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TRANSFORMER DIFFERENTIAL RELAYS
(When Used on Breaker-And-One-Half or Ring Busses)

CHARLES L. BALLENTINE
ERIK A. HALE

BLACK & VEATCH
LAKE OSWEGO, OR

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INTRODUCTION

When breaker and one-half or ring bus positions are used to source transformer banks, the relay engineer is faced with the decision to either use the transformer differential to protect the short bus tap, or install additional bus protection, which is expensive. There are some concerns if the transformer differential is used due to potential problems during heavy thru current in the bus due to either fault current or load current.

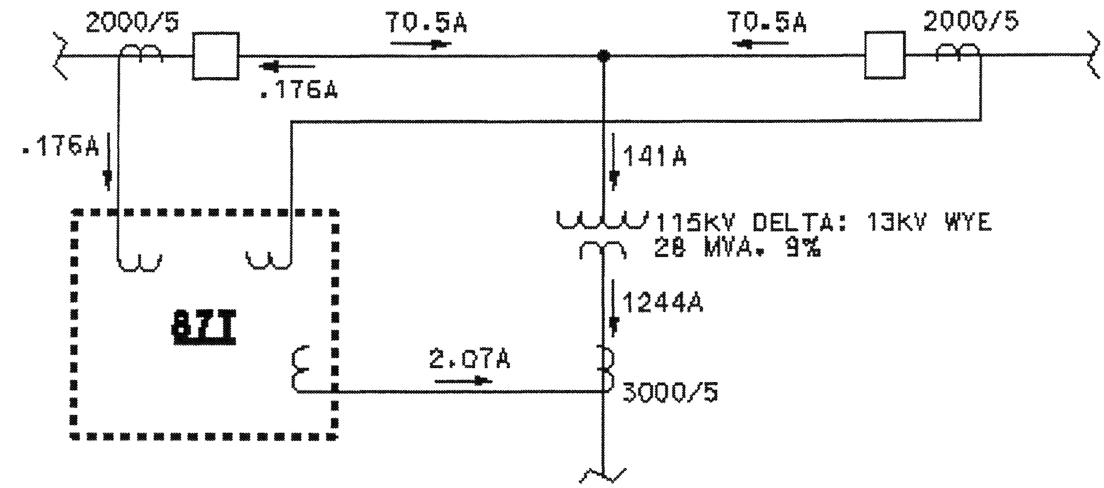
When a transformer differential relay that has a restraint element for each high side CT is used, the relay may not operate for faults on the low side during heavy thru load current. If the transformer is relatively small the fault will not produce much operate current for the relay, and the restraint current may be enough to keep the relay from operating.

When a transformer differential relay with only two restraint elements is used, there may be a false trip during a heavy thru fault due to CT mismatch. One criteria for preventing relay operation is that the minimum operate current of the relay should be greater than 1% of the thru fault current. This is the current that would flow in the operate element if there were a 1% mismatch in the CTs.

This paper will provide an innovative CT connection that will help alleviate the above problems.

TRANSFORMER DIFFERENTIAL RELAY WITH THREE RESTRAINT ELEMENTS

When a transformer differential relay with a restraint element for each high side CT is used to protect a transformer with a high ratio (such as 115/13 kV) on a breaker-and-a-half or ring bus, there should be no problem for the differential unit operating during a thru fault. However, too much restraint may be provided due to thru load current during faults on the low side of relatively small transformers. This type of installation is shown in Figure 1.



Transformer Differential Relay With Three Restraint Elements
Figure 1

The differential relay uses Ratio Correction Factors to compensate for the difference in current between the high and low side transformer CTs. At full load (28 MVA) the current on the high side of the transformer would be 141 Amps. Assuming equal current in each 2000/5 CT, the secondary currents would be 70.5/400=.176 A. The current on the low side would be 1244 Amps making the secondary current to the relay 1244/600=2.07 A. For a ratio correction factor of 2.00 for the high side (RCFH) the ratio correction factor for the low side (RCFL) would have to be .34 for the currents to balance, as shown in the following equation:

$$2*.176+2*.176-.34*2.07=0$$

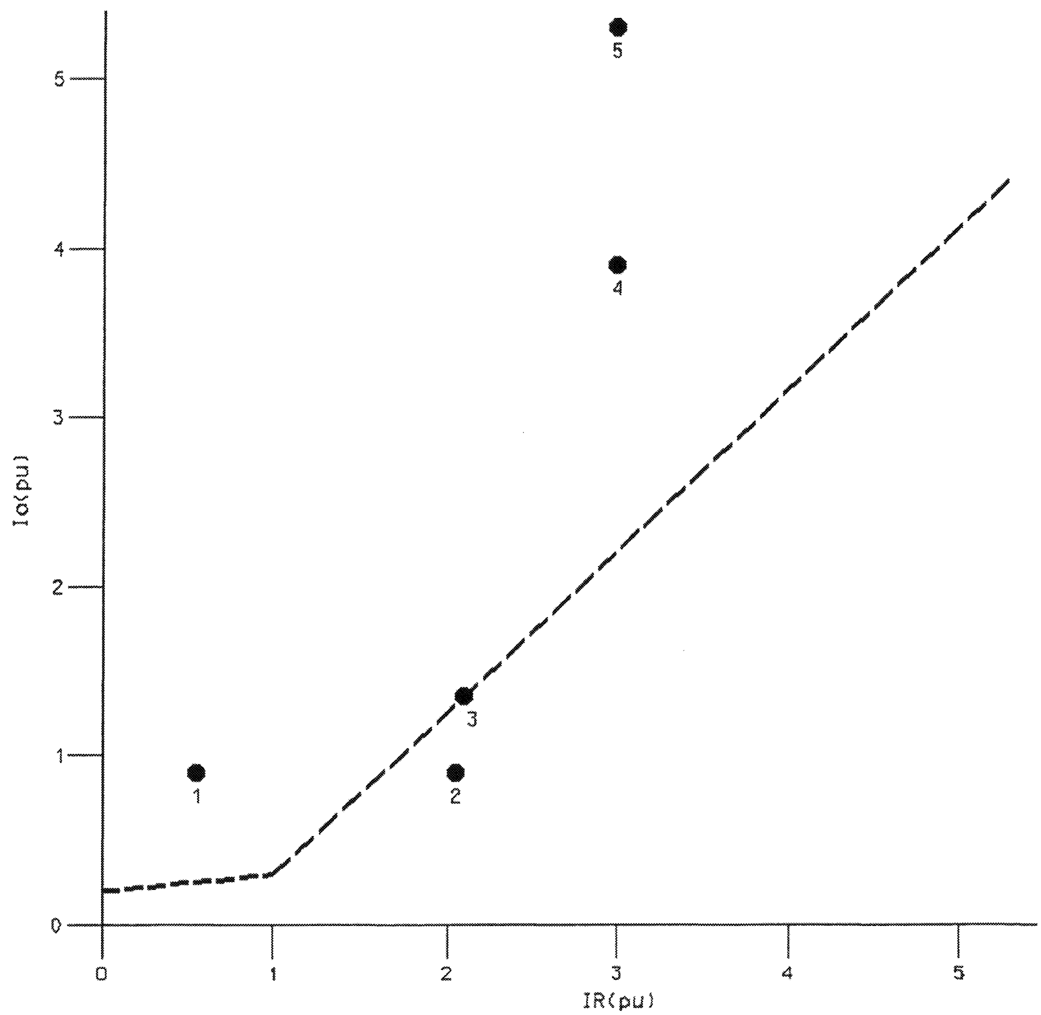
For a ground fault on the low side inside the differential zone, the current in two of the phases on the high side will be 900 Amps. This will produce 2.25 Amps total secondary current in the high side CTs. If the relay is rated 5 Amps the equation for pu operate current is

Io=Isec*RCFH/5, or
Io=2.25*2/5=.9 pu

The equation for pu restraint current is

Ir=(Isec/2)*RCFH/5, or
Ir=(2.25/2)*2/5=.45

Where, for this relay, the restraint current is reduced by a factor of 2. If the operate/restraint curve is as shown in Figure 2, Point 1 describes the above condition.



Operate/ Restraint Curve
Figure 2

Since Point 1 is well within the operate region, the relay will operate satisfactorily. If, however, there is a large amount of thru current flowing in the high side CTs due to load, say 2000 Amps, the operation of the relay might not be so positive. Assuming that the fault current is the same in both breakers, and is 90 deg. out of phase with the thru current due to load, the secondary restraint current becomes

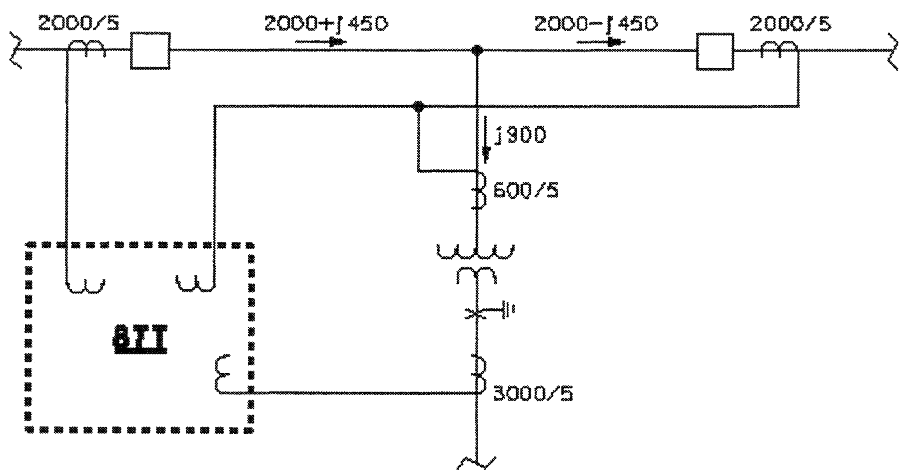
$$Isec=\sqrt{((2.25/2)^2 + (2000/400)^2)}\ *2=10.25\ A$$

and the pu restraint current becomes

$$Ir=(10.25/2)*2/5=2.05\ pu$$

Point 2 on the operate/restraint curve (Figure 2) describes this condition. It is seen that for this extreme case the relay will not operate.

A solution to this problem is to use a CT on the high side of the transformer as shown in Figure 3.



Three Element Differential With High Side CT
Figure 3

Now, at 28 MVA, the secondary current to one of the high side relay elements would be the same, .176 A. The secondary current to the other high side element would become (70.5/400 + 141/120)=1.35 A. The secondary current to the low side relay element would be the same, 2.07 A. If a RCFH of 2 is used for the high side CTs the RCFL for the low side CT will have to be 1.48, as shown in the equation below:

$$2*.176+2*1.35-1.48*2.07=0$$

For a ground fault on the low side inside the differential zone, and a thru current of 2000 Amps the secondary operate current becomes

$$Isec=(900/400 + 900/120)=9.75\ A$$

and the pu operate current becomes

$$Io=9.75*2/5=3.9\ pu$$

The secondary restraint current becomes

$$Isec=\sqrt{((450/400)^2 + (2000/400)^2)} + \sqrt{((450/400+900/120)^2 + (2000/400)^2)}$$
$$= 15.1A$$

and the pu restraint current becomes

$$Ir=(15.1/2)*2/5=3.0\ pu$$

Point 4 on the operate/restraint curve describes the above condition. It is seen that the relay will operate with a margin of 160%.

If 300/5 CTs on the high side of the transformer are used, or if the current from the 600/5 CT is applied to both high side inputs of the differential relay, the RCFs become

RCFH=1.53   RCFL=2.00

For the previous ground fault and 2000 Amps thru current, the secondary operate current becomes

$$Isec=(900/400 + 900/60)=17.25\ A$$

and the pu operate current becomes

$$Io=17.25*1.53/5=5.3\ pu$$

The total secondary restraint current becomes

$$Isec=\sqrt{((450/400 + 900/120)^2 + (2000/400)^2)}*2=19.9\ A$$

and the pu restraint current becomes

$$Ir=(19.9/2)*1.53/5=3.0$$

Point 5 on the operate/restraint curve describes this condition. It is seen that the relay now operates with a margin of 350%.

It is acknowledged that 2000 Amps thru current is an extreme condition, however if the breakers and bus are rated 2000 Amps, it would seem prudent to consider this condition in evaluating the relay performance.

Sensitive ground protection could be provided by using restricted earth fault protection on the low side. This would require a 3000/5 CT in the neutral of the transformer for preferred relaying. There would still be a problem for phase-phase faults however. For a phase-phase fault on the low side the current in two of the phases on the high side would be 1353 Amps. This would produce a total secondary current of 3.38 Amps and an operate current of

$$Io=3.38*2/5=1.35\ pu$$

With 2000 Amps thru current the total secondary restraint current would be about

$$Isec= 10.3\ A$$

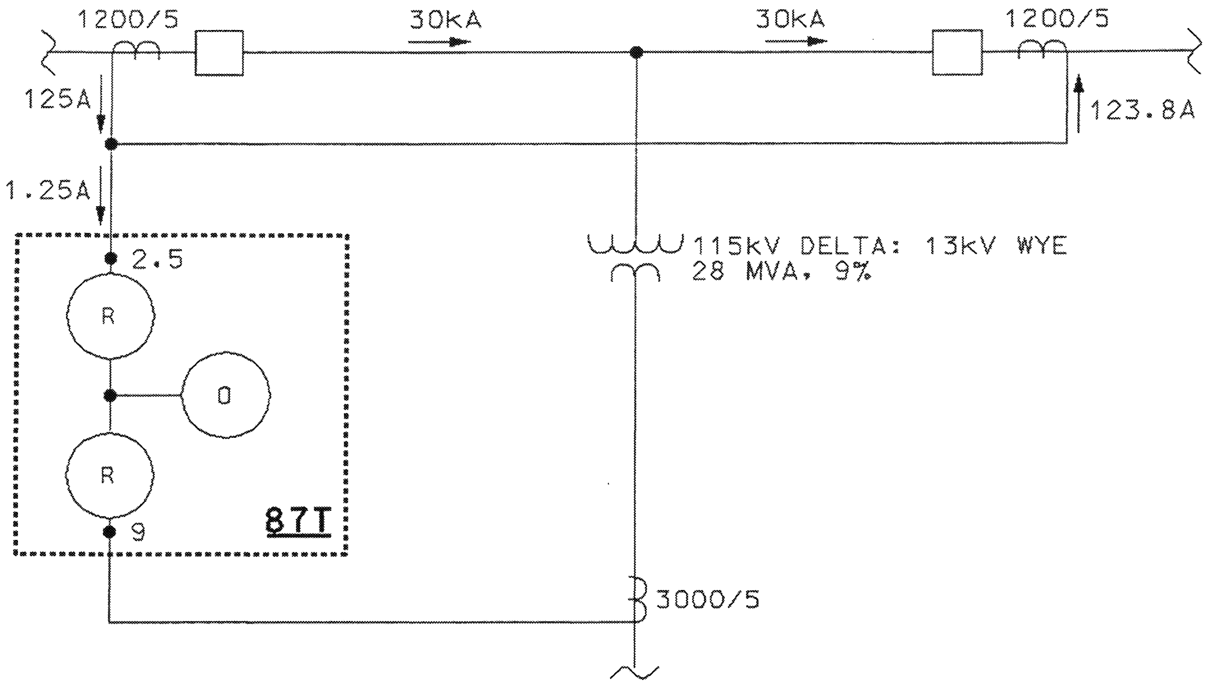
and the pu restraint current would be

$$Ir=(10.3/2)*2/5=2.1\ pu$$

Point 3 on the operate/restraint curve describes this condition. It is seen that for this extreme case the operation of the relay will be marginal.

TRANSFORMER DIFFERENTIAL RELAY WITH TWO RESTRAINT ELEMENTS

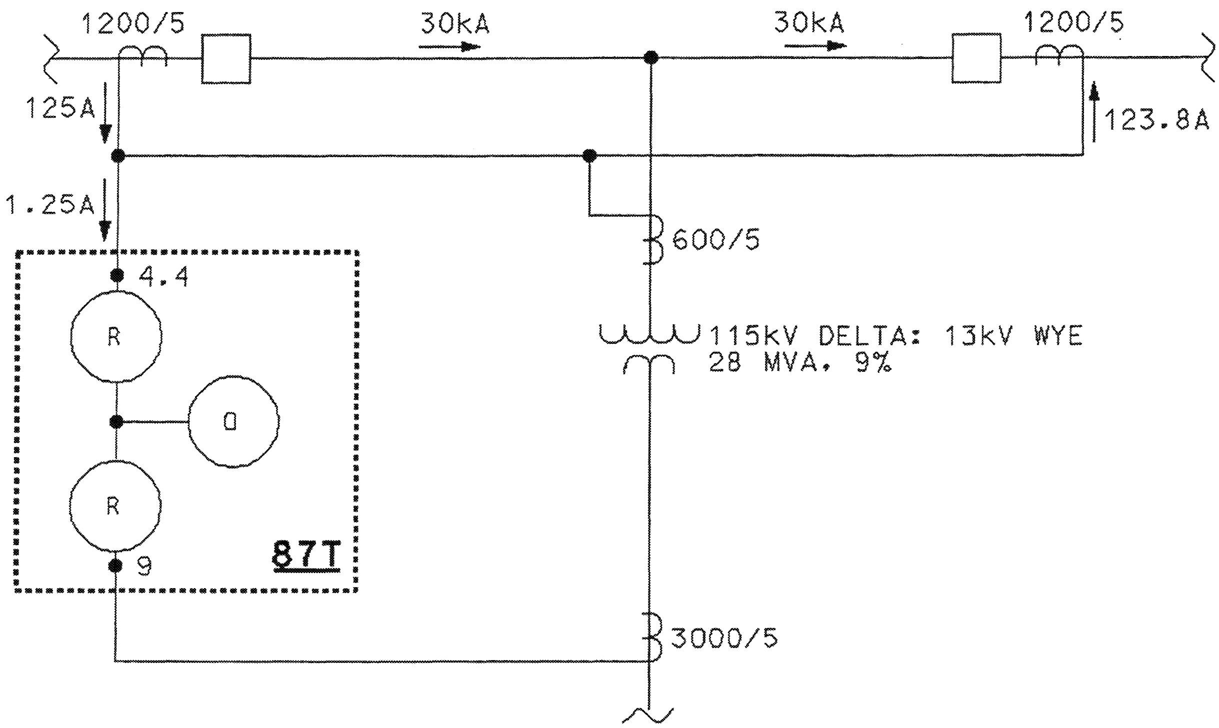
When a transformer differential relay with two restraint windings is used to protect a transformer with a high ratio (such as 115/13 kV) on a breaker-and-a-half or ring bus, there may be some concern about a false trip during a thru fault. Figure 4 illustrates this problem.



Transformer Differential Relay With Two Restraint Elements
Figure 4

For a thru fault of 30 kA there would be a secondary current of 125 amps. If there were a mismatch of 1% of the CTs there would be 1.25 Amps in the operate element of the relay. Assuming that the "taps" of the relay are set approximately as shown, and that it takes about 30% of the tap to operate the relay, it would take 2.5*0.3=.75 Amps to operate the relay, or, for the above condition, the relay would false trip.

A solution for this problem is also to add one set of the CTs on the high side of the transformer to the transformer differential. This is shown in Figure 5.



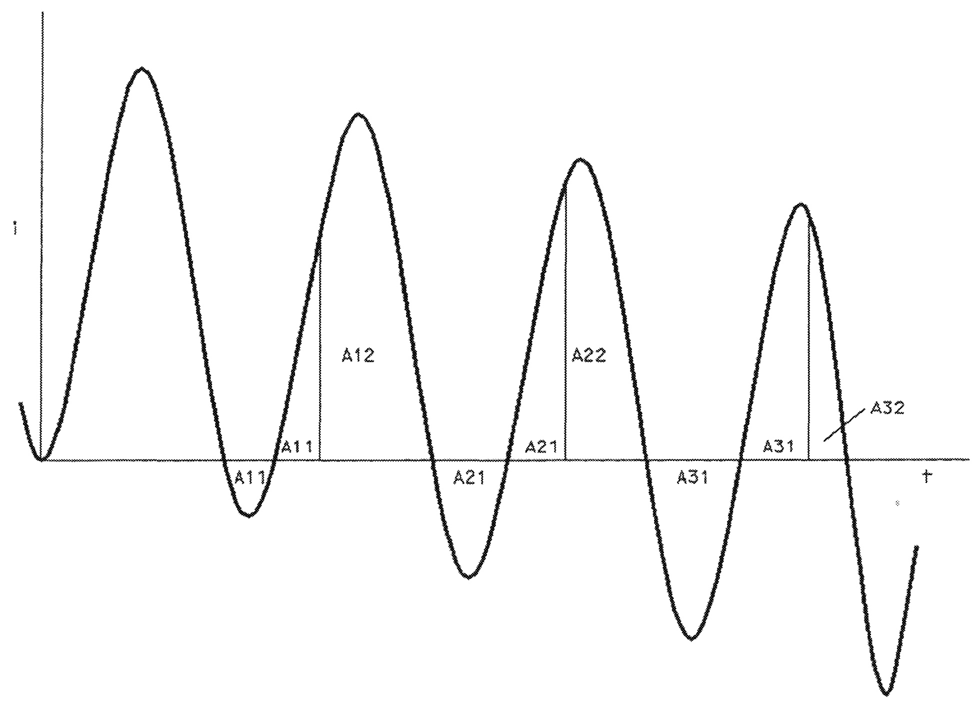
Two Element Differential With High Side CT
Figure 5

By adding the transformer high side CT to the transformer differential the corresponding tap is increased from 2.5 to 4.4 and the pickup current from .75 to 1.32 Amps, which is above the 1% mismatch value of 1.25 Amps. The sensitivity of the relay is increased somewhat. Three times as much operate current is provided to the relay and the pickup current increased only by a factor of 1.76.

It is the author's opinion that 1% mismatch is quite conservative. Mismatch would be due to a difference in the number of secondary turns or the exciting currents. If the CTS are 1200/5 there are 240 secondary terms. A 1% difference would be 2.4 turns, which, is not very likely. The exciting current depends on the secondary voltage and the excitation curve. The burden on the CTs is about 1.3 ohms therefore the secondary voltage is 125*1.3=163 volts. The exciting current for a 1200/5, C-800 CT is about 0.1 Amps at this voltage and the mismatch would be much less. Current due to this type of mismatch would tend to operate the relay since it would contain lots of the first harmonic. A good rule of thumb is to size the CTs so that the secondary voltage during any fault is less than one-half their C-Rating.

A comparison can be made of the security of the two restraint element transformer differential relay (87T) with a high empedance bus differential relay (87B). Whereas the above 87T releay will operate for a mismatch of 1.32 Amps, a typical 87B relay will operate on a mismatch of only 0.18 Amps. The security of the above 87T relay is therefore greater than a typical 87B relay during thru fault current without dc offset.

There is a possibility that only one of the 1200/5 CTs would saturate during a thru fault because of the transient dc offset. This is what might be called the classical problem for bus differential relays. A fault occurs outside the differential zone and most of the fault current flows thru only one breaker. The CTs in this breaker will tend to saturate due to the dc offset (It is assumed that the CTs have been sized to not saturate for steady state conditions). There is a good possibility that the CTs in the other breakers will not saturate because they are carrying less fault current. In our case, however, both breakers are seeing the same fault current and if the CTs in one breaker saturates, the CTs in the other breaker should also, however it is prudent to assume that the CTs in only one breaker saturates. If this occurs, most of the current from the good CT would flow in the relay and could be quite high (100+ Amps). Saturation would occur only during part of a cycle and the current would be similar to "inrush" current and have enough second harmonics to restrain the relay. An example of transient dc offset current is shown in Figure 6. A good rule of thumb to see if the CTs will saturate is to see if the quantity (1 + X/R) times the secondary voltage is greater than the C-Rating of the CT.



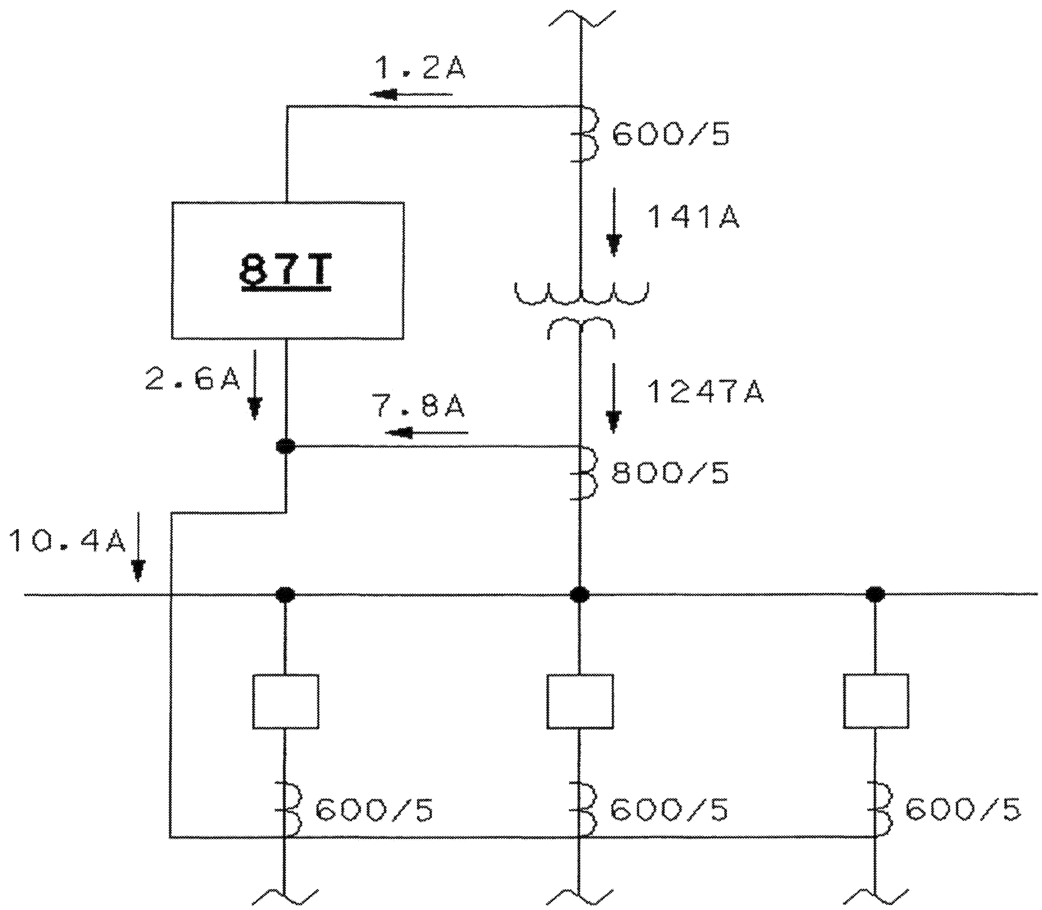
Transient DC Offset Current
Figure 6

Since the burden on the CT is resistive the voltage curve will be the same as the current curve. The CT will saturate when the area under the voltage curve (volt-seconds) equals the capacity of the CT. (A C-800 CT has a capacity of 6 volt-seconds during steady state conditions but only 3 volt-seconds for transient dc offset conditions). After the CT saturates it will continue to be saturated until the voltage becomes negative. It will remain unsaturated while the voltage is negative and will saturate again when the area under the curve when the voltage becomes positive equals the area under the curve while the voltage was negative. When these areas are equal is determined solely by the X/R of the system. As mentioned before, the second harmonic content of the current during CT saturation will be what keeps the relay from operating. If the first and second harmonic currents are determined for the current represented by the area A21 in Figure 6 for a system X/R of 15 it is found that the ratio $I_2/I_1 = 51\%$. This ratio would be higher for lower X/R ratios and somewhat higher for higher X/R ratios. A second harmonic restraint setting of 15% is commonly used for 87T relays, thus the relay should not operate for the above condition.

It is noted that these high magnitude, uni-directional currents also flow in the non-restrained instantaneous overcurrent element. This element has to be smart enough to not operate for these currents. If saturation will occur it would be wise to increase the pickup of the instantaneous overcurrent element accordingly. This also applies to the three restraint element relay.

A SIMILAR APPLICATION ON THE LOW SIDE

For a transformer installation where there is no low side breaker and it is wished to include the low side bus in the transformer differential, an auxiliary CT is normally used since the feeder breaker have low ratio CTs. An application where one of the transformer CTs is used instead of an auxiliary CT is shown in Figure 7.



A Scheme For Extending The Transformer Differential To Include The Low Side Bus
Figure 7

As shown in Figure 7 the transformer CT connected differentially with the feeder CTs provides balanced current inputs to the relay. This connection should also provide more sensitive protection for low side bus faults than if an auxiliary CT were used.

THE BLUE LAKE APPLICATION

The relay scheme described in this paper and shown in figure 8 has been used on a number of recent projects. From the point of view of the Substation Engineer the ultimate proof of a relay protection scheme is actual fault detection and clearing recorded for analysis on a relay's event recording facilities. There has only been one fault within a zone protected by the connection discussed in this paper. It occurred at Blue Lake Substation when a low side surge arrester failed. The design analysis of this station will be discussed and the fault record will be analyzed.

The connection was selected for a recent construction project for Portland General Electric (PGE), designed and constructed by the joint venture between Black and Veatch and Brink Electric Construction. Blue Lake Substation features two 115 kV lines (expandable to four), a 115 kV three breaker ring bus expandable to four rows of breaker-and-a-half, and one 28 MVA, 115/13.2 kV transformer with metal-clad switchgear. An expansion planned for 1999 will install a 230/115 kV bulk power transformer.

The criteria for relay selection for this project were simple, the lowest cost scheme that provides for rapid detection and clearing of faults within the scheme's zone of protection. There was also a preference that only relays that were presently in use on PGE's system be used. A percent differential relay with two restraints was selected for the transformer and associated high and low side busses. The bus and transformer protection scheme is shown in figure 8. The cost considerations were simple, protect two zones with one relay scheme, and select the lowest priced relay that will accomplish the task.

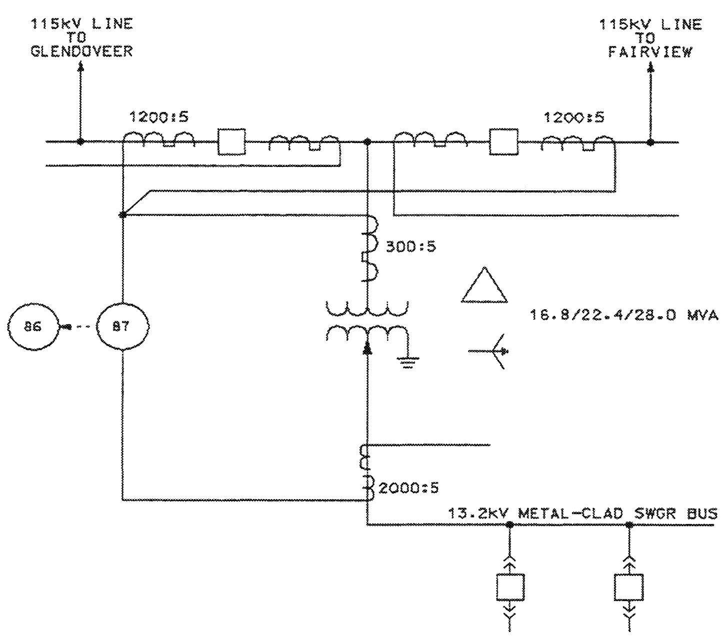


FIGURE 8

A word about the relays being used. This scheme has been implemented by the authors with three relays to date: the GEC KBCH; the ABB TPU; and the SEL 587. These were the relays considered for use at Blue Lake. The SEL 587 was selected for based solely on cost. Readers should not interpret statements in this as paper as an endorsement of any relay or relay manufacturer.

ANALYSIS

In ring bus applications, protecting the high side bus and transformer together with a percent differential relay generally didn't work because of the relatively high (1200:5 Amp in the case of Blue Lake) CT ratio on the 115 kV bus. The Ratio Correction Factors of digital relays didn't allow for a CT ratio that produced as little as 1 Amp at transformer full load. Reducing the CT ratio of the bus BCTs was ruled out because of the 1200 Amp rating of the bus and the desire to avoid any saturation problems during large faults.

By the time the Blue Lake Substation project began, the benefits of the connection had been demonstrated on a number of projects. Early in the design process, the following analysis was done to verify the applicability of the proposed protection scheme. Figure 9 divides the station into 5 subzones of protection that must be analyzed to determine how each will react to faults.

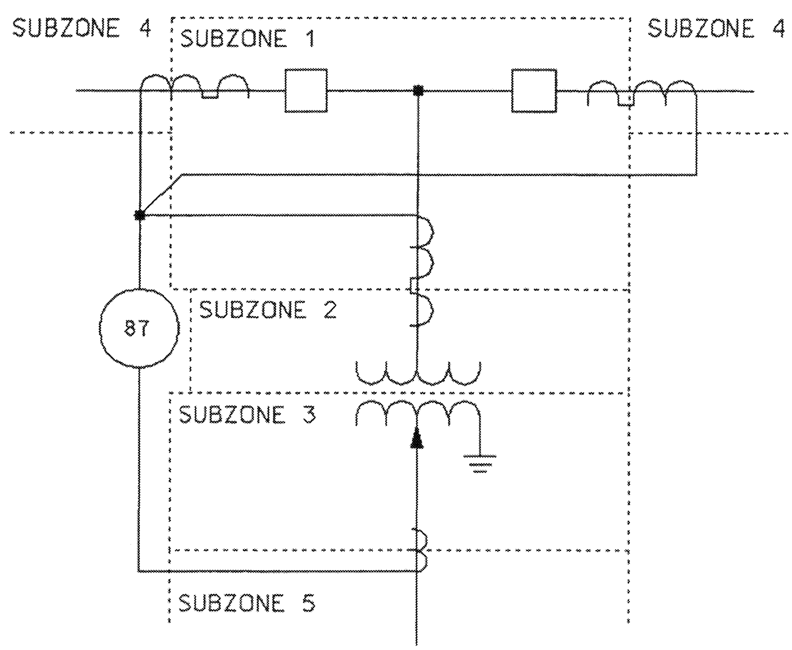


FIGURE 9

Subzone 1 is the high side bus. Faults in this area are seen by the relay only through the breaker BCTs at a ratio of 1200:5. There isn't a source on the low side of the transformer. Faults in this subzone will typically be high magnitude, usually involving a downed conductor, and are quite rare. Because of the violent nature of these faults and the associated system wide disruption, rapid clearing is essential. Figure 10 is graph of the restraint current vs. operate current. In the case of the bus fault the operate current and the restraint current will be equal (some relays will calculate the restaint current at half). DC saturation of the BCTs does not change this. To defeat the scheme, the saturation would have to be complete enough on all faulted phases to reduce the operate current in the relay below the .3 Amp offset of the trip threshold (50 Amps primary), which is quite unlikely. Based on the description of the relay in the instruction manual, the relay should pick up in 2 cycles or less. This level of performance coordinates with the line relaying looking into the station.

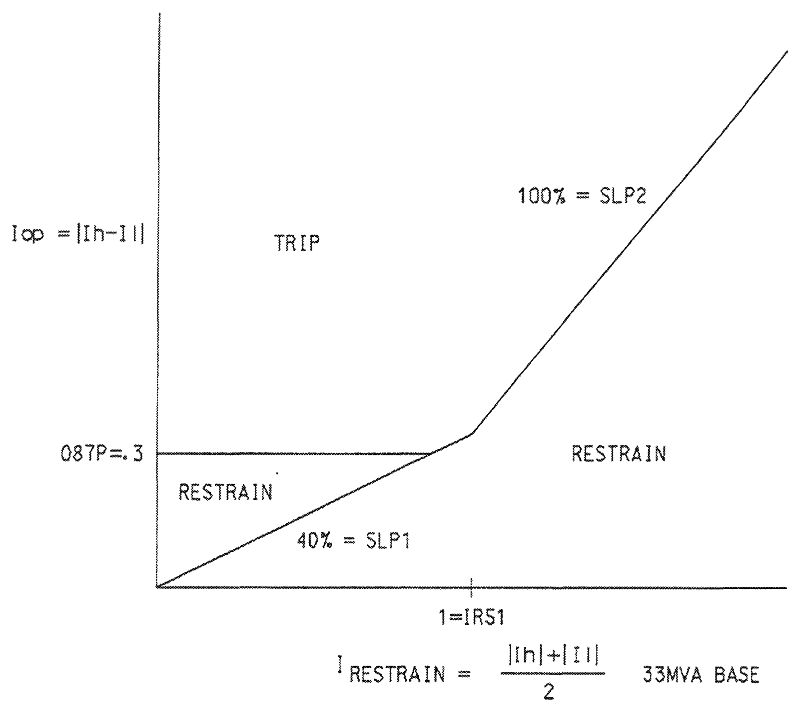


FIGURE 10

Subzone 2 is the high side of the transformer. Faults in this zone are arguably the easiest to detect. The effective CT ratio of the connection is 48:1. For high magnitude faults, if the 300:5 Amp CT were to saturate completely, the 1200:5 Amp BCTs will still provide ample current to operate the relay. For lower magnitude faults, perhaps the shorting of high side windings, the relatively low CT ratio will allow for rapid detection. As in subzone 1, the operate current and the restraint current are equal. Relay performance of the scheme for faults in subzone 2 is expected to be 2 cycles or better.

Subzone 3 is the low side of the transformer and the 13.2 kV bus entrance to the metal-clad switchgear. Once again, faults in this subzone are seen only by the high side BCTs. The impedance of the transformer, approximately 9%, and the system impedance keep the fault current well under 9,000 Amps. At the high side of the transformer, this fault current would be less than 1,000 Amps. With fault current this low, CT saturation is not a concern.

Faults on the 13.2 kV bus would be the most difficult to detect if the high side CT ratio was 1200:5. However, with the addition of the transformer BCTs, the effective ratio drops to 240:5. With this CT ratio, based on the relay manufacturer's guidelines, fault detection in this subzone should be fast and accurate. This subzone includes the low side surge arresters.

Subzone 4 is the portion of the 115 kV system not a part of the zone of protection of this scheme. Faults in this subzone can cause current to pass through subzone 1. If the two sets of breaker BCTs perform differently in the case of a through fault, perhaps caused by different levels of DC saturation, a differential current will be seen by the relay. For the analysis, the worst case situation would be a close in fault, perhaps within the substation, on one of the 115 kV lines that was accompanied with significant DC offset. Once a bulk power transformer and 230 kV ring bus is installed (scheduled for 1999 construction), fault currents will exceed 20 kA. Clearing of a fault of this nature can be anticipated to be about four cycles. During the fault, the bus voltage would drop which would reduce the load current on the transformer which will reduce the restraint current significantly. All of this makes an unwanted trip more likely. The benefit of the connection is that the differential current produced from the 115 kV breaker BCTs enters the relay at a 1200:5 ratio. Multiplied by the ratio correction factor of 1.45, approximately 50 Amps of primary differential current would have to be produced by the differential saturation for the operate current in the relay to exceed the .3 Amp threshold. This was considered an acceptable risk. The problem could have been avoided by buying a three restraint relay.

Subzone 5 is the distribution system fed by the metal-clad switchgear. Faults in this subzone are limited in magnitude to less than 9,000 Amps. However, the duration of lower magnitude faults may be rather long. Considering the C800 accuracy of the CTs in the switchgear and the relatively low fault current, CT saturation in this subzone is unlikely. Thus, differential current in a fault in this subzone would also be low. Restraint current, on the other hand, would be contributed from both restraint windings and would be relatively high. Unwanted trips caused by faults in this subzone are unlikely.

SURGE ARRESTER FAILURE

About two months after energizing the substation, the A phase low side surge arrester failed. The event was captured by the event recorder in the relay. The event report is included in appendix 1. The transformer was lightly loaded, as very little load had yet been connected. Because the transformer has an ANSI standard delta-wye connection, the A phase low side fault produced equal magnitude current on A and C phases of the high side. Initially, the magnitude of the secondary fault current entering the relay was just under 2 Amps, which translates into about 95 Amps primary. The failure in the surge arrester destroyed one or more of the zinc-oxide wafers, but left the others in place. Gases vented through the composite housing of the arrester. From the relatively low magnitude of the fault, it appears that a portion of the arrester remained in the fault path and may not have been conducting for the portion of the wave form near zero volts. This non-linear impedence may have contributed to the second harmonic elements picking up at the beginning of the fault, although a DC phenomena also probably was involved. These elements dropped out after approximately 1 ½ cycles. Once the differential relay picked up and tripped the lockout relay and started the tripping of the high side breakers, fault current essentially stopped. This is likely due to the portion of the arrester that stayed in the circuit. The relay picked up in about 1 ½ cycles, and the breakers had completely opened within 4 cycles.

This fault had a relatively high impedance, making it among the most difficult for a relay to detect in this application. The 115 kV fault current was only about 70% of full load. Had the high side CT ratio been set at 1200:5 Amps, the secondary current seen by the relay would have been less than .4 Amps. Only a high CT correction factor setting in the relay would place this low of a differential current reliably in the operate zone of the relay. It is the opinion of the authors that in the challenging environment of a substation, setting a differential relay to operate on secondary currents as low as .4 Amps is not prudent.

The excellent performance during the clearing of this fault should be attributed not only to the overall scheme as described in this paper, but also to the differential relay used, the other relays involved including the lockout relay, and the superbly fast 115 kV breakers installed. It is with great pride that we present these results.

APPENDIX

Event Report, Blue Lake Substation

```
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0 ...... ...... ....... .... ...
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0 ...... ...... ....... .... ...
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0 ...... ...... ....... .... ...
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0 ...... ...... ....... .... ...

Event: TRP1 TRP2 TRP3    Targets: 87 A C               Duration:   0.13 cyc
Winding 1 Currents (A Sec), ABCQN:    0.7    0.2    0.9    1.6    0.0
Winding 2 Currents (A Sec), ABCQN:    0.2    0.2    0.2    0.1    0.0
=>
TXPU  = 0.000    TXDO  = 0.000    TYPU  = 0.000    TYDO  = 0.000
NFREQ = 60       PHROT = ABC

SELogic Equations
X      =NA
Y      =NA
MTU1   =87R + 87U
MTU2   =87R + 87U
MTU3   =87R + 87U
MER    =87R + 87U
OUT1   =TRP1
OUT2   =TRP2
OUT3   =TRP3
OUT4   =TRP1


87T1                                        Date: 01/10/97   Time: 18:31:12.065
XFMR WR1


FID=SEL-587-R105-V5a-D950929

                                                       Relay Elements       OUT I

  Operating Qty        Restraint_Qty        Max Hrm     888888 222555 TTT        PQN   A
    Amps Sec             Amps Sec           Amps Sec    777777 HHHHHH RRRXYCO TDDD 13L
                                                        UUURRR BBBBBB PPPTTCC HEEE &&R
 IOP1   IOP2   IOP3   IRT1   IRT2   IRT3   IF2     IF5  123123 123123 123     5MMM 24M

  0.0    0.0    0.0    0.1    0.1    0.1    0.0    0.0 ...... ...... ....... .... ...
  0.0    0.0    0.0    0.1    0.1    0.1    0.0    0.0 ...... ...... ....... .... ...
  0.0    0.0    0.0    0.1    0.1    0.1    0.0    0.0 ...... ...... ....... .... ...
  0.0    0.0    0.0    0.1    0.1    0.1    0.0    0.0 ...... ...... ....... .... ...

  0.0    0.0    0.0    0.1    0.1    0.1    0.0    0.0 ...... ...... ....... .... ...
  0.0    0.0    0.0    0.1    0.1    0.1    0.0    0.0 ...... ...... ....... .... ...
  1.0    0.0    1.0    0.5    0.1    0.6    0.6    0.1 ...... *.*... ....... .... ...
  1.0    0.0    1.0    0.6    0.1    0.6    1.2    0.1 ...... *.*... ....... .... ...

  1.7    0.0    1.7    0.9    0.1    1.0    1.2    0.1 ...... *.*... ....... .... ...
  1.7    0.0    1.7    0.9    0.1    1.0    1.2    0.1 ...... *.*... ....... .... ...
  0.7    0.0    0.7    0.4    0.2    0.5    0.6    0.0 ...... *.*... ....... .... ...
  0.7    0.0    0.6    0.4    0.1    0.5    0.0    0.0 ...*.* *.*... ***.... .... bb.

  0.0    0.0    0.0    0.1    0.1    0.1    0.0    0.0 ...... ...... ***.... .... bb.
```

0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	***....	....	bb.
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	......	....	...
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	......	....	...
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	......	....	...
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	......	......	......	....	...

```
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0  ...... ...... ....... .... ...
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0  ...... ...... ....... .... ...
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0  ...... ...... ....... .... ...
  0.0    0.0    0.0    0.0    0.0    0.0    0.0    0.0  ...... ...... ....... ....   .

Event: TRP1 TRP2 TRP3    Targets: 87 A C                Duration:   0.13 cyc
Winding 1 Currents (A Sec), ABCQN:    0.7    0.2    0.9    1.6    0.0
Winding 2 Currents (A Sec), ABCQN:    0.2    0.2    0.2    0.1    0.0
=>
TXPU  =
=>
=>HIS
=>HIS

87T1                                      Date: 01/13/97   Time: 15:48:21.488
XFMR WR1

#     DATE        TIME            EVENT               TARGETS
1     01/10/97    18:31:12.065    TRP1 TRP2 TRP3      87 A C
2     10/18/96    13:49:43.944    TRP1 TRP2 TRP3      87 A

=>EVE 1
=>EVE 1

87T1                                      Date: 01/10/97   Time: 18:31:12.065
XFMR WR1


FID=SEL-587-R105-V5a-D950929

                                                         Relay Elements    OUT I

              Winding 1                   Winding 2               555555 555555 888  A
              Amps Sec                    Amps Sec                111000 111000 777 13L 1
                                                                  PQNPQN PQNPQN URB &&R &
  IRW1   IAW1   IBW1   ICW1   IRW2   IAW2   IBW2   ICW2  111111 222222   L 24M 2

 -0.0   -0.0   -0.2    0.1   -0.0    0.1    0.1   -0.2   ...... ...... ... ... .
  0.0    0.2   -0.1   -0.1    0.0   -0.1    0.1    0.0   ...... ...... ... ... .
  0.0    0.0    0.2   -0.1    0.0   -0.1   -0.1    0.2   ...... ...... ... ... .
 -0.0   -0.2    0.1    0.0   -0.0    0.1   -0.1   -0.0   ...... ...... ... ... .

 -0.0   -0.0   -0.2    0.2   -0.0    0.1    0.1   -0.2   ...... ...... ... ... .
  0.0    0.2   -0.1   -0.1    0.0   -0.1    0.1    0.0   ...... ...... ... ... .
 -0.0    1.0    0.2   -1.2    0.0   -0.1   -0.1    0.2   ...... ...... ..* ... .
 -0.0   -0.5    0.1    0.4   -0.0    0.1   -0.1    0.0   ...... ...... ..* ... .

  0.0   -1.7   -0.2    1.9   -0.0    0.0    0.1   -0.2   ...... ...... ..* ... .
  0.0    0.5   -0.1   -0.4   -0.0   -0.1    0.1   -0.0   ...... ...... ..* ... .
  0.0    0.7    0.2   -0.9   -0.0   -0.1   -0.1    0.2   ...... ...... ..* .   .
 -0.0   -0.2    0.1    0.1   -0.0    0.1   -0.2    0.0   ...... ...... .** b   .

 -0.0   -0.0   -0.2    0.2   -0.0    0.1    0.1   -0.2   ...... ...... ... bb. .
  0.0    0.2   -0.1   -0.1    0.0   -0.1    0.2    0.0   ...... ...... ... bb. .
```

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