Case Study: Deploying and Operating a Point-to-Point Digital Secondary Substation at One Power

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***Abstract*—The integration of digital secondary system (DSS) technology in substation protection and control represents a pivotal advancement in power system design and operation, opening the door to an array of benefits. However, there is still a significant demand for additional real-world data that contrast the practical benefits and challenges of a DSS when compared to conventional systems.**

On September 7, 2023, One Power Company (One Power), located in Findlay, Ohio, completed the constructing, commissioning, and energizing of their first substation, utilizing a point-to-point (P2P) digital protection and control architecture for high-volume power connections. This substation has created a valuable data set for the application of DSSs. Since its inception, the company has continued successful commercial operation of the substation with plans to fully embrace DSS technology and help pioneer further adoption and implementation across the industry.

This paper reviews the company's design, implementation, and operation of a purpose-built and in-service DSS substation that utilized a P2P process bus solution. The paper discusses why the engineers of the company selected this DSS architecture, which commissioning and operating strategies were utilized, and what benefits and challenges were realized throughout the project. The paper also covers their vision to drive innovation in the deployment of future DSS installations.

I. Introduction

Protective relaying is a critical part of the electric power system. Reliable protection allows the grid to operate efficiently, ensures the longevity of critical assets, and offers safeguards against hazardous conditions. Historically, as power systems, utility processes, and technologies have evolved, protection has been adapted to accommodate, notably with the introduction of digital relays several decades ago. Introducing new, revolutionary tools leads to increased visibility, data sharing, and easier troubleshooting methods. These tools include digital fault recorders, relay digital behavior recording, diverse communications capabilities, and flexible protection and automation-based logic. Such advancements allow for the development of more comprehensive solutions, providing value beyond singular apparatus protection.

DSSs represent a new approach to deploying advanced protection and monitoring of power systems. A DSS digitizes all analog and digital signals between the substation yard and the control enclosure via the installation of a merging unit (MU) device in the yard acting as a primary interface with the current transformer (CT), potential transformer (PT), status, alarm, and trip, and close signals. The MU concept allows for a device in the yard to consolidate, disseminate, and react to the real-time system via fiber-optic links connected to multiple relays. With this approach, a user can realize several benefits, including material savings in secondary cabling, speed of installation, and simplification of engineering.

There are two DSS architectures that are typically deployed: networked and point-to-point (P2P). A networked architecture uses Ethernet protocols and switches to broadcast information between devices in the protection scheme. A P2P architecture connects MUs directly to relays with no switching device in between. There are pros and cons to each approach, but in general, the networked approach has increased flexibility with the tradeoff of added complexity. The P2P solution has the inverse effect, in which deployments can be simplified but flexibility is limited by the number of connections available between devices.

For the application in this paper, engineers of the company evaluated the pros and cons of both architectures and decided a P2P architecture was the best fit. This paper examines the benefits and challenges observed by engineers during deployment.

II. About the Company

Established in 2009, One Power is a vertically integrated industrial power solutions company and the largest installer of onsite behind-the-meter wind energy in the United States. Specializing in developing, constructing, owning, and operating state-of-the-art power solutions for industrial clients [1], the company is actively implementing the Utility 2.0 concept—a decentralized, user-centric power grid that empowers industrial clients to produce their own onsite renewable energy [1]. These projects enable better power system monitoring, long-term competitive-rate visibility, and enhanced reliability [1]. Featuring advanced technology with an emphasis on reliable and robust designs, the company leverages real-time data rather than pure device redundancy.

III. The Company's Design Goals

One Power has been deploying behind-the-meter industrial generation for over 15 years using relays enclosed within local equipment cabinets on systems 34.5 kV and below. In 2022, the need for more complex relaying for voltages that interconnect at the transmission level led to the exploration of new technologies like DSS concepts. A framework was developed, and the company's Utility 2.0 substation philosophy became the following:

> The substation should be hassle-free, be easily replaceable, and have maximum uptime. One Power believes that the current substation design is out-of-date and needs to be improved. A substation design should emphasize reliability, safety, security, and state-of-the-art protection and control.

With that philosophy applied, the company quickly gravitated toward the P2P solution. P2P is analogous to the plug-and-play methodology seen in the early stages of the computing industry and is still widely used today.

A P2P solution accomplished every goal in the Utility 2.0 substation philosophy statement. Placing MUs in the yard with P2P connections can be conceptualized as making the MU a direct extension of the relay, rather than an independent device.

- Reliability—fault tree calculations of P2P DSS solutions compared to conventional systems can be shown to have similar exemplary values for reliability [2].
- Safety—localized CT/PT to MU wiring in the yard cabinet with relay interfaces being in the control enclosure reduces hazards to personnel and is inherently safer.
- Security—the elimination of a networked architecture and usage of a nonroutable protocol are highly secure.
- State of the art—protection schemes utilizing a P2P DSS architecture are emerging technologies offering new advantages and capabilities over conventional systems as well as maintaining tried-and-true protection and control functions.

IV. The DSS's Design

An overhead view of the DSS substation is shown in Fig. 1.

Fig. 1. The 138 kV/34.5 kV DSS substation.

A. *Station Layout*

Fig. 2 depicts the station one-line diagram with mappings for the MU-to-relay connections and protective relay elements implemented.

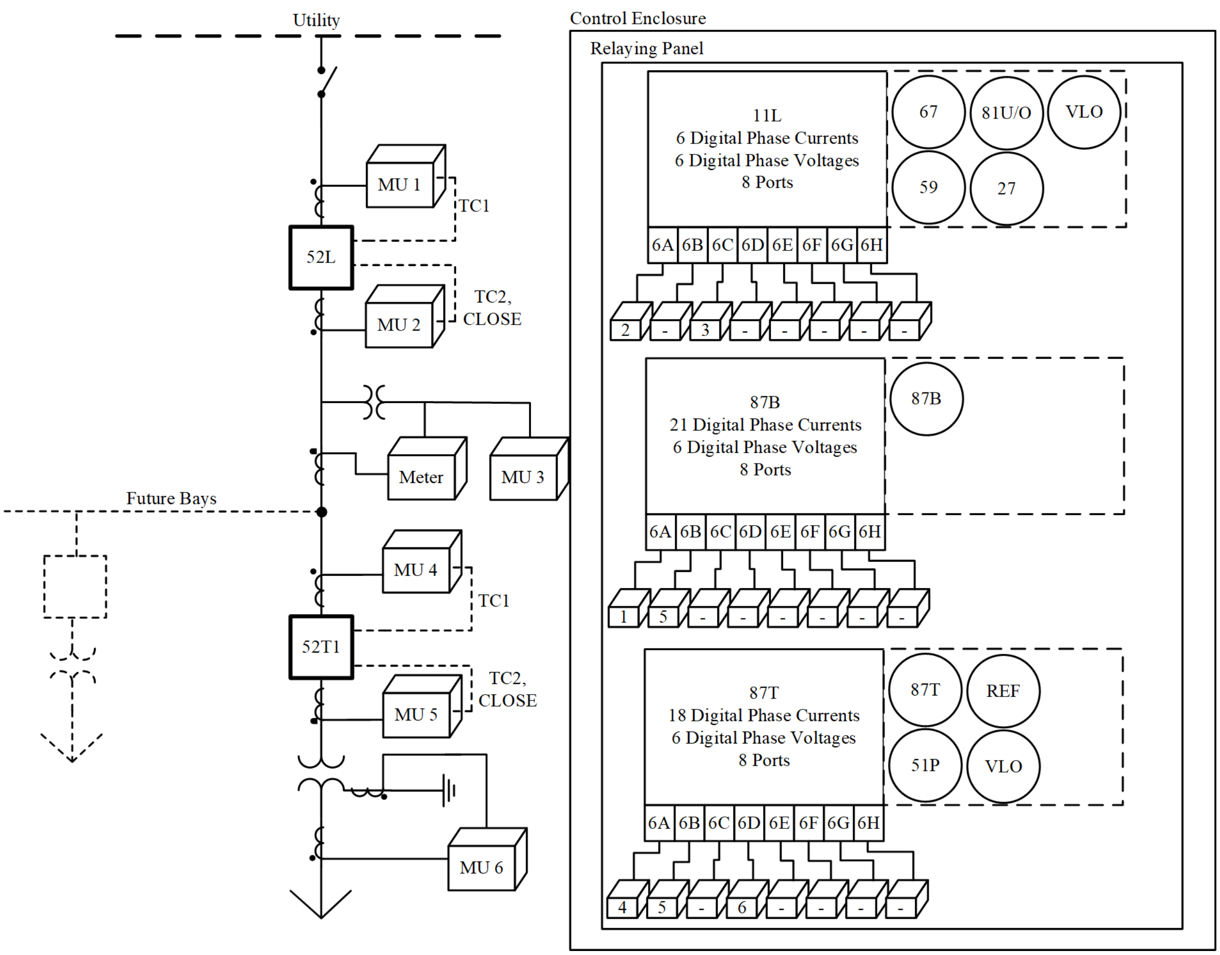

Fig. 2. System one line of the company's DSS substation.

The company's substation connects to the local utility's 138 kV transmission system. A motor-operated disconnect (MOD) switch isolates the entire substation from the electric system. The MOD switch is controlled via a remote input/output (I/O) module that communicates via P2P serial communications over fiber-optic cabling. The remote I/O module has physical dual-position control switches that establish the settings for the communications channel but is otherwise a settings-free device. The remote I/O module is connected to the 11L relay that performs the logical control of the MOD switch.

Downstream of the MOD switch is the line breaker 52L, which has two MUs installed in its control cabinet. One MU is connected to CTs on the source side of 52L, and the other is connected to the load-side CTs. The source-side MU is connected via fiber-optic cabling to the 87B relay, and the load-side MU is connected to the 11L relay.

Each MU has its own connection to one of the two trip coil circuits available on the breaker. Only one of the two MUs per breaker is wired to the close coil of the breaker. Having a single MU for a breaker closing allows for a single point of close and lockout logic. For maintenance and troubleshooting, the breakers can be operated independently using the hardwired switches inside the local control cabinets. Each of the MUs has a Form B contact that is logically held open under normal conditions, connected to an input on the other MU in that cabinet. This serves as an indication of device health reported between the two devices and is further discussed in Subsection B. Downstream of the 52L breaker are two sets of freestanding CT/PT metering transformers, along with two separate secondary cabinets. One cabinet provides the connections to the connecting bulk electric system utility's revenue meter. The other contains the company's revenue and power-quality (PQ) meter in addition to an MU used for providing the protective relays with digital voltage measurements from the 138 kV bus. All of the 138 kV conductors are aluminum conductor steel-reinforced (ACSR)-type flexible strain buses; these allow for easier and faster system reconfigurations over rigid bus conductors. The transformer high-side breaker (52T1) has a similar configuration to the 52L breaker, with two MUs measuring currents on the source and load sides.

The 30 MVA, 138 kV to 34.5 kV delta-wye transformer has a single MU in its cabinet. This MU provides current measurement data for the transformer low-side winding as well as transformer neutral current from a CT on the neutral leg. The low side of the transformer then connects via underground cabling to pad-mounted switchgear to feed the respective industrial load.

MU fiber connections run to a small patch panel within the primary equipment cabinets. These fibers are patched to a 6-pair fiber-optic bundle (allowing for rapid link restoration should a fiber failure occur) that routes from the control enclosure through trenches in the substation yard. Each bundle is brought into another fiber patch panel within the control enclosure, where the singular fiber pairs are then run to the corresponding DSS relay port. Instrument transformers are connected in the primary equipment cabinets via color-coded terminal blocks, promoting standardized wiring dictated by the company's standards. Test switches are included within each primary equipment cabinet, allowing for the ability to isolate MUs from secondary signals.

The substation is designed to be easily expandable with a future build planned out of five total transformer bays. The expansion has been modularized to be a copy of the existing 52T1 breaker, transformer, and feeders. When all five transformer bays are added, the farthest distance between the primary equipment cabinets to the control enclosure will be around 500 feet.

The control enclosure is 10 by 20 feet with three 19-inch equipment racks (open frame and server style). One rack contains the networking, supervisory control and data acquisition (SCADA), and human-machine interface (HMI) equipment. The other two racks contain the protective relays. Even with the substation fully expanded to five transformer bays, the existing two relay racks have space for future protective devices. This is attributed to the smaller form factor of the DSS protective relays and the test switches being installed in the primary equipment cabinets with the MUs. Also housed in the control enclosure are the battery backup system, custom-made ac/dc load centers, fiber-optic patch panels, ancillary lighting, and station monitoring equipment.

B. Relay Programming and Protection Philosophy

This substation is a tapped load off the utility transmission line, and line protection is not included in this scheme. The 11L relay provides directional overcurrent, overvoltage or undervoltage, and overfrequency or underfrequency protection. While the 87B relay provides low-impedance bus differential protection, the 87T relay provides low-impedance transformer differential, restricted earth fault (REF), and high-side overcurrent protection. The 87B relay is also the aggregator of the lockout and relay failure signals from the other relays in the station because it has MUs in all current and future breakers. This provides a single point of reference for the breaker lockout status that is desired for a virtual lockout relay [3]. When the 11L or 87T relay issues a trip, a status is sent via P2P serial communications to the 87B relay to activate the virtual lockout logic in the 87B relay. The 87B relay can also use a local trip from the relay to declare a breaker lockout status. Once the lockout logic is activated, the 87B relay returns serial communications to digitally block close operations from being issued at the respective devices. The logic in these relays prevents the breaker close logic in MU2 and MU5 from operating. This lockout signal is programmed in nonvolatile memory that retains its state if the relay is power-cycled. The use of these virtual lockout relays allows the removal of physical lockout devices, saving additional space and reducing wiring.

Breaker failure (BF) protection is handled similarly to virtual lockout statuses. A BF initiate is triggered by a protection trip in the local relay or a digital bit received from P2P serial communications between devices.

MU failure is handled via the hardwired contacts between the pair of MUs at each breaker. The contact is a Form B contact that is energized under normal conditions. For an MU failure or loss of power, the contact would fall to its de-energized state, indicating a failure to its corresponding MU. When an MU failure occurs, a trip to that breaker is issued from the other MU. Similarly, the PQ meter has a hardwired contact to an input on MU3 to allow the communication of an alarm or failure status to the 87B relay. Relay failure is communicated via hardwired contacts to the 87B relay that aggregates and distributes trip signals similarly to how an MU failure is handled.

All relays in the scheme have hardcoded algorithms to monitor the status of the communications channels of their connected MUs. When data loss is detected on an analog channel required for protection functions, the affected elements are automatically blocked via the relay's internal supervisory logic or based on custom user logic. In the company's scheme, the bus differential element is automatically blocked upon current analog data loss in the 87B relay. After the loss of current analog data in the 87T relay, the transformer differential and REF elements are automatically blocked. In the 11L relay, loss-of-voltage analog data from the connection to MU3 result in the relay's loss-of-potential logic asserting, which in turn, blocks the directional overcurrent elements. All relays in the scheme can digitally invert the instrument transformer polarity. This allows for standardized wiring for breaker cabinets while still being able to have the correct secondary signal polarity for protection elements.

C. Installation Strategies

Engineers of the company worked with the breaker manufacturer to include the MU preinstalled and fully wired. This was the first time an MU of this type was integrated into a circuit breaker cabinet by the given manufacturer. Provisions had to be made to allow space on both sides of the MU to access the analog, digital, and communications ports. The ability to have the MU factory installed into the yard equipment streamlines installation. Upon installation at the site, the secondary breaker terminated one 12-conductor cable for ac and dc power (five conductors were spares) and one 6-pair fiber cable.

D. Brownfield vs. Greenfield Conversion

The substation was originally constructed using rental circuit breakers, shown in Fig. 3, due to the long lead times from the factory for new breakers with the MUs installed. This required MUs and test switches to be retrofitted into the breaker cabinet design via a supplementary primary equipment cabinet. Retrofitting existing cabinets with MUs was a straightforward process; however, it required engineering resources to create drawings, and additional time was required for field installation.

As breaker replacement for a conventional scheme may take two to three days, depending on the application and situation; instead, engineers of the company were able to swap both rental breakers with their permanent replacements in a single day. Greenfield applications in which equipment can be ordered with MUs installed from the manufacturer offer the greatest benefit in engineering-resource saving. This is discussed in more detail in Section VI.

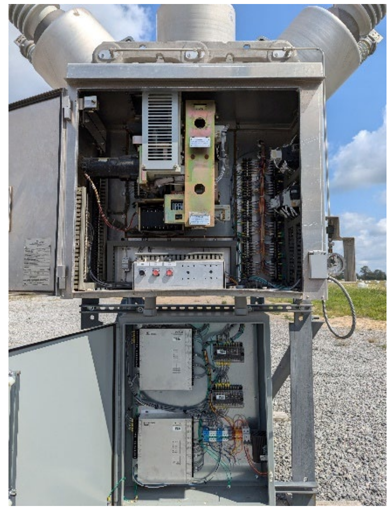

Fig. 3. Rental breaker MU retrofit.

The benefits of a DSS presented themselves early on when the permanent primary equipment, shown in Fig. 4, was received and swapped out with the rental equipment. The breaker manufacturer installed MUs into permanent breakers and cabinets, which allowed the company to swap equipment faster.

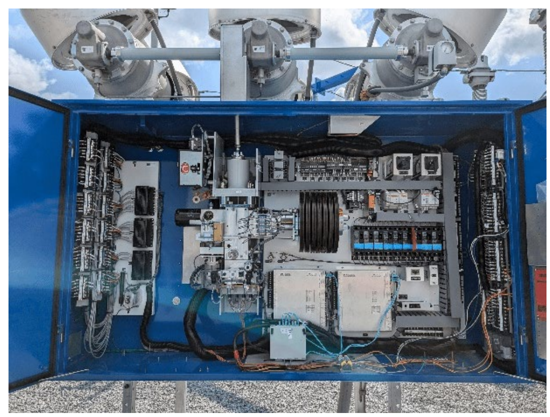

Fig. 4. Permanent breaker MU integration.

E. Security

Based on the design plan, engineers of the company chose to implement software-defined networking (SDN)-capable Ethernet switches to perform SCADA communications. These switches have built-in security for operational technology networks, requiring communications to be purposely engineered for enhanced performance and security [4]. These devices deny by default, allowing only whitelisted communications to take place. This design choice was independent of the decision to utilize a P2P DSS solution but was selected as the technology of choice for securing their station bus communications. The station was also designed with a redundant relay, MU, and breaker control power via an onsite battery bank, backup ac propane generator, and dc uninterruptable power supplies.

F. DSS Adoption

The adoption of a DSS is more than a change to secondary and control circuit wiring. Engineers of the company observed a change in the skill set required to commission, test, and troubleshoot a DSS application. Field technicians now need skills and knowledge in establishing, validating, and troubleshooting fiber-optic communications channels and relay digital signal mapping instead of interpreting physical contact and control circuit schematics. To aid in this change in skill set, engineers implemented changes in drawings using color and highlighting to relate MUs back to the protective relay function. An example of how this could look is shown in Fig. 5, Fig. 6, and Fig. 7. In addition, the company's openness to leveraging relay logic to perform many functions traditionally performed outside of digital relays (such as the implementation of virtual lockout relays) has led to a simplification of drawing packages.

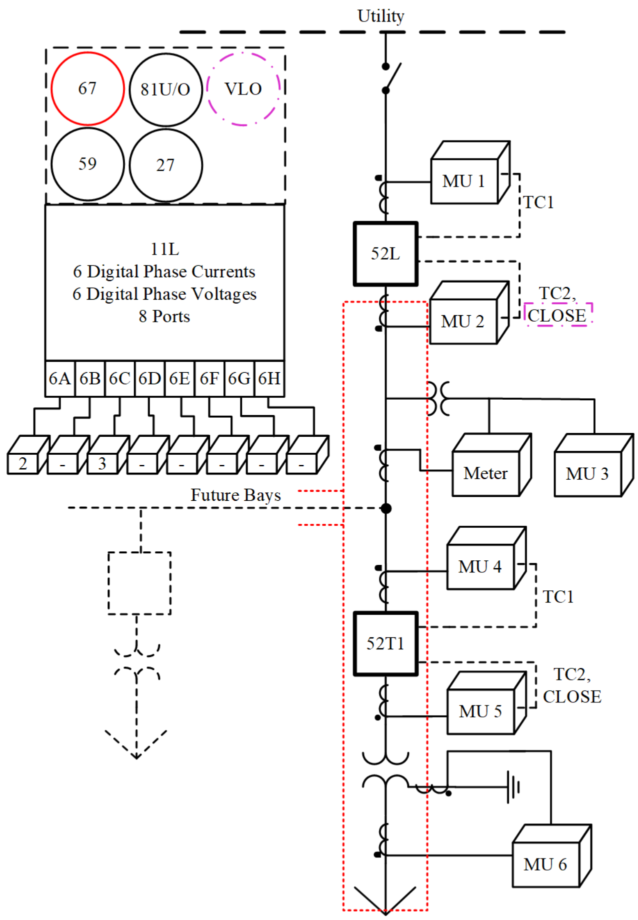

Fig. 5. Highlight of the 11L relay protection element zone.

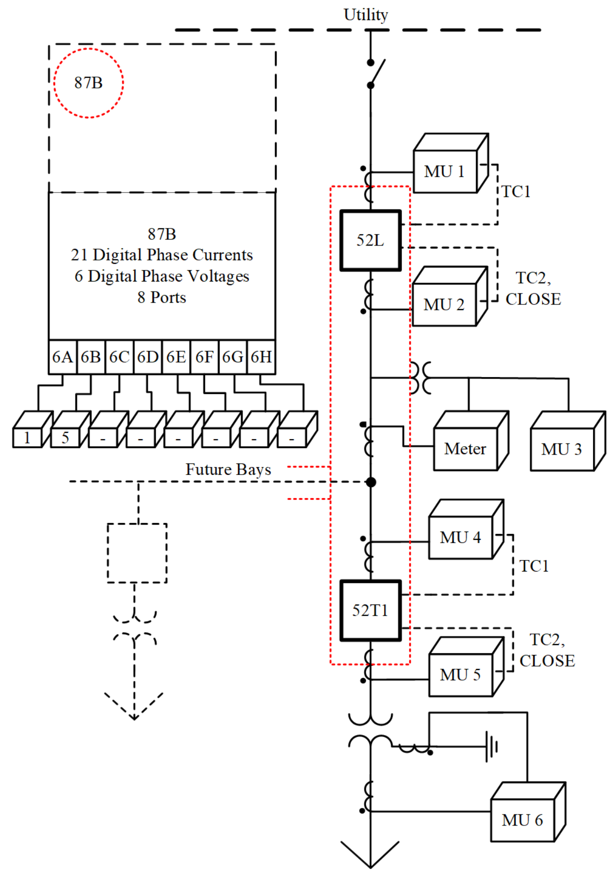

Fig. 6. Highlight of the 87B relay protection element zone.

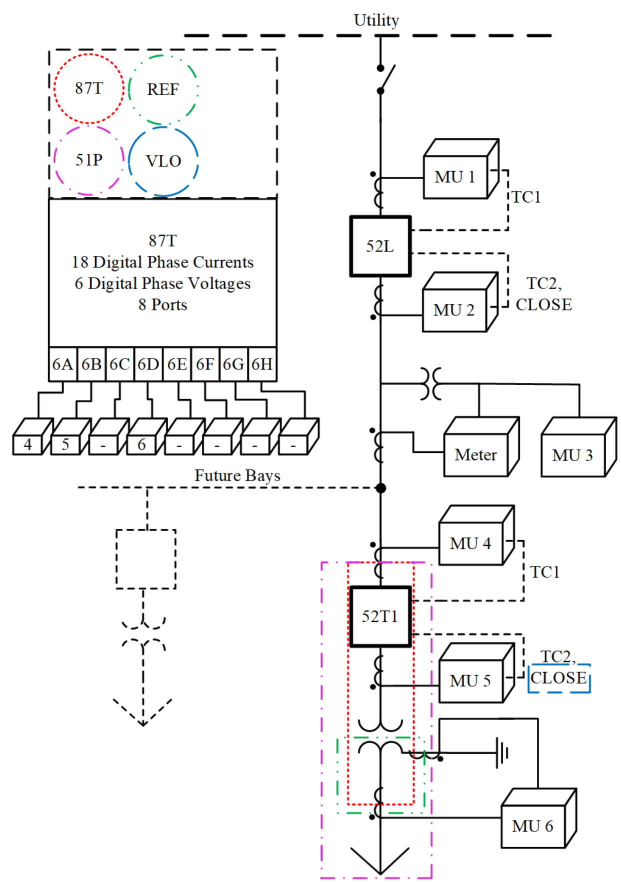

Fig. 7. Highlight of the 87T relay protection element zone.

V. Installing, Testing, and Commissioning

The implementation of a P2P DSS retains many of the same operating principles as analog secondary systems while simplifying the installation by moving from multiple secondary cables to fiber-optic connections. As mentioned earlier, using a P2P architecture allows users to conceptually treat the MU as an extension of the relay. This architecture allows field personnel to acclimate quickly because many deployment concepts remain unchanged, with procedures now just taking place at the MU instead of in front of the relay. However, because of the distributed nature of the system, new working procedures to implement these concepts are required to make the system practical.

Prior to construction and as part of relay setting development, the MU-to-relay digital mapping needs to be laid out properly to streamline deployment in the field. This mapping applies analog and digital signals in the MU to logical quantities in the relay, analogous to landing secondary cables on terminal block connections. Mapping MU quantities to relays is straightforward and is contained in a settings file used by the relay. This means the mapping is stored and controlled just like any other relay settings file, and managing the digital "wiring" between devices becomes as simple as a few settings changes.

During construction, it is extremely important to verify that all fiber-optic cables are tested to ensure the proper path of connectivity and that no glass is broken. This resembles a traditional installation method in which each cable is tested with a dc injection test set to verify that the insulation is not damaged. Additionally, the transmit and receive terminations for each fiber pair need to be confirmed; it is a simple but common mistake to shine a light on a fiber, confirm continuity, and then plug it into the port backward. It is also common when using intermediate patch panels to swap pairs, which results in multiple fiber path issues that can be tedious to organize. An example of the proper transmit and receive fiber pair with intermediate patches is shown in Fig. 8.

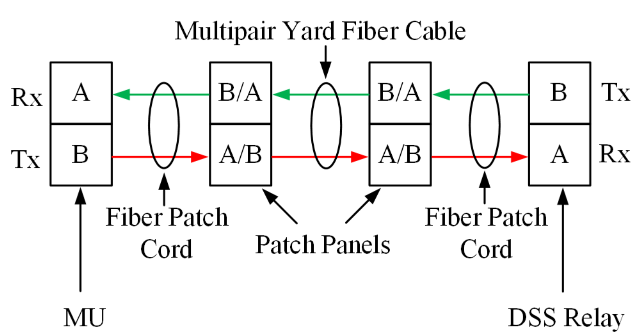

Fig. 8. Example MU to DSS relay fiber-optic cabling.

Once relay power is available for both the relays in the control enclosure and the MUs in the yard, the basic communications between the devices can be verified. For the company's implementation, this first required uploading the settings to the relays, inclusive of the MU port mapping. During this upload, the MUs were digitally commissioned to associate the proper MU-to-relay connections and allow for communications verification. While generating a standard report of verification checks for the user, the relay and MU automatically verify fiber port connections, health, expected analog channels, and expected inputs/outputs. If the devices are not connected and communicating properly, the digital commissioning fails, and the relay reports an error message to help indicate which problems were encountered. The company performed troubleshooting to achieve proper connectivity that generally consisted of the reverification of fiber paths, the swapping of small form-factor pluggable (SFP) modules in the MU, and, in one case, the replacement of an MU. Working with the manufacturer, engineers from the company found the issue to be a loose internal cable with a removable connector; additional processes were rapidly deployed by the manufacturer to ensure there were no future issues. Using the P2P topology makes this process more straightforward because each connection only has a limited number of failure points to be checked. Alternatively, in a networked system topology, users would need to cross-reference switch settings and use tools like Wireshark to troubleshoot connections and traffic.

After the equipment installation was completed, relay testing and site commissioning activities began. One approach to test a P2P DSS deployed from the company was to apply traditional testing methods used with analog secondary systems. The primary difference in testing methodology was the physical location where the signals needed to be applied. For example, in an analog secondary system, the test set is situated in the control enclosure within a few feet of the relay(s) under testing. This allows for current and potential injections directly into the relay as well as monitoring breaker status, trip, and close timing. A high-level diagram of this workflow is shown in Fig. 9.

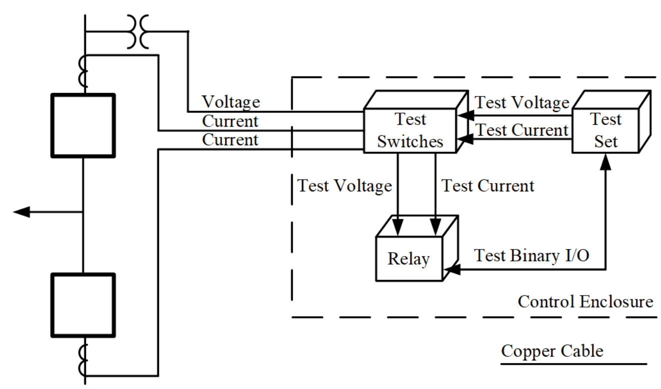

Fig. 9. Conventional secondary system testing configuration.

Relays that employ the DSS architecture do not have all of the analog and binary inputs and outputs readily available. There are ways to simulate analog inputs to the relay locally, but the binary inputs and outputs that are used for trip, close, and breaker status are located at the MU. Therefore, some testing of the full system must be done via the MUs in the yard, as shown in Fig. 10. When a relay utilizes multiple MUs for protective functions (such as a bus differential), the MUs are not in the same physical location.

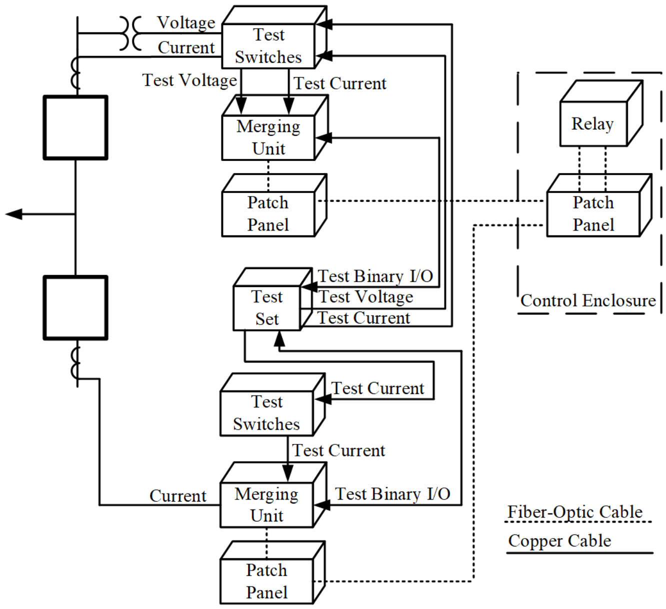

Fig. 10. DSS testing configuration used by the company.

This can be problematic because of the distance between MUs, sometimes 50 feet or more, depending on the installation location; this requires checks to avoid an excessive voltage drop with the test set cables and connectors. This was not an issue for the installation detailed in this paper because the site is compact and the additional cabling requirements did not impede testing. To address any concerns related to voltage drops, engineers of the company ensured relay metering checks were not out of tolerance when compared to steady-state test set values. For larger sites, this may require multiple GPS-synchronized test sets or other means of validating the analog-to-digital (A/D) conversion and subsequent relay setting validation tests.

The testing of a DSS should consider the ability and requirement to communicate with the relay during test procedures. Typical processes may include reprogramming output contacts to simulate an operation to the test set, while others may include MU I/O validation. Engineers of the company addressed this issue by utilizing a wireless transceiver to connect the laptop running the tests to the relay in the control enclosure.

The trip, close, and lockout functions were all tested manually via relay pushbuttons and the local substation HMI. This substation's design consisted of digital lockouts built into the relay setting logic and P2P serial communications, rather than a physical 86 lockout relay (LOR). Without a physical device to perform the lockout functions, additional care and attention to test the proper operation are recommended.

An element that procedures cannot control when testing DSSs is the weather. In this case study, engineers performed testing when the weather was relatively mild. Inclement weather makes testing in the yard more challenging. Therefore, strategies to mitigate this challenge should be a part of any test planning by users of DSSs.

VI. Benefits and Challenges

Many different power system owners and operators have expressed interest in DSS technology because of the potential benefits such systems bring compared to traditional relays. Common motivators include cost savings in materials or design, protection design modularity, or shorter deployment time. However, these benefits are often referenced abstractly since the number of actual installations that fully utilize DSSs is limited.

The company gained unique insight designing a full DSS on paper, building the substation, retrofitting existing primary equipment, field-modifying integrated manufacturer solutions, commissioning, and operating the DSS substation. The real-world implementation provides valuable data, not only regarding cost and time savings but also systematic and operational processes necessary for this type of design.

A practical set of DSS evaluation criteria can be found in [5], which has been revisited from the company's perspective. These include asset management, engineering resources, commissioning, material cost, performance, reliability, and safety.

A. *Asset Management*

- Overall, the change in design from traditional hardwired devices to a P2P DSS solution results in the need for a greater number of total devices. However, it should be noted that the MU from the manufacturer selected for the company does not have any configurable settings, microprocessors, or firmware. This means that it is unnecessary to track the MU with regard to settings or firmware. Due to the isolated P2P communications, updates to functionality or security patches are much more limited than a device on a networked system. However, if an MU update is necessary, the update is performed through its existing connection to a relay. Notably, the selected MU does have a serial number that may be considered for individual station asset tracking, whether that be for physical device tracking or tracking any desired security patches. By leveraging primary equipment manufacturers to include the MU in their delivered package, engineers of the company were able to log this as a single asset and simplify inventory.
- The MU utilized in the company's design also offers only two variants, one with four voltage inputs and four current inputs and another with eight current inputs. All other design features, such as the power supply, digital inputs, output contacts, and communications ports (supporting SFPs), remain standardized. The universal design of the MU, in addition to the fact that there is less variability in the relay options per application, offers greater simplicity for stocking. In this case study, the company utilized up to 75 percent of available MU inputs (transformer alarms) and 20 percent of available outputs (breaker trip and close).

- The small number of variants to MUs also helped with lead times. The limited number of options meant that the manufacturer stocked standard part numbers and lead times were extremely fast.
- A lesson learned during commissioning is that having additional MUs on hand can be helpful for troubleshooting since they can be used to check fiber connections at multiple points between the relay and field MU. Any user looking to implement these systems should consider ordering extra units as part of their bill of material for a substation.
- Overall, the experience shows that moving from a conventional design to a DSS P2P design had minimal impact on asset management.

B. Engineering Resources

- For the company, their substation drawing package utilizing a DSS architecture retained all the same elements as a conventional system but reduced the complexity of specific components. The areas that saw the most significant reduction were the dc schematics and raceway requirements. In this case study, the company realized an approximate reduction in drawings of 50 percent and 75 percent in drawing complexity.
- With proper processes, the drawings required for a DSS are much easier to complete. Engineers of the company originally retrofitted rental circuit breakers because lead times were too great for the new breakers to come preinstalled with the MUs. These retrofits were straightforward but created more engineering work on the drawings to integrate (as well as more fieldwork). Users of a DSS architecture see the greatest benefit for engineering on greenfield sites when primary equipment is replaced and the station is rebuilt. When the MU is shipped with new equipment, the drawing development is pushed to the manufacturer, and it becomes as simple as providing ac power, dc power, and fiber connections to the equipment.
- Based on the company's past performance, users should expect to provide additional guidance to manufacturers on how to approach the integration of the DSS equipment. For example, the company received their primary equipment cabinet housed with MUs without SFPs installed and the manufacturer did not leave sufficient space to install the SFPs onsite. Modifications to the wireways were required to both rectify this issue and install the SFPs for this installation. Engineers of the company also had to add test switches in the field to ensure proper isolation and test capabilities. These items are discussed as potential upcoming design improvements to highlight better ways to resolve these issues in the future.
- A good example of a drawing simplification is one used for a large power transformer. The company's order of the transformer with the MUs was already installed and wired. These MUs were wired by the transformer manufacturer and included every alarm as an input to the MU. Wiring to inputs can either be specified ahead of time or left to the manufacturer to land in a preferred or standard fashion. The final wiring diagrams from the manufacturer can then be used to digitally map the inputs. This meant that each of the alarms was made available for operations without the end user wiring a single copper cable. In addition to simplifying the drawings, this reduced cabling to the control enclosure by 20 conductors.
- For this project, the MUs were all fully tested and commissioned in the field. In the future, the engineers of the company intend to work with primary equipment manufacturers to test the MUs in the factory, helping to further reduce onsite commissioning time. Because MUs require a relay connected to perform meaningful testing, new testing methodologies need to be developed, and this is explored in Section VII of the paper.
- By adopting certain new practices, engineers of the company were able to improve the installation standardization process. For instance, they developed a standard, color-coded terminal strip to land a single cable with the needed number of conductors once the equipment was delivered onsite. This included power supplies for two dc systems, one ac system, and seven total conductors used. For installations that have different I/O requirements, this setup remains the same because all of the I/O is wired by the equipment manufacturer to the MU located in the local control cabinet.
- This project was unique in that the company tested both greenfield and brownfield installations of MUs. Initially, they had to add MUs to the existing breakers onsite before installing the new equipment with MUs integrated. The company's two approaches when installing MUs in the existing breakers include: installing the unit directly in the interior of the local control cabinet and adding an enclosure near the cabinet. Installing the MUs directly inside the cabinets was the preferred method, but using an external enclosure was needed because some cabinets did not have enough physical space. Integrating MUs to the equipment with the conventional methodologies was straightforward. Instead of running secondary cabling back to the control enclosure, the connectors were simply terminated on the MU, either within the cabinet or after runs of a couple of feet to the new enclosure. For retrofit applications, current test switches need to be added to cabinets to allow for the safe isolation and testing of MU circuitry.
- Relay settings development was not much different than a conventional system. Protection settings were identical to a conventional relay, which made settings development straightforward for the protection schemes. The difference between the two is the

- mapping of I/O and analogs from the MUs to the relay. This work was simple and involved utilizing the relay manufacturer's settings software and a purpose-built mapping interface to indicate MU port connectivity. The tool also provided the available MU analogs mapped to relay functions and demonstrated how the I/O was linked between hardware and digital statuses.
- As engineers of the company plan on expanding the DSS station discussed in this paper, the DSS architecture will drastically accelerate this process. The acceleration will limit fieldwork to the installation of a new dedicated 87T relay, a small change to the digital mapping and settings of the 87B relay, and the connection of the new MUs and recommissioning the DSS.

C. Construction

- Secondary cabling in the yard was drastically reduced by using the DSS architecture, which resulted in fewer raceways. For this installation, the main raceway used a 24-by-24-inch trench and the local control cabinets required a 2-inch conduit; a conventional installation typically has a multiple of 2- or 3-inch conduits. Even with the reduced sizing of the conduit, the spacing was more than sufficient with the 2-inch conduit having a fill of less than 10 percent. Similarly, the 24-by-24-inch trench was more than large enough and was primarily driven by the availability of parts at the time of construction. For future projects, a smaller raceway could be considered.
- As was expected for DSSs, the time to pull and land secondary cabling was reduced significantly. Typically, a full week of labor is required to pull and land secondary cabling in a substation of this size. Because DSSs replace most cables with fiber optics, all secondary cabling work was done in a single day, which resulted in a reduction of 86 percent in labor hours.
- As mentioned earlier, this installation used both the existing breakers as well as new ones with the MU installed. This allowed engineers of the company to simulate replacing a breaker for an older installation. When the new circuit breakers arrived onsite, commissioning was simplified because relay settings and logic tests had already been completed. This meant the only testing needed was local to the breakers and included performing functional trip and close. When the new breakers arrived onsite, the swap was able to be completed within 8 hours.
- The company's DSS station is not under NERC CIP jurisdiction. While steps to ensure strong security were taken, compliance related to the MU and the electronic security perimeter was not evaluated as part of this project. Cabinet doors were restricted with normal padlocks for security.

D. Material Cost

- Replacing multiple secondary cables with a single fiber-optic cable allows users of DSSs to see material savings through a reduction in copper cables. Compared to a traditional installation, 5 cables with 28 copper conductors of various sizes for each breaker are eliminated. Although fiber-optic cabling is more expensive than copper cable per foot, the reduction in total material quantity results in a savings upwards of 50 percent.
- An additional benefit seen from DSSs is the space savings that are naturally required for the control enclosure. Because DSS relays do not need secondary connections, the sizes can be reduced and test switches can be eliminated from inside the control enclosure. In this case, the protective relays were reduced in size from 7RUs (12.15 inches) to 4RUs (7 inches). This meant more relays could fit on the panel and remain easily accessible. Additionally, because the I/O was contained in the MU and the LOR was implemented digitally, no test switches or manual controls were required in the control enclosure. For the full capacity of 150 MW with 5 transformers, the total number of racks required is 3, including both HMI and SCADA. Within this case study, the company realized a cost reduction of approximately 50 percent for the control enclosure and panels. The company also saw a reduction in control enclosure size from 16 by 30 feet to 10 by 20 feet when compared to similar non-DSS designs.

E. Performance

- While reducing the length of secondary cabling directly results in material savings, it also has a secondary effect of reducing the effective burden on the CT. This burden typically includes the CT winding resistance, secondary cabling resistance, and the burden of any connected relays. The total value of these burdens is commonly dominated by the secondary cabling resistance when utilizing a microprocessor-based relay. Lowering the effective CT burden allows each CT to have a higher current magnitude limitation before saturation occurs. While engineers of the company selected highly robust CTs for their application, it is an interesting consideration to review the benefits obtained from utilizing a DSS. Based on the company's standard cable sizes, CT specifications, estimates of secondary cable length, and standard CT saturation calculations found in [6], the local bay CTs would be able to handle up to 8.1 percent additional fault current magnitudes prior to saturation. When considering the full station expansion to Bay 5, the CTs are estimated to be able to handle up to 320 to 490 percent additional current magnitudes over a similar conventional system prior to experiencing any saturation. Notably, maintaining standard conventional CT sizing enhances system robustness. However, considering the improved performance of a DSS, this benefit may lead to opportunities for downsizing or tapping CTs, offering additional cost savings or improved low-end metering accuracy.

F. Safety

- CT circuits are all contained in the local control cabinets in the yard, which provides a huge safety benefit. An open CT is extremely dangerous, and having secondary connections restricted to the inside of a locked equipment control cabinet reduces the likelihood that someone can inadvertently touch or modify these circuits in an unsafe manner.
- Another safety benefit of DSSs is that the high-energy cables are removed from areas where personnel typically work. By only having the PT/CT connections out in the local control cabinet of each piece of equipment, personnel who frequently work on the substation are unlikely to touch or modify this cabling by accident.
- The safety benefits detailed previously also apply to any nonworking visitors at the substation. These visits can be very informative for those attending, and visitors often remain near the control enclosure. Removing the connections from the control enclosure reduces the risk profile of the visits significantly.

G. Reliability

- During the initial testing and commissioning of the station, the company identified a faulty SFP and an MU that would not fully enable. The SFP was easily identified and replaced with a spare, while the MU was sent back to the manufacturer for a diagnosis. The manufacturer discovered a loose internal cable with a removable connector and adjusted their manufacturing process to eliminate similar issues in the future. Since the commissioning, the protection system has continued to operate without issue.
- Fault tree calculations of P2P DSS solutions compared to conventional systems have been shown to have similar exemplary values for reliability [2].

VII. Looking Forward

In addition to the planned expansion of the substation discussed throughout this paper, engineers of the company are actively designing multiple projects utilizing the DSS architecture. These include industrial sites where the company deploys renewable generation, interconnects with the grid, and manages the medium- and high-voltage systems on behalf of their users. The plug-and-play style architecture of P2P DSSs allows the company to have new equipment installed quickly and maximize uptime and power delivery to users. For complex and physically diverse automation needs on industrial campuses, a fiber-based system can manage the most advanced requirements.

As the company proceeds with future DSS designs and deployments, there are several items that have been identified for improvement related to manufacturer products, tools, designs, and procedures. This section shares those insights.

- Single-line diagram visualization is more challenging than conventional systems. In conventional systems, the primary zones of protection can be inferred based on CT connections and polarities. With a DSS, there may be a physical fiber connection for an I/O that does not include analogs and is more challenging to follow. The company is experimenting with different ways to represent the protection zones but is planning on using color-coded drawings, such as Fig. 5, Fig. 6, and Fig. 7, within Section IV.
- As the company uses DSSs on larger and more complex systems, a challenge with P2P systems becomes the limited number of fiber ports on MUs and relays. The company's current station only utilizes half (or less) of the total available ports on the relays and MUs. After all planned station expansions are complete, 50 percent of MU ports and 75 percent of the 87B relay ports are utilized. Leveraging additional ports enhances protection flexibility and automation across multiple MU analogs and digitals. These connections enable high-speed relay-to-relay digital communications through MUs, which make them easily accessible to relays. This availability allows for the addition of extra protection elements, schemes, and redundancy. Relay manufacturers could easily address this limitation by offering P2P DSS products with additional ports.
- While troubleshooting the DSS, it became evident that the selected manufacturer MU's inability to be interrogated and interact directly with the user in the same way as a relay presented a new challenge to the existing processes. It required trial and error to determine the best way to troubleshoot fiber, SFP, and MUs to identify the source of problems. The manufacturer provided additional tools to assist in communicating with the relay, collect more detailed information about the state of the DSS, and act accordingly. This knowledge and tools are leveraged in the future should any issues arise.
- Based on the engineers' experience, they deduced that substation equipment manufacturers may not have prior experience implementing MUs into their local control cabinets. The company adopted a standardized layout for the incoming power terminal strip and fiber patch panel to be used, which simplifies drawing reviews once a manufacturer is established. Additionally, shorting style test switches for CTs need to be added in control cabinets, which are also not common for equipment manufacturers.
- To avoid spatial issues found when trying to install SFPs into the MU onsite post manufacturer integration, the company specifies a clearance from the walls of the enclosure in the future. Even if the

SFPs are installed prior to installation, having this extra space helps with fiber clearance requirements and allows for more ports to be installed in future expansions or for the ability to replace existing SFPs.

- Although the company was able to successfully commission the currently deployed P2P DSS with relative ease, there were clear limitations identified with their commissioning process. The process may not be easily scaled to larger substation layouts with extensive distances between MUs and the control enclosure. As the company became more familiar with the DSS's behavior and available tools, in partnership with the selected DSS manufacturer, they identified several opportunities to streamline the commissioning process. These improvements aim to save time on validation and troubleshooting. Future P2P DSS substations have the plan to pilot the commissioning process outlined in the Appendix. With more testing and validation being performed in the digital realm, relay manufacturers should continue to work toward providing end-users with guidance on how to properly test the units while maintaining the rigorous requirements necessary to place equipment into service.
- The company is continuing to evaluate the following enhancements and tools available with the P2P manufacturer solution.
  - Unused ports could be allowed to become redundant paths for relaying information, such as establishing connections for both the 87T and 87B relays to both MUs within the transformer high-side breaker. This enhancement allows protection to dynamically swap from one set of the high-side currents to another if the primary selection becomes unavailable due to an MU, SFP, or fiber issue.
  - The transformer protective relay could be upgraded to provide additional consolidated protection and control features that would offer redundancy for 87B or 51 backup protection.
  - Active link monitoring between the relays and MUs can be used to a greater extent, establishing redundancy and higher reliability.
  - The use of standard commissioning reports could confirm fiber connections; the DSS relays the company employed can provide a standard report upon successful commissioning to the P2P MU. As part of this report, the relay identifies the serial number associated with the MU on each port.
  - Serial numbers can be challenging to read on the MU, and an improved serial number label would be a simple change the manufacturer could make, then the standard report could be compared to the numbers at each location to confirm the device connected to each relay matches the design.
  - In addition to having spare MUs to help troubleshoot communications problems, these spare units can be used to do some of the commissioning tests locally instead of having to do all the work in the yard. This can significantly reduce, but not eliminate, work that needs to be completed in the substation yard. If the settings to map MUs to the relays are altered, the spare MU can simulate the other devices on the system for protection testing. These settings are treated as a different group from all protection settings and can be isolated when changes are made. When testing is done, the connections can be restored to the original mappings and confirmed with the standard report, as described in the previous section.
- The company has also proposed several enhancements to DSS manufacturers based on their experience, including the following features:
  - The expansion of DSSs exists across all relaying platforms; in the company's design, the revenue and PQ meter and remote I/O devices did not offer support for DSS applications. This resulted in integrating those devices out in the yard cabinets and establishing serial communications over fiber.
  - The addition of a more flexible DSS test mode would remove some of the in-service security checks to allow a DSS relay to be more easily tested with a generic set of MUs.

VIII. Conclusion

There is a strong desire for additional real-world data on the design and deployment of DSSs within the power system protection and control industry. This paper discussed One Power Company's experience after designing, constructing, commissioning, and operating their first purpose-built, fully DSS substation. While there were some challenges to deploying this system, there were many overall benefits that helped them gain efficiency in deploying upcoming projects. This includes improvements to products and processes for easier future deployments.

IX. Appendix

The company's future DSS commissioning plan has been optimized to reduce the total number of steps, minimize time spent double-checking connections or performing troubleshooting, and ensure applicability in both small and large footprint applications. This new process includes the following:

1. Energizing the digital relays and MUs—ensuring the green-enabled light is present on both the relay and MU front panels. Confirming or installing all relay and MU SFPs associated with all ports that are used in the design.
2. Preparing for relay testing inside the control enclosure—using a set of test MUs and a secondary injection test set (potentially available from the pool of spare units or invested in as a set of dedicated test equipment). The number of test MUs required is

dictated by the user's preference of performing digital remapping for each test, the types of MUs providing information to the relay on each port (4I/4V or 8I), and whether or not the deployed programming in the relay allows for dynamic disabling of nonactive test windings while performing testing on elements expecting inputs from multiple MUs (such as differential or directional elements).

For the current configuration of the company's station, this would be a maximum of two 8I MUs and one 4I/4V MU.

3. Setting the DSS relays—using the appropriate relay software to send the relay settings.

   This results in the assertion of the alarm LED on all relay ports expecting MU fiber connections.
4. Testing—to start testing, a set of test MUs needs to be connected to every active port on the relay (indicated by the alarm port LEDs) for the given test.
5. DSS relay commissioning—after all active relay ports are connected to their respective test MU port, the commissioning of the relay allows it to verify and accept the connected MUs.
6. Determining the connection health—once commissioned, the connection health of the relay can be determined by verifying that the active relay ports all show as enabled and not alarmed. Now, each MU is able to successfully simulate current or voltage and I/O according to the mapping associated with each port.

   If any issues are observed with a failure to obtain an enabled light, then establishing a connection with the relay allows for the DSS status command to be used, presenting additional troubleshooting information on the observed issue and the next actions for troubleshooting.
7. Performing secondary injection test—traditional secondary injection test processes (or automated test plans) should be directly applicable or easily adaptable to allow for relay settings validation.
8. Establishing in-service connections—once all relay settings are validated, disconnecting all test MUs and connecting all fibers going into the substation yard to each relay port as designed (indicated with an alarm LED on all relay ports expecting fiber connections), establishes the in-service connections within the control enclosure.
9. Proceeding with fiber optics—establishing all fiber connections between the relays and any patch panels, followed by connecting the fibers to the MU that corresponds to each relay port connected in the previous action, completes the in-service fiber connections.

   It is encouraged to reference a documented topology map that shows which relay ports are connected to which MU.

   Once an MU connection is made via a valid fiber path, the MU port LED lights up green. This indicates that both fiber paths are healthy, the MU is connected to the relay port, and the polarity of the fibers is correct. While performing MU connections, it is helpful to utilize a written checklist to indicate the physical location and serial number of each MU to validate the digital mapping report provided by the relay.

   Note 1: If a solid green port light is not observed on the MU, swapping fibers on the MU port may resolve the issue. If this does not remedy the issue, further troubleshooting is required.

   Note 2: Issuing a DSS status command to the relay and noting the response may offer additional guidance on the source of the issue.
10. Verifying communications health—if communications health could not be verified in Bullet 9, then verification of the health of each fiber segment is important. This can either be achieved using dedicated fiber-optic throughput test equipment or with the help of one of the test MUs.

    Note: If using a test MU, it is suggested to start with a direct fiber connection to the back of the relay. If a solid green port light is obtained on the MU, the MU should be relocated past the next patch panel connection. Continue this approach until either reaching the MU cabinet or failing to obtain a successful port indication. This process hopefully indicates if there is a fiber, patch panel, or field MU issue. If the test MU works in place of the field MU, attempt to isolate it further by swapping or replacing the SFPs.
11. Verifying DSS mapping—once all MUs are connected, connecting to the relay and issuing the DSS status command through a terminal connection indicates the status of each port, whether an MU is connected, whether the SFP is a valid model, which MU type is connected (8I or 4V/4I), and what the serial number of the MU is.

    The checklist from Bullet 9 validates if each MU is connected to the correct port on the relay, crosschecking with the documented digital topology map.
12. Isolation—ensuring that the outputs of all MUs are isolated via the tools provided in the system design (test switches, relay programming, etc.) helps to avoid any unintended operations. Test switches allow for ease of output isolation, CT shorting, and analog injection using a test paddle. Therefore, test switches are assumed in most applications.
13. DSS recommissioning—At this point, the DSS relay is ready to be recommissioned using the relay settings software. All active relay ports should now indicate enabled and not alarm. All field MUs should now be commissioned with the relay and be actively providing analog/digital data. The relay has now locked in the specific MU serial number to each relay port.
14. Validating the MU-to-relay metering—it is now possible to perform a standard current/voltage

injection at each MU in the yard with a secondary injection test set to validate that the relay is metering correctly with the correct analogs (according to the digital mapping) showing the expected magnitude and phase angle.

15. Validating MU I/O health—additional I/O checks validating MU I/O health and relay to MU mapping (52A status, trip circuit, close circuit) ensure that all parts of the system have been tested.
    Note 1: I/O validation can be performed with a variety of methods, including remote communications to the relay (e.g., wireless communications or extended communication cables), remote communications to another individual in the control enclosure (e.g., radio or cellphone), or a spare relay at the MU location (utilizing a test program and a spare MU port). During testing, pickup voltage can be applied to each digital input and relay targeting can be used to validate associated relay digital bit assertion. This can then be followed by issuing pulse commands for each output mapped to a given MU and verifying each one's operation.
    Note 2: Alternatively, creative logic could be utilized in the relay to allow for a local test mode to be entered for each MU to allow for ease of testing. For example, custom logic could allow for outputs, and inputs are operated normally via the relay until a certain logical condition is met (such as a relay-based test mode [protection latch] and an MU-based test mode [dedicated digital input asserts]), in which case the relay loops the MU digital input states with the MU digital output states. A user could then apply voltage to pick up Input X on the MU, and as a result, Output X on the MU would assert. Likewise, Input Y would assert Output Y. This could continue until all inputs and outputs have been validated.
    Given an MU output assertion is witnessed as a result of voltage being applied to an input, the digital input, fiber communications, and output contacts must all be functioning properly.
16. Validating MU I/O health cont.—proceeding with both analog and I/O testing for all MUs ensures all system checks have been completed.
17. Validating mapping—now all relay settings, MU functionality, and topology mapping have been validated.
18. Deisolation—Removing the isolation for each MU (analogs and outputs), likely through closing all test switches, is necessary to ensure the system is ready to be in service. Once connected to the system, issuing manual trip/close commands to each breaker and verifying that the full secondary circuit is functional (relay controls, relay SFP, fiber, MU SFP, MU output, and breaker circuitry), and that input statuses, such as the breaker status, are indicating properly is highly encouraged.
    This may also include further testing, such as relay schemes, BF, direct transfer tripping, and blocking schemes.
19. Finishing—the DSS should now have been fully validated and is ready for operation.

X. References

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XI. Biographies

Brian Curkendall earned his BS in electrical engineering from the Colorado School of Mines and currently serves as the director of engineering at One Power Company. With over 17 years of experience in substation engineering, design, and construction across the United States, Brian has worked on a wide range of projects with primary voltages from 4 kV to 765 kV. His expertise includes early adoption and implementation of digital substation process bus and station bus for multiple utilities. As a registered professional engineer in California since 2011, Brian maintains active registrations in numerous states and is a member of IEEE.

Erica Johnson earned her BS in mechanical engineering from The Ohio State University in 2018 and promptly joined One Power Company and currently serves as an engineering manager. At One Power, she has played a pivotal role in development, design, construction, and operations of Wind for Industry®, solar, and Managed HV® projects, focusing on net-metered solutions for industrial customers. These projects underscore Erica's commitment to innovative energy solutions and sustainability in the engineering sector. In 2023, Erica further solidified her expertise by obtaining her professional engineer certification in Ohio.

Chris Burger received his Bachelor of Science degree in Electrical Engineering from Virginia Polytechnic Institute and State University in 2015 and his Master of Engineering in Electrical Engineering from the University of Idaho in 2022. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2015, where he works as a protection application engineer in the Sales and Customer Service division. Chris also obtained his PE certification in the state of Ohio in 2021.

Scott Wenke received his BS degree in electrical engineering with a power emphasis from Washington State University. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2013, Scott worked at Itron. At SEL, he is a product manager in the power systems group of Research and Development and is responsible for transmission and substation product lines.

Travis Remlinger received his BS in electrical and computer engineering from The Ohio State University. He began working for Schweitzer Engineering Laboratories, Inc. (SEL) in 2018 and is currently a protection application engineer. He is a member of IEEE and a registered professional engineer in Ohio.