Point-to-Point Digital Secondary System Design for a Transmission Substation at Duke Energy: Challenges and Solutions

Stephen B. Ladd and Ethan Haithcox
Duke Energy

Kelby Perren, Robert Koch, Kaitlin Slattery, Matthew Weaver, and Matthew Zahn
University of North Carolina at Charlotte

Arun Shrestha, Sathish Kumar Mutha, and Luke Booth
Schweitzer Engineering Laboratories, Inc.

Presented at the
76th Annual Georgia Tech Protective Relaying Conference
Atlanta, Georgia
May 3–5, 2023

Previously presented at the
76th Annual Conference for Protective Relay Engineers, March 2023

Originally presented at the
49th Annual Western Protective Relay Conference, October 2022

Point-to-Point Digital Secondary System Design for a Transmission Substation at Duke Energy: Challenges and Solutions

Stephen B. Ladd and Ethan Haithcox, *Duke Energy*
Kelby Perren, Robert Koch, Kaitlin Slattery, Matthew Weaver, and Matthew Zahn, *University of North Carolina at Charlotte*
Arun Shrestha, Sathish Kumar Mutha, and Luke Booth, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—This paper discusses a collaborative case study done by Duke Energy, the University of North Carolina at Charlotte (UNCC), and Schweitzer Engineering Laboratories, Inc. (SEL) on point-to-point digital secondary system (P2P DSS) design for a transmission substation. A P2P DSS uses the simplest network architecture, in which a merging unit (MU) is directly connected to a P2P relay using a fiber-optic cable. Challenges encountered while designing P2P DSS for certain power system configurations are discussed, and solutions are provided. Following the design, P2P DSS is compared against traditional design using total device count, protection scheme unavailability, and protection system operation speed as criteria. Duke Energy plans to use this case study's outcome to evaluate P2P technology for their substations.**

I. Introduction

Duke Energy is currently evaluating the use of a point-to-point digital secondary system (P2P DSS) to reduce the amount of copper utilized in traditional substation protection designs. Physically large substations with substantial system fault duties introduce design challenges by requiring the use of large current transformer cables installed over long distances. In addition, older substations requiring the installation of new cables often meet the challenge of full yard cable trays/trenches requiring significant switchyard modifications beyond adding additional cable.

In recent years, Duke Energy has increased the use of fiber optics in the protection, control, alarming, and communication schemes. However, the traditional use of copper has been utilized for the connection of current transformers (CTs) and potential transformers (PTs) to protective relays and metering devices. Protective relays are also referred to as intelligent electronic devices (IEDs), and these terms are used interchangeably in this paper. According to one study, 75 percent of North America's traditional protection and control (P&C) system installation cost is related to labor [1]. In contrast, a modern substation employing a DSS uses fiber-optic cables to communicate between IEDs in the control house and merging units (MUs) in the switchyard. This solution eliminates copper cables between the primary equipment and the protective relays, replacing them with a few fiber-optic connections, potentially leading to lower substation construction costs and reduced construction time [1] [2].

Two types of DSS are currently available [3] [4]. The first system uses a simple P2P architecture in which an MU is directly connected to an IED using a fiber-optic cable. The second system uses switched network architecture to communicate between MUs and IEDs. Both solutions have their own merits and unique challenges. Duke Energy's initial focus has been placed on evaluating designs that use a P2P approach to obtain the benefits of reducing the use of copper while eliminating the need for additional network devices like network switches and clocks. This approach requires fewer components, minimizes the need for additional knowledge and skills required for a switched network, and minimizes changes required to existing setting templates/designs.

This paper presents the findings of a collaborative case study by Duke Energy, the University of North Carolina at Charlotte (UNCC), and Schweitzer Engineering Laboratories, Inc. (SEL). This paper describes a P2P DSS design for an existing 100 kV transmission substation at Duke Energy. Using P2P IEDs and MUs available from an IED manufacturer, P2P DSS is designed for each bus, transmission line, capacitor bank, and step-down transformer. Following the P2P DSS design, the paper compares the protection scheme unavailability between the traditional substation and the P2P DSS design using fault tree analysis. Adding an MU between an IED and the primary equipment adds a finite delay for fault detection and another delay for the transfer of trip signals. If these delays are significant, they can adversely impact protection system operation speed. Test results from the actual P&C devices that compare the protection system operation speed between the traditional system and P2P DSS are included in the paper.

The P2P MU and the protection IEDs used for this study have four and eight communication ports, respectively. This port limitation poses a unique challenge when implementing bus differential protection for 10 breakers. Similarly, supplying bus voltages to 18 IEDs requires multiple MUs connected to the same PT. Solutions for these problems are described in detail in the paper. In summary, this paper provides a detailed P2P DSS design for an existing transmission substation at Duke Energy. Similarly, it includes quantitative data on total device count, protection scheme unavailability, and protection system operation speed of two secondary systems. The technical data will assist Duke Energy with the decision-making process regarding the evaluation of a P2P DSS for their system.

II. Overview of Duke Energy's Transmission Substation

The transmission substation utilized in this study consists of six pairs of double-circuit 100 kV network-sourced transmission lines for a total of 12 individual line terminals, two bus lines sourced independently from 230/100/44 kV auto banks at an adjacent station, three 100/44 kV power transformers serving two network-sourced 44 kV subtransmission lines and three radial 44 kV subtransmission lines, one 100 kV two-stage capacitor and one 44 kV single stage capacitor. Fig. 1 shows the single-line diagram of the transmission substation used for the case study. For brevity, only the 100 kV section of the substation is shown.

The 100 kV bus structure is configured double-bus with manual disconnect switches allowing each of the 16 breakers to be served from either bus. The buses are electrically connected through four busline breakers. The normal configuration for the station includes half of the network double-circuit lines tied to the Red Bus and half tied to the Yellow Bus. Likewise, the four busline breakers are also split between both buses evenly. The three 100/44 kV power transformers are split between the 100 kV buses, with two tied through a high side breaker on one bus and one tied through a high side breaker on the other bus. All breakers run normally closed.

A. *General Protection Philosophy*

Duke Energy's approach to protection within transmission substations is built around maintaining fast protection. Protection zones are generally established for buses, transformers, capacitors, etc. Fast protection is implemented with differential protection for all buses and transformers. Zone overlap on breakers is required for all zones of protection. For transmission substations at voltage levels of 100 kV and above, redundancy in IEDs will be required for future substations whenever possible. Past practices did not require full redundancy at subtransmission voltage levels but it will likely be required in future greenfield designs. For this study, full redundancy was required for the P2P DSS design.

B. *Line Protection*

The line protection applications in this study vary depending on multiple factors, including source impedance ratio, line length, and tapped load. All line relays contain completely redundant protection functions except for reclosing. Redundant pilot scheme applications are used on several network lines for which high source impedance ratios exist. Line schemes used in this study include either stepped distance, permissive overreaching transfer trip (POTT), line current differential (87L), or overcurrent for radial applications.

The potential sources for all line relays are located on the station buses. A single potential source is shared for all line relays normally connected to that bus to mitigate multiple runs of the conductor and, more importantly, to limit fault exposure from additional potential sources. A selector switch can be utilized to place all lines on the same potential source for maintenance. A synchronization source is also included on the line side of each network terminal. The current source for each line relay is a bushing CT located on the bus side of the line breaker.

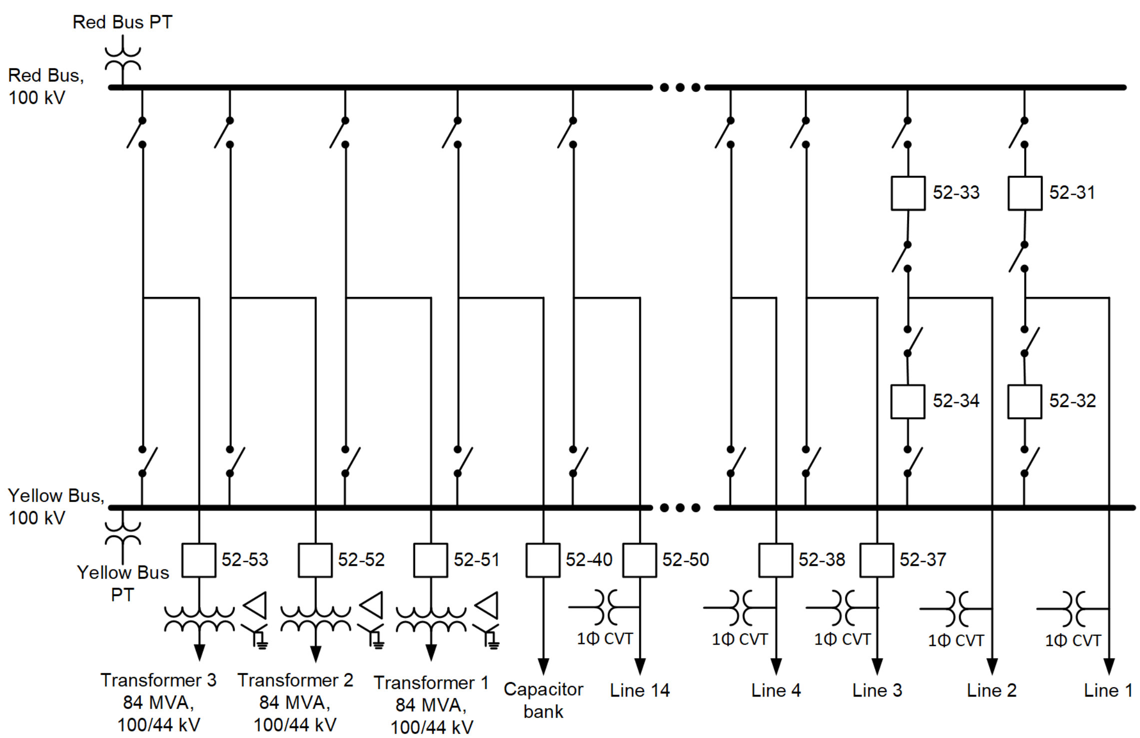

Fig. 1. Single-line diagram of 100 kV section of transmission substation at Duke Energy.

C. Bus Protection

Due to a large number of breakers and the ability to manually configure the bus connections, redundant high-impedance differentials are used in real-world applications. The current sources for the differential relays are the bushing CTs on the line side of each breaker. In addition, current selector switches are included to allow a single differential zone to cover both buses for ease of maintenance and switching.

D. Transformer Protection

The 100/44 kV power transformers use standard percentage restrained transformer differential elements with backup overcurrents on the high side, low side, and neutral. In addition to the transformer differential relays, independent overcurrent and breaker failure relays are included on both the high and low side breakers for each transformer. Current sources for all relays in the transformer zone are bushing CTs on the high and low side breakers and transformer neutral.

III. Duke Energy's Exploration of Copper Reduction and DSS

Copper reduction is viewed as an opportunity to reduce cost and potentially reduce exposure to the challenges of working with CTs within the substation control house. This can be achieved by using IED technologies that use MUs located throughout the substation. Currently, there are two available solutions to achieve the copper reduction goal, either P2P or Ethernet-based solutions like IEC 61850. The challenges of each technology should be considered and evaluated before implementing either. In addition, for both technologies, a thorough evaluation of all change management issues should be made before proceeding with their installation and use. Some of the key change management issues and questions to be answered include the following:

1. What additional engineering and field "skill sets" would be required to implement the technology? Protection and application engineers are typically knowledgeable of power systems, fault analysis, and substation apparatus but are not network engineers.
2. In addition to new "skill sets," will additional engineering and field resources be required to program or configure additional devices/networks if a new technology is implemented? Skills include installation, testing, troubleshooting, programming/configuration, etc.
3. How would field testing and commissioning change? Traditional testing and test equipment that applies voltages and current to the IEDs will be different. How do you verify CT connections at the MUs?
4. Are there any compliance impacts of introducing new devices and routable protocols outside the control house? If yes, what additional measures would be required to secure?
5. How is the engineering process impacted, including the population of a relay database, with new programmable devices? How are their settings/configurations issued to the field for installation if additional network devices are used? Where are the new settings stored?
6. How easy can the new technology be changed in future additions, modifications, or upgrades?
7. If new nonrelay devices are used to implement the new technology, can hardened devices be obtained to implement? What is the expected life of the new devices?
8. How is configuration management handled for failure scenarios where devices must be replaced and reconfigured in the field?

While many utilities have been excited to try and implement the new digital technologies, many did not fully evaluate the change management issues before implementation. Those who have successfully implemented Ethernet network-based DSS have also executed a thorough change management plan. Before proceeding, they invested considerable resources, time, and work to develop and thoroughly test repeatable solutions. As a result, change management issues for these utilities were not an afterthought, but an investment in the engineering process changes.

When evaluating the objective of reducing copper in protection, P2P technologies offer an attractive solution to work with the new technology, but with fewer challenges and change management requirements than the Ethernet network-based approach. Network skills and additional programmable devices are not required. The technology can be implemented with minimal changes to existing setting templates and engineering expertise. The challenges of learning how to test and field commission would be the same for either P2P or network technologies that use MUs. By viewing the P2P technology as an initial step, the journey of pursuing additional copper reduction could be accomplished in a relatively shorter time with considerably fewer change management issues.

The work performed in the case study helped Duke Energy identify what a P2P solution for a typical transmission substation would look like. Key questions need to be answered, and the case study helped clarify many questions before considering moving forward with a predeployment of the new technology. Some of the key questions that need to be answered included:

1. Are there any impacts on protection speed? In other words, will the protection be slower? If yes, how much slower?
2. How many MUs would be required?
3. Could a rough estimate of cost benefits be made? Our initial thinking is that a smaller substation would have fewer quantifiable benefits than a substation with control and instrument transformer cables running thousands of feet.

IV. P2P DSS Overview

A P2P DSS uses the simplest and most secure network architecture to exchange process data between an MU and an IED. Fig. 2 shows a simple substation designed using P2P DSS. In P2P DSS, a fiber-optic cable connects an MU directly to an IED. MUs are installed in the switchyard, close to the primary equipment, and P2P IEDs are usually installed in the control house. A P2P DSS does not require network switches and clocks for the process bus. This removes the complexity of configuring switches and clocks. Instead, P2P IEDs use their internal clock to time-align data received from multiple MUs before processing the signals for executing protection algorithms. Fewer devices in the substation improve the protection system reliability at a lower cost. A P2P DSS can use a standard protocol or a manufacturer-specific protocol.

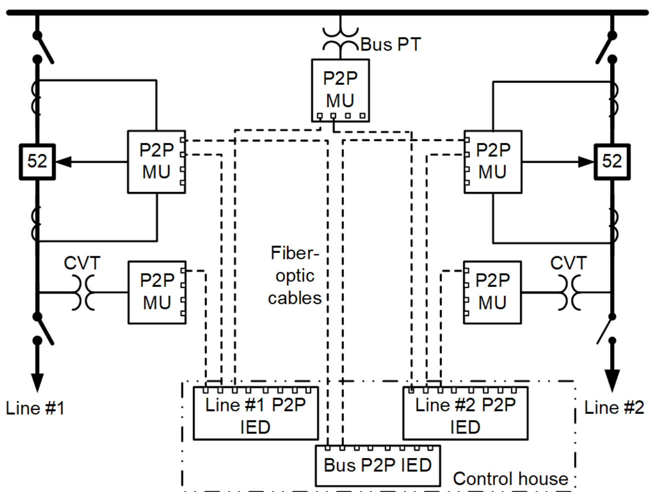

Fig. 2. A simple substation utilizing P2P DSS.

For this case study, P2P MUs and P2P IEDs offered by a particular IED manufacturer are used [3]. Technical details on these P2P devices are presented in Section IV Subsection A–C.

A. P2P MUs

The IED manufacturer offers two P2P MU types. The first type consists of eight CT inputs and the second type has four CT and four PT inputs. Both MUs have seven binary outputs and 16 binary inputs. The first MU type is suitable for installation near circuit breakers and transformers, allowing it to measure currents from both ends of the primary equipment. The second MU type is suitable for measuring PTs and capacitive voltage transformers (CVTs) voltage signals. Each MU can communicate with four IEDs over a direct fiber-optic connection. The MUs use a manufacturer-specific, nonroutable protocol to exchange analog and binary signals with IEDs. The network latency is small as the signals are exchanged at 10 kHz. The MUs do not have any settings.

B. P2P IEDs

Different P2P IEDs are available for protection and control of transmission lines, transformers, buses, and feeders. IEDs have eight communication ports, allowing an IED to communicate with up to eight MUs. In the substation, MUs are connected to the IED with fiber-optic cables, and the process termed 'commissioning' is executed from the IED configuration software. The commissioning process locks the connected MUs with the IED. If a fiber-optic cable is removed from a commissioned MU and is connected to a new MU, the IED detects this issue and rejects data from the new MU. This feature provides security against erroneous connections during substation maintenance. The IED supports one binary input-output board, allowing the IED to send control signals to breakers or other IEDs. The IED supports multiple protocols for station bus communication.

C. Benefits and Challenges of P2P DSS

As previously discussed, a P2P DSS can potentially lower substation construction costs and reduce construction and commissioning time if engineered and implemented correctly. When copper cables are replaced with fiber-optic cables, the number of terminations required for P&C devices is reduced considerably [2]. Similarly, the size of cable trays and cable trenches becomes smaller. P2P DSS does not require network switches and clocks for operation, so one does not have to worry about the cost and complexity associated with these devices [5]. The P2P IEDs can monitor the status of fiber-optic cables, improving the system's overall reliability.

The number of MUs that an IED can communicate with and the number of IEDs that an MU can communicate with are limited by the number of communication ports available. This is usually not an issue for most power system configurations. However, whenever a bus voltage needs to be shared with 4+ IEDs or whenever a bus IED needs to receive current signals from 8+ breakers, the P2P DSS design can be challenging. For the first scenario, additional MUs connected to the same bus voltage source are required. For the case of a bus IED, one MU will need to measure current signals from multiple breakers. The solutions for these two scenarios are described in detail in Section V.

Depending on the size of the substation and protection scheme redundancy philosophy, the total number of MUs required for the P2P DSS can be large. The total number of MUs directly impacts the capacity of the station dc power system. This factor should be considered when designing a new P2P DSS or upgrading a traditional substation to P2P DSS. When additional MUs are installed for redundancy, the space inside the breaker and transformer cabinets can become a challenge.

In a traditional substation, during the commissioning phase, IEDs are tested by opening test switches and injecting secondary signals. Since P2P IEDs do not use test switches, commissioning a P2P DSS system can become another challenge as a secondary injection is no longer possible at the IED location. Similarly, lockout IEDs are generally not used in P2P DSS. Hence, the P2P DSS requires new operation and testing procedures.

V. P2P DSS Design

This section describes the P2P DSS design for the transmission substation under study. Since the substation is large, the design is broken down into multiple subsystems based on the configuration used for protecting a network element. For each subsystem, the secondary system and its associated P&C devices for the existing traditional substation are presented first. Next, the P2P DSS design for the same subsystem is described. When developing P2P design, full redundancy of P&C devices is considered.

Similarly, the existing protection philosophy and operation methodology are maintained in the new P2P design. Although the P2P DSS design is carried out for the complete substation, for brevity, only double-bus double-breaker, double-bus single-breaker, bus differential, and bus PT configuration are discussed. A similar case study for P2P and network-based DSS design of a distribution substation is discussed in [6].

A. Double-Bus Double-Breaker Configuration

As shown in the substation single-line diagram, Lines 1 and 2 are connected to the Red and Yellow Buses via two breakers. The double-bus double-breaker configuration provides reliability and operational flexibility regarding maintenance and network switching. Fig. 3 shows the secondary connection between primary equipment (CBs, CTs, PTs, and CVTs) and protection IEDs for Line 1. Separate CTs, PTs, and CVTs are installed to aid the design of redundant protection systems. Two-line IEDs, primary and secondary, provide redundant line current differential protection to Line 1. Line current differential (87L), pilot scheme (85-DTT), distance (21), and ground overcurrent (51G) elements are enabled in line IEDs. For each breaker, a separate bay controller IED is installed. The bay controller IED provides breaker failure (50BF) and line synchronization (25) functions. The Yellow Bus provides bus voltage to line IEDs and the second bay controller IED (52-32). Line IEDs can trip both breakers independently. Each bay controller IED can trip and close the breaker to which it is assigned. The secondary connection and protection IEDs for Line 2 are identical to Line 1.

P2P DSS design for Line 1 protection is shown in Fig. 4. To maintain independence between primary and secondary protection, separate P2P MUs and line IEDs are used for each system. Two P2P MUs are used for each breaker to measure breaker currents. Each P2P MU measures the current entering and exiting the breaker. However, the CT connections on the line side of the breakers to the P2P MU are not shown for simplicity. The P2P MUs connected to the CTs provide three-phase current measurements to line IEDs and bay controller IEDs. The same MUs provide three-phase currents exiting the breakers to bus differential IEDs (connection not shown). In traditional design, the Yellow Bus provides bus voltage to both line IEDs and the second bay controller IED (52-32). Two separate MUs provide bus voltage to primary and secondary line IEDs in P2P DSS design. The MUs connected to bus PTs are shared with other line IEDs. For Line 1 protection, nine P2P MUs and four P2P IEDs are required. P2P DSS design for Line 2 is identical to Line 1.

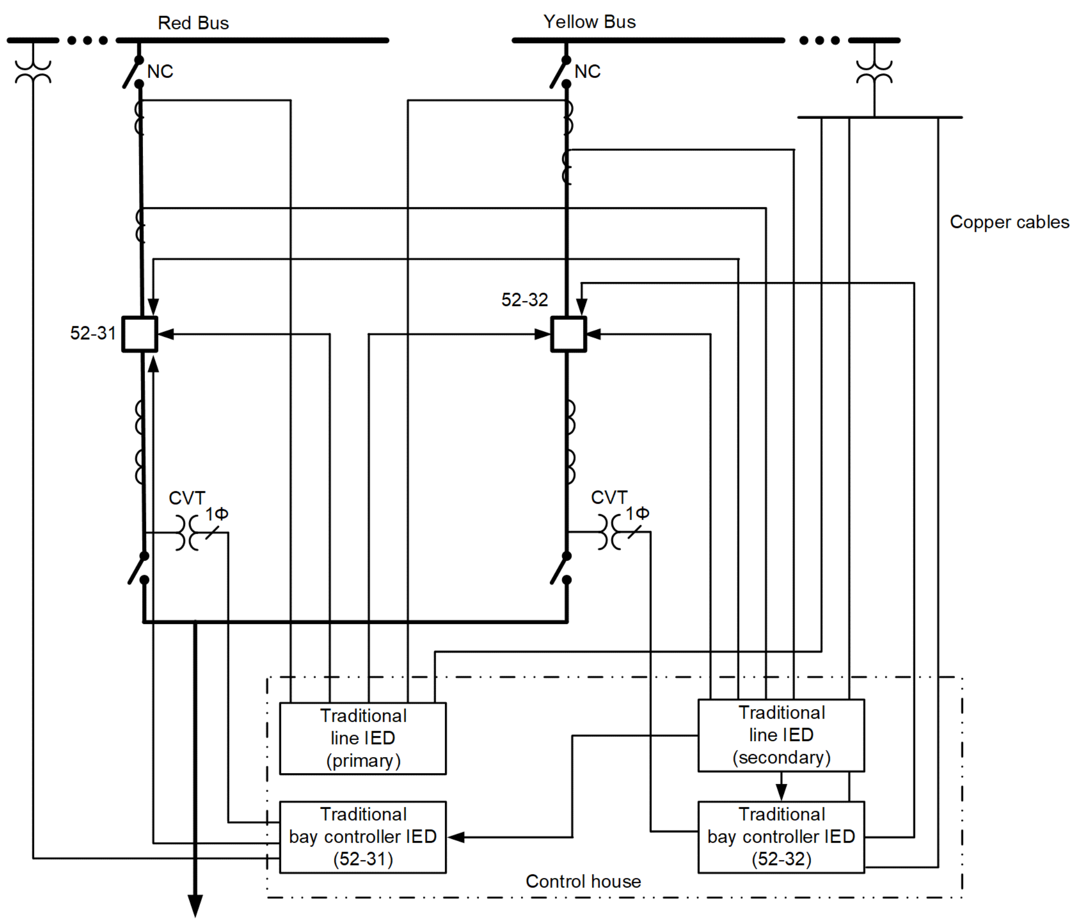

Fig. 3. Traditional secondary connections and IEDs for Line 1 protection.

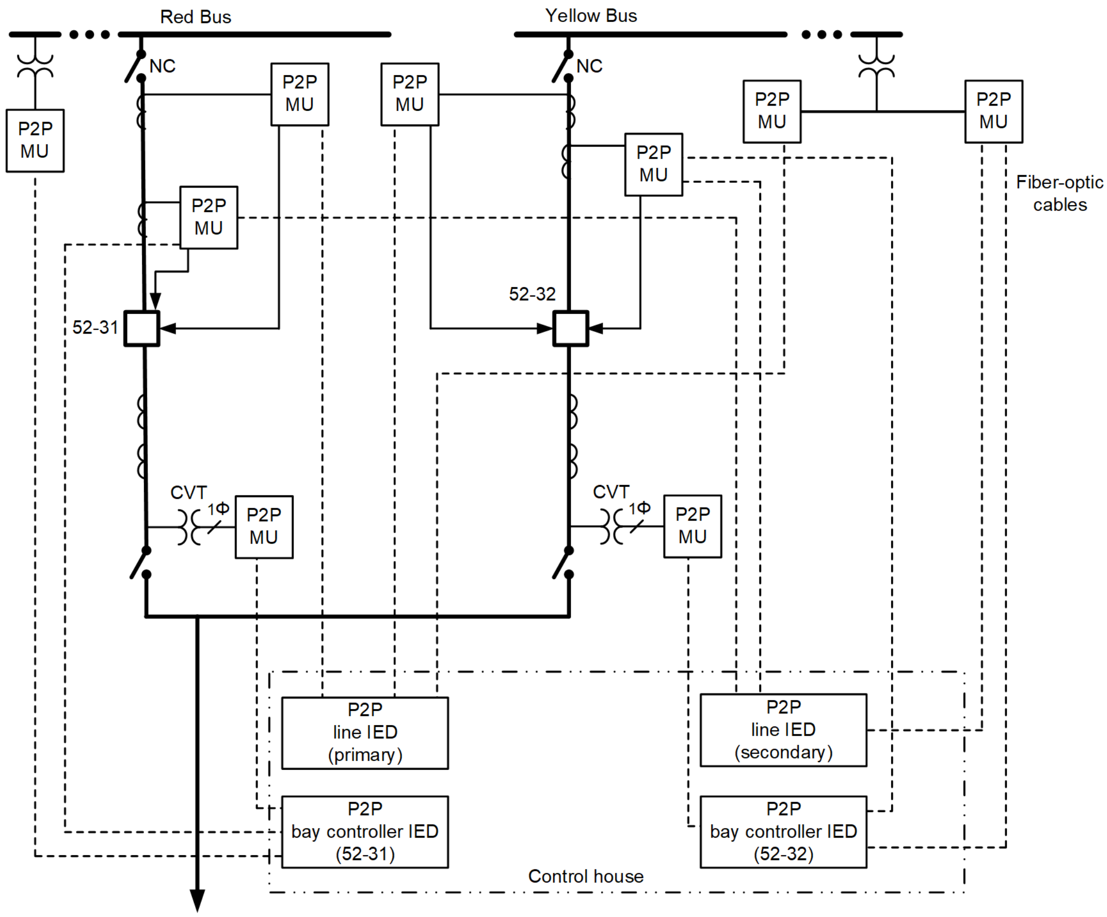

Fig. 4. P2P DSS design for Line 1 protection.

B. Double-Bus Single-Breaker Configuration

Out of 14 transmission lines in the substation, Lines 3 through 14 are connected in a double-bus single-breaker configuration. Six lines are normally connected to the Red Bus, and the remaining six are connected to the Yellow Bus. Two sets of CTs are available on both ends of the breaker. Fig. 5 shows the secondary connection and protection IEDs for Line 3. In the existing design, only one set of CTs are used to connect both primary and secondary line IEDs. The second set of CTs are shorted and not used. If the CT used in the design fails, it adversely impacts both primary and secondary protection. Therefore, the existing design reduces the overall availability of the Line 3 protection system. The CTs at the transmission line end are used for bus differential protection (connection not shown). Unlike the Line 1 protection system, Line 3 IEDs provide protection and breaker control functions. Dedicated bay controller IEDs are only installed for critical lines. Distance (21), Pilot scheme (85-POTT), overcurrent (50/51), and breaker failure (50BF) protection are enabled in both IEDs. Line synchronization (25) and reclosing (79) functions are only used in the primary IED. The secondary connection and protection IEDs for Lines 4 through 14 are identical to Line 3.

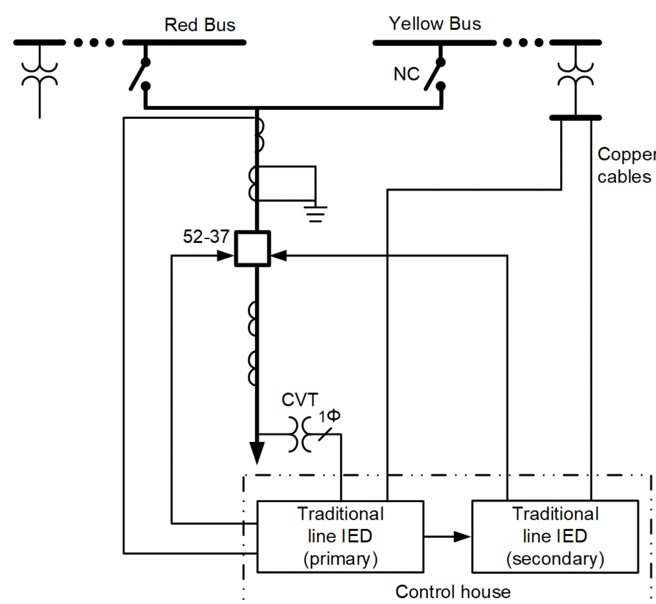

Fig. 5. Traditional secondary connections and IEDs for Line 3 protection.

Fig. 6 shows the P2P DSS design for Line 3 protection. This design requires five P2P MUs and two line IEDs. Two MUs are connected to two separate CTs to make the protection system truly independent. In the event of an MU failure or a line IED failure, the redundant protection system protects Line 3. Line IEDs control the breaker via the MU connected to the CTs. The

MUs connected to the bus PT are shared with other line IEDs. P2P DSS design for Lines 4 through 14 are identical to Line 3.

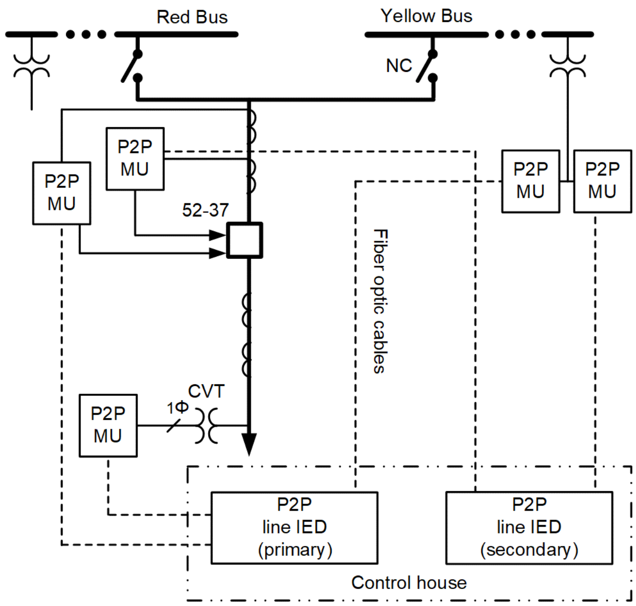

Fig. 6. P2P DSS design for Line 3 protection.

C. *Bus Differential Configuration*

The substation single-line diagram shows that 14 lines, one two-stage capacitor bank, and three step-down transformers are alternately connected to the Red and Yellow Bus. As Line 1 and Line 2 are connected to both buses, ten breakers are connected to each bus. Fig. 7 depicts the secondary connection and IEDs for the Red Bus primary bus differential protection. The Red Bus secondary bus differential protection is identical to the one shown in the figure and uses the second set of CTs associated with each breaker (connection not shown). An electromechanical high-impedance differential IED is used for bus differential protection for each phase. Phase A currents from all ten breakers are physically summed before connecting them to the Phase A high-impedance differential IED. A similar connection is made between Phase B and Phase C currents and the remaining differential IEDs as shown in the figure. For an in-zone fault, the differential IEDs command a separate auxiliary relay to trip all ten breakers connected to the Red Bus. Similarly, for Yellow Bus differential protection, three high-impedance differential IEDs are used for primary, and three additional high-impedance differential IEDs are used for the secondary system.

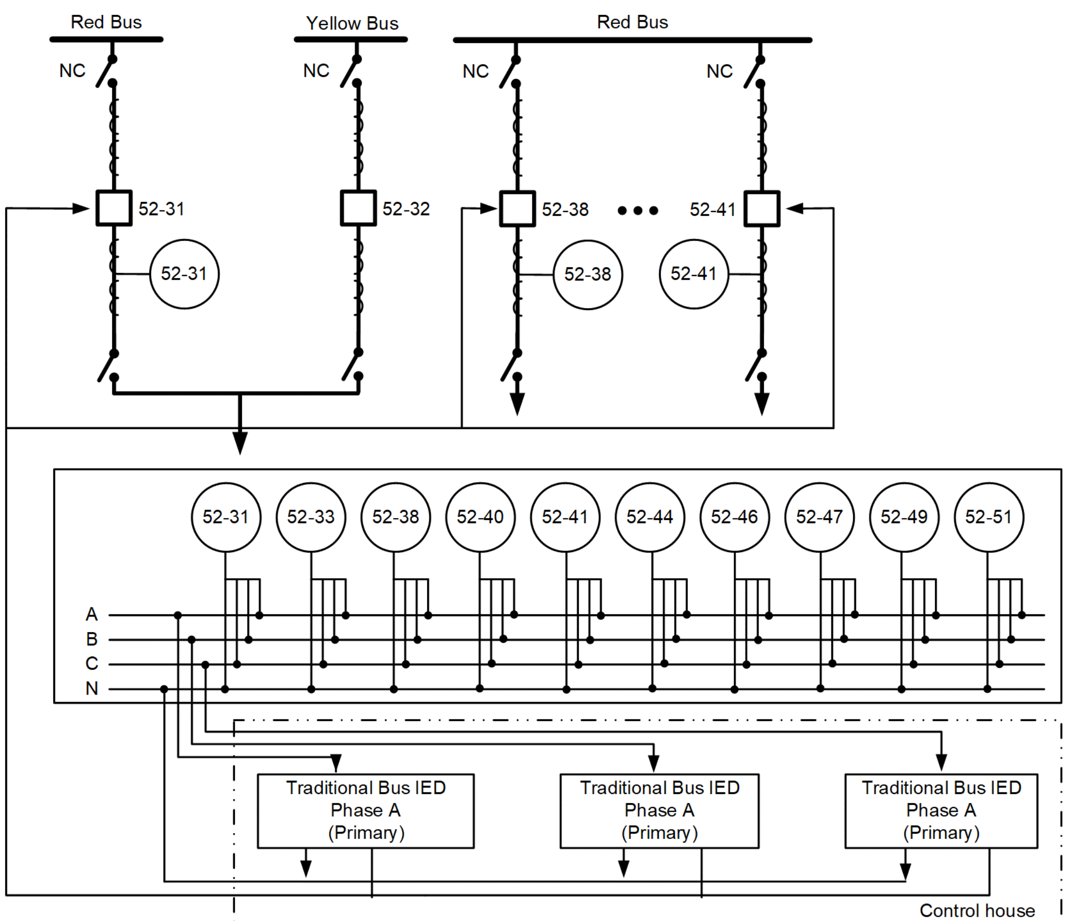

Fig. 7. Traditional secondary connections and IEDs for the Red Bus primary bus differential protection.

The P2P Bus IED used for the study supports high-speed, low-impedance bus differential elements. Each bus IED supports six protection zones and three independent check zones. One bus IED can provide three-phase bus differential protection for up to seven terminals. It can also support bus differential protection for up to 21 terminals (breakers) when one IED is used per phase. In the transmission substation under study, 10 breaker terminals are connected to each bus. This configuration requires three separate P2P Bus IEDs for the Red Bus primary protection, one IED per phase. Each P2P IED has eight communication ports, which can be connected to a maximum of eight P2P MUs. One P2P MU is used to measure currents from two breaker terminals to overcome the port limitation. Three MUs measure currents from six breaker terminals. CTs from two physically close transmission lines, are connected to a single MU. Fig. 8 shows the overall P2P DSS design for the Red Bus primary differential protection. Each bus IED acquires currents from 10 breaker terminals via seven MUs. Overall, the P2P DSS design uses seven MUs and three Bus IEDs for the Red Bus primary protection. For the Red Bus secondary protection, separate MUs connected to the second set of CTs and bus IEDs are connected like the one shown in Fig. 8. A total of 28 MUs and 12 Bus IEDs are used for both primary and secondary protection for the Red and Yellow Buses.

If the P2P Bus IED needs to provide bus differential protection to all 20 breaker terminals, A-phase current from eight breakers can be connected to a P2P MU type with eight CT inputs. When the MU is connected to the bus IED, it can receive currents from eight breakers using one communications port. With a similar connection between breaker currents and two other MUs, the bus IED can receive A-phase currents from 20 breakers using just three communication ports. Similarly, other sets of MUs can be connected to B- and C-phase breaker currents and connect to bus IED for B- and C-phase bus protection.

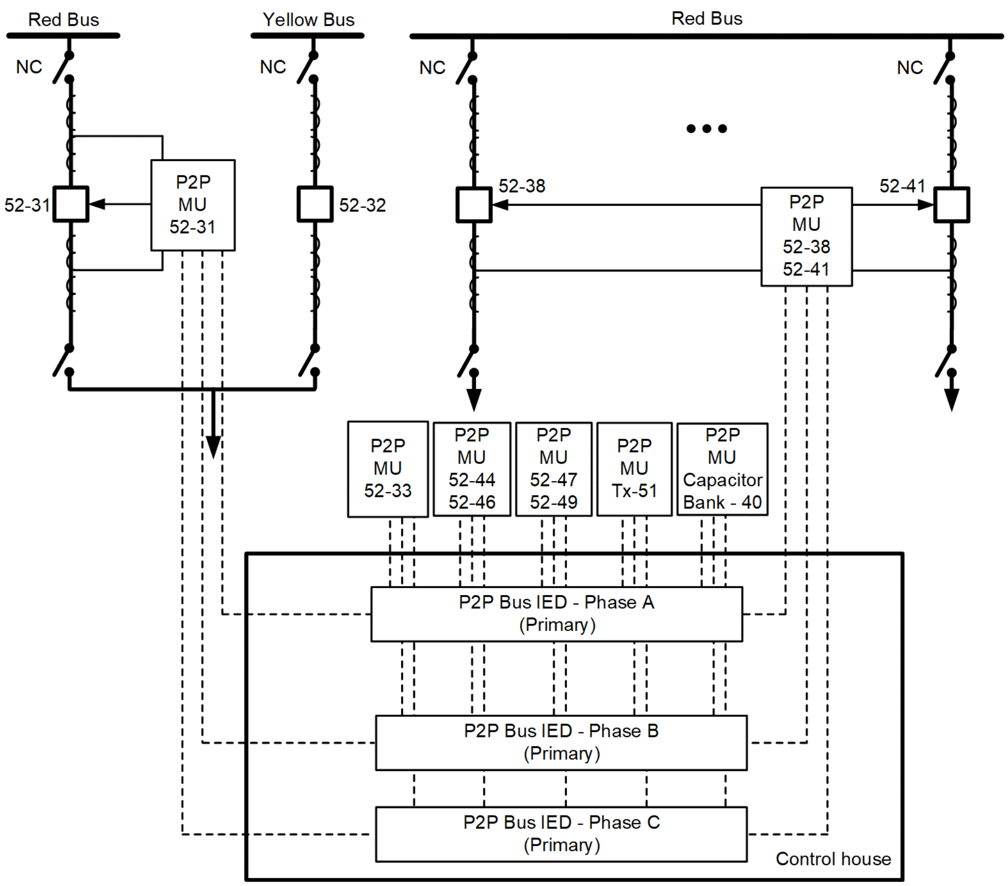

Fig. 8. P2P DSS design for the Red Bus primary bus differential protection.

D. Bus PT Configuration

In the transmission substation under study, 18 IEDs receive three-phase bus voltage from the Red Bus. Similarly, another 18 IEDs receive separate three-phase bus voltage from the Yellow Bus. For a traditional secondary system, this is not a concern. The voltage terminals of all 18 IEDs are connected in parallel with the bus PT secondary circuit. Sharing bus voltage to a large number of IEDs requires multiple P2P MUs in P2P DSS, as the number of communications port on an MU is limited to four. Fig. 9 shows the P2P DSS design for sharing Red and Yellow Bus voltage to IEDs. Five MUs are needed to share the Red Bus voltage to 18 IEDs.

Similarly, another five MUs provide the Yellow Bus voltage to the other 18 IEDs. Within each bus, separate MUs provide bus voltage to primary and secondary protection IEDs. This design ensures that the loss of an MU does not disable both primary and secondary protection for a particular network element.

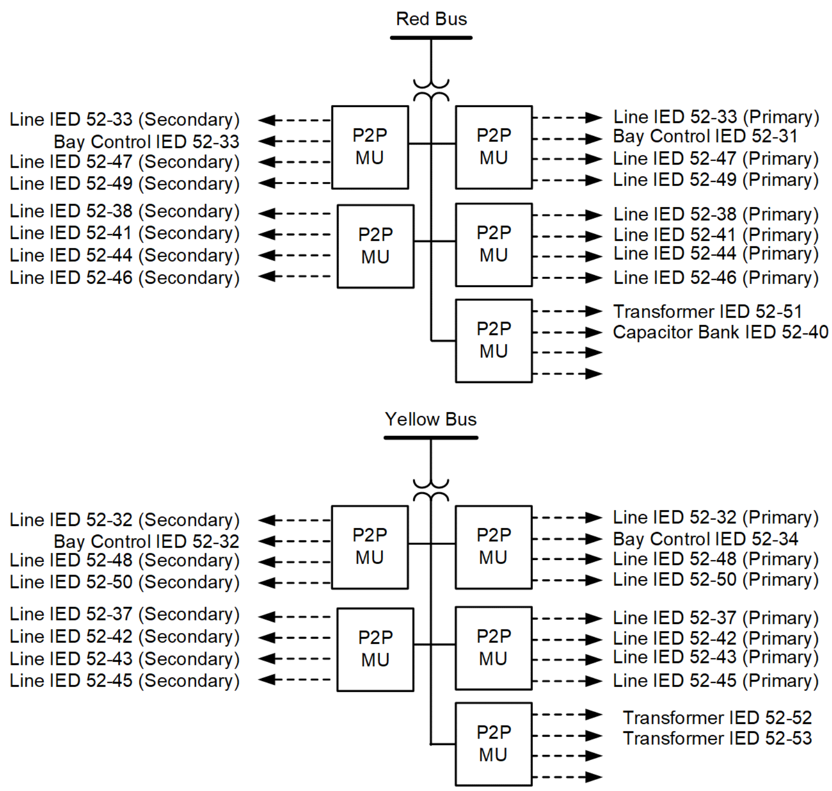

Fig. 9. P2P DSS design for sharing bus voltage.

VI. Comparison Between Traditional and P2P DSS Design

In the previous section, we presented traditional secondary systems and P2P DSS designs for the substation. Next, we compare these two designs analytically by using device count, protection scheme unavailability, and protection system operation speed as criteria. The technical data included in this section will highlight the benefits and challenges of adopting a P2P DSS design for a transmission substation of a similar size.

A. Device Count

In this subsection, we focus on various devices used in traditional substation and P2P DSS design. Table I lists various devices used in the traditional substation. In a traditional substation, copper cables connect CTs and PTs secondary to IEDs. Similarly, copper cables are used for connection between breakers and IEDs for control. The total copper cable length of 73,342 ft is calculated using 4c12 cable type for CTs/PTs and 3c8:9c12 cable type for control. Four-line current differential IEDs are used for Line 1 and Line 2 primary and secondary protection. For Lines 3 through 14, 24 distance IEDs are used for primary and secondary protection. Three transformer IEDs are used to protect Transformers 1, 2, and 3. Twelve single-phase high-impedance bus differential IEDs provide primary and secondary protection for the Red Bus and Yellow Bus. Nine overcurrent IEDs are used for protection of the capacitor bank, bay control for Line 1 and Line 2, and the backup protection for transformers.

TABLE I
DEVICES USED IN A TRADITIONAL SUBSTATION

Description	Units
Copper cables	73,342 feet
Test switch	80
Line current differential IED	4
Distance IED	24
Overcurrent IED	9
Transformer IED	3
Bus differential IED	12
Lockout IED	10

A tabulated list of devices used in the P2P DSS design is shown in Table II. The P2P DSS is designed to maintain the existing protection philosophy and operation methodology. As a result, the number of protection IEDs remains the same between the two designs. A total fiber-optic cable length of 67,775 ft is calculated by assuming a cable with 2 fibers. The total length decreases significantly if fiber-optic cables with 4 or 8 fibers are used. A total of 69 MUs and 52 IEDs are used in the P2P DSS design. As discussed in the previous section, 10 MUs are alone used for distributing the Red and Yellow Bus voltages to 38 IEDs. Adding 69 MUs will require the station dc power system capacity to double. Finally, test switches and lockout IEDs are no longer needed in P2P DSS.

TABLE II
DEVICES USED IN P2P DSS DESIGN

Description	Units
Fiber-optic cable	67,775 feet
Merging unit	69
Line current differential IED	4
Distance IED	24
Overcurrent IED	9
Transformer IED	3
Bus differential IED	12

B. Protection Scheme Unavailability

Compared with traditional design, the P2P DSS design includes additional devices like MUs and fiber-optic cables. In this subsection, we use the well-known fault tree analysis technique to compare the two designs' relative unavailability of protection schemes [7]. A fault tree consists of a top event, the failure of interest, and basic events related to the top event and is typically expressed with a logic gate. Each basic event has an unavailability value that can be calculated using (1). Unavailability is the fraction of time when a device cannot function. It is unitless.

$$q \cong \lambda T = \frac{T}{MTBF} \quad (1)$$

where:

q is the unavailability value.

λ is some constant failure rate.

T is the average downtime per failure.

MTBF is the mean time between failures (λ^{-1}).

Table III lists the MTBF value and unavailability for each component used in the fault tree analysis. This paper uses the average downtime per failure of two days to calculate unavailability from the MTBF value. The calculation assumes human failures are 100 times less likely than hardware failures and take one year to detect and repair. Hence, unavailability for IED misapplication is calculated by multiplying the hardware MTBF by 100 and taking an inverse [7]. For simplicity, the MTBF values for traditional IED, P2P MU, and P2P IED are assumed to be equal.

TABLE III
UNAVAILABILITY FOR EACH COMPONENT

Component	MTBF (Years)	Unavailability (10^{-6})
Traditional IED	600	9.13
P2P MU and IED	600	9.13
IED Misapplication	NA	$(\text{MTBF} \bullet 100)^{-1} \bullet 1$ Year
Fiber-optic cable	5,000	1.10
Copper wiring	10,000	0.54
87L channel	NA	100
Circuit breaker	NA	300
dc power system	NA	50
Current transformer (per phase)	NA	10

1) Fault Tree Analysis for Line 1 Protection

The first fault tree analysis is carried out on Line 1 protection scheme for both the traditional system and P2P DSS design. The top event for the analysis is Line 1 protection fails to clear the in-section fault in the prescribed time. For this top event, we assumed that the remote substation design is identical to the local substation. Fig. 10 shows the fault tree for the top event for the traditional substation. This fault tree is constructed using the traditional protection system design shown in Fig. 3. This failure occurs if breakers, CTs, PTs, dc power system, wiring, 87L channel, or IEDs from either local or remote substation fail. Using redundant line current differential IEDs and CTs lowers the unavailability to 0.0074e-6 from 271.6e-6 for a single-line current differential scheme. Note that the substation under study has only one dc power source for both primary and secondary systems. The dc power system includes batteries, battery chargers, and dc power distribution.

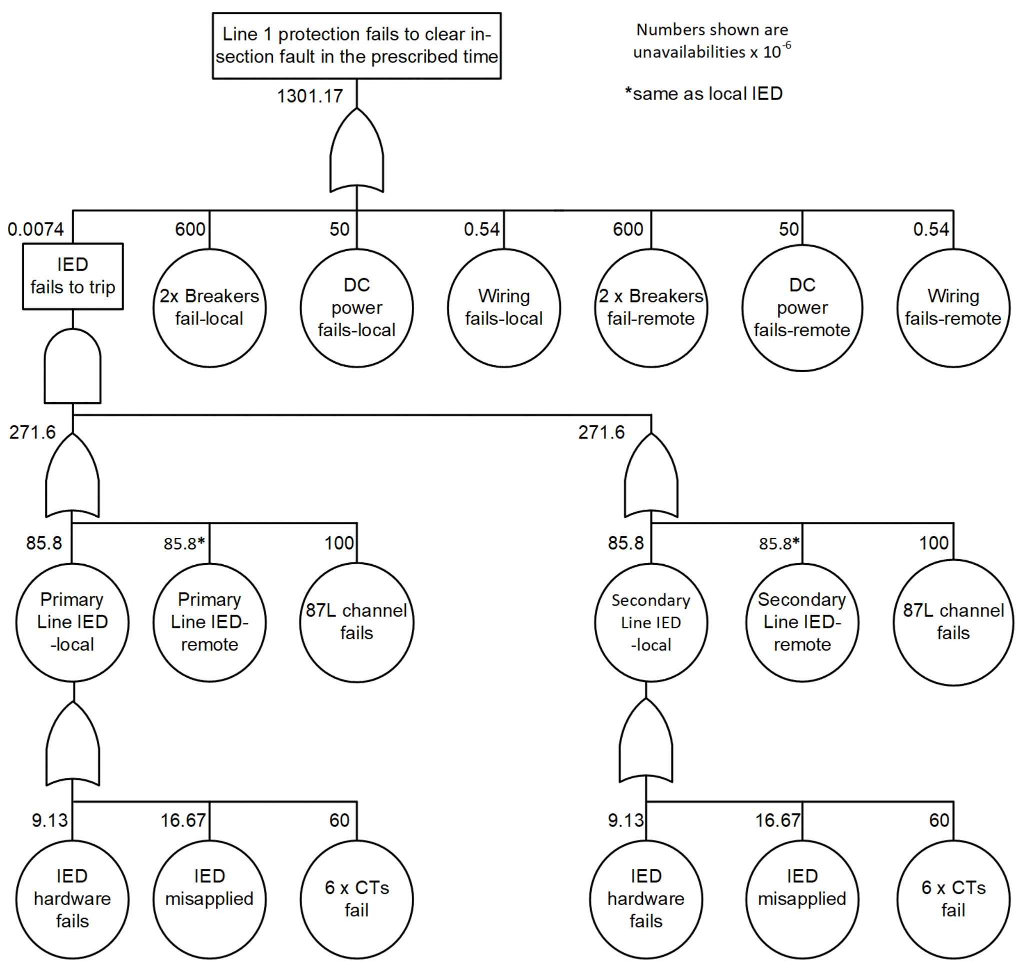

Fig. 10. Fault tree for Line 1 protection in a traditional substation.

The fault tree for the same top event for the P2P DSS design is shown in Fig. 11. The fault tree is constructed using the P2P DSS design from Fig. 4. For each IED, two P2P MUs and two fiber-optic cables are needed to subscribe signals from two CTs. Adding these devices increases the unavailability for 'Primary line IED – local' to 106.25e-6 from 85.8e-6 for traditional design, i.e., a 24 percent increase in unavailability. Using redundant MUs and IEDs for primary and secondary protection significantly lowers the unavailability value. The top event's overall unavailability difference between the two designs is negligible.

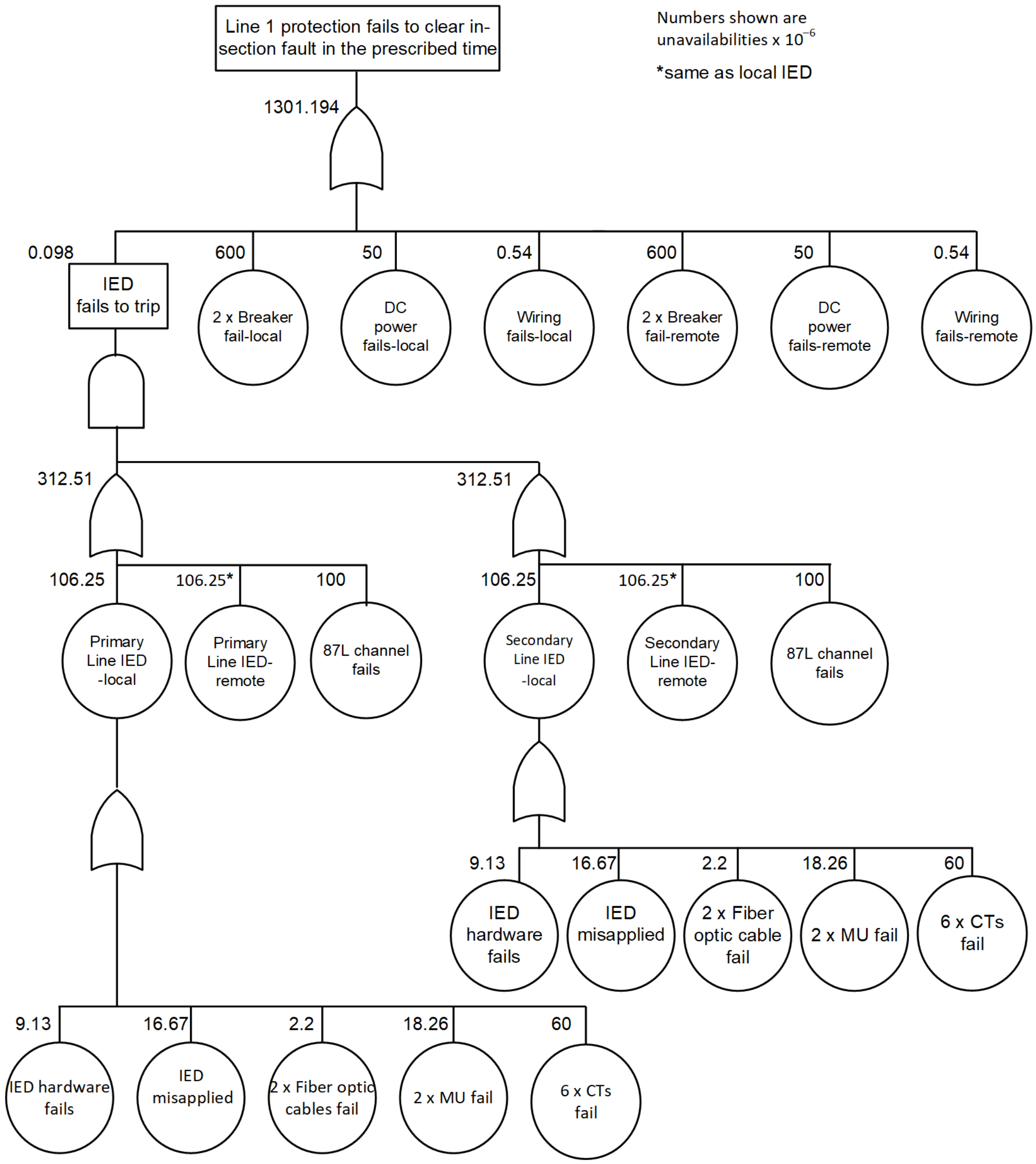

Fig. 11. Fault tree for Line 1 protection in a P2P-based substation.

2) Fault Tree Analysis for Bus Protection

Next, we consider the second top event—Bus protection fails to clear in-section fault in the prescribed time. The fault tree for the traditional substation is shown in Fig. 12. The fault tree is constructed using the design from Fig. 7. The overall unavailability value is primarily due to breakers and the dc power system. Redundant CTs and bus IEDs for primary and secondary bus protection minimized the IEDs impact on overall unavailability.

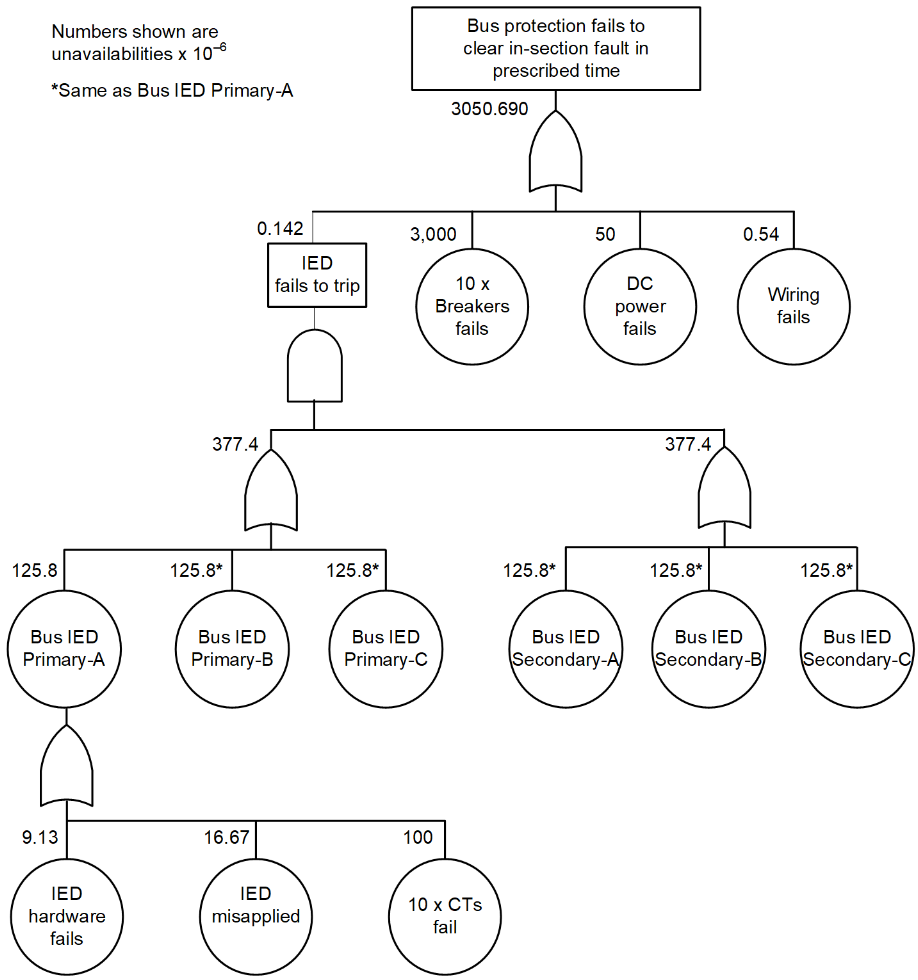

Fig. 12. Fault tree for bus protection in a traditional substation.

Fig. 13 shows the fault tree for the second top event constructed using the P2P DSS design from Fig. 8. Seven MUs and 21 fiber-optic cables are added to primary bus IEDs in the P2P DSS design. Redundant bus protection design minimized the impact of MUs, fiber-optic cables, and bus IEDs in the overall unavailability.

The overall unavailability of each solution for two top events is shown in Table IV. For each case, the unavailability of P2P DSS design is similar to the traditional design. Unavailability can be improved by selecting high-quality components with high MTBF values, designing simpler systems, or adding redundancy. Redundancy improves dependability, degrades security, and increases complexity and cost [8].

TABLE IV
OVERALL UNAVAILABILITY (10^{-6})

Solution	Line 1 Protection	Bus Differential Protection
Traditional substation	1301.170	3050.690
P2P-based substation	1301.194	3050.764

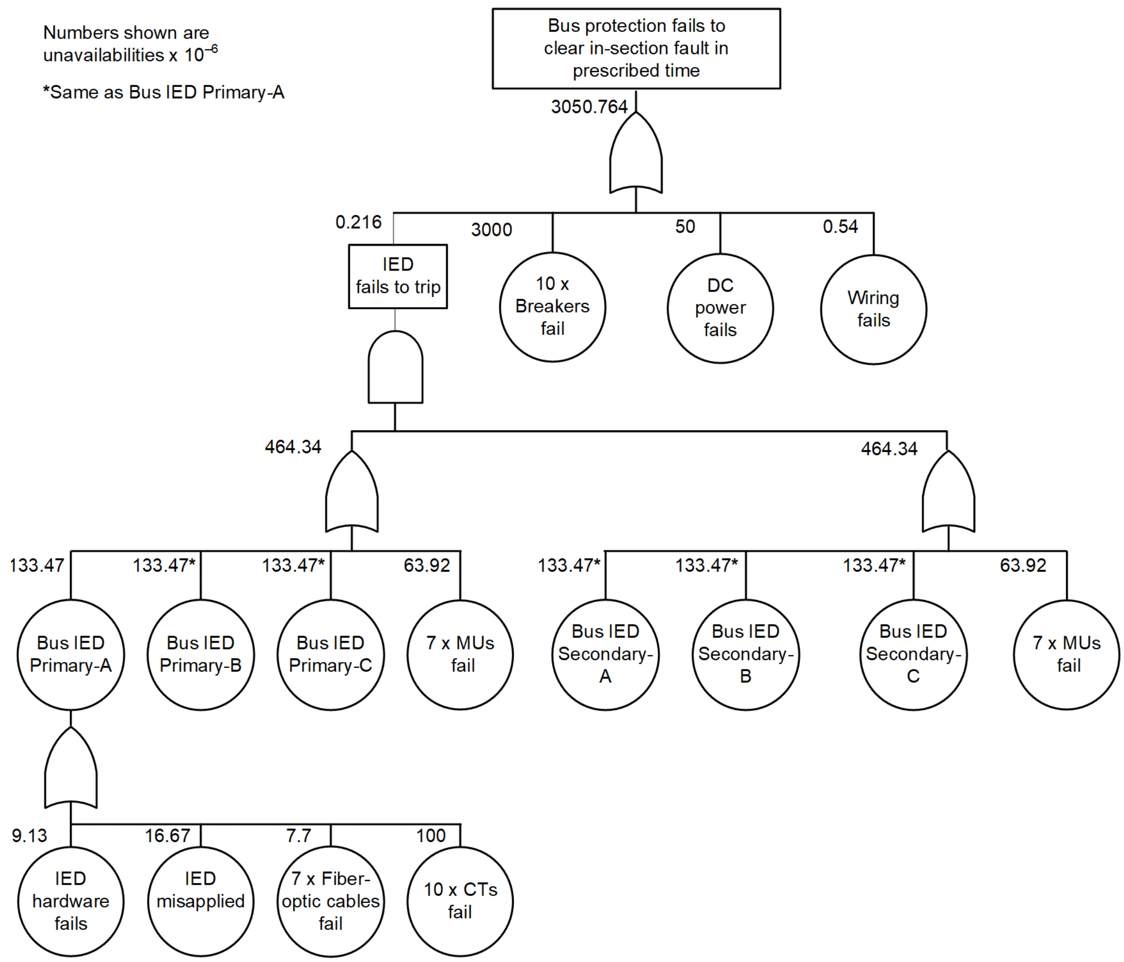

Fig. 13. Fault tree for bus protection in a P2P-based substation.

C. Protection System Operation Speed

Fast protection speed is one of the requirements for transmission substations at Duke Energy. Fast protection system operation speed results in faster fault-clearing time. When faults are cleared quickly, it enhances personnel safety, limits equipment wear and equipment damage, and improves the power quality. Similarly, transient stability is improved, and the power transfer can be increased when faults are cleared faster than the critical clearing time [9]. In this subsection, we compare traditional IEDs' protection system operation speed with P2P DSS IEDs.

In a P2P DSS, MU digitizes CT and PT signals and publishes them to the P2P IED. Similarly, the P2P IED sends a trip signal digitally to the MU. Since the MU acts as an interface between the primary equipment and the IEDs, there is a finite delay for fault detection and another delay for transferring trip signals. Consequently, protection system operation speed is adversely impacted if these delays are significant [5].

Fig. 14 illustrates the test setup used to compare the two solutions' protection system operation speed. A simple two-source power system connected by a transmission line is modeled in a real-time digital simulator. The local amplifier receives low-level signals from the simulator and provides voltage and current signals to the local end of traditional IEDs and P2P MUs. Similarly, the remote amplifier provides voltage and current signals to remote end traditional IED and P2P MU. Fiber-optic cables connect MUs and line P2P IEDs on both local and remote ends. Between two traditional line IEDs and two P2P Line IEDs, fiber-optical cables are connected for an 87L channel. Both IED pairs are configured with the same protection settings to protect a line. P2P Line IEDs have one binary output board, allowing the IEDs to send control signals to breakers or other IEDs. High-speed output contacts from traditional IEDs, P2P MUs, and P2P IEDs are connected to the simulator to send the trip signal.

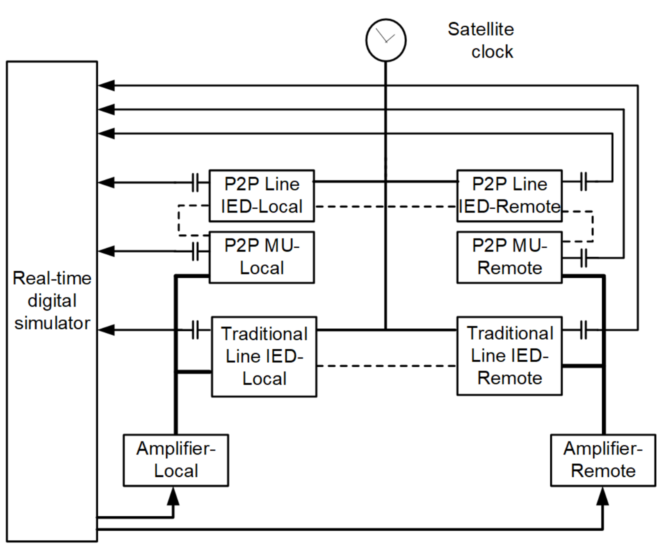

Fig. 14. Test setup used to compare protection system operation speed between traditional and P2P IEDs.

To compare the operation speed of the line current differential element (87L) between two systems, an A-phase-to-ground fault is applied at 10 percent of the line, and the IEDs response is recorded. Fig. 15 shows the time-aligned event reports from four IEDs following the fault. The current waveforms for the P2P IEDs lag behind the traditional IEDs' waveforms. This delay is set in the P2P IED to account for P2P MU sampling time and the communication delay between the MU and the P2P IED. For the P2P IED, the delay is fixed at 1 ms. As expected, the 87L element in the traditional IEDs operates faster than in P2P IEDs.

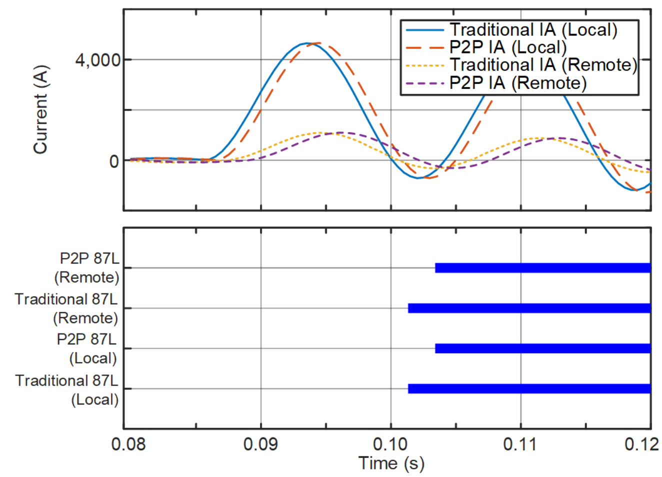

Fig. 15. 87L element operation time between traditional and P2P IEDs.

The time difference between the fault initiation and the trip signal's reception is called round-trip time. To compare the round-trip time of an 87L element, a fault is repeated 50 times. Fig. 16 shows the round-trip time measured by the simulator for traditional IEDs, P2P Line IEDs, and P2P MUs. The round-trip time is the lowest for the traditional IED and the highest for P2P MU. The variation in the round-trip time is due to the periodic nature of the test conducted and the processing interval of the IEDs. The difference between the maximum and minimum round-trip time for each IED is around 2 ms, which corresponds to the processing interval of the IEDs. Next, another test was executed to compare the round-trip time of distance (21) element.

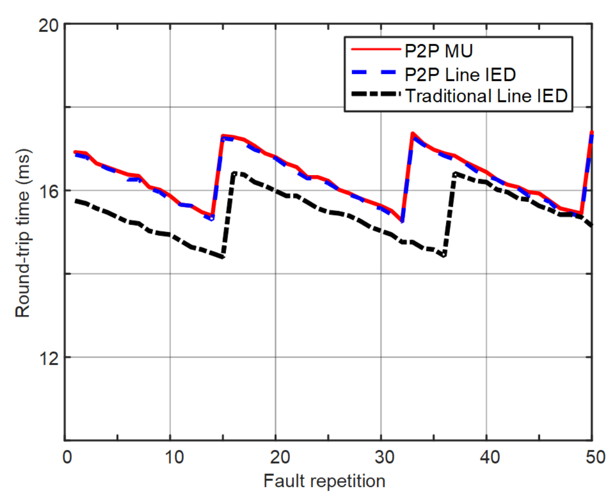

Fig. 16. Round-trip time for traditional IEDs, P2P MUs, and P2P IEDs.

The average round-trip times for 87L and 21 elements are tabulated in Table V. The traditional IED was the fastest to respond to faults, followed by P2P IED and P2P MU. Therefore, compared with the traditional system, the P2P-based system operation speed is slightly slower, around 1 ms. In other words, when P2P DSS design is selected, the overall IED operating time is delayed by 1 ms.

TABLE V
AVERAGE ROUND-TRIP TIME AND DIFFERENCE WITH RESPECT TO TRADITIONAL IED

Solution	87 Element		21 Element	
	Trip Time (ms)	Difference (ms)	Trip Time (ms)	Difference (ms)
Traditional IED	15.427	NA	21.251	NA
P2P IED	16.261	0.834	21.965	0.714
P2P MU	16.316	0.889	22.025	0.774

VII. Lessons Learned and Future Plans

There were many lessons learned from this collaborative case study. With the design requiring full redundancy in all devices and relays, the number of MUs and IEDs required was quite significant (52 IEDs, 69 MUs). This issue alone resulted in the need for a much larger substation battery. The full redundancy requirement with the P2P provided a highly reliable design with virtually no impact on protection reliability. Limitations were noted with the number of ports on the MUs when applied to the substation design used in this study. This substation also has many breakers (and CTs) per bus section and one set of bus PTs tied to many relays.

Initial plans are to start with lab testing of the P2P technologies. This testing will include formulating plans for how all components would be tested and commissioned in the field. Initial testing in the laboratory would allow setting engineers the opportunity to convert existing setting templates to what would be required for the P2P technology. The next steps would include introducing the new technology to field resources to determine the testing required and how commissioning would occur in the actual substation. Key commissioning questions would need to be answered:

1. How can CT connections to MUs be verified?
2. Will test blocks for injecting test currents at the MUs be required?
3. How will configuration data on MUs be captured and stored in the relay database? (Note: the MU from the manufacturer does not have any settings.)
4. Will any additional security measures be required to secure physical access to MUs to ensure all compliance requirements are met?

After the lab testing and development work with field technicians is completed, plans would include selecting a predeployment location on the system. Initially, a transmission line terminal would be selected, allowing all the traditional line protective relaying to be replaced with a new standard protection package and a third relay utilizing the new P2P technology. No tripping would be allowed from the new P2P relay, but this would allow the full testing and commissioning process to occur in a substation. Caution should be utilized in moving any new technology from the lab to the real world. Any system faults that occurred within the protected line would allow for the full comparison of relay speed in tripping. Any faults outside of the protected line would provide confidence in the security of the new technology. There is no better way to build confidence and a working knowledge of a P2P protection package other than by evaluating how it operates and performs in a real application.

With predeployment, lessons will be learned, and further evaluation of the P2P technology will be made to determine if a larger-scale implementation should be considered. For example, if unseen problems of implementation/testing difficulties are experienced or if objectives and goals of copper reduction are not achieved, a larger-scale implementation might not be attempted.

If the P2P technologies prove to be reliable and can be installed and tested with little difficulty or challenges, they will provide another useful tool in the application engineer's toolbox. Additional work would then be required to determine the criteria of when to use the technology.

The successful implementation of copper reduction with P2P technologies would provide a steppingstone for additional digital substation protection technologies in the future. However, if the challenges and objectives cannot be met with the P2P technology that is viewed as "simpler" or "less complex" as compared to the network-based approach, then the addition of an Ethernet network, additional devices, and programming would not be an attractive solution to pursue.

VIII. Conclusion

Duke Energy's future plan includes the use of P2P DSS to reduce the amount of copper utilized in traditional substation protection designs. To learn more about P2P technology, a detailed P2P DSS design for Duke Energy's existing 100 kV transmission substation was carried out as a collaborative case study. The P2P MU and the protection IEDs used for this study have four and eight communication ports, respectively. This port limitation poses a unique challenge when implementing bus differential protection for 10 breakers. Similarly, supplying bus voltages to 18 IEDs requires multiple MUs connected to the same PT source. Solutions for these problems are described in detail in the paper. Following the design, the P2P DSS is compared against traditional design using total device count, protection scheme unavailability, and protection system operation speed as criteria. It was observed that the P2P DSS design requires multiple MUs. On the other hand, protection scheme unavailability and protection system operation speed are found to be very close between the two designs.

Duke Energy is planning to use the technical data from this case study to evaluate P2P technology. In addition, the plan is to start lab testing on P2P MU and P2P relays. Following successful lab testing, the company plans to pursue the predeployment of P2P technology in a transmission line application.

IX. References

[1] R. Hunt, "Process Bus: A Practical Approach," *PACWorld Magazine*, Spring, 2009, pp. 54–59.

[2] J. M. Byerly, "AEP and Process Bus: Balancing Business Goals and Choosing the Right Technical Solutions," proceedings of the 42nd Annual Western Protective Relay Conference, Spokane, WA, October 2015.

[3] Schweitzer Engineering Laboratories, Inc., "Digital Secondary Systems," August 2021. Available: selinc.com/products/distribution/protection/digital-secondary-systems/.

[4] IEC 61850-90-4: 2020, *Communication Networks and Systems for Power Utility Automation - Part 90-4: Network Engineering Guidelines*.

[5] A. Shrestha, M. Silveira, J. Yellajosula, and S. K. Mutha, "Understanding the Impacts of Time Synchronization and Network Issues on Protection in Digital Secondary Systems," proceedings of the 8th Annual PAC World Americas Conference, August 2021.

[6] A. Shrestha, S. K. Mutha, D. Kattula, N. McAfee, R. Vergara, M. Webb, and V. Cecchi, "Comparative Evaluation of Two Process Bus Solutions for a Distribution Substation," proceedings of 48th Annual Western Protective Relay Conference, Spokane, WA, October 2021.

[7] E. O. Schweitzer, III, B. Fleming, T. J. Lee, and P. M. Anderson, "Reliability Analysis of Transmission Protection Using Fault Tree Methods," proceedings of the 24th Annual Western Protective Relay Conference, Spokane, WA, October 1997.

[8] E. O. Schweitzer, III, and D. E. Whitehead, "Resetting Protection System Complexity," proceedings of the 46th Annual Western Protective Relay Conference, Spokane, WA, October 2019.

[9] E. O. Schweitzer, III, B. Kasztenny, A. Guzmán, V. Skendzic, and M. V. Mynam, "Speed of Line Protection - Can We Break Free of Phasor Limitations?" proceedings of the 41st Annual Western Protective Relay Conference, Spokane, WA, October 2014.

X. Biographies

Stephen B. Ladd received his BSEE from Grove City College in 1986, MSEE from Georgia Tech in 1987, and MBA from Queens University of Charlotte in 2003. He has been a member of IEEE for 37 years and a member of IEEE-PES since 1987. He is a registered Professional Engineer in the state of North Carolina and has worked at Duke Power, Duke Engineering & Services, and Duke Energy Corporation since 1987. Mr. Ladd has held engineering positions in Substation Apparatus, Protection & Control, and Asset Management. He is currently a Principal Engineer in the Transmission System Standards group.

Ethan Haithcox received his BSEE and MSEE degrees from North Carolina State in 2014 and 2020, respectively. He is a registered professional engineer in the state of North Carolina and has worked at Duke Energy since 2014. Ethan has held positions as a protection engineer and, more recently, as the Protection and Control Settings group manager.

Kelby Perren recently graduated from the University of North Carolina at Charlotte. He received a BS in electrical engineering, and his interests primarily focus on renewable energy and microelectronics.

Robert Koch recently graduated from the University of North Carolina at Charlotte. He received a BS in electrical engineering, and his interests primarily focus on power and energy systems.

Kaitlin Slattery is a recent alumna of the University of North Carolina at Charlotte. Her degree is in electrical engineering, and her interests are in power and energy systems.

Matthew Weaver is a recent alumnus of the University of North Carolina at Charlotte. His degree is in computer engineering.

Matthew Zahn recently graduated from the University of North Carolina at Charlotte with a BS degree in computer engineering.

Arun Shrestha received his BSEE from the Institute of Engineering, Tribhuvan University, Nepal, in 2005, and his MS and PhD in electrical engineering from the University of North Carolina at Charlotte in 2009 and 2016, respectively. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2011 as an associate power engineer in research and development. He is presently working as a senior engineer. His research areas of interest include power system protection and control design, real-time power system modeling and simulation, wide-area protection and control, power system stability, and digital substations. He is a senior member of IEEE and is a registered Professional Engineer. He is a member of IEEE PSRC and a U.S. representative of IEC 61850 TC 57 WG 10.

Sathish Kumar Mutha received his MS degree in electrical engineering in 2020 from the University of North Carolina at Charlotte. Prior to earning his MS degree, he worked as a power plant operation engineer in India. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2019 as an engineer intern. He is currently a power engineer at SEL.

Luke Booth received his BSEE from the Georgia Institute of Technology in 2015. Upon graduation, he joined the Protection and Control Field Service division of Georgia Power, where he commissioned protective relays across Georgia Power's system. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2017. He is currently a field application engineer for SEL, supporting Duke Energy and other SEL customers in western North Carolina. Luke focuses on system protection and is a registered Professional Engineer.

20220909 • TP7084-01