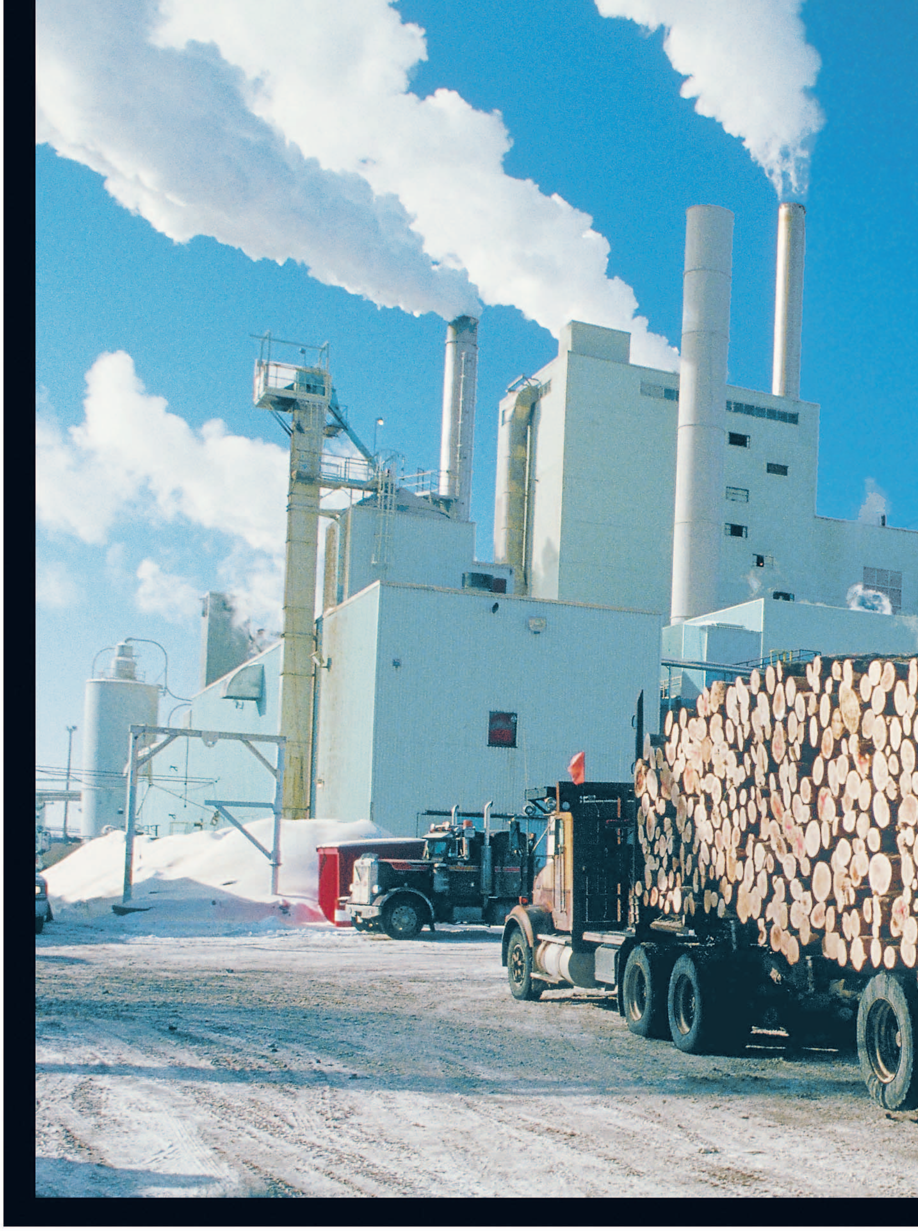
GEORGIA-PACIFIC'S Broadway Street Paper Mill in Green Bay, Wisconsin, is resolving an arc-flash hazard (AFH) problem by installing microprocessor (μP) bus-differential relays on medium-voltage switchgear and selectively replacing electromechanical (EM) overcurrent relays with μP relays. In addition to providing critical bus-differential protection, the μP relays will provide analog and digital communications for operator monitoring and control via the power-plant distributed control system (DCS) and will be ultimately used as the backbone to replace an aging hard-wired load-shedding system.

The low-impedance bus-differential protection scheme was installed with existing current transformers (CTs) using a novel approach that required only 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



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UPGRADING POWER SYSTEM PROTECTION

To improve safety, monitoring, protection, and control

BY JEFF HILL & KEN BEHRENDT

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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 the bus-voltage data, also monitored by the relay, to provide real-time MW (real power) and MVAR (reactive power) power-flow information.

This article discusses the design of the bus-differential protection scheme, studies required to verify that the existing CTs were adequate for the bus-differential application, design of end-zone protection, and math computations used to provide real-time power-flow data. It 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.

AFH: Identifying the Hazard

Power-System Description

The 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 (Z bus) through a current-limiting reactor. The synchronizing bus also serves as the local utility's connection to the plant.

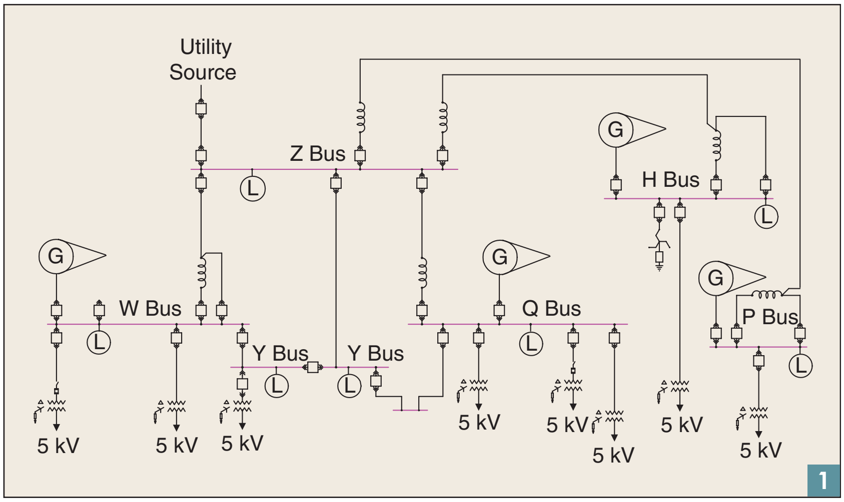
The power-plant electrical-distribution system consists of seven 15-kV buses, seven 5-kV buses, and numerous 480-V buses. The one-line diagrams of a 15- and 5-kV system are shown in Figures 1 and 2. Each 5-kV bus in the power plant is supplied from two 15-kV buses. All paper mill and converting loads are either supplied from the 15- or 5-kV power-plant buses. Three of the power plant's buses used 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 zig-zag 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.

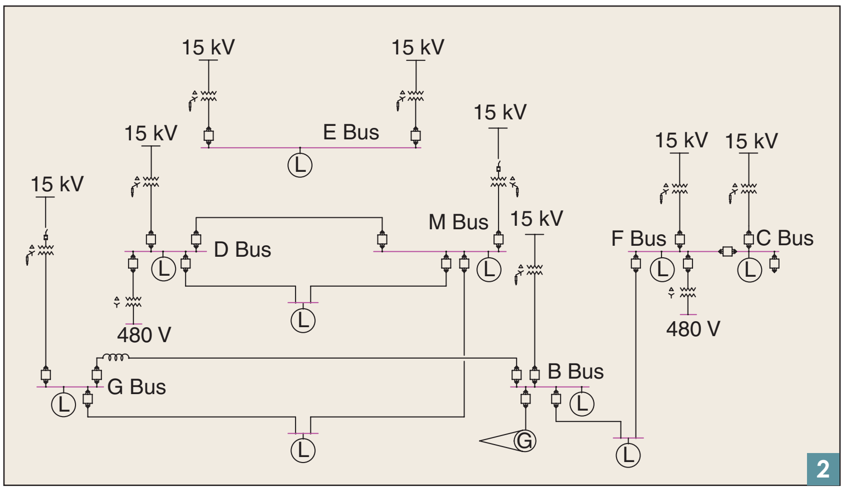
Most 480-V unit substation transformers throughout the mill are high-impedance grounded with 10-A resistors. Very few of the 480-V unit substations have secondary main protective devices.

AFH Study Results

The mill had recently completed a three-year program, replacing all overdutied electrical equipment when the 2004 edition of the *Standard for Electrical Safety in the Workplace* (NFPA-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 motor control centers (MCCs) and fused distribution panels. The available three-phase fault current levels at the 15-kV, 5-kV, and 480-V buses are 40-, 20-, and 50-kA rms symmetrical. With this level of fault current and the existing plant-protective relay settings, the calculated incident energies (IEs) (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 use 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.



One-line diagram a 15-kV power-plant system.



One-line diagram a 5-kV power-plant system.

Mitigation Techniques Studied

5- and 15-kV Levels

Studies indicated that adding instantaneous elements to 5- 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 in) 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- and 15-kV buses would improve overcurrent coordination and significantly speed up tripping for bus faults and faults associated with racking breakers.

480-V Level

Studies to reduce the IE on 480-V switchgear included setting the maximum limit for arc-flash clearing times at 2 s for buses less than 1,000 V, based on comments from the IEEE 1584 arc-flash standard [1]. 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 more then 1,000 ft 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. Although 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- and secondary-side protective relay.

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 μP bus-differential and overcurrent relays. Significant benefits to improve monitoring and control were also realized because of the installation of μP devices. (See "Operational Benefits of μP Relays" for further discussion.)

Bus-Differential Relays at the 5- 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- and 15-kV buses. Three of the existing buses were relatively new, and although they had originally been supplied with 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 "Low-Impedance Bus-Differential Protection."

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 that 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 required only for multiphase faults. Therefore, the high-speed tripping bus-differential scheme is required only to operate for multiphase faults. The 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 Phases A and C single-phase-to-ground faults.

Each bus-differential relay can support 18 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. However, for buses with more than nine breakers, 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 whether 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 selected bus-differential relay needs at least 2 ms of undistorted CT secondary current to securely determine whether the fault is external to the bus. The IEEE CT performance calculation Microsoft Excel spreadsheet [2] was used to determine whether 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 (see "Low-Impedance Bus-Differential Protection" for information relevant to CT performance).

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

OPERATIONAL BENEFITS OF μP RELAYS

Among both utility and industrial customers, μP relays have gained widespread acceptance. The relay functions are generally the same as those for EM and solid-state (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. The 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 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.

The 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, and so the manufacturer typically performs repairs on the returned product. Therefore, the manufacturer's repair service and warranty are important considerations in relay selection.

The μP relays often provide a wider settings range than their EM and SS predecessors. These 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.

The 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. These 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, when compared with 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 EM relays (three phase and one neutral/ground overcurrent), 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.

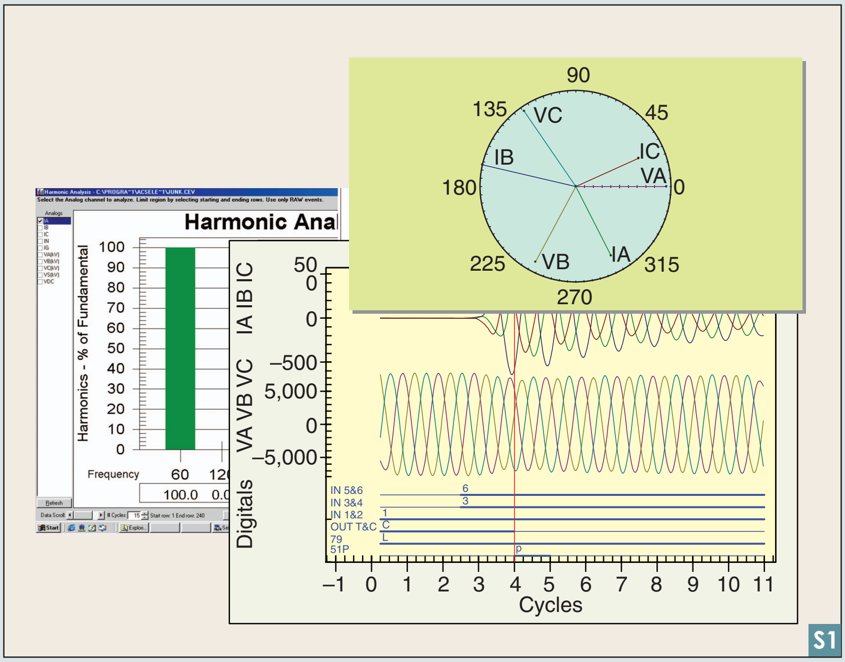
Oscillographic Data Event Reports

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 (Figure S1). Harmonic analysis can also be performed on raw data extracted before digital filter processing. Many relays store both raw and filtered event report data.

Sequential Event Recording

Modern digital relays include a sequential event 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 500–1,000 state changes are stored in the buffer



S1

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

depending on the relay's memory capability. When the buffer is full, the newest record overwrites the oldest record.

The 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 shown in Figure S2, the trip output contact OUT1 deasserts after being asserted a minimum of nine cycles because of the minimum trip duration timer setting (time difference: 09:52:15.039 minus 09:52:14.889 equals 0.15 s or nine 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 s or 30 cycles). A CLOSE command is issued via OUT2.

The 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 52-A status contact, but the SER alias BKR_1 can be substituted

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	IOUT2	Deasserted
12	02/07/97	13:11:43.892	79L0	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	02/1197	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

S2

Example SER report from μP relay.

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.

Real-Time Operating Data

Like the bus-differential relay discussed earlier, the 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 the 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. The real-time analog and status information are therefore available from the μP relays through communications ports on the relay. The relay can be interrogated directly by the plant DCS, if the relay supports the DCS 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.

LOW-IMPEDANCE BUS-DIFFERENTIAL PROTECTION

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 Figure S3. 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.

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.

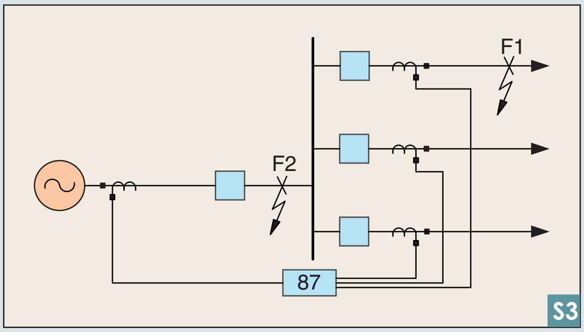
CT performance is critical to the security of the bus-differential scheme performance. CT saturation during external faults can cause a false differential current in the relay, exposing the scheme to false tripping. To be secure, bus-differential relays must provide a means to tolerate CT saturation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

CT Performance Requirements

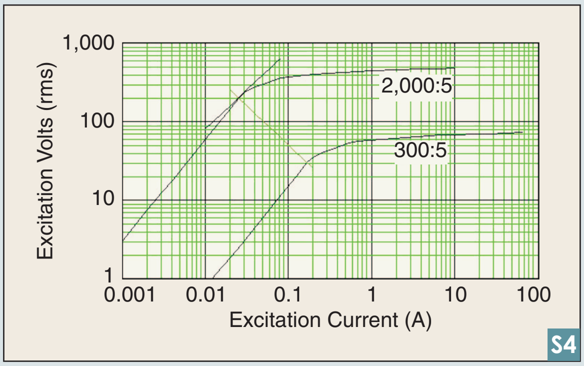
Protective relay schemes generally rely on the faithful reproduction of primary current, scaled to secondary quantities that the protective relay measures to detect power system faults. Relaying accuracy CTs are expected to produce a secondary current value that is within 10% of the primary current divided by the CT ratio for currents up to 20 times the CT current rating. The error in the ratio 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 current ratio is within 10% when the excitation current is less than 10% of the secondary current. At 100-A secondary CT, 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 Figure S4.

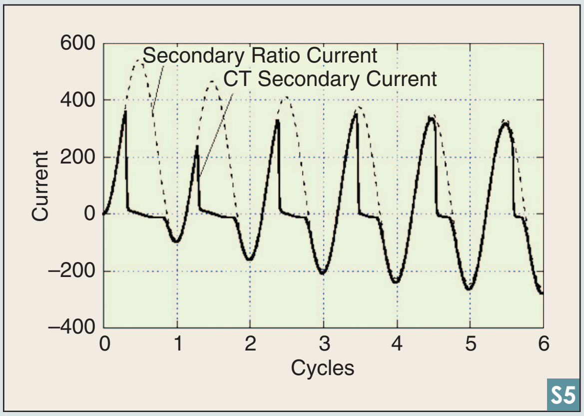
As shown in this example CT excitation curve, the excitation voltage must be well above the CT knee-point voltage to produce a significant excitation current. The example curve also shows that



The low-impedance bus-differential scheme showing an external fault, F1, and an internal fault, F2.



2,000:5 CT excitation curve and its 300:5 tap, both with knee-point tangents and normal lines [4].



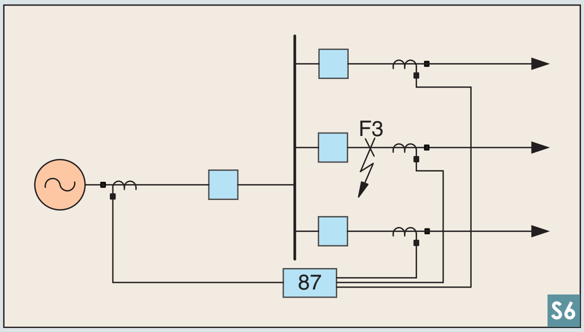
The current waveforms of a C100, 1,200:5 CT, burden 0.5 Ω, 50 kA, and *X*/*R* = 17 [5].

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% 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 increases 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 Figure S5.



The low-impedance bus-differential scheme showing an end-zone fault, F3, between the breaker and CT.

Low-impedance current-differential relays must deal with the reality of CT saturation. The relay selected and discussed in this article 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 the 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 [2].

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.

End-Zone Fault Detection

End-zone faults occur between the circuit breaker and the CT associated with the breaker, shown as fault F3 in Figure S6.

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.

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 (subsidence current) that can delay zero-current detection by more than 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.

The 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.

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 MW and MVAR 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 MW and MVAR 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 1.

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 “Low-Impedance Bus-Differential Protection” for a description of end-zone protection).

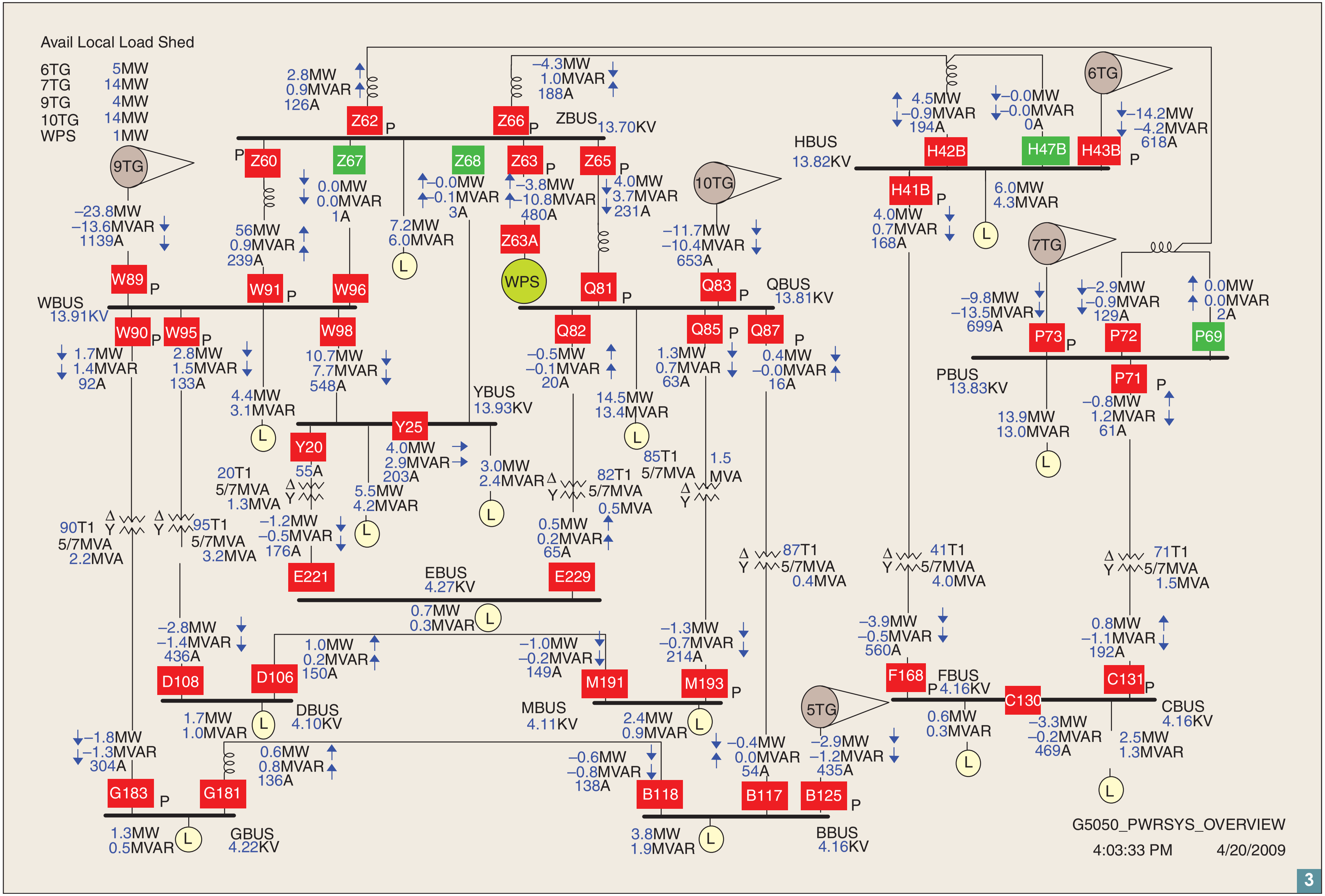
Automation and Control at the 5- and 15-kV Level

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. The selected bus-differential relays have automation registers and protection registers that can be freely programmed to fit any automation and control strategy.

The bus-differential relays incorporate voltage inputs, providing the ability to combine voltage and current measurements to make directional MW and MVAR calculations. 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 potential transformers (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

TABLE 1. 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 toward infinity
FLOOR	Rounds to the nearest integer toward minus infinity
−	Negation



HMI screen for a 15- and 5-kV system.

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 1. 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.

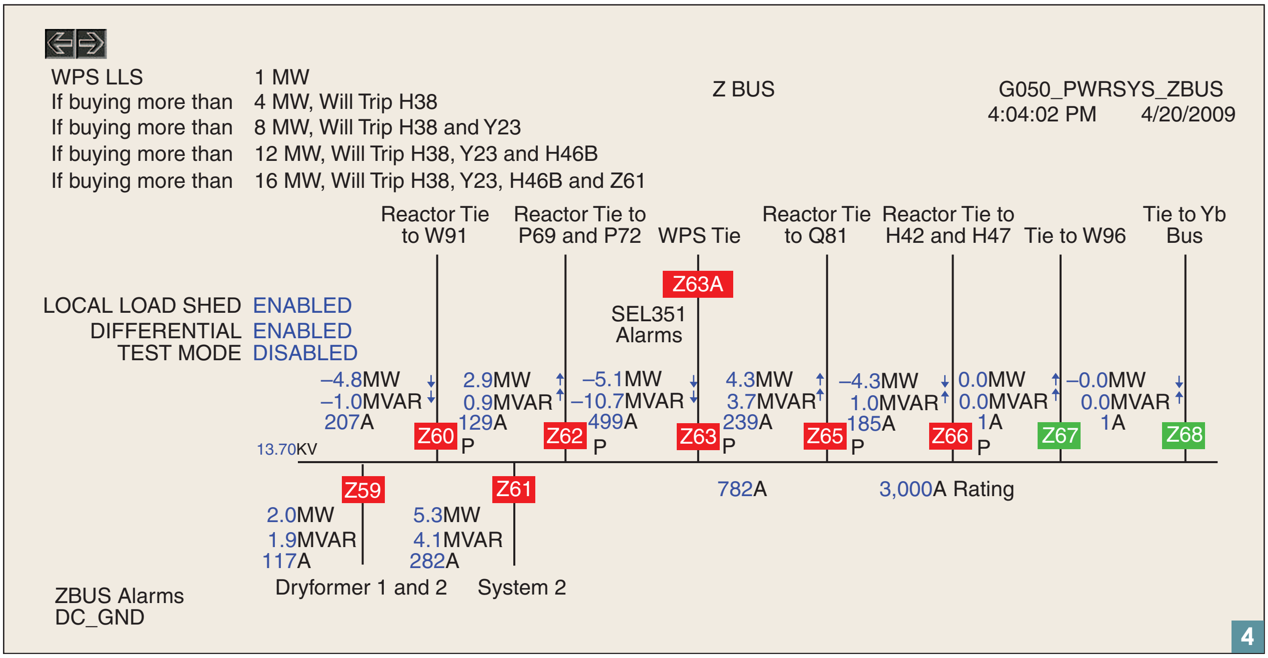
The calculated analog data in the bus-differential relays are passed to the power-plant control-room human–machine interface (HMI) via three communications processors that gather and consolidate the relay data using a fast binary protocol operating over serial connections. The communications processors 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-in liquid crystal display (LCD) monitors displaying the mill system one-line diagrams. The analog data are presented for each breaker. See Figures 3 and 4 for typical HMI screens.

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 the 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.

IN ADDITION TO PROVIDING CRITICAL BUS-DIFFERENTIAL PROTECTION, THE μP RELAYS WILL PROVIDE ANALOG AND DIGITAL COMMUNICATIONS FOR OPERATOR MONITORING.

The bus-differential relays were also used to replace the existing hard-wired 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 the pushbuttons provided 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 the 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 five of the bus-differential relays together, using a binary communications protocol over a serial link that allows 8 b 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 five relays could be load



HMI screen for an individual 15-kV system bus.

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 the Z bus in Figure 4).

Digital Relay Replacements at the 5- 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 s), 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 BUS-DIFFERENTIAL RELAY PROVIDES FAST FAULT CLEARING TO REDUCE THE AFH CONDITION.

The 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 [3].

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 these disconnects anyway because they were overdutied. The general power substations were all upgraded in 2007. The converting operation transformers were upgraded in 2008. Using a new-style compact vacuum breaker in a 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- and secondary-side CTs and associated relays were also installed. The primary relay provided the necessary transformer protection, whereas 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 and pulp-processing transformers will be dealt with in 2009/2010. New secondary-side CTs and relays will be added and wired to trip the main powerhouse breaker, which feeds all transformers associated with a system. The consensus was that losing one system transformer would bring a system down anyway.

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 will also be replaced by the new relay system in the near future. This 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 input/output (I/O) modules will probably be added in the near future to bring status information from some of the more critical 5-kV transformers into the new HMI system.

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.
- The maintenance personnel can now rack breakers knowing that AFH levels have been reduced as much as possible.
- The centralized directional metering data are finally available to the power-plant operations department. This information is proving invaluable when making power-system decisions.
- The local load shedding is now implemented through the new bus-differential relays. The tripping assignments can be changed without any wiring changes, and the total load to be shed is updated and displayed in real time.

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