

# Use of Resistive Voltage Dividers for Transformer Tertiary Ground Detection

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## Abstract:

The Bonneville Power Administration (BPA) has a ‘tertiary ground detection’ scheme that detects line-to-ground faults by looking for an imbalance in the delta—configured transformer tertiary windings. This is a rather complex arrangement involving special 25-Hz PTs and auxiliary PTs all carefully designed to avoid Ferro-resonance. Despite these precautions, high voltage fuses feeding the PTs in this scheme still occasionally blow, resulting in unwanted outages necessary to replace them.

Engineers at BPA have proposed the use of off-the-shelf resistive voltage dividers (sensors) to measure the voltage to ground on each phase. These are robust, inexpensive, and immune to Ferro-resonance. The output of the sensor is measurable by a modern digital relay, which would detect the imbalance and react accordingly. Engineers must take into account the impact of the parallel resistance of the measuring relay to resistance of the voltage divider. Another consideration is that the cable length for these sensors is limited. The relay must measure the output voltage of the sensors near the structure where they are to be installed. 61850-compliant relays have been configured for this application using merging units for the remote sensing required for this scheme. These relays and their respective merging units are to be tested in the lab using real time based digital power system simulators (RTDS). Following the computer modeling and lab testing, the proposed scheme is to be demonstrated at the BPA Medium Power Lab on the Ross complex in Vancouver, WA. The Medium Power Lab is fed from a transformer bank which is already equipped with a conventional tertiary ground detection scheme. Full and partial line-to-ground faults will be applied to this feeder as needed to test the scheme.

This paper will describe the existing the scheme, the proposed scheme, the modeling and lab testing of the scheme, and an analysis of the data collected from the results of the stage fault testing of the new scheme.

## 1. Introduction:

Large power transformers often have three windings: primary, secondary, and tertiary. Tertiary windings are generally connected in delta configuration. The delta winding is commonly used to supply station service power to devices such as cooling fans and pumps located on the transformer bank. A single ground on the delta bus will not result in ground fault current because except for shunt capacitance it is largely isolated from ground. If the system is loaded, the resulting low currents from faults are difficult to distinguish from noisy loads or switching events. Voltage measurement systems are usually applied to the detect faults on ungrounded systems. There is significant phase shift in the voltage when the one of the delta connected phases is grounded. Traditional voltage transformers (VT) connected to ungrounded voltage systems can develop Ferro-resonance oscillations between the ground capacitance and the

transformer characteristics caused by switching operations or from arcing ground faults. Depending on system conditions, the Ferro-resonance oscillations may lead to higher phase-to-ground voltages than normal which results in repetitive saturation of the transformers that cause high currents. These conditions lead to overheating and eventual failure of the potential transformers. [1] During a ground fault condition, the insulation across the transformer tertiary winding is severely stressed and can fail. The insulation rating of the tertiary winding and the lightning arresters is based on the normal phase to neutral voltage. When a ground occurs, the phase to neutral voltage increases by a factor of the square-root-of-three. A ground fault on the tertiary of a BPA transformer caused the lightning arrester to explode. For these reasons BPA has applied a unique voltage sensing scheme that has been largely successful in protecting the voltage transformers from Ferro-resonance oscillations but has been less than reliable.

## 2. BPA tertiary ground scheme:

Figure 1 shows a typical 3- winding Auto-Transformer Bank. The 230 kV windings are connected as a grounded wye, but the 13.8 kV tertiary windings are connected in delta configuration. Usually, this delta winding is used to supply station service power to devices such as cooling fans and pumps located on the transformer bank.

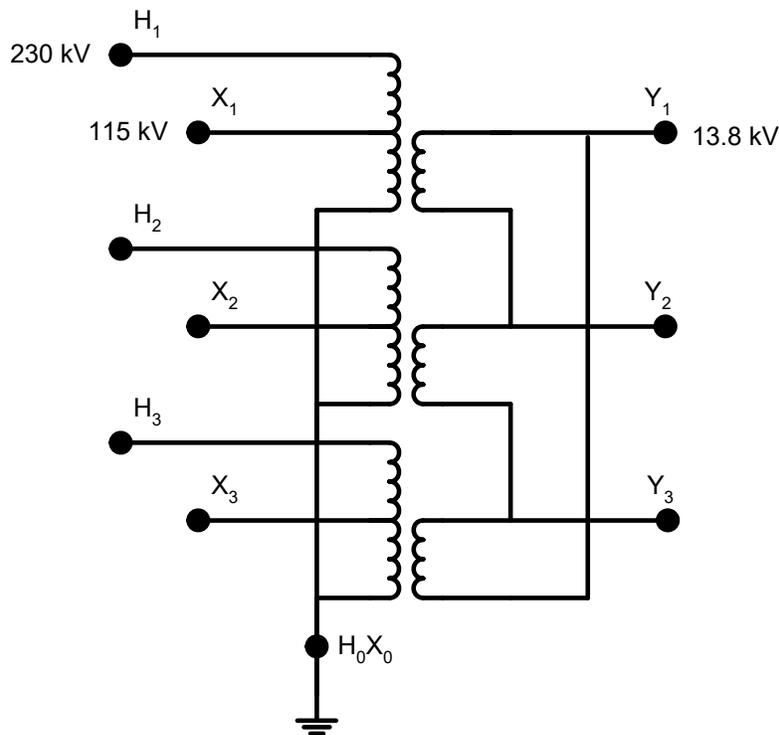


Figure 1 – Typical 3-Winding Auto Transformer Bank

The tertiary ground detector is used to detect a ground on any phase of the 13.8 kV delta winding, transmit an alarm to SCADA, trigger the station event recorder and trip the bank. Maintenance crews are then dispatched to correct problems.

The tertiary ground detector schematic diagram is shown as Figure 2. Note that the scheme consists of 3 small power transformers with their secondaries connected to an auxiliary broken delta connected transformer. The broken delta is connected to a Voltage relay.

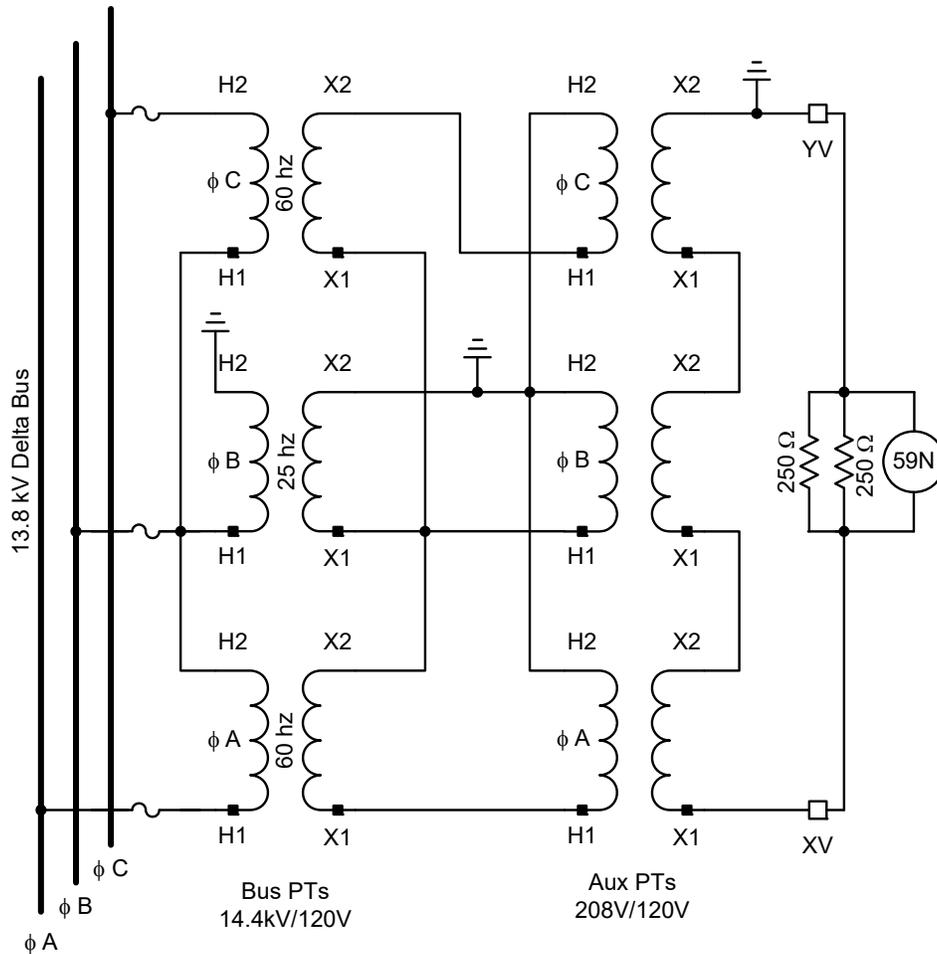


Figure 2 – BPA Tertiary Ground Detector Scheme

Figure 7 shows a detailed schematic of the detector. On the left, the transformer represents the 13.8 kV delta winding of the main power transformer. This is the transformer being monitored for a grounded phase. The ground detector consists of three voltage transformers with the ratio of 14,400-120 volts.

Transformer #1 is a single phase, 60 Hz station service type transformer connected A-phase to B-phase.

Transformer #2 is a single-phase 25 Hz station service type transformer connected B-phase to ground. The 25 Hz transformer has a large impedance that is the same size 60 Hz transformer, thus preventing any Ferro-resonance from occurring.

Transformer #3 is the same type as A-phase, however it is connected B-phase to C-phase. Under normal conditions, the voltage across the relay is 0 volts. All the voltages of the broken delta configuration balance each other out, and they sum to zero. However, a ground on one phase of the delta will cause an imbalance within the broken delta which results in 120 volts across the XVA-YVC terminals (see Figure 2). This voltage causes the Voltage relay to pick-up.

Table 1-1 shows the relay voltage for the grounding of each phase.

Table 1 Open Delta Voltages on Ground Tertriary Scheme.

	No Ground	AØ Grounded	BØ Grounded	CØ Grounded
Voltage VXVA-YVC	0 Volts	115 $\angle 150^\circ$ Volts	115 $\angle 30^\circ$ Volts	115 $\angle -90^\circ$ Volts

This scheme has demonstrated to be successful, however BPA still experiences blown fuses feeding the PTs in this scheme leading to unwanted outages that are necessary to replace them.

### 3. Proposed Scheme:

An engineer at BPA proposed a new scheme that utilizes, off-the-shelf resistive voltage dividers connected to ground, to measure the voltage on each phase connected. See Figure 3.

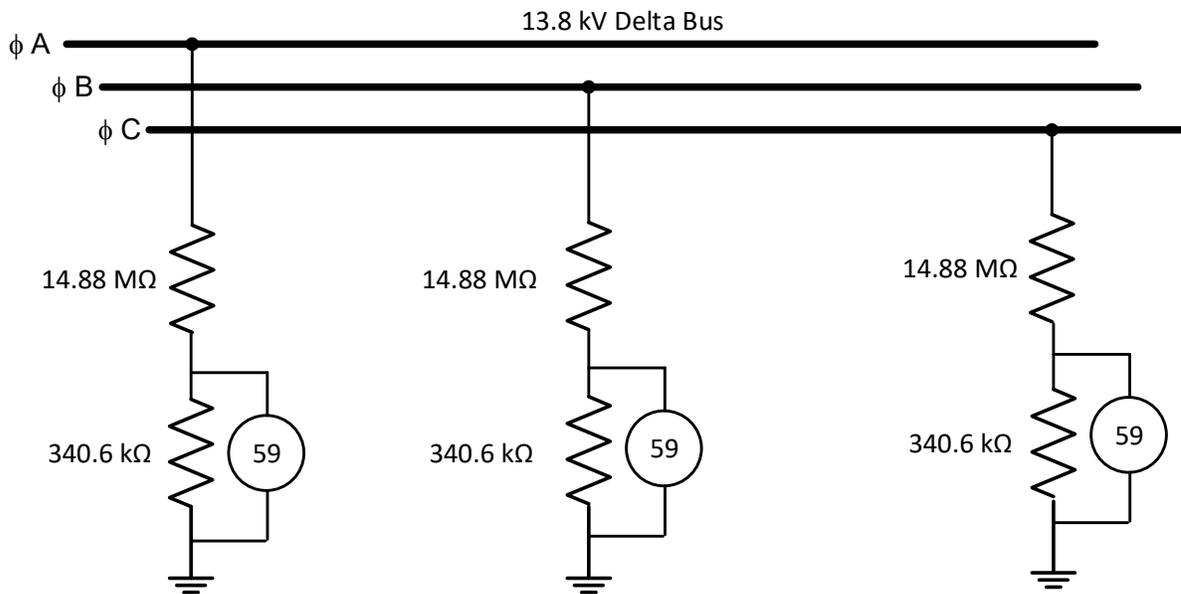


Figure 3 Voltage Shunt Divider Protection Scheme

The resistive voltage dividers consist of a high accuracy (better than 1%), zero-phase shift resistive voltage sensor contained in a body with full electrical and mechanical post insulator

ratings. The shunt resistor is tuned to provide a voltage ratio of sixty-to-one for a voltage sensor with an impedance value 1 Mega-ohm. See Figure 4.

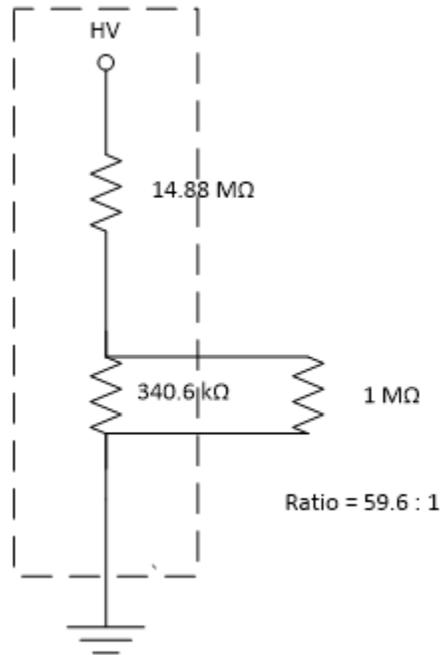


Figure 4 Shunt Voltage divider with tuned Impedance.

Voltage sensors with impedances other than one-Mohm will influence the voltage ratio of the divider. In Figure 5 the voltage ration jumps from 59.6:1 to 69.5 when a sensor with a 600 kilo-ohm voltage sensor.

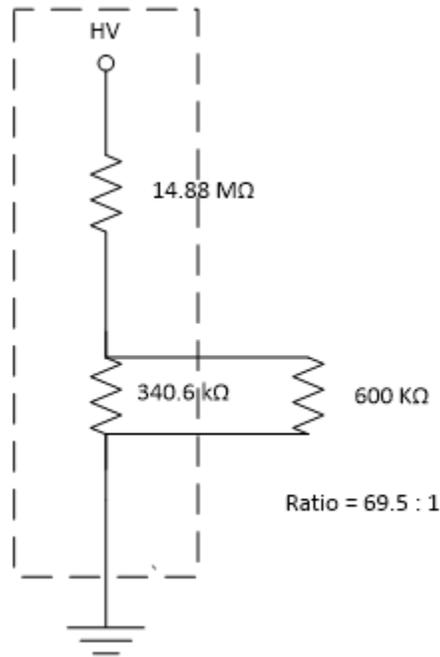


Figure 5 Shunt Voltage Divider with Alternate Impedance

The under voltage settings are on set at 70% of the single-to-line ground base voltages with a five-second pickup delay.

The main hurdle that must be overcome for this to work is that the cable length for these sensors is limited. It has a maximum length of 35' for low voltage cabling. Therefore, the relay must have a fiber-optic front end located at the structure where the sensors are installed. This has become increasingly common with the adoption of 61850-compliant relays.

### **Voltage Measurement**

Dividing resistor selected for the scheme has relatively short leads, thus, the voltage measurement technology has to be able to

1. make sufficiently accurate voltage measurements at the voltage division point in the substation field,
2. make these measurements available to the protective relay located in the substation control building.

Research on the available methods that meet the above requirements turned towards IEC 61850 technology.

### ***Sampled Values and Merging Units***

Sampled Values (SVs) is a concept defined by IEC 61850-9-2 standard [3] for communication-based transmissions of analog data. This technology replaces conventional copper wiring between

instrument transformers and protective relays or intelligent electronica devices (IEDs) per IEC 61850 term, by a fiber optic Ethernet data connection. One can think about this as moving an analog to digital (A/D) converter module out of a microprocessor-based relay and placing it next to the measurement transformer, as shown on Figure 6.

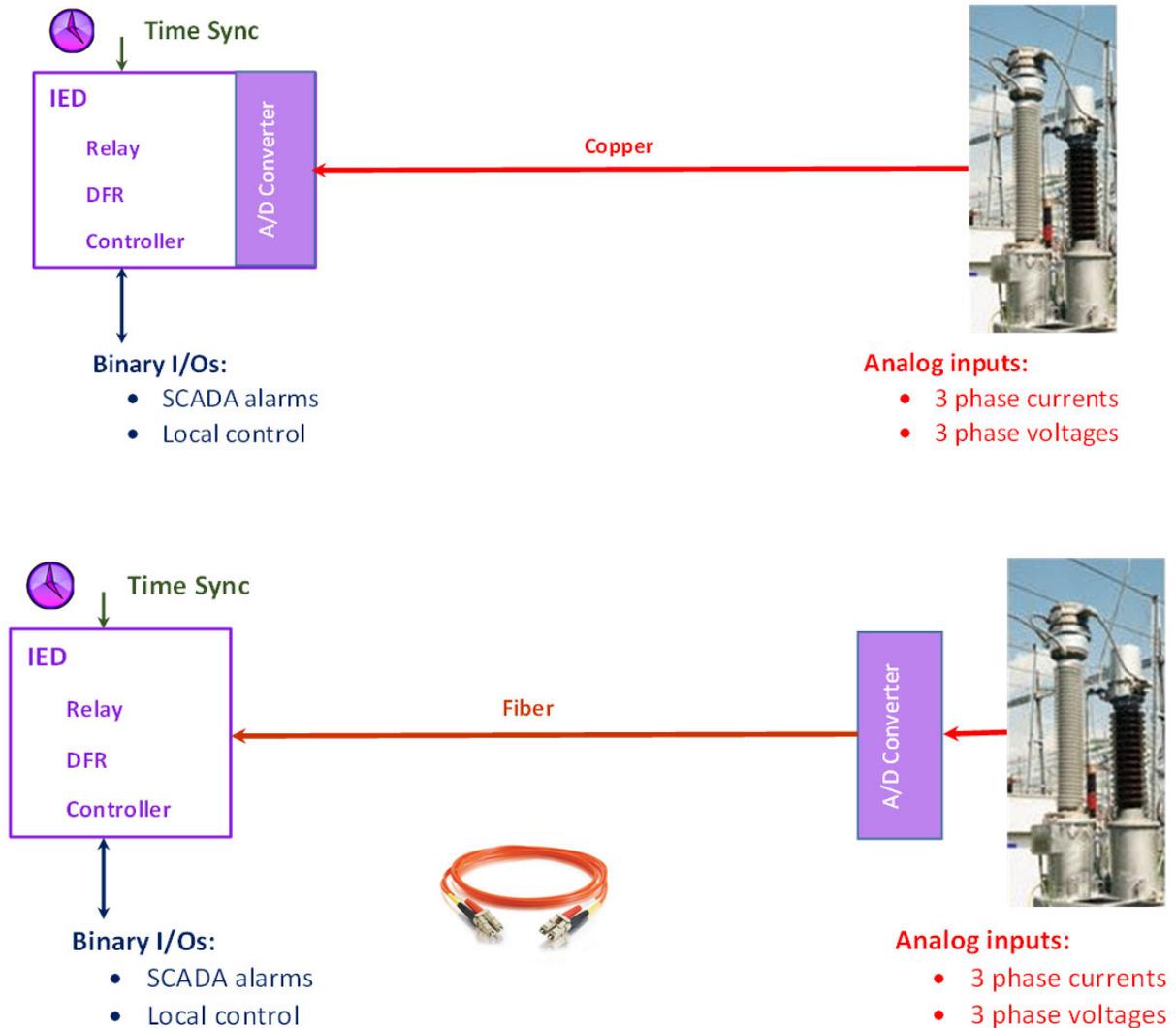


Figure 6. Moving A/D Converter to the data source, e.g. to an instrument transformer

This functionality is supported by devices called Merging Units (MUs). An illustration of MU functionality is shown on Figure 7, including per phase data sampling, samples synchronization and sampled values streaming. Note that NCIT in this picture stands for Non-Conventional Instrument Transformer.

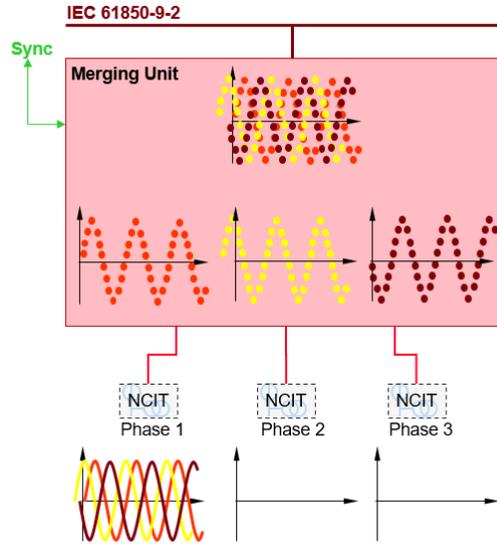


Figure 7. Illustration of Merging Unit functionality

### ***Merging Unit Types and Specifications***

Various types of merging units exist. Most commonly, these support streaming of 4 currents and 4 voltages (3 phases and neutral) as described in the UCA International User Group Implementation Guideline [4], that is widely known as IEC 61850-9-2LE for Light Edition. This multi-vendor Implementation Guideline specifies transmission rates of 80 and 256 samples per power cycle (16.66ms for 60Hz system) and requires using optical 1 pulse per second (PPS) signal for time synchronization. High quality communication and precise synchronization (for synchronized sampling) are required for reliable reception of such sampled values data.

Other data rates and time synchronization sources are specified by the latest IEC standards for dynamic merging unit behavior, namely IEC 61869-6 [5] and IEC 61869-9 [6]. These offer more flexibility for sampling rates, data sources, data grouping and sample synchronization, so that only the required by the application data can be streamed. Various time synchronization sources can be used as well. Table 2 lists key characteristics of MU data streaming variants defined by the UCA IEC 61850-9-2LE and IEC 61869-6/9 standards.

Table 2: Key characteristics of MU data streaming per UCA IEC 61850-9-2LE and IEC 61869 standards

	UCA IEC 61850-9-2LE	9-2LE possible Issues	IEC 61869-6/9
<b>DataSet Content</b>	Fixed 4I+4U	Use of modern sensors – only current sampling	Content is configurable by the user and is described 9-2LE is always supported for backward compatibility
<b>Time synchronization</b>	PPS, sync/no sync	Separate physical network No graceful degradation („local sync“)	Preferred support for PTP time synchronization
<b>Input/output characteristics</b>	Not defined	Each pair of devices must be tested for interoperability, performance of protection functions	Defines input/output characteristics, response „envelope“
<b>Sampling rates</b>	80s or 256s per power system cycle	Sampling depends on power system frequency; no multiples for protection and power quality	Per second sampling – 4800 Hz. Power quality is multiple of base sampling frequency (3x). Transmit rate is ½ of sampling (2400 Hz)

### Modular Merging Unit Architecture

Modular MU architectures have shown to be the most future proof as they flexibly support legacy as well as the new IEC standards' capabilities. A conceptual diagram of a modular MU architecture is shown on Figure 8.

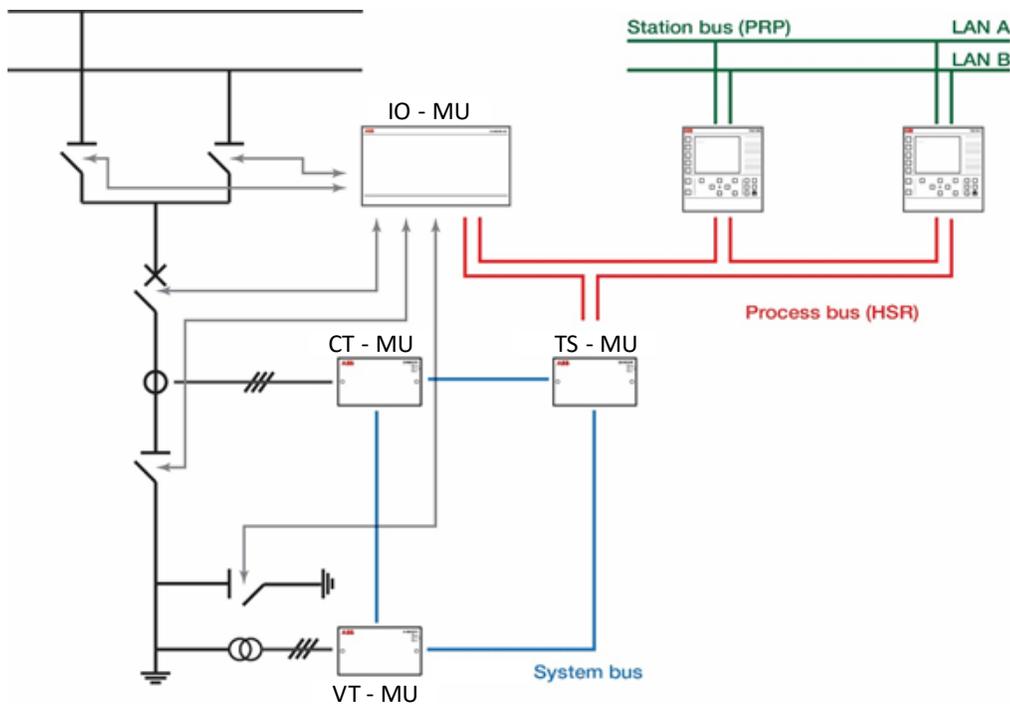


Figure 8. Modular MU architecture

In the above architecture each MU module supports its own functionality as follows

1. Current measurements, sampling and streaming
2. Voltage measurements, sampling and streaming
3. Time synchronization

In this architecture, Current Transformers (CTs) connect to CT modules, Voltage Transformers (VTs) connect to VT modules. Time synchronization (TS) module synchronizes the whole MU system, and can act as its reference source, as well as a time source for the relay(s) receiving SVs. To support legacy timing, TS module can be synchronized over a 1PPS input and can output up to 8 dedicated 1PPS signals for other devices. CT and VT modules as well are interconnected over an Ethernet cable to exchange and merge their measurements and allow transmissions of both currents and voltages in the same data stream. Their sampling is synchronized by TS module over the same Ethernet connection using Precision Time Protocol (PTP).

This modular architecture, in addition to providing the most common IEC 61850-9-2LE streaming, supports custom stream configurations by daisy-chaining various modules as applications require. For example, up to 10 CT modules can be connected (so that low impedance bus differential scheme with up to 10 feeders can be implemented). Such system as well supports multiple time synchronization methods, including the legacy 1PPS and Ethernet-based PTP synchronization. Note that the PTP profile for IEC 61850 applications is specified by the IEC/IEEE 61850-9-3:2016 standard [7].

### ***Merging Unit Solution Selected***

Another side of the modular solution's flexibility is the ability to simplify and reduce the number of modules to the bare minimum, i.e. the ability to operate with a single module only. This specific feature has been selected for the application discussed in this paper, where a single VT module was used.

As the tertiary ground fault protection scheme discussed only requires voltage measurements to be taken at the voltage divider, and the voltage dividing resistor has rather short leads/distance of 8 feet, the use of a single VT module was found to be the ideal solution meeting this application requirements.

A diagram of this MU configuration is shown in the Figure 9 below.

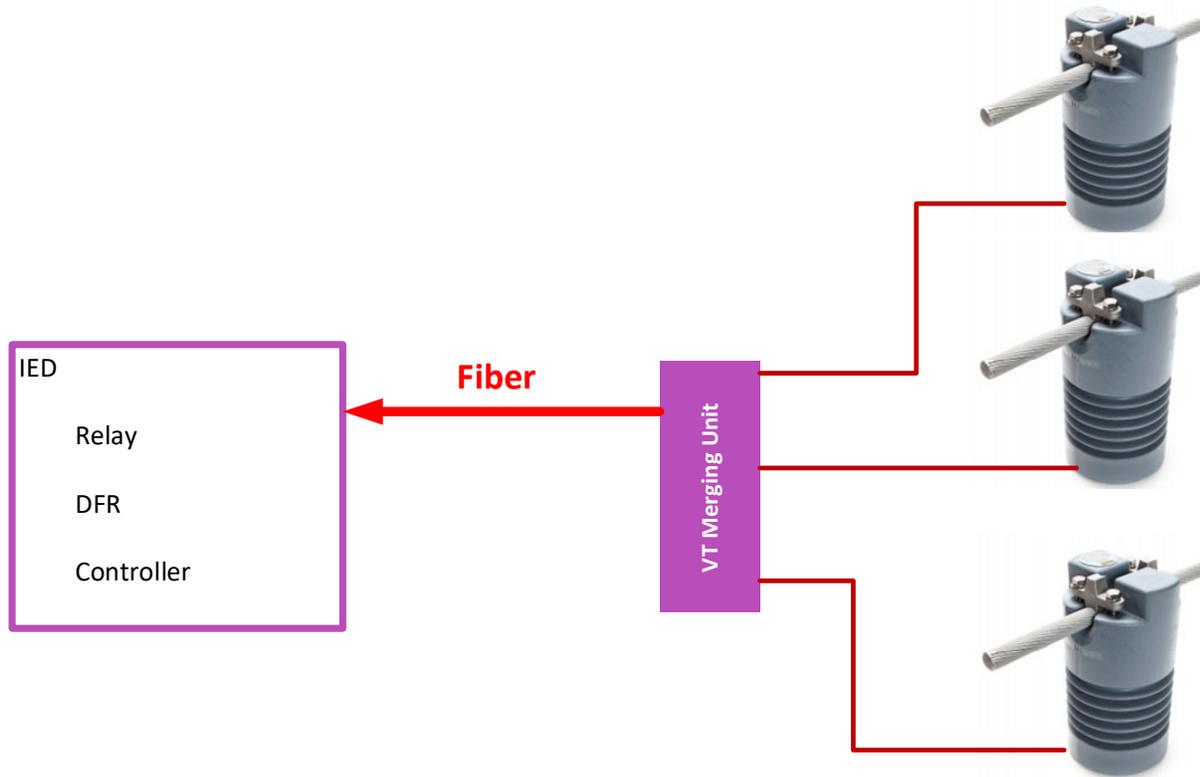


Figure 9. An application diagram with use of single VT module

As shown on Figure 4, VT module measures the voltage in the field, at the voltage divider point, and sends voltage data samples to a protective relay in the control building over a fiber optic Ethernet cable. Fairly long range of distances between control room and voltage measurement point can be accommodated due to the ability of fiber optic cables to support long distances.

As VT module's sampling can be synchronized from the relay receiving data samples over the same fiber optic Ethernet cable, there was no need to use a dedicated TS module for this application. The relay and VT module had to be configured to allow the relay to be a PTP Master and VT module to act as a PTP Slave

For more information on possible configurations, technical details, modular MU functionality and operation, interested readers can refer to [8].

The VT module under test, offered the following fixed secondary quantities: 100V, 110V, 115V, 120V, and 125V, while the primary nominal transducer quantity is offers an adjustable range between 1kV and 1100kV. The expected voltage of the system is the single to ground of the 13.8kV system or  $13.8\text{kV}/\sqrt{3} = 7.97\text{kV}$ . 120V was selected as fixed secondary voltage for the VT module unit. As shown in Figure 10, the impedance was measured to be 600 kilo-ohms. The measured voltage across the secondary was 113.3V shown below.

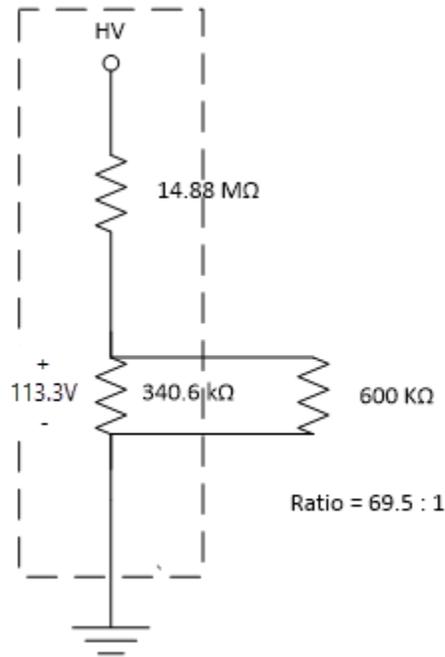


Figure 10. Measured Voltage Across Voltage Divider

The calculated quantity according to the voltage divider with the observed impedances is 114.7V. This is within the 1% of error of the voltage divider.

To display the proper voltage to ground a corrective factor is calculated to be a ratio of the fixed secondary transducer voltage to the measured voltage. In this case it is 120V/113.3V.

To achieve the expected line to ground voltage of 7.97kV it must be multiplied by 120V/113.3V to calculate the adjusted primary nominal transducer value of the VT module. The calculated quantity for the primary nominal transducer voltage is shown below in equation 1.

Equation 1. 
$$V_{transducer} = (120V/113.3V)*7.9kV = 8.46kV$$

The proposed scheme must be demonstrated. An excellent demonstration can be done at Medium Power Lab on the Ross complex at the Bonneville Power Administration. This test facility is fed from a power transformer which is already equipped with a conventional tertiary ground detection scheme. Full and partial faults can be applied to this feeder as needed to test the scheme. Computer modeling carried out prior to the fault tests will be used to determine the best test scenarios to cover.

#### 4. Modeling

A computer model was built to simulate the Medium Power Lab feeder and voltage divider along with a resistor representing the VT-MU on its output. The simplified oneline diagram is shown below.

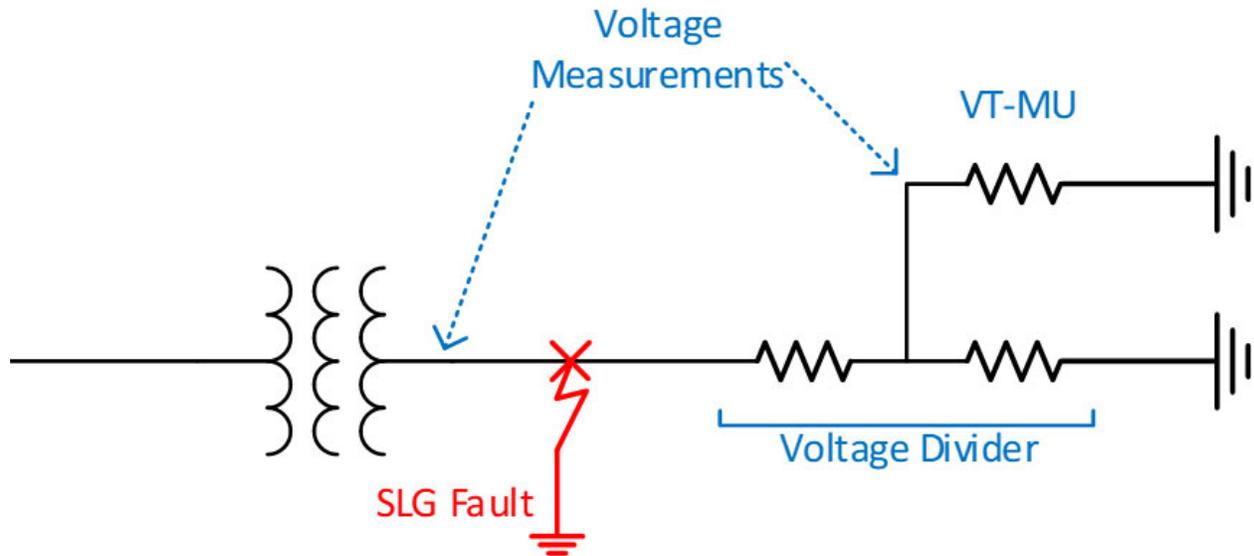


Figure 11 – Simplified Oneline Diagram of Modeled System

An A-phase single line to ground fault was placed on the high side of the voltage divider and voltage measurements were taken on the high side and output of the voltage divider.

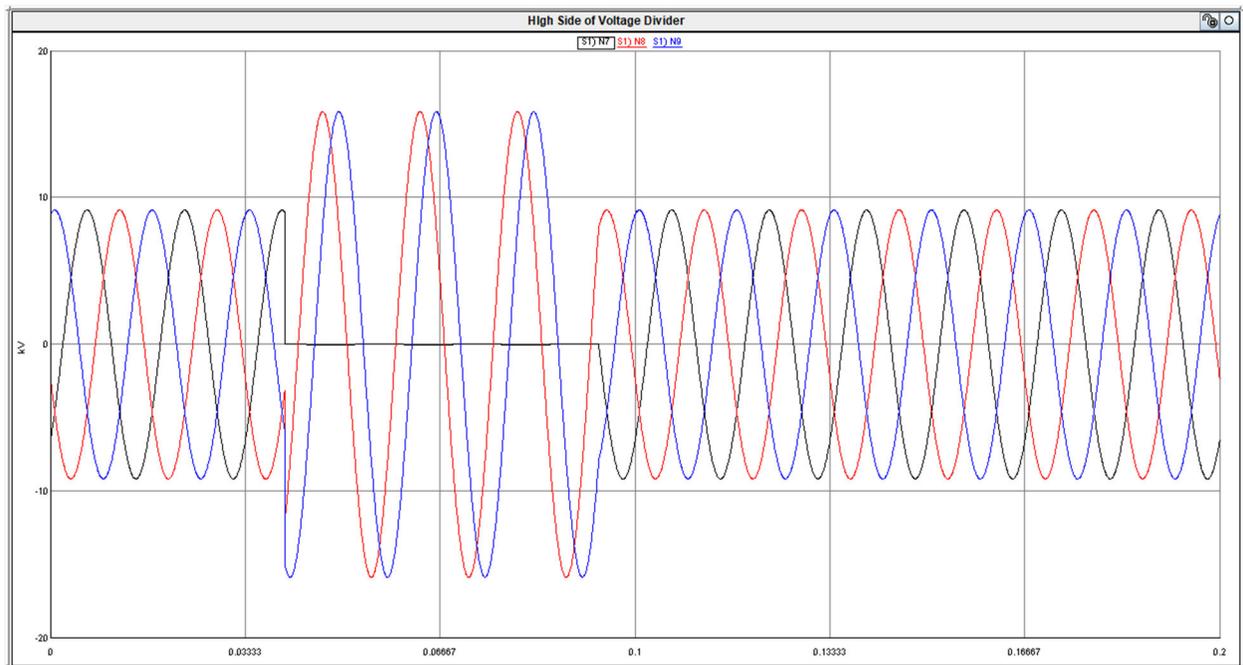


Figure 12 – High side of Voltage Divider – With VT-MU

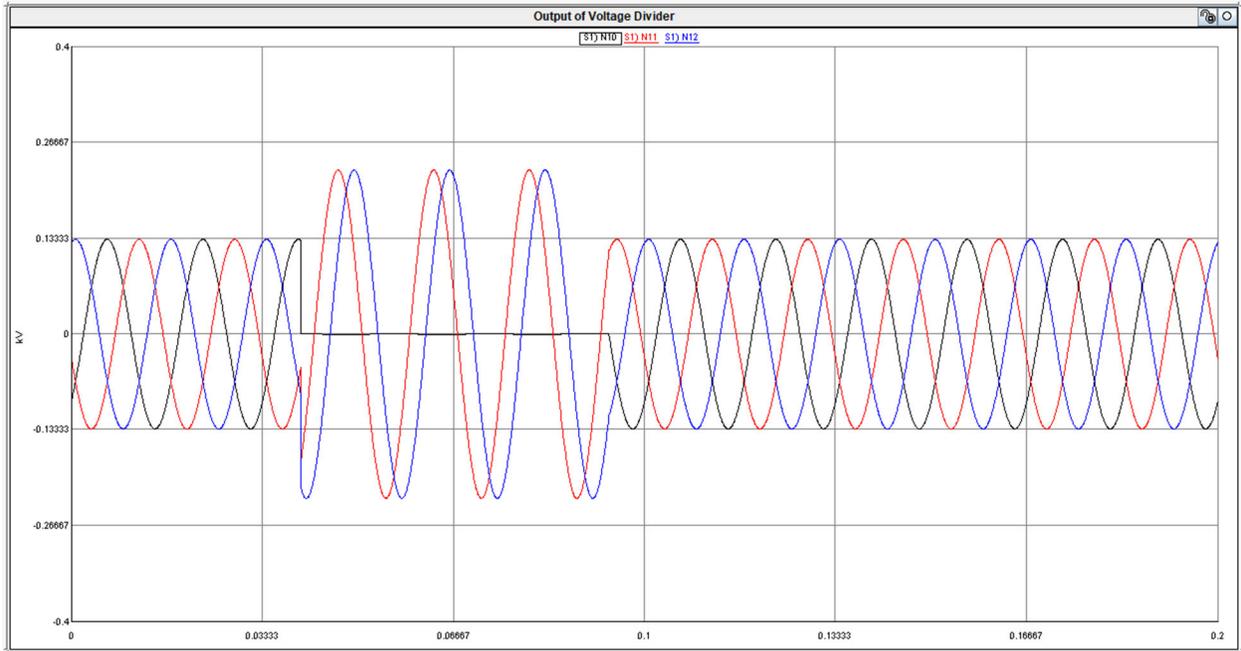


Figure 13 – Output of Voltage Divider – VT-MU

The VT-MU was then removed, modeled in RSCAD and measurements taken.

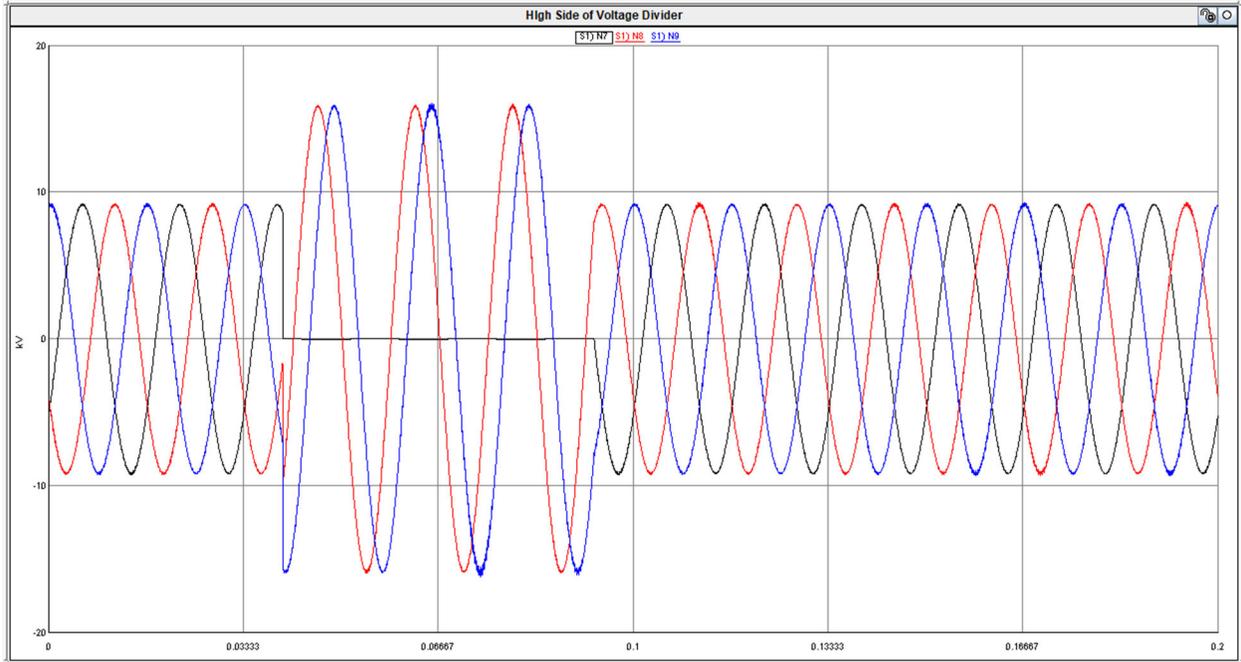


Figure 14 – High Side of Voltage Divider – Without VT-MU

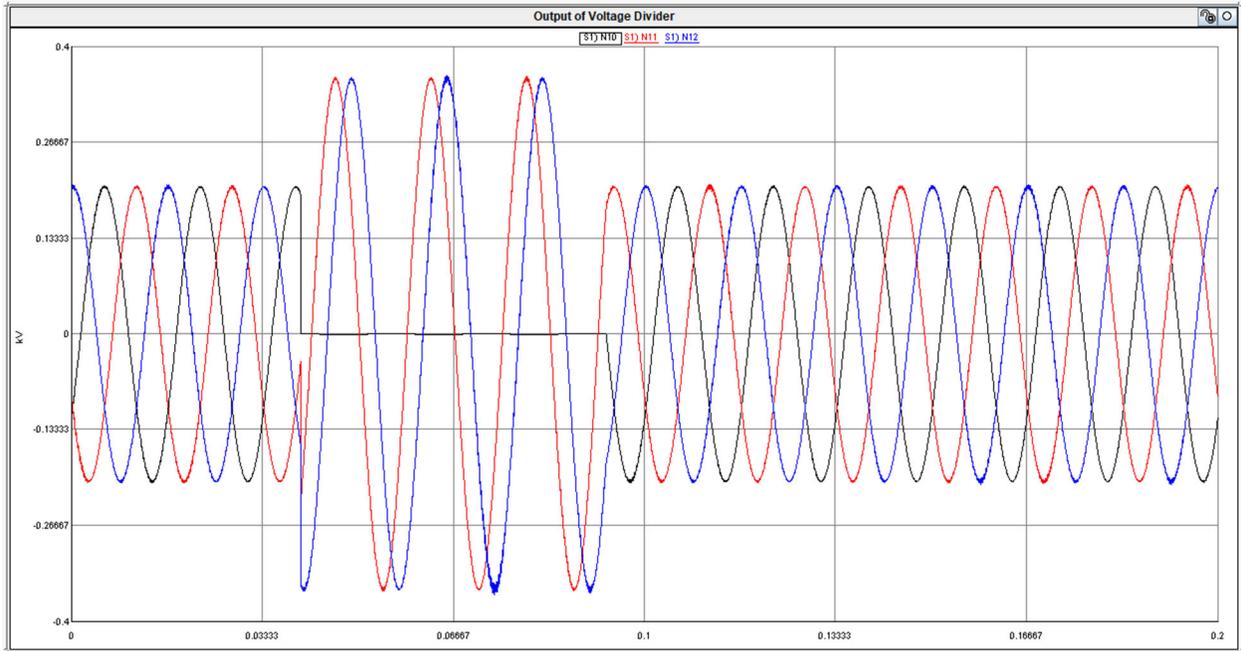


Figure 15 – Output of Voltage Divider – Without VT-MU

The voltage divider was then removed from the model and measurements were taken.

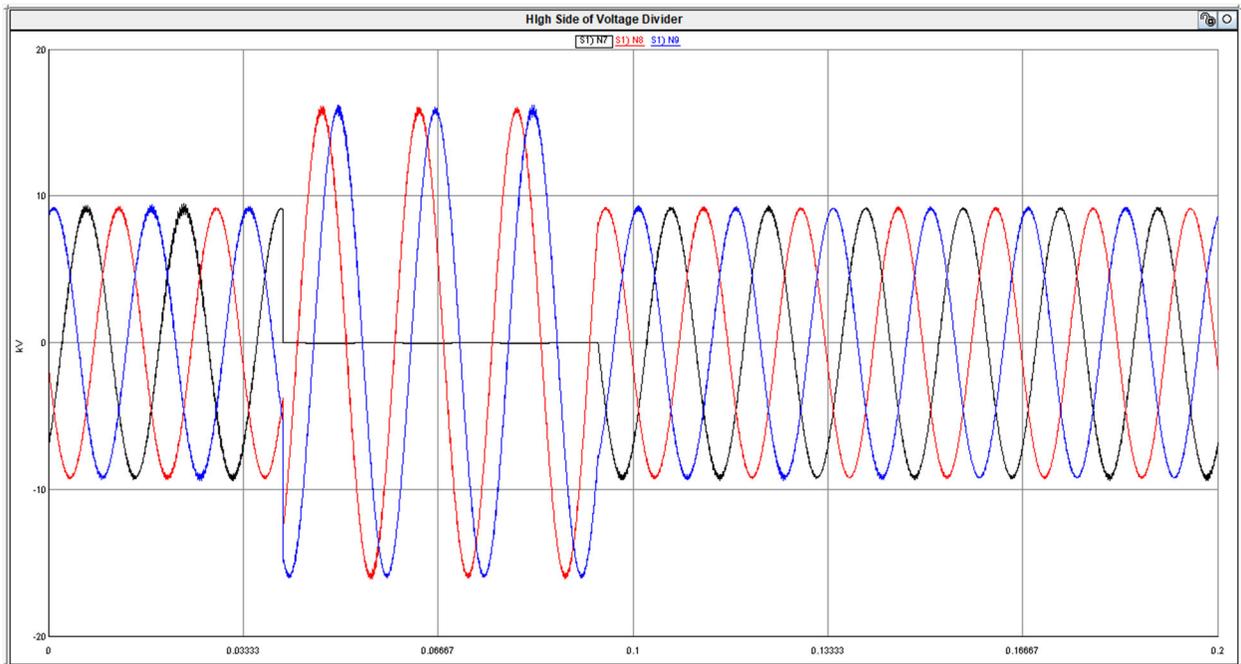


Figure 16 High Side of Voltage Divider – Without VT-MU

As can be seen from Figures 12, 14 and 16; the voltage magnitude was 15.87 kV for the unfaulted phases with a phase angle difference of roughly  $60^\circ$ . Since there is no change in

voltage magnitude or phase angles between the different scenarios, there is no meaningful impact on the delta connected system from the voltage divider with or without the VT-MU.

## 5. Full Scale Testing

Relays have already been configured to implement the tertiary ground detection scheme. Compatibility with the resistive voltage divider has been demonstrated by applying a known high voltage to the sensor and making sure its output is read correctly by each relay. Next, the voltage dividers will be installed on all three phases of the Medium Power Lab Feeder. All customer loads will be moved off of the bank used to supply the lab. The following tests will be performed while verifying that the relay operates correctly:

1. Relay
  - a. Hard single line-to-ground (SLG) fault, A phase
  - b. Hard single line-to-ground (SLG) fault, B phase
  - c. Hard single line-to-ground (SLG) fault, C phase
  - d. Partial (impedance TBD) single line-to-ground (SLG) fault, A phase
  - e. Partial (impedance TBD) single line-to-ground (SLG) fault, B phase
  - f. Partial (impedance TBD) single line-to-ground (SLG) fault, C phase

### Conclusion:

Detection of ground faults on ungrounded delta-tertiary systems traditionally has been a difficult challenge. Traditional voltage transformers are vulnerable to damage incurred from Ferro-resonance conditions that are known to occur on these systems. This paper presented a new approach using shunt resistance voltage dividers that are immune from Ferro-resonance condition. This solution is not without its own unique challenge and considerations. The resistance-based voltage divider scheme requires that the voltage measurements to be taken in the substation field at the voltage division point. A 61850 compliant merging unit publishing a sample value stream, is able to sense the voltage at the voltage division point. Also discussed is the impact the impedance of the voltage measuring devices directly affects the measurement.

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- [2] J. Daume, T. Kocjan, "Transformer Detector Scheme" BPA, SPC Engineers's Handbook Control and Alarm Circuitry Operation, August 2003

[3] IEC 61850-9-2:2011+AMD1:2020 CSV Consolidated version Edition 2.1 Communication networks and systems for power utility automation - Part 9-2: Specific communication service mapping (SCSM) - Sampled values over ISO/IEC 8802-3

[4] UCA International Users Group Implementation Guideline for Digital Interface to Instrument Transformers using IEC 61850-9-2, 2004.

[5] IEC 61869-6:2016 Edition 1.0 Instrument transformers – Part 6: Additional general requirements for low-power instrument transformers.

[6] IEC 61869-9:2016 Edition 1.0 Instrument Transformers - Part 9: Digital Interface For Instrument Transformers

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[8] SAM600 process bus I/O system technical manuals available at [ure](#)

#### **Authors:**

**Galina Antonova** serves as a Technical Sales Engineer with Hitachi ABB Power Grids in North America. She has over 20 years of experience in the area of electrical engineering, data communications and time synchronization, which she applied to the electrical power industry. In her current role Galina is applying her expertise to substation automation and protective relay applications. Galina received her M. Sc. Degree with Honors in 1993 and a Ph.D. in 1997 in Electrical Engineering and Data Communications from the State University of Telecommunications, St. Petersburg, Russia, and spent one year at University of British Columbia (UBC) on a scholarship from the Russian President. She is actively involved with IEEE PSRC, PSCC and is a Canadian member of the IEC TC57 WG10. In her spare time Galina enjoys ice dancing, playing piano and growing lavender.

**J.G. Hildreth** was born in Palm Beach Gardens, FL. He graduated from the Georgia Institute of Technology, Atlanta GA, with a BS degree in Electrical Engineering in 1995 and a MS degree in Electrical Engineering in 2002. His employment experience includes the design of high-speed digital circuits at Intel Corporation in Portland, OR and the testing of power system components at the NEETRAC High Voltage Lab in Forest Park, GA. He currently works at the Bonneville Power Administration's Carey High Voltage Lab in Vancouver, WA. His interests include high voltage testing, data acquisition, and computer control of test apparatus. He is an active, senior member of the IEEE and part-time adjunct professor at Washington State University.

**Aaron Martin** received a BSEE from University of Idaho in 2000, and a MEEE from the University of Idaho in 2007. He is licensed professional engineer in the state of Washington and a member of the PSRC Main Committee. In 1999 Aaron Martin began work for the Army Corp of Engineers as a Maintenance Engineer at Lower Granite Dam, located on the Snake River, in Washington State. In 2002 he left the USACE to work for the Bonneville Power Administration as a system protection field engineer in The Dalles, Oregon. In 2006 he transferred to BPA's

Branch of System Protection and Control in Vancouver, Washington. His main duties involve system protection issues on 115kv, 230kv, and 500kv transmission systems. He is currently working in that position.

**Chris Martin** graduated from Portland State University with a BS in Electrical Engineering in 2006. He started his career as an RF Engineer for Nexius Solutions and T-Mobile USA. In 2012, he started working for Bonneville Power Administration in the Commissioning and Testing group. In 2015, he started working in the System Protection group and supports Phasor Measurement Units, System Protection, Automation and Power System Simulation.