Understanding Differences in Harmonic Restraint and Harmonic Blocking in Transformer Differential Protection

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I. Introduction

It is common practice for utility companies to apply primary and secondary differential protections for large transformers. Company standards often require the use of two relays from different manufacturers for the primary and secondary protections. The settings of differential protections in the primary and secondary relays are often set similarly. However, field experiences indicate that only one of the two differential relays operated correctly in several recorded energization events at Xcel Energy. This prompted an investigation for the root cause as to why two relays with similar settings responded differently for the same events.

Although most microprocessor relay designs are based on the same principal, the difference in detailed design results in different responses to the same event. The paper will discuss various differences in the internal design of several commercially available differential relays and will focus on one of the major differences – harmonic restraint and harmonic blocking in providing secure and dependable relay operations during transformer energization. This paper will explain the difference between harmonic restraint and harmonic blocking, both mathematically and graphically.

II. Event Description

Two 115 – 34.5 kV auto-transformers are parallel connected, as shown in Figure 1. Both TR1 and TR2 have a maximum rating of 120 MVA with a base rating at 72 MVA. Before the event, TR1 was de-energized and TR2 was fully loaded at 120 MVA. The 115kV line through disconnect switch 5X150 was switched out and transformer TR1 was de-energized as well. Upon closing of 5X148, TR2's secondary differential relay initiated a differential lockout. The result of the lockout tripped open 5X148 and isolated TR2. With neither TR1 nor TR2 in service, the wind generators on the low side of the transformer banks were all off-line.

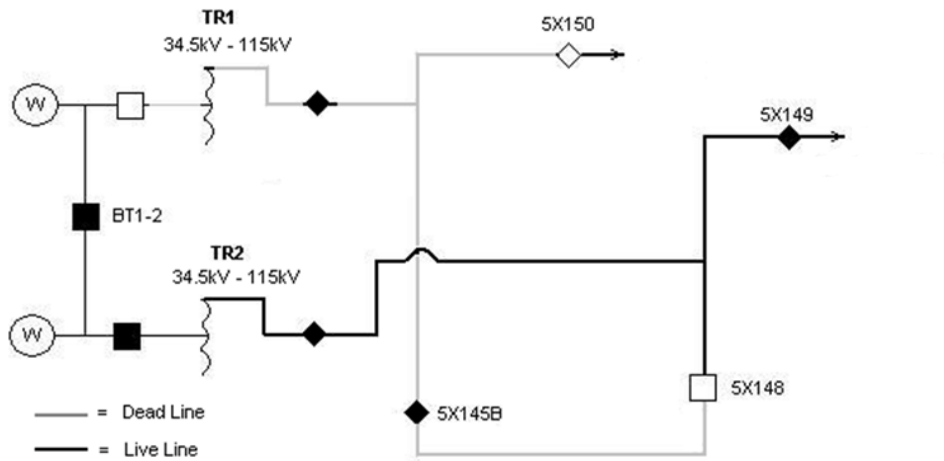

Figure 1 System Configuration before the Event

Since the two transformers are paralleled, the first thought may be whether the sympathetic inrush current caused the differential operation. After checking into the protection design, it was conformed that each of the two paralleled transformers has its own differential protection. TR2 has primary and secondary differential protections from two microprocessor relays made by two manufacturers. Protection set points of the two differential relays are basically the same. However, only the secondary differential relay operated during this event.

We would have thought that two relay set similarly should operate the same way. This event prompted us to look into the minor differences in the design of modern differential relays.

III. Principles of Transformer Differential Protection

The concept of transformer differential protection is reviewed here. For electromechanical differential relays, as illustrated in Figure 2, CT in the Y-connected transformer winding is delta-connected and CT in the delta-connected transformer winding Y-connected. For microprocessor relays, the secondary currents in CT are usually compensated internally in the relay. Microprocessor based differential relays are capable of using internal algorithms to compensate the differential transformer connections, transformer winding turns ratio, CT ratio differences, etc.

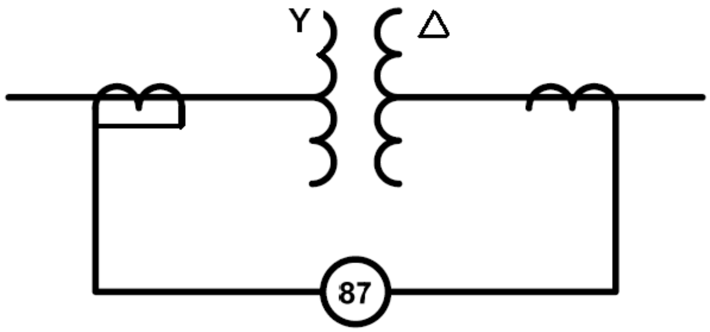

Figure 2 Concept of transformer differential protection

The concept of transformer differential protection can be easily extended to multi-winding transformers. Let vector $I_{comp\,i}$ be the compensated current in winding *i* of a multi-winding transformer. The operating current is generally defined as

$$Iop = \quad |\sum_{i} I_{comp\,i}| \tag{1}$$

However, there is less consistency in the definition of restraint current. The restraint current I_R is most commonly defined as either the maximum or average of the amplitude of the compensated currents.

$$I_R = Max \quad (|I_{compi}|) \tag{2}$$

$$I_R = \quad (\sum_{i} |I_{compi}|)/2 \tag{3}$$

With the operating and restraint current calculated, the operating characteristic can be decided from a well-known "percentage" slope, as illustrated in Figure 3.

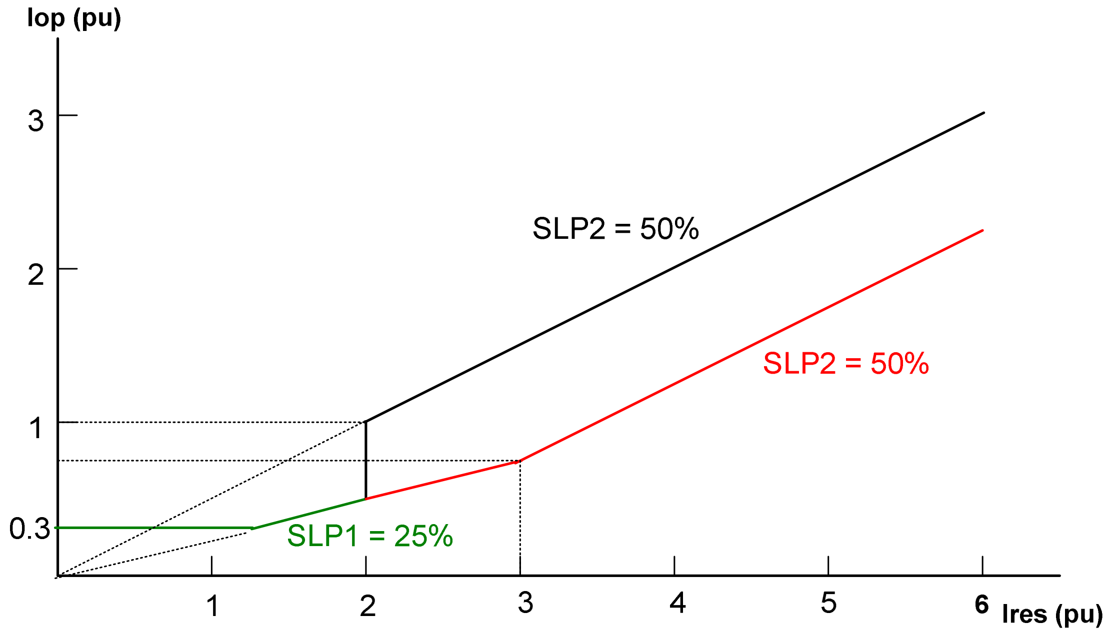

Figure 3 Percentage Differential Characteristic

In Figure 3, the height of horizontal line is I87min. I87min is the minimum pickup setting to avoid differential misoperation due to CT and relay metering accuracy, transformer excitation current, etc. Two commercially available percentage differential characteristics are included in Figure 3. The continuous curve is a little more mathematically involved. The minimum operating currents in three piecewise linear segments can be mathematically expressed as

$$When\ I_R \leq \frac{O87P}{SLP1},\quad I_{op} = O87P \tag{4}$$

$$When\ \frac{O87P}{SLP1} < I_R \leq I_{RS1},\quad I_{op} = SLP1 \cdot I_R \tag{5}$$

$$When\ I_R > I_{RS1},\quad I_{op} = SLP1 \cdot I_{RS1} + SLP2 \cdot (I_R - I_{RS1}) \tag{6.1}$$

$$When\ I_R > I_{RS1},\quad I_{op} = SLP2 \cdot I_R \tag{6.2}$$

Equation (6.1) and (6.2) represents continuous slope characteristic and discontinuous characteristic respectively. Equation (4), (5), (6.1) and (6.2) can be expressed by a general function as

$$I_{op} = f(I_R) \tag{7}$$

IV. Harmonic Restraint and Harmonic Blocking in Transformer Differential Protection

Other than different computation methods for restraint current and the difference in operating curve when restraint current is high, one major difference among microprocessor relays from different manufacturers is how a relay restrains from operation during transformer energization.

Transformers experience magnetizing inrush current during energization and inrush current appears to be a true differential current. The rich second harmonic component in inrush current is most commonly used to identify the condition of transformer energization. Differential operation is supposed to be blocked during normal transformer energization.

Harmonic restraint was used in early electro-mechanical relays [1]. In the method described in [1], the restraint current includes all the harmonics excluding fundamental but including DC. Current flowing in the restraint coil tends to restrain the operation from current flowing in the operating coil, which contains fundamental frequency only. Harmonic blocking method has been introduced in many modern microprocessor relays. With harmonic blocking, usually the second harmonic component is used (fourth harmonic is used by some relay manufacturers). When the ratio of the second harmonic component to the fundamental is greater than second harmonic set point, inrush condition is announced and the differential operation is blocked.

For harmonic blocking method, the differential operation criteria are

$$I_{op} > f(I_R) \tag{8}$$

And

$$\frac{I_{op2nd}}{I_{op}} < \frac{PCT2}{100} \tag{9}$$

And if fourth harmonic blocking is enabled,

$$\frac{I_{op4th}}{I_{op}} < \frac{PCT4}{100} \tag{10}$$

where PCT2 and PCT4 are the set points for 2nd-harmonic blocking percentage and 4th-harmonic blocking percentage respectively.

Harmonic restraint method may also be used in microprocessor relays. In one design, it uses only second and optional fourth harmonic component. The same settings PCT2 and PCT4 are used. The differential operation criteria is

$$I_{op} > f(I_R) + \frac{100}{PCT2} \cdot I_{op2nd} + \frac{100}{PCT4} \cdot I_{op4th} \tag{11}$$

Where I_{op2nd} and I_{op4th} are the magnitude of 2nd and 4th harmonic components. At first glance, there is not direct relationship between harmonic restraint and harmonic blocking. If we rewrite inequality (9) and (10),

$$I_{op} > \frac{100}{PCT2} \cdot I_{op2nd} \tag{12}$$

$$I_{op} > \frac{100}{PCT4} \cdot I_{op4th} \tag{13}$$

It is obvious that when inequality (11) hold, inequalities (8), (12) (equivalent of (9)) and (13) (equivalent of (10)) must hold. If a harmonic restraint based different protection operates, the corresponding harmonic blocking based differential protection must operate too. Harmonic restraint based differential protection is more secure than harmonic blocking based differential protection. However, it can also be observed that harmonic blocking based differential protection is more dependable and operates faster compared to the harmonic restraint based differential protection.

To understand how much a harmonic restraint curve could affect or deviate from a non-harmonic restraint curve, we will use a simple one-slope only differential operating curve. Inequality (11) can be rewritten as

$$I_{op} > \frac{SLP1}{100} * I_R + \frac{100}{PCT2} \cdot I_{op2nd} + \frac{100}{PCT4} \cdot I_{op4th}$$

Or,

$$I_{op} > \left(\frac{SLP1}{100} + \frac{100 * \frac{I_{op2nd}}{I_R}}{PCT2} + \frac{100 * \frac{I_{op4th}}{I_R}}{PCT4} \right) * I_R \tag{14}$$

From inequality (14), we see that the actual operating slope would be depended on the actual harmonic ratios ($\frac{I_{op2nd}}{I_R}$ and $\frac{I_{op4th}}{I_R}$) and the settings of the harmonic percentages (PCT2 and PCT4).

Example: A differential relay has settings of PCV2=15, PCT4 = 10. In an energization event, $\frac{I_{op2nd}}{I_R}$ = 30%, $\frac{I_{op4th}}{I_R}$ =7.5%, then from inequality (14),

$$I_{op} > \left(\frac{SLP1}{100} + \frac{100 * 0.3}{15} + \frac{100 * 7.5}{10} \right) * I_R = (\frac{SLP1}{100} + 2.75) * I_R$$

We see that if setting $SLP1 = 25$, for this energization event, the differential operation would need $I_{op} > 3I_R$, or the actual required operating slope from 25% to 300%.

If average restraint (Equation(3)) is used, the maximum theoretical slope is 200%. With high harmonic components, the differential relay is not able to operate for a 300% slope. However, if a transformer experiences a severe internal fault during energization, the harmonic ratio will be limited (provided limited CT saturation) and the differential operation is not likely to be blocked. If a transformer experiences a moderate internal fault, it is possible that the differential operation be blocked until the energizing harmonic dies out or the moderate internal fault develops to a more severe one.

It would be interesting to see graphically how much the actual differential slope would be raised for a specific harmonic restraint setting. For simplicity, only the 2nd harmonic restraint is considered in this example. The setting of the 2nd harmonic ratio (PCT2) is assumed to be 15%. SLP1 = 25%, SLP2 = 50%. The affect on the 2nd slope part is ignored for simplicity.

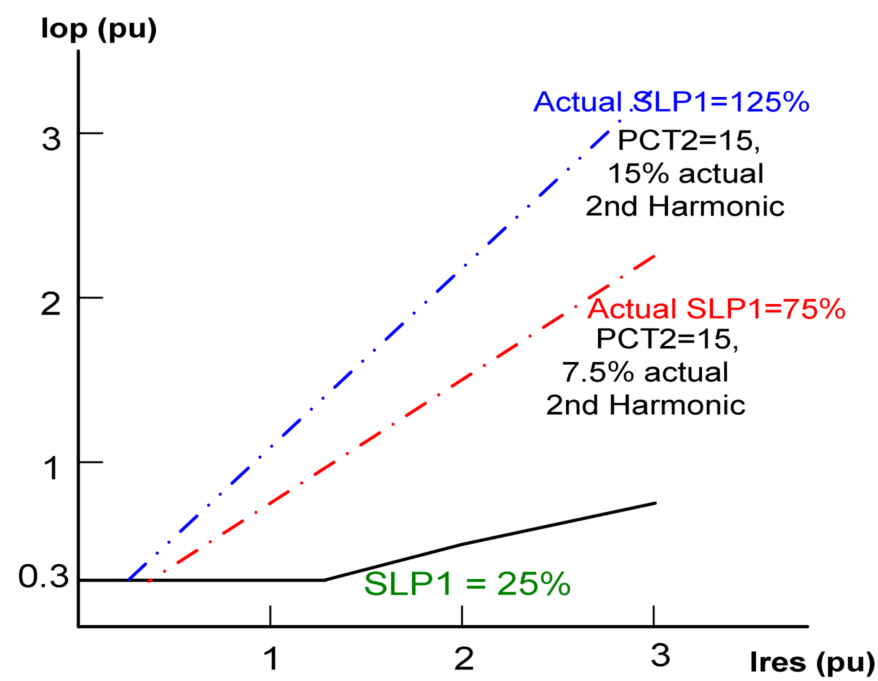

Figure 4. Dynamic shifting of operating curve for harmonic restraint

In Figure 4, the black operating curve is for the regular differential protection with harmonic blocking mechanism. The red operating curve is for differential protection with 7.5% of 2nd harmonic ratio. Since we ignored the 4th harmonic restraint, the difference between the red curve black curve is $\frac{100}{PCT2} \cdot I_{op2nd}$, which is equivalent to

$\dfrac{100 * \dfrac{I_{op2nd}}{I_R}}{PCT2} * I_R$, as we can see from equation (14). Per equation (14), the actual differential slope is $\dfrac{25}{100} + \dfrac{100 * 0.075}{15} = 75\%$ if the actual 2nd harmonic is 7.5%. The blue operating curve is associated with 15% of 2nd harmonic ratio. The slope is calculated to be 125% from equation (14) if the actual 2nd harmonic ratio is 15%.

In Figure 4, only the 2nd harmonic component is used in the harmonic restraint. If the 4th harmonic restraint is enabled with the 2nd harmonic component, the slope of the operating curve would be raised more significantly. In an energization event, the harmonic ratios fluctuate slightly. The actual operating curve changes dynamically with the actual calculated harmonic ratios.

We have studied and illustrated the difference between and harmonic restraint and harmonic blocking in transformer differential protection. It is important to understand the difference when we set transformer differential protection.

V. Analysis of transformer differential events

Let us review the event we introduced section II. The recorded related SCADA events are listed in Table 1.

Table 1: Recorded SCADA events

Date and Time	Operation
10/21/2008 7:06:58 AM	BT1-2 Breaker Closed by Operator
10/21/2008 7:07:42 AM	TR1 34.5kV Breaker Opened by Operator
10/21/2008 7:08:18 AM	115kV 5X148 Breaker Opened by Operator
10/21/2008 7:08:50 AM	115kV 5X150 MOD Opened by Operator
10/21/2008 7:09:35 AM	115kV 5X148 Breaker Closed by Operator
10/21/2008 7:09:35 AM	115kV 5X148 Breaker Opened
10/21/2008 7:09:35 AM	TR2 34.5kV Breaker Opened
10/21/2008 7:29:53 AM	TR2 34.5kV Breaker Closed by Operator
10/21/2008 9:02:03 AM	115kV 5X148 Breaker Closed by Operator
10/21/2008 9:02:32 AM	TR1 34.5kV Breaker Closed by Operator
10/21/2008 9:02:12 AM	BT1-2 Breaker Opened by Operator

At 10/21/2008 7:09:35 AM, we see the operator closed 115kV 5X148 Breaker to energize the transformer TR1 from 115kV side. Breaker 5X148 was immediately tripped open at 7:09:35 AM by the secondary differential relay protecting transformer TR2. Transformer TR2, which had full load at 120MVA, was brought down by opening of TR2 34.5 kV breaker at 7:09:35 AM. The primary differential relay did not operate during this event. The misoperation of the secondary relay was suspected and after the removal of the secondary relay, both transformer TR1 and TR2 were successfully brought into service after about twenty minutes of outage.

Common settings for both the primary and secondary relay: Transformer rating 120 MVA, VW1=34.5 kV, VW2=121 KV, CTR1 = 600, CTR2 = 120, TAP1 = 3.35 A, TAP2 = 4.77A, I87min = 0.2 pu, I2nd = 15%, SLP1 = 25, SLP2 = 50. Slope setting is not involved in this event since the operating point is at the flat part of 87 operating curve. Harmonic restraint is used in the primary relay while harmonic blocking is used in the secondary relay.

To analyze the event, COMTRADE files were downloaded from the secondary relay. In Figure 5, channels 1 through 10 were field recorded. Channels 11 through 21 were derived per differential algorithm. Channels 11 and 12 are derived zero sequence current (I0) for 34.5kV and 115kV winding. Channels 13 through 18 are tap compensated current after removing zero sequence current. Channels 19 through 21 are derived operating currents. Phase B and C of the operating currents do show obvious characteristics of typical inrush currents.

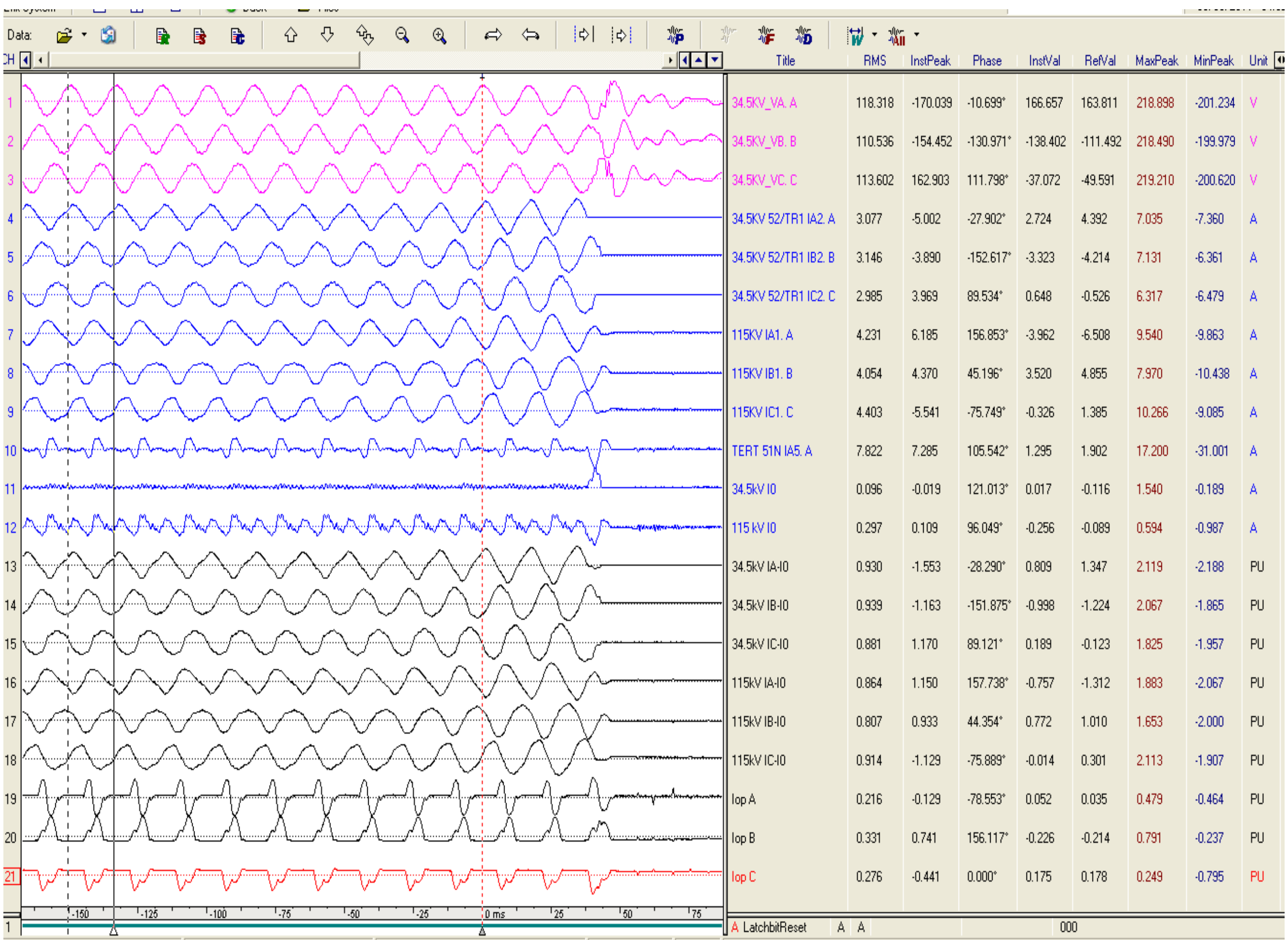

Figure 5: Field recorded waveforms and derived current waveforms for differential study

Figure 6 illustrates that the differential relay would operate if proper restraint (blocking) is not enabled.

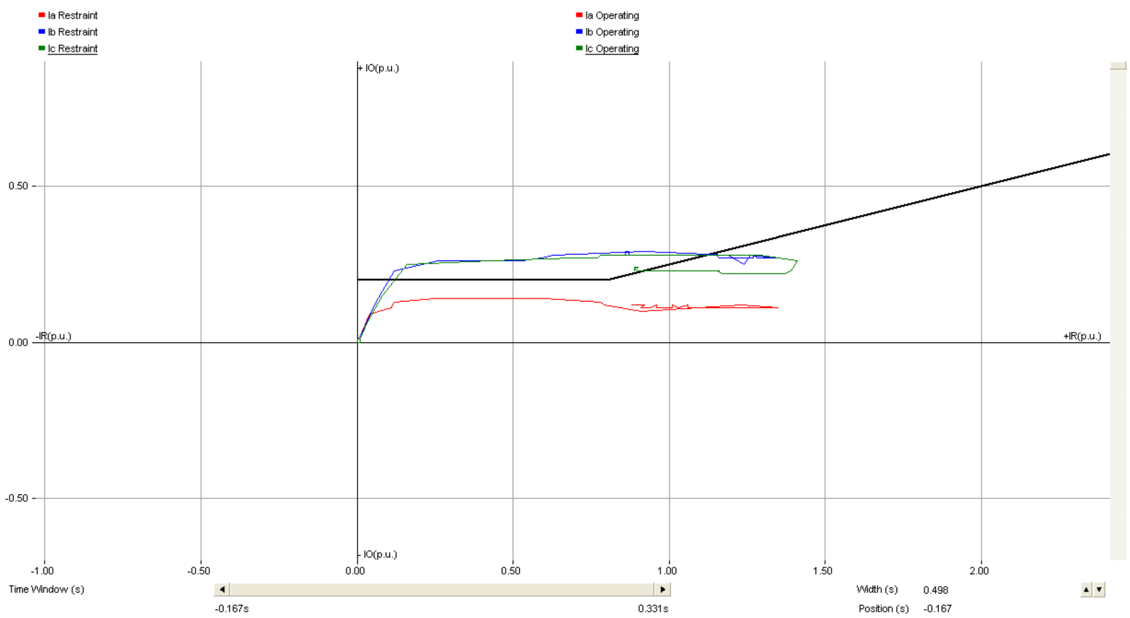

Figure 6: (Iop, IR) indicates differential trip without proper restraint

As we discussed Section IV, the harmonic component plays an important role in the security of differential operation during energization. Tables 2 through 4 list the harmonic components for each phase of the operating current.

Table 2: Harmonic components in phase A operating current

Harmonics

Channel Name: (19) Iop A Samp#: 192

Order	DFT Peak	DFT RMS	DFT An...	% of Fund.	% of Tru...
1	0.164	0.116	0.000°	---	53.506%
2	0.192	0.136	147.061°	117.311%	62.769%
3	0.143	0.101	312.536°	87.623%	46.883%
4	0.085	0.060	126.546°	51.715%	27.671%
5	0.031	0.022	313.223°	18.854%	10.088%
6	0.013	0.009	191.062°	7.883%	4.218%
7	0.015	0.011	319.039°	9.349%	5.002%
8	0.020	0.014	60.261°	12.238%	6.548%
9	0.013	0.009	200.233°	8.133%	4.352%
10	0.006	0.004	142.052°	3.475%	1.859%
11	0.009	0.007	297.868°	5.763%	3.084%
12	0.003	0.002	37.770°	2.046%	1.095%

True RMS: 0.216 Calculated RMS: 0.216

Table 3: Harmonic components in phase B operating current

Harmonics

Channel Name: (20) Iop B Samp#: 192

Order	DFT Peak	DFT RMS	DFT An...	% of Fund.	% of Tru...
1	0.396	0.280	0.000°	---	84.553%
2	0.204	0.144	137.405°	51.471%	43.520%
3	0.094	0.066	242.904°	23.719%	20.055%
4	0.082	0.058	354.581°	20.668%	17.475%
5	0.048	0.034	144.621°	12.050%	10.189%
6	0.009	0.006	23.567°	2.283%	1.930%
7	0.025	0.018	234.924°	6.441%	5.446%
8	0.014	0.010	11.991°	3.484%	2.946%
9	0.008	0.006	64.229°	2.039%	1.724%
10	0.011	0.008	135.378°	2.709%	2.291%
11	0.010	0.007	249.752°	2.588%	2.188%
12	0.005	0.004	11.693°	1.254%	1.060%

True RMS: 0.331 Calculated RMS: 0.330

Table 4: Harmonic components in phase C operating current

Harmonics

Channel Name: (21) Iop C Samp#: 192

Order	DFT Peak	DFT RMS	DFT An...	% of Fund.	% of Tru...
1	0.329	0.233	0.000°	---	84.255%
2	0.152	0.107	176.912°	46.123%	38.862%
3	0.058	0.041	78.826°	17.618%	14.844%
4	0.104	0.073	278.087°	31.564%	26.594%
5	0.067	0.047	95.860°	20.230%	17.045%
6	0.018	0.013	319.408°	5.563%	4.687%
7	0.014	0.010	178.964°	4.349%	3.664%
8	0.006	0.005	147.819°	1.954%	1.646%
9	0.014	0.010	335.239°	4.383%	3.693%
10	0.008	0.006	142.458°	2.443%	2.058%
11	0.001	0.001	273.450°	0.439%	0.370%
12	0.003	0.002	29.578°	0.827%	0.697%

True RMS: 0.276 Calculated RMS: 0.275

We see all phases have sufficient 2nd harmonic ratio to have the differential operation blocked. However, if a relay is designed with 2nd harmonic ratio calculated from each current input instead of the operating current, the 2nd harmonic ratio is very low in this event. Tables 5 through 10 give the harmonic components for each phase of transformer TR2 high side and low side currents separately.

Table 5: Harmonic components in TR2 115kV A phase current

Harmonics

Channel Name: (7) 115KV IA1. A Samp#: 957

Order	DFT Peak	DFT RMS	DFT Angle	% of Fund.	% of TrueR...
1	7.260	5.134	0.000°	---	99.029%
2	0.814	0.576	203.495°	11.217%	11.109%
3	0.161	0.114	226.163°	2.214%	2.192%
4	0.174	0.123	207.125°	2.401%	2.378%
5	0.203	0.144	136.264°	2.799%	2.771%
6	0.071	0.050	106.821°	0.980%	0.970%
7	0.069	0.049	165.483°	0.948%	0.938%
8	0.088	0.062	112.078°	1.208%	1.196%
9	0.043	0.030	151.389°	0.587%	0.582%
10	0.036	0.026	210.813°	0.497%	0.492%
11	0.078	0.055	346.310°	1.069%	1.058%
12	0.113	0.080	212.975°	1.559%	1.544%

True RMS: 5.184 Calculated RMS: 5.173 THD: 12.396%

Table 6 Harmonic components in TR2 115kV B phase current

Harmonics

Channel Name: (8) 115KV IB1. B Samp#: 957

Order	DFT Peak	DFT RMS	DFT Angle	% of Fund.	% of TrueR...
1	7.060	4.992	0.000°	---	97.891%
2	1.335	0.944	206.889°	18.903%	18.505%
3	0.280	0.198	72.023°	3.960%	3.876%
4	0.269	0.190	84.544°	3.808%	3.728%
5	0.105	0.074	32.485°	1.489%	1.458%
6	0.201	0.142	123.475°	2.841%	2.781%
7	0.034	0.024	12.564°	0.482%	0.472%
8	0.116	0.082	65.298°	1.640%	1.606%
9	0.039	0.027	112.461°	0.546%	0.535%
10	0.100	0.071	133.069°	1.421%	1.391%
11	0.085	0.060	177.471°	1.200%	1.175%
12	0.066	0.047	50.246°	0.940%	0.920%

True RMS: 5.100 Calculated RMS: 5.093 THD: 20.196%

Table 7 Harmonic components in TR2 115kV C phase current

Harmonics

Channel Name: (9) 115KV IC1. C Samp#: 957

Order	DFT Peak	DFT RMS	DFT Angle	% of Fund.	% of TrueR...
1	7.535	5.328	0.000°	---	99.126%
2	0.878	0.621	237.030°	11.655%	11.553%
3	0.055	0.039	341.991°	0.726%	0.719%
4	0.384	0.271	291.527°	5.092%	5.047%
5	0.128	0.090	211.709°	1.692%	1.678%
6	0.104	0.074	68.107°	1.385%	1.373%
7	0.019	0.013	159.236°	0.250%	0.248%
8	0.092	0.065	134.245°	1.227%	1.217%
9	0.035	0.025	336.523°	0.470%	0.466%
10	0.062	0.044	156.113°	0.819%	0.812%
11	0.089	0.063	271.385°	1.183%	1.173%
12	0.205	0.145	319.184°	2.720%	2.697%

True RMS: 5.375 Calculated RMS: 5.376 THD: 13.428%

Table 8 Harmonic components in TR2 34.5kV A phase current

Harmonics

Channel Name: (4) 34.5KV 52/TR1 IA2. A Samp#: 957

Order	DFT Peak	DFT RMS	DFT Angle	% of Fund.	% of TrueR...
1	5.175	3.660	0.000°	---	98.745%
2	0.469	0.332	168.496°	9.071%	8.957%
3	0.527	0.373	236.583°	10.187%	10.059%
4	0.110	0.078	86.499°	2.121%	2.095%
5	0.174	0.123	171.201°	3.354%	3.312%
6	0.082	0.058	117.054°	1.591%	1.571%
7	0.069	0.049	183.164°	1.332%	1.316%
8	0.033	0.023	46.321°	0.640%	0.632%
9	0.059	0.042	122.731°	1.147%	1.133%
10	0.011	0.008	253.521°	0.213%	0.210%
11	0.090	0.064	24.068°	1.744%	1.722%
12	0.093	0.066	222.689°	1.804%	1.781%

True RMS: 3.706 Calculated RMS: 3.699 THD: 14.710%

Table 9 Harmonic components in TR2 34.5kV B phase current

Harmonics

Channel Name: (5) 34.5KV 52/TR1 IB2. B Samp#: 957

Order	DFT Peak	DFT RMS	DFT Angle	% of Fund.	% of TrueR...
1	5.380	3.804	0.000°	---	99.153%
2	0.347	0.245	146.318°	6.447%	6.393%
3	0.406	0.287	152.612°	7.552%	7.488%
4	0.148	0.105	294.493°	2.748%	2.724%
5	0.226	0.160	52.162°	4.201%	4.165%
6	0.106	0.075	143.426°	1.967%	1.950%
7	0.086	0.061	121.697°	1.592%	1.579%
8	0.029	0.020	100.283°	0.538%	0.534%
9	0.011	0.008	193.458°	0.198%	0.196%
10	0.067	0.047	123.141°	1.240%	1.230%
11	0.129	0.091	163.201°	2.389%	2.368%
12	0.017	0.012	62.231°	0.307%	0.304%

True RMS: 3.837 Calculated RMS: 3.831 THD: 11.931%

Table 10 Harmonic components in TR2 34.5kV C phase current

Harmonics

Channel Name: (6) 34.5KV 52/TR1 IC2. C Samp#: 957

Order	DFT Peak	DFT RMS	DFT Angle	% of Fund.	% of TrueR...
1	5.109	3.612	0.000°	---	99.421%
2	0.323	0.228	174.130°	6.323%	6.287%
3	0.275	0.195	328.530°	5.390%	5.358%
4	0.155	0.110	197.935°	3.038%	3.020%
5	0.219	0.155	307.511°	4.292%	4.267%
6	0.117	0.082	112.375°	2.283%	2.270%
7	0.041	0.029	39.222°	0.806%	0.801%
8	0.043	0.031	155.210°	0.846%	0.841%
9	0.014	0.010	180.885°	0.275%	0.273%
10	0.015	0.011	270.389°	0.291%	0.289%
11	0.121	0.085	278.061°	2.360%	2.347%
12	0.153	0.108	332.833°	2.992%	2.975%

True RMS: 3.633 Calculated RMS: 3.635 THD: 11.103%

Since the secondary relay tripped on this event, we suspected and confirmed that the restraint in the secondary relay is based on each current input instead of the operating current. The root cause for this misoperation event from the secondary relay is the harmonic blocking is based on harmonic ratio calculated from the individual current inputs. In a sympathetic energizing event, the calculated harmonic ratio from one side of transformer would be small due to existing large load currents.

What we learned from this operation is to understand as much as we can in the internal relay design and its operation principle. Understanding the internal workings also helps to explain why differential operates or does not operate in event analysis.

Here is another interesting and mysterious event happened to a distribution transformer. A 115kV/13.8kV DABy (Dy1) transformer has a maximum rating of 28 MVA. It has differential protection with both 2nd and 4th harmonic restraint. Differential slope was set at 25%. Both 2nd and 4th harmonic ratios were set at 15%. CT ratios are CTR1 = 80 and CTR2 = 400. On July 27, 2011, the transformer was tripped mysteriously. Figure 7 illustrates the recorded current waveforms. CT 1 was connected to the high side and CT 2 was connected to the low side.

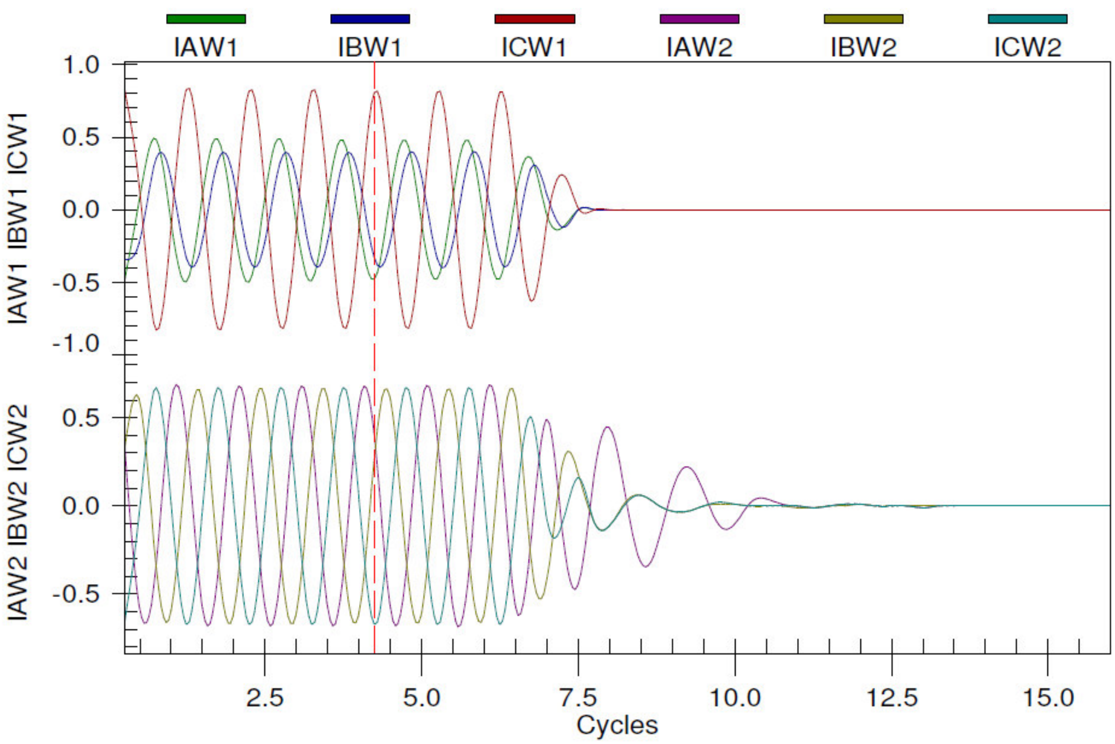

Figure 7 Waveform from a mysterious trip of a Dy1 transformer

From the recorded waveform, we see the load side currents were not disturbed before the trip. The high side currents were abnormal before the trip. Since the low (load) side currents were not disturbed, we suspected that it was a misoperation. After passing a series of thorough tests on the CTs, transformers gas and wiring connections, the transformer was brought into service without any problem. Load test indicates operating current is zero. The root cause of the event remains unknown. What makes this event more interesting is that the same differential relay correctly restrained a feeder fault two days before this mysterious event. Figure 8 illustrates the recorded operating, restraint and 2nd harmonic current.

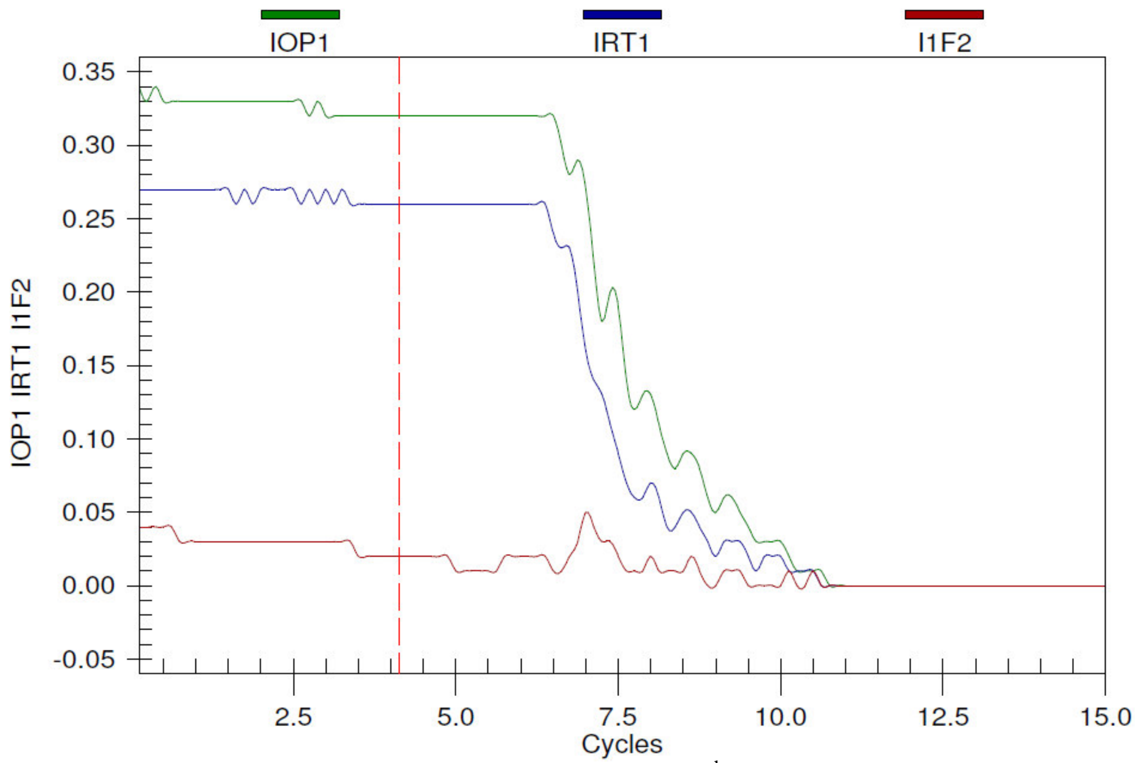

Figure 8 Recorded operating, restraint and 2nd harmonic current.

Provided the recorded waveforms, operating current, restraint current, and 2nd harmonic current are all correct, it is interesting to see that the differential relay was delayed at least 4 cycles.

At t = 2.5 Cycles,

IOP=0.33 pu, IRT=0.27 pu,

Calculated Differential Slope=IOP/IRT = 0.33/0.27 = 122%.

It looks like the differential trip should have tripped earlier per design. However, the differential tripped

At t = 4 Cycles,
IOP=0.32 pu, IRT=0.26 pu,
Calculated Differential Slope = IOP/IRT = 0.32/0.26 =123%.

The 1st slope setting is 25% and the operating region did not reach the 2nd slope region. Since harmonic restraint was used, we need to check how much the differential slope would be raised dynamically.

At t = 2.5 Cycles,

2nd harmonic I1F2 = 0.03 pu,

2nd harmonic ratio = I1F2/IOP1 = 0.03/0.33 = 9.1 %.

The actual differential slope raised by 2nd harmonic would be 9.1%/15% = 61%.

The minimum operating slope is 25% + 61% + Slope raised by 4th harmonic
= 86% + Slope raised by 4th harmonic

If slope raised by 4th harmonic is greater 36% to restrain (which requires minimum of 5.4% 4th harmonic ratio), then differential operation is restrained.

At t = 4.0 Cycles,

2nd harmonic I1F2 = 0.02 pu,

2nd harmonic ratio = I1F2/IOP1 = 0.02/0.33 = 6.1 %.

The actual differential slope raised by 2nd harmonic would be 6.1%/15% = 41%.

The minimum operating slope is 25% + 41% + Slope raised by 4th harmonic
= 66% + Slope raised by 4th harmonic.

If slope raised by 4th harmonic is less than 56% (which requires maximum 4th harmonic ratio smaller than 8.4%), the differential operation is unrestrained.

The actual 4th harmonic during the event is unknown since downloaded waveform already removed harmonics. The only reasonable assumption is that the 4th harmonic ratio was between 5.4% and 8.4%during this event.

Although the root cause of this event remains unknown, we see that how harmonic components can raise the operating slope significantly for differential relay with harmonic restraint implemented. This event tells us that it is very important to avoid CT saturation during internal fault if harmonic restraint is used.

VI. Conclusion

An interesting field sympathetic inrush event, which prompted the initial study of this paper, is presented in the paper. When a de-energized transformer was connected in parallel to a fully loaded transformer, the fully loaded transformer was tripped out by its differential relay. Since each of the two parallel transformers has its own differential protection, the unwanted trip is of particular interest for this sympathetic inrush event. A thorough analysis from the event record explains the different responses from the two relays. The primary relay uses harmonic restraint method and the secondary relay uses the harmonic blocking method. Another important difference is that harmonic calculation is based on the operating current in the primary relay but harmonic calculation is based on each current input only. It is concluded that harmonic restraint provides better security and harmonic blocking provides better dependability for transformer protection. It is also concluded that harmonic calculation based on operating current offers better security for transformer energization during transformer energization.

This study may help protection engineers to have a better understanding the internal workings of harmonic restraint. In setting differential relays, to achieve closer performance, it may be helpful to set the harmonic ratio slightly higher for differential relays with harmonic restraint and set harmonic ratio slightly lower for differential relays with blocking.

VII. References

[1] General Electric GEH-1816, BDD15B/BDD16B Transformer Differential Relay with Percentage and Harmonic Restraint

[2] Behrendt K., Fischer N., Labuschagne C, ”Considerations for Using Harmonic Blocking and Harmonic Restraint Techniques on Transformer Differential Relays”, 2006 Western Protective Relay Conference

VIII. Acknowledgement

The authors would like to thank Mark Gutzmann, Joshua Erdman and John Berzins at Xcel Energy for their valuable discussions during the development of this paper. The author would also like to thank several relay manufacturers for their coordination to provide information on their internal designs.

IX. Biography

John Wang received his B.S. and M.S. in electrical engineering from Zhejiang University in 1985 and 1988 respectively. He earned a second M.S. in electrical engineering from University of Missouri-Rolla in 1997. He was an assistant professor in Zhejiang University from 1988 to 1994. He joined Basler Electric in 1998, was a principal engineer and had almost 12 years experience designing protective relays and supporting customer relay applications. He joined Xcel Energy in September 2010 as a Principal Engineer in System Protection Engineering. He is a registered professional engineer, a senior member of IEEE, a member of the IEEE Standard Association, IEEE Power Engineering Society, and IEEE Power System Relaying.

John Grimm received his B. S. in Electrical and Electronis Engineering from North Dakota State University in 1986. He has over 20 years of protective relaying experience. He is presently the Supervisor of the System Protection Enginneering (NSP) at Xcel Energy. He is a registered professional engineer in the State of Minnesota, and a member of IEEE.