Upgrading Power System Protection to Improve Safety, Monitoring, Protection, and Control

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***Abstract*—One large Midwestern paper mill is resolving an arc-flash hazard (AFH) problem by installing microprocessor-based (µP) bus differential protection on medium-voltage switchgear and selectively replacing electromechanical (EM) overcurrent relays with µP relays. In addition to providing critical bus differential protection, the µP relays will provide analog and digital communications for operator monitoring and control via the power plant data and control system (DCS) and will ultimately be used as the backbone to replace an aging hardwired load-shedding system.**

The low-impedance bus differential protection scheme was installed with existing current transformers (CTs), using a novel approach that only required monitoring current on two of the three phases. The bus differential relay provides fast fault clearing to reduce the AFH condition and also detects other problems outside the bus differential zone that could indicate a possible problem with switchgear breaker performance. Using the µP bus differential relay's math functionality, the current data from each feeder and source position were combined with bus voltage data also monitored by the relay to provide real-time watt and VAR power flow information.

This paper discusses the design of the bus differential protection scheme, the studies required to verify that the existing CTs were adequate for the bus differential application, the design of end-zone protection, and the math computations used to provide real-time power flow data. The paper also discusses how the analog and digital information from this scheme, and others like it, will be concentrated and processed to provide an overall plant power management system.

I. Arc-Flash Hazard (AFH): Identifying the Hazard

A. Power System Description

Georgia-Pacific's Green Bay Broadway Street paper mill is a large consumer of electricity with 80 MW of load. The mill's five steam turbine generators (four at 15 kV and one at 5 kV) are capable of supplying this load while supplying process steam to the paper machines. Each 15 kV generator bus is connected to a synchronizing bus through a current-limiting reactor. The synchronizing bus also serves as the local utility's connection to the plant.

The power plant electrical distribution system consists of seven 15 kV buses, seven 5 kV buses, and numerous 480 V buses. The 15 kV and 5 kV system one-line diagrams are shown in Fig. 1 and Fig. 2, respectively. Each 5 kV bus in the power plant is supplied from two 15 kV buses. All paper mill and converting loads are supplied from either the 15 kV or 5 kV power plant buses. Three of the power plant's buses utilized high-impedance bus differential relays installed during switchgear upgrades within the last eight years.

The generator neutral points are not grounded. Instead, a 15 kV zigzag grounding transformer had been installed on one of the generator buses, establishing a low-impedance ground source that limits single-line-to-ground faults to 400 A. Each of the 5 kV bus source transformers is also low-impedance grounded with 400 A resistors.

Most 480 V unit substation transformers throughout the mill are high-impedance grounded with 10 A resistors. Very few of the 480 V unit substations have secondary main protective devices.

B. AFH Study Results

The mill had recently completed a three-year program replacing all overdutied electrical equipment when the 2004 edition of NFPE-70E was released. Because of the new AFH requirements, the mill began an extensive AFH study of their power distribution system that took until the end of 2006 to complete. The prepared software model was extensive and included more than 1,000 buses, encompassing the utility's 138 kV system down to most of the 480 V MCCs (motor control centers) and fused distribution panels. The available three-phase fault current levels at the 15 kV, 5 kV, and 480 V buses, respectively, are 40 kA, 20 kA, and 50 kA rms symmetrical. With this level of fault current and the existing plant protective relay settings, the calculated incident energies (IE) in cal/cm^2 at the 15 kV buses were greater than 1,000 (40 is extreme danger). The 15 kV bus IE results were high because of generator fault current contribution and existing relay settings that did not utilize instantaneous elements. The 5 kV bus results were high because of dual source feeds. The 480 V bus results were high because of the lack of secondary main protective devices and because existing primary protective devices were not able to provide fast enough clearing for secondary-side faults.

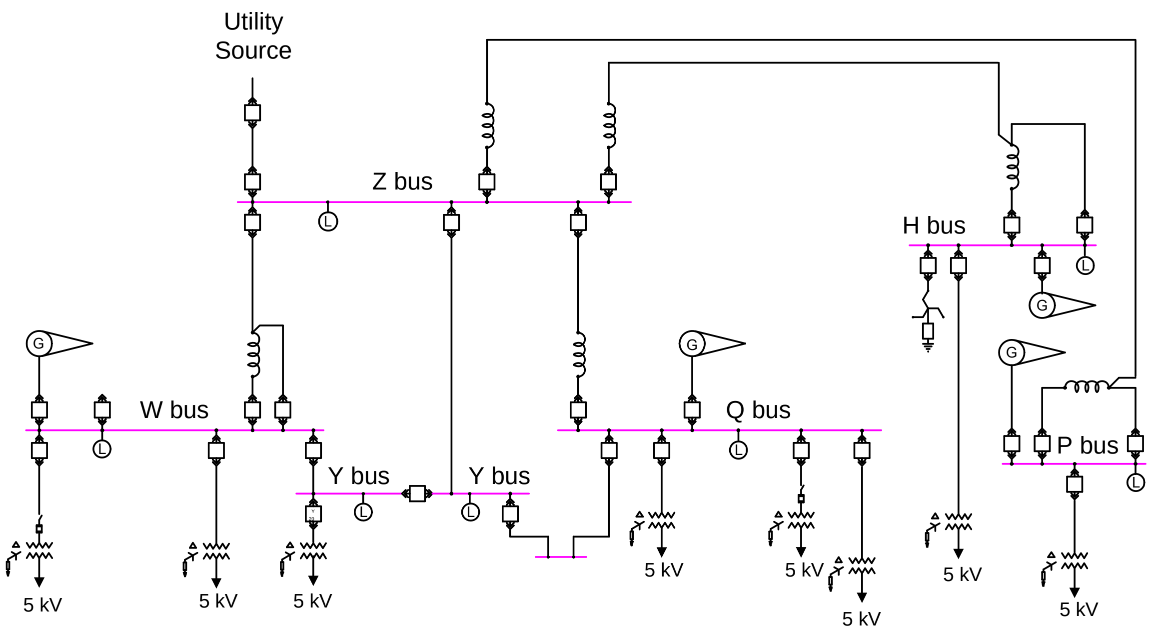

Fig. 1. 15 kV power plant system one-line diagram

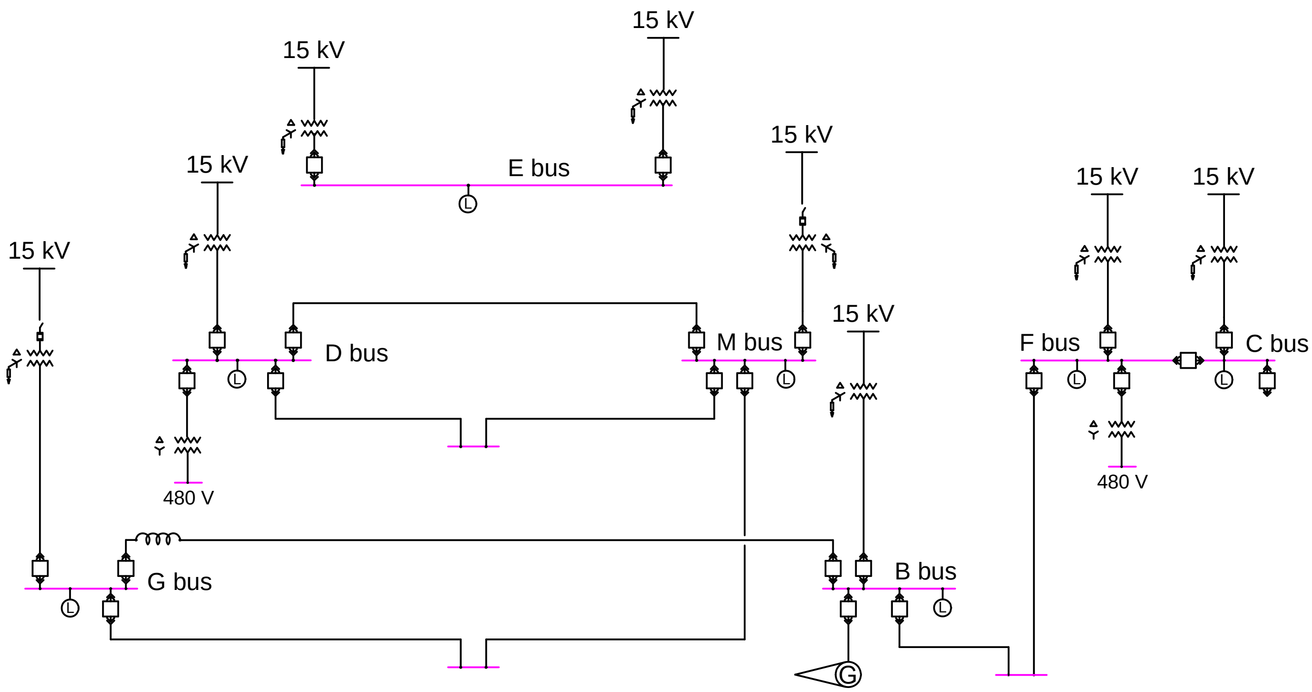

Fig. 2. 5 kV power plant system one-line diagram

C. Mitigation Techniques Studied

1) 5 kV and 15 kV

Studies indicated that adding instantaneous elements to 5 kV and 15 kV relays would work but doing so would completely destroy selective coordination. In many cases, it was still not possible to obtain IEs below 40.

Increasing the arc-flash distance in the model calculations (beyond the default 18 inches) was studied but was deemed not practical in most cases because of the lack of remote operators for switchgear racking or room space constraints.

Studies indicated that adding bus differential relays to all power house 5 kV and 15 kV buses would improve overcurrent coordination and significantly speed up tripping for bus faults and faults associated with racking breakers.

2) 480 V

Studies to reduce the IE on 480 V switchgear included setting the maximum limit for arc-flash clearing times at 2 seconds for buses less than 1,000 V, based on comments from the IEEE-1584 arc-flash standard. This would lower subsequent IE calculations but not below the extreme danger level of 40 cal/cm^2.

Adding secondary main breakers to the 480 V unit substations would solve the problem for the secondary-side bus but would still leave the secondary main breaker exposed to AFH when racking it in and out of the cell. It was quickly determined that in most cases this solution was not possible or practical because of installation limitations, not to mention the cost.

Adding secondary main CTs and a secondary main relay to trip the upstream switchgear breaker was considered as a possible approach. In some cases, however, the power house switchgear breaker was over 1,000 feet away. The cost of conduit installation to support this solution was prohibitive. The biggest problem with this solution was that multiple transformers are fed from the same power house feeder breaker, which means that a secondary-side fault on one transformer would trip all other transformers on that feeder. While this might be acceptable for paper machine feeders, it is not acceptable for converting operations and/or general power and building feeders.

Studies also included replacing the transformer primary-side fusible disconnect with a circuit breaker capable of being tripped from both a primary-side and secondary-side protective relay.

II. AFH: Defining and Implementing the Solution

The majority of the AFH safety problems were greatly mitigated through the improved protection provided by the installation of microprocessor-based (µP) bus differential and overcurrent relays. Significant benefits to improve monitoring and control were also realized because of the installation of µP devices. Appendixes A, B, and C provide detailed descriptions of the operating characteristics and benefits of µP relays.

A. Bus Differential Relays at the 5 kV and 15 kV Levels

Engineering decided to purchase and install low-impedance bus differential relays to provide AFH mitigation through rapid detection and interruption of bus fault current for all power house 5 kV and 15 kV buses. Three of the existing buses were relatively new, and although they had originally been supplied with electromechanical (EM) high-impedance bus differential relays, the high-impedance relays were replaced with the new low-impedance relays. A detailed explanation of low-impedance bus differential protection and the characteristics of the relays installed on this project is included in Appendix A.

The selected low-impedance bus differential relay operates on a per-phase basis, with all the circuit breaker CTs from a single phase creating a single-phase bus differential protection zone. Generally, CTs are installed on each phase of all circuit breakers, so three bus differential zones are established, one for each phase. Individual bus differential zones on each phase permit detection of all fault types, single-phase-to-ground involving any phase, all combinations of phase-to-phase faults, and three-phase faults.

The bus differential application at the mill presented a unique challenge because most power plant breakers only have two-phase CTs instead of the customary three-phase CTs. Having only two-phase CTs means that a bus differential zone can be created for only two out of the three available phases. Fortunately, because single-phase-to-ground fault current magnitudes are limited by the 400 A neutral-connected resistors, high-speed tripping for AFH mitigation is only required for multiphase faults. Therefore, the high-speed tripping bus differential scheme is only required to operate for multiphase faults. Bus differential zones were therefore established for Phases A and C, which were the two phases that had CTs. The two bus differential zones provide sufficient coverage to detect all combinations of phase-to-phase faults, three-phase faults, and Phase A and Phase C single-phase-to-ground faults.

Each bus differential relay can support eighteen CTs. This means that any bus with nine or fewer breakers would only require one relay with two defined zones, i.e., Phase A and Phase C. For buses with more than nine breakers, however, two separate differential relays would be required, one for Phase A and the other for Phase C.

A thorough CT inventory and analysis was completed to determine if the existing CT ratios and rating classifications were high enough to prevent false bus tripping for external through faults (faults outside of the protected bus zone). The bus differential relay needs at least 2 ms of undistorted CT secondary current to securely determine if the fault is external to the bus. The IEEE CT performance calculation Microsoft® Excel® spreadsheet [1] was utilized to determine if at least 2 ms of undistorted CT secondary current could be obtained for each CT application under the worst-case external fault condition. As a result of this study, all breakers on two of the 5 kV buses and some of the 15 kV breakers needed to have their CTs replaced with new ones with higher ratios and classifications.

A large number of breakers in the power plant had their CTs mounted on the stationary bottles that were on the bus side of the breaker instead of the line (cable) side. Each of these CTs was removed from the bus-side bottle and installed on the line-side bottle. This was done so that the breaker could be included within the bus differential zone of protection. For example, faults occurring on the line-side terminal of a breaker during a racking operation will generate a differential bus trip, thereby protecting the operator from an AFH. For a fault occurring between the breaker line-side terminal and the CT, tripping of the bus breakers would not necessarily remove all fault current if the faulted line is fed from a source. In that event, the remote source breaker is tripped by an end-zone protection system (see Appendix A for a description of end-zone protection).

B. Automation and Control at the 5 kV and 15 kV Level

Although the primary reason for the bus differential relays was protection, these relays also provide automation and control functionality that was exploited during the project design. The bus differential relay is naturally suited to measure current on each of the circuit breakers associated with the bus because of its CT connections. Each bus differential relay has automation registers and protection registers that can be freely programmed to fit any automation and control strategy.

The selected bus differential relay includes voltage inputs, providing it with the ability to combine voltage and current measurements to make directional MW and MVAR measurements. Directional metering information, which was not previously available, was needed in the power plant, where many buses are supplied from two or more sources. All but one of the buses included phase-to-phase connected PTs in an open-delta configuration. The other bus PTs were connected in a wye configuration. The CT restrictions (only two CTs per breaker) associated with the installation also meant that computations would be required to calculate full three-phase MW and MVAR measurements from two currents and two voltages. This was accomplished using math variables and a variety of math operators included in the relay, as shown in Table I. When two bus differential relays were applied to a bus, one for each phase, single-phase power measurements were calculated by one relay and multiplied by three to get full three-phase power quantities, assuming the load was balanced.

TABLE I
OPERATORS AVAILABLE FOR MATH CONTROL EQUATIONS

Operator	Description
( )	Parentheses
+, –, *, /	Arithmetic
SQRT	Square root
LN, EXP, LOG	Natural logarithm, exponentiation of e, base 10 logarithm
COS, SIN, ACOS, ASIN	Cosine, sine, arc cosine, arc sine
ABS	Absolute value
CEIL	Rounds to the nearest integer towards infinity
FLOOR	Rounds to the nearest integer towards minus infinity
–	Negation

The calculated analog data in the bus differential relays are passed to the power plant control room human-machine interface (HMI) via three communications processors that gather and consolidate the relay data. These communications are by a fast binary protocol operating over serial connections. The communications processors and the upstream HMI are all interconnected via Ethernet, which, among other benefits, makes it possible to log into a communications processor or an individual relay over existing network connections. The HMI consists of two 46-inch LCD monitors displaying the mill system one-line diagrams. Analog data are presented for each breaker. See Fig. 3, Fig. 4, and Fig. 5 for typical HMI screens.

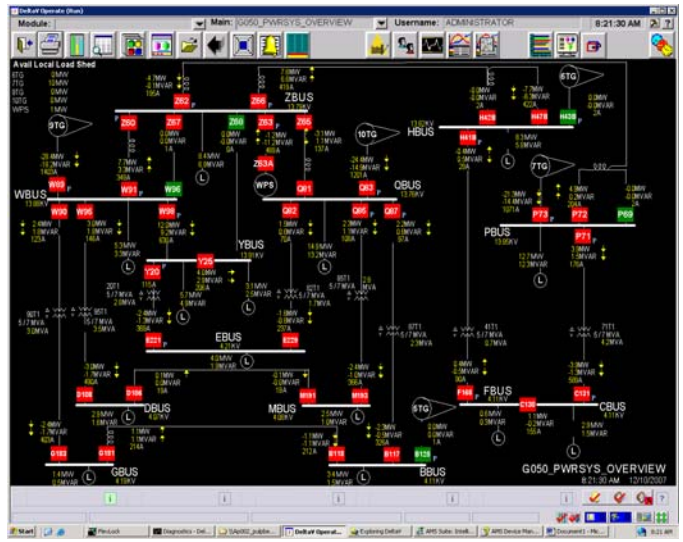

Fig. 3. HMI screen for a 15 kV and 5 kV system

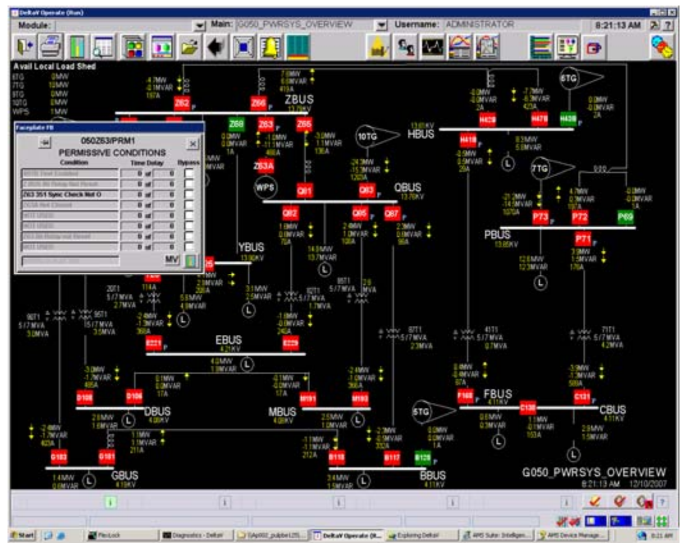

Fig. 4. HMI screen for a 15 kV and 5 kV system with an informational breaker popup window

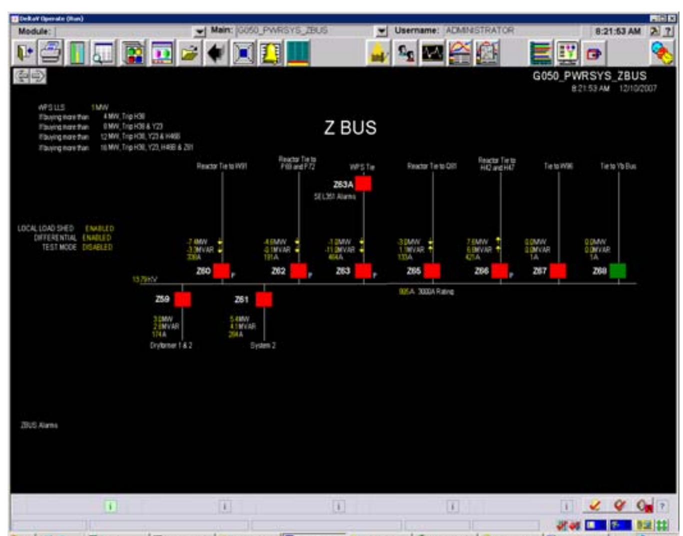

Fig. 5. HMI screen for an individual 15 kV system bus

Protection equations were implemented in the bus differential relays that permit remote **OPEN/CLOSE** commands to be received and processed from the control room HMI. Each breaker open/close status is displayed on the HMI as well as permissive interlock lists that help operators determine why a breaker might not close. The mill felt that remote breaker operation was very important, so that operations personnel would no longer have to stand in front of a breaker to operate it. If and when future regulations are announced that arc-blast hazards are now to be mitigated, the mill will be a step ahead.

The bus differential relays were also used to replace the existing hardwired local load-shedding system for each of the four 15 kV generators. Each scheme simply trips select load breakers upon a trip of either the generator breaker or, if the generator was down for maintenance, a trip of a source breaker to the bus. The local load-shedding systems can now be enabled/disabled locally at the bus differential relay using its provided pushbuttons or remotely from the power house control room HMI. The new system permits changes to be accomplished on the fly without wiring modifications.

A simple utility tie line load-shedding scheme was also implemented that will trip preselected load breakers throughout the power plant, based on the magnitude of tie line MW import, if the utility tie breaker trips. This was accomplished by connecting four of the bus differential relays together, utilizing binary communications protocol over a serial link that allows eight bits to be sent and received continuously while being monitored by hardware/software communications health status alarm bits. By using this scheme, any breaker controlled by these four relays could be load shed based on the magnitude of the utility import MW. The real-time total of MW to be load shed at any one time is displayed on the HMI (see Z Bus in Fig. 5).

C. Digital Relay Replacements at the 5 kV and 15 kV Level

A large number of EM 50/51 relays were replaced with digital equivalents. The new relays incorporate a definite time-delay setting (up to 0.4 seconds), which allows for lower instantaneous pickup settings while still providing selective coordination with downstream protective devices. This had a huge impact on lowering the AFH on downstream buses. The digital replacements were easy to install because they did not require any wiring modifications.

Dual source 5 kV bus relays were replaced with µP relays that offered synchronism check and reverse current functionality. Reverse current settings were chosen to limit AFH on the source transformer primary bus due to reverse fault current provided from the secondary source. A discussion of overcurrent protection implemented with µP relays is included in Appendix B.

D. Primary and Secondary Protection at the 480 V Level

It was decided that all general power and converting operation transformer primary fusible disconnects would be replaced with new metal-enclosed, draw-out circuit breakers. In some cases, the mill was planning to replace them anyway because they were overdutied. The general power substations were all upgraded in 2007. The converting operation transformers will be upgraded in 2008. Use of a new-style compact vacuum breaker in metal-enclosed switchgear (versus metal-clad, which is typically the paper mill standard) allowed for a smaller footprint so that they could be close-coupled to the transformer as if they were fusible disconnects. New transformer primary-side CTs, secondary-side CTs, and associated relays were also installed. The primary relay provided the necessary transformer protection, while the secondary-side relay limited the AFH on the 480 V switchgear bus to Category 3 or lower. Tripping of only the faulted transformer instead of all units daisy-chained from the power house breaker was deemed a necessity.

The paper machine transformers will be dealt with in 2009. New secondary-side CTs and relays will be added and will be wired to trip the main power house breaker, which feeds all transformers associated with the paper machine. The consensus was that losing one paper machine transformer would bring the paper machine down anyway.

E. Future Plans

The newly installed relays and HMI system will be the backbone for a centralized load-shedding scheme that will be implemented in the near future, replacing the mill's old hardwired system.

The existing mill tie line control computer system (PLC/HMI) will also be replaced by the new relay system in the near future. The system allows one generator to be selected as the swing unit and tie line MW to be controlled to an operator set point by controlling the steam throttle on the swing unit.

Remote I/O modules will probably be added in the near future to bring status information from some of the more critical 480 V unit substations into the new HMI system.

III. Conclusions

The protection improvements made to mitigate AFH through the use of µP relays provide substantial benefits to improve safety, monitoring, protection, and control. These benefits include the following:

- The power plant operations department can now operate breakers remotely, safe from the AFH of standing in front of the gear.
- Maintenance personnel can now rack breakers knowing that AFH potentials have been dealt with in a very secure manner.
- Centralized directional metering data are finally available to the power plant operations department. This information will be invaluable when making future power system decisions.
- Local load shedding is now implemented through the new bus differential relays. Tripping assignments can be changed without any wiring changes, and the total load to be shed is updated and displayed in real time.

IV. Appendix A: Low-Impedance Bus Differential Protection

A. Overview

A low-impedance bus differential scheme derives its name because the differential relay current inputs have a low impedance. This allows the CTs to be shared with other relays, meters, transducers, etc. The low-impedance bus differential scheme typically has one set of current inputs for every set of CTs in the scheme, as shown in Fig. 6. This also allows the circuits comprising the differential zone to have different CT ratios, an important attribute where the CTs are shared with other protection and monitoring functions.

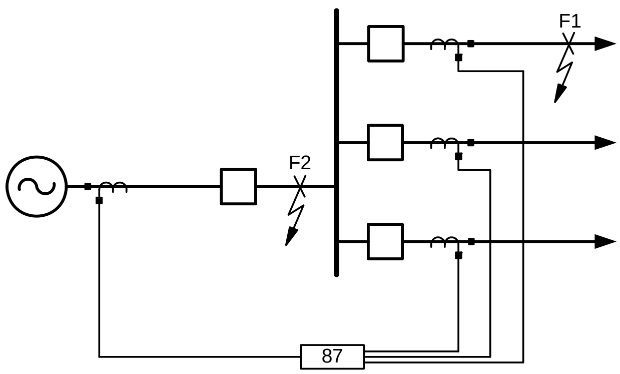

Fig. 6. Low-impedance bus differential scheme showing an external fault, F1, and an internal fault, F2

The differential function sums current from all CT inputs to detect an internal fault (i.e., internal to the protection zone defined by the location of all CTs connected to the relay). Conversely, the relay must be secure against tripping for external faults, switching transients, and normal through-current load flow.

CT performance is critical to the security of the bus differential scheme performance. CT saturation during external faults can cause a false differential current in the relay, exposing the scheme to false tripping. To be secure, bus differential relays must provide a means to tolerate CT saturation on external faults without tripping.

B. CT Performance Requirements

Protective relay schemes generally rely on the faithful reproduction of primary current, scaled to secondary quantities that the protection relay measures to detect power system faults. Relaying accuracy CTs are expected to produce a secondary current value that is within 10 percent of the primary current divided by the CT ratio for currents up to 20 times the CT current rating. The ratio error is caused primarily by the amount of excitation current diverted to the magnetizing branch of the CT. With a typical 5 A secondary CT, the primary to secondary ratio current is within 10 percent when the excitation current is less than 10 percent of the secondary current. At 100 A secondary, the excitation current must be less than 10 A.

CT excitation curves are available or can be created by test, showing the relationship between applied voltage and excitation current. An example CT excitation curve is shown in Fig. 7.

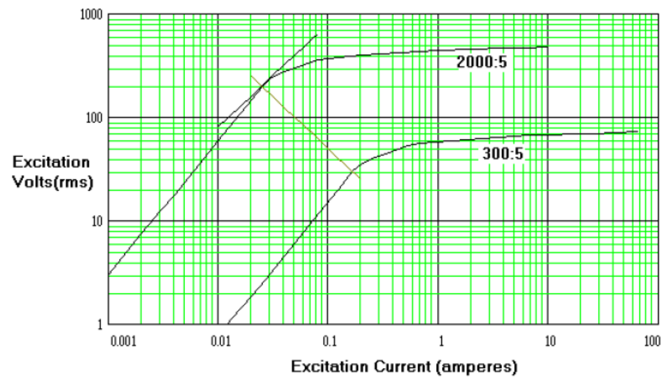

Fig. 7. 2000:5 CT excitation curve and its 300:5 tap, both with knee-point tangents and normal lines

As shown in this example CT excitation curve, the excitation voltage must be well above the CT knee-point voltage to produce a significant excitation current. The example curve also shows that lowering the connected tap on multiratio CTs reduces the excitation voltage required to produce significant excitation current.

The excitation voltage applied to a CT is a function of the voltage drop produced by the CT secondary current as it passes through the secondary circuit consisting of CT leads, relays, meters, and transducers. The voltage required to produce 10 percent or more excitation current is sometimes referred to as the CT saturation voltage.

Unfortunately, CT saturation is an undesirable reality in many applications and is quite common in industrial applications using switchgear. Very often, low-accuracy CTs are provided in switchgear because of the limited space made available for CTs by the switchgear manufacturer. Small ratio CTs are also commonly applied to improve relaying sensitivity and metering resolution on circuits that supply small loads. The combination of low-accuracy rating and low ratio increase the likelihood of CT saturation as fault current levels and source X/R ratios increase.

CT saturation presents itself as a nonsinusoidal waveform with a reduced peak magnitude, reduced output energy (area under the curve), and an advanced (more leading) current phase angle, as shown in Fig. 8.

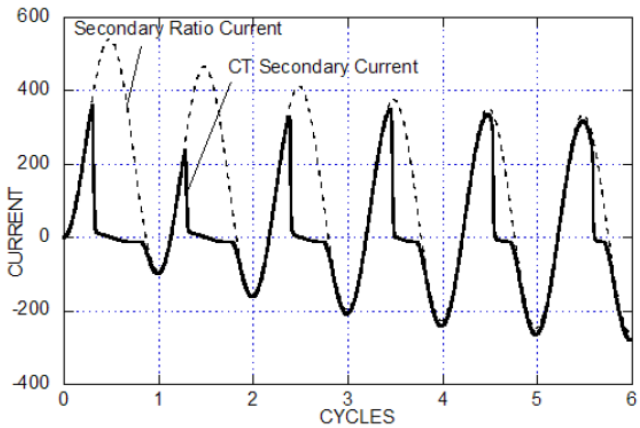

Fig. 8. Current waveforms of a C100, 1200:5 CT, burden 0.5 ohms, 50 kA, X/R equals 17

Low-impedance current differential relays must deal with the reality of CT saturation. The relay selected and discussed in this paper includes multiple techniques used to establish security against tripping for external faults with severe CT saturation. The primary technique continuously compares operate current to restraint current.

Under ideal conditions, operate current, which is the phasor sum of all like-phase currents measured in the differential scheme, is zero. The restraint current is the algebraic sum of all like-phase current magnitudes measured by the relay. The relay normally computes the ratio of the operate current to the restraint current. If the operate-to-restraint current ratio exceeds a fixed threshold called a slope setting, the differential relay will trip. For an internal fault, both the operate current and the restraint current will increase at the same time. However, for an external fault with CT saturation, the increase in operate current will occur a short time after the increase in restraint current because of the time it takes for CT saturation to occur at the beginning of each half-cycle. When a delayed increase in operate current is detected, the relay shifts to a higher, more secure slope setting and also applies an additional short security delay to the trip output. The relay never blocks the trip output because the external fault may migrate to an internal fault location, requiring the relay to perform a valid trip.

To permit enough time for the relay to make a valid comparison between operate and restraint current quantities, the CT time-to-saturation must be at least 2 ms. CT performance must therefore be examined under expected worst-case conditions to determine the minimum CT time-to-saturation. Fortunately, calculation tools are available, such as the IEEE Power System Relay Committee report and accompanying Excel spreadsheet, to perform this sophisticated analysis.

C. *Supplemental Protection Functions*

The µP bus differential relay selected for AFH mitigation includes additional monitoring and logic to perform supplemental protection functions, such as end-zone fault detection and breaker failure detection.

1) *End-Zone Fault Detection*

End-zone faults occur between the circuit breaker and the CT associated with the breaker, shown as fault F3 in Fig. 9.

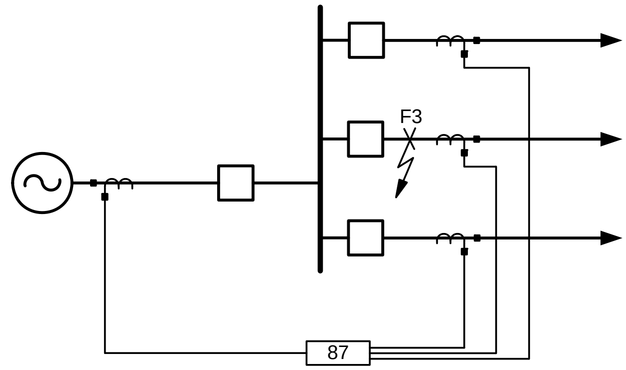

Fig. 9. Low-impedance bus differential scheme showing an end-zone fault, F3, between the breaker and CT

The end-zone fault is detected as an internal fault by the bus differential protection scheme, but the fault current may not be interrupted by opening all of the breakers associated with the bus differential scheme if there is a source on the remote end of the faulted circuit. The relay's end-zone protection logic determines that the breaker is open, but the current measured by the CT has not gone to zero. The logic sends a transfer trip to the breaker at the remote source, thereby interrupting the final source of current to the fault.

2) *Breaker Failure Detection*

Breakers called upon to trip can fail to interrupt current for a variety of reasons. The operating mechanism may fail to mechanically open the breaker for electrical or mechanical reasons. Or, if the breaker operates to mechanically open the current-interrupting contacts, the arc may not be interrupted because sufficient dielectric strength is not established between the two poles of the interrupting contacts.

In either case, breaker failure protection can be implemented by starting a timer when the breaker trip is applied and detecting if the current is interrupted by the end of the fixed time delay. The time delay is established based on the rated breaker interrupting time plus some small margin. That margin is determined, in part, by how fast the relay recognizes that the current is interrupted.

CT secondary current includes a dc component known as subsidence current that can delay zero-current detection by over one cycle, sometimes by as much as several cycles. Unless accounted for, breaker failure time-delay settings must include sufficient margin to accommodate this subsidence current.

Subsidence current detection logic ensures zero-current detection in less than three-fourths cycle, thereby minimizing the required time-delay margin and speeding up breaker failure fault detection to improve the total clearing time.

When a breaker fails to interrupt current, backup tripping is required to open all other sources of current to the failed breaker. The bus differential relay selected for this application has built-in breaker failure detection logic with timers and current detection thresholds. It can trip all of the breakers on the bus, either individually if trip outputs are wired to each breaker, or as a group, through a bus lockout auxiliary relay.

D. Real-Time Operating Data

The bus differential relay is naturally suited to measure current on each of the circuit breakers associated with the bus because of its CT connections. The selected bus differential relay also includes voltage inputs, providing it with the ability to combine voltage and current measurements to make directional watt and VAR measurements. The bus selected for the initial bus differential application included phase-to-phase connected PTs in the conventional open-delta configuration. The CT restrictions (only two CTs on some breakers) associated with the initial installation also meant that computations would be required to calculate full three-phase watt and VAR measurements from two currents and two voltages.

Again, the selected relay met the task because it included a variety of math operators, as shown earlier in Table I.

APPENDIX B: OVERCURRENT RELAY PROTECTION

A. Overview

There are many types of protective relays and protection schemes available. Overcurrent relays represent the simplest and most widely used for line, transformer, capacitor, bus, and motor protection. Overcurrent relay operation, as its name implies, operates when the current magnitude exceeds a predetermined current threshold. Overcurrent relays can operate instantaneously (without any intentional time delay), after a fixed time delay (definite time), or with inverse-time-current characteristics (time overcurrent).

An overcurrent relay can also be directional, which is normally accomplished by controlling or supervising the overcurrent relay with a separate "directional" element that determines the direction of the operating current. The directional element requires an additional reference, such as a voltage or current input, to determine if the fault direction is forward or reverse.

Although versatile and reliable, the application of overcurrent relays, particularly EM and solid-state (SS) relays, may be limited by an inability to provide adaptive settings to accommodate dynamic system configuration changes, inability to distinguish between load and fault current, slow operating speeds due to the necessity of coordination with downstream devices, or the inability to coordinate with other protective devices under all system conditions.

B. CT Performance Requirements

On many systems, especially at industrial facilities, high fault currents, low ratio CTs, and high system X/R ratios contribute to CT saturation during faults with asymmetrical dc offset current. Secondary CT burden also contributes to CT saturation, as discussed in Appendix A. µP relay burden is generally much lower than EM relay burden. Replacing EM relays with low-burden µP relays may reduce CT saturation but cannot eliminate saturation where extremely high fault current and X/R ratio are combined with low ratio and poor accuracy CTs. Regardless of the type of relay used, CT saturation reduces the apparent current seen by the relay. This reduction in apparent current can result in delayed operation of inverse time-overcurrent relays and may possibly prevent operation of high-set, instantaneous-overcurrent relay elements.

µP relays typically use analog and digital filtering to obtain phasors that eliminate dc and harmonic components. This is superior for most applications, but the ideal filter for an instantaneous overcurrent element must also detect bipolar peaks for high-current faults during extreme CT saturation. Thus it is important to apply overcurrent elements that respond to the fundamental in the absence of saturation but respond to peak currents during saturation [2].

C. Peak Detecting vs. Filtered Fundamental Overcurrent Elements

Digital filters used in µP relays cannot make an accurate measurement of fault current once saturation occurs. Fig. 10 shows that the magnitude of the fundamental frequency value in a severely saturated current waveform is a poor representation of the actual fault current.

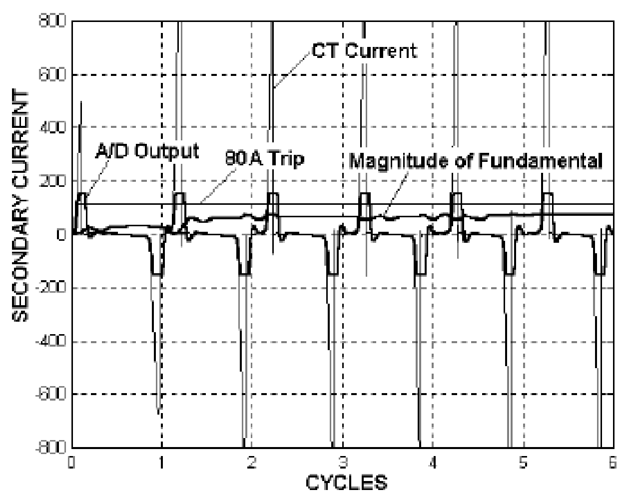

Fig. 10. CT and relay signals for a 40 kA fault using C50, 100:5 CTs

However, the fast rising response of the RMS and the peak filter is more representative of the actual magnitude. The responses of the peak, RMS, and cosine filters are compared in Fig. 11.

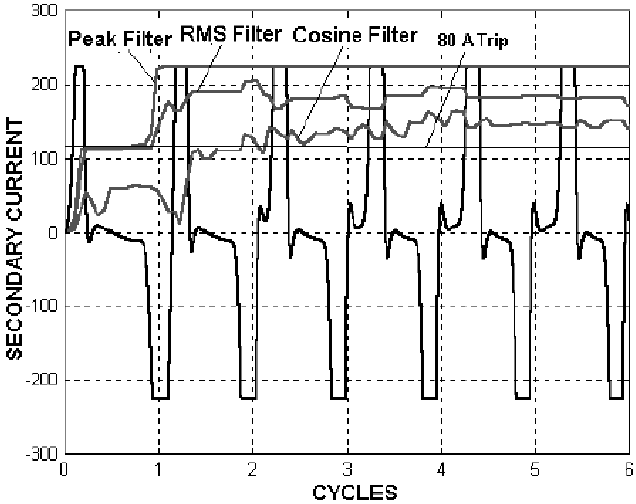

Fig. 11. Filter response, fault 40 kA, X/R equals 20, C100, 200:5 CT, 0.5 Ω burden

The peak and RMS filters both respond quickly to a fast rising signal. The cosine filter, which responds to the fundamental frequency component of the signal, is slow to respond. But the peak and RMS filters both exhibit a prohibitively high transient overreach because they respond to the dc component in asymmetrically offset waveforms. Of the three filters, the comparison shows that the bipolar peak detector makes the best magnitude acquisition to provide the fastest response under severely saturated CT conditions. The digital cosine filter has an excellent performance with respect to dc offset and removal of harmonics. Combining the bipolar peak detector with the digital cosine filter provides an efficient solution for the ideal instantaneous element. This instantaneous element, shown in Fig. 12, is called a cosine-peak adaptive filter because it incorporates both filters. The cosine filter supplies the magnitude for normal sine-wave operation. The bipolar peak detector provides magnitude for saturated waveforms. A detector measures the degree of saturation by evaluating the level of distortion and switches the input to the bipolar peak detector when the distortion reaches a predetermined value. This combination provides accurate timing response for optimum coordination during most faults and fast operation for high-current faults with heavy CT saturation when arc-flash protection is needed most.

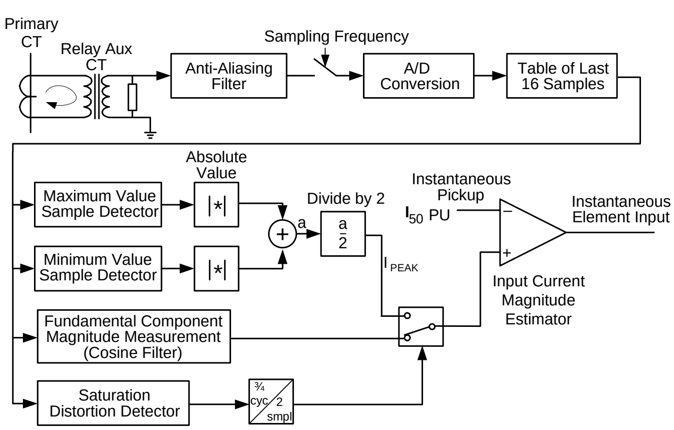

Fig. 12. Instantaneous element using the cosine-peak adaptive filter

Appendix C: Operational Benefits With µP Relays

µP relays have gained widespread acceptance among both utility and industrial customers. The relay functions are generally the same as those for EM and SS electronic relaying, but µP relays have features that provide added benefits.

The benefits of µP relays include the ability to combine multiple relay functions into one economical unit. Where an EM overcurrent relay may only be a single-phase device, a µP relay will often include three phases and a neutral. It could also include directional elements, synchronism check, over- and undervoltage, and over- and underfrequency. The computational power of the microprocessor permits the relay to make multiple uses of the same power system analog measurement. An EM scheme will normally consist of individual relays for each phase and zone of protection. Wiring is required to combine the EM relay outputs to provide the desired scheme logic. µP relays include programmable logic that can be used to create and modify scheme logic without wiring changes.

The µP relay also carries the concept of making use of measurements beyond protection. These devices can include nonrelaying functions such as metering, sequential event recording, oscillographic data recording, control switches, and control lights. All of these functions are contained in an enclosure that requires a fraction of the space and cost of the combination of relays and other devices they duplicate.

A µP relay also has self-monitoring diagnostic capabilities that provide continuous status of relay availability and reduce the need for periodic maintenance. If a relay fails, it is typically replaced. Repairs are generally beyond the capability of the end user, so the manufacturer typically performs repairs on the returned product. The manufacturer's repair service and warranty are therefore important considerations in relay selection.

µP relays often provide a wider settings range than their EM and SS predecessors. µP relays also provide continuous settings ranges, rather than the discrete taps of the EM relays. Because these relays have multiple features, functions, increased settings ranges, and increased flexibility, fewer spares need to be stocked.

µP relays also have communications capabilities that allow for remote interrogation of meter and event data and fault oscillography. This also permits relay setting from a remote location. The relays have low power consumption and low CT and PT burdens. Some relay models also accommodate both wye- and delta-connected CTs and PTs. For instance, µP transformer differential relays can compensate internally for ratio mismatch and the phase shift associated with delta-wye connections.

All of these features have economic benefits in addition to the lower initial costs and potentially reduced maintenance costs that µP relays have when compared to individual relays. Although there are fewer disadvantages than advantages, there are some worth noting. The operating energy for most EM relays is obtained from the measured currents and/or voltages, but most µP relays require a source of control power. Another disadvantage is that the multifunction feature can result in a loss of redundancy. For instance, with a full complement of three phase and one neutral ground overcurrent EM relays, the failure of a single phase overcurrent relay is backed up by the remaining two phase and neutral relays, which can still detect any combination of single- and multiphase faults. In a µP relay scheme, the phase and neutral elements are frequently combined in one package, and a single failure can disable the protection. Similarly, a µP transformer protection package that has both differential and overcurrent relaying provides less redundancy than a scheme comprising separate relays. The self-diagnostics ability of the µP relay and its ability to communicate failure alarms mitigate some of the loss of redundancy. However, the lower cost and size of the µP relay make it practical to apply multiple µP relays to achieve the desired level of redundancy.

A. Oscillographic Data Event Reports

If there is one feature that distinguishes the µP relay from its EM and SS predecessors, it is the ability to provide oscillographic data event reports. These reports include sample-by-sample records of power system analog quantities and the corresponding response of the internal relay elements and logical elements. This single feature provides extremely valuable information to confirm power system response to fault conditions and how the relay elements and logic perform under actual system conditions.

Software tools are available to process the oscillographic data records, presenting the user with both oscillography and phasor display of the measured analog quantities. Harmonic analysis can also be performed on "raw" data extracted prior to digital filter processing. Many relays store both raw and filtered event report data.

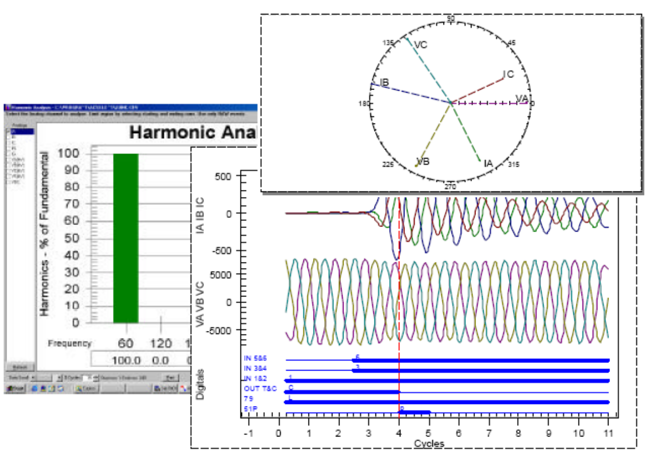

Fig. 13. Software tools convert numerical event report data into graphical plots and charts

B. Sequential Event Recording

Modern digital relays include a Sequential Events Recorder (SER) report. The relay monitors the status of user-selected relay elements (e.g., relay protection elements, internal programmable logic elements, timers, and the logical status of hardwired inputs and outputs) every processing interval. Processing intervals are typically one-eighth or one-quarter of a power system cycle. When one of the selected elements changes state, the relay time-tags the change and logs the event in the SER report. The relay stores these changes in a circular, nonvolatile memory buffer. Usually the latest 500 to 1,000 state changes are stored in the buffer, depending on the relay's memory capability. When the buffer is full, the newest record overwrites the oldest record.

SER reports are extremely useful for quickly reviewing a timing sequence, such as time-delayed tripping elements, programmable timers, and other logic during testing or after an operation. For example, in the SER report in Fig. 14, the trip output contact OUT1 deasserts after being asserted a minimum of 9 cycles because of the minimum trip duration timer setting (time difference: 09:52:15.039 minus 09:52:14.889 equals 0.15 seconds or 9 cycles at 60 Hz). As soon as the trip contact, OUT1, deasserts, the first auto reclosing open interval begins timing on its setting of 30 cycles (time difference: 09:52:15.535 minus 09:52:15.039 equals 0.496 seconds or 30 cycles). A **CLOSE** command is issued via OUT2.

FEEDER 1 Date: 02/11/97 Time: 13:13:09.558
STATION A

FID=XXX-351-X111-Vf-D970128 CID=1F00

#	DATE	TIME	ELEMENT	STATE
19	02/07/97	13:10:46.360	Relay newly powered up or settings changed	
18	02/07/97	13:11:33.444	IN2	Asserted
17	02/07/97	13:11:38.812	LB4	Asserted
16	02/07/97	13:11:38.812	OUT2	Asserted
15	02/07/97	13:11:38.816	LB4	Deasserted
14	02/07/97	13:11:38.887	IN1	Asserted
13	02/07/97	13:11:38.887	OUT2	Deasserted
12	02/07/97	13:11:43.892	79LO	Deasserted
11	02/11/97	09:52:14.877	51G	Asserted
10	02/11/97	09:52:14.881	51P	Asserted
9	02/11/97	09:52:14.889	50P1	Asserted
8	02/11/97	09:52:14.889	79CY	Asserted
7	02/11/97	09:52:14.889	OUT1	Asserted
6	02/11/97	09:52:14.964	50P1	Deasserted
5	02/11/97	09:52:14.973	51P	Deasserted
4	02/11/97	09:52:14.977	IN1	Deasserted
3	02/11/97	09:52:14.981	51G	Deasserted
2	02/11/97	09:52:15.039	OUT1	Deasserted
1	02/11/97	09:52:15.535	OUT2	Asserted

Fig. 14. Example SER report from µP relay

SER reports are very helpful for testing inverse-time overcurrent element operating time or other time-delayed tripping elements and logic without having to program and wire output contacts to external test equipment timers. This saves testing time and provides a more accurate measure of the relay's internal time delays because it eliminates the delays associated with external interfaces.

Selecting the desired list of elements to track for troubleshooting is important. Generally, any bit associated with the protection elements, internal logic, and inputs and outputs used for the protection and control scheme should be included in the list of elements tracked by the SER. Elements that may "chatter," such as alarm points, should be avoided unless the relay has the ability to suppress chattering elements in the SER logic. Chattering elements can fill up the SER log very quickly, causing a loss of valuable troubleshooting information.

Some relays also provide user-settable SER alias names for the internal relay elements and the output states. For example, input IN101 may be the bit that reflects the status of a breaker 52A status contact, but the SER alias BKR_1 can be substituted for IN101 to make it more meaningful for the end user. CLOSED can be substituted for ASSERTED, and OPEN can be used to replace DEASSERTED to make the state easier for the plant engineer or operator to accurately interpret.

C. Real-Time Operating Data

Like the bus differential relay discussed earlier, µP overcurrent relays continuously sample current (and voltage, if equipped) and compute current (and voltage) magnitudes to compare with the fault detecting thresholds associated with overcurrent relay elements. In the process, metering data are continuously available to support real-time operating functions. Relays with both current and voltage measurement often compute real-time power quantities also. In addition, the µP relay continuously monitors the status of control inputs, such as breaker contact status. Real-time analog and status information are therefore available from µP relays through communications ports on the relay. The relay can be interrogated directly by the plant data and control system (DCS), if the relay supports the plant DCS communications protocol. Often communications processors are used to request data directly from the relay, concentrate the information, and make it available for plant DCS data requests, providing a more efficient data collection process.

V. References

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VI. Further Reading

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VII. Biographies

Jeff Hill received his BSEE from Michigan Technological University in 1975. Upon graduating, he worked 6 years with Westinghouse Electric in Milwaukee as a field service engineer. From Milwaukee, he moved to Neenah, Wisconsin and accepted a paper mill consulting position at Marathon Engineers, where he remained for 21 years. He joined Jacobs Engineering in 2001 and remained there until 2007, when he joined the Georgia-Pacific Green Bay Broadway Street mill as a project engineer. He is a member of IEEE and has authored a paper on the application of large synchronous condensers in a paper mill environment.

Ken Behrendt received his BSEE from Michigan Technological University in 1970. Upon graduating, he served nearly 24 years at Wisconsin Electric Power Company (now WE-Energies), where he worked in distribution planning, substation standards development, distribution protection, and transmission planning and protection. He joined Schweitzer Engineering Laboratories, Inc. in 1994, where he is a senior application engineer, located in New Berlin, Wisconsin. He is a senior member of IEEE, a member of the Power System Relay Main Committee, and has authored and presented several papers on power system protection topics.

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