SELECTING CTS TO OPTIMIZE RELAY PERFORMANCE

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ABSTRACT

Although there is an abiding interest in the application of current transformers for relaying, few written rules exist for selecting ratings. For example, the PSRC document C37.110 "IEEE Guide to the Application of Current Transformers for Relaying Purposes" contains selection rules for differential relay applications. However, it offers no guidance for other applications where these rules do not apply. Small cores, long leads, high burdens, high currents, and offset lead to saturated cts. Saturation affects virtually all relay elements that use current. This paper examines the effects of saturation on various elements, and gives application guidelines that eliminate or minimize the risk of ct saturation.

KEY WORDS:

Ct Selection, Ct Saturation Effects, Ct Application.

INTRODUCTION

To introduce the subject of ct selection we first review the relation between the excitation curve and the standard burden and voltage ratings of a ct. We then examine the relation between the flux density and the time integral of the voltage. Using this information, we relate the fault current, the ct burden, and the system X/R ratio in an expression which ultimately determines the useful range in any ct. The paper then identifies the effects of degrees of saturation on various relay elements, and gives application guidelines which eliminate or minimize the risk of ct saturation.

CT RATINGS AND THE EXCITATION CURVE

A finite amount of ampere-turns are required to establish flux in a ct core and can be expressed as magnetizing current measured at the secondary terminals. The excitation current, which is subtracted from the ratio current, has definite values for each value of voltage as shown in Figure 1. This curve depicts steady-state voltage versus excitation current where the voltage is measured with an average reading voltmeter calibrated rms. It is actually a plot of flux versus magnetizing current since the average voltage is the volt-time integral averaged over the period of the sine wave.

The excitation curve, shown in Figure 1 for a C400, 2000:5 multi-ratio bushing ct, is a measure of ct performance and can be used to determine ratio correction factors at various levels of steady-state excitation. While the excitation curve has a well-defined knee-point [1], it has no discernible point of saturation. For this reason relaying accuracy ratings are based on a ratio correction not exceeding 10 percent and ratings are designated by classification and secondary voltage. The secondary voltage rating is the voltage the ct will support across a standard burden with 20 times rated current without exceeding 10 percent ratio correction.

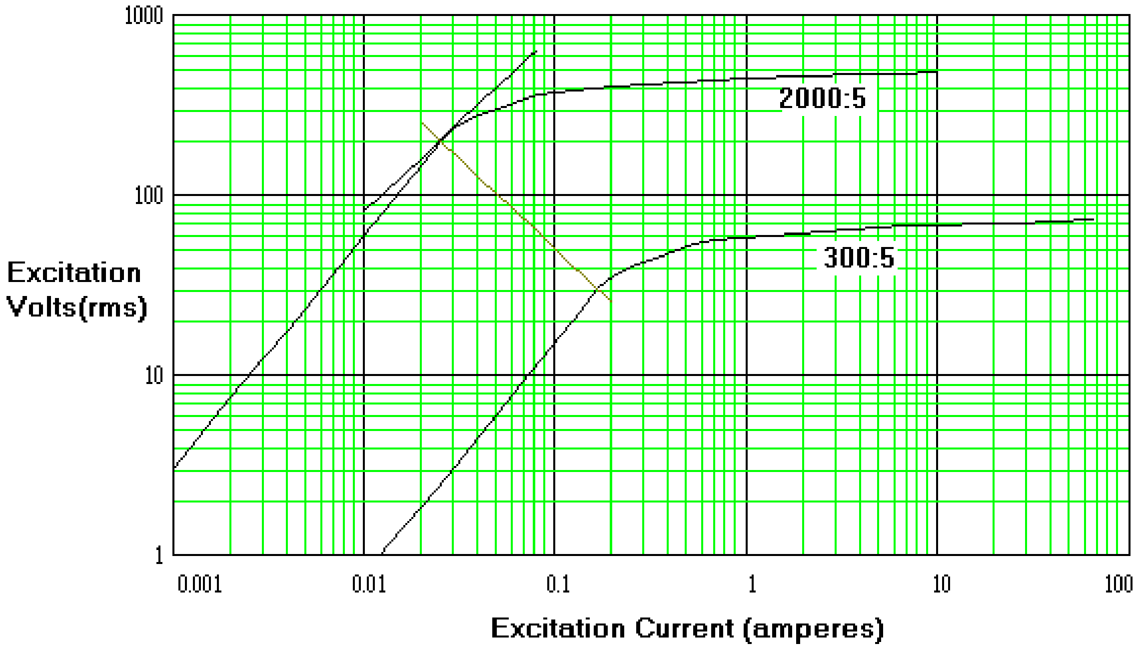

Figure 1: 2000:5 Ct Excitation Curve and its 300:5 Tap Shown With Knee-Point Tangents and Normal Lines

The standard burdens for relaying are 1, 2, 4, and 8 ohms, all with an impedance angle of 60°. Consequently, at 20 times the 5 ampere rated secondary current, the standard ratings are 100, 200, 400, and 800 volts. Since the ct rating occurs with 100 amps of secondary current at a 10 percent ratio correction factor, the voltage rating can be read from the excitation curve at 10 amperes of excitation current. We must first subtract the internal voltage drop due to the dc resistance of the winding. For the 2000:5 ratio winding in Figure 1, the voltage read the from curve at 10 amperes is 496 volts. In this case the voltage is less than the 800 rating and greater than 400. Therefore the rating is C400 provided the 400 turn winding has less than a 0.0024 ohms per turn dc resistance to guarantee an internal voltage drop less than 96 volts.

THE VOLT-TIME AREA

The burden voltage v is related to core turn N and the rate of change of the core flux ϕ by the induction equation:

$$v = N \cdot \frac{d\phi}{dt} \tag{1}$$

We can integrate Equation (1) to show that the flux density in the core is represented by the area under the voltage waveform. Therefore the flux linkages in the core are given by integral Equation (2) where the flux is expressed as flux density B times the core cross sectional area A.

$$\phi \cdot N = B \cdot A \cdot N = \int_0^t v \cdot dt \tag{2}$$

We can now recognize the significance of the ANSI voltage rating because the area under the sine wave of that magnitude represents the saturated flux density B_S. That volt-time area signifies the threshold of saturation and marks the boundary of saturation-free operation.

Figure 2 shows the shaded volt-time area produced by asymmetrical fault current. Here I_F is the magnitude of the fault current in the secondary, Z_B is the burden impedance, and L/R is the time constant of the primary fault circuit. The sine wave and exponential components of the wave are shown dashed for comparison. The plot emphasizes the fact that although we think of the C-rating as a sine wave, we in fact must consider the increased volt-time area of the asymmetrical fault when selecting a ct.

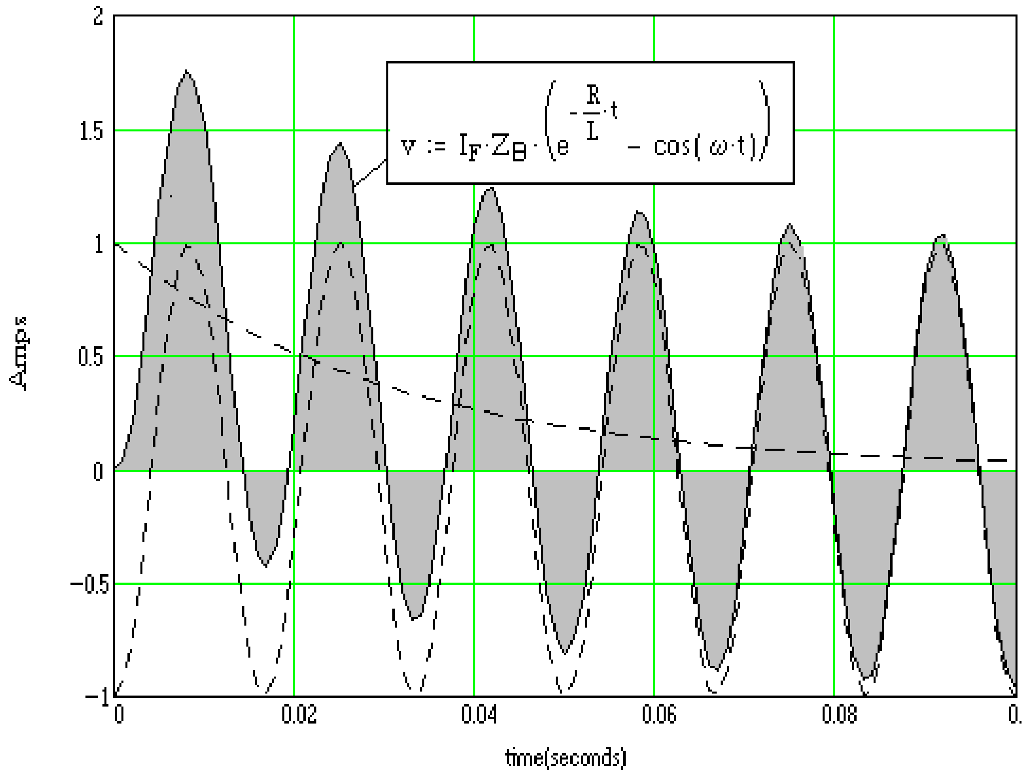

Figure 2: Burden Voltage for Asymmetrical Fault Current

Using the asymmetrical voltage in Equation (2) we can write:

$$B_S \cdot N \cdot A \cdot \omega = I_F Z_B \left[-\frac{\omega L}{R} \int_0^t e^{-\frac{R}{L}t} \left| -\frac{R}{L} dt \right| - \int_0^t \cos(\omega t)(\omega dt) \right| \tag{3}$$

In Equation (3), the limit of the integral of the exponential term is the X/R ratio of the primary circuit. Since the limit integral of the cosine term is unity we can write the equation:

$$B_S \cdot N \cdot A \cdot \omega = \left| \frac{X}{R} + 1 \right| \cdot I_F Z_B \tag{4}$$

Equation (4) expresses the C-rating voltage in terms of the physical parameters of the ct, namely the saturated flux density B_S, the turns ratio N, the core cross-sectional area A, and the system frequency ω. Moreover, it determines the saturation-free operation range of the ct in terms of the system X/R ratio, the maximum fault current I_F, and the ct burden Z_B.

The Criterion to Avoid Saturation

We can derive a more versatile form of Equation (4) by recognizing that the rating voltage is 20 times the voltage across the standard burden at rated current. If we then express the fault current I_F in per unit of the rated current and the burden Z_B in per unit of the standard burden, Equation (4) becomes the simple criterion to avoid saturation:

$$20 \geq \left| \frac{X}{R} + 1 \right| \cdot I_f \cdot Z_b \tag{5}$$

where :		
	I_f	is the maximum fault current in per unit of ct rating
	Z_b	is the ct burden in per unit of standard burden
	X/R	is the X/R ratio of the primary fault circuit

Here is an example of how the criterion is used: A transmission line has an 85.24° impedance angle (i.e., the X/R ratio is 12). The maximum fault current is 4 times the rated current of the C800 ct. Equation (5) is satisfied when Z_b is equal to or less than 0.38 per unit of the standard 8 ohm burden. Therefore saturation is avoided by keeping the ct burden at 3.02 ohms or less.

Selecting CTs for Line Protection

In practice, modern line relays clear faults in cycles to preserve stability, accurately identify fault type for single-pole reclosing applications, and determine an accurate fault location. To do this, line relays require undistorted ct secondary current to perform phasor measurement in the presents of the dc offset. How well are ct rated for line protection? The criterion stated in Equation (5) can be used to check any given application.

For example, the line relaying for a 4.5 mile 138 kV transmission uses a vt ratio of 1200:1 and a ct ratio of 300:1. The ct is C800, 2000:5 multi-ratio on the 1500:5 tap. The maximum fault is 4625 MVA or 19349 amps and the line and source impedance angle is 74°. The parameters for Equation (5):

$$I_f = \frac{19349\text{A}}{1500\text{A}} = 12.9 \qquad \frac{X}{R} = \tan(74) = 3.48 \tag{6}$$

Substitute these values in Equation (5) to determine the maximum burden in per unit of the standard burden:

$$Z_b \le \frac{20}{\left|\frac{X}{R}+1\right|\cdot I_f} = \frac{20}{(3.48+1)\cdot 12.9} = 0.345 \tag{7}$$

Equation (7) indicates that the burden should be is less than or equal to 0.345 per unit of the standard burden. Although the standard burden is 8 ohms for the C800 rating, based on constant volts per turn we must use three-quarters of that value because the 1500:5 tap is used. Consequently saturation is avoided if the total burden is equal to or less than:

$$Z_B = 0.345\cdot 6 = 2.073\,\Omega \tag{8}$$

The burden budget for the installation is:

Ct leads 200 feet full circuit run of #11 AWG (1.261 Ω/1000′)	0.252 Ω
Ct winding 300 turns at 0.0025 Ω/turn	0.750 Ω
Allowable relay burden	1.071 Ω
Total burden	2.073 Ω

The relays, consisting of a microprocessor based distance relay with negligible burden and an overcurrent relay used as a current detector, have a combined burden easily less than the allotted 1.071 ohms. Consequently, ct saturation is avoided for all asymmetrical as well as symmetrical faults on the line.

CT Selection Procedure

The above example suggests the following ct selection procedure using Equation (5) in any given line relay application:

1. Determine the maximum fault current I_F in primary amperes.
2. Determine the corresponding primary circuit X/R ratio.
3. Select the ct voltage rating. Then determine the total burden in per unit of the ct standard burden.
4. Using Equation (5) calculate I_f which is the fault current in per unit of ct nominal rating.
5. Divide the maximum primary fault current I_F by the per unit current to determine the ct nominal current rating. Select the nearest standard rating greater than the calculated value.

Over what range of applications can the procedure be successful? Whether or not Equation (5) can be satisfied depends on the X/R ratio and the magnitude of the maximum fault current. You can specify the burden and the X/R ratio and then use Equation (5) to calculate the maximum fault current for a given ct ratio. Table 1 lists the maximum fault currents versus X/R ratio for which saturation is avoided using 3000:5, 2000:5, or 1500:5 cts.

Table 1: Maximum Current to Avoid Saturation

Line Angle	X/R ratio	C800, 3000:5 $Z_B = 2.5$	C800, 2000:5 $Z_B = 2.0$	C400, 1500:5 $Z_B = 2.0$
75°	3.7	40,547 amps	33,812 amps	12,680 amps
77°	4.3	36,012 amps	30,010 amps	11,254 amps
80°	5.7	28,780 amps	23,983 amps	8,994 amps
82°	7.1	23,689 amps	19,715 amps	7,393 amps
83°	8.1	20,997 amps	17,479 amps	6,561 amps
84°	9.5	18,261 amps	15,217 amps	5,707 amps
85°	11.4	15,446 amps	12,872 amps	4,827 amps
86°	14.3	12,548 amps	10,457 amps	3,921 amps
87°	19.1	9,561 amps	7,968 amps	2,988 amps
88°	28.6	6,478 amps	5,399 amps	2,025 amps

CALCULATING CT BURDEN

In the process of ct selection we are interested in minimizing the total burden that consists of the internal resistance of the ct winding itself, the resistance of the leads from the ct to the relay including the return path, and the burden of the connected relays.

Higher ratio cts (3000:5) contribute a resistance of 0.0025 ohms per turn to the burden and lower ratios (300:5) 0.005 ohms per turn. Consequently, applying a 600 turn (3000:5) ct contributes an internal resistance of 1.5 ohms. In new installations we can choose the wire size to control the resistance for a circuit run. For example, the log of resistance per 1000 feet of wire is proportional to the AWG gage of the wire. A benchmark for copper wire is 0.9989 ohms/1000′ for #10 gage AWG wire. Decreasing the gage by 3 numbers halves the resistance and increasing it by 3 doubles the resistance. Consequently, the handy formula for resistance versus AWG wire gage is:

$$\Omega / 1000' = e^{0.232G - 2.32} \tag{9}$$

where: $\Omega/1000'$ is the resistance in ohms per 1000 feet
G is the AWG gage number

A good practice is to size the leads to limit the lead resistance to 0.5 ohms or less. Under this rule, #10 wire would be the choice if the cts were located 250 feet from the relays for a total run of 500 feet to and from the cts.

Finally, we can contrast the almost negligible burden of a multi-function microprocessor based relay with the burden in the order of ohms contributed by electromechanical relays for the same function. The advantage of the low burden is seen in view of the burdens and fault current restrictions versus X/R ratio listed in Table 1.

LIMITS OF THE CRITERION

Can saturation be avoided in all applications? A limit to the criterion is indicated in Table 1 where the permissible maximum fault current for a given ct rating is severely decreasing with increasing X/R ratio. The limit occurs where high X/R ratio and high fault current are experienced near a generator. It then becomes impractical to size the ct to avoid saturation during an asymmetrical fault. We must then abandon the criterion and rate the ct for the reasonable sensitivity for line end faults. It then remains that we must assess the effect of saturation during the offset.

Statistics of Asymmetry

When the current is less than 20 times ct nominal rating and the burden is less than the rated standard burden, no saturation will occur for symmetrical fault current. Furthermore, an insulation breakdown or a flashover is more likely to occur at a voltage peak where the reactive current is at a natural zero. Consequently, line-to-ground faults are more likely to be symmetrical faults. However, in any three-phase faults all currents cannot be at a zero simultaneously in each phase and dc offset is inevitable in one or more phases. In addition the phase displacement causes unequal dc offset to occur in each phase.

A Case History

How does saturation affect the response of a distance relay? The effect is less dramatic than one might imagine and is best illustrated by an example. Consider a 31 mile 230 kV line protected by a microprocessor distance relay where the vt and ct ratios are 2000:1 and 600:1 respectively. The ct has a C800, 3000:5 rating with a total burden of 2.5 ohms. The line is one of the lines connecting a generating station to the system where the maximum three-phase fault duty is 17,184 MVA and the X/R ratio of the line and the source is 25. The fault current of a three-phase fault on the line at 1.55 miles from the station is 33,195 amps per phase. The relay response to a severe fault of this type at various inception angles is presented in the following three event reports.

33 kA Fault with Ideal CTs

Event 1 is the ideal case of the three-phase fault with no ct saturation. The report contains quarter-cycle samples in a sequence of events format. Samples 9 through 36 of the report show pre-fault, fault, and post-fault current and voltage samples and the states of all the fault measuring elements, outputs and inputs. Currents and voltages are labeled left to right at the top with the element labels (read vertically) toward the right. Time progresses from top to bottom in quarter-cycle intervals. With a quarter-cycle representing 90° between samples, any sample and the previous sample form the real and the imaginary parts of the phasor yielding magnitude and phase angle of the measured quantity.

The event, triggered at the 16^{th} sample, shows pickup of the supervisory instantaneous overcurrent element 50H. The negative-sequence element 51Q picks up momentarily as a complete cycle of data is accumulated. However, the significant point is that the first of the phase-to-phase mho elements (ZBC) declares a Zone 1 fault and actuates the trip contacts 1 and 2 (indicated by the B in that column) before the full cycle of data is acquired. The relay then continues to measure until the current is interrupted and in this interval determines an accurate fault location. The relay then appends the fault type, the front-panel targets, the fault location, and the tracking frequency at the end of the report.

Event 1 - 33 kA ABC Fault at 1.55 Miles on a 230 kV (Theoretical - No Ct Saturation)

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EXAMPLE: BUS B, BREAKER 3             Date: 07/11/96    Time: 08:49:42.742



    CURRENTS (pri)             VOLTAGES (kV pri)     RELAY ELEMENTS  OUT   IN

                                                    ZZZZZZO  555566L 1357 1357
                                                    ABCABCO 31110770 &&&& &&&&    Event
   IR     IA     IB     IC     VA      VB      VC   BCAGGGS 2NQPPNQP 2468 2468    Sample

  -12     -3     -3     -6   60.2    74.9  -135.2 ....... ........ .... 1...    9
    0      0      0      0 -121.3   112.9     8.5 ....... ........ .... 1...    10
    0      0      0      0  -60.2   -74.9   135.2 ....... ........ .... 1...    11
   -9     -3     -3     -3  121.3  -112.9    -8.5 ....... ........ .... 1...    12

   -9     -3     -3     -3   60.2    74.9  -135.2 ....... ........ .... 1...    13
   -3     -3      0      0 -121.3   112.9     8.6 ....... ........ .... 1...    14
    0      0      0      0  -60.1   -74.9   135.2 ....... ........ .... 1...    15
  -84  -7065  -1323   8304  104.8   -84.8   -20.1 ....... ....H... .... 1...    16

  201  10425 -10416    192   40.3    57.1   -97.6 .1..... Q.p.H... B4.. 1...    17
   66  13899  11169 -25002  -58.0    41.4    16.8 111.... Q.p.H... B4.. 1...    18
 -243 -25761  24000   1518  -17.1   -28.3    45.6 111.... Q.p.H... B4.. 1...    19
   18 -13668 -19701  33387   27.8   -26.0    -2.0 111.... ..p.H... B4.. 1...    20

   60  30663 -27171  -3432   13.7    17.3   -31.2 111.... ....H... B4.. 1...    21
  -21  13662  19707 -33390  -27.8    26.0     2.0 111.... ....H... B4.. 1...    22
  -72 -30666  27162   3432  -13.8   -17.3    31.2 111.... ....H... B4.. 1...    23
   15 -13659 -19710  33384   27.8   -26.0    -2.0 111.... ....H... B4.. 1...    24

   63  30666 -27165  -3438   13.7    17.3   -31.2 111.... ....H... B4.. 1...    25
  -24  13650  19710 -33384  -27.8    26.0     2.0 111.... ....H... B4.. 1...    26
  -60 -25059  17940   7059  -16.3   -13.4    27.3 111.... ....H... B4.. 1...    27
   -3  -7653 -13023  20673   33.6   -21.5   -10.1 111.... ....H... B4.. 1...    28

   12   9720  -4362  -5346    9.4     4.8   -11.8 111.... ....H... B4.. 1...    29
    9    828   3165  -3984  -19.8     8.5     9.1 111.... Q.p.H... B4.. ....    30
    3      0      0      3   -0.0     0.0     0.0 111.... Q.p.H... B4.. ....    31
   -9     -3     -3     -3   -0.0    -0.0     0.0 ....... Q.p....* B... ....    32

   -9     -3     -3     -3   -0.0    -0.0    -0.0 ....... Q......* B... ....    33
    0      0      0      0    0.0     0.0    -0.0 ....... Q......* B... ....    34
    0      0      0      0    0.0     0.0     0.0 ....... Q......* B... ....    35
   -9     -3     -3     -3   -0.0    -0.0    -0.0 ....... Q......* B... ....    36


Event:  ABC    Location:   +1.55    Frequency:    60.0

Targets: INST ZONE1 EN A B C       V1 Mem:   135.0 / 333
```

This event is of course purely theoretical because (1), dc offset can not be avoided for a three-phase fault and (2), the specified ct rating, burden and X/R ratio indicate that dc offset will cause saturation with as little as 7413 amps of fault current. The severe ct saturation caused by the 33 kA fault with maximum offset in A-phase is shown in Figure 3.

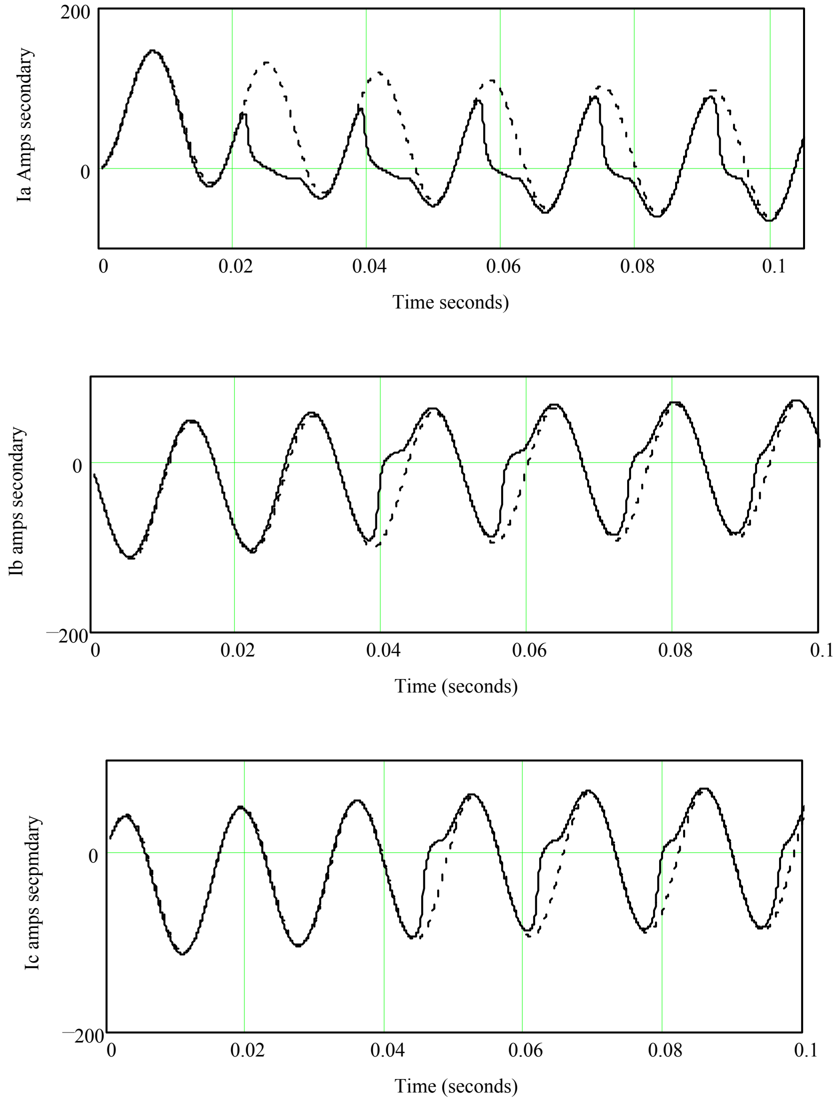

Figure 3: Secondary Current in a C800, 3000:5 With 33 kA Offset Three-Phase Fault at 1.55 Miles With 0.066 Primary Time Constant

THE SATURATION EFFECT

We can see the effects of saturation in the waveforms of Figure 3. A large portion of the A-phase ratio current has gone to magnetizing current. What is left of the ratio current in the burden is severely reduced and distributed toward the leading edge of the waveform. The digital filtering used in a microprocessor relay extracts the fundamental component of the waveform [3]. Consequently, the relay extracts a fundamental current reduced in magnitude and advanced in phase when compared to the ratio current. At the same time because the maximum offset is in the A-phase, saturation is delayed in B- and C-phase.

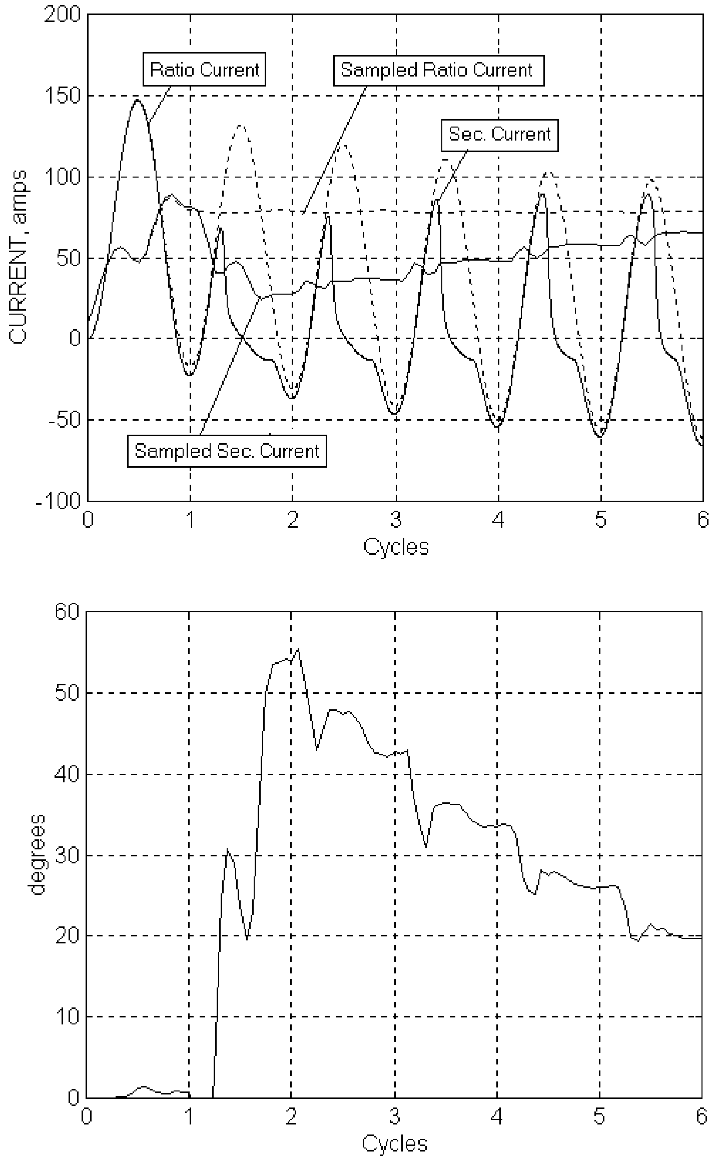

Figure 4: Magnitude and Phase Difference of Sampled Secondary Current

The result of sampling the A-phase current with a 16 sample per cycle cosine filter is shown in Figure 4. The saturated secondary and the magnitude of the fundamental are shown solid, with the ratio current and the magnitude of its fundamental shown dashed. Immediately below is a plot of the phase angle by which the fundamental of the saturated signal leads that of the ratio current.

Ratioing the fundamental of the saturated secondary current to ideal secondary ratio current results in a complex factor. We may think of this factor as being applied to the samples of the ratio current to produce the saturated waveform. For example, the sample by sample factors for the first two cycles of the waveforms of Figure 3 are listed in Table 2. The factors show little change one cycle into the fault. However, at 1.5 cycles A-phase secondary current is 58.3 percent of ratio and leads the ratio current by 23.7°.

Table 2: Saturation Factors Resulting From Maximum Offset in A-Phase

Phase A Current			Phase B Current			Phase C Current		
cycles	I_{sec}/I_{ratio}	δ angle	cycles	I_{sec}/I_{ratio}	δ angle	cycles	I_{sec}/I_{ratio}	δ angle
0	0.9993	0.0004	0	0.9987	0.0021	0	0.9978	0.0127
0.0625	0.9991	0.0020	0.0625	0.9984	0.0121	0.0625	0.9975	0.1045
0.1250	0.9988	0.0061	0.1250	0.9979	0.0293	0.1250	0.9994	0.1646
0.1875	0.9983	0.0151	0.1875	0.9973	0.0600	0.1875	1.0004	0.1018
0.2500	0.9976	0.0361	0.2500	0.9967	0.1181	0.2500	1.0002	0.0562
0.3125	0.9963	0.0893	0.3125	0.9963	0.2245	0.3125	0.9998	0.0377
0.3750	0.9945	0.2330	0.3750	0.9976	0.3653	0.3750	0.9994	0.0342
0.4375	0.9934	0.6050	0.4375	1.0008	0.3845	0.4375	0.9990	0.0433
0.5000	0.9993	1.2230	0.5000	1.0021	0.2724	0.5000	0.9985	0.0690
0.5625	1.0147	1.4725	0.5625	1.0017	0.1976	0.5625	0.9983	0.1153
0.6250	1.0255	1.0979	0.6250	1.0010	0.1753	0.6250	0.9986	0.1722
0.6875	1.0271	0.6637	0.6875	1.0005	0.1794	0.6875	0.9996	0.2079
0.7500	1.0233	0.4677	0.7500	1.0003	0.1942	0.7500	1.0005	0.2012
0.8125	1.0206	0.5630	0.8125	1.0004	0.2072	0.8125	1.0010	0.1699
0.8750	1.0202	0.8042	0.8750	1.0007	0.1998	0.8750	1.0010	0.1422
0.9375	1.0245	0.7519	0.9375	1.0008	0.1653	0.9375	1.0008	0.1298
1.0000	1.0238	0.6500	1.0000	1.0002	0.1603	1.0000	1.0008	0.1315
1.0625	1.0068	-1.381	1.0625	0.9992	0.1747	1.0625	1.0008	0.1333
1.1250	0.8951	-7.223	1.1250	0.9978	0.2349	1.1250	1.0008	0.1319
1.1875	0.7017	-9.300	1.1875	0.9961	0.3922	1.1875	1.0008	0.1268
1.2500	0.5235	2.9531	1.2500	0.9951	0.7292	1.2500	1.0006	0.1197
1.3125	0.5240	24.3842	1.3125	0.9978	1.2680	1.3125	1.0003	0.1141
1.3750	0.5866	30.8397	1.3750	1.0062	1.6627	1.3750	0.9997	0.1185
1.4375	0.6180	28.9589	1.4375	1.0142	1.5694	1.4375	0.9988	0.1472
1.5000	0.5830	23.7362	1.5000	1.0149	1.2803	1.5000	0.9978	0.2216
1.5625	0.4831	19.4597	1.5625	1.0098	1.3004	1.5625	0.9972	0.3659
1.6250	0.3674	23.0943	1.6250	1.0066	1.6398	1.6250	0.9980	0.5793
1.6875	0.3089	37.5746	1.6875	1.0065	1.9396	1.6875	1.0009	0.7760
1.7500	0.3226	49.7819	1.7500	1.0080	2.0592	1.7500	1.0048	0.8242
1.8125	0.3426	53.5113	1.8125	1.0087	2.1352	1.8125	1.0068	0.7346
1.8750	0.3499	53.6025	1.8750	1.0089	2.0608	1.8750	1.0060	0.6691
1.9375	0.3510	54.1780	1.9375	1.0088	2.1106	1.9375	1.0043	0.7319
2.0000	0.3475	53.8137	2.0000	1.0042	1.9722	2.0000	1.0037	0.8540

33 kA Fault with Maximum Asymmetry in A-phase

The effect of the saturation factors are apparent in the samples recorded in the next event report. The Zone 1 trip is similar to that of the ideal case. The 50M instantaneous element asserts first followed by the momentary pickup of the negative-sequence directional element 32Q and the negative-sequence overcurrent element 51Q during the acquisition of a full cycle of three-phase information. As in the previous case the event is triggered at the 16th sample and the phase elements ZAB, ZBC, and ZCA all indicate a Zone 1 trip in the 18th sample before a full cycle of samples have accumulated. Once the trip is issued the relay continues measurement to identify the fault type and location. The effect of A-phase saturation is seen with the appearance of false residual current at the 21 and 22 sample. Consequently, the fault identification logic [4] detects a ground fault at the 23rd sample, declares a BC-to-ground fault and blocks two of the phase elements. In this case, despite the reduced A-phase current and the false residual, the relay calculated the fault location at 1.52 miles using BC voltage and current.

Event 2 - 33 kA ABC Fault at 1.55 Miles on a 230 kV (Ct Saturation Caused by Maximum Offset in A-Phase)

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EXAMPL: BUS B, BREAKER 3 - S/N 96030003 Date: 07/16/96    Time: 10:02:13.933



    CURRENTS (pri)            VOLTAGES (kV pri)     RELAY ELEMENTS  OUT   IN

                                                   ZZZZZZO  555566L 1357 1357
                                                   ABCABCO 31110770 &&&& &&&&    Event
   IR     IA     IB     IC     VA      VB      VC  BCAGGGS 2NQPPNQP 2468 2468    Sample

     0      0      0      0 -135.2    60.1    75.1 ....... ........ .... 1...    9
     0      0      0      0    8.9  -121.5   112.7 ....... ........ .... 1...    10
   -12      6     -3    -15  135.2   -60.1   -75.1 ....... ........ .... 1...    11
    -6    -36      9     21   -9.0   121.6  -112.9 ....... ........ .... 1...    12

     3      9    -39     33 -135.3    60.1    75.2 ....... ........ .... 1...    13
    -6     84      0    -90    9.1  -121.8   112.9 ....... ........ .... 1...    14
   -36  -2343   -315   2622  130.1   -51.0   -79.2 ....... ....M... .... 1...    15
   108   4812  -3096  -1608  -11.9   110.0   -98.3 ....... Q.p.M... .... 1...    16

   -42   5406   6309 -11757 -103.4    28.5    75.1 ..2.... Q.p.H... .4.. 1...    17
  -243 -17718   9633   7842   13.6   -76.0    62.6 111.... Q.p.H... B4.. 1...    18
   168  -3123 -19248  22539   60.7   -11.9   -49.1 111.... Q.p.H... B4.. 1...    19
 -5811  23661 -13695 -15777   -8.1    42.2   -34.2 111.... Q.p.H... B4.. 1...    20

  4098   2439  28704 -27045  -34.8    10.9    24.2 111.... ....H... B4.. 1...    21
 15828 -17961  14397  19392    2.7   -29.0    26.3 111.... ....H... B4.. 1...    22
 -8157  -4851 -30600  27294   30.5   -13.5   -17.3 .1..... Qpp.H... B4.. 1...    23
-23016  11343 -14604 -19755   -1.9    27.8   -25.9 .1..... Qpp.H... B4.. 1...    24

  4602   1506  30330 -27234  -31.0    13.9    17.3 .1..... Qpp.H... B4.. 1...    25
 24432  -6042  11436  19038    1.2   -26.8    24.9 .1..... Qpp.H... B4.. 1...    26
 -3159   -318 -26355  23514   33.4   -13.3   -19.2 .1..... Qpp.H... B4.. 1...    27
-12699   6159  -3582 -15276    0.2     3.6    -2.1 .1..... Qpp.H... B4.. 1...    28

  3357    210  14139 -10992   13.7   -13.3    -2.6 .1..... Qpp.H... B4.. 1...    29
  1368  -4320   -510   6198  -27.9    75.9   -49.0 .1..... Qpp.H... B4.. 1...    30
  -870   1044  -2940   1026  -92.8    26.5    67.3 .1.1... Qpp.H... B4.. ....    31
    -3     -3      0      0   55.0  -133.5    78.7 .1..... ....M... B4.. ....    32

    -3     -3      0      0  122.3   -13.6  -108.6 ....... ....L... B... ....    33
    -6     -3     -3      0  -54.9   133.5   -78.7 ....... ........ B... ....    34
    -6      0     -3     -3 -122.4    13.7   108.5 ....... ........ B... ....    35
    -3      0     -3      0   54.8  -133.5    78.7 ....... ........ B... ....    36


Event:  BCG    Location:   +1.52    Frequency:    60.0

Targets: INST ZONE1 EN A B C Q      V1 Mem:   128.3 /  94
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33 kA Fault With Offset in B-Phase and C-Phase

An incorrect fault identification is the only consequence of the ct saturation condition in the previous case. The last case considered is Event 3 where the fault inception angle causes no offset in A-phase with equal offset in B- and C-phase. As in the previous case, the event is triggered at the 16th sample and the Zone 1 trip is declared in the 17th sample with the assertion of both trip contacts indicated by the B in that column. The false residual is caused by saturation in both B- and C-phases. This effect causes the assertion of the A-phase-to-ground distance element ZAG. After the trip the relay uses the subsequent samples to correctly identify a three-phase fault. However, the reduced B- and C-phase current caused the calculation of an erroneous fault location of 3.45 miles.

Event 3 - 33 kA ABC Fault at 1.55 Miles on a 230 kV (Ct Saturation Caused by Offset in B- and C-Phase)

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EXAMPLE: BUS B, BREAKER 3 - S/N 96030003 Date: 07/18/96    Time: 11:08:43.197



    CURRENTS (pri)            VOLTAGES (kV pri)     RELAY ELEMENTS  OUT   IN

                                                   ZZZZZZO  555566L 1357 1357    Event
                                                   ABCABCO 31110770 &&&& &&&&    Sample
   IR     IA     IB     IC     VA      VB      VC   BCAGGGS 2NQPPNQP 2468 2468

     0      0      0      0 -100.8   -27.9   128.7 ....... ........ .... 1...    9
     0      0      0      0   90.5  -132.6    42.2 ....... ........ .... 1...    10
   -12     27      0    -39  100.8    27.8  -128.7 ....... ........ .... 1...    11
   -12   -165     21    132  -90.8   133.1   -42.5 ....... ........ .... 1...    12

    12    405   -165   -228 -100.6   -29.2   129.9 ....... ........ .... 1...    13
   -24  -1161    303    834   89.8  -129.0    39.2 ....... ....L... .... 1...    14
     3   -843  -1845   2691   92.5    34.6  -127.4 ....... ....M... .... 1...    15
    60   8469  -1044  -7365  -80.2   103.9   -23.8 ....... Q.p.H... .... 1...    16

    51  -4065  11631  -7515  -65.9   -35.5   101.6 .11.... Q.p.H... B4.. 1...    17
  -510 -18927  -1212  19629   55.4   -62.5     7.1 111.... Qpp.H... B4.. 1...    18
  1449  14790 -24765  11424   35.2    23.0   -58.4 111.... Qpp.H... B4.. 1...    19
  2130  23901   3435 -25206  -29.7    35.6    -5.8 111.... .pp.H... B4.. 1...    20

 -8814 -22086  27222 -13950  -23.2   -10.0    33.3 111.... ....H... B4.. 1...    21
 -3591 -24165   1365  19209   20.6   -30.2     9.5 111.... ....H... B4.. 1...    22
 12840  23547 -22347  11640   22.9     6.4   -29.6 .1..... ....H... B4.. 1...    23
  2109  23994  -6156 -15729  -20.5    30.5    -9.8 .1..... Qpp.H... B4.. 1...    24

 -8013 -23109  18702  -3606  -23.8    -6.2    29.7 .1.1... Qpp.H... B4.. 1...    25
 -1635 -21435   6036  13764   21.3   -28.9     7.1 .1.1... Qpp.H... B4.. 1...    26
  8658  19737 -13143   2064   24.9     4.5   -27.4 .1.1... Qpp.H... B4.. 1...    27
   -66  11067  -2865  -8268  -21.2    19.4     1.3 .1.1... Qpp.H... B4.. 1...    28

 -6393  -9435   5196  -2154  -14.3    -1.8    14.1 .1.1... Qpp.H... B4.. 1...    29
  1488  -1593     96   2985   10.0    -5.8    -3.5 .1.1... Qpp.H... B4.. ....    30
   162   1017   -504   -351    1.8     0.2    -1.6 .1.1... Qpp.H... B4.. ....    31
    -3      0      0     -3   -0.0    -0.0    -0.0 .1.1... Qpp.M..* B4.. ....    32

     0      0      0      0    0.0     0.0     0.0 ....... Q......* B... ....    33
     0      0      0      0    0.0     0.0     0.0 ....... Q......* B... ....    34
    -6     -3      0     -3    0.0    -0.0    -0.0 ....... Q......* B... ....    35
    -6      0     -3     -3   -0.0    -0.0    -0.0 ....... Q......* B... ....    36


Event:  ABC    Location:   +3.61    Frequency:    60.0

Targets: INST ZONE1 EN A B C Q      V1 Mem:   132.1 / 132
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CONCLUSIONS

1. The relation between the ANSI voltage rating, ct burden, maximum fault current, and system X/R ratio defines the threshold of ct saturation. Stated as an equation with parameters expressed in per unit of ct rating, it serves as the criterion for rating cts for line protection.
2. The derived equation provides the ct rating criterion for line protection in new installations and can identify the threshold of ct saturation in older installations.
3. The criterion has been used in a five step ct selection procedure for line protection which determined the ct ratio using the maximum fault in amperes, the system X/R ratio and the ct burden expressed in per unit of a ct rated standard burden. Guide lines are include for estimating ct burden using typical ct ohms/turn resistance values and a convenient formula for calculating lead resistance in ohms/1000′ as a function of AWG wire gage.
4. The procedure can be applied in most line applications. However, the ct ratings that avoid saturation for asymmetrical current are impractical in applications near a generator bus where X/R ratio and the fault current are both extremely high. Where dc saturation is unavoidable, the cts can only be rated to retain reasonable sensitivity.
5. Tests show that the trip time of a modern distance relay is unimpaired by ct saturation due a dc offset with extremely high currents. However, saturation modifies the phasor measurement of one or more currents and affects the ability of the relay to properly identify the fault type and/or location.

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