Smart Substation: design, installation, testing, and training experience

Presented to

44th Annual Western Protective Relay Conference

Spokane, Washington

Steven Kunsman, ABB Inc. Raleigh, NC

George Gresko, PECO Energy, Philadelphia, PA

Samuel Morbin, ABB Inc. Raleigh, NC

Mike Kockott, ABB Inc. Raleigh, NC

1.0 Introduction

Digital substations are gaining traction, with real world commercial installations being accepted among utilities. Main enablers for this technology are the non-conventional instrument transformers and standalone merging units, utilizing IEC 61850 process bus communication. IEC 61850 offers to improve the overall reliability and resiliency of the 21st century substation using digital communication. High voltage measurement and control has recently been improved to offer easily installed sensors with direct digital outputs that have excellent accuracy, stability, and faster frequency response. By going directly to digital, these state-of-the-art sensors preserve signal integrity and ease of connections by using fiber communications. Unlike previous optical sensors that had some reliability concerns, the introduction of a new Fiber Optic Current Sensor (FOCS) design combines the inherent isolation of the optical current sensor with redundant systems to power, accurately process, and output signals capable of directly supporting substation automation. These modern optical sensors can be embedded in free-standing form using modern polymer insulators free of oil or SF6 gas, integrated into other power equipment such as live or dead tank breakers and gas insulated substations or can be used to in place of slip over bushing current transformers. Integrated with voltage merging units creates an architecture delivering the full promise of IEC 61850.

The introduction of stand-alone merging units provides an equivalent approach to digitizing the secondary signals available in the switchyard. This approach also simplifies the mode of communication between the equipment in the switchyard to the relays in the control panel. In accordance to the IEC61850 standard, the merging units easily virtualizes any Current Transformer (CT) or Potential Transformer (PT) signal available today from a conventional instrument transformers. By implementing these merging units in a process bus network, the overall benefits of the IEC61850 standard can begin to be realized.

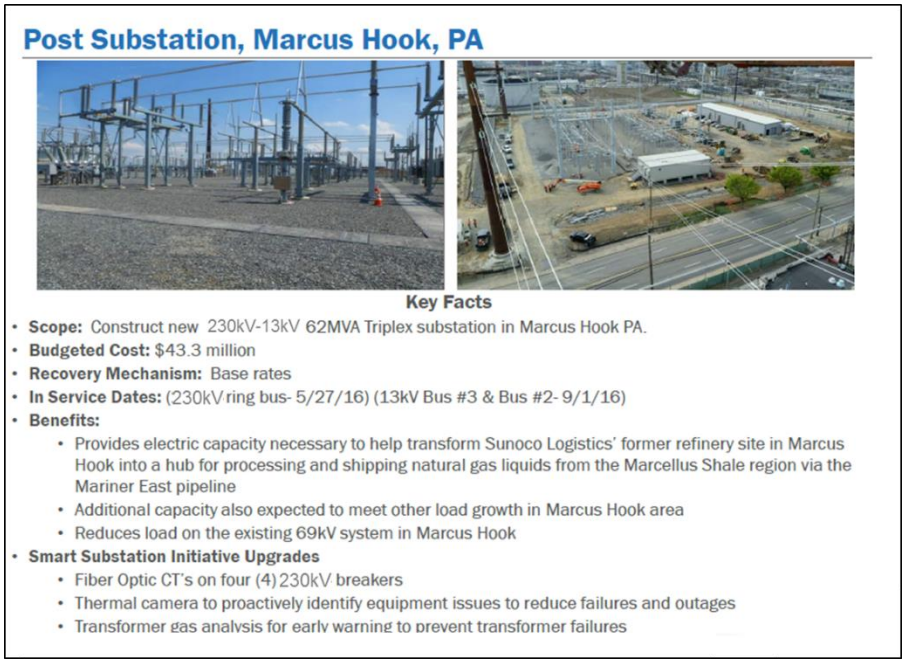
This paper discusses a pilot substation application where fiber optic current sensors and voltage based merging units drive redundant protection and control system to gain field experience. The paper will also overview the digital substation's key benefits highlighting safety, reliability, functional consolidation, and cost drivers leading to utility savings. Utilities are facing an increased demand on substation information

and the digital substation opens the door for real time data exchange of information that can drive asset health center or wide area protection systems. The Digital Substation solution's key technologies (relays, advanced substation automation and modern instrument transformers) provide the key advantages while utilizing IEC 61850/Ethernet must be viewed as technology enablers and not obstacles.

2.0 PECO Post Substation Pilot Digital Substation

In 2016, PECO completed construction of the new $43 million Post Substation. Post is a 230 kV – 13 kV Distribution Substation placed in service to support increased demand and future growth in Marcus Hook, Delaware County. Each year, PECO invests more than $500 million to enhance its system infrastructure through preventive maintenance and equipment upgrades to ensure safe and reliable service for customers. Driven by Exelon's culture of innovation, the Post Substation project, which began in August 2015, incorporated the latest innovations in smart substation technology to provide customers with enhanced electric service reliability. This includes the installation of fiber-optic current transformers and diagnostic systems that process real-time analysis of transformers, circuit breakers and battery systems. In addition, thermal imaging is used to identify potential issues before they occur by recording temperature variations within a piece of equipment while in operation.

While Post Substation was another significant investment designed to enhance PECO's electric system to meet the needs of our customers, the smart substation technology was added to leverage new, innovative solutions and advanced analytics to anticipate maintenance issues to avoid customer outages. The 230 kV transmission portion of Post Substation includes a six circuit breaker ring bus tapped into a line between two existing transmission substations. The transmission design included several reliability innovations. First, Fiber Optic current transformers were installed for independent primary and backup line protection schemes for both resulting line sections. Each line section included two ring bus circuit breakers; therefore, a total of twenty-four fiber optic current transformers were installed.



Additionally, circuit breaker condition monitors were installed on all six transmission circuit breakers. Thirdly, thermal imaging was installed to monitor key transmission system components. Finally, the substation DC power was supplied by redundant chargers, each with a condition monitor. Smart substation innovations

included on the distribution portion of Post Substation consisted of 230 kV – 13 kV Power Transformer condition monitors.

3.0 Digital Substation and the Industry Challenges

Digital substations have evolved over the past two decades. The introduction of the microprocessor into substation automation, protection and control has revolutionized the utility industry for the good and the bad. The push from a dumb grid to a "Smart Grid" has enabled the digital world to expand well beyond the traditional scope of protection, control and SCADA. The ideal vision of knowing all aspects of every substation networked into an intelligent grid opens the opportunity to have information at our finger tips. The challenges continue to be the strangle hold from regulatory standards for reliability and security when in reality, a smarter and highly intelligent automation system can in fact make the grid much more reliable and dependable. The other challenge results as utility personnel struggle to find adequate time to research and explore new technologies that could change the landscape of the power system protection and control network. Our younger and upcoming generation of system and protection engineers have lived in the digital world their entire life. As the aging infrastructure continues to feebly perform, the system has very little knowhow on whether it is working or not, on the ability to take proactive decision to limit outages or damage, restore customers much faster and provide the valuable post mortem information to make necessary improvements.

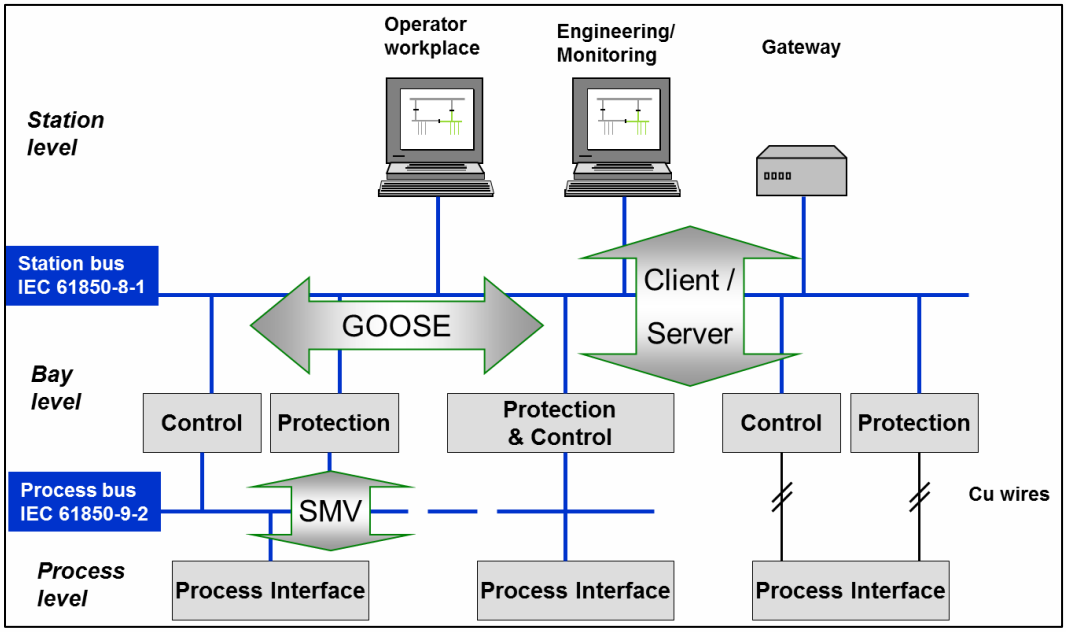
The last challenge is our aging and retiring workforce. The amount of knowledge leaving our industry annually is mind blowing. Reverting back to the point on the younger generation, another challenge is the company loyalty or should we say lack of company loyalty. This has flown out the window long ago, where today's younger employees have no concept of a lifetime at a single employer and likewise, companies with the increasing business pressure on performance, have also lost the ability to retain the younger employee in dire times. From a technology perspective, the younger generation has grown up in the digital world. Try taking their iPhone or Droid away from them as it will cause a meltdown. In all seriousness, the digital world in the society has only been possible with the tight integration of information, resources on a common platform (open standards) and Moore's Law continuing to prove that if it is not possible today, technology will continue to advance making it practical tomorrow.

The digital substation is no different. Open standards are now in place and have matured to the point of different manufacturers (some more than others) interoperating on common platform. Technology for the complete digitization of the power system information as well as the speed and performance of the information exchange allow real-time performance at a better accuracy and open up the possibilities for the digital substation to be embraced. To that point, who will be embracing this new technology? You do not have to look far as our younger generation has the capability and, oh by the way, they have spent their entire lives in the digital era so they are also fearless to these new technology advances and are the key to pushing this new technology to revitalize protection, control and automation into the modern era.

4.0 The Standard – IEC 61850

Without standards, we revert back to the 1990s when proprietary solutions resulted in vendor A system not communicating to vendor Y system or even products being installed with network interface modules (NIMs) to at least try to have minimal information available to the Network Control Centers. The industry today is very appreciative of the John Burger vision from American Electric Power who started a movement in the US market to migrate the industry to a common single standard. The history of the EPRI LAN Initiative to Utility Communication Architecture (UCA) to IEC 61850 is a paper in itself but what has transitioned in the last twenty years has changed the landscape for today and tomorrow's modern control systems.

The wide scale adoption of digital messaging for intra substation communication is only possible if it is based on a common open standard. Otherwise, we will revert back to the time when information was piecemeal and fragmented, with mutually incompatible signaling creating an assortment of messaging within silos or also known as islands of automation. IEC 61850 “Communication networks and systems for power utility automation.” This standard is not just a protocol but rather a comprehensive standard defining a communication architecture and philosophies that specify how the functionality of substation devices should be described, how they should communicate with each other and what they should communicate. A main goal of this open standard is to achieve multi-vendor interoperability and realize the benefits of a truly digitalized substation.

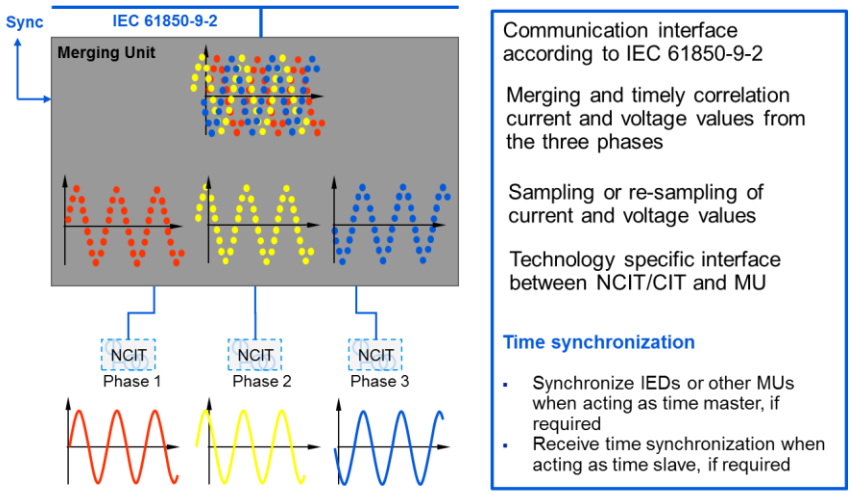


IEC 61850 defines two main communication hierarchies inside the substation for the purpose of information exchange between devices and from device to the sensing interface in the primary equipment. For inter device communication, IEC 61850-8-1 part of the standard also known as the “Station Level” bus can be generalized as the necessary requirements for inter bay and communications to the outside world. From the initial release of the IEC 61850 standard in 2004, the station bus brought the main benefit of the standard and was widely implemented by most vendors who had a vested interest to realize the changing world environment. The station level bus provided a means for the common architecture targeting interoperability across vendors, significant reduction in copper wires through the introduction of unsolicited peer-to-peer device communication also known as Generic Object Oriented Substation Event (GOOSE) messaging, based on hardened Ethernet technology usable in the harsh substation environment.

The second communication hierarchy was the process bus as defined in IEC 61850-9-1 (point to point unidirectional) and IEC 61850-9-2 (multipoint bidirectional) for the purpose of communication between the protection and control bay level devices and modern instrument transformers installed at the primary apparatus in the switch yard. Edition 2 of IEC 61850 released over the past two years, IEC 61850-9-1 has been removed as its usefulness and application where limited. IEC 61850-9-2 for process bus communications main attributes are the streaming Sampled Measure Values (SMV) where the modern sensor digitalize the power system current and/or voltage measurements into a package of synchronized measurement values communicated to the protection and control devices. The standard does not define

the type of sensor or the means for the digital transformation but rather it defines a merging unit that collects the sensor information and prescribes a standard means to package and communicate the output.

The exchange of sampled values between these modern sensors or non-conventional instrument transformers (NCIT) and intelligent electronic devices (IED) devices for protection functions and other purposes allows for the real-time digital information exchange. The interconnection between the sensors and actuators, which are physically connected to the power system process, is why the term “process bus” has been used as the interface to the protection and control systems. This enables the standard-compliant digitalization of the last mile in substation automation, and brings with it a wide range of benefits in The Digital Substation.



4.0 Non-Conventional Instrument Transformer Designs

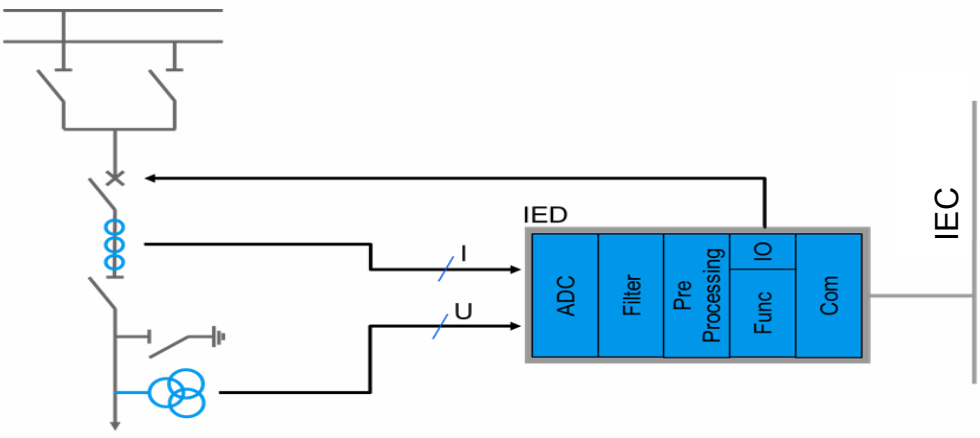
In today’s electrical systems, currents in high voltage equipment are measured using bulky and heavy current transformers (Photo shows 420kV oil-filled CTs) in oil insulated or SF6 insulated designs. These use the principle of electromagnetic induction to generate a small secondary current, typically 5A or 1A nominal at rated current, from a primary current, which then serves as an input for protection relays or energy meters. Such transformers have represented the state of the art for many decades and they operate reliably under the harsh conditions found in an outdoor substation.

However, besides their size and weight, they have a number of additional shortcomings - the most important of which is that, as a result of magnetic saturation and limited bandwidth, the waveform of the secondary current is often not a true image of the primary current. Over 40 years ago, it was recognized that the Faraday Effect could be the basis of a new, and better, technology for current measurement. But it is only in the last 20 years that appropriate technology has become sufficiently mature to allow it to be used as a commercially attractive basis for fiber optic current sensor (FOCS) applications. The remarkable progress made by the optical communications business has provided many components that can be deployed in utility grade sensors - such as light sources, fiber-optics, modulators and photodetectors.

Optical current sensors have found significant interest in recent years for use in electric power transmission. Particularly, fiber-optic current sensors have become rather mature and have been finding commercial applications not only in high voltage systems but also in industry, e.g., in the measurement of high direct currents (dc) in the electro-winning of metals (aluminum, copper, etc.). Optical sensors offer considerable benefits over conventional instrument transformers. They are inherently free of magnetic saturation and typically have a measurement bandwidth in the range of kilohertz (determined by the data rate). But also bandwidths in the range of tens or hundreds of kHz are feasible. As a result fiber-optic current transformers deliver within their measurement range a true image of the primary current, also in case of fast transient currents, short circuit currents, and alternating current (ac) with dc offset. Furthermore, optical CTs are lightweight and of small size. This makes it possible to operate them not only as freestanding devices but one can easily integrate them into other power products. Substation footprint and installation costs are reduced. Other advantages are enhanced safety (no risk from open secondary CT circuits or catastrophic failure) and environmental friendliness (no oil). Optical current sensors are immediately compatible with modern digital substation communication, which helps to eliminate large amounts of copper cabling.

5.0 Stand Alone Merging Unit for the Conventional Instrument Transformer

While NCITs are ideal solutions for new installations, it is also important to provide retrofit solutions for brownfield upgrades. To provide a bridge between traditional and digital technology, stand-alone merging unit (SAMU) is used. The SAMU is used to digitize the potential and current instrument transformer's analog secondary (120V, 1A or 5A nominal) into digital sample measured values for communications to and utilization by the protection and control devices. SAMU is functionally shown in the figure below.



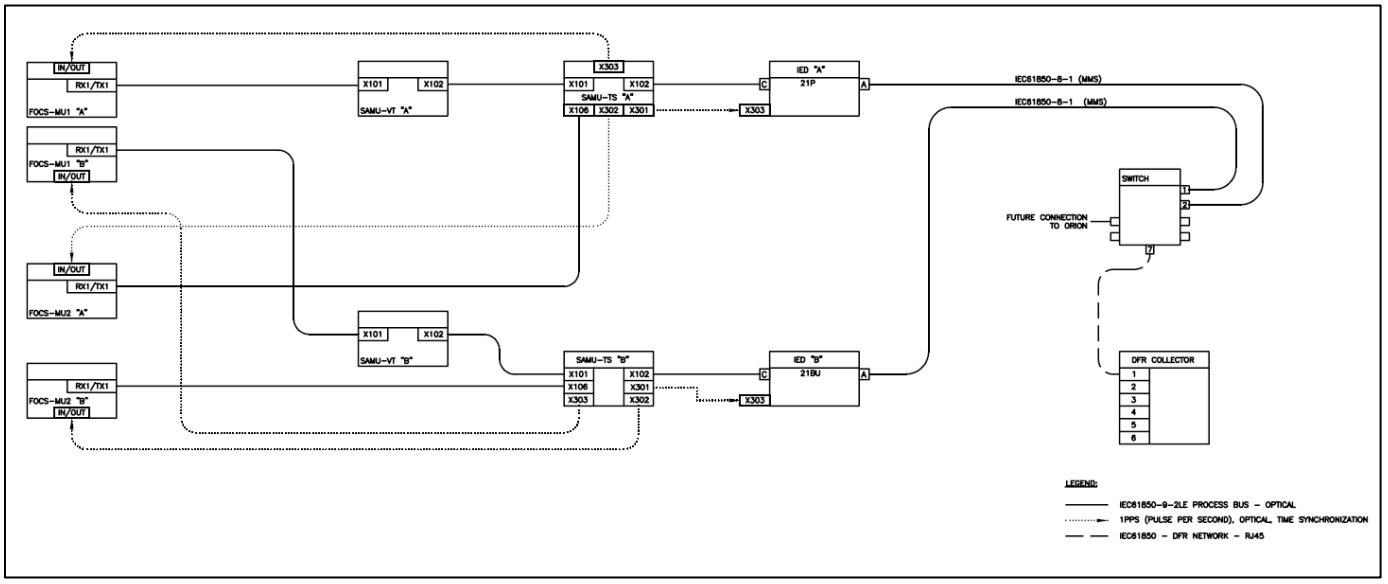
The three single phase sensors are fed into a FOCS merging unit where its IEC 61850-9-2 three phase current sample measured value output is received by the voltage standalone merging unit to combine (or merge) the synchronized voltage and current measurements. The SAMU system bus communicates the 3 phase current and voltage messages via an IEC 61850-9-2LE compliant stream. This combined IEC 61850-9-2LE stream is available on all IEC 61850 access points on all SAMU modules.

6.0 New Technology installation into The Digital System

The system installation required the fiber optic sensor to slip over the bushing of the existing dead tank circuit breaker at Post Substation. The sensor's fiber optic cables were routed to the control room as the sensor merging unit for this installation was located in the protection panel. The protection and control system has the following components:

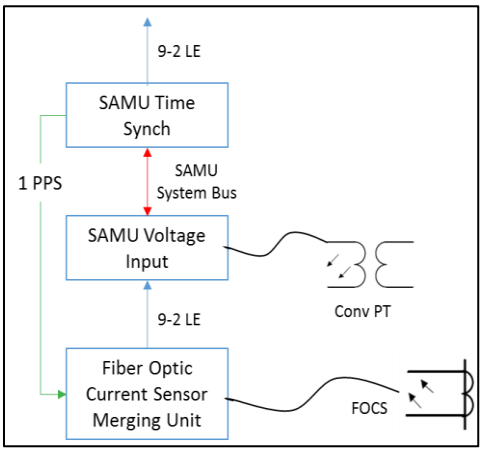
- Stand-alone merging unit (SAMU) for voltage
- Time synchronization module for the process bus
- Fiber optic current sensor merging unit
- Line distance relay
- Station bus Ethernet switch
- Data concentrator to collect events and disturbances

The SAMU-VT interfaces receives the conventional voltage transformer with a configurable input voltage to measure the PT 120 VAC nominal secondary. The neutral voltage is calculated in the SAMU-VT as the vector summation of the three phase voltages and is provided as a sampled measured value to the synchronized IEC61850-9-2 stream. The redundant protection and control system has two fibers (A & B protection) from the FOCS merging unit respectively FOCS-MU"A" / FOCS-MU"B".



The network diagram shows each device is interconnected to the protection system. The redundant system is separated into "A" and "B" and each system is identical devices with independent synchronization, svID (sampled values identification) and MAC (media access control) address. As the interconnection diagram for the "A" and "B" systems has identical structures, describing one, covers both. The SAMU time synchronization is the time master and provides time synchronization for the whole process bus and protection system. It synchronizes the SAMU-VT module using an internal system bus with an accuracy of 1µs over IEEE1588. The other merging units: FOCS-MU1 ; FOCS-MU2 and line protection IED required a pulse per second (PPS) time source provided by the 1PPS outputs of the SAMU time synchronization module.

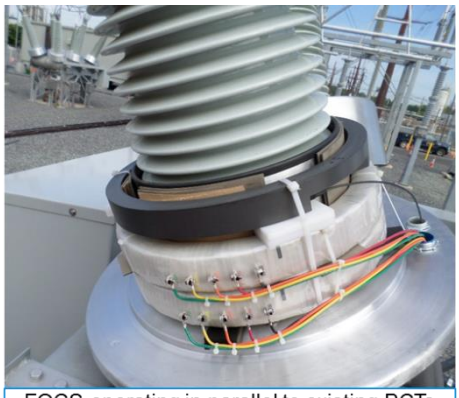
Additionally, the SAMU subsystem merges the voltage and current sample measured values and provides the point-to-point Ethernet connection to the line protection IED. The scenario using a FOCS-MU1 and the SAMU-VT as a "hybrid" merging unit (see side figure). The IEC61850-9-2LE stream of the FOCS-MU1 is combined with the analog data acquired by the SAMU-VT module. The combined IEC61850-9-2LE stream is available to the subscribing line protection IEDs. Additionally, the FOCS merging unit makes use of a free SAMU port pass-through of IEC61850-9-2LE process bus traffic direct to the line protection IED which is later used to comparison of the acquired process bus and analog data. Future improvements will allow the system to interface with the supervisory system via IEC61850-8-1 station bus to report measurement, protection and discrepancy alarm signals. A data collection system has been installed using an industrial computer to retrieve event and disturbance records triggered in the line protection IED.



7.0 Application Comparing Conventional vs The Digital System

All protection personnel are well accustomed to connecting conventional CT and PT secondary analog values to their protection relays, and more recently to their protection IEDs, following the emergence of numerical technology-based protection devices. However, following the continued evolution of digital technologies, and the coming to fruition of the IEC61850-9-2 LE process bus standard, the direct connection of the secondary analog quantities to the protection IEDs is no longer the only method by which these devices can receive these quantities.

The main objective of the joint pilot project is to compare in as many ways as possible the performance of the protection functions fed by conventionally connected analog quantities with like/identical functions fed by a digital connection of the same quantities. The pilot project comprises two line distance protection IEDs. These IEDs are not connected to trip the live circuit breakers of the line. PECO used their standard protection IEDs for this purpose. The in-service line protection IEDs are fed by conventionally connected CT and PT secondary quantities. The picture illustrates the mounting fiber optic sensor which contains the A and B system fiber in one fiber sensor encapsulation compared to the separate A and B protection system bushing CTs.



FOCS operating in parallel to existing BCTs allow pilot projects to compare results of digital versus analog without affecting normal breaker functionality or substation performance

The application is ring bus. Analog connections to the pilot IEDs are as follows:

IED A: PT_A, $CT1_A$, $CT2_A$, MU_A. Connections to MU_A are PT_A, $FOCS1_A$, $FOCS2_A$.

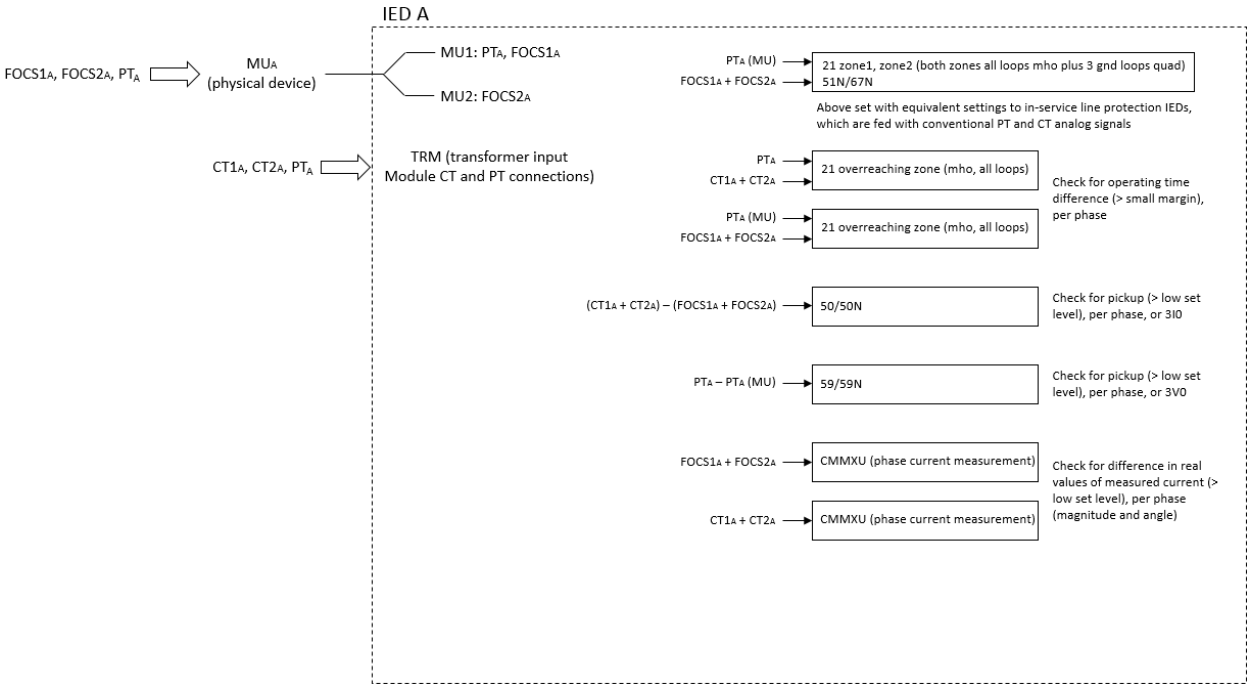
IED B: PT_B, $CT1_B$, $CT2_B$, MU_B. Connections to MU_B are PT_B, $FOCS1_B$ $FOCS2_B$.

One part of the conventional vs digital comparison is to compare the performance of the conventional analog quantity fed in-service IEDs with the performance of the same functions in the pilot IEDs, but fed by digitally connected quantities. Each pilot IED has two 21 distance zones (mho + ground quad), applied as standard zone 1 under reaching and zone 2 over reaching, as well as a 51N/67N function. The settings for these functions on the pilot IEDs were calculated to match those on the in-service IEDs. The pilot IEDs are connected with disturbance recorder trigger signals from the in-service IEDs. This ensures that operation of the in-service IEDs, operating on conventionally connected quantities, can be compared, and analyzed, against the performance of like, but digitally fed, functions in the pilot IEDs, even if these latter digitally fed functions do not exhibit the same performance.

However, it is the other part of the conventional vs digital comparison that is more comprehensive, because each of the comparisons are performed within the same IED, and where applicable, between identical functions. It should just be noted that the two pilot IEDs do not perform identical comparisons, but some are performed in one IED, and other comparisons in the other, to maximize the number of comparisons performed. The details are as follows:

Configuration of IED A (Distance, Overcurrent and Under/Over Voltage Protection)

21 zone of mho distance protection fed by directly connected conventional CT and PT inputs, plus another identical 21 zone of mho distance protection, with identical settings, fed by the digitally connected quantities. Large reach setting to get highest probability for operation. Monitored is the operate time difference, per phase, between the conventional and digitally fed functions. An operate time difference greater than a small margin is identified, and causes a disturbance record to be triggered.



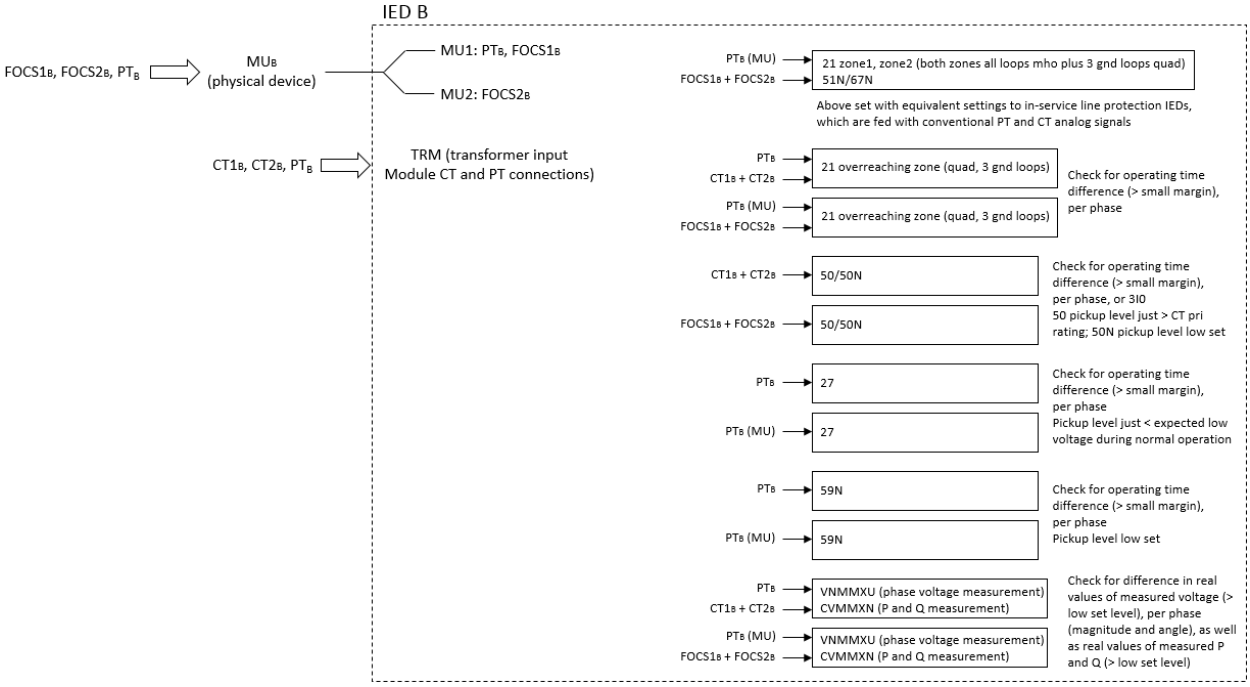
The difference between the conventional connected currents and the digital currents [($CT1_A$ + $CT2_A$) – ($FOCS1_A$ + $FOCS2_A$)] are fed to 50 and 50N functions. Similarly, the difference between the conventional connected voltages and the digital voltages [PT_A – PT_A(MU)] are fed to 59 and 59N functions All 50, 50N, 59 and 59N functions have low set settings. Any pickup indicates a conventional current/digital current or

conventional voltage/digital voltage difference greater than its set threshold, and causes a disturbance record to be triggered. The phase and neutral difference currents, as well as the phase and neutral difference voltages, are recorded by the disturbance recorder.

Two current measurement functions, one fed from conventionally connected currents ($CT1_A + CT2_A$), the other from the digitally connected quantities ($FOCS1_A + FOCS2_A$). A difference in the measured real value of current, per phase, greater than a low set threshold is identified, and causes a disturbance record to be triggered

Configuration of IED B (Distance, Overcurrent and Under/Over Voltage Protection)

21 zone of ground quad distance protection fed by directly connected conventional CT and PT inputs, plus another identical 21 zone of ground quad distance protection, with identical settings, fed by the digitally connected quantities. As with the mho zone in IED A, a large reach setting has been set to get highest probability for operation. Monitored is the operate time difference, per phase, between the conventional and digitally fed functions. An operate time difference greater than a small margin is identified, and causes a disturbance record to be triggered.



50 and 50N functions fed by directly connected conventional CT inputs ($CT1_B + CT2_B$), plus further identical 50 and 50N functions, with identical settings to the conventionally fed 50 and 50N functions, but fed by the digitally connected quantities ($FOCS1_B + FOCS2_B$). Similarly, 27 and 59N functions fed by directly connected conventional PT inputs (PT_B) plus further identical 27 and 59N functions, with identical settings to the conventionally fed 27 and 59N, but fed by the digitally connected quantities PT_B(MU). 50 pickup threshold set just above CT primary rating, and 27 pickup threshold set just below expected low voltage during normal operation, to get highest probability for operation. 50N and 59N pickup thresholds low set. Monitored is the operate time difference, phase or neutral, between the conventional and digitally fed functions. An operate time difference greater than a small margin is identified, and causes a disturbance record to be triggered.

Two VN (phase-ground) voltage measurement functions, as well as two P and Q measurement functions, one instance of each fed from conventionally connected voltages and currents (PT_B, $CT1_B$ + $CT2_B$), plus, the other instance of each from the digitally connected quantities [PT_B(MU), $FOCS1_B$ + $FOCS2_B$]. A difference in the measured real value of voltage, per phase, or P or Q, greater than low set thresholds, is identified, and causes a disturbance record to be triggered.

System disturbances with no disturbance records would indicate performance of protection functions fed from conventional or digital quantities to be "identical", and that would not be a bad result. However, with the above being so, no disturbance records would be triggered. Therefore the decision was made to trigger disturbance records also for pickup of the protection functions, even if no performance discrepancy was detected between conventional and digital fed functions. In this way the recorded quantities, e.g. CT connected input vs FOCS MU input, could be further analyzed for system disturbances/faults.

This approach would yield valuable data, but would be very infrequent. So a further feature was added, whereby a disturbance record in both pilot IEDs would be simultaneously triggered every three hours. An automatic upload facility for these records was also engineered to ensure all records would be retrieved before overwritten in the IED. This regular recording permits detailed analysis of the recorded quantities, e.g. CT vs FOCS, $FOCS_A$ vs $FOCS_B$, etc., covering seasonal changes, load variations over time, etc.

8.0 New technology installation process experience

Design, installation, and testing of a greenfield PECO substation is based on issued standards and practices. Introducing new technology presents challenges to these activities. The approach taken to address these challenges utilized the experience of the manufacturers of this innovative technology. Two manufacturers were selected to each provide design and equipment for one independent primary and backup line protection scheme; including equipment panels, fiber optic CTs, and cables. PECO installed the control room panels, outdoor boxes, and cables. However, due to the specialized nature of the fiber optic CTs, they were installed on the circuit breakers in the field by the manufacturers. In the future, the installation and testing process could be improved by integrating the fiber optic CTs into the circuit breakers at the factory. After installation and connection to the IEDs, apparatus testing was also performed by the manufacturers, who provided Performance Test Reports.

The manufacturers configured, started up, and tested this equipment. PECO relay testing was involved in functional testing of the AC portion, which was done in conjunction with AC testing of our standard protection equipment. The conventional tests included CT and Network Megger, Polarity, Ratio, and Impedance tests. Primary injection tests were performed on both types of CTs; although the conventional network was tested as a whole, while the manufacturers tested the Fiber Optic CT by individual circuit breaker. Functional testing of the DC portion by PECO relay testing was not necessary, since these IEDs were not wired to trip the circuit breakers. PECO relay testing involvement at this time was well accepted and provided the benefit of informal training. Formal training sessions for PECO field testing personnel were scheduled after equipment energization.

After energization, a failed fiber optic CT component was found that was originally not identified during manufacturer's apparatus testing. The manufacturer was scheduled to revisit the site and found that

cabling was the cause and a spare fiber was used to correct the problem. This seems to indicate that more consideration should be given to integrity checking during apparatus testing.

PECO's involvement helped identify other potential test plan improvements. For example, during the primary injection testing, the known conventional CT Polarity was used to check the fiber optic CT Polarity. If the polarity were wrong, it could be changed with a setting; however, there should be more specific definition of Fiber Optic CT polarity conventions and plans for independent injection testing. This would be essential if fiber optic CTs alone were utilized for a protection scheme, without conventional CTs to provide a polarity reference. Additionally, it was identified that additional ability to isolate one set of Fiber Optic CTs used in a protection zone involving multiple circuit breakers is desired. Without this, the IED and other CTs could not be kept in service for a load test during partial primary equipment outages. This requirement occurred during the substation energization sequence. If the IEDs were wired to trip the circuit breakers as we would expect to do in the future, it would have been necessary to take the transmission line out of service to install new equipment. PECO installs links and/or test switches to isolate a set of Conventional CTs and avoid this requirement. This demonstrates that business processes need to be considered in the design of new technology as it is applied.

9.0 Data collection system and analysis process

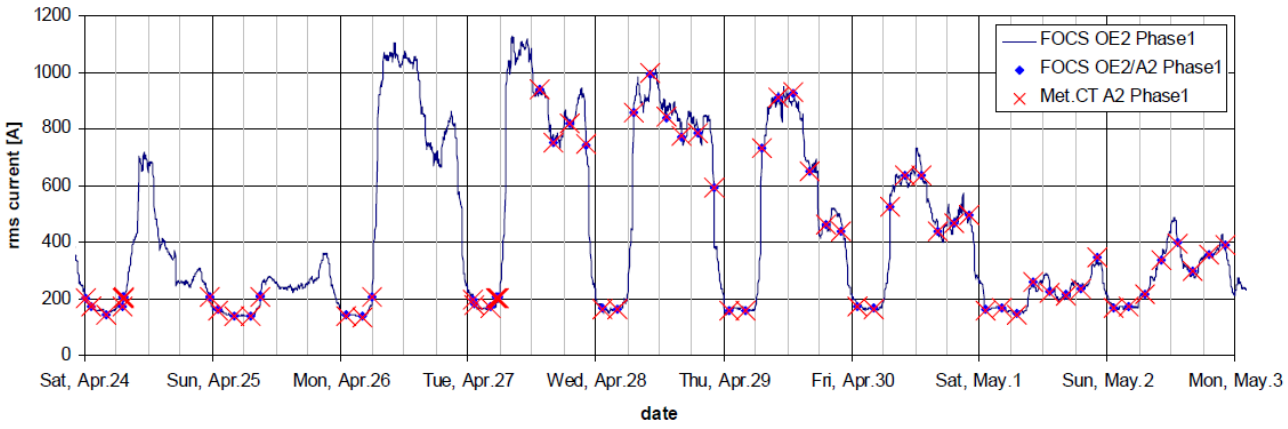
As Post is a pilot substation, one the main goals of the digital system is to investigate the behavior and performance between the sampled measured values and the conventional protection system. A data collection system has been installed to capture events and disturbances (e.g. line trip). Additionally, the comparison of the conventional CT vs the digital system is desired and since the system might not experience a line fault. To collect data at a greater frequency, the distance protection relay was configured to trigger fault recordings every 3 hours and capture measurements during variations in load as well weather conditions.

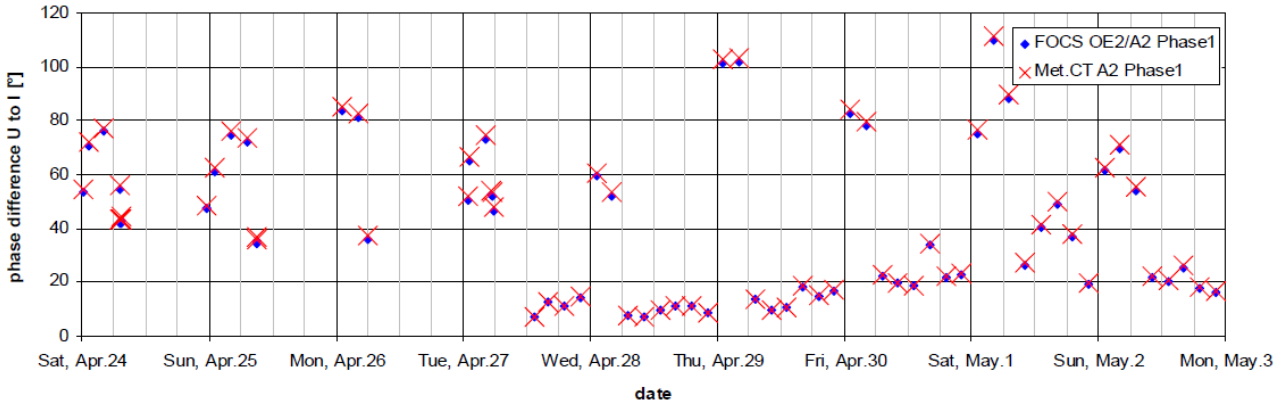
The line relaying triggering records every 3 hours trigger will generate a huge data amount filling up the relays records storage. To avoid overwriting the relay record storage and risk lose important data, a data collection server was installed using an industrial computer. An event record software automatically retrieves the disturbance record fully utilizing IEC61850 interfaces to interrogate the relays for new records. The data collection system analyzes the incoming data and produces concise reports so patterns of activity can be observed. In the future, the system can serve as centralized disturbance storage allowing information to be shared for analysis and aggregated across substations creating a holistic view and correlation of associated events.

Regarding the conventional versus digital system comparison the following evaluation will be performed from the disturbance records capturing a mixed mode of analog measurements:

- Current magnitude and phase comparison over the time
- Voltage magnitude and phase comparison over the time

For instance, the results will be compared in the figures below:





The goal is to evaluate the protective relay performance comparing the conventional versus digital measurement systems. However, the Post Substation process bus relays have recently been configured to more frequently capture the analog and digital measurements for comparison. At the writing of this paper, data collection and comparison between conventional and digital systems are still in progress.

10.0 Benefits of the digital process bus replacing copper

Every copper wire in a substation is a potential risk whether it is from a CT or PT circuit or a 125V DC control wire. The highly inductive current transformer secondary circuit poses the largest safety concern. The hazard results when an energized current transformer wire is unknowingly disconnected. From inductive circuit theory, current flowing through an inductive circuit cannot be instantaneously changed from 5 Amps to zero. A quick thanks to Wikipedia; the mathematics formula, $v(t) = L\frac{di}{dt}$, implicitly states that a voltage is induced across an inductor, equal to the product of the inductor's inductance, and current's rate of change through the inductor. As the inductance does not change during the open circuit, the rate of change in current from 5 to 0 Amps instantaneously has the derivative (di/dt) resultant go to infinity. Thus, the formula's product voltage is dominated by the derivative blowing up to infinity and produces a very large voltage across the open circuited wires. Related to the substation application, an open CT secondary is equivalent to the inductive current going to zero and depending on the secondary load, arcing will occur as

these dangerously high voltages build putting field personnel at risk of serious injury or even fatality and equipment and the substation at risk from electrical fire. Minimizing copper leads to greatly improved safety.

The digital substation process bus where replacing copper control wires with digitized binary information for breaker status and control can alone justify the switch to digital. Going digital can cut the quantity of copper wires in a substation by upwards of 80% which is a substantial cost saving and, more importantly, a significant safety enhancement.

10.1 Benefits of the Digital Substation

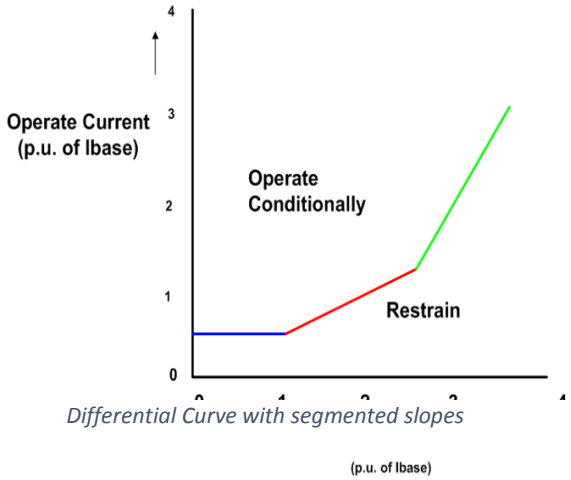
A fully digital substation is smaller, more reliable, has a reduced life-cycle cost and is simpler to maintain and extend than an analog one. It offers increased safety and is more efficient than its analog equivalent. Not every substation needs to be catapulted into a wholesale digital world – it depends on the substation size and type, and whether it is a new station or a retrofit of the secondary system. Different approaches and solutions are required. Flexible solutions allow utilities to set their own pace on their way toward the digital substation.

- Increased system availability by replacing of electromechanical, static or old fashioned digital secondary equipment with modern numerical devices bundled to a real-time communication network and connected to a higher level system such as a substation automation system or SCADA, allows continuous monitoring of all connected secondary equipment.
- Increased system and personnel safety utilizing remote control combined with authority and rule-based access and remote testing, allows increased system safety and security. Personnel safety is increased since more tests can be done without putting the test personnel close to primary equipment or without the risk of inadvertently opening current transformer (CT) circuits.
- Increased performance with fewer components as the sensor delivers a true image of the primary current waveform that is not affected by magnetic saturation or remanence. The DC contents of a current are correctly recorded. The sensor accuracy and dynamic range allow for a single sensor to have the accuracy required for metering and the ability to detect high fault currents for protection without saturation.
- Increased functionality with a fully distributed architecture coupled with un-restricted communication and process capability enables the system to add new functions easily with zero or minimal outage time, giving the user additional benefit with respect to safe and secure system.
- Interoperability through deployment of IEC 61850 compliant solutions with regard to communications with other manufacturer's equipment can be achieved. The benefit is IEDs from different suppliers can be mixed on the same bus without concern for communication incompatibilities.

10.2 Benefit of sensors not saturating

The result of using a current sensor that does not saturate can have a profound effect on the setting, and thus the sensitivity of a relay. Take for example, the differential relay. A differential relay relies on current sensors to provide the exact reproduction of the primary currents to it for analysis. It then adds the current vectors together and computes a differential current. Then using an operating curve, as shown in Figure 8 determines whether to operate or not. If the differential current falls above the characteristic curve for a given restraint current, the relay operates. If not, it restrains.

The slopes in red section, and green section are there to adjust for the performance of a conventional current transformer. As the restraint current goes up, the chances of two conventional current transformer operating exactly the same reduces. This output difference between the current transformers is compensated for by increasing the slope of the characteristic such that more differential current is needed to operate as the restraint current increases. The red section typically has a slope of 40%, and the green section typically has a slope of 80%. While this compensation is necessary for conventional current transformers to make it secure during current transformer saturation, it has the effect of decreasing the sensitivity of the differential scheme. With the use of non-conventional current sensors, these slopes can be set to close to zero which increases the sensitivity of the differential scheme during high current conditions.



Differential Curve with segmented slopes

11.0 Conclusion

The Post substation pilot IEC 61850 system has been in operation since May 2016. At the writing of this paper, the substation has not experience any events to compare the digital to the conventional protection and control system. The relay configurations have recently been changed to allow capturing of the non-conventional instrument transformer data and conventional current transformer measurements for offline analytics. The Post substation experience will provide invaluable information on the performance over time and environmental conditions. The analytics assessment will be a chapter for future paper on the digital substation.

The introduction of the IEC 61850-9-2 process bus standard in substations has provided a platform that all manufacturers can develop upon to achieve the overall goal of interoperability. John Burger's visionary ideas are being realized with the technology available today. In addition to the interoperability benefits, footprint of primary switchgear reduction using sensors (NCIT) replacing conventional measuring transformers allows a much safer work environment. On the secondary system, a reduction of process cabling going from thousands of copper conductors to a few fiber optic communication cables will mean reduced costs and installation time. Also, the improvements in fiber optic current sensors and the integration of the standalone merging units provide utilities and engineering firms with a great tool box for the future deployment of this maturing technology. For retrofit applications, the possibility of installing the new process bus system in parallel with the existing system will allow the substation to remain in service during the main part of the work. This will be a big advantage, reducing outages to a minimum, during the retrofit process.

References

1. K. Bohnert, P. Gabus, H. Brändle, and A. Khan, “Fiber-optic current and voltage sensors for high-voltage substations”, in 16th Int. Conference on Optical Fiber Sensors, Nara, Japan, October 13-17, 2003, Technical Digest, pp 752-755.
2. Rahmatian, G. Polovick, B. Hughes, and V. Aresteanu, Field experience with high voltage combined optical voltage and current transducers. Cigre (Paris), Session 2004, paper A3-111.
3. J. Wang, Z. Guo, G. Zhang, Study on longterm stability of 110 kV power optical sensor solution - optical current transducer, in Proceedings APPEEC 2010 (Asia-Pacific Power & Energy Engineering Conference 2010), Chengdu, China, 28-31 March 2010, pp 1178-1179.
4. K. Bohnert, P. Gabus, J. Nehring, H. Brändle, M. Brunzel, Fiber-optic high current sensor for electrowinning of metals, J. of Lightwave Technol., 25(11), 3602 (2007). 5. German patent E4224190B4, 22.7.1992.
5. W. Wimmer, “Systems' Reliability and Maintainability - The Impact of Topology awareness”, PacWorld pp. 54-59 March 2010
6. L. Andersson, K-P Brand, D. Fuechsle, “Optimized Arechitectures For Process Bus With IEC61850-9-2”, B5-101 CIGRE (2008)
7. IEC 61850-9-2 Communication networks and systems in substations – Part 9-2: Specific Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802-3
8. IEC 61850-8-1 Communication networks and systems in substations – Part 8-1: Specific Communication Service Mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3
9. S. Kunsman, N. Powers, et al, “Protection and Control System Utilization of NCIT & Process Bus”, Pac World Americas 2016

Authors Information

Steven A. Kunsman – Director Product Management and Applications, ABB Power Grids - Grid Automation North America steven.a.kunsman@us.abb.com

Steve joined ABB Inc. in 1984 and has over 33 years of experience in Substation Automation, Protection and Control. He graduated from Lafayette College with a BS in Electrical Engineering and Lehigh University with an MBA concentrated in Management of Technology.

Today, Steve is responsible for ABB North American Substation Automation business’ technical team. He is an active member of the IEEE Power Engineering Society PSRC & PSCC Committees, PSCC Cyber Security Subcommittee chair and has held multiple working group chairs, an IEC TC57 US delegate in the development of the IEC61850 communication standard and UCA International Users Group Executive Committee Co-chair.

George Gresko - Principal Engineer, PECO Transmission & Substation Protection & Control Engineering group george.gresko@peco-energy.com

George has 34 years’ experience in Transmission & Substation. He graduated from Rensselaer Polytechnic Institute in 1982 with a Bachelor of Science in Electrical Engineering and from the University of Pennsylvania in 1987 with a Master of Science in Electrical Engineering. He received his Professional Engineering license in the state of Pennsylvania in 1987.

He has held numerous positions including Relay and SCADA Engineer, Maintenance & Reliability Program Lead, Project Engineer for SCADA, NERC CIP and Relay projects, Lead Responsible Engineer for major substation retirements, additions and upgrades. He is an IEEE member and has participated and received awards as a member of IEEE Power System Relaying and Control Committee Working Groups.

Samuel Morbin – Protection & Control Engineer, ABB Power Grids - Grid Automation North America samuel.morbin@us.abb.com

Samuel joined ABB Brazil in 2010 as a Protection & Control Engineer and later worked as Lead Engineer for Substation Automation Systems. Today, he is located in ABB Raleigh, North Carolina and has been part of the Grid Automation North America team since June 2015. Samuel graduated from Universidade Federal de Itajuba, Brazil with a B.S. in Electrical Engineering with a concentration in Power Systems.

Mike Kockott - Senior Applications Specialist / Senior Relion Product Specialist, ABB Power Grids - Grid Automation North America mike.kockott@us.abb.com

Mike obtained his B.Sc. (Electrical Engineering) degree from the University of Cape Town, South Africa, in 1980. Following a two-year period of military service, Mike joined Eskom, the national power utility of South Africa, as an engineer-in-training at the beginning of 1983. With Eskom Mike rose to become Line Protection Design Manager, then on to become Senior Consultant, Protection (Transmission). In 1996, Mike was appointed as the South African member to Cigré SC34 (now B5).

In November 1999, Mike joined ABB AB at the Substation Automation Products factory in Västerås, Sweden, in January 2000. Mike worked as a Senior Applications Specialist / Senior Technical Manager for 12 years at the SA Products factory in Sweden. In November 2011, Mike relocated from Sweden to join ABB Inc., NAM SA Products, in Raleigh, North Carolina, where he works as Senior Applications Specialist / Senior Relion Product Specialist. In the US, Mike has become active in IEEE PSRC, where he is currently vice-chair of one working group, and chair of another.