Arc Flash Mitigation Through Use Of Voltage Controlled/Voltage Restrained Overcurrent Elements

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Introduction

As owners of industrial electrical systems lead the way in responding to the hazards of electrical arc flash, the first stage was performing arc flash hazard calculations per the requirements of NFPA-70E and IEEE-1584. These calculations can show equipment that has arc flash hazard levels beyond the capabilities of any Personal Protective Equipment (PPE), or equipment that can require the use of onerous levels of PPE. Once the initial assessment has been made, owners are often interested in finding solutions that reduce the arc flash hazard. While there is a variety of relaying techniques that easily can reduce clearing times and, therefore, arc flash hazard, enhanced protection of many portions of the typical system requires communication of system status from one location to another. The information to be communicated can be blocking signals, CT circuits, or information between a pair of line differential relays. Line differential is an expensive solution for industrial systems and generally is not used. There are inherent problems in running CT circuits over longer distances; while it can be done, it requires larger than usual CT circuit wiring and would require use of different types of relays than typically found in these industrial systems. In these systems, the blocking scheme may be the most practical, but it does require interconnecting wiring and requires a certain amount of delay before tripping.

One of the authors had been looking at this problem and had recognized that the use of a distance element would allow instantaneous tripping on the primary of transformers in radial circuits. He also recognized that this type of element is not in the relaying equipment typically used in industrial systems and the setting of distance relays would add unnecessary complexity to the protection of these systems. The concept was left aside and other techniques were worked with. At one point, the other author, Johnson, asked a question about using voltage-controlled or voltage-restrained overcurrent as a quasi distance element. Beach thought that it would not work as proposed, but saw this as a possible solution to the original desire for a distance element for use in industrial systems.

Typical Industrial System

For this paper, a typical industrial system will be considered to take service from the utility at medium voltage or higher and be primarily radial in nature. The system may have local generation operating in parallel with the utility, but the portion of the system with sources on both ends of a feeder or on both sides of a breaker would be small compared to the strictly radial portion of the system. The medium voltage distribution of this typical system would consist of 15kV to 35kV class circuits and equipment and would supply transformers that feed loads on low voltage or 5kV class circuits.

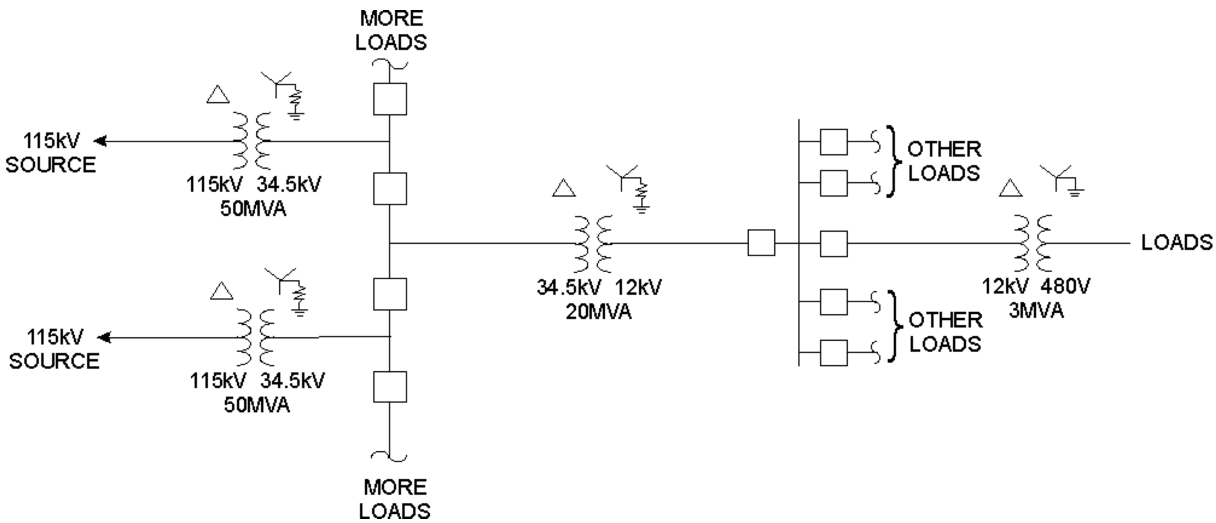


Figure 1 – One Line Diagram

These systems could range from a single 15kV service feeding a single line up of switchgear, to large systems served from multiple transmission circuits and having a sub-transmission level distribution to additional transformers that supply the 15kV class switchgear.

The system modeled for this paper is shown in figure 1. This system was selected to provide a stiff system with the goal of maintaining voltage as much as possible during faults.

It is also assumed that these typical systems will have circuit breaker based switchgear as opposed to switch and fuse distribution or free standing circuit breakers. This switchgear can be characterized as having one or two forward compartments with circuit breakers, the second compartment (if present) above the first, figure 2. The space between the front of the breaker and the door of the compartment is used for control wiring and protective relays. Immediately behind the breaker compartments is the horizontal cross-bus, and behind that is the power circuit wiring area. If there are two breaker compartments per section, the wiring area will be similarly subdivided. The circuit breakers in this gear are drawout and the power circuit connections to the breaker pass through current transformers mounted at the rear of the breaker compartment. Typically, there are provisions to allow two CTs per phase on the bus side of the breaker and two CTs per phase on the line side of the breaker.

This typical system will have overcurrent relaying at each breaker and may have other protection, although most are limited to overcurrent protection. Traditionally, this overcurrent protection is selectively coordinated using time-overcurrent elements, and tripping times increase as the point of protection moves from the load toward the source. Typically, the CTs used for this overcurrent protection are on the bus side of the breaker so that the breaker is in the zone of protection. Often, bus differential relays have been used in addition to the overcurrent relays. Where bus differential relaying is used, the CTs for the bus differential generally will be on the line side of the breaker, again to include the breaker in the zone of protection. Where a switchgear lineup is provided with multiple sources, partial differential schemes may have been implemented using overcurrent relays, particularly for segmenting the lineup for protection against ground faults.

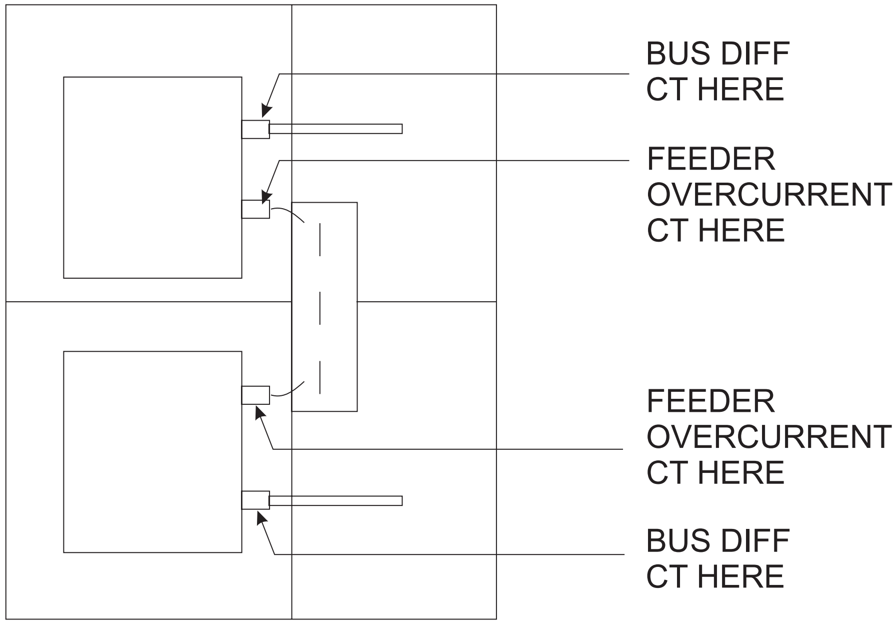


Figure 2 – Typical Switchgear Feeder Section

Enter Arc Flash Awareness

As the industry has become increasingly aware of the hazards of arc flash, the initial response is to determine clearing times at each location in the system for various fault types and magnitudes. With fault magnitude and clearing time known, the arc flash incident energy can be calculated and a required level of PPE assigned. In many cases, this may indicate the need for levels of PPE that do not allow for sustained, comfortable, working conditions, or it may indicate that no level of PPE exists that can protect against the arc flash hazard.

The second response to arc flash hazard awareness is a search for methods to reduce the hazard level. The arc flash hazard level can be reduced by reducing the fault current feeding the arc or by reducing the duration of the arc through faster clearing of the fault current. Reductions in available fault current generally will require significant changes to the physical configuration of the system and are generally not a practical solution. Reductions in clearing times can be achieved through various relaying techniques. If selective coordination is to be retained, it is necessary to supplement conventional time overcurrent relays with additional protection.

While there are many possibilities, this paper considers the use of two schemes for bus protection in the switchgear and offers a new solution for the problem of the feeder circuits.

Bus Protection

Bus differential protection is highly effective in providing fast, selective protection against faults on the bus or at the circuit breakers. By including the circuit breakers in the zone of protection, bus differential protection can provide fast clearing for arc flash events that occur during the racking of breakers on to or off of the bus. Retrofitting bus differential protection to switchgear previously without bus differential relays can be disruptive and expensive. New CTs will need to be added at each circuit breaker; additional new CT wiring will be required in each switchgear section; a bus differential relay will be required; and a means of tripping all circuit breakers on the bus will be required. It may also be necessary to trip a breaker in other switchgear upstream of the gear to be protected to interrupt the supply of current.

If bus differential was not originally implemented, a less involved means of providing fast bus protection is to implement a blocking scheme where the relay at each feeder breaker uses a low set instantaneous element to send a blocking signal to the next breaker upstream indicating that the feeder relay has seen a potential fault current flowing downstream and that the upstream breaker need not trip for that potential fault. The relay at the upstream breaker is also programmed with a low set definite time element with a delay of a few cycles. If this relay receives a blocking signal from one of the downstream relays, this element relay is blocked from tripping the breaker. If the blocking signal is not received, the element will cause the breaker to trip. This blocking scheme requires more time to clear bus faults than a bus differential scheme, as it is necessary to allow time to be sure that there is not a blocking signal before tripping. There is also a need for wiring between relays, and interposing relays are often used to separate the DC circuit of one relay from the DC circuit of other relays. These interposing relays add time to the propagation of the blocking signal. It often requires between 3 and 4 cycles from onset of the detected current until an upstream relay can safely assume a blocking signal has not been sent and can trip.

The Gap in High Speed Protection

With the bus protected, is the switchgear protected? As can be seen in figures 3 and 4, neither the bus differential nor the blocking scheme provides enhanced arc flash performance on the back side of the switchgear, and the blocking scheme does not provide enhanced arc flash performance for the breaker itself. The circuit feeding from the gear also lacks enhanced arc flash protection. By combining voltage with current, it becomes possible to close this gap such that fast tripping is available for any fault in a feeder section of the switchgear. Fast tripping for all faults in the incoming section can require tripping of upstream devices through differential schemes or communications assisted tripping.

The Model System

To allow testing of multiple relay schemes under various fault conditions, a system model was developed in ATP with sensing and protection components developed using TACS (Transient Analysis of Control Systems) components. The ATP model uses a four sample per cycle filter to generate current and voltage measurements for the relay components. RMS magnitudes and accompanying phase angles are generated every quarter cycle. More precise results and faster tripping decisions could have been achieved using more samples per cycle, but the additional complexity of the model was not deemed necessary to prove the concepts studied. The system modeled is shown in figure 1. To provide multiple conditions to evaluate, a sample system was developed for a large customer, fed from two 115kV transmission circuits. These two circuits are stepped down to 34.5kV and fed into a ring bus with multiple transformer circuits. Each of these transformers steps down the 34.5kV to 12kV. Each 12kV secondary feeds a lineup of switchgear, and the feeder breakers in each switchgear lineup feed smaller transformers that provide utilization voltage for facility loads. The transformer in this model has a 480V secondary, but 2400V and 4160V would also be found in facilities of this nature. The 34.5kV and 12kV systems are low impedance grounded while the 480V system is solidly grounded.

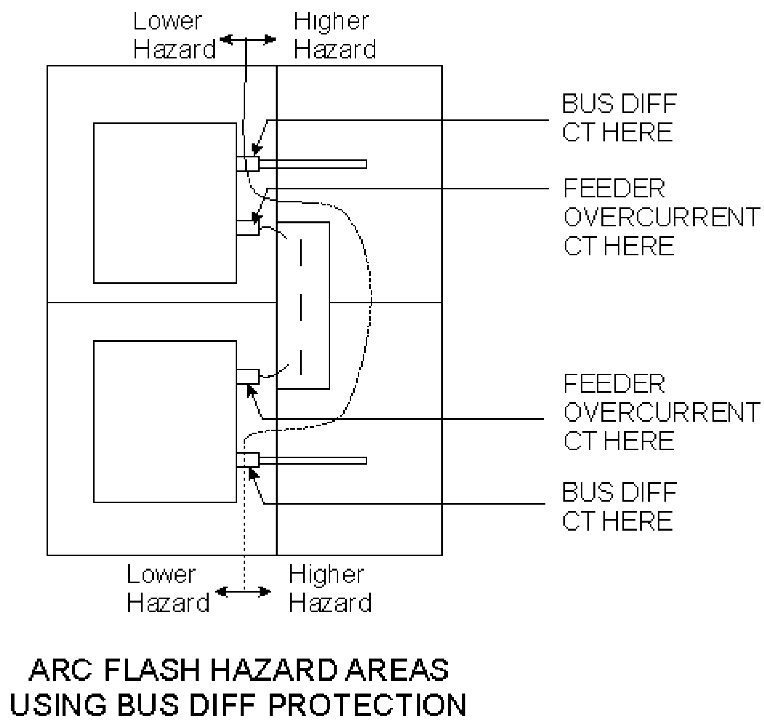
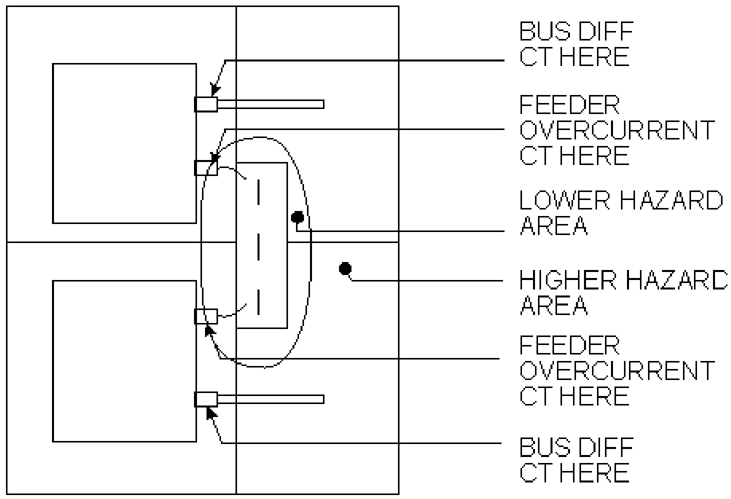


Figure 3 – Switchgear Section with Bus Diff Zones

Review of Voltage Controlled and Voltage Restrained Overcurrent

If one does not work with generator protection, the distinction between Voltage Controlled and Voltage Restrained Overcurrent protection may be a bit fuzzy; a quick refresher follows. Both types of elements were developed for use in protection of generators against close-in faults that might depress the terminal voltage and drive the fault current contributed by the generator to below maximum load current. Voltage Controlled and Voltage Restrained Overcurrent elements, typically a time overcurrent element, are designed to allow tripping for currents less than load under conditions of depressed voltage.



ARC FLASH HAZARD AREAS
USING BLOCKING SCHEME

Figure 4 – Switchgear Section with Blocking Zones

Voltage Restrained Overcurrent elements are set for a pickup current at nominal voltage and, as the voltage goes down, the pickup current goes down proportionally. Thus, when the voltage is at 50% of nominal, only 50% of the set current is necessary for the element to pickup. This proportional response holds to some voltage level, often 25%, below which point the pickup current no longer reduces with decreasing voltage but rather stays constant. The pickup also remains constant at the set value for voltages above nominal. See figure 5.

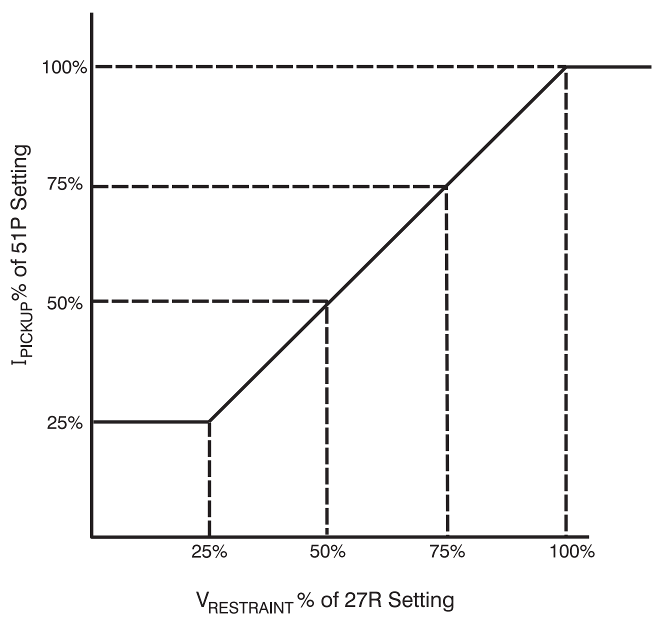


Figure 5 – Voltage Restrained Overcurrent

Voltage Controlled Overcurrent elements are set for a single value of current pickup and a single voltage level. When the system voltage is above the set voltage, the element is turned off and the level of current does not matter. When the system voltage is below the set voltage, the element will respond to currents above the pickup current.

Of the two, the Voltage Controlled Overcurrent element generally is easier to set and coordinate with other protection. The Voltage Restrained Overcurrent Element generally provides better protection of the generator if properly set.

For the protection problem at hand, the goal is to protect a portion of the system defined in a manner that allows instantaneous tripping without the need for coordination with other protection and, as such the elements evaluated will be instantaneous rather than time overcurrent.

Voltage Restrained Overcurrent

The first approach evaluated for closing the gap in protection was the use of Voltage Restrained Overcurrent protection; the pickup of the element is proportional to the voltage. Through analysis of the model system, using ATP, it was found that Voltage Restrained Overcurrent was not sufficiently secure over all conditions evaluated. We believe that Voltage Restrained Overcurrent would have exhibited better security on a solidly grounded system where ground fault currents were of similar magnitude to phase currents. Settings low enough to trip on a single phase fault could also operate on secondary faults. It may be worth revisiting Voltage Restrained Overcurrent in further research using a Voltage Restrained Ground Overcurrent Element similar to the Voltage Controlled Ground Overcurrent Element developed below.

Voltage Controlled Overcurrent

After evaluating Voltage Restrained Overcurrent, the model was altered to implement a Voltage Controlled Overcurrent element. The fixed tripping characteristics of this element made it much easier to set the element for phase faults, but there were problems setting the element to clear ground faults on the primary (relay) side of the downstream transformer without causing the element to respond to faults on the secondary side of the transformer. We determined that an additional element was necessary (see the discussion of the Voltage Controlled Ground Overcurrent Element below). We found that the element would perform as desired and that settings could be readily developed. Using the elements may be a bit more difficult, as they may not be directly available in most relays. In some relays, it is possible to set a Voltage Controlled Time Overcurrent element and set the coefficients of the trip curve used to zero out the inverse portion of the equation. Often the trip equation is:

$$T_T = \frac{A * D}{M^N - C} + B * D + K \qquad (1)$$

Setting A and B=0 will create an instantaneous trip with a time delay of K. Usually, the value of K is fixed by the manufacturer of the relay. Setting A=0 and B to some non-zero value will result in an adjustable definite time element. This curve, with B=1, is available in some relays and is referred to as a fixed time curve. This fixed time curve, however, may have a minimum time setting higher than desired.

When using a relay that does not provide a Voltage Controlled Time Overcurrent element with user programmable trip equation coefficients, the element can be created in relay logic by ANDing together an instantaneous overcurrent element and an undervoltage element in the relay logic.

Voltage Controlled Ground Overcurrent Element

A low impedance grounded system was selected for the study to provide the largest variety of operating conditions. This model fulfilled its intended purpose by highlighting the need for an element that could respond to a single phase-to-ground fault on the primary of the transformer without responding to secondary faults or requiring a voltage setting so low that a bolted fault was required to generate sufficient current and a low enough voltage at the relay. To resolve this issue, an element was created that could be called a Voltage Controlled Ground Overcurrent Element, but unlike other voltage controlled elements, this one operates when the sensed voltage, 3V0, is above the setting rather than when the sensed voltage is below the setting.

The question of the need for this element may come to mind; after all, won't a conventional ground overcurrent element work just as well? In the sample system modeled, a conventional ground element might work nearly as fast, but would have to be slow enough to allow residual currents associated with transformer inrush to dissipate without tripping the breaker. While currents exhibit many fault-like characteristics during transformer inrush, the voltages remain nearly unaffected. This stability of system voltages during transformer inrush provides security that allows higher speed operation of the Voltage Controlled Ground Overcurrent element than of a conventional ground overcurrent element. Similarly, the Voltage Controlled Overcurrent element is secure against operation due to the phase currents associated with transformer inrush as the phase voltages do not collapse during the transformer inrush.

If the relay were protecting a circuit feeding a grounded-wye / grounded-wye transformer, more likely in a utility system than in an industrial system but possible in any system, an instantaneous ground element could not be used on the primary of the transformer, but the Voltage Controlled Ground Overcurrent element would still function properly.

Setting Considerations

The plots that follow, figures 6 through 15, are generated from ATP and show the values of variables in the model. Extending a relay model developed in part by Dr. Brian Johnson PE of the University of Idaho, the variable naming scheme was retained and expanded resulting in the names used. Variables starting with a 'Z' are currents, and variables starting with a 'Y' are voltages. The '3' indicates the location in the system (the feeder breaker to the 480V transformer as shown in figure 1), the 'A', 'B', or 'C' is the phase, and the 'PU' indicates an RMS Per Unit value. The use of four samples per cycle in the model results in significant steps in the value of the variable every quarter cycle, but was deemed sufficiently accurate for the purpose at hand.

The model used exhibited numeric oscillation in the voltages downstream of the breaker following operation to clear a fault. This oscillation shows up as voltage noise after t=0.130s in figures 9 and 13.

Setting the element is reasonably straightforward. For systems where the source impedance – as seen from the relay – remains relatively constant, four values are needed for the setting of the phase Voltage Controlled Overcurrent element: the currents and voltages seen by the relay for bolted faults at the primary and secondary terminals of the transformer. The current and voltage settings used for the element need to be selected such that they are between the values from the two terminal faults. The closer to the values from the secondary fault, the further into the transformer the element will protect. More importantly, perhaps, the closer to secondary fault values used, the more resistance a fault on the primary can have and still be cleared by the element.

For instance, in the modeled system, in its normal configuration, a fault on the secondary of the 12kV – 480V transformer is seen to produce a current that peaks just over 20pu (figure 6) and a voltage of 0.845pu (figure 7). In each of the figures, the voltages and currents are those seen at the relay location. With the fault on the primary of the transformer, the current exceeds 100pu (figure 8) and the voltage is reduced to less than 0.065pu (figure 9). In each case, the fault is initiated at time 0.05s. For the primary faults, the relay element causes the breaker to open, clearing the fault. The voltages after 0.13s in the primary fault condition are artifacts of numeric oscillations within the model.

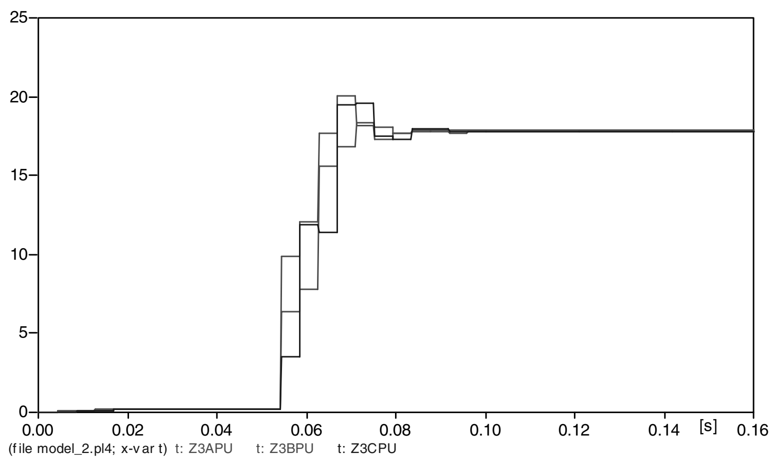


Figure 6 – P.U. Currents for Secondary Fault

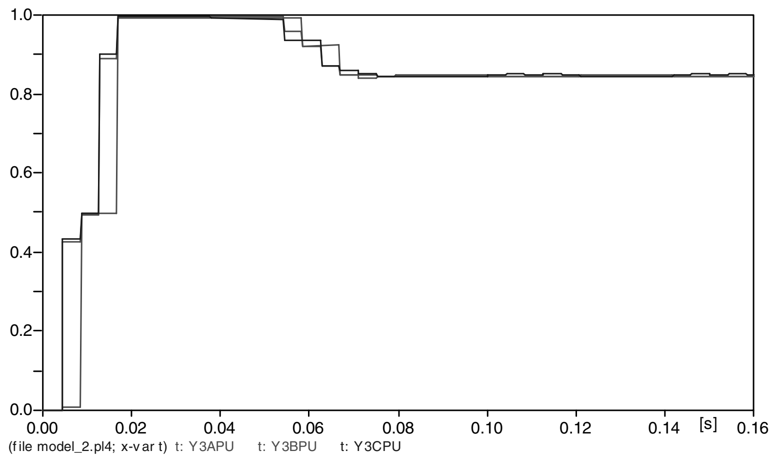


Figure 7 – P.U. Voltages for Secondary Fault

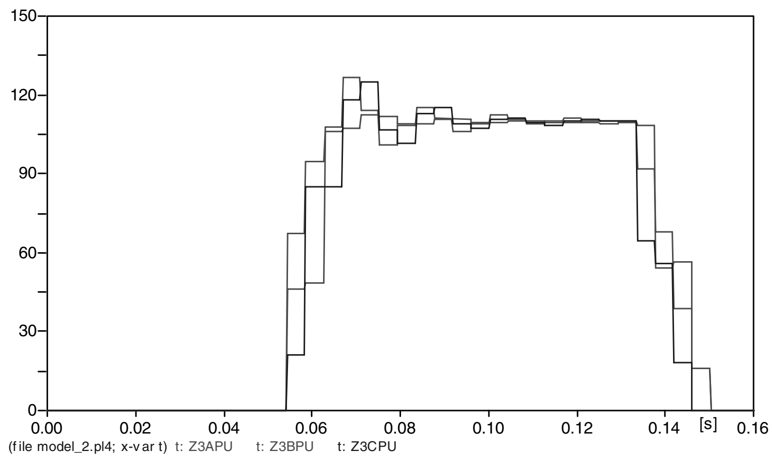


Figure 8 – P.U. Currents for Primary Fault

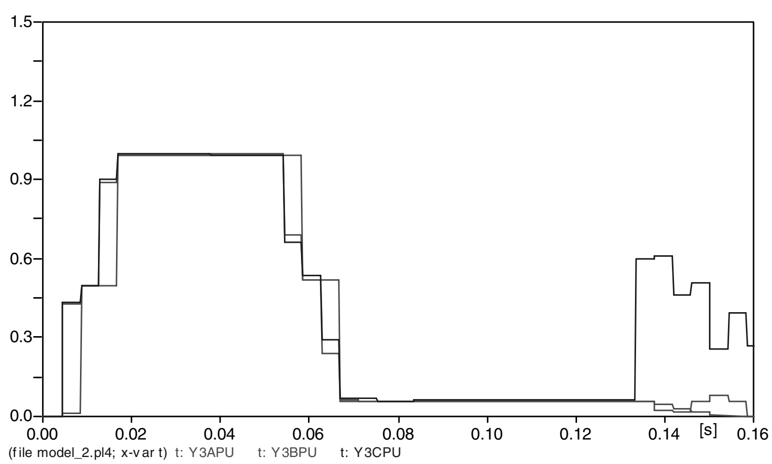


Figure 9 – P.U. Voltages for Primary Fault

In this case, a voltage setting of 0.7pu will keep the element inactive for all faults on the secondary of the transformer. Now, the current can be set lower than the 20pu or higher setting that would be necessary without consideration of the voltage. This allows a higher fault resistance the closer the fault is to the CT location, as long as the fault can pull the voltage down to below 0.7pu. The difference between this setting and the 100pu fault current on the primary terminals of the transformers allows the fault to have considerable resistance, as is common in arcing faults, and still be detected by the element and cleared by the breaker.

When the system can operate with differing source impedance as seen from the relay, it is necessary to look at both the lowest source impedance and the highest source impedance conditions. In the model studied, loss of one of the 115kV sources increases the source impedance as seen from the relay. With only one 115kV circuit in service, a fault on the secondary of the 12kV – 480V transformer is seen to produce a current peaking at just over 19pu (figure 10) with a voltage of about 0.80pu (figure 11). Moving the fault to the primary of the transformer produces a current peaking at nearly 93pu (figure 12) and voltages of less than 0.05pu (figure 13).

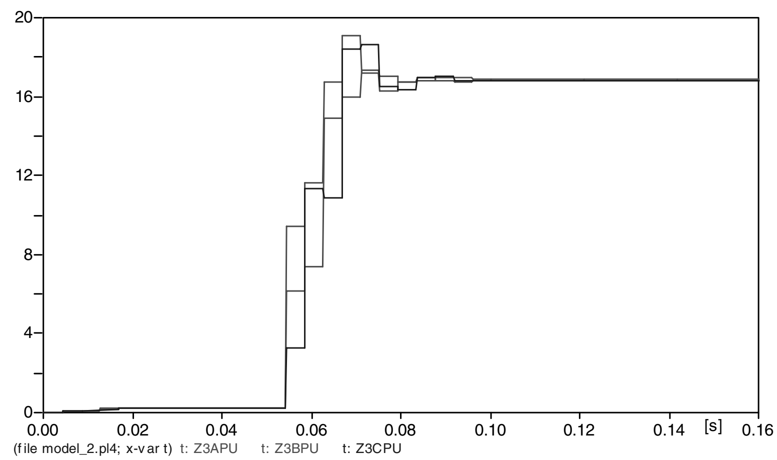


Figure 10 – Single Source, P.U. Secondary Fault Current

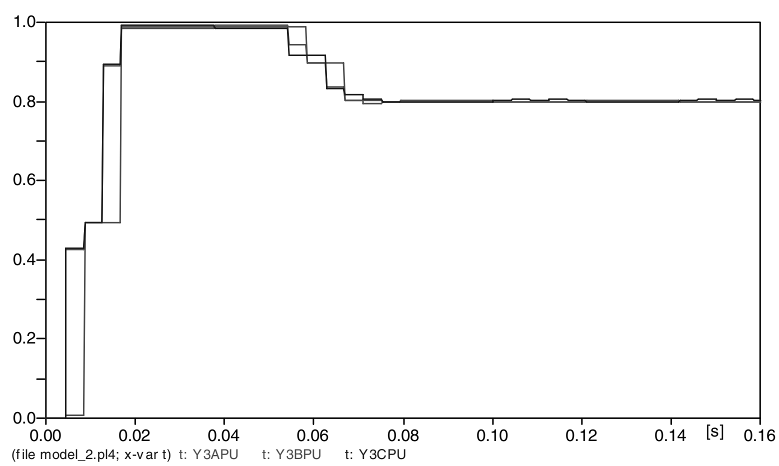


Figure 11 – Single Source, P.U. Voltages for Secondary Fault

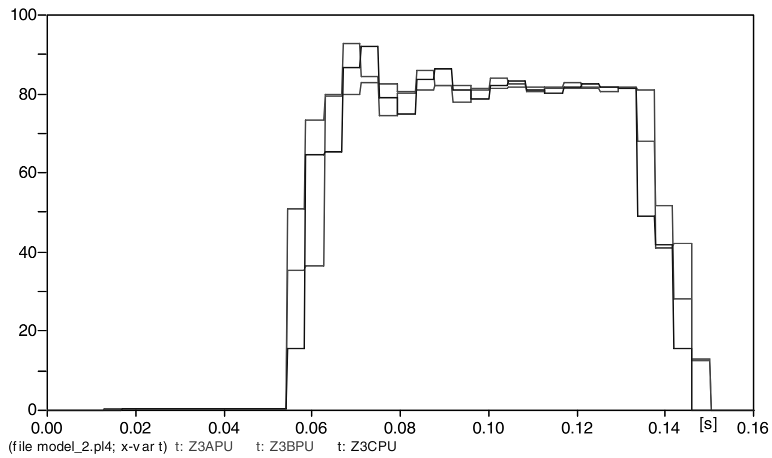


Figure 12 – Single Source, P.U. Primary Fault Currents

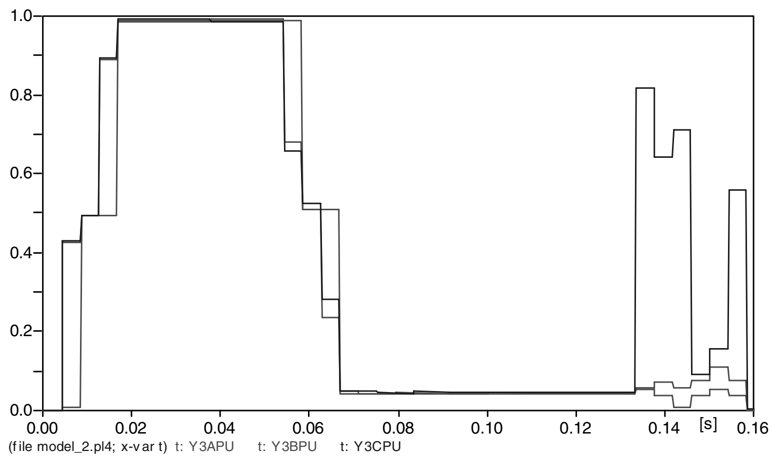


Figure 13 – Single Source, P.U. Voltages for Primary Fault

In this case, the change in source impedance did not significantly change the currents or voltages. A setting of 0.70pu voltage and a current setting of less than 20pu would provide good protection against faults between the CTs and the secondary of the transformer.

Transformer inrush is often a consideration in setting instantaneous elements on the primary of the transformer; the need to not trip on inrush requires a setting of 15 to 25pu current. Transformer inrush does not have a significant impact on system voltage and would not reduce voltage nearly as much as a fault on the secondary terminals of the transformer. With transformer inrush not able to create the conditions to trip the voltage controlled element, it is possible to set the current setting less than inrush for increased sensitivity for faults in or near the switchgear.

The lower limit for the current setting is established by the amount of fault current the circuit under consideration can supply to a fault on the supply, bus, or on an adjacent circuit. Any of those fault locations can depress the voltage sufficiently to meet that requirement of the element, so it is necessary for the current setting to be high enough to not trip for these faults. If the entire load on the feeder consists of motors, this fault contribution could approach 6 times load current if the transformer is not considered. With the transformer impedance providing a limitation of the fault current, this fault contribution is unlikely to exceed 4 times load current.

Using a 50% margin over that possible reverse fault current, and assuming a fully loaded transformer, a minimum current setting of 6pu should provide an adequate minimum setting. This is considerably less than the setting necessary when voltage is not considered.

In all cases, system fault studies need to be performed to determine setting appropriate for each installation.

Ground Element

For a single phase to ground fault on this low impedance grounded system, fault currents will be much lower than for faults involving two or three phases. The ground fault will also provide a strong zero sequence voltage for use in controlling the element. Figure 14 shows the currents for a bolted ground fault at the primary terminals of the transformer, trace Z30PU is added to this plot and shows the magnitude of the 3I0 current relative to the 200A that can be supplied from the upstream transformer. In this case, the fault draws about 0.99pu.

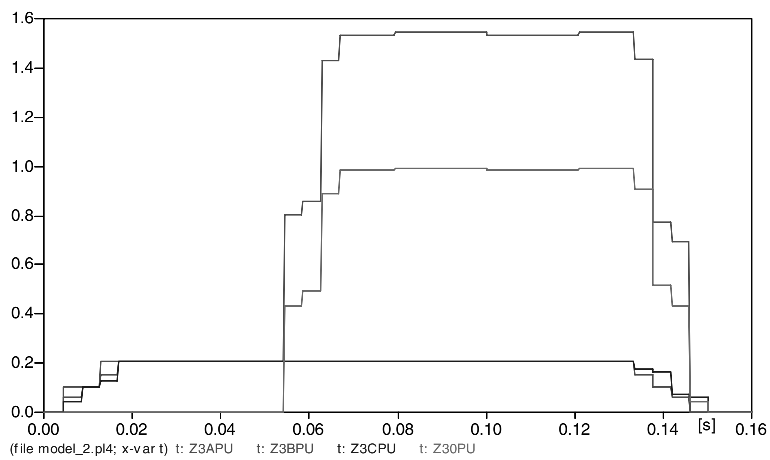


Figure 14 – P.U. Currents for Primary Ground Fault

Figure 15 shows the voltages associated with this fault. As expected, the voltage on phase A, the faulted phase, drops to near zero while the other two phase voltages raise to around 1.7pu. The zero sequence voltage associated with the fault exceeds 2.95pu.

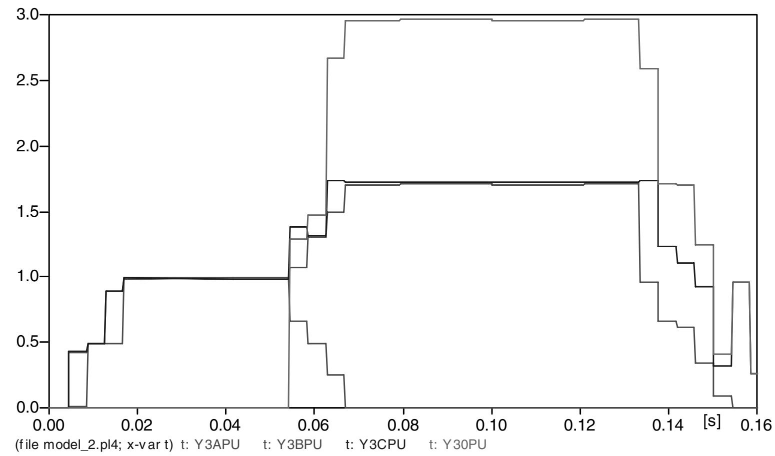


Figure 15 – P.U. Voltages for Primary Ground Fault

Comparing the pre- and post-fault portions of these plots, it is apparent that a significant change occurs that allows settings to be selected to clearly distinguish this fault from the idealized pre-fault condition. In a real system, it is quite likely that there will be a certain amount of standing imbalance and that any setting will have to allow for this standing imbalance.

Implementation

Using a relay with voltage controlled/voltage restrained time overcurrent elements, the Voltage Controlled Overcurrent element can be created simply by setting the phase element as voltage controlled and setting the curve coefficients so that ‘A’ and ‘B’ are set to zero. The steps for one particular relay are shown in figures 16 and 17.

Figure 16 shows the selection of the type ‘P’ curve, allowing user selected coefficients, and figure 17 shows the coefficients set for an instantaneous trip. To allow a definite time trip, the value of ‘B’ would be set to some non-zero value. The exact value selected would control the range of times selected by the time dial setting.

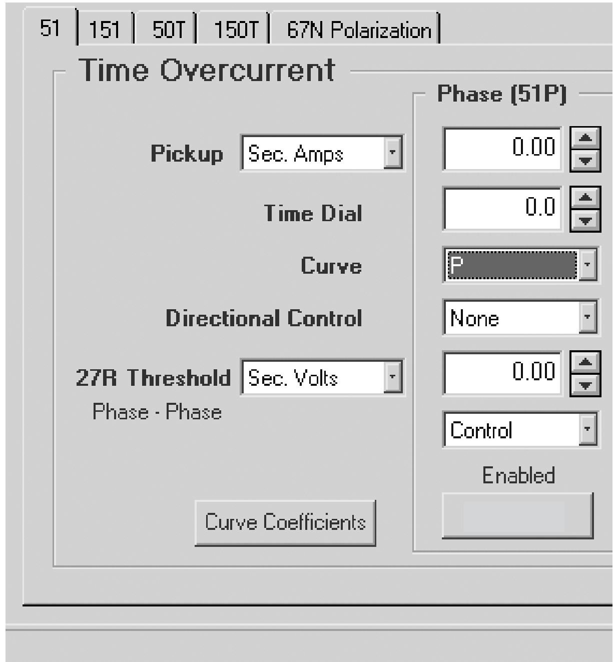


Figure 16 – Setting Example

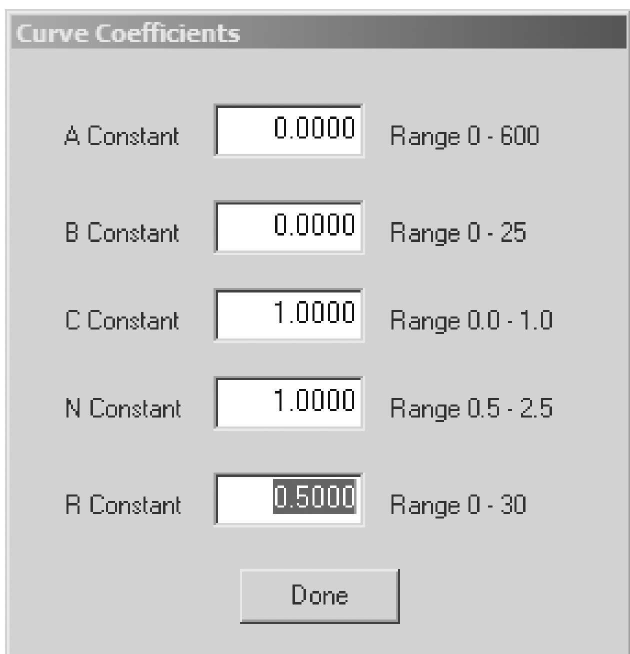


Figure 17 – Setting Coefficients

Setting the Voltage Controlled Ground Overcurrent element is likely to be more involved. The steps for setting this element in the same relay used for the phase example follow in figures 18 through 20.

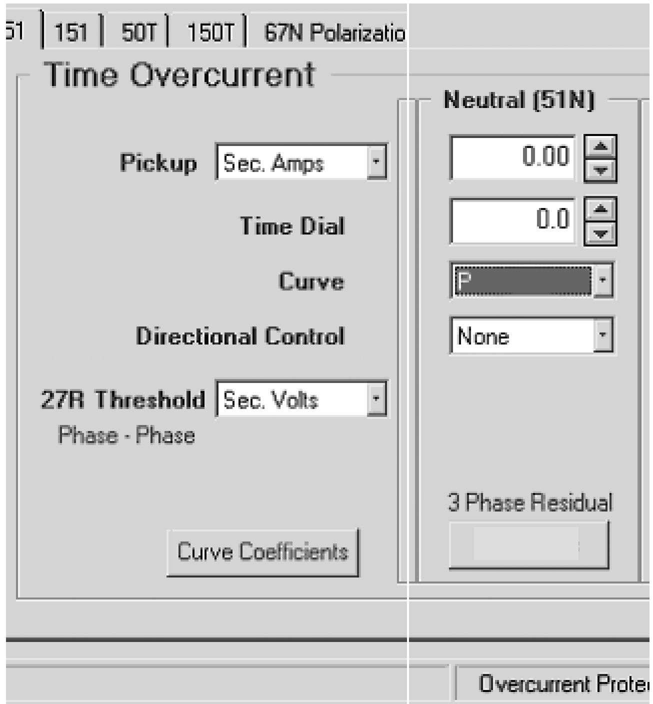


Figure 18 – Setting Ground Element

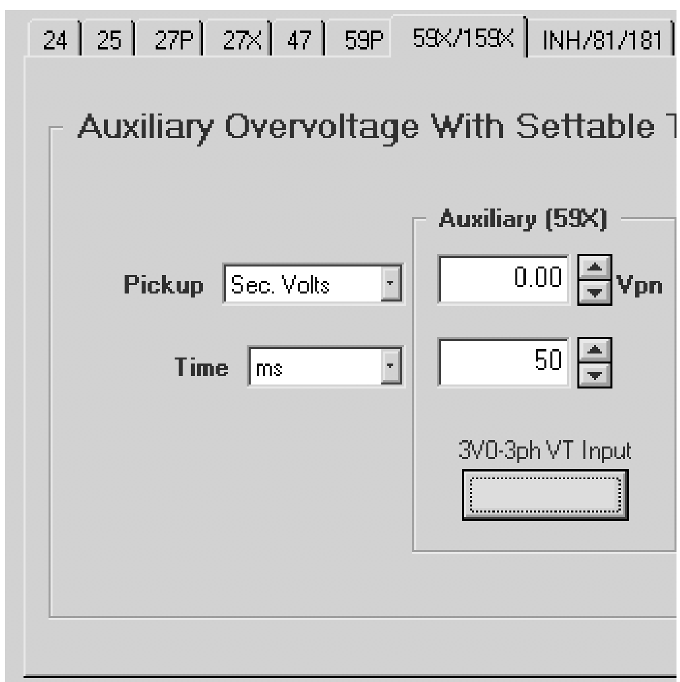


Figure 19 – Setting 3V0 Overvoltage

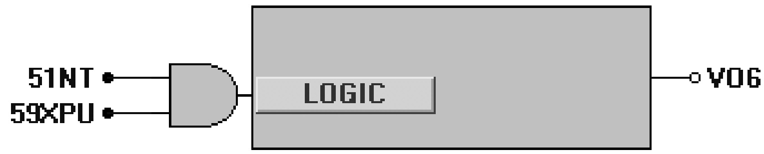


Figure 20 – Setting Logic

Figure 18 shows the neutral overcurrent element set for three-phase residual current and the user defined curve, assuming the same coefficients as shown in figure 17. Figure 19 shows the setting of the voltage element setting, an overvoltage element responding to a calculated 3V0 derived from the 3-phase VT inputs. Figure 20 shows the two elements being ANDed together as virtual output VO6.

Why Not Just Instantaneous Overcurrent?

The question has probably arisen in the mind of the reader as to why this is necessary and why not just use conventional instantaneous overcurrent set for faults on the primary of the transformer. Conventional instantaneous overcurrent protection would have to be set high enough so as not trip for faults on the secondary of the transformer. When arc resistance is considered, the current of an arcing fault may fall below the pickup of an element that does not reach through the transformer. Using voltage controlled overcurrent, it is possible to set the current pickup low enough to ensure tripping for arcing faults that likely would not be cleared by a conventional instantaneous overcurrent element set to coordinate with downstream protection.

The Gap in High Speed Protection Filled

With Voltage Controlled Overcurrent used alone, the bus area of the switchgear is the only remaining higher hazard area; see figure 21.

Figures 3 and 4 on page 4 show the relative arc flash hazards with bus protection, adding the Voltage Controlled Overcurrent to bus protection. The result is that the entire feeder section is in the lower hazard area as shown in figure 22.

Coordination Examples

Figures 23 through 25 show three alternatives for setting the protection of the circuit under consideration. In each plot, the two thick traces are the 480V breakers. The 12 kV Feeder is the relay on the circuit feeding the transformer stepping the 12 kV down to 480V. The 12 kV Main is the relay on the circuit coming into the 12 kV switchgear from the 34.5-12 kV transformer. The 34.5 kV Primary is the relay on the primary of the 34.5-12 kV transformer.

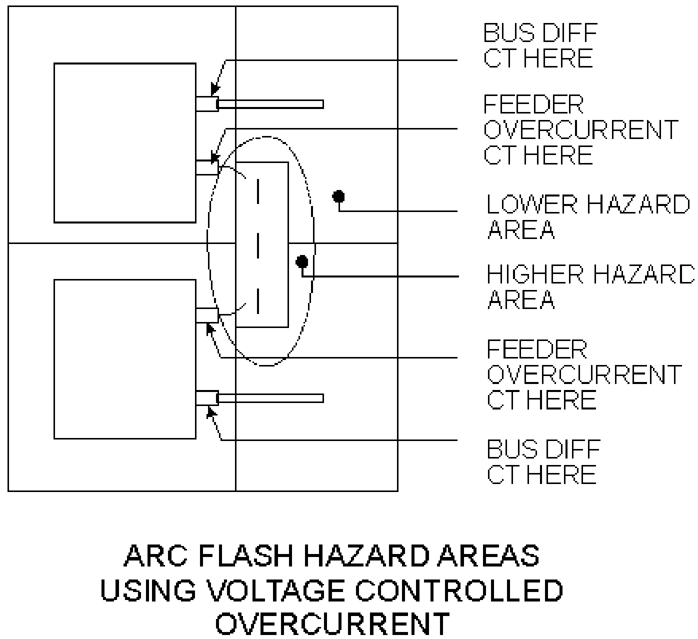


Figure 21 – Switchgear Section with Voltage Controlled Overcurrent Zones

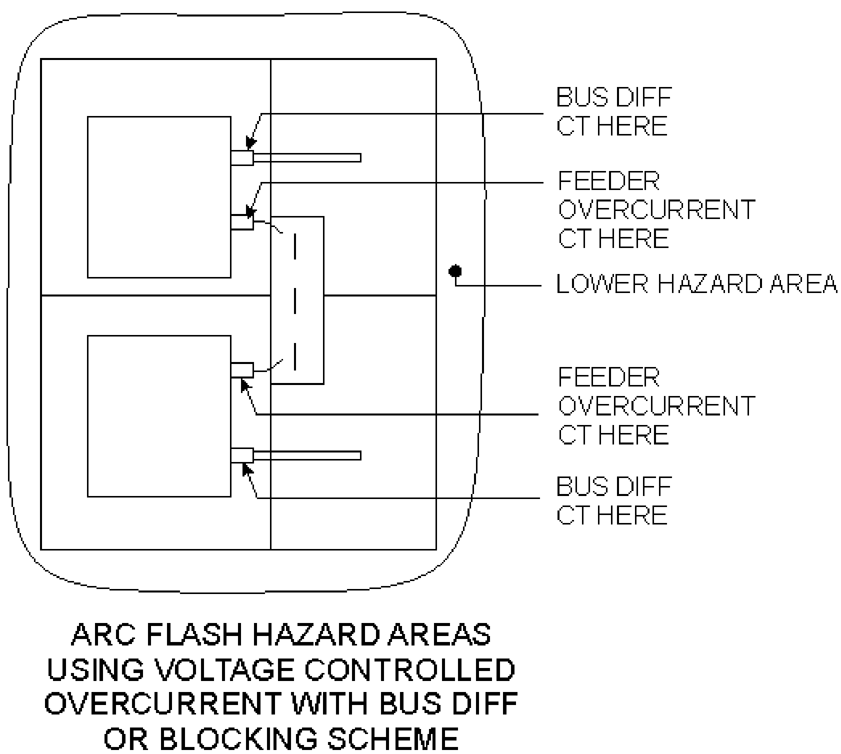


Figure 22 – Switchgear Section with Combined Bus and Voltage Controlled Overcurrent Zones

Figure 23 shows the use of time overcurrent elements without the use of instantaneous elements. This type of protection (without instantaneous) would not be expected to be encountered in practice but is included to establish a baseline to which instantaneous protection can be added. Figure 24 adds instantaneous overcurrent, which is coordinated strictly on current magnitude.

Figure 25 shows what is possible with the use of Voltage Controlled Overcurrent elements. Looking strictly at the current levels, this appears to be very poorly coordinated, but is actually fully coordinated when voltage is included in the tripping decision. In addition to the protection shown, an element in the feeder relay should be set as indicated in figure 24 to provide backup protection for faults not cleared by the 480V Main that do not reduce the voltage sufficiently to turn on the Voltage Controlled Overcurrent element.

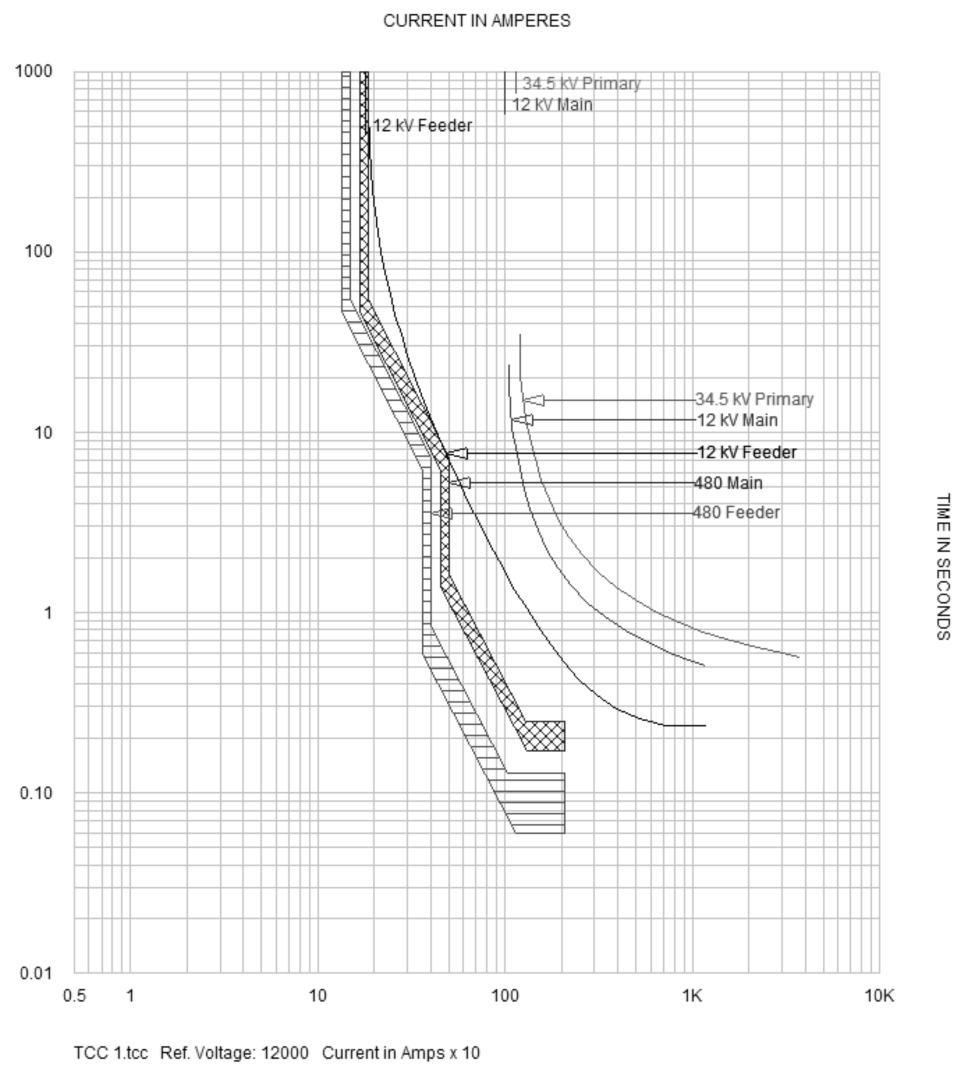


Figure 23 – Time Overcurrent Only (Intended as a Point of Comparison Only)

The Arc Flash Study

Performing an arc flash study, per NFPA-70E, on each of the three protection schemes represented in figures 23 through 25, the following results were achieved:

Table 1

	Fig 23 51	Fig 24 50/51	Fig 25 VC50/51
12kV Bus 12kV Main	Cat 4	Cat 3	Cat 3
12kV Bus 34.5kV Pri	Danger	Cat 4	Cat 4
12kV Lugs 12kV Feeder	Cat 3	Cat 2	Cat 2

The first column indicates the location in the system and the device providing the protection. In each case, any bus zone protection is omitted from the calculations.

The results of the arc flash study do not show as drastic an improvement as the reduction in settings might suggest. This is due in part to the standards only considering low resistance arcing faults. The presence of instantaneous elements in figure 24 provides much of the improvement, and the reduced pickup currents associated with figure 25 are not considered in the study calculations. Other systems will exhibit differing results.

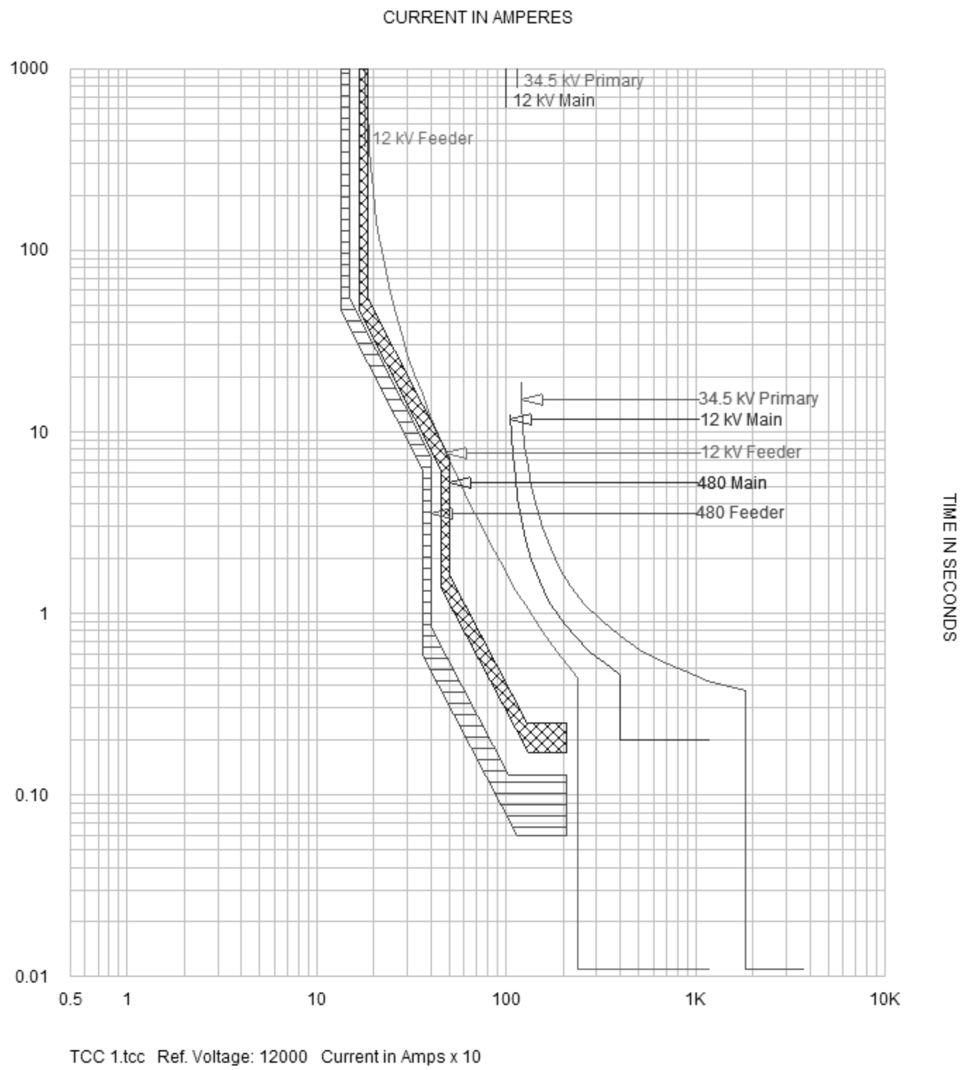


Figure 24 – Conventional Protection with 50/51 Protection

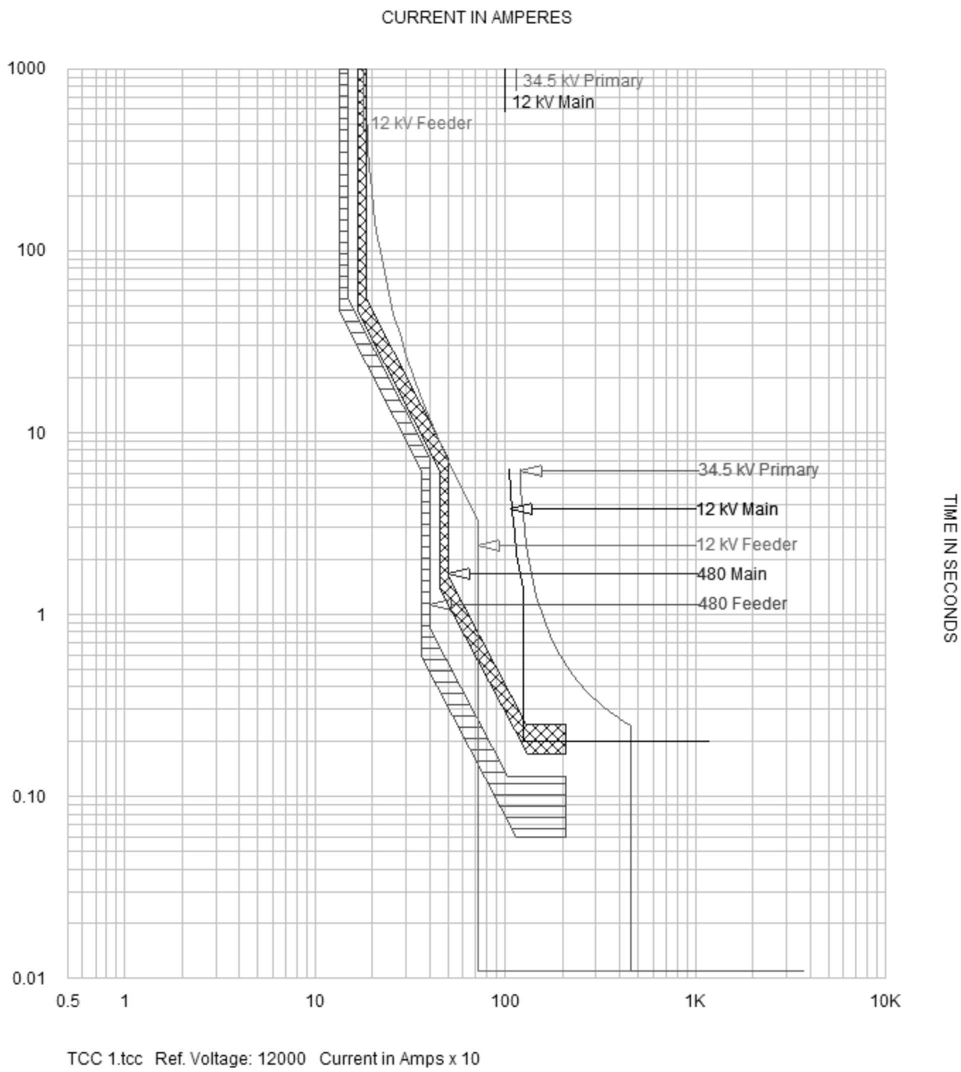


Figure 25 – Reduced Instantaneous Settings Through Use of Voltage Controlled Overcurrent

Of particular note, the arc flash results for the 12kV Bus, when protected by the 12kV Main, are reduced from Category 4 PPE to Category 2 PPE. The back side of the gear does not show an improvement between figures 24 and 25, but any arcing fault that starts through some fault resistance will be picked up sooner, not necessarily having to wait until the fault evolves to being phase-to-phase.

It is also necessary to consider the results of the study to spot locations where the voltage controlled aspect of these elements may provide erroneous results. In the study, the figure 25 results for the 12kV bus when protected by the 34.5kV Primary relay is Category 2 PPE, but any fault on the 12kV system will not reduce the voltage on the 34.5 kV system enough to turn on the voltage controlled overcurrent. Without the voltage controlled element active, the tripping time at the 24.5kV Primary relay will be the same as in figure 24, resulting in the same level of PPE as in figure 24 for that location.

Because the standards do not presently address arcing phase-to-ground faults, the arc flash studies are not able to show results for the improved clearing times for phase-to-ground faults on this low impedance grounded system afforded by the use of the Voltage Controlled Ground Overcurrent element.

Conclusions

Voltage Controlled Overcurrent and Voltage Controlled Ground Overcurrent elements were explored and shown to provide a means of allowing pickup currents to be set much lower than in conventional time coordinated overcurrent without loss of coordination. Examples were provided for setting these elements, using built-in relay functions and using relay logic.

Compared to a system using only inverse time overcurrent, use of Voltage Controlled Overcurrent elements reduces the PPE requirements around the switchgear in the system modeled. When compared to conventional time coordinated overcurrent using instantaneous elements in addition to inverse time overcurrent elements, the use of Voltage Controlled Overcurrent did not show a reduction in PPE requirements as the relevant standards do not consider variable resistance in the arcing faults.

Further Study

Areas for further study include:

- Application to Utility distribution feeders. Long circuits with many small transformers do not seem likely to benefit. Shorter circuits with a small number of larger transformers seem likely to benefit.
- Simulations of other systems with differing fault levels. Were the results seen here driven by the very stiff system modeled?
- The impact of revisions to the standards. Phase-to-ground faults and faults with high arc resistance benefit more from this approach than do the arcing faults based on bolted fault currents.
- Voltage Restrained Overcurrent Applications.
- Considerations of an element similar to Voltage Restrained Overcurrent, except where the tripping current increases with reduced voltage.

Biographies

David Beach received a BS degree in Electrical Engineering from California State University, Fresno in December of 1982. Since that time, David became a Registered Professional Engineer, licensed in the states of California, Oregon, and Washington. David worked in the Consulting Engineering business until February 2005 when he joined Basler Electric Company as a Senior Application Engineer. In December 2006, David became a Protection Engineer with Portland General Electric. David is a Senior Member of the IEEE, a member of the Industrial Applications Society and the Power Engineering Society of IEEE.

Gerald Johnson is a Senior Application Engineer for Basler Electric Company, based in Richmond, Virginia. Prior to joining Basler in 1999, Jerry spent 29 years in the System Protection organization of Virginia Power, including 12 years as Director of the System Protection Engineering Department. Jerry is a graduate of Virginia Commonwealth University and is a registered professional engineer in the State of Virginia. He is a senior member of IEEE and a working member of the Power System Relaying Committee since 1993. Mr. Johnson also is a member of the Georgia Tech Planning Committee.