer energization is a typical cause of inrush currents, but any transient in the transformer circuit may generate these currents. Other causes include voltage recovery after the clearance of an external fault or the energization of a transformer in parallel with a transformer that is already in service. The magnitudes and waveforms of inrush currents depend on a multitude of factors and are almost impossible to predict [16]. The following summarizes the main characteristics of inrush currents:

- Generally contain dc offset, odd harmonics, and even harmonics [15] [16].
- Typically composed of unipolar or bipolar pulses separated by intervals of very low current values [15] [16].
- Peak values of unipolar inrush current pulses decrease very slowly. Their time constant is typically much greater than that of the exponentially decaying dc offset of fault currents.
- Second-harmonic content starts with a low value and increases as the inrush current decreases.
- Delta currents (a delta winding is encountered in either the power transformer or CT connections or is simulated in the relay) modify the inrush because currents of adjacent windings are subtracted, and:
 - DC components are subtracted.
 - Fundamental components are added at 60 degrees.
 - Second harmonics are added at 120 degrees.
 - Third harmonics are added at 180 degrees (they cancel out), and so forth.

Sonnemann, Wagner, and Rockefeller initially claimed that the second-harmonic content of the inrush current was never less than 16 percent to 17 percent of the fundamental [15]. However, transformer energization with reduced voltages and variations in point-on-wave initiation may generate inrush currents with second-harmonic content considerably less than 10 percent, as exhibited later in this paper.

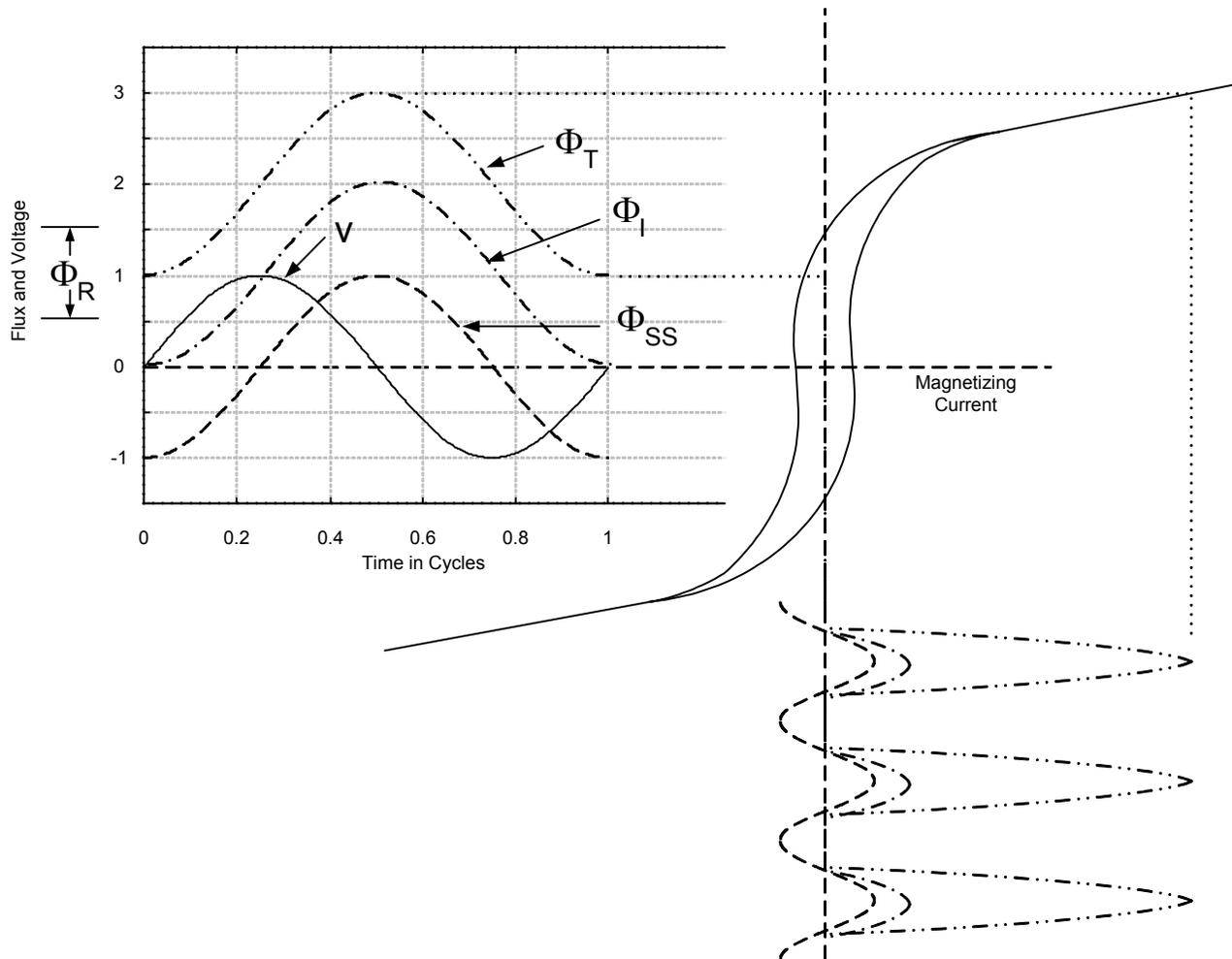


Fig. 5. Voltage, Flux, and Current During Transformer Energization

Fig. 5 shows the voltage, flux, and current during a magnetizing inrush where the transformer is energized at zero on the voltage wave. V is the voltage waveform, Φ_{SS} is the steady-state flux, Φ_I is the initial flux at voltage energization, Φ_R is the residual flux, and Φ_T is the total flux ($\Phi_I + \Phi_R$) at voltage energization. The associated magnetizing (exciting) characteristic shows the nonlinear relationship between the magnetizing current and the flux in an iron-core transformer. The magnetizing current increases significantly when the total flux exceeds the saturation density point.

When switching at a voltage zero, the full flux change is required during the first half cycle, but with the flux initially zero, the maximum flux developed will be nearly twice the normal peak value (Φ_I). In a linear inductor, such as an air-core inductor, twice the normal peak flux will produce twice the normal steady-state value current. However, in nonlinear iron-core transformers where the normal peak flux is close to the saturation point, an increase in flux to twice the steady-state value causes the magnetizing (inrush) current to rise to a very high value, possibly even exceeding the rated full load current value.

When the transformer core, prior to energization, contains a relatively high residual flux (Φ_R), the inrush current can increase still further. Residual (remanent) flux can be quite

high following an external fault or after transformer testing procedures, such as dc continuity tests performed on the transformer windings. If the initial residual flux has the same relative value as the first half cycle of energizing voltage waveform, the peak inrush current on that phase can be several times the full load current.

Switching at other points on the voltage wave produces other, less severe values of inrush current. If the point-on-wave happens to coincide with the residual flux that is correct for that instant under steady-state conditions, then no transient will occur. This nontransient condition is very rare, especially with three-phase transformers.

Three-phase transformers generally produce a mix of transient inrush conditions because the point-on-wave differs for each phase that is energized. Also, interphase coupling occurs because of the common core design in most three-phase transformers. This interphase coupling produces distortion in the current on a phase with point-on-wave energization that, by itself, would produce no offset. Fig. 6 shows a fairly typical transient inrush waveform for the energization of a three-phase transformer. As seen, IB and IC are fully offset in opposite directions, and IA is more symmetrical, but definitely nonsinusoidal.

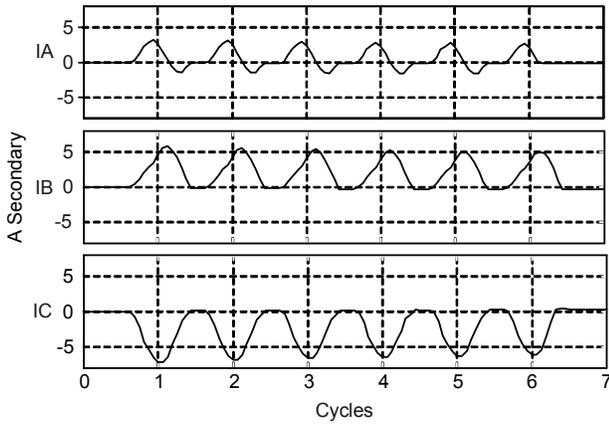


Fig. 6. Typical Three-Phase Transformer Magnetizing Inrush Current

B. Transformer Overexcitation

The magnetic flux inside the transformer core is directly proportional to the applied voltage and inversely proportional to the system frequency. Overvoltage and/or underfrequency conditions can produce flux levels that saturate the transformer core. These abnormal operating conditions can exist in any part of the power system, so any transformer may be exposed to overexcitation.

Transformer overexcitation causes transformer heating and increases exciting current, noise, and vibration. A severely overexcited transformer should be disconnected to avoid transformer damage. Because it is difficult, with differential protection, to control the amount of overexcitation that a transformer can tolerate, transformer differential protection tripping for an overexcitation condition is not desirable. Separate transformer overexcitation protection should be used instead, and the differential element should not trip for this condition. One alternative is a V/Hz relay that responds to the voltage/frequency ratio.

Overexcitation of a power transformer is a typical case of ac saturation of the core that produces odd harmonics in the exciting current. Fig. 7 shows the exciting current recorded during a real test of a small, unloaded, single-phase laboratory transformer. The current corresponds to an overvoltage condition of 150 percent at nominal frequency. For comparison purposes, the peak value of the exciting current (57.3 A) is nearly the same as the transformer nominal full load current of 61.5 A.

Table I shows the most significant harmonics of the current signal depicted in Fig. 7.

TABLE I HARMONIC CONTENT OF THE CURRENT SIGNAL SHOWN IN FIG. 7

Frequency Component	Magnitude Primary A	Percentage of Fundamental
Fundamental	22.5	100.0%
Third	11.1	49.2%
Fifth	4.9	21.7%
Seventh	1.8	8.1%

Harmonics are expressed as a percentage of the fundamental component. The third harmonic is the most

suitable for detecting overexcitation conditions, but either the delta connection of the CTs or the delta connection compensation of the differential relay filters out this harmonic. The fifth harmonic, however, is still a reliable quantity for detecting overexcitation conditions.

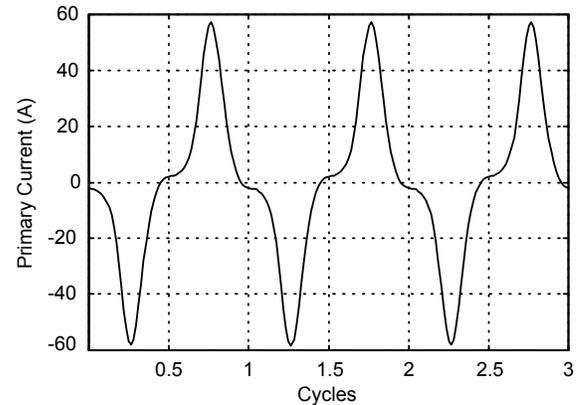


Fig. 7. Exciting Current of an Overexcited Transformer; Overvoltage of 150 Percent Applied to a Single-Phase Transformer

Einval and Linders [10] were first to propose using the fifth harmonic to restrain the transformer differential relay. They recommended setting this restraint function at 35 percent of the fifth harmonic with respect to the fundamental. Fig. 8 [18] shows the harmonic content of the excitation current of a power transformer as a function of the applied voltage. As the voltage increases, saturation eventually occurs and the exciting current increases. The odd harmonics, expressed as a percentage of the fundamental, first increase and then begin to decrease at overvoltages on the order of 115 percent to 120 percent. Setting the differential relay fifth-harmonic restraint to 35 percent ensures security for overvoltage conditions less than 140 percent. For greater overvoltages, which could destroy the transformer in a few seconds, it is desirable to have the differential relay fast tripping added to that of the transformer overexcitation relay.

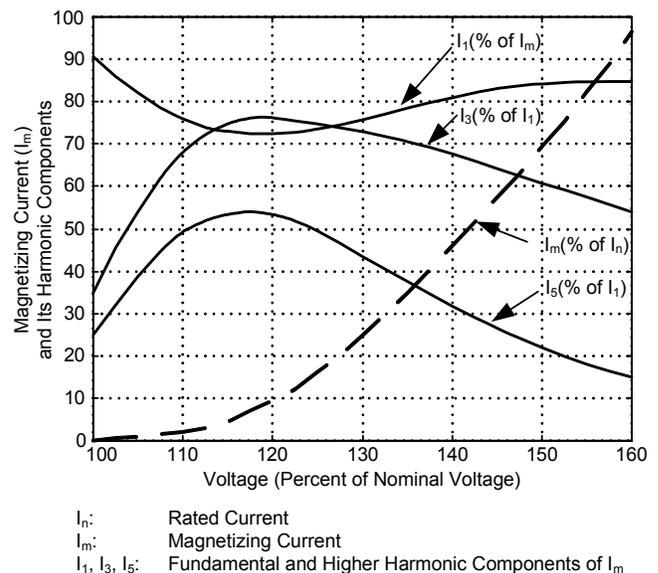


Fig. 8. Harmonic Content of Transformer Exciting Current as a Function of the Applied Voltage [18]

C. CT Saturation

CT saturation during faults and the effect of CT saturation on protective relays have received considerable attention [19] [20] [21] [22] [23] [24]. In the case of transformer differential protection, the effect of CT saturation is double edged. For external faults, the resulting false differential current may produce relay misoperation. In some cases, the percentage restraint in the relay addresses this false differential current, particularly with variable-slope or dual-slope percentage restraint characteristics. For internal faults, the harmonics resulting from CT saturation could delay the operation of differential relays having harmonic restraint or blocking.

The main characteristics of CT saturation are as follows:

- CTs faithfully reproduce the primary current for a given time after fault inception [23]. The time to CT saturation depends on several factors but is typically one cycle or longer.
- The worst CT saturation is produced by the dc component of the primary current. During this dc saturation period, the secondary current may contain dc offset and odd and even harmonics [11] [21].
- When the dc offset dies out, the CT has only ac saturation, characterized by the presence of odd harmonics in the secondary current [10] [11] [19].

Fig. 9 shows a typical secondary-current waveform for computer-simulated ac symmetrical CT saturation. This figure also depicts the harmonic content of this current and confirms the presence of odd harmonics and the absence of even harmonics in the secondary current. Generally speaking, symmetrical nonsinusoidal waveforms contain predominately odd harmonics, and asymmetrical waveforms contain predominately even harmonics.

Asymmetrical CT saturation caused by dc offset is one source of even harmonics that can adversely affect performance of percentage restraint current differential relays that use even harmonics for harmonic blocking or harmonic restraint.

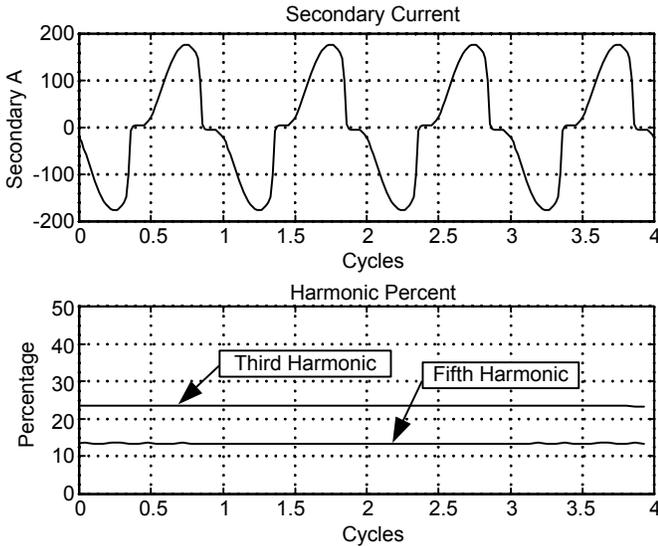


Fig. 9. Typical Secondary Current for Symmetrical CT Saturation and the Harmonic Content It Contains

IV. METHODS FOR DISCRIMINATING INTERNAL FAULTS FROM INRUSH AND OVEREXCITATION CONDITIONS

Early transformer differential relay designs used time delay or a temporary desensitization of the relay to override the inrush current. Other designs used an additional voltage signal to restrain or to supervise (block) the differential relay. All of these concepts struggled with the conflict between providing reliable and fast internal fault detection versus providing security against tripping for external faults, magnetizing inrush, and overexcitation.

Modern percentage current differential relays address this conflict in one of two ways: using harmonics to restrain or block or using waveshape identification. This paper discusses and focuses on the harmonic-based methods.

We can use the harmonic content of the differential current to restrain or block the relay, providing ways to differentiate between internal faults and inrush or overexcitation conditions. Historically, the technical literature on this topic has not clearly identified the differences between harmonic restraint and harmonic blocking, sometimes using the two interchangeably. The purpose of this paper is to clarify the difference between the two techniques and put forth some application guidelines for using the two techniques.

A. Harmonic Restraint

The original harmonic-restrained differential relays used all harmonics to provide the restraint function. The resulting high level of harmonic restraint provided security for inrush conditions at the expense of operating speed and dependability for internal faults with CT saturation. This concept has been carried forward in modern relays, with subtle changes, to provide restraint using selected harmonics instead of all harmonics.

The harmonic restraint principle leverages the percentage current restraint concept by creating additional current differential restraint from the selected harmonic content of the multiple winding current inputs. This concept is expressed in the following equation:

$$I_{OP} > I_{RT} \cdot f(\text{SLP1}, \text{SLP2}) + (K_{h1}I_{h1} + K_{h2}I_{h2} + K_{h3}I_{h3} \dots + K_{hx}I_{hx}) \quad (6)$$

where K_{hx} is a settable constant for each harmonic x , I_{hx} is the measured x^{th} harmonic content in the operate current, I_{OP} , keeping in mind that the operate current is the phasor sum of winding currents. This equation can be represented in logic form as follows:

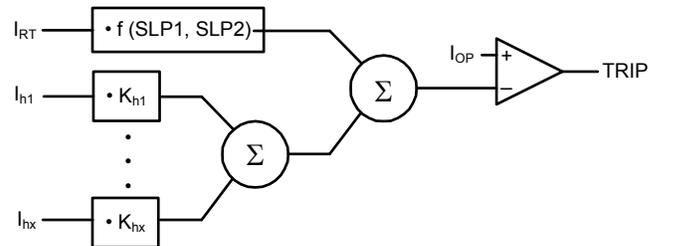


Fig. 10. Logic Diagram for Harmonic Restrained Percentage Current Restraint Differential Function

The resulting differential characteristic, as shown in Fig. 11, increases the restraint region and decreases the operate region by effectively pushing the characteristic slope line up by the amount of additional restraint generated by harmonics.

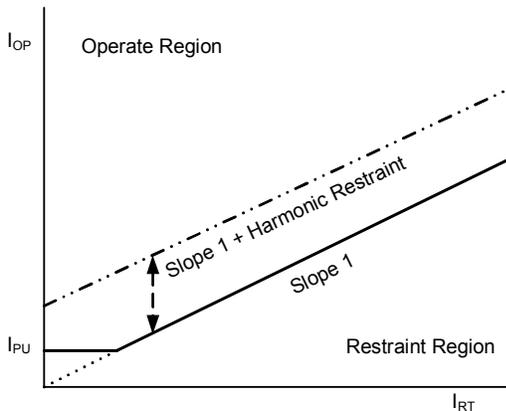


Fig. 11. Percentage Current Differential Harmonic Restraint Characteristic

The problem with this representation is that the harmonic content typically changes throughout a disturbance, therefore, the operate/restraint area represented in Fig. 11 changes continuously, making evaluation of this characteristic difficult. Fig. 12 takes this into account by plotting the operate current against the sum of the restraint current plus harmonic restraint component.

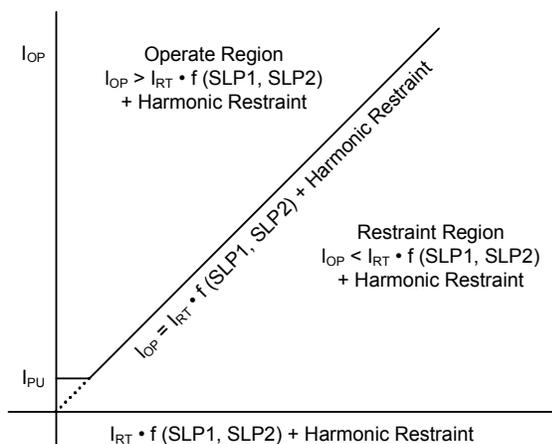


Fig. 12. Alternate Harmonic Restraint, Percentage Restraint Characteristic

The factor “K” in the harmonic restraint element is typically based on the inverse of the percent harmonic setting, where the percent value is entered as a setting for each selected harmonic. For example, a setting of 10 percent for the second-harmonic restraint means that 10 times the second-harmonic component will be added to the fundamental restraint current. Likewise, a setting of 20 percent means that 5 times the harmonic component will be added to the restraint current. The lower the percent setting, the greater the restraint.

For a relay that uses even harmonic restraint, namely the second and fourth harmonics, (6) becomes:

$$I_{OP} > I_{RT} \cdot f(SLP1, SLP2) + [(100/PCT2) \cdot I_{h2} + (100/PCT4) \cdot I_{h4}] \quad (7)$$

B. Harmonic Blocking

Fig. 13 depicts a simplified logic diagram of the transformer differential relay with harmonic blocking. This relay is simpler in concept than the harmonic restraint relay. Each selected harmonic blocks the output of the differential element if its magnitude is greater than a percentage, specified by a settable constant K, of the operate current.

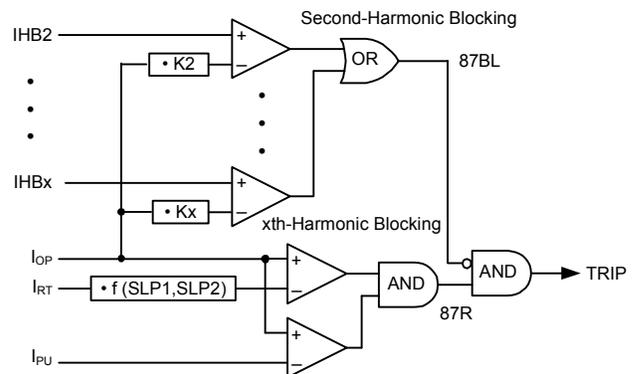


Fig. 13. Simplified Logic Diagram for Percentage Current Restraint Differential With Harmonic Blocking

Typically, transformer differential relays use second-harmonic blocking logic to prevent undesired operation during transformer energization. Additional even harmonic blocking, such as fourth-harmonic blocking, may also be used. The blocking logics run in parallel, so when either harmonic, second or fourth, exceeds its respective threshold setting, the relay blocks the percentage restraint current differential output.

Differential relays may also use fifth-harmonic blocking to prevent undesired operation during overexcitation. Fig. 14 shows a logic diagram of a differential element having second- and fifth-harmonic blocking. A tripping signal requires fulfillment of (6), without fulfillment of the following blocking conditions (8) and (9):

$$I_{OP} \cdot K_2 < I_2 \quad (8)$$

$$I_{OP} \cdot K_5 < I_5 \quad (9)$$

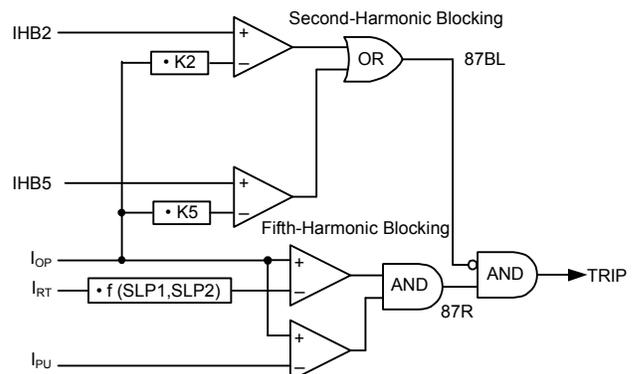


Fig. 14. Percentage Current Differential Logic With Second- and Fifth-Harmonic Blocking

The factor “K” is typically set as a percentage of fundamental frequency operate current. For example, setting K2 equal to 12 percent means that the second-harmonic blocking element will assert when the second-harmonic content of the operate current equals or exceeds 12 percent of the fundamental frequency component of the operate current. Likewise, setting K5 equal to 35 percent would require the fifth-harmonic content of the operate current to equal or exceed 35 percent of the operate current fundamental frequency component to assert the fifth-harmonic blocking element.

Single-phase differential relays can only monitor the operate, restraint, and harmonic currents on an individual phase basis. In a harmonic blocking relay, this is considered “independent harmonic blocking.” During an inrush condition, if the harmonic content in one of the phases falls below the selected percentage of operate current on that phase, the relay will trip. In a three-phase percentage current differential relay, harmonic blocking can be made more secure by implementing “common harmonic blocking.” In common harmonic blocking, as long as the harmonic content is above the selected percentage of operate current on one phase, the relay blocks all three phases. Fig. 15 shows the three-phase versions of the transformer differential relay with independent and common harmonic blocking. The relay is composed of three differential elements of the types shown in Fig. 15. In both cases, a tripping signal results when any one of the relay elements asserts.

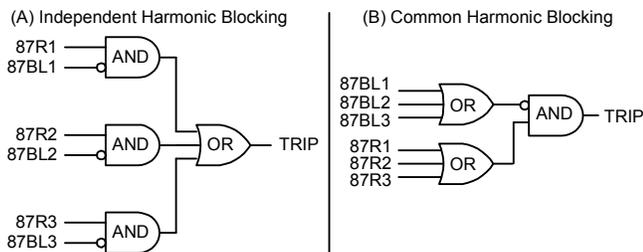


Fig. 15. Three-Phase Differential Relay With: (A) Independent Harmonic Blocking and (B) Common Harmonic Blocking

V. HARMONIC RESTRAINT VS. HARMONIC BLOCKING

In the harmonic restraint element, the operating current, I_{OP} , must overcome the combined effects of the restraining

current, I_{RT} , and the harmonics of the operating current for the element to assert a trip output. Any measurable harmonic content provides some benefit toward the goal of preventing differential relay operation during inrush conditions.

On the other hand, in the harmonic blocking element, the operating current is independently compared with the restraint current and those selected harmonics when the harmonic content is above a specified threshold. When the harmonic content is below the specified threshold, the harmonic blocking has no effect.

The selection of harmonics, and the variables used to compare harmonics with the operate current in either a harmonic blocking or harmonic restraint relay, are crucial to the successful operation of either type of scheme. “Successful” is the operative word, however. How do we judge the success of either scheme? Generally, harmonic blocking or harmonic restraint elements are successful if they fulfill all of the following requirements:

- Permit fast tripping for all internal transformer faults with minimal delay when energizing a faulted transformer
- Prevent transformer differential relay operation during transformer overexcitation
- Prevent differential element operation during transformer energization and during voltage recovery following a power system fault

Previous experience and literature suggests that these goals are best met using even harmonic blocking or harmonic restraint. The second harmonic, most prevalent in transformer inrush, is a key component in their operation. Fourth-harmonic measurement provides additional benefit in harmonic restraint but has questionable value in a harmonic blocking scheme because of its generally lower percentage magnitude compared with the second-harmonic component.

Odd harmonics, particularly third harmonics, which are prevalent in symmetrical CT saturation, are not desirable because they could delay or prevent differential relay operation during internal transformer faults if used in harmonic restraint or blocking. Fifth harmonic, on the other hand, is preferred to detect overexcitation and is, therefore, desirable to use in a blocking mode, provided the threshold settings permit its operation for overexcitation conditions but not for symmetrical CT saturation.

TABLE II
COMPARISON OF HARMONIC RESTRAINT AND BLOCKING METHODS

GOAL	EVEN HARMONIC RESTRAINT (HR)	INDEPENDENT HARMONIC BLOCKING (IHB)	COMMON HARMONIC BLOCKING (CHB)	REMARKS
Security for external faults	High	Low	Moderate	HR always uses harmonics from asymmetrical CT saturation for additional restraint. IHB and CHB block if the even harmonic content is sufficiently high. Odd harmonics from symmetrical CT saturation have no effect; therefore, CTs should be sized to avoid symmetrical CT saturation for external faults.
Security for inrush	High	Moderate	Highest	HR adds to the effectiveness of percentage differential, even if harmonic content is low. IHB and CHB only block if the harmonic content is sufficiently high. CHB blocks if the harmonic content is sufficiently high on at least one phase.
Security for overexcitation	Low	Low	Low	Even harmonic blocking and restraint schemes are ineffective for preventing differential relay operation on overexcitation. However, adding fifth-harmonic blocking to any scheme greatly increases security.
Dependability for internal faults	High	High	High	Even harmonics from asymmetrical CT saturation reduce the sensitivity of HR for internal faults and cause IHB and CHB to delay tripping.
Dependability for internal faults during inrush	High	High	Moderate	Even harmonics from inrush on unfaulted phases may cause CHB to delay tripping more than with HR and IHB.
Speed for internal faults	Lower	Higher	Higher	Percentage differential and harmonic blocking run in parallel in IHB and CHB, allowing the differential to respond faster when blocking drops out.
Slope characteristic	Harmonic dependent	Well defined	Well defined	IHB and CHB slope characteristics are independent from harmonics. HR performance evaluation is more complex.
Testing	Results depend on harmonics	Straight forward	Straight forward	IHB and CHB permit simple tests with direct harmonic variation. HR testing is more complex.

Table II summarizes the results of a qualitative comparison of the harmonic restraint and blocking methods for transformer differential protection and suggests the following:

- All harmonic restraint and blocking techniques have advantages and disadvantages.
- Although subjective, a good combination includes even harmonic restraint and fifth-harmonic blocking to provide a good balance of security and dependability.

Guzmán, Benmouyal, Zocholl, and Altuve established that some supplemental waveform detection techniques may be required to improve security for unique combinations of fault and inrush conditions [1].

Common harmonic blocking logic provides high security but sacrifices some dependability. Energization of a faulted transformer could result in harmonics from the inrush currents of the nonfaulted phases, and these harmonics could delay relay operation.

A. Speed and Security

As with all protection element evaluations, speed and security are contradictory requirements. The two factors that influence the speed and security of the harmonic elements are the harmonic “combination” and the digital filtering. In this regard, harmonic combination refers to the series/parallel

combination of the harmonics. Although the same harmonics are available for both harmonic blocking and harmonic restraint, the specific harmonic combination produces a different result in the element performance. Equation (6) shows that in the harmonic restraint differential element, the harmonics are summed (series combination). When the harmonics are summed, all harmonics included in the equation contribute to increase the restraint quantity. This total harmonic contribution significantly enhances the security of the differential element.

In microprocessor-based relays, the relays calculate the harmonics by means of digital filters. In essence, these digital filters are integrators, summing a number of sampled current values over a specified time period. Therefore, a large numeric value remains in the digital filter for the total specified time period. Because the relay uses these filtered values directly in calculating the restraint quantity, a filter that includes large numeric values causes delayed tripping. Depending on the numeric value, this delayed tripping can be up to one power system cycle.

Fig. 14 shows that the harmonics are evaluated independently in the harmonic blocking differential element, i.e., the values of the harmonics are not summed (parallel combination). Because the element is less secure when

evaluating the harmonics independently, the use of common harmonic blocking increases the element security (see Fig. 15). However, because one phase blocks all three differential elements, common harmonic blocking can significantly delay tripping if the harmonic content of the unfaulted phase(s) remains high during an internal transformer fault. This is of particular concern when selecting differential protection for single-phase transformers.

Clearly, there are advantages and disadvantages to either application. However, in general, harmonic restraint elements are more secure than harmonic blocking elements, but harmonic restraint elements are slower in operation.

B. Selection of Harmonics and Thresholds

There is general agreement that the second harmonic is the preferred harmonic for use in both harmonic blocking and harmonic restraint in transformer percentage current differential relays. The second-harmonic component is by far the most prevalent in virtually all inrush waveforms and does not appear in any significant quantity in symmetrical CT saturation. The fourth harmonic is the “next best” harmonic to supplement the second harmonic toward the goal of preventing percentage restraint current differential relay operation during transformer inrush.

Fig. 16 shows a very typical set of transformer inrush waveforms captured during the energization of the 115 kV side of a 30 MVA (OA), 115 kV wye/27.6 kV delta transformer. IB and IC are fully offset, and IA shows the typical effects of interphase coupling, with some symmetry about the horizontal axis but still highly nonsinusoidal.

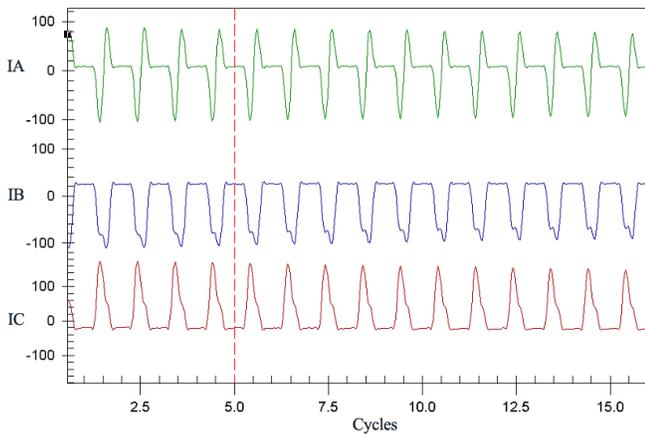


Fig. 16. Typical Set of Transformer Inrush Waveforms

Closer examination of these waveforms, with harmonic analysis, shows that all of these waveforms have a strong second-harmonic component, with a fourth-harmonic component, the next most prevalent harmonic, in two out of the three phases. The third harmonic, the second strongest in one out of the three phases, is considered a poor choice for blocking and restraint because of its presence in symmetrical CT saturation and zero-sequence current for ground faults. The fifth harmonic is present but in a relatively low percentage.

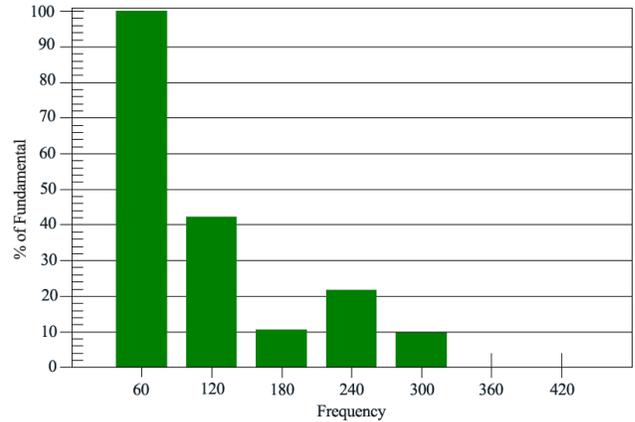
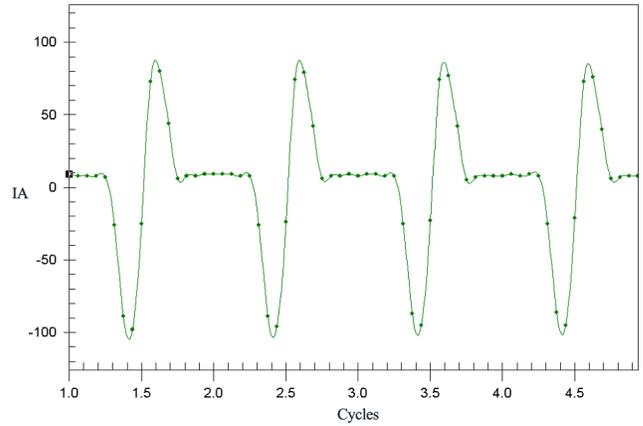


Fig. 17. Harmonic Analysis for Phase A

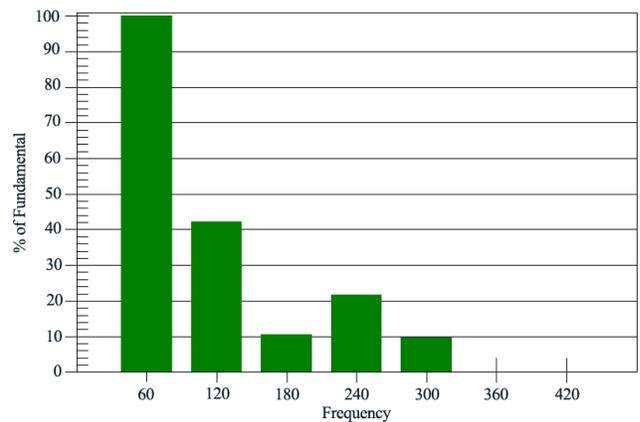
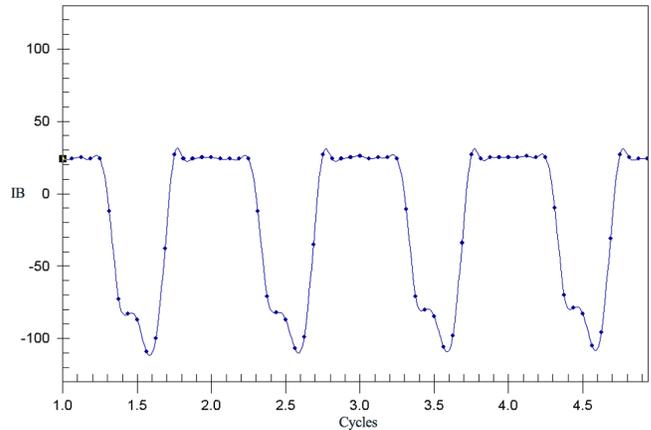


Fig. 18. Harmonic Analysis for Phase B

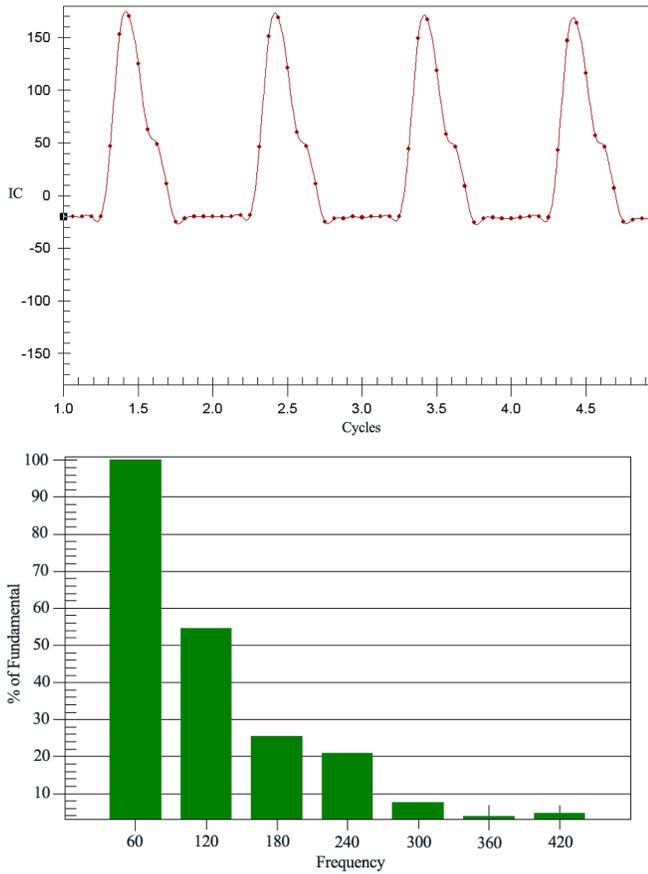


Fig. 19. Harmonic Analysis for Phase C

The initial inrush waveform from the previous example is shown in Fig. 20.

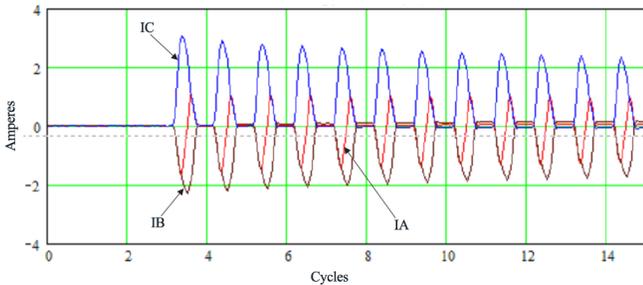


Fig. 20. Inrush Waveform

Analysis of the initial inrush waveform capture in the time domain, shown in Figs. 21, 22, and 23, confirms that the second harmonic is substantial on all three phases for the duration of this waveform capture, well above the 12 percent PCT2 threshold on the graph. Note that in Figs. 21, 22, and 23, operating current, I_{OP} , is in per unit of TAP setting, and the harmonics are plotted in per unit of I_{OP} .

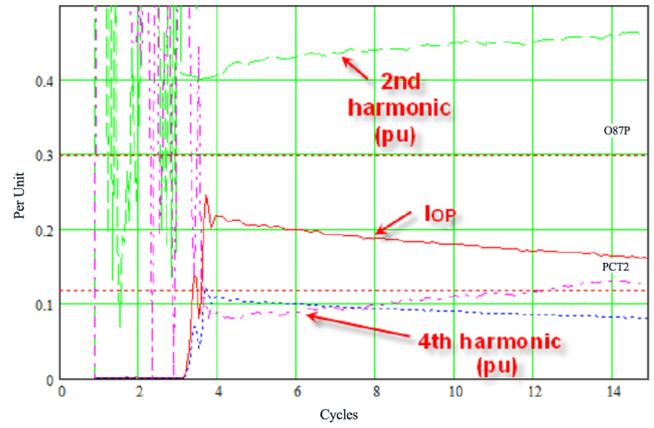


Fig. 21. Phase A Differential and Harmonic Components

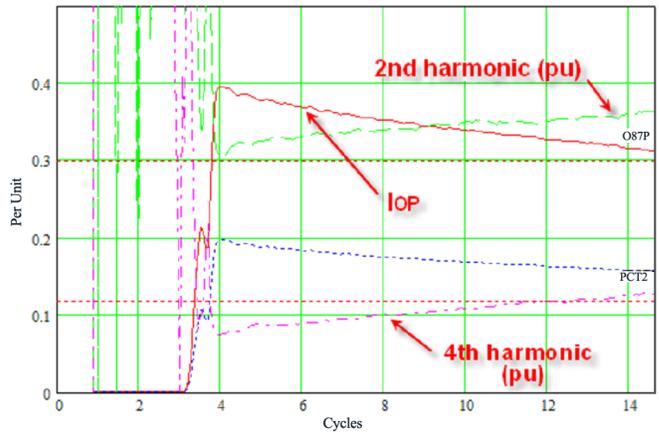


Fig. 22. Phase B Differential and Harmonic Components

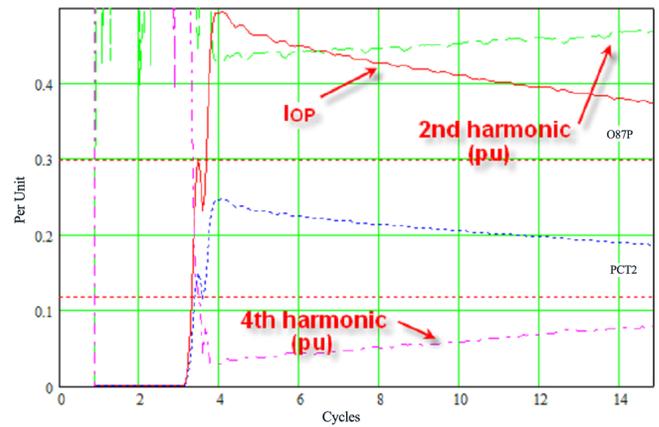


Fig. 23. Phase C Differential and Harmonic Components

The fundamental component of operate current on Phases B and C of this example is above the operate current pickup threshold (O87P on each figure), so the differential element could have operated. Without harmonic blocking or harmonic restraint, the differential relay would have misoperated. Figs. 24 through 29 show this for both the traditional percentage restraint current differential characteristic (Figs. 24, 26, and 28) associated with harmonic blocking relays and for the modified percentage restraint current differential characteristic (Figs. 25, 27, and 29) associated with the harmonic restraint function.

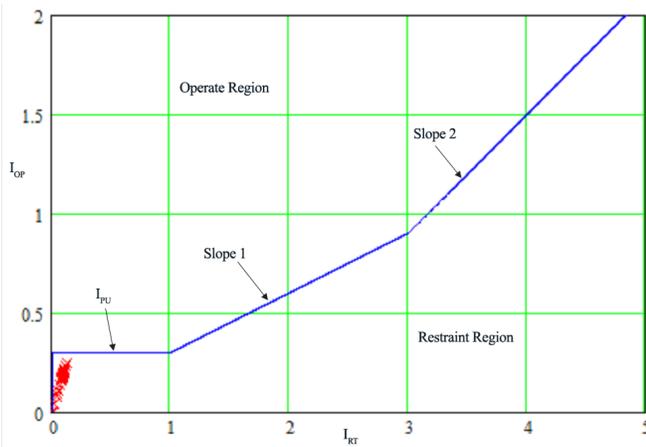


Fig. 24. Phase A Traditional Percentage Restraint Current Differential Plot

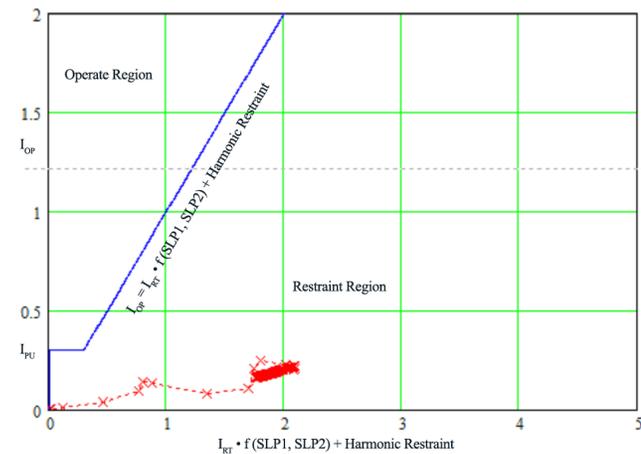


Fig. 25. Phase A Harmonic Restraint Differential Plot

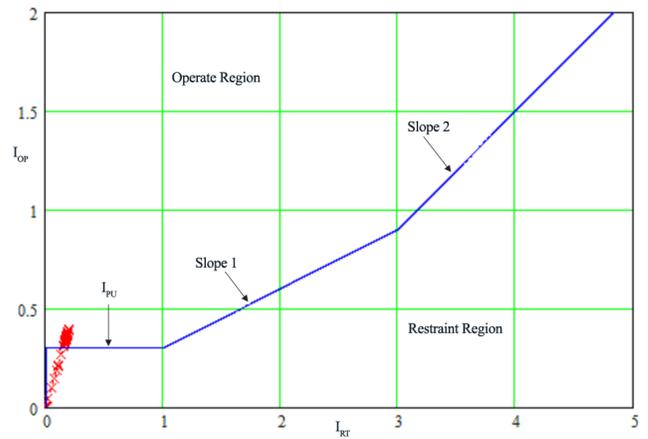


Fig. 26. Phase B Traditional Percentage Restraint Current Differential Plot

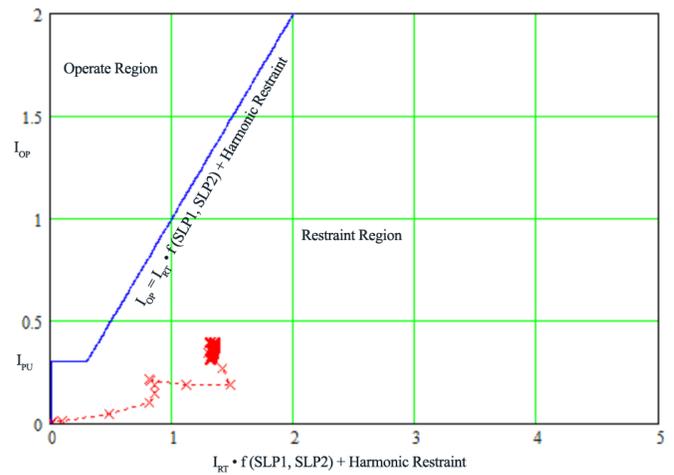


Fig. 27. Phase B Harmonic Restraint Differential Plot

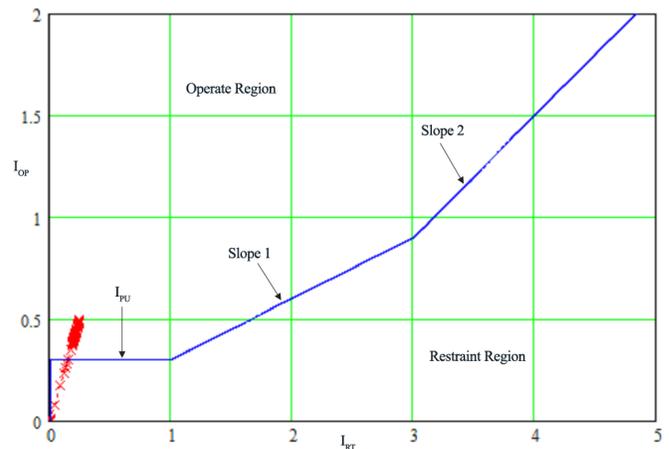


Fig. 28. Phase C Traditional Percentage Restraint Current Differential Plot

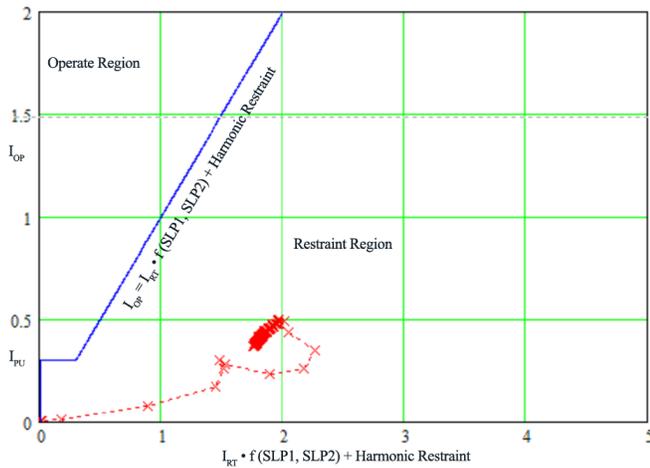


Fig. 29. Phase C Harmonic Restraint Differential Plot

Next, we analyze another inrush waveform capture from the same transformer as in the example above. Fig. 30 shows the unfiltered waveform.

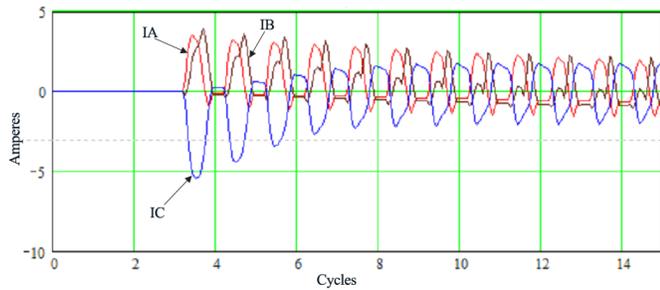


Fig. 30. Three-Phase Unfiltered Current Inrush Waveform

As before, we will examine the differential currents from each phase (see Figs. 31 through 33):

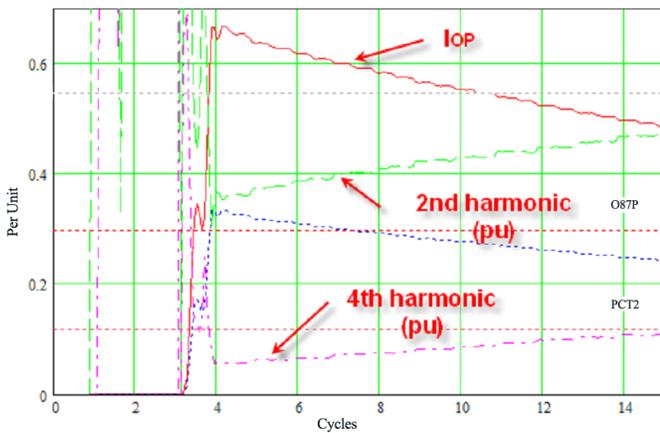


Fig. 31. Phase A Differential Currents and Harmonic Components

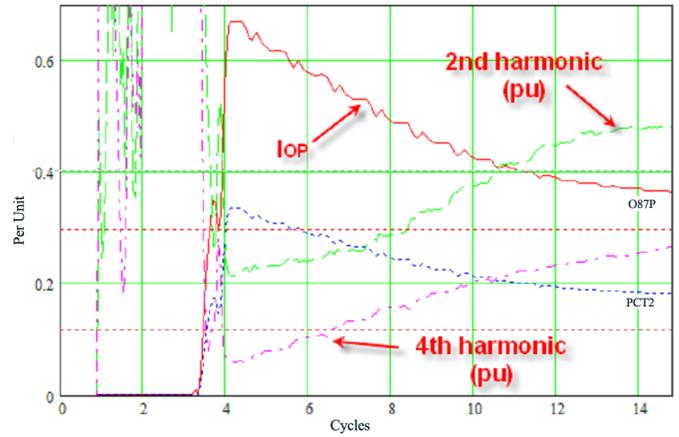


Fig. 32. Phase B Differential Currents and Harmonic Components

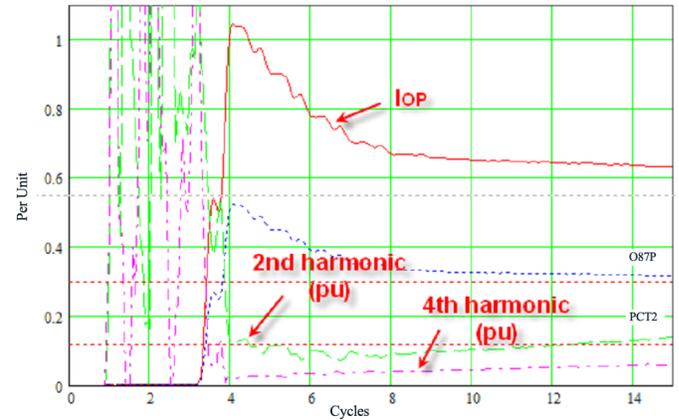


Fig. 33. Phase C Differential Currents and Harmonic Components

Examination of Figs. 31, 32, and 33 shows that the fundamental component of operate current, I_{op} , is above the minimum pickup threshold on all three phases. Therefore, it is critical that some form of restraint or blocking be used to prevent the current differential relay from misoperating on the false differential current. It is also notable that both the second- and fourth-harmonic components are below the 12 percent threshold setting denoted by the PCT2 line on the Phase C plots during the time that I_{op} is above the minimum pickup threshold, O87P. As we will see, this means that independent harmonic blocking will fail to block the differential relay from misoperating for this inrush condition. Common harmonic blocking will effectively block the differential relay from operating because the harmonic content is sufficient on the other two phases to assert a block output. Further analysis is required to determine if harmonic restraint can effectively prevent the differential relay from operating.

Figs. 34, 35, and 36 show the harmonic restraint characteristic plot for Phases A, B, and C, respectively, for this inrush case.

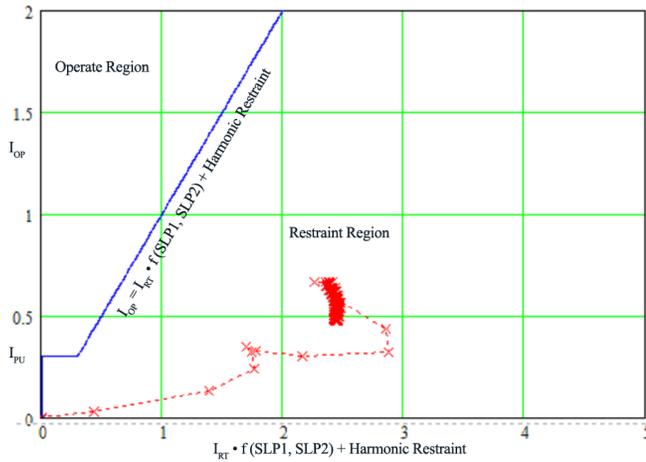


Fig. 34. Phase A Harmonic Restraint Differential Plot

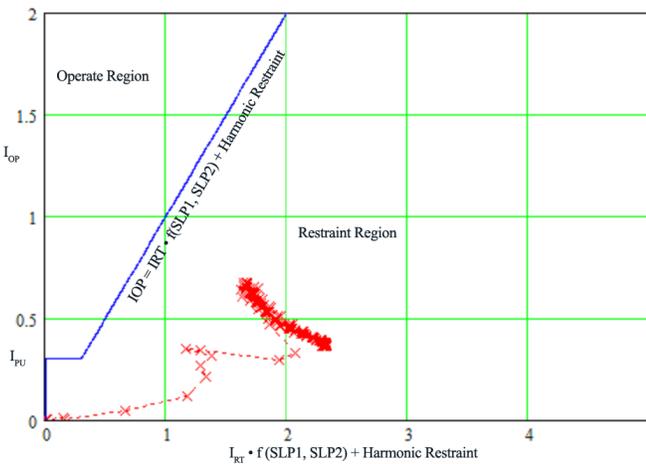


Fig. 35. Phase B Harmonic Restraint Differential Plot

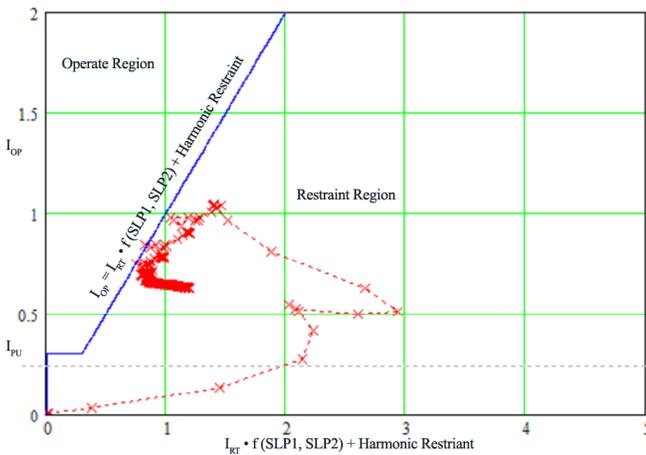


Fig. 36. Phase C Harmonic Restraint Differential Characteristic Plot

From the harmonic restraint plots, it is clear that Phases A and B effectively restrain the differential relay from tripping. Phase C, which has the lowest second- and fourth-harmonic components of the three phases, appears to be effectively restrained, except for one or two nonconsecutive samples.

This is also clearly shown in Fig. 37, where we see the restraint current, supplemented with second and fourth harmonics, falling just below the operate current on one sample.

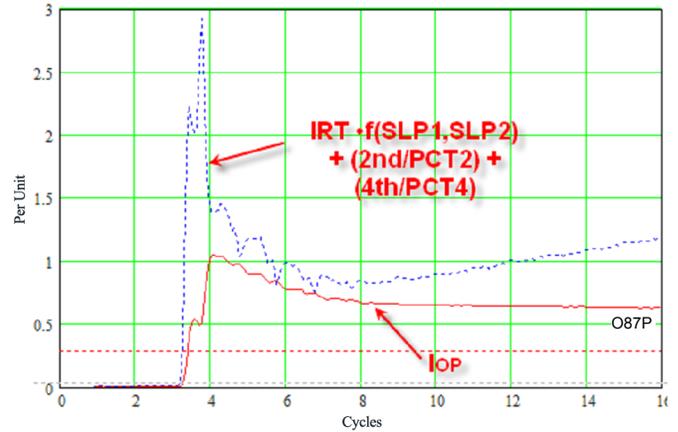


Fig. 37. Plot of Phase C Harmonic Restraint vs. Operate Current

Examination of the relay logical output verifies that the restraint output operates for a single-sample processing interval. Typically, the relay internal logic requires that the output be high for more than one processing interval for security purposes. Regardless, this shows quite clearly that the harmonic restraint characteristic is more effective than the harmonic blocking logic, which has a fixed threshold of operation.

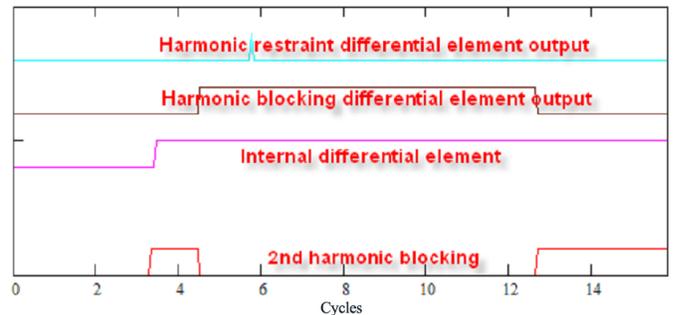


Fig. 38. Differential Relay Logic

The final example we will examine is from a previous paper [1]. In this case, the transformer was energized while Phase A was faulted and the transformer was not loaded. The transformer was a three-phase, delta-wye-connected distribution transformer; the CT connections were wye at both sides of the transformer.

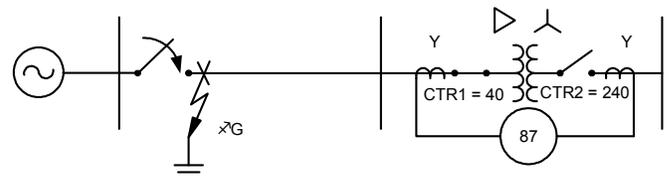


Fig. 39. Transformer Energization While Phase A Is Faulted

As before, we present the three-phase unfiltered inrush waveform (shown in Fig. 40).

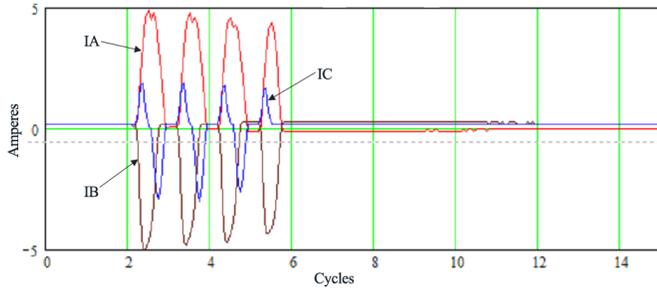


Fig. 40. Unfiltered Three-Phase Transformer Inrush Waveform

The waveform only exists for four cycles because the relay in this case tripped the high-side breaker. As we will see, the basic second-harmonic blocking technique used by the relay was not effective in blocking operation of the percentage restraint current differential relay.

Figs. 41, 42, and 43 show the individual phase waveform analysis for the final example.

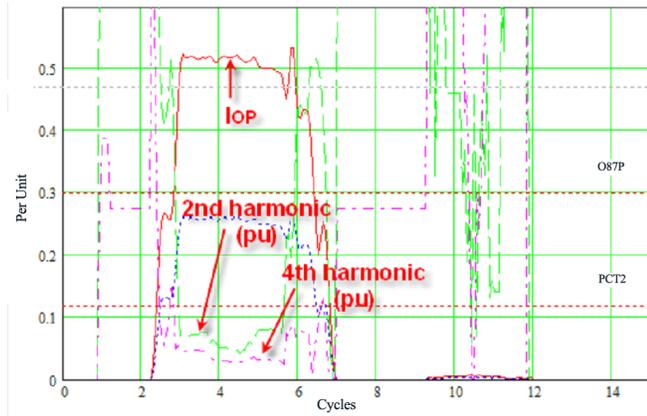


Fig. 41. Phase A Differential and Harmonic Components

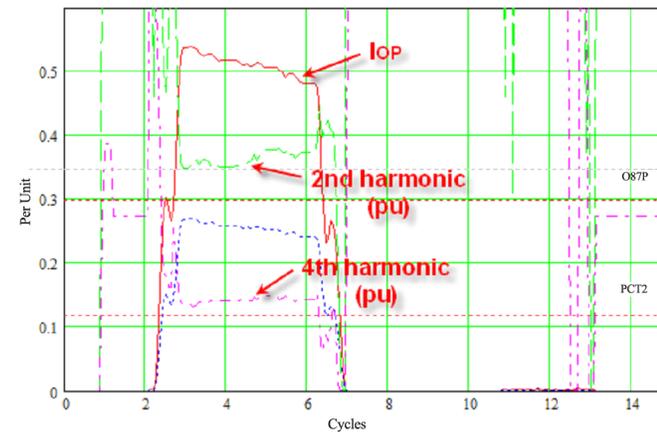


Fig. 42. Phase B Differential and Harmonic Components

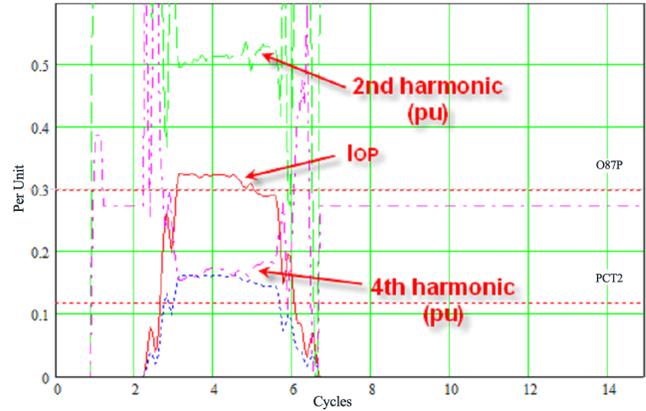


Fig. 43. Phase C Differential and Harmonic Components

When examining Figs. 41, 42, and 43, we see that the operate current exceeds the minimum pickup current, O87P, on all three phases. Therefore, some form of restraint or blocking is required to prevent operation of the differential element for this inrush condition. A close examination of the Phase A plot in Fig. 41 reveals that both the second- and fourth-harmonic components are below the 12 percent harmonic threshold setting on the relay. In fact, the harmonic content falls below 5 percent at their lowest points.

Given this analysis, we expect that independent harmonic blocking cannot effectively prevent differential relay operation unless the harmonic percent threshold setting is drastically reduced to 4 percent or below. In this case, common harmonic blocking would have been successful because both the second- and fourth-harmonic components exceed the 12 percent harmonic percentage threshold setting chosen for this analysis.

We next examine the harmonic restraint characteristic performance to see how it performs. Figs. 44, 45, and 46 show the modified percentage restraint current differential characteristic for Phases A, B, and C using the harmonic restraint function.

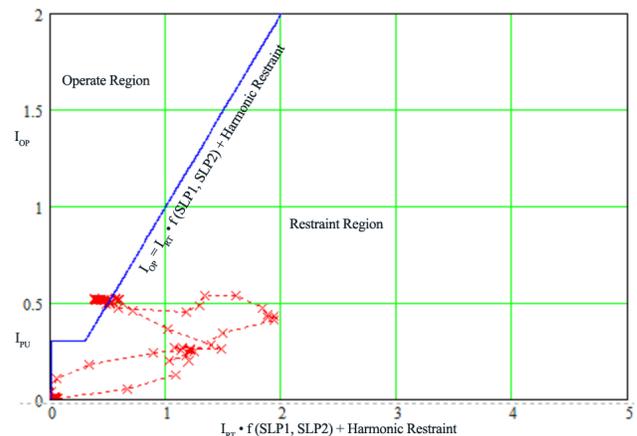


Fig. 44. Harmonic Restraint Characteristic Performance on Phase A

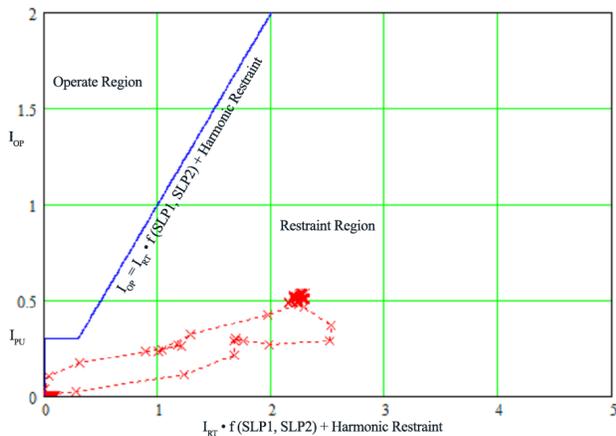


Fig. 45. Harmonic Restraint Characteristic Performance on Phase B

Analysis of the harmonic restraint characteristic performance in Fig. 44 shows that the Phase A differential element would have operated for this inrush condition with the existing 12 percent second- and fourth-harmonic threshold settings. Figs. 45 and 46 clearly show that Phases B and C effectively restrained from tripping. As stated previously, common harmonic blocking would have been effective in this case. However, concerns that common harmonic blocking may delay differential relay tripping when energizing a faulted transformer may discourage this approach. Further analysis of the harmonic restraint performance indicates that the second- and fourth-harmonic percent settings must both be reduced to 8 percent or less to prevent differential element operation on Phase A. This may have undesirable consequences, as explained in the next section. If so, then some other form of security, typically a waveform recognition technique such as proposed by Guzmán, Benmouyal, Zocholl, and Altuve [1], is recommended for further security improvement.

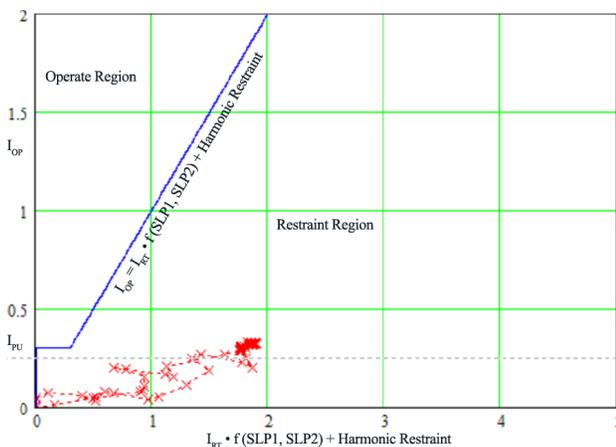


Fig. 46. Harmonic Restraint Characteristic Performance on Phase C

C. Harmonic Sensitivity Settings

The example cases presented in this paper used a 12 percent second- and fourth-harmonic setting to perform the analysis. Better security may be obtained by reducing this harmonic sensitivity setting. However, improving security against misoperating on transformer inrush may decrease the relay's dependability to detect internal faults. Some measure

of harmonic content can be expected for internal transformer faults because of the nonlinear behavior of iron-core inductive devices. Typical harmonic sensitivity settings in the range of 10 percent to 15 percent are considered reasonable. Settings below 10 percent may jeopardize dependable operation of the differential relay for internal faults. Very little experience is available in this area because of the relatively few occurrences of transformer faults. It seems prudent to endure the occasional differential relay operation on transformer energization, or use a supplemental security measure, such as waveshape recognition, in order to ensure fast and dependable tripping for an internal fault.

VI. CONCLUSIONS

1. Most transformer differential relays use the harmonic content of the operating current to distinguish internal faults from magnetizing inrush conditions using either harmonic blocking or harmonic restraint techniques.
2. The harmonic blocking technique uses a fixed harmonic threshold, below which the differential element is free to operate on its normal percentage-slope characteristic.
3. The harmonic restraint technique, as described in this paper, adds the harmonic component of the operate current to the fundamental component of the restraint current, providing dynamic restraint during transformer inrush.
4. Harmonic restraint and blocking methods ensure relay security for a very high percentage of transformer inrush cases. Harmonic restraint tends to be more secure than even harmonic blocking because the harmonic restraint function benefits from even small quantities of harmonic content. However, relays using the harmonic restraint technique may operate slightly slower for internal faults than those using harmonic blocking.
5. Common harmonic blocking increases differential relay security but could delay relay operation for internal faults combined with inrush currents in the nonfaulted phases.
6. Harmonic blocking and harmonic restraint techniques may not be adequate to prevent differential element operation for unique cases with very low harmonic content in the operating current. Some form of waveshape recognition may be required to ensure security for these unique conditions without sacrificing fast and dependable operation when energizing a faulted transformer.

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VIII. BIOGRAPHIES

Ken Behrendt received a Bachelor of Science Degree in Electrical Engineering from Michigan Technological University. He was employed at a major Midwest utility where he worked in Distribution Planning, Substation Engineering, Distribution Protection, and Transmission Planning and Protection until 1994. From April of 1994 to present he has been employed with Schweitzer Engineering Laboratories, Inc. as a field application engineer, located in New Berlin, Wisconsin.

Ken is an IEEE Senior Member and an active member of the IEEE Power System Relay Committee. He has served as the U.S. representative on CIGRE Joint Working Group 34/35.11 on Teleprotection, and is a registered Professional Engineer in the state of Wisconsin. Ken has authored and presented several papers at major power system and protective relay conferences.

Normann Fischer joined Eskom as a protection technician in 1984. He received a Higher Diploma in Technology, with honors, from the Witwatersrand Technikon, Johannesburg in 1988, a B.Sc. in Electrical Engineering, with honors, from the University of Cape Town in 1993, and a M.S.E.E. from the University of Idaho in 2005. He was a senior design engineer in Eskom's Protection Design Department for three years and then joined IST Energy as a senior design engineer in 1996. In 1999, he joined Schweitzer Engineering Laboratories, Inc. as a power engineer in the Research and Development Division. He was a registered professional engineer in South Africa and a member of the South Africa Institute of Electrical Engineers.

Casper Labuschagne, P.E., joined Schweitzer Engineering Laboratories, Inc. in December 1999 as a product engineer in the Substation Equipment Engineering group. He brought 20 years of experience with the South African utility, Eskom, where he worked in the design department. He earned his M.D. in 1991 from Vaal Triangle Technikon near Johannesburg. He is registered as professional technologist with the Engineering Council of South Africa.