A Consideration of Inrush Restraint Methods in Transformer Differential Relays

Russell W. Patterson
Tennessee Valley Authority

Walter P. McCannon
Georgia Power Company

Gary L. Kobet
Tennessee Valley Authority

Presented to the
54th Annual Georgia Tech
Protective Relaying Conference
May 3-5, 2000

Background

On March 19, 1999 a TVA substation experienced a transformer bank differential misoperation on inrush (for details see appendix C of this paper along with reference [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 on our system for properly restraining on inrush currents. 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 paper was to present our method for analyzing inrush currents and to further educate ourselves and stimulate discussion on this topic. Since our purpose is to share and to learn, the authors would appreciate if you would bring to our attention any errors or discrepancies you find in this paper. Matlab®[1] and Mathcad®[2] files used for this paper can be found at http://www2.msstate.edu/~rwp1/paper. 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 differential protection is the most commonly used type of protection for banks larger than 10-MVA [2]. The differential principle is simple and provides the best protection for phase and ground faults.

Although differential protection is relatively simple to apply, it does have its problems. 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 because the impedance of the magnetizing branch can be very low, and 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 giving the appearance of an internal fault. Figure 1 illustrates the typical current waveforms present during a three-phase transformer bank energization.

[1] "Matlab" is a registered trademark of The MathWorks, Inc. For more information, see http://www.mathworks.com.
[2] "Mathcad" is a registered trademark of Mathsoft, Inc. For more information, see http://www.mathsoft.com.

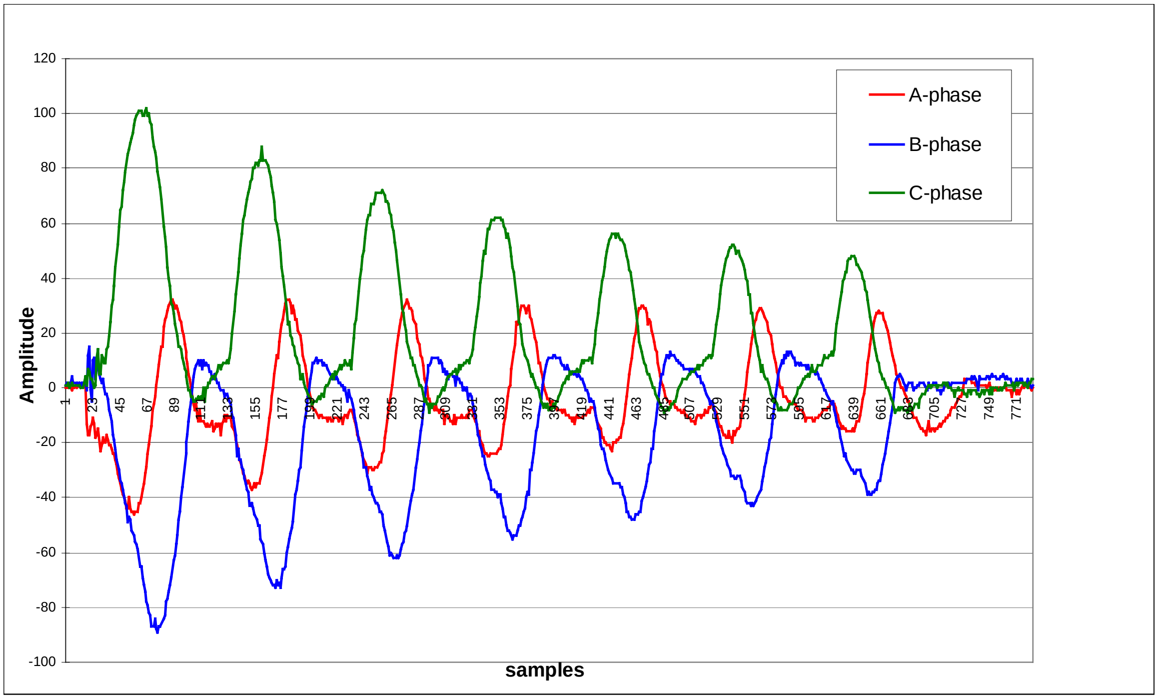


Figure 1. Inrush currents during transformer energization

Methods of Preventing Misoperation of Transformer Differential Relays on Inrush

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

1. Ignore it. That is, if it can be verified that there was actually 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[3]. 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 cutout switch closed.
2. Desensitize the relay by:
    - Raising the pickup;
    - Using an auxiliary relay operating on bus voltage to determine whether or not a fault is present on energization. On inrush, it is assumed that the bus voltage will not drop appreciably, 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] Except 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.

3. Use slow-speed induction-type relays with long time and high current settings.
4. Power differential method - 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 [3].
5. Rectifier relay - This method takes advantage of the fact that magnetizing inrush current is in effect a half-frequency 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 in order 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. [4]
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 uses to declare an inrush condition. Such relays typically expect the dwell time to be at least ¼ of a cycle, and will restrain tripping if this is measured.
7. Another unique method uses the flux-current relationship of the transformer to provide restraint. [5]
8. Harmonic current restraint - This is the most common method 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 high second harmonic content [6], with relatively low third harmonic content [7]. 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 second 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 particular threshold. Different manufacturers chose different thresholds. Table 1 lists the harmonic thresholds of three different types of transformer differential relays.

Table 1. Harmonic Restraint Thresholds for Some Transformer Differential Relays

Relay	Harmonic Threshold
Westinghouse HU-1	15%[4] 2^{nd}[5]
General Electric BDD	35% 2^{nd}, 20-25% 3^{rd} and above[6]
General Electric STD16C	20%[7] 2^{nd}
Asea RADSE	32% 2^{nd}

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). However, it is possible for the subtraction effect of the delta connection to reduce the amount of second harmonic in the currents seen by the relay, even if the phase currents have plenty of second harmonic [1, 8]. This has resulted in false-tripping.

[4] Can be modified to lower threshhold to 7.5%.
[5] W.A. Elmore, ABB Protective Relaying Theory and Applications, Marcel Dekker, Inc., New York, 1994, p. 151.
[6] General Electric, Instructions GEH-1815, Transformer Differential Relays with Percentage and Harmonic Restraint - Types BDD15 and BDD16, p. 6.
[7] General Electric, Instructions GEK-45307C, Transformer Differential Relays with Percentage and Harmonic Restraint - Types STD15C and STD16C, p.15

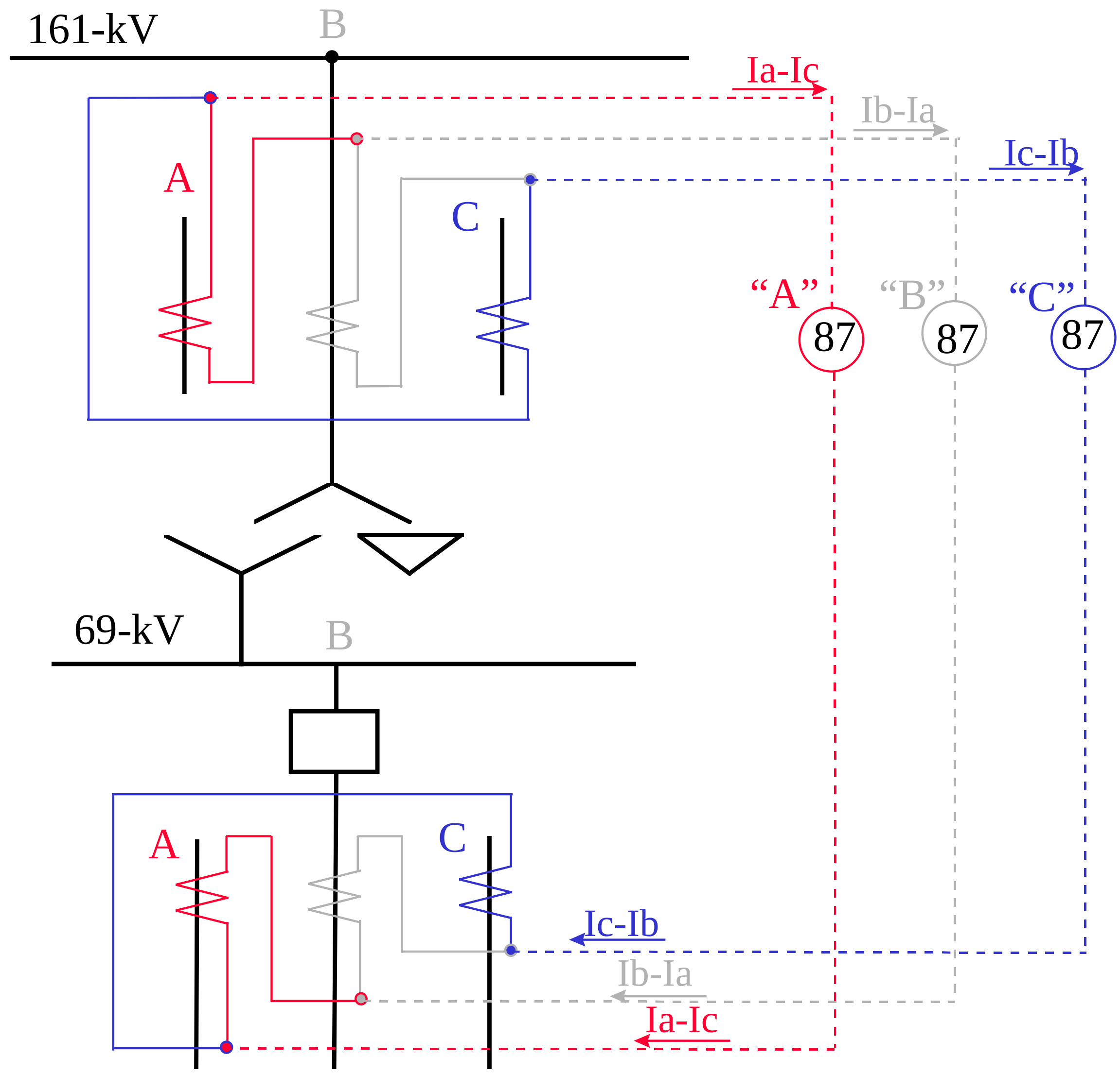


Figure 2. CT connections to differential relays on wye-wye-delta transformer bank

One study reported the minimum possible level of second harmonic content in magnetizing inrush current was about 17% [7]. That being the case, it would appear that a 15% threshold would be a good choice. However, newer transformer designs are producing transformers that can have inrush current with second harmonic levels as low as 7% [9]. In that case, the above 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.

Harmonic restraint methods analyzed in this paper

We reviewed four methods for detecting inrush currents. They are described below.

<u>Simple 2nd harmonic restraint</u>: 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 are between 15 and 35% of fundamental) the relay is restrained. This is simply a per-phase calculation of 2nd harmonic current (in Amps) divided by fundamental current (in Amps). e.g. If the waveform has 4A of 2nd harmonic and 10A of fundamental it has a 2nd harmonic level of 40%. This method is titled Method A in this paper.

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 Amps) all three differential currents. e.g. If the sum of 2nd harmonic current from all three differential currents is 9A and the particular phase of interest (this calculation is performed for each phase) has 10A of fundamental its restraining quantity is 90%. This method attempts to avoid misoperating on the lack of 2nd harmonic content in one phase that commonly occurs on bank energization. This method is titled Method B in this paper.

Cross blocking: Cross blocking is described in the next 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 paper.

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 paper.

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. Each of these three independent relays monitored one particular phase's currents, comparing for example, the high side winding's phase two current to the low side winding's phase two current.

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

An important aspect of the new 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 phases of the transformer. One aspect of this logic is a feature that is commonly known as "cross-blocking".

A quick example of this cross-blocking logic begins with envisioning a differential relay protecting a transformer that is now being energized. The relay typically senses the harmonic content of the current flowing into each phase of the transformer and "blocks" the probable tendency of that phase's protective element to operate. Cross-blocking logic blocks all three phases' protective elements from operating if sufficient harmonic content is measured in one or two of the phases' currents.

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

Recall our example above, but now add a few unfortunate details. First of all, the protected transformer bank consists of three single-phase tanks that comprise a large capacity, expensive, 500/230kV autotransformer bank. Secondly, the phase one tank of this bank has a fault between a large number of the winding's turns.

With the differential relay's cross-blocking logic in place, the transformer bank is energized. Phase two and phase three, the unfaulted tanks, exhibit normal levels of second harmonic content in the energizing current flowing into the two tanks. The harmonic blocking in the phase two and phase three elements immediately activate the relay's cross-blocking feature. The tremendous fault current flowing into the faulted phase one tank leave 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. The cross-blocking feature is then turned off and a trip output is allowed to be issued if the phase one element is still picked-up.

This method is titled Method C in this paper 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 phases from operating.

Applying actual currents to the various methods

The following pages were generated from a Mathcad® analysis of various transformer bank energization currents. These events are labeled "Braytown Event", "Walter Event 1", "Walter Event 2", "Rowbottom Event 1", and "Stan Event 1".

The page immediately following the graph of the energization currents is the first sheet analyzing Method A. The results of the Mathcad® equations at the top of the page is graphed in the three plots of the first row. The lower two plots (green and blue) are the restrain and fundamental logic levels. The upper trace (in red) is the trip logic level. It is not a true test of whether a relay employing this method would operate or not it is simply asserted (logic 1) whenever the restraint is absent and the fundamental quantity is sufficient to trip. Simply stated the trip trace goes high whenever the restraint quantity is below the threshold *and* the fundamental quantity (60Hz current) is above its trip threshold.

For display purposes the restraint trace (green) declares a restraint condition by going to a logic level of zero. A logic level of 1 for this trace means it is not restraining. The fundamental trace is exactly the opposite. A logic level of 0 for the fundamental trace means it does not have enough quantity to declare a trip. A logic level of 1 for the fundamental means it does have enough quantity to declare a trip. This added confusion was needed to easily decide on a trip output (red trace) by using an AND of the trip and restraint quantities. Below is a key for your convenience:

Restraint (green) trace: Logic level 0 when restraining.
Fundamental (blue) trace: Logic level 1 when it sees enough 60Hz current.
Trip (red) trace: Logic level 1 (4 on trace) when both restraint and fundamental are 1.

Braytown event

The following pages indicate that Method A would allow a misoperation on inrush for the Braytown currents. Method B would properly restrain as would Method D. It should be noted that my interpretation of Method D is strictly my own without affirmation of my accuracy from any manufacturers using this method.

An added page to the analysis of this event is titled "Method B, Braytown Event – supplemental". This page points out the care that 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. The supplemental page shows an estimation of the sensitivity to the shared harmonic level. This indicates that good inrush restraint can be achieved without sacrificing too much coverage of the lower magnitude energization faults. For example, the third trace from the top on the supplemental page is a conservative estimate of the fundamental current required to trip the relay when using a shared second harmonic threshold of 45%. To trip would require on the order of 1000-1200A of primary fundamental current.

Summary

In summary we can say that using the simple restraint method with too high restraint levels invites misoperations on inrush. Likewise, using cross blocking is an invitation to allow a faulted transformer to remain energized for a lengthened amount of time increasing the possibility of damage. As protection engineers, it is our responsibility to weigh the tradeoffs and benefits of the various methods and to decide for ourselves which works best for our purposes.

Bibliography

1. Kobet, G.L., Patterson, R.W., “Matlab Analysis of Braytown Transformer Differential Inrush Misoperation”, paper presented to the 2000 Georgia Tech Fault and Disturbance Analysis Conference.
2. ANSI/IEEE C37.91-1985, IEEE Guide for Protective Relay Applications to Power Transformers, IEEE, New York, 1991, pp. 12, 15-17.
3. Yabe, K., “Power Differential Method for Discrimination between Fault and Magnetizing Inrush Current in Transformers”, IEEE Transactions on Power Delivery, Vol. 12, No. 3, July 1997, pp. 1109-1118.
4. Michelson, E.L., “Rectifier Relay for Transformer Protection”, AIEE Transactions, May 1945, Volume 64, pp. 253-254.
5. Phadke, A.G., Thorp, J.S., “A New Computer-Based Flux-Restrained Current-Differential Relay for Power Transformer Protection”, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-102, No. 11, November 1983, pp. 3624-3629.
6. Kennedy, L.F., Hayward, C.D., “Current-Restrained Relays for Differential Protection”, AIEE Transactions, May 1938, Vol. 57, pp. 262-271.
7. Sonnemann, W.K., Wagner, C.L., Rockefeller, G.D., “Magnetizing Inrush Phenomena in Transformer Banks”, AIEE Transactions, October 1958, Vol. 77, pp. 884-892.
8. Zocholl, S.E., “Transformer Protection - An Analysis of Field Cases”, paper presented to the 53rd Annual Georgia Tech Protective Relay Conference.
9. Blackburn, J. Lewis, Protective Relaying: Principles and Applications, 2nd edition, Marcel Dekker, New York, 1998, pp. 275-280.
10. McPherson, G., Laramore, R.D., An Introduction to Electrical Machines and Transformers, John Wiley & Sons, New York, 1990, pp. 180-186.
11. Hayward, C.D., “Harmonic Current-Restrained Relays for Transformer Differential Protection”, AIEE Transactions, 1941, Vol. 60, p. 377.
12. AIEE Relay Subcommittee Report, Relay Protection of Power Transformers, AIEE Transactions, 1947, Vol. 66, pp. 911-912.
13. Heathcote, M.J., J&P Transformer Book, 12th edition, Newnes Publishing, Oxford, 1998, pp. 501-562.
14. Kulidjian, A., Kasztenny, B., “An Improved Transformer Inrush Restraint Algorithm Increases Security While Maintaining Fault Response Performance”, GE paper, presentation unknown.
15. “Enhanced Transformer Protection Through Inrush-Proof Ratio Differential Relays”, The Brown Boveri Review, April 1945, pp. 129-133.
16. Blume, L.F., et al, “Transformer Magnetizing Inrush Currents and Influence on System Operation”, AIEE Transactions, 1944, Volume 63, pp. 366-374.

Biographical Sketches

Russell W. Patterson is a Project Specialist, System Protection for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. He is responsible for reviewing and making protective relaying recommendations on new construction and retrofit projects for the generation and transmission system. Russell also has responsibility for protective relaying and control settings and field support. Prior to his position as Project Specialist Russell was TVA's Power Quality Manager responsible for field and customer support on PQ related issues and disturbances. Russell has performed transient simulations using EMTP for breaker Transient Recovery Voltage (TRV) studies including recommending mitigation techniques. Mr. Patterson earned the B.S.E.E. from the Mississippi State University in 1991 and has completed all coursework toward the M.S.E.E. at Mississippi State University. Russell is a registered professional engineer in the state of Tennessee.

Walter P. McCannon is a Principal Engineer of the Georgia Power Company, Protection & Control, Substation Design and Construction Department in Atlanta, Georgia. His responsibilities include the review of protective relaying applications, relay setpoint calculations, and protective device coordination on the Georgia Integrated Transmission System (ITS). Mr. McCannon is a member of the Southern Company Protection and Control Standards Committee and the ITS Relay Working Group. His prior position with Georgia Power involved the commissioning and troubleshooting of substation protective relaying and control schemes as a field test engineer. He is a senior member of the Institute of Electrical and Electronics Engineers (IEEE). Mr. McCannon earned the B.E.E. degree from the Georgia Institute of Technology in 1980.

Gary Kobet is a Project Specialist, System Protection for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. His responsibilities include scoping relaying schemes on transmission and generation projects, as well as relay setpoint calculations. He has performed transient studies using EMTP for breaker TRV studies and switching surge overvoltages. Previously he worked as a field engineer and as Power Quality Specialist. Mr. Kobet earned the B.S.E. (electrical) from the University of Alabama in Huntsville in 1989 and the M.S.E.E. from Mississippi State University in 1996. He is a member of Eta Kappa Nu, Tau Beta Pi, and is a registered professional engineer in the state of Alabama.

Appendix A Description of Inrush Restraint Methods used in this paper.

<u>METHOD A</u> 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 425A, a 2nd harmonic current of 180A.
Coil 2 has a fundamental current of 670A, a 2nd harmonic current of 125A.
Coil 3 has a fundamental current of 435A, a 2nd harmonic current of 230A.

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

Coil 1 percent second = 180A/425A * 100 = 42.3%
Coil 2 percent second = 125A/670A * 100 = 18.6%
Coil 3 percent second = 230A/435A * 100 = 52.9%

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

<u>METHOD B</u> This method uses second harmonic "sharing". The magnitude (in per unit of tap) of the second harmonic operating current is summed from all three phases. This resulting magnitude is then compared to the fundamental operating current on a per phase basis (as opposed to each phase comparing its own second harmonic content to its fundamental).

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

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

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

The "shared" 2nd harmonic quantity = (180A + 125A + 230A)/TAP = 267.5A

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

Coil 1 restraint quantity = 267.5A/425A * 100 = 62.9%
Coil 2 restraint quantity = 267.5A/670A * 100 = 39.9%
Coil 3 restraint quantity = 267.5A/435A * 100 = 61.5%

For comparison below are the per phase percentages of 2nd harmonic content.

Coil 1 percent second = 180A/425A * 100 = 42.3%
Coil 2 percent second = 125A/670A * 100 = 18.6%
Coil 3 percent second = 230A/435A * 100 = 52.9%

Note: To operate this relay requires 1 60Hz cycle of operate fundamental above TAP Amps while the restraint quantity is below its threshold.

<u>METHOD C</u> This method is a "common" restrain method. A restraint quantity is calculated for each phase (as above for METHOD C) and if at least one of those three quantities is above the threshold all three phases are restrained from operation.

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

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

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

Coil 1 percent second = 180A/425A * 100 = 42.3%
Coil 2 percent second = 125A/670A * 100 = 18.6%
Coil 3 percent second = 230A/435A * 100 = 52.9%

For this example even though Coil 2 has less restraint quantity than the threshold it would be restrained from tripping because Coil 1 and/or Coil 2 have greater than the threshold level.

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

METHOD D This method is 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.

Appendix B Example and explanation of analysis.

In this appendix the method used to compute harmonic content is described with a test waveform generated in Excel 97.

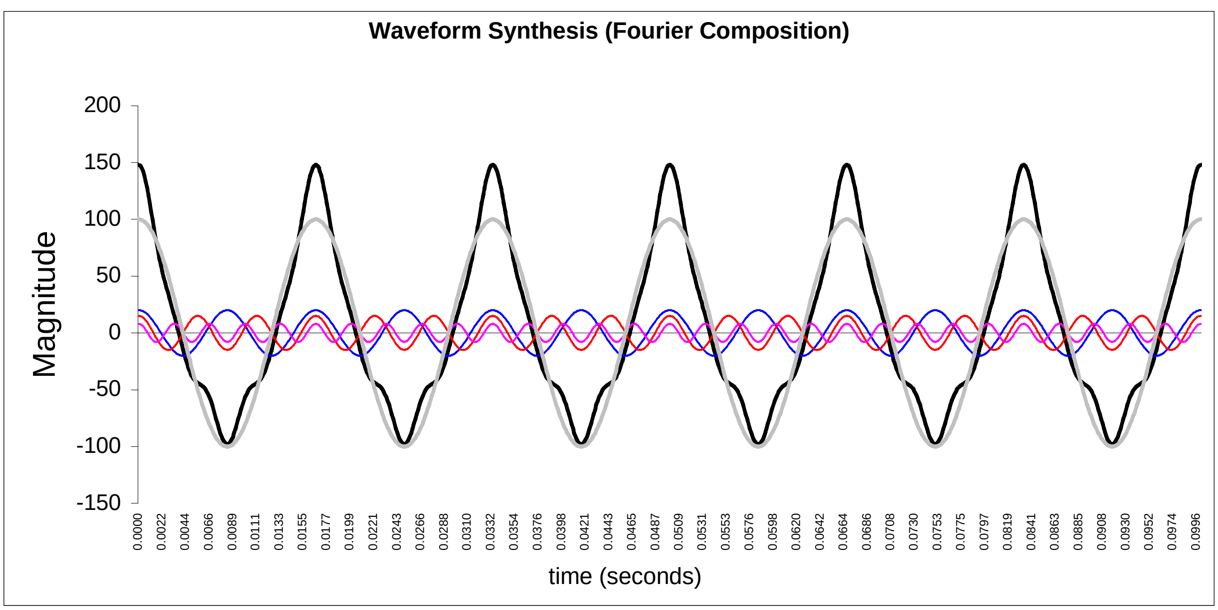
The 6 cycle waveform f(t) was calculated from the following automatically generated formula.

= 100*COS(2*PI()*60*A12 + 0) + 5 + 20*COS(2*2*PI()*60*A12 + 0) + 15*COS(3*2*PI()*60*A12 + 0) + 8*COS(5*2*PI()*60*A12 + 0)

Below is a snapshot of the Excel 97spreadsheet used to calculate this waveform. The harmonics in the waveform are entered along with their desired magnitude and phase. The harmonics are plotted in addition to the composite wave for demonstration purposes. This spreadsheet, text data file, and Mathcad®7 file can be obtained at *http://www2.msstate.edu/~rwp1/gatech2000/* in the fourier.zip file.

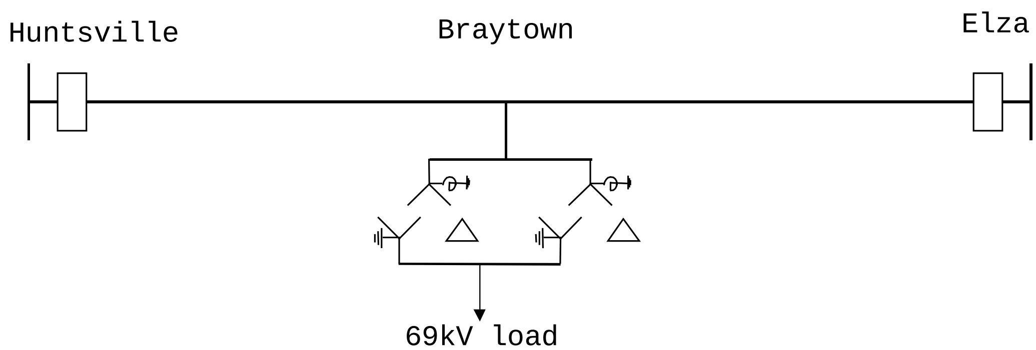
time step:	**0.000130**		# points				Function:	**COS**
fund. Mag:	**100.0**		**768**					
fund. Phase:	**0.0**							
cycles to plot:	**6.0**		sampling frequency:	**7,680 Hz**				
			samples per cycle:	**128**				
Harmonic	**2**	**3**	**5**			DC		
Magnitude	20.00	15.00	8.00			5		
Phase	0.0	0.0	0.0					
Plot?	☑	☑	☑	☐	☐			
t	f(t)	H1(t)	H2(t)	H3(t)	H4(t)	H5(t)	fund(t)	
0	148	20	15	8			100	
0.000130208	147.3811378	19.90369	14.837648	7.76025			99.87955	
0.000260417	145.5436532	19.61571	14.354105	7.05537002			99.51847	
0.000390625	142.5439056	19.13881	13.559839	5.9276088			98.91765	

The above pictured spreadsheet was used to create the following waveforms. The dark black composite curve being the waveform imported into Mathcad®and analyzed to evaluate my analysis method (blue – 2^{nd}, red – 3^{rd}, pink – 5^{th}, gray – fundamental, dc – not shown, black – composite).



**Appendix C	Braytown Differential Misoperation**

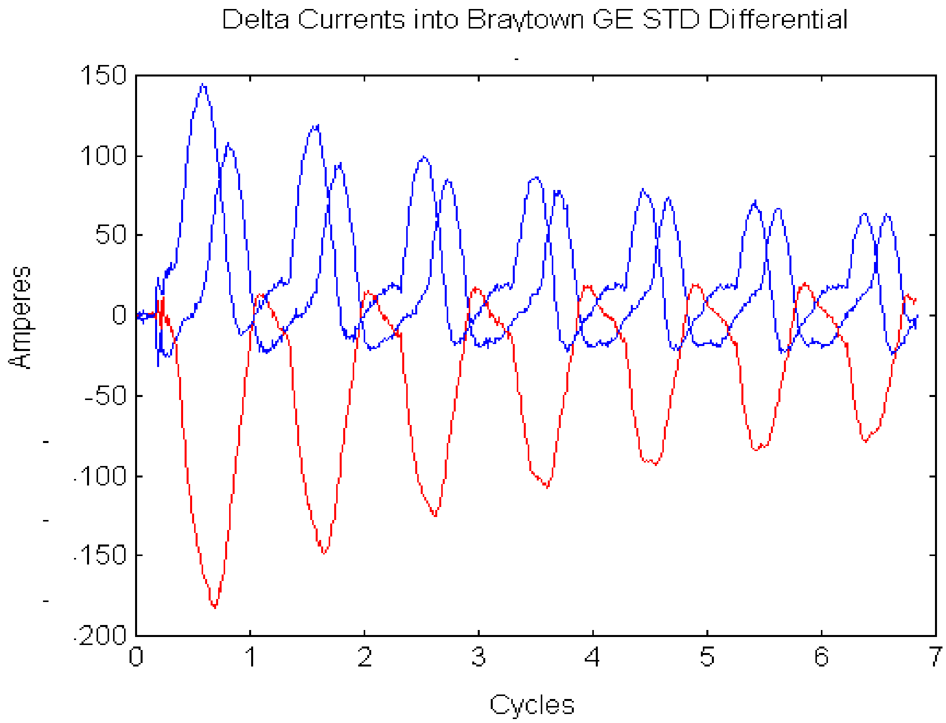
Date:		3/19/1999
Time:		0752 system time
Targets:	Device 87 C-phase time target (differential)
Relay type:	GE type STD style 12STD16C5A



Two banks in parallel, each rated as follows:
25/33.3/41.7 MVA
161kV-Y / 69kV-Y / 13kV delta
85-ohm neutral reactor on 161-kV side

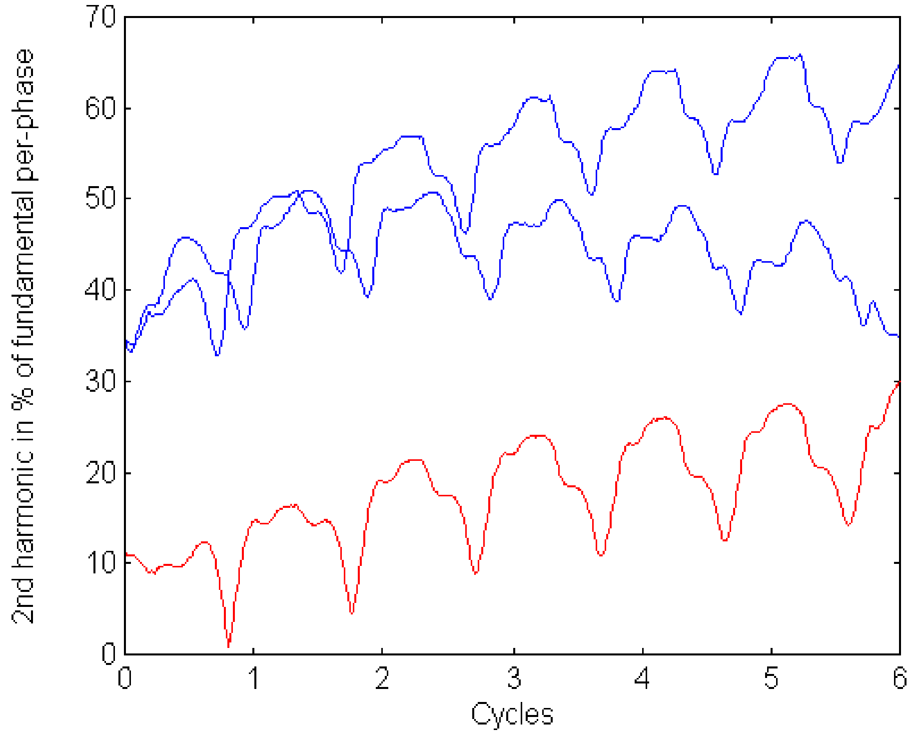
Station is tapped 23 miles from Huntsville terminal of the Huntsville - Elza 161-kV line. Above event occurred on dead-line reclose from Huntsville after auto-sectionalizing had isolated the permanently-faulted Elza-Braytown section (broken static wire). Upon reenergizing the Braytown bank the transformer differential tripped on inrush.

Analysis: The only waveforms available were from the DFR at Huntsville. The actual high-side currents going into the differential relays were the delta combinations of these three. A common phenomenon in these three (unknown to the authors at the time of this event) differential currents is that one of them will have a very small percentage of 2^{nd} harmonic content. The level present in the CA differential was below the 20% harmonic restraint required and the relay operated properly. Below is a plot of the three differential currents followed by a plot of the 2^{nd} harmonic content of the three high-side differential current waveforms calculated with a sliding window Fourier analysis of the first 6 cycles after re-energization.

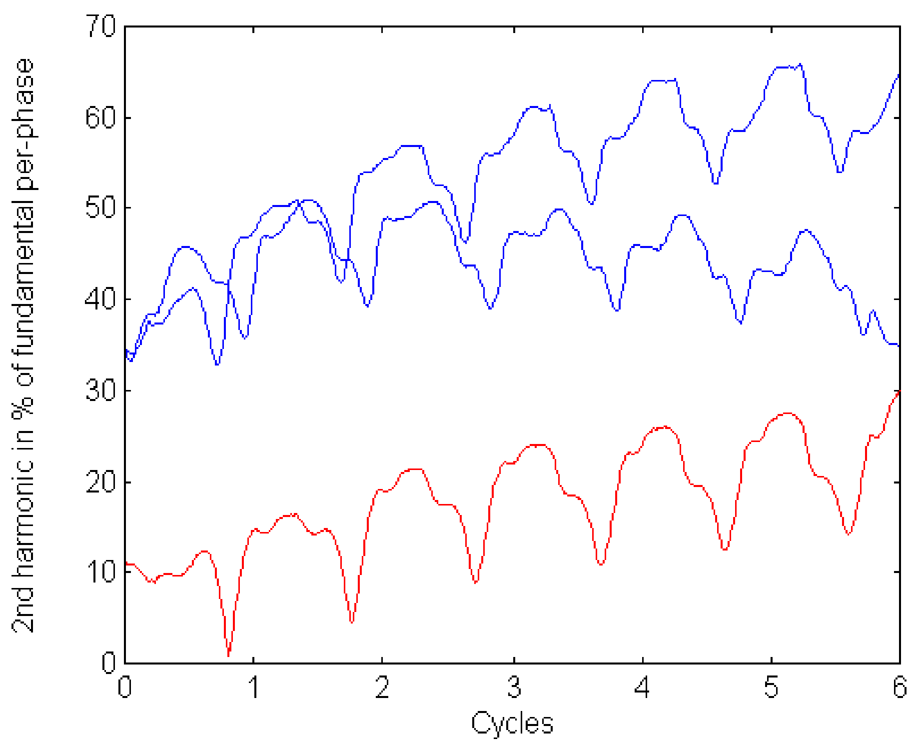


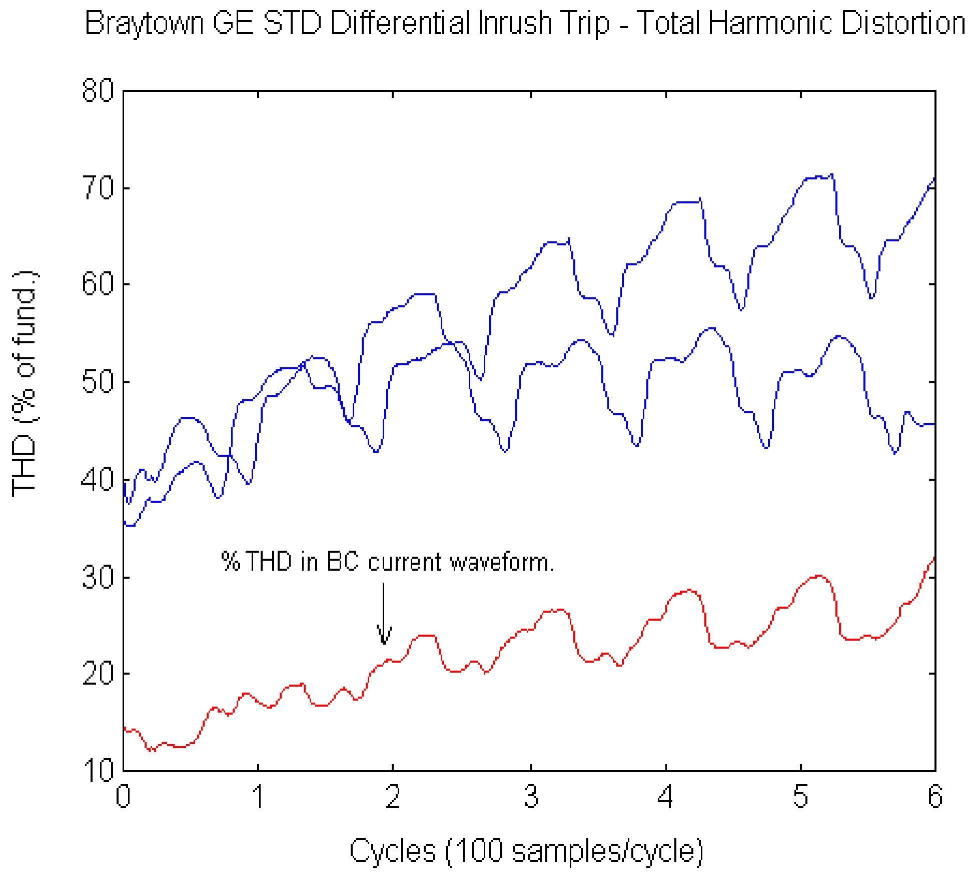
Analysis of these currents revealed a very low level of 2nd harmonic content in the BC current. Below is a graph of this harmonic content created in Mathcad® by using a sliding DFT window (described in appendix B & D). The BC 2nd harmonic content is in red.

Braytown GE STD Differential Inrush Trip - Second Harmonic Content

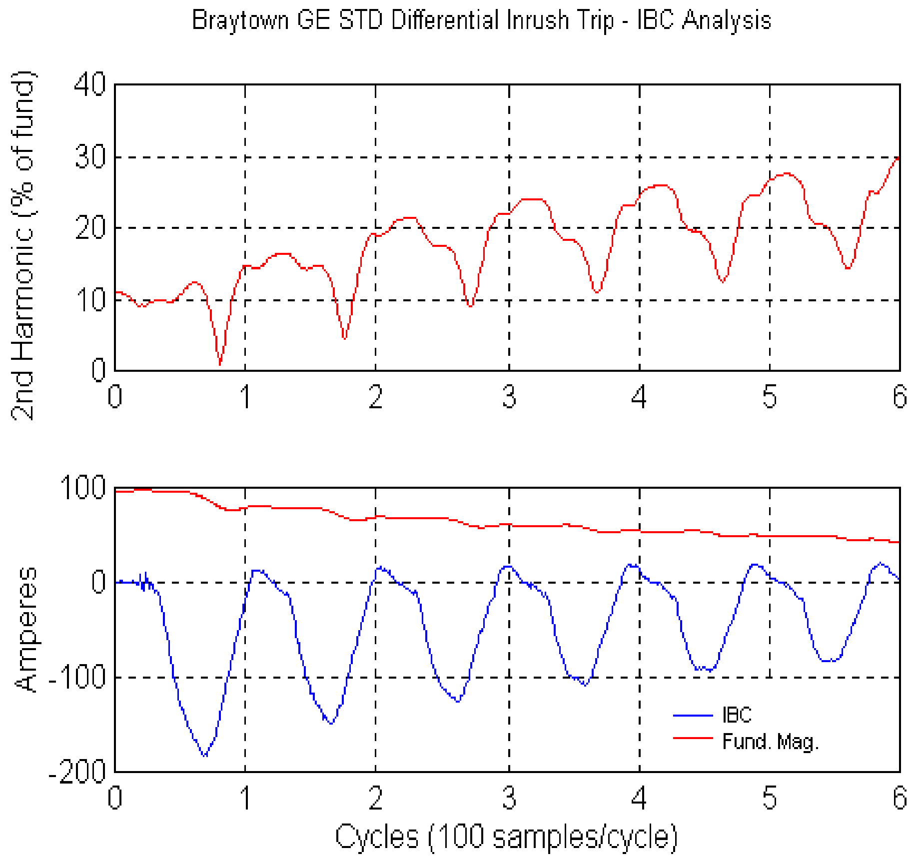


Braytown GE STD Differential Inrush Trip - Second Harmonic Content





From this analysis it can bee seen that the B-C current (in red) had less than 20% harmonic for over the 2.2 cycle operate time of the relays differential element resulting in the misoperation on inrush.



The lower plot above shows the amplitude of the fundamental component (in red) in the B-C 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 3.2A the relay would have picked up with current in the range of 0.64A to 1.28A with the midpoint being 0.96A. 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 current can be calculated as:

$$\mathrm{Iop} = \frac{\frac{75\mathrm{A}}{\sqrt{2}}}{\frac{400}{8.66}} = 1.15\mathrm{A}$$

As the 69kV load was picked up when the bank was energized there was some current flowing in the 69kV restraint coil. While there is no way to know what this value actually was we can calculate a value for an upper limit for this current to compare to estimations.
The formula for percent mismatch in a percentage differential relay equipped with taps is:

$$\%\mathrm{M} = \frac{\left|\frac{I_L}{I_H} - \frac{T_L}{T_H}\right|}{S} x100\%$$

Where S is the smaller of the two ratios in the numerator.

Appendix D Matlab 4.0 script files.

```
% FFT sliding window to plot 2nd harmonic content of Braytown
% differential currents.
%
% Input signal as IA, IB & IC from the file bray.m
%
% Russell Patterson
% rwpatterson@tva.gov
% http://www2.msstate.edu/~rwp1
% June 1999
%
%
clear  % clear all variables

bray;           % this loads the 3 current waveforms
IAB = Ia-Ib;    % this creates the delta currents
IBC = Ib-Ic;
ICA = Ic-Ia;
N = 100;        % samples per cycle of digital recorder
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 point
  WINDOW_of_IBC(j) = IBC(i+j-1);   % window
  WINDOW_of_ICA(j) = ICA(i+j-1);
 end
 FFT_of_WINDOW_IAB = fft(WINDOW_of_IAB);  % 2nd harmonic calc. For 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 sepeartely
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 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),my
second_ICA(1:P),'b');
xlabel('Cycles');
ylabel('2nd harmonic in % of fundamental per-phase');
title('Braytown GE STD Differential Inrush Trip - Second Harmonic
Content');
```