Application Note

Arc Flash Hazard Mitigation Through Relaying

Arc flash hazard awareness is a critical topic for those responsible for the management of electrical power systems. NFPA 70E requires an evaluation of the arc flash hazard level at each piece of electrical equipment and a listing of the Personal Protective Equipment (PPE) necessary if the equipment is to be worked on while energized. NFPA 70E and IEEE Standard 1584-2018 provide the means of calculating the hazard level in terms of incident energy of the arc. In the evaluations used in both standards, the hazard level becomes a function of available bolted fault current at the point being evaluated and the time that a fault might be allowed to persist before some portion of the protective system clears the fault. Reducing either the bolted fault current or the clearing time will reduce the arc flash hazard, and a sufficient reduction of the hazard will allow use of less restrictive PPE. The magnitude of the available fault current is dependent on the configuration of the system, the sources available, and other factors beyond the scope of the protective system. The clearing time, on the other hand, is directly controlled by the protective system. This application note provides suggestions for how to use relaying techniques to reduce clearing time without compromising the existing protection, including selectivity.

Figures 2 and 3 show representative one-line and relay connection diagrams to illustrate many of the techniques mentioned. These techniques can be used individually or in combination. The one-line in Figure 2 represents an industrial system, served at medium voltage from the utility (bus 1 in room 1), that has a second medium voltage switchgear location (bus 2 in room 2), and a transformer stepping down the voltage to 480V for utilization at bus 3. A real-world system likely would be much larger, but would have similar features. Figure 3 illustrates connections among multifunction relays discussed below.

Settings Groups

A system using digital relays typically has multiple settings groups or plenty of additional functions available, and this capability can provide a means of arc flash mitigation without the need for additional relays. A way to use settings groups for arc flash mitigation is to have one group provide normal, fully coordinated protection, with the high hazard level associated with the normal protection. Using switches at the entrance to each switchgear room, the relays can be switched to a different settings group, providing faster clearing times and allowing work on energized equipment with a lower level of PPE than the normal settings. The switch would be wired to an input on each relay and used to control which of the two settings groups is active. With the switch in the “normal” settings group position, there would be no change from the settings previously in use. With the switch in the “hot work” settings group position, each relay would have an instantaneous element set no more than 150% of maximum load, with an allowance for any starting inrush currents that might occur while workers are performing hot work. This instantaneous setting will not necessarily coordinate with downstream devices but is only used while energized equipment is being serviced.

Ideally, the change in settings groups would also be applied to the relay of the breaker supplying the gear in question, because the reduced hazard only applies for faults beyond the CTs connected to the relay with “hot work” settings applied. If the supply breaker is in the switchgear in question, that section of the gear will not have the same lower hazard level associated with the remainder of the gear.

Figures 2 and 3 show an example of this application. In Figure 2, note the location of relays 1, 2, and 3; and in Figure 3, note the connections to input IN3 of each of these relays. Relay 1 is on the main breaker on the incoming line from the utility to switchgear bus 1 in room 1. Relay 2 is in the same gear as relay 1 and protects the feeder to switchgear bus 2. Relay 3, at switchgear bus 2, is on a feeder supplied by bus 2. A switch at the entrance to switchgear room 1 would activate IN3 on relays 1 and 2 to change the settings groups of these relays. Unfortunately, there is no means of increasing the speed of the utility protection ahead of relay 1, so the fast tripping will not apply for faults on the supply side of the main breaker; that section will have a higher incident arc energy than the remainder of the gear. A switch at the entrance to switchgear room 2 controls relay 3 and other relays in that gear, as well as relay 2 in switchgear room 1 on the feeder to switchgear bus 2. To allow the control switches at each room to control relay 2 through the same input, the diodes shown are used to block the signal from traveling beyond the intended relays. That way, when the switch for room 2 is on, relay 3 and the other relays in that room are in the "hot work" settings group as is relay 2 in room 1. The upper diode prevents the signal from reaching relay 1 and other relays on that bus, leaving the coordinated protection active.

One thing to consider when contemplating this approach is how the relay responds to the command to change settings groups. Basler relays make the change from one settings group to another between

1/4 cycle scans and are never off-line. Relays from other manufacturers are known to go off-line during the time the settings groups are changing, and the relay does not provide any protection during that time.

Additional Relays

In many cases, the greatest reduction in arc flash hazard can be achieved through the use of additional relays, particularly differential relays. The beauty of differential relaying from an arc flash mitigation standpoint is that each differential relay protects a clearly defined zone within the system and does not require any delay to coordinate with protection for other portions of the system.

Bus differential protection, such as provided by the BE1-FLEX and BE1-87B (Figure 1), provide a means of responding to faults on a bus without the need for any delay to coordinate with other portions of the system; trip decisions can be made in one to three cycles from the onset of the fault to the trip contact closing. Adding in breaker time, a bus fault can be cleared in 6 cycles or less (0.10 sec at 60 Hz). This is a vast improvement over conventional overcurrent protection times that can extend into the seconds or even tens of seconds. One caution when using bus differential for arc flash mitigation with metal clad switchgear is that, with the CTs mounted on the breaker bushings, as is the typical installation method, the zone of protection ends at the CTs and a fault at the line terminals will not be cleared by the bus differential.

Figure 1 - The BE1-87B (left) and BE1-FLEX (right) provide a way to respond to faults on a bus without the need for any delay

In Figure 2, a BE1-87B is shown with CTs paralleled from each line in and out switchgear bus 1. Not shown in the diagram is the tripping connection between the relay and the breakers in the gear. Typically, that tripping connection would be through a lockout relay with a trip contact for each breaker. If a bus differential relay were applied at switchgear bus 2, CTs would be needed on the incoming feeder, and the lockout relay for this gear would need to trip the supply breaker associated with relay 2.

Transformer differential relays can be useful in arc flash hazard mitigation, particularly if the zone of protection is expanded from the usual zone of protection. Often, transformer differential relays are applied with the CTs at the terminals of the transformer, and this limits the zone of protection to the transformer itself. If, on the other hand, the CTs of the transformer differential are installed at the breakers on each side of the transformer, the zone of protection will extend to the switchgear. With the transformer differential CTs on the bus side of the breakers and the bus differential CTs on the line side of the breakers, the zones will overlap and there will not be locations where a fault could persist for longer periods of time while waiting for a time overcurrent element to time out.

The BE1-FLEX Protection, Automation and Control System, could be used around the transformer, with the CTs located at the gear at each end of the circuit.

In many industrial installations, lines are short enough that two terminal differential capable relays, such as the

BE1-FLEX, could be used for line differential with the CTs at both ends of the line brought to the relay. Used this way, careful analysis of the burden of the CT circuits can help avoid CT saturation. The relay burden is low enough that the burden seen by the CT secondary is essentially the impedance of the conductors to the relay.

If the BE1-FLEX shown around the transformer were to be connected on the feeder between the two pieces of switchgear, faults on the feeder could be cleared instantaneously.

Communications

Communications between relays can greatly reduce the relay time without the need for additional relays, although it does require the use of multifunction relays. In the simplest implementation (see Figure 2), consider two relays on a radial circuit, one upstream of the other. In addition to the normal time and instantaneous overcurrent settings, we will add an additional low set definite time (instantaneous with time delay) setting on each relay. We will also connect an output of the downstream relay to an input of the upstream relay. Digital communications such as IEC61850 Goose messaging could alternatively be used for this peer-to-peer communications. For each relay, this new setting will be set above load, for example 150% of load, but does not necessarily need to coordinate with inrush or other transient events. The upstream relay may be set less sensitively as it may serve more load than the downstream relay, or they may be set nominally the same if they see the same load, but in no case should the upstream relay be set more sensitively than the downstream relay. To avoid inadvertent lack of coordination, the upstream relay should be set less sensitively than the downstream relay by at least twice the relay/CT tolerance. The downstream relay logic will be set to activate the output whenever the low set element is picked up.

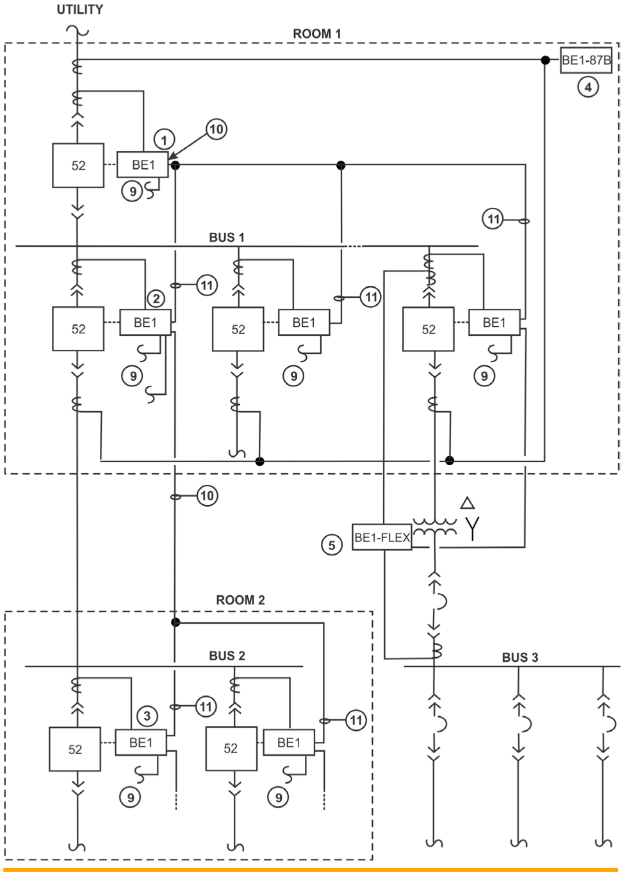

Figure 2 - One-Line Diagram

The upstream relay will receive, through its input, a signal that the downstream relay sees something unusual. The NOT of this signal will be ANDed with the trip of the low set element in the upstream relay. Knowing that the fault, or other abnormality, is beyond the next relay downstream, the upstream relay does not need to trip. If the upstream relay low set element picks up, but the blocking signal is not received, it can trip after a delay long enough to allow receipt of the blocking signal, plus some margin, as it will have been determined that the fault is located between the relays. With relays directly connected, the delay time can be 3 cycles or less; with an interposing relay the delay time can be 4 cycles. Testing during system commissioning can determine the nominal signal time, and the protection engineer can add the desired margin to arrive at the time setting. With this technique, it is helpful to use a very short recognition time and a very long debounce time for the input on the upstream relay. The short recognition time is desired to ensure than the signal is recognized as soon as possible, thereby allowing a shorter delay time. The long de-bounce time is desired to keep the blocking signal in place until after the element on the upstream relay has dropped out. Making these adjustments to the input processing times increases the security of this scheme.

The scheme can be extended to include more relays up- and downstream of the two considered above. As with the bus differential, if this scheme is used only within one piece of switchgear there will be very fast clearing for faults on the bus itself, but faults that occur on the cable terminals of outgoing feeders will be beyond the CTs of the downstream relay. Communications from the next switchgear or from the load will extend the scheme and provide complete protection.

This scheme is illustrated in the figures with the connections detailed in Figure 3. Starting with relay 3, OUT5 closes whenever the low set picks up. This signal becomes an input to relay 2, shown as IN4 in this example. The signal from OUT5 is paralleled with outputs of other relays at the same level in the system so that any relay can provide the blocking signal. Relay 2 receives the blocking signal from relay 3 and has also sent a blocking signal upstream to relay 1. If a fault occurred on bus 2 (Figure 3), the low set element on relays 1 and 2 would pick up; relay 1 would receive a blocking signal and would not trip. Relay 3 would not see the fault current, so no blocking signal is sent to relay 2 resulting in a high speed trip to clear the fault. The tripping decision would be made in 3 to 4 cycles, significantly less than using coordinated time-overcurrent elements.

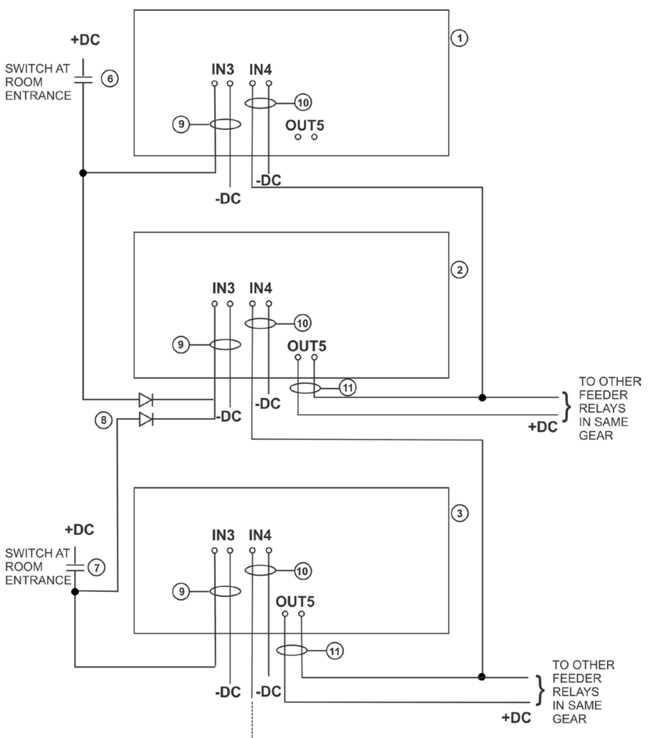

Figure 3 - Relay Connections

LEGEND, Figures 1 and 2

1 BE1 -FLEX relay at main breaker.
2 BE1-FLEX relay at feeder breaker in main board.
3 BE1-FLEX relay at feeder breaker in sub-board.
4 BE1-87B Bus Differential Relay.
5 BE1-FLEX Transformer Differential capable relay.
6 Contact of switch at entrance of Switchgear Room 1.
7 Contact of switch at entrance of Switchgear Room 2.
8 Diodes used to allow two switches to control the same relay input without mixing signals.
9 Connections to relay from switch at room entrance.
10 Blocking signal input to relay room downstream relays.
11 Blocking signal output from relay to upstream relay.

In Figure 2, the connection shown between the BE1-FLEX and the upstream relay can be used similarly. An overcurrent element operating on the CTs on the secondary of the transformer can provide a blocking signal which indicates that the fault has occured on the 480V system rather than somewhere between the medium voltage gear and the low voltage gear.

CT Placement

In all protection schemes, the boundary of the zone of protection is defined by the location of the CT. Traditionally, switchgear has been designed to allow CT installation on the bushings of the circuit breakers. This provides a convenient location for the installation of the CTs and provides good physical protection of the CTs (See Figure 3). Also, at this location there are no concerns of cable shields interfering with proper measurement of the current. As pointed out above, this location can create the situation of faults within the switchgear being seen as beyond the zone of the switchgear. If the CTs are moved to the cable compartment, the zone of protection can be extended to include the cable terminations. Unfortunately, in this location it will be necessary to provide support for the CTs, run the cable shields back through the CT to cancel any current flowing on the shield, and find a path for the CT secondary circuit from the cable compartment to the control compartment.

Breaker Failure Protection

All of the protection ideas discussed to this point assume that the intended breaker will trip at the proper time, but what happens if that assumption is false? The possibility of a breaker failing to trip is accounted for in conventional coordinated time overcurrent settings where each device is backed up by all devices further upstream; failure of one device to clear a fault means that the next device will have an opportunity to clear the fault after the set time delay. The fact that times for this backup protection can get into the seconds becomes a serious issue if failure of one interrupting means is considered when evaluating arc flash hazard. Using the breaker failure protection features of the Basler digital relays, it is possible to have backup protection operate within a few cycles of a breaker failure rather than a few seconds.

In Figure 2, if relay 3 sent a trip signal to its breaker, but the breaker failure logic of the relay indicated that the breaker did not open to interrupt the current, the relay would try to retrip the breaker. Simultaneously, or with a user-selected delay, it would also send a trip signal to the breaker associated with relay 2 to clear the fault at that location. Using breaker failure protection, the breaker at relay 2 will be tripped to clear a fault beyond the fauled breaker at relay 3, and that tripping can occur witha delay of less than 20 cycles afer the initial attempt to trip the breaker at relay 3.

Summary

Historically, protection systems have relied on time coordinated overcurrent protection for selective clearing of system faults. The need for selectivity has resulted in clearing times that become progressively longer the further upstream in a system the fault occurs. When arc flash hazards are considered, this increased time results in increased levels of required PPE, until the hazard becomes so great that there is not an adequate level of PPE available. Using the relaying techniques discussed above, it is possible to significantly reduce the clearing time for faults at any location in the system while maintaining full selectivity. It is a realistic goal to achieve primary clearing times of less than 10 cycles and backup clearing times of less than 20 cycles for an entire system while maintaining full selectivity for all primary protection.

For More Information

For information on Basler's complete range of digital relay systems, visit the download section at www.basler.com to access product documentation, Application Notes, and Technical Papers.

To discuss your application, consult Basler at the factory at (618) 654-2341.

Figure 4 - Basler digital relays with BF function (BE1-FLEX pictured) use faster backup protection

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