# Hybrid Digital Substation Design Experience: Comparing Conventional and Non-Conventional Communication-based Measurements

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## Abstract

Digital substations based on IEC 61850 technology obtain analog and binary signals over Ethernet communication instead of conventional copper wires. Analog values are shared as Sampled Values (SVs), while binary signals use Generic Object-Oriented Substation Event (GOOSE) messages. Comparing conventional and communication-based measurements is of value for any digital substation design. In addition to using Ethernet communication for sharing analog and binary signals, non-conventional measurement transformers can be used as well.

This paper provides an overview of a digital substation design approach with conventional and non-conventional measurement transformers. Design includes fiber-optic current sensors with the IEC 61850-9-2 Light Edition (LE) interface, protective relays with conventional and communication-based interfaces, time synchronization sources, communication devices and test gear. The site chosen for the installation is a double circuited 500kV transmission line that spans 224 miles and averages 10 faults a year.

Protection functions (line distance protection) and extensive monitoring functions implemented are covered. Lessons learned during engineering, commissioning and operation are presented. Comparative analysis of the initial fault data obtained through conventional copper interfaces and communication-based interfaces to non-conventional measurement transformers are discussed. Future papers will present more results for protection functions and measurements as the deployed system collects more data.

This paper describes the experience of two fiber-optic current sensor manufacturers applied at the same BPA location.

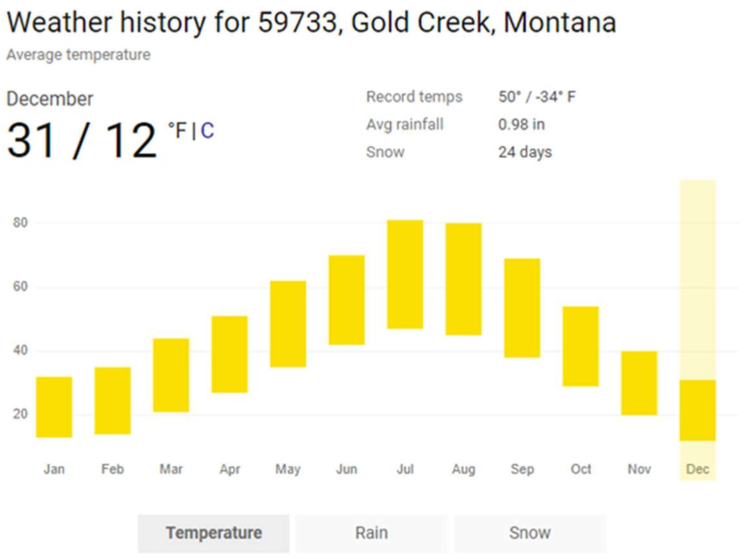
## I. Introduction

Transitioning from conventional, wire-wound current transformers (CTs) to fiber-optic current sensors (FOCS) eliminates a common source of safety and property hazards while enhancing the resilience of the BPA transmission system. This demonstration project investigates the suitability of systems that were commercially available from the participating vendors and identifies concerns and considerations to incorporate into potential BPA design specifications.

Fiber-optic current sensor technology has become practical for protection of transmission facilities. This demonstration project assesses the applicability of products for the BPA transmission system while validating the potential to eliminate a serious safety threat, enhance BPA seismic resilience, and eliminate an environmental contamination risk.

Fiber-optic current sensors have associated Merging Units (MUs) that output IEC 61850 sampled values. This system hardens transmission facilities in the following ways:

- *Reduces risk of extended disruptions of critical transmission assets, services, and functions from extreme events:* free-standing and retrofit fiber-optic current sensors are significantly lighter and smaller than their iron-core counterparts. This puts less mechanical burden on the free-standing current transformers footings and power circuit-breaker footings. Also, less copper cabling and cable terminations are required for implementing FOCS technology
- *Enhances human safety: prevents injury and loss of life.* One of the technology characteristics of the fiber-optic current sensors is the absence of iron cores or secondary windings that creates hazardous CT secondary energy that often causes injuries or casualty. The output of the current sensors are either a light signal encompassed in a fiber-optic cable or a low-voltage output in direct proportion to the primary current on the bus
- *Reduces system restoration times:* fiber-optic current sensors have a wide dynamic current measurement range. When reconfiguring a transmission line or bus that requires current transformer ratio changes, it eliminates the need for field engineers to conduct CT phase identification, ratio, burden and insulation testing
- *Provides resilience to Electro-Magnetic Pulse (EMP):* Because the output of the fiber-optic current and voltage sensors are light signals, devices that are connected to them, are fully decoupled from the power lines, which mitigates EMP [1].



Weather history for 59733, Gold Creek, Montana

Average temperature

December

31 / 12 °F | C

Record temps 50° / -34° F

Avg rainfall 0.98 in

Snow 24 days

Figure 1. Weather history for Gold Creek, MT

Fiber-optic current sensors perform the same function as current transformers (CTs) using a completely different technology. This difference required an extensive orientation for the BPA support team to become familiar with the devices and acceptance testing to qualify FOCS for use on the BPA transmission system. Initially, the team compiled a description of minimum specifications and features necessary for use on the BPA system. Different specifications are required for 500kV, 230kV, and 115kV models. The team decided to test devices rated for 500kV service because this system provides the most rigorous test of FOCS capability and informs applicability to the BPA transmission system.

Qualifying FOCS units were installed at the BPA Garrison substation for evaluation. The Garrison substation is located near Gold Creek, Montana, which experiences some of the more extreme temperature differences across the BPA system, as shown in Figure 1.

BPA personnel chose the Garrison Broadview #1 500kV line. The Garrison Broadview 500kV line #1 runs 225 miles, parallel to the Garrison Broadview #2 500kV line through the heart of Montana, see Figure 2.

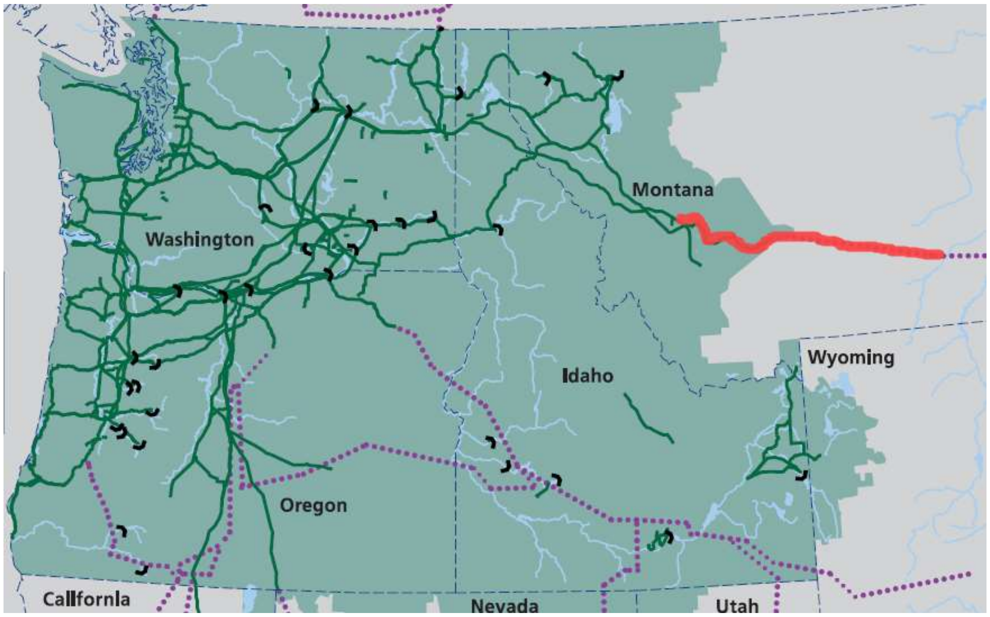


Figure 2 Garrison Broadview transmission lines location

Figure 3 details that the first 92 miles leaving Garrison of both lines are double circuited, sharing the same transmission tower. The remaining 133 miles are single circuits, running on separate towers.

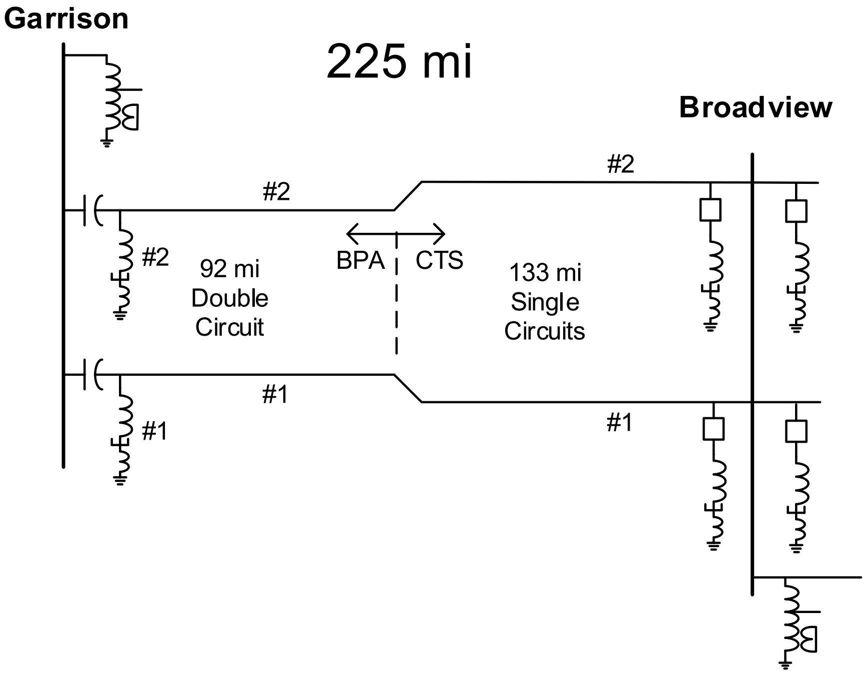


Figure 3 Garrison-Broadview 500kV transmission lines

Table 1 Faults on Garrison Broadview 500kV transmission system

| Year | Faults |
|---|---|
| 2020 | 15 |
| 2019 | 8 |
| 2018 | 19 |
| 2017 | 12 |
| 2016 | 6 |
| 2015 | 10 |
| 2014 | 10 |
| 2013 | 5 |
| 2012 | 6 |
| 2011 | 8 |
| Average | 10 |

Long-term performance and accuracy are important for assessing the FOCS system. The prospect of encountering frequent faults on the 500kV system distinguishes the opportunity for field testing at Garrison. For the years 2011 to 2020 the line has averaged 10 faults a year, as seen in Table 1.

It is important to identify these events and correlate the FOCS performance with the environmental conditions under which these occur.

Project goals were accompanied by collecting as much useful data as possible utilizing embedded and designed in features as well as extended monitoring capabilities of digital substation technologies.

## II. Deployed System Description

This project was deployed in November 2020 in BPA Garrison substation for the Garrison Broadview #1 500kV line. Aerial diagram of Garrison substation is shown on Figure 4.

Figure 4. Aerial diagram of the Garrison substation

To fully instrument the breaker-and-a-half design, both circuit breakers PCB 35E (referred to as tie breaker) and PCB 38E (referred to as bus breaker) required current sensors (six total for each manufacturer). For details consult Figure 5 and system architecture diagram on Figure 7.

BPA design engineers collaborated with the manufacturers' engineering groups to specify and plan cabling, indoor rack designs, and equipment positions inside the control house and outside in the substation yard.

Single line diagram with locations of fiber-optic sensors is shown on Figure 5.

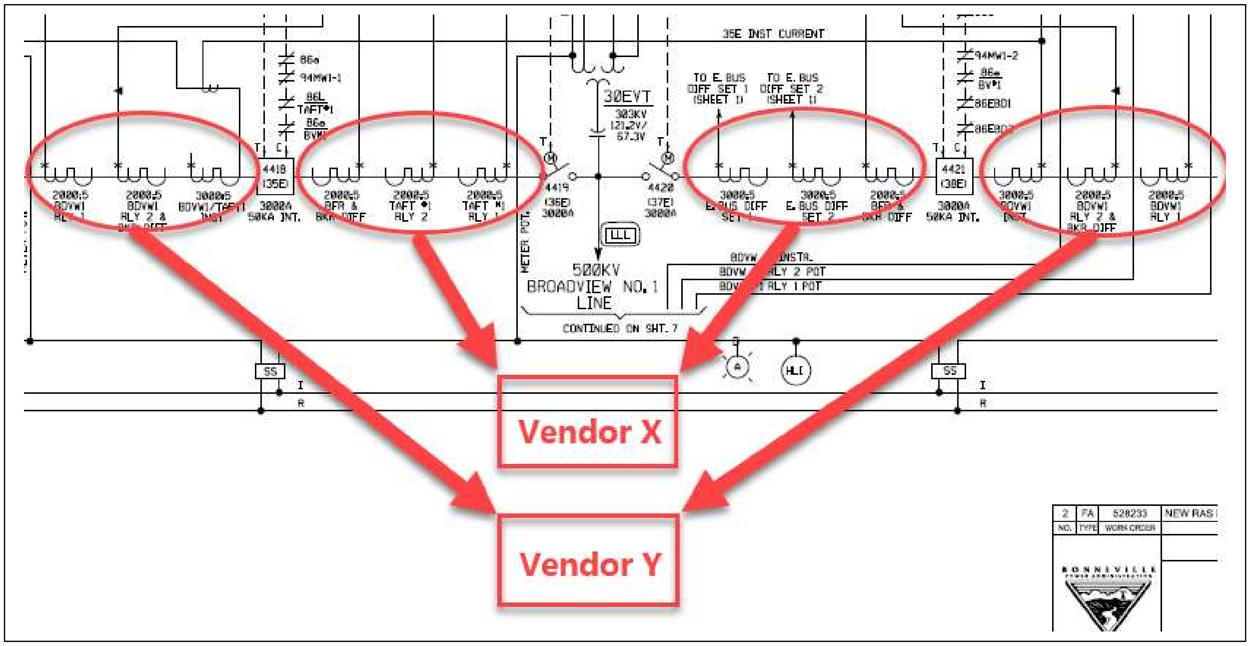


Figure 5 Fiber-optic sensors placement in breaker-and-a-half configuration

Location of the bus (PCB 38E) and tie (PCB 35E) breakers and trench to the control house is depicted on Figure 6.

Figure 6. Location of tie and bus breakers and the trench to the control house

### A. System architecture

IEC 61850 technology specified in [2] and [3] was selected for this project. It relies on communication-based exchange of analog and binary signals in lieu of conventional copper connections. Communication technologies used in digital substations are covered in [4] and [5]. Among other benefits, BPA identified that the use of IEC 61850 simplifies and speeds up testing opportunities thus assists in detailed and prompt system event analysis [6]. BPA has also demonstrated IEC 61850 technology for a unique protection application [7].

Communication-based signal exchange in addition to conventional copper connections was selected for this project to test and compare the two approaches. including their effects on operation of line protection schemes. A similar approach was taken but a utility in East Coast US, as described in [8]. In addition, as discussed in Introduction, fiber-optic current sensors were used.

An overall system diagram is shown on Figure 7. Note that connections to currents and voltages are provided via traditional copper cabling, as well as over communication-based analog data in IEC 61850-9-2LE format.

UCA IEC 61850-9-2 Light Edition (LE) implementation Agreement specifies streaming 4 currents and 4 voltages (3 phases and a neutral) [3]. For guidance on data structure details and bandwidth usage readers can refer to [5].

Devices providing digital samples of analog signals are called Merging Units (MUs). A classical MU with copper connections is used for voltage connections in this system. Non-conventional current transformers (FOCSs) provide current connections to current MUs. Physics of FOCS operation is covered in an IEEE guide [9] and numerous industry literature. These devices have an IEC 61850-9-2LE interface and act as MUs.

As discussed in [6], sampling synchronization is critical when using IEC 61850 process bus technology. Sample count uniquely identifies the time instance when an analog measurement was taken, before it was converted to a digital value. Sampling shall be synchronized with a +/- 4-μs per [10] or even a +/-1 μs of time accuracy[1]. Synchronization to a global time reference is not required, but sampling of all signals used in a protection scheme shall be synchronized to a common reference. Sampling synchronization errors lead to sample shifts, i.e., phase errors that can compromise protection scheme reliability (security and dependability).

Fiber-optic sensors in the system deployed for this project use optical 1 pulse per second (PPS) signal for sampling synchronization, per UCA IEC 61850-9-2LE [3]. Protective relays and Ethernet switches are synchronized over Precision Time Protocol, IEC/IEEE 61850-9-3:2016 base profile [11].

As shown on the overall system architecture on Figure 7, a GPS traceable clock from the utility is used as a time reference. This time is distributed over PTP through PTP capable Ethernet switches to protective relays and conventional merging units.

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[1] Note that while time accuracy term is commonly used, it is really precision that matters most. Accuracy is defined as a deviation from a mean value, but the mean value itself may have an offset from a reference. Precision includes both an offset and a deviation.

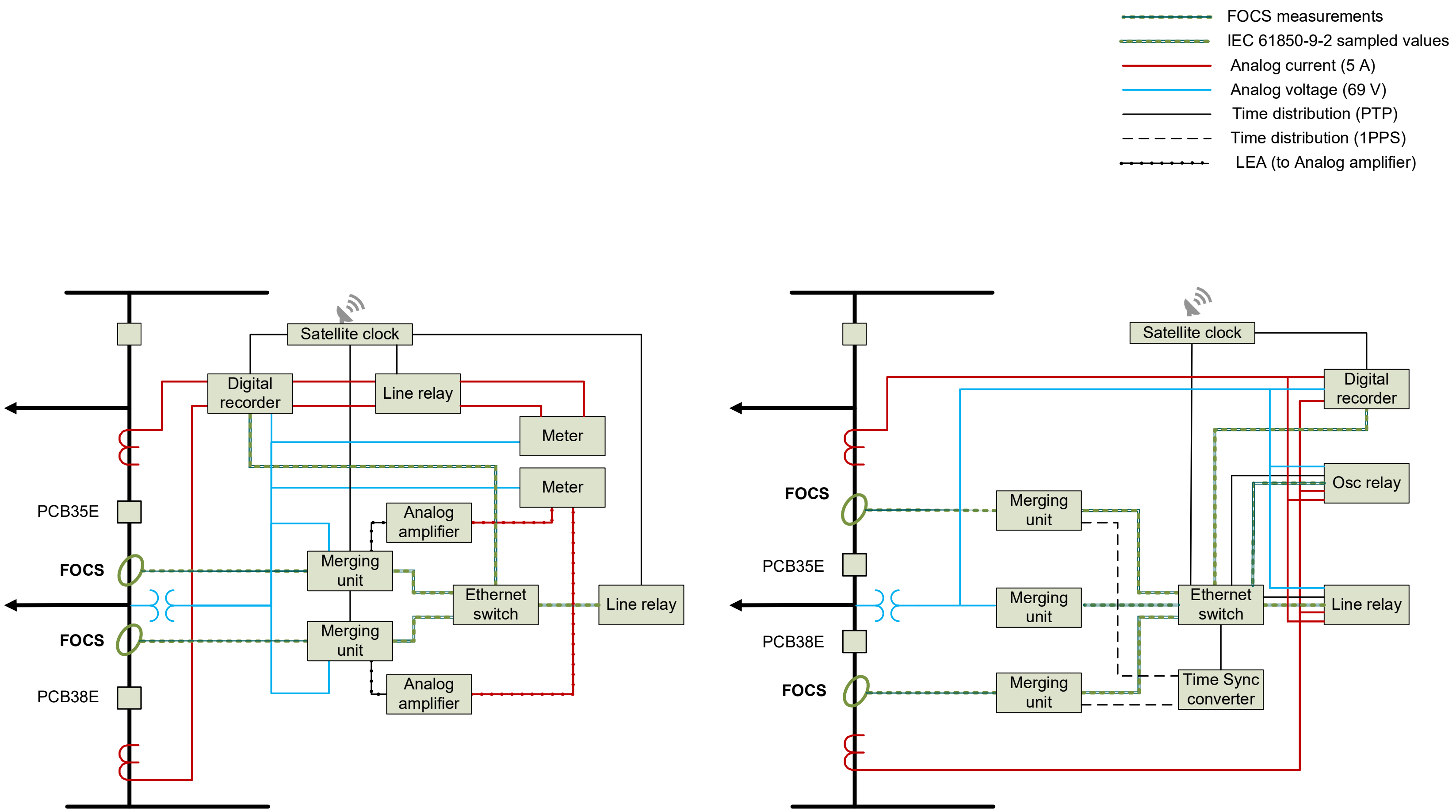


Figure 7 Overall System Architecture with both vendors setups shown (Satellite clock and Digital recorder are common)

These Ethernet switches can become a PTP grandmaster in the system, if required. A MU time sync module for one vendor as well supports time distribution conversion function. This module receives time over PTP and outputs optical 1PPS signals to up to 8 recipients. Two of these outputs are connected to two FOCS devices installed in substation yard.

Ethernet switches (or bridges; per IEEE term), forward sampled values data from all MUs to all protective relays. They also act as PTP transparent clocks in the time distribution chain.

For one vendor, relays receive analog signals from hard-wired conventional copper inputs and process bus-based connections. Another vendor relay uses process bus-based inputs, while an in-service line relay with conventional connections is used for comparisons. A Digital recorder provided by BPA receives and captures both process bus-based signals and conventionally connected currents and voltages.

Thus, the whole system receives bus voltage, bus and tie circuit-breaker currents over both conventional copper connections and process bus-based connections. Process bus-based currents are streamed by FOCS devices over fiber-optic Ethernet connections. These signals feed into Line relays (executing impedance-based and other protection functions) and Osc relay that monitors current and voltage oscillations occurring at different frequencies to identify dominating modes. The Osc relay uses conventional and process bus-based connections as well.

Please note that all relays in this project monitor currents and potentials, are not controlling BPA system equipment.

### B. Installed equipment

FOCS units were mounted on six single-phase circuit breakers; one of the two manufacturer's sensors on each side. Breaker bushings are shown on Figure 8. Installed FOCS devices are shown on Figure 9.

Figure 8. Breaker bushings

Figure 9. FOCS devices from two vendors installed on a 500kV circuit breaker.

Both FOCS systems' toroidal current sensors were mounted to the breakers' bushing bases using a BPA stainless steel clamp design. The design was proven at BPA – Ross Complex using a spare system breaker of the same make and model at Garrison. Proper dielectric withstand clearance distances, snow, ice wind loading and mechanical failure modes were evaluated and approved by the relevant BPA design groups.

Location of the vendors cabinets installed in the substation field, are shown on Figure 10.

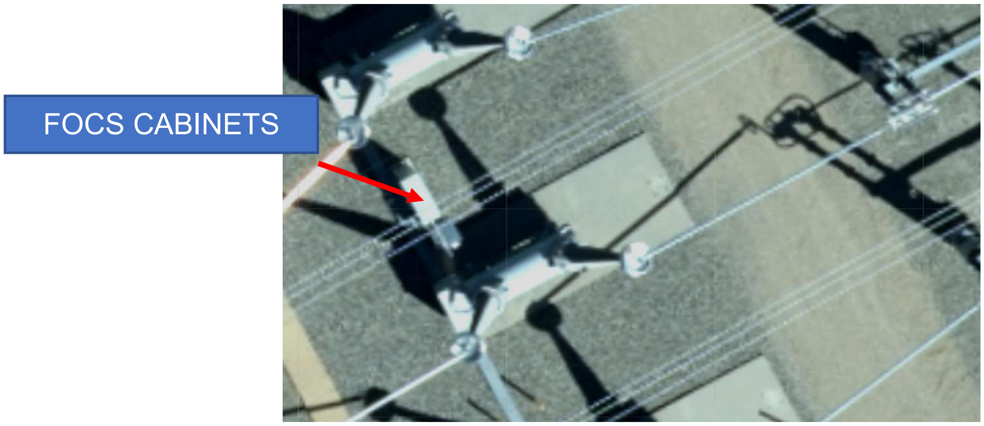


Figure 10. Vendors cabinets location in substation yard

Cabinets and their content for both vendors are shown on Figure 11 and Figure 12.

As shown on Figure 11 one manufacturer's installation included small cabinets in the substation yard for the MUs. These are installed near the breakers as the length of the specially calibrated fiber-optic cable used between the sensor and MU is limited and is shorter than the distance to the substation control house.

Another vendor also installed small cabinets in the substation yard, but mainly to splice cables, as their MUs were installed in the substation control house, see Figure 12 below.

Figure 11 One vendor cabinet with FOCS electronics module installed in the yard

Additionally, the sensor protruding from the upper right of this cabinet provides temperature compensation to the FOCS MUs installed in the substation control house. Temperature compensation in the FOCS systems is crucial for maintaining measurement accuracy. The wide ambient temperature variations at this installation site provide a good test case.

Figure 12. Another vendor cabinet with fiber cables installed in the yard

Panels installed in control house are shown on Figure 13. One vendor has current merging units, recorder and Line relay in the left rack. The middle rack has the system clock and the BPA monitoring equipment, including a digital recorder for sampled values and conventional analog signals. The right rack has another vendor Line relay, Osc relay, voltage merging unit and time sync converter. All three racks have their own Ethernet switches.

Figure 13. Three panels installed in the control house

Rear view of these three panels is shown on Figure 14. Note that voltage merging unit and time sync converter are installed at the rear of one rack.

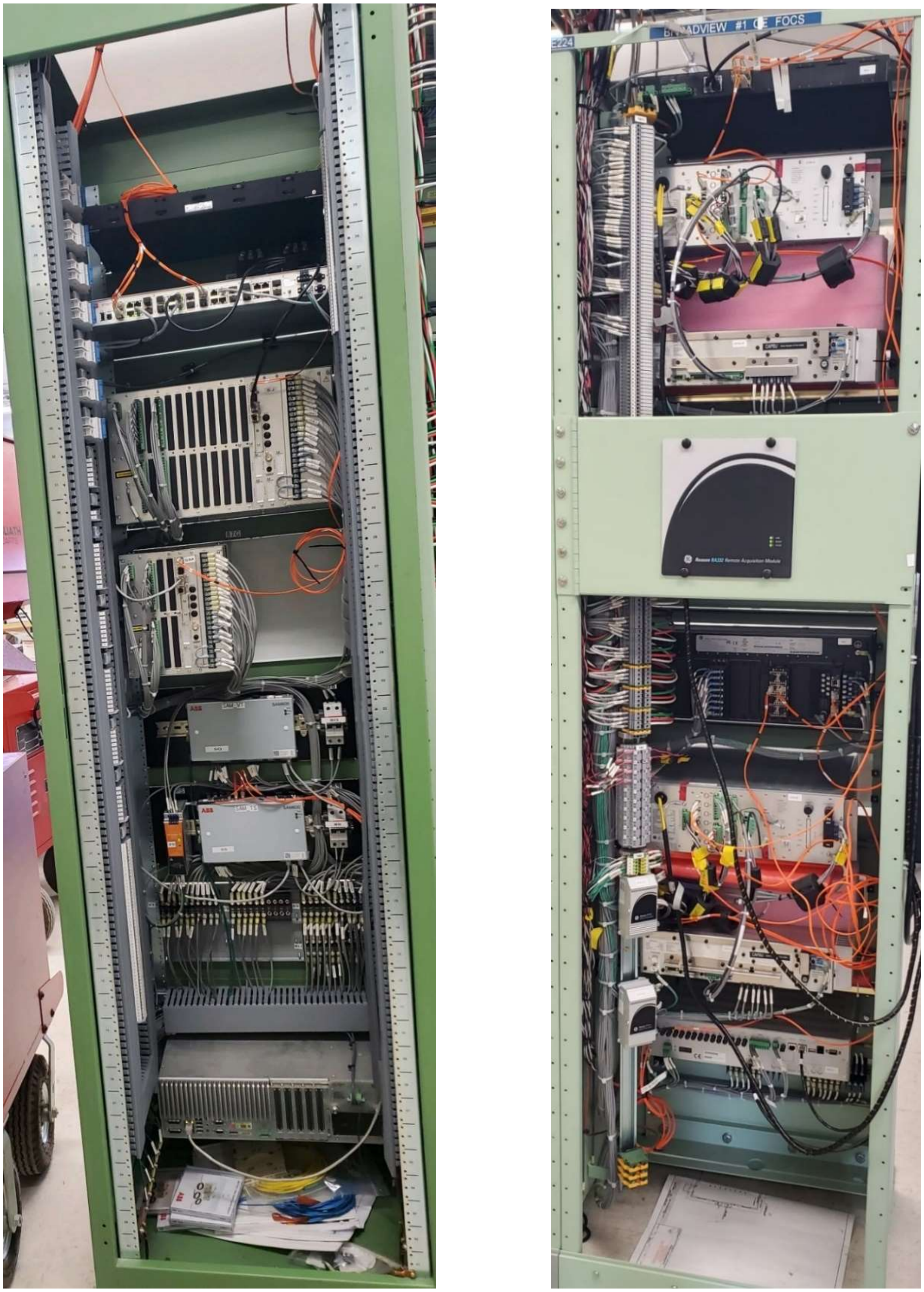


Figure 14. Merging units and interface connections at the rear panels

## III. Comparison of conventional and digital measurements and protection function

### A. Protection functions

One objective of the project for one of the vendors is to compare, in as many ways as possible, the performance of the protection functions fed by conventionally connected analog quantities with identical functions within the same relay fed by a digital connection of the same quantities. The project comprises two protection relays – one a line distance protection relay (Line Relay) and the other a relay set up to measure DC current and subharmonic quantities (Osc Relay). Empirical data will be obtained as more system events data becomes available.

*Line Relay*

Figure 15 illustrates the digital and conventional analog signal connections to the Line Relay, and the internal connection of these quantities to identical functions within the relay. The conventional analog CT and PT signals are connected to the relay via a Transformer Input Module (TRM) within the relay.

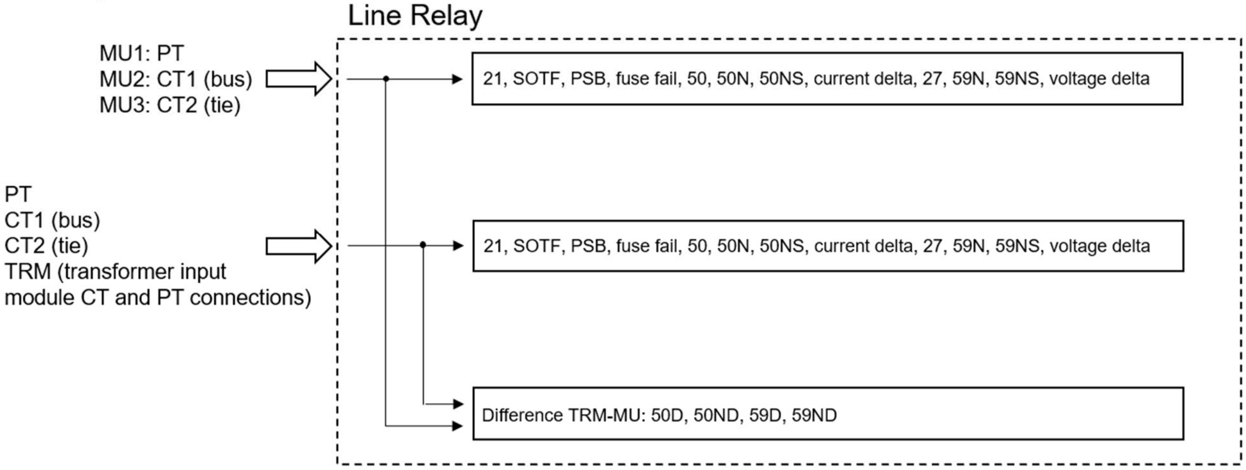


Figure 15. Line Relay traditional and MU (sampled value) analog connections and the internal functions to which these analog quantities are connected

Table 2 List of compared 21-function (and 21-function related) operate signals

| | | | |
|---|---|---|---|
| Zone 1 | Trip A | Time-domain Element Reverse Direction | Pickup A |
| | Trip B | | Pickup B |
| | Trip C | | Pickup C |
| | Pickup Non-directional | Phase Selection Forward Fault | A |
| Zone 2 | Pickup A | | B |
| | Pickup B | | C |
| | Pickup C | Phase Selection Reverse Fault | A |
| | Pickup Non-directional | | B |
| Reverse Zone | Pickup A | | C |
| | Pickup B | SOTF | Trip |
| | Pickup C | Power Swing Blocking Outer Boundary | Pickup |
| Time-domain Element Forward Direction | Pickup A | | |
| | Pickup B | Power-Swing Blocking | Detected |
| | Pickup C | Fuse Fail | Detected |

Table 2 and Table 3 list the signals included in the performance comparison. For each signal listed, the performance of the TRM-connected function is compared with the performance of the identical MU-connected function.

Table 3 List of compared current and voltage function operate signals

| | | | | |
|---|---|---|---|---|
| Instantaneous Phase Overcurrent | Trip A | | Undervoltage | Pickup A |
| | Trip B | | | Pickup B |
| | Trip C | | | Pickup C |
| Instantaneous Ground Overcurrent | Trip | | Ground Overvoltage | Pickup |
| Negative-sequence Overcurrent | Pickup | | Negative-sequence Overvoltage | Pickup |
| Current Delta Detection | Pickup A | | Voltage Delta Detection | Pickup A |
| | Pickup B | | | Pickup B |
| | Pickup C | | | Pickup C |

Note that the measured currents in Table 3 are the line currents, i.e., CT1 (bus) + CT2 (tie). The same applies to Table 4 and Table 6.

The comparison of performance of each of the operate signals listed in Table 2 and Table 3 above is made as illustrated in Figure 16. Operate signal performance comparison logic

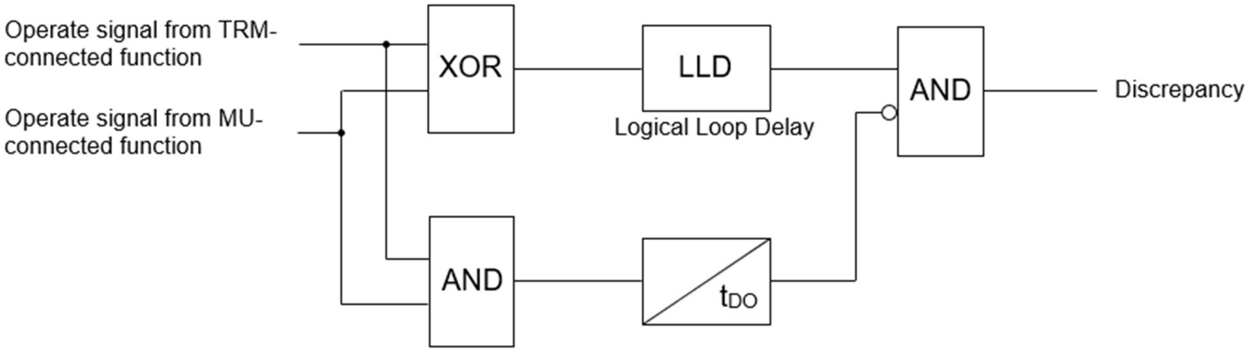


Figure 16. Operate signal performance comparison logic

Each pair of operate signals (one from a TRM-connected function and one from the identical MU-connected function) are connected to an XOR-gate (exclusive OR-gate) and to an AND-gate. If both signals become logic 1 at the same time (within the execution of the same processing loop), the output of the AND-gate becomes logic 1 and blocks any discrepancy declaration. If one signal becomes a logic 1 and not the other signal within the execution of the same processing loop, the output from the XOR-gate becomes logic 1. However, because of the logical loop delay, a discrepancy is not declared immediately when this happens. If the other signal becomes a logic 1 within the execution of the next processing loop, the output of the AND-gate becomes logic 1 and blocks any discrepancy declaration. If the other signal does not become logic 1 within the execution of the next processing loop, the logic declares a discrepancy in the operate performance between the TRM-connected function and the MU-connected function. Note, for no discrepancy to be declared, the functions must issue operate signals not more than one processing loop apart. The drop out timer ensures a discrepancy is not declared during signal reset.

Checking is also made for a discrepancy that could arise in a different way. The difference between the conventionally connected currents and the digital currents (TRM - MU) are fed to overcurrent 50 and 50N functions. Similarly, the difference between the conventionally connected voltages and the digital voltages (TRM - MU) are fed to overvoltage 59 and 59N functions. These 50, 50N, 59 and 59N functions have low set pickup settings (5% of the respective nominal current and voltage values). Therefore, any pickup indicates a conventional current/digital current or conventional voltage/digital voltage difference greater than the set threshold. These are summarized in Table 4 and Table 5.

Table 4. Measured difference between TRM and MU signals

| | | | |
|---|---|---|---|
| Difference (low-set Instantaneous Phase Overcurrent) | Trip A | Difference (low-set Phase Overvoltage) | Pickup A |
| | Trip B | | Pickup B |
| | Trip C | | Pickup C |
| Difference (low-set Instantaneous Ground Overcurrent) | Trip | Difference (low-set Ground Overvoltage) | Pickup |

Table 5. Measured difference between TRM and MU signals

| | |
|---|---|
| Difference CT1 and MU2 (bus-side CT currents) (low-set Instantaneous Overcurrent) | Pickup any phase |
| Difference CT2 and MU3 (tie-side CT currents) (low-set Instantaneous Overcurrent) | Pickup any phase |

A comprehensive selection of both analog and binary signals is connected to the internal disturbance recorder to facilitate a complete and thorough comparative performance analysis following any system event calling for the operation of any of the included protection functions.

Discrepancy between the measured values for line current, phase-to-ground voltage, active power, reactive power, power factor and frequency is also made and if any differ by more than a pre-defined amount, a discrepancy is declared.

*Osc Relay*

Figure 17 illustrates the digital and conventional analog signal connection to the Osc Relay, and the internal connection of these quantities to identical functions within the relay.

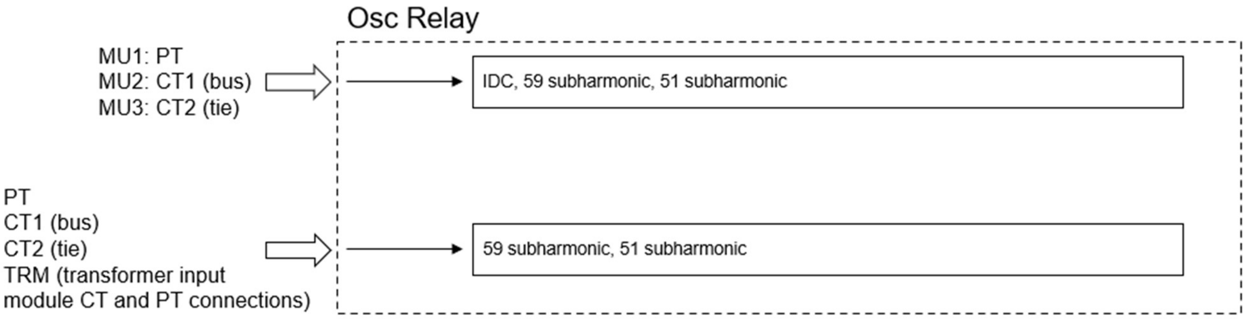


Figure 17. Osc Relay traditional and MU (sampled value) analog connections and the internal functions to which these analog quantities are connected

The digital currents (MU2 and MU3) come from fiber-optic current sensors. The MU2 and MU3 inputs are connected to a generator differential 87G function within the Osc Relay that extracts the DC component in the current for each phase (line current = MU2+MU3). Four levels are assigned, and each time the measured DC current exceeds a level a count is made, separately for each phase. In this way the Osc Relay keeps a log, until reset, of the number of times the assigned levels have been exceeded.

The Osc Relay also extracts selected subharmonic phasors (i.e., magnitude, phase angle and actual frequency) that may be present in the line currents or voltages. Two filters are assigned to the voltage inputs, one connected to the TRM-connected voltage inputs, and one connected to the MU-connected voltage inputs. Both these filters have identical settings with the set frequency for extraction = subharmonic 1. Four filters are assigned to the current inputs, two connected to the TRM-connected current inputs, and two connected to the MU-connected current inputs. Each pair of filters (one TRM-connected and one MU-connected) has identical settings. One pair has the set frequency for extraction = subharmonic 1, and the other pair has the set frequency for extraction = subharmonic 2.

The output from a filter is the phasor with the highest magnitude within the pass frequency band around the set frequency. For the voltage-connected filters this is presently set at ±12Hz around the subharmonic 1 set value (30Hz), and for the current-connected filters this is presently set at ±7Hz around the subharmonic 1 set value (25Hz) as well as the subharmonic 2 set value (35Hz).

The output from each of the voltage-connected filters is connected to an overvoltage function to detect phase-ground overvoltage of the extracted subharmonic phasor. Two overvoltage levels are applied (0.15% and 0.5% of 525kV = $V_{nominal}$).

The output from each of the current-connected filters is connected to an overcurrent function to detect overcurrent of the extracted subharmonic phasors (subharmonic 1 and subharmonic 2). Two overcurrent levels are applied for each (0.1% and 0.5% of 2000A = $I_{nominal}$).

Table 6 lists the signals included in the performance comparison. For each signal listed, the performance of the TRM-connected function is compared with the performance of the identical MU-connected function.

Table 6. List of compared current and voltage function operate signals, TRM-connected functions vs MU-connected functions

| | | | |
|---|---|---|---|
| Overcurrent, subharmonic 1, level 1 | Pickup A | Overvoltage, subharmonic 1, level 1 | Pickup A |
| | Pickup B | | Pickup B |
| | Pickup C | | Pickup C |
| Overcurrent, subharmonic 1, level 2 | Pickup A | Overvoltage, subharmonic 1, level 1 | Pickup A |
| | Pickup B | | Pickup B |
| | Pickup C | | Pickup C |
| Overcurrent, subharmonic 2, level 1 | Pickup A | | |
| | Pickup B | | |
| | Pickup C | | |
| Overcurrent, subharmonic 2, level 2 | Pickup A | | |
| | Pickup B | | |
| | Pickup C | | |

The comparative performance for the operate signals listed in Table 6 is performed exactly as illustrated in Figure 17. Osc Relay traditional and MU (sampled value) analog connections and the internal functions to which these analog quantities are connected

As with the Line Relay a comprehensive selection of both analog and binary signals is connected to the internal disturbance recorder to facilitate a complete and thorough comparative performance analysis.

### B. Optical CT accuracy

The reference iron core current transformer single phase line current analog quantities were measured across single phase current shunts that were connected in series with the in-service line protective relay set 2 current secondary circuits.

Digital instrument transformers feed secondary Intelligent Electronic Devices (IEDs) with accurate measurements of current and voltage. Benefits of using Non-Conventional Instrument Transformers (NCITs) are listed below:

- A wider operating range, and not susceptible to magnetic saturation
- Accurate measurement of DC and AC to the 100th harmonic with excellent phase accuracy
- Low-latency signal processing for measuring fast transients at substations.

This project compared data from the digital recorder with inputs for conventional analog CTs and FOCS devices, refer to Figure 7 for the overall system diagram.

The conventional, 5A output magnetic CTs connect to the digital recorder and to line relays in the substation control house via long copper cables. The output of the FOCS installed at circuit breakers PCB 35E and PCB 38E connect to a substation yard marshaling cabinet, and then via fiber-optic Ethernet cable to merging units and relays in the substation control house. The merging units transmit an IEC 61850-9-2LE sampled values streams to the Ethernet switch. The Ethernet switch feeds both sampled values streams to the digital recorder. A satellite clock synchronizes MU streams and provides time stamping for recorded events.

### C. Metering Accuracy

This project compared the output of the conventional, magnetic CTs with FOCS high-energy analog amplifiers, devices that produce nominal protection-level currents (5A output in this system). Figure 7 shows that the output of the FOCS merging units feed the analog amplifiers via a low-energy analog (LEA) signal. Average magnitude accuracy is within 2 percent, and average angle accuracy is less than 0.5 percent.

Note that these measurements were produced in different meters, both of which are Class 0.1 meters. Calibration inaccuracy between the two meters is a factor, but is negligible.

## IV. Initial Data Captured

Various data were captured by relays and by the digital disturbance recorder.

### A. July 16, 2021 event

An event occurred on July 16, 2021 that demonstrates the response of the FOCS and the conventional CTs. This was a B-Phase to ground fault, digital disturbance recorder record is shown in Figure 18.

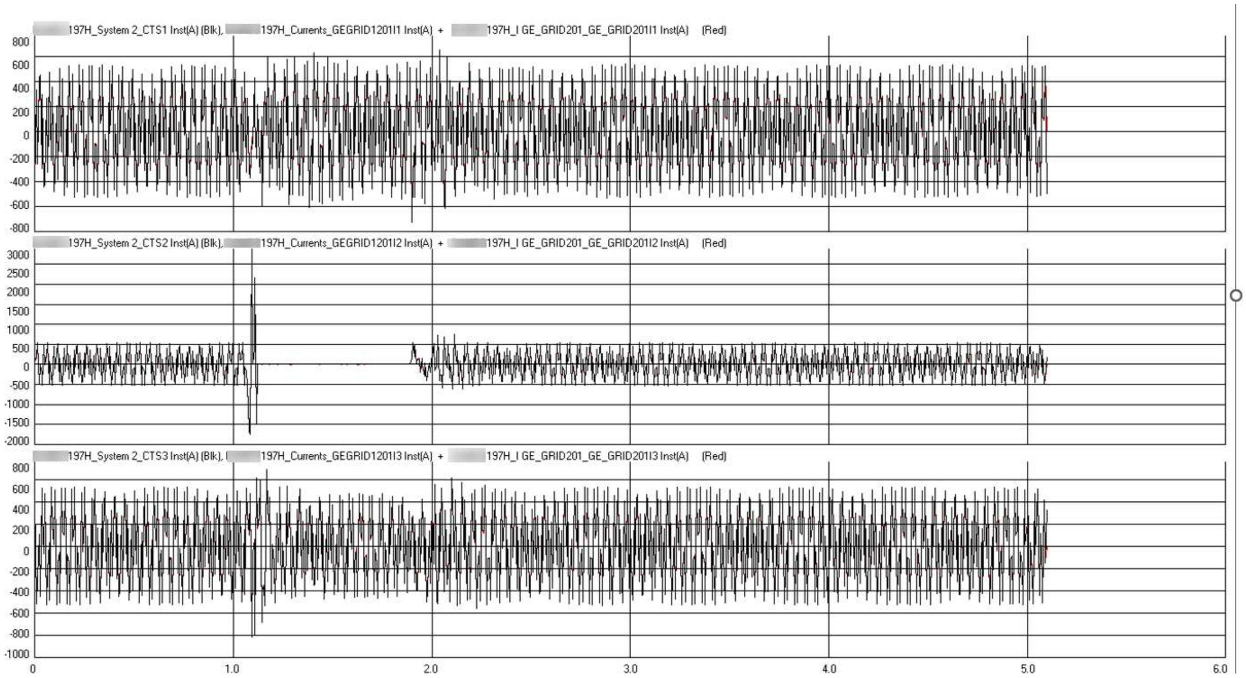


Figure 18. B-Phase phase to ground fault, July 16, 2021

Figure 19 shows a zoomed-in view of the fault occurrence around 1.09 s displays the two current signals. The black line represents the conventional, magnetic CT current, sampled at 10 kHz. The red line is one vendor FOCS current signal sampled at 4.8 kHz. The two traces track very closely in amplitude. In addition, the FOCS representation of current shows negligible latency throughout the recording.

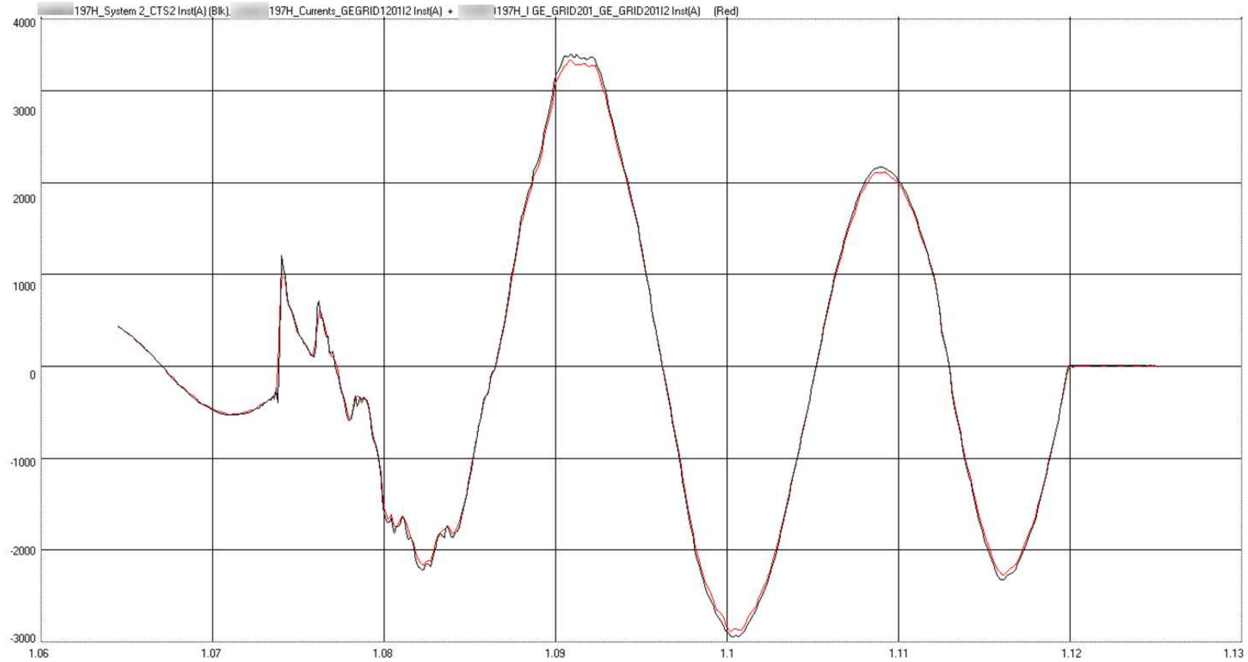


Figure 19. Zoomed-in view of the fault, showing data from one vendor

Zooming in further shows slight magnitude error at the peak current at fault inception at 1.074 seconds, in Figure 20. The magnitude error was 9 percent on the first peak and second peaks. Time latency is within 100 μs.

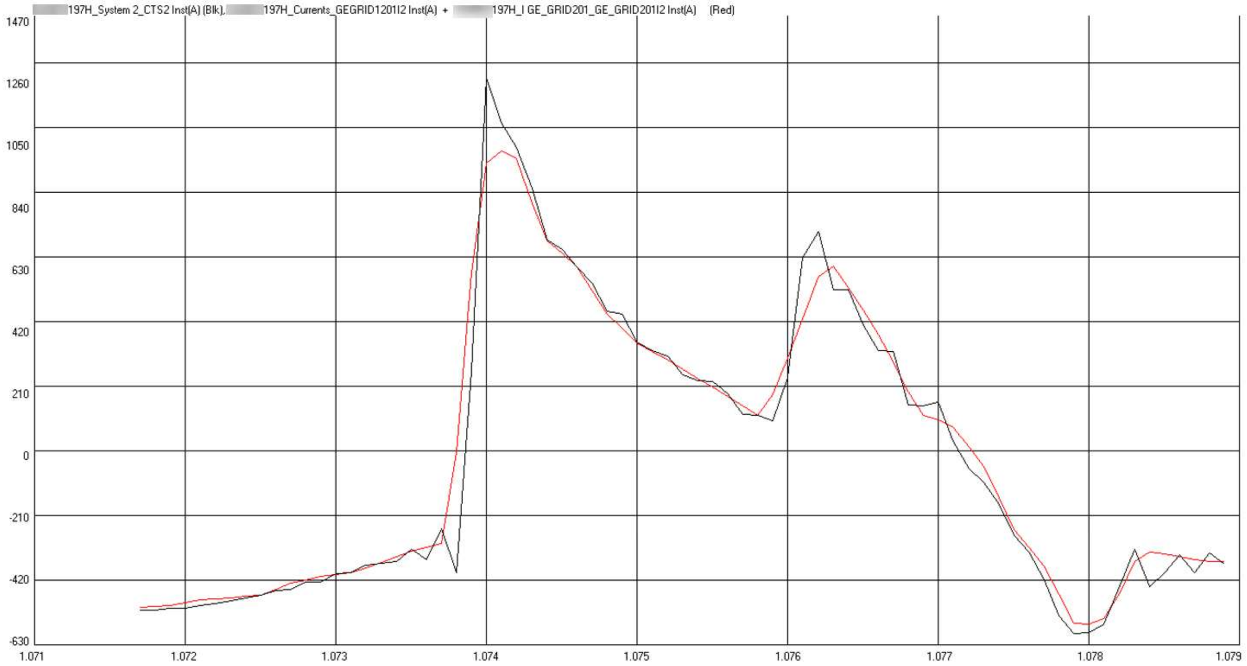


Figure 20. Close-up view of fault-inception peak current, showing data from one vendor

Another vendor relay as well captured the same event.  Figure 21 and Figure 22 illustrate this.

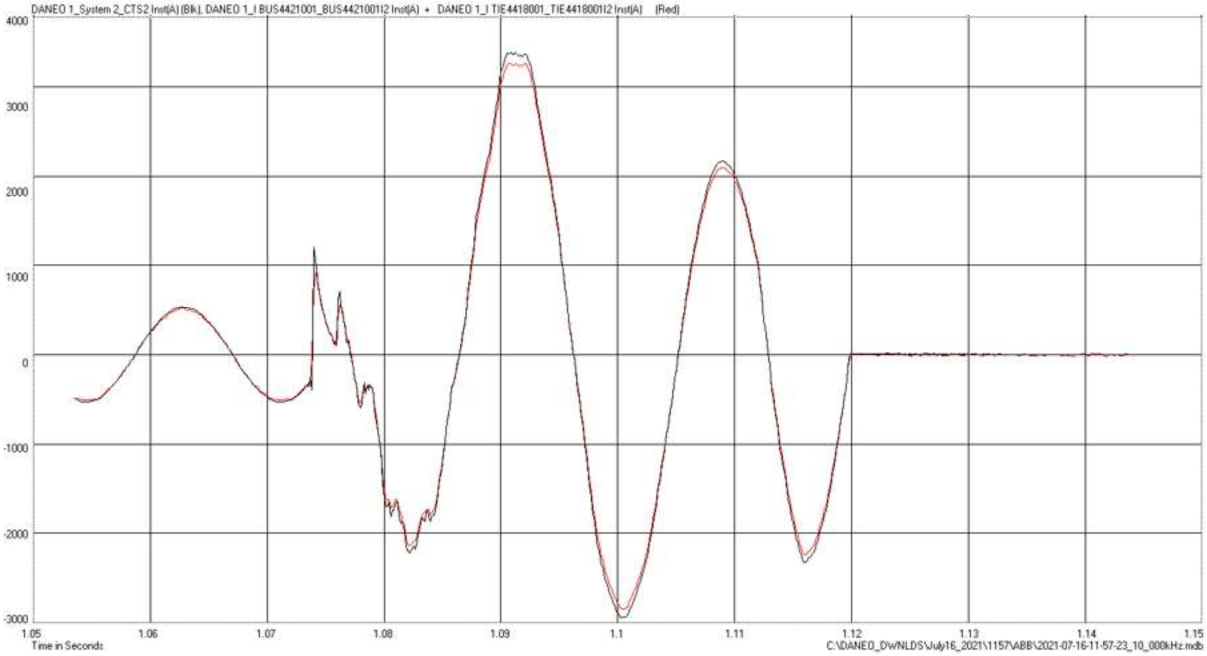


Figure 21. Zoomed-in view of the fault, showing data from another vendor

FOCS latency with regards to shunt current waveform is negligible throughout the recording. B phase shows magnitude error (67.1%) at first peak. Black trace is depicting the shunt current, sampled at 10kHz, and red trace is capturing the FOCS line current from this vendor, sampled at 4.8kHz.

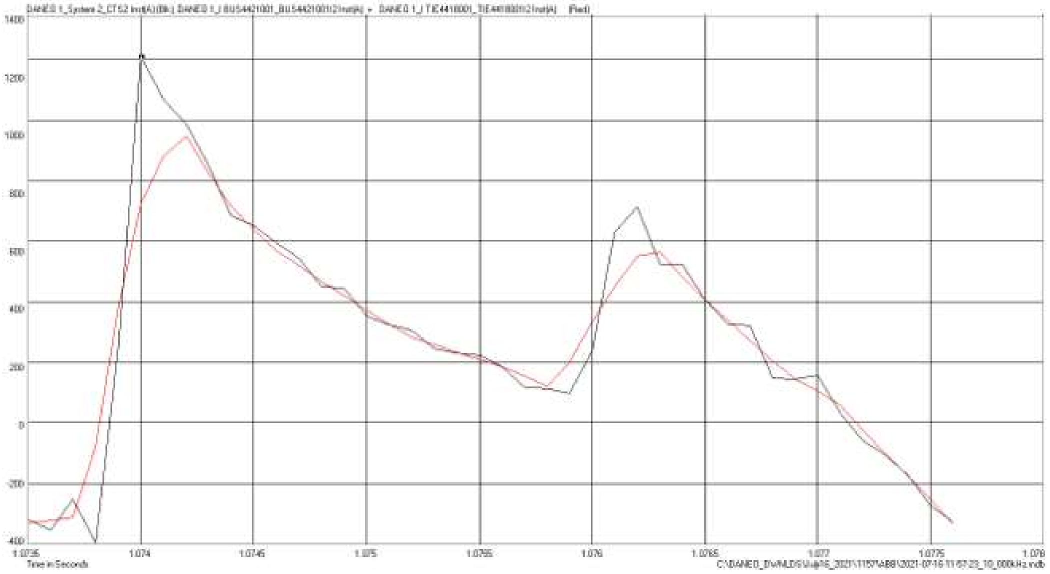
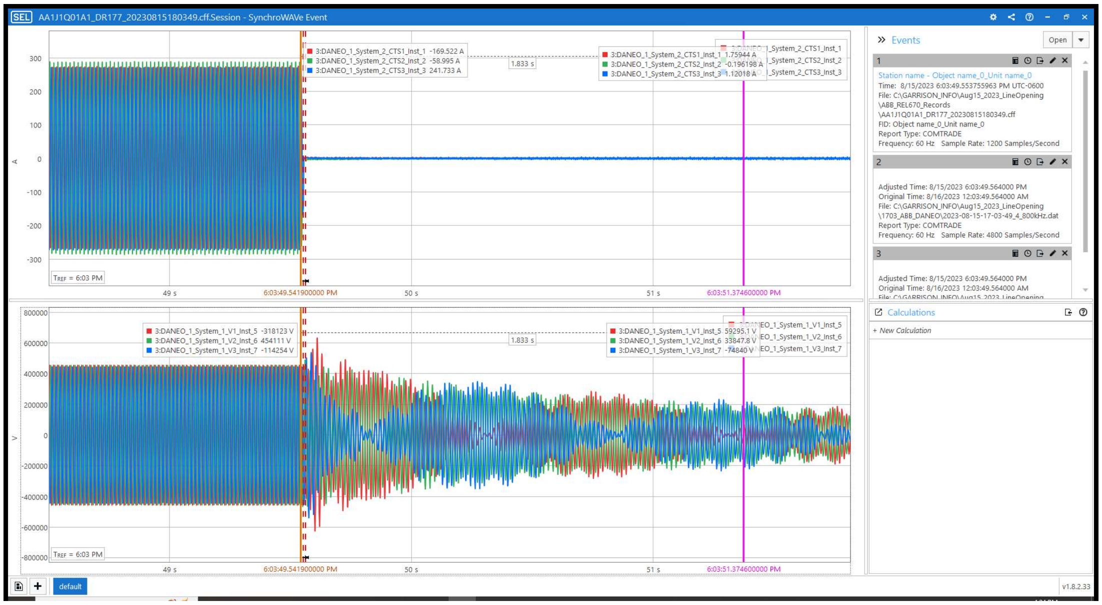


Figure 22. Close-up view of fault-inception peak current, showing data from another vendor

## B. August 15, 2023 event

During a planned site visit the Garrison Broadview #1 500kV line, was found to be out of service. The utility at the Broadview end of the line was cleaning their insulators to reduce number of faults on the line. On August 15, 2023 line switching provided an opportunity to review captured data. The line was supposed to be returned back to service, however, an unexpected line opening occurred after the closing of the bus breaker. This, was followed by a breaker closing a few seconds later.



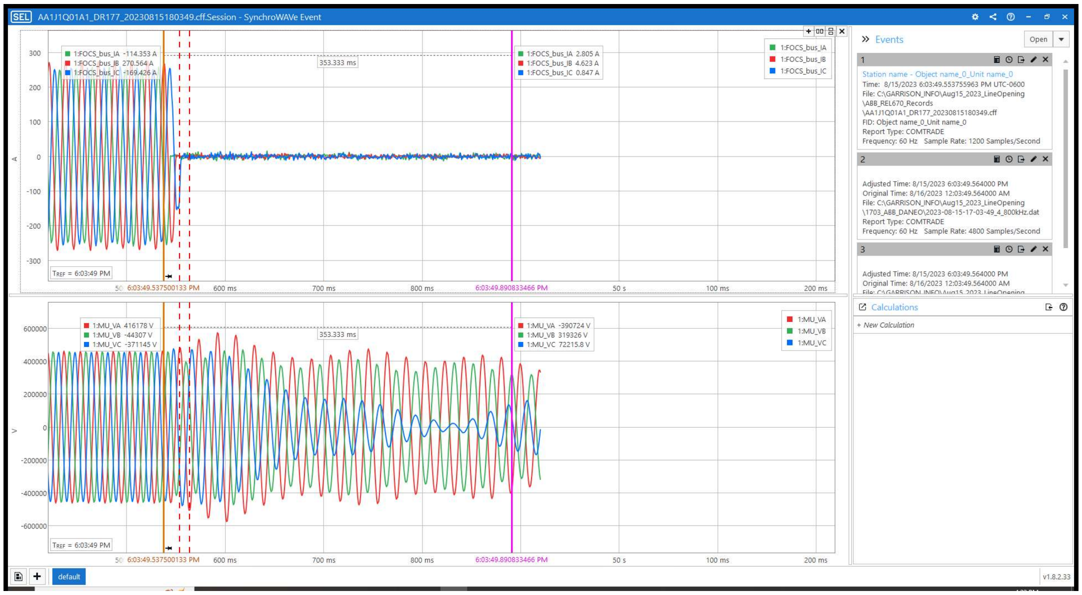
1
Station name - Object name_0_Unit name_0
Time: 8/15/2023 6:03:49.553755963 PM UTC-0600
File: C:\GARRISON_INFO\Aug15_2023_LineOpening\ABB_REL670_Records\AA1J1Q01A1_DR177_20230815180349.cff
FID: Object name_0_Unit name_0
Report Type: COMTRADE
Frequency: 60 Hz Sample Rate: 1200 Samples/Second

2
Adjusted Time: 8/15/2023 6:03:49.564000 PM
Original Time: 8/16/2023 12:03:49.564000 AM
File: C:\GARRISON_INFO\Aug15_2023_LineOpening\1703_ABB_DANEO\2023-08-15-17-03-49_4_800kHz.dat
Report Type: COMTRADE
Frequency: 60 Hz Sample Rate: 4800 Samples/Second

3
Adjusted Time: 8/15/2023 6:03:49.564000 PM
Original Time: 8/16/2023 12:03:49.564000 AM

Figure 23 Digital recorder record for Line Trip with PCB 38E (bus), August 15, 2023

Digital recorder data for the PCB 38E (bus) breaker opening is shown on Figure 23, and closer up view of this event is depicted on Figure 24.



1
Station name - Object name_0_Unit name_0
Time: 8/15/2023 6:03:49.553755963 PM UTC-0600
File: C:\GARRISON_INFO\Aug15_2023_LineOpening\ABB_REL670_Records\AA1J1Q01A1_DR177_20230815180349.cff
FID: Object name_0_Unit name_0
Report Type: COMTRADE
Frequency: 60 Hz Sample Rate: 1200 Samples/Second

2
Adjusted Time: 8/15/2023 6:03:49.564000 PM
Original Time: 8/16/2023 12:03:49.564000 AM
File: C:\GARRISON_INFO\Aug15_2023_LineOpening\1703_ABB_DANEO\2023-08-15-17-03-49_4_800kHz.dat
Report Type: COMTRADE
Frequency: 60 Hz Sample Rate: 4800 Samples/Second

3
Adjusted Time: 8/15/2023 6:03:49.564000 PM
Original Time: 8/16/2023 12:03:49.564000 AM

Figure 24 Zoomed-in view of Line Trip on August 15, 2023

One vendor FOCS currents (sum of bus and tie breaker) and shunt current are captured on Figure 25. The sum of FOCS currents is shown in Red, and shunt current is shown in Blue.

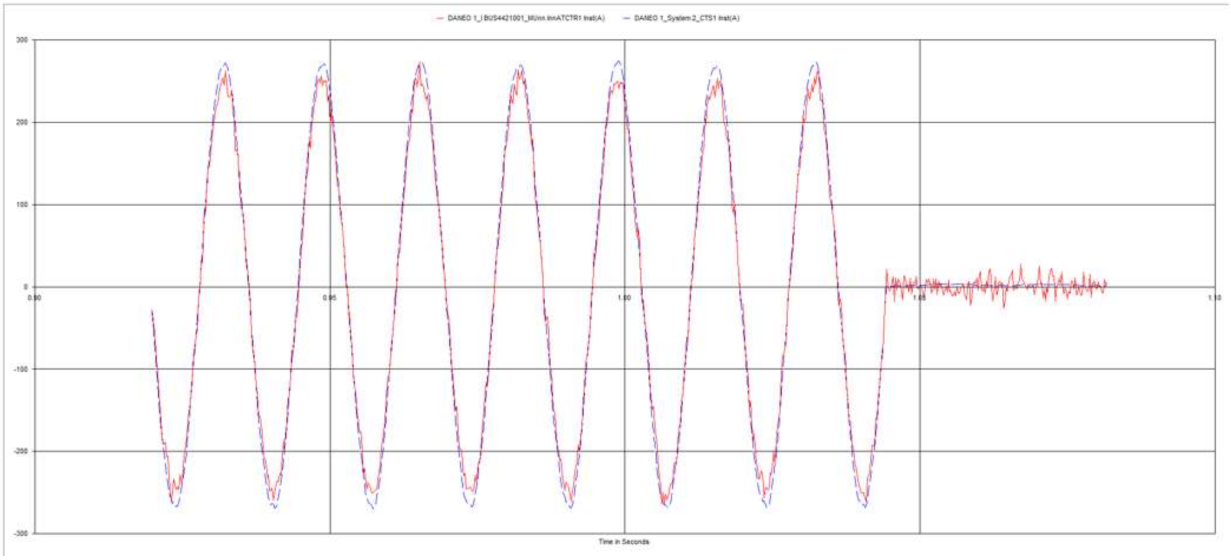
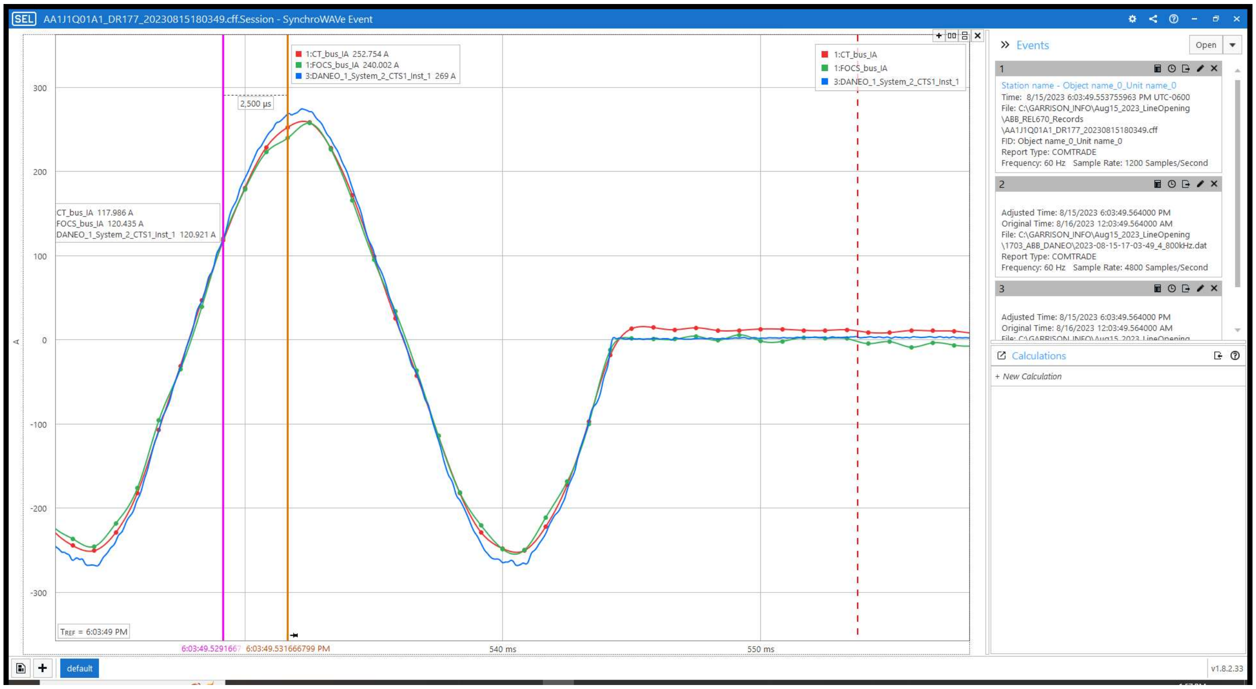


Figure 25. One vendor FOCS currents and shunt current

A closer up view of the A phase current for the same vendor, comparing conventional CT current (Red), FOCS current (Green) and shunt current (Blue) is provided on Figure 26.



🟥 1:CT_bus_IA 252.754 A
🟩 1:FOCS_bus_IA 240.002 A
🟦 3:DANEO_1_System_2_CTS1_Inst_1 269 A

CT_bus_IA 117.986 A
FOCS_bus_IA 120.435 A
DANEO_1_System_2_CTS1_Inst_1 120.921 A

🟥 1:CT_bus_IA
🟩 1:FOCS_bus_IA
🟦 3:DANEO_1_System_2_CTS1_Inst_1

1
Station name - Object name_0_Unit name_0
Time: 8/15/2023 6:03:49.553755963 PM UTC-0600
File: C:\GARRISON_INFO\Aug15_2023_LineOpening\ABB_REL670_Records\AA1J1Q01A1_DR177_20230815180349.cff
FID: Object name_0_Unit name_0
Report Type: COMTRADE
Frequency: 60 Hz Sample Rate: 1200 Samples/Second

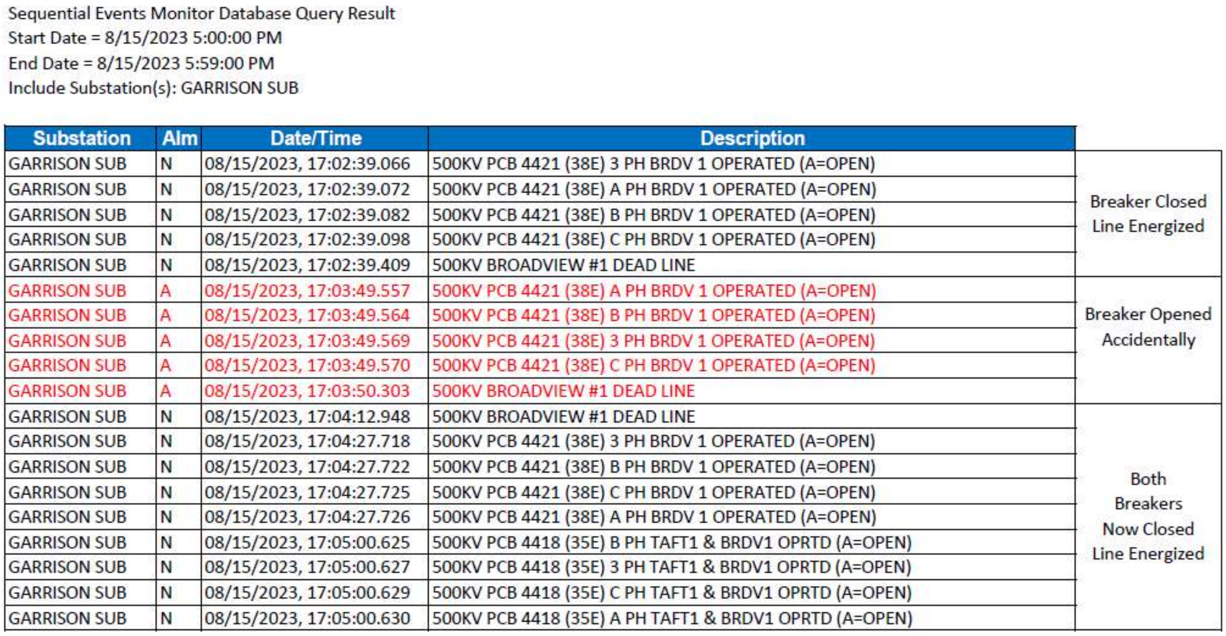
2
Adjusted Time: 8/15/2023 6:03:49.564000 PM
Original Time: 8/16/2023 12:03:49.564000 AM
File: C:\GARRISON_INFO\Aug15_2023_LineOpening\1703_ABB_DANEO\2023-08-15-17-03-49_4_800kHz.dat
Report Type: COMTRADE
Frequency: 60 Hz Sample Rate: 4800 Samples/Second

3
Adjusted Time: 8/15/2023 6:03:49.564000 PM
Original Time: 8/16/2023 12:03:49.564000 AM

Figure 26. One vendor event record for A phase current at bus breaker CT, FOCS and shunt

The Garrison Substation's Sequential Events Monitor captured the unexpected breaker opening and breaker closing a few seconds after. Timestamps in Sequential Events Monitor and records capture by digital recorder and relays' disturbance recorder are closely aligned.

A list of events pertaining these operations is depicted on Figure 27.



Sequential Events Monitor Database Query Result
Start Date = 8/15/2023 5:00:00 PM
End Date = 8/15/2023 5:59:00 PM
Include Substation(s): GARRISON SUB

| Substation | Alm | Date/Time | Description | |
|---|---|---|---|---|
| GARRISON SUB | N | 08/15/2023, 17:02:39.066 | 500KV PCB 4421 (38E) 3 PH BRDV 1 OPERATED (A=OPEN) | Breaker Closed Line Energized |
| GARRISON SUB | N | 08/15/2023, 17:02:39.072 | 500KV PCB 4421 (38E) A PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:02:39.082 | 500KV PCB 4421 (38E) B PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:02:39.098 | 500KV PCB 4421 (38E) C PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:02:39.409 | 500KV BROADVIEW #1 DEAD LINE | |
| GARRISON SUB | A | 08/15/2023, 17:03:49.557 | 500KV PCB 4421 (38E) A PH BRDV 1 OPERATED (A=OPEN) | Breaker Opened Accidentally |
| GARRISON SUB | A | 08/15/2023, 17:03:49.564 | 500KV PCB 4421 (38E) B PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | A | 08/15/2023, 17:03:49.569 | 500KV PCB 4421 (38E) 3 PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | A | 08/15/2023, 17:03:49.570 | 500KV PCB 4421 (38E) C PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | A | 08/15/2023, 17:03:50.303 | 500KV BROADVIEW #1 DEAD LINE | |
| GARRISON SUB | N | 08/15/2023, 17:04:12.948 | 500KV BROADVIEW #1 DEAD LINE | Both Breakers Now Closed Line Energized |
| GARRISON SUB | N | 08/15/2023, 17:04:27.718 | 500KV PCB 4421 (38E) 3 PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:04:27.722 | 500KV PCB 4421 (38E) B PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:04:27.725 | 500KV PCB 4421 (38E) C PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:04:27.726 | 500KV PCB 4421 (38E) A PH BRDV 1 OPERATED (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:05:00.625 | 500KV PCB 4418 (35E) B PH TAFT1 & BRDV1 OPRTD (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:05:00.627 | 500KV PCB 4418 (35E) 3 PH TAFT1 & BRDV1 OPRTD (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:05:00.629 | 500KV PCB 4418 (35E) C PH TAFT1 & BRDV1 OPRTD (A=OPEN) | |
| GARRISON SUB | N | 08/15/2023, 17:05:00.630 | 500KV PCB 4418 (35E) A PH TAFT1 & BRDV1 OPRTD (A=OPEN) | |

Figure 27. Substation Sequential Events Monitor capture for August 15, 2023 event

## V. Conclusions

This paper describes a hybrid multivendor substation system deployed for a 500kV transmission line in BPA system. Various lessons were learned while designing, commissioning and operating this system. Among main challenges encountered is the project schedule that coincided with COVID-19 pandemic, making all project stages more difficult and lengthier. Various lessons were learned on this journey, including thorough wiring checks, hardware health assessments and replacements, firmware updates for relays and communication devices, configuration updates to capture all data of interest and avoid excessive triggering. It was also discovered that use of FOCS in the lab provides only limited testing capabilities, and field testing is required for complete assessments. As one of the key project objectives is to obtain as much useful data as possible, the data collection and analysis will continue as more events occur.

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Adrienne Pradith – Outdoor design, Technician
Craig Basta – Outdoor design, Technician
John Bussard – Garrison SPC Craftsman
Wade Murphy and the Garrison Outdoor Field Crew

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