When Dual-Pilot Goes Wrong: A Case Study in Retrofit Line Protection

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***Abstract*—Short transmission lines connected in a looped configuration are typical of some industrial power systems, but they can present numerous protection coordination difficulties because of their inability to effectively use underreaching elements. The typical solution is to rely on dual-pilot protection schemes; however, not all dual-pilot schemes are created equal. In 2019, a steel mill in northern Indiana suffered a total outage of their 138 kV transmission loop, which was caused by a failure in their existing dual-pilot protection when a line fault occurred. This event caused a severe financial impact. Although most of the 138 kV lines in the plant still used pilot wire differential using electromechanical relays, the failure originated in a more recent retrofit design. The fault was eventually cleared by the local utility, whose connecting line terminals had remote backup elements enabled.**

This paper outlines a successful retrofit project to upgrade the protection for each of the steel mill's 138 kV lines to a solution that eliminates many vulnerabilities, such as the one that precipitated the outage event in 2019. While still relying predominantly on dual-pilot protection, improvements were implemented along multiple crucial dimensions, including true redundancy for communications and backup elements in the event of communications failure. The challenges of this steel mill are representative of many industrial facilities, and it was these challenges that directed the project's ultimate solution. The paper details this result, which consists of three main elements: a standardized design for custom prewired relay plates integrating within the legacy protection panels, the philosophy for the protection itself, and the strategy used for commissioning.

I. Introduction

A fully integrated steelmaking facility in Northwest Indiana suffered a blackout incident in 2019 that was traced to protection that failed to operate during a fault on one of its seven 138 kV transmission lines. The interconnecting utility's backup overreaching distance elements eventually cleared the fault at both of its terminals feeding the steel mill, which caused the plant-wide blackout.

Both existing primary and backup protection systems that failed to operate were not the electromechanical relays, which protected most of the plant's 138 kV lines, but were in fact later microprocessor-based relays that were retrofit-installed in 2006 with the addition of a new substation. This protection was designed to maintain the previous pilot wire differential scheme. While many contributing factors likely played a role, it is clear that this attempt to use the legacy communications media for a newer protective relaying system proved to be problematic.

As a result, the steel mill's management sought to completely upgrade the protection for each of this plant's seven 138 kV transmission lines, including the one that precipitated the incident. The new protection scheme included identical microprocessor-based transmission line relays for both primary and backup systems. The relays themselves were principally one-for-one replacements with the legacy relays (electromechanical and microprocessor-based); however, the overall scheme, including the communications architecture, was chosen to deliver extensively improved reliability using modern technologies and methodologies.

II. Background

A. The Power System

The steel mill's 138 kV topology includes five outdoor substations that are connected in a "looped" configuration with seven total 138 kV lines, as shown in Fig. 1. The loop begins with two parallel utility-owned lines connecting to the steel mill's terminals at Sub 1 (see Fig. 1).

Each substation uses a single-bus single-breaker configuration for the 138 kV line terminals. Because most of the substations include both sides of the 138 kV loop, step-down power transformers used for plant power distribution can be connected to either side of the 138 kV loop, which constitute two separate 138 kV buses according to the relative geography of the sides of the loop. This design effectively allows plant operations fed by a particular substation with this configuration to remain online in the case of a 138 kV bus outage.

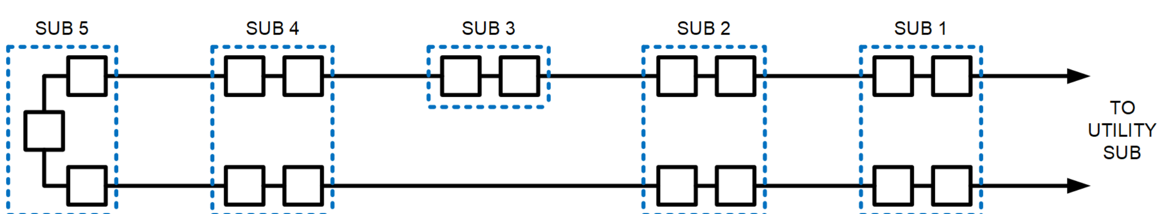

Fig. 1. Simplified steel mill 138 kV one-line diagram.

B. Legacy Design

The electromechanical transmission line differential relays were panel mounted inside the control house at each substation. Typically, the primary and backup relays are located on the same panel; but in some stations, the primary relays associated with a specific 138 kV bus were mounted together on one panel, and the backup relays were mounted on a separate panel. Electromechanical pilot wire monitoring relays were also mounted with the differential relays.

The protection design differed slightly by station, but some typical features can be outlined:

- Dual-pilot wire line differential relays and pilot wire monitoring relays directly tripped each terminal's 138 kV line circuit breaker.
- Electromechanical breaker failure relays initiated breaker failure timing on protective trips to the 138 kV line breakers and tripped the bus lockout relay upon local breaker failure.
- Pilot wire monitoring relays handled monitoring as well as sending a transfer-trip signal to the remote terminal in the event of local breaker failure.
- No backup relay elements were implemented to supplement the pilot wire differential elements.

The new 138 kV line protection scheme has the following requirements:

- The new protection should use microprocessor-based protective line relays and be fully redundant.
- The scheme should avoid using existing pilot wire communications media.
- Backup elements should be active and coordinate properly with other protection to disallow another total blackout incident if both relays have failed communication.
- Relays should have similar form factor and be panel mounted on the existing relay panel, if possible, to conserve space.

C. Pilot Wire Technology

Developed in the 1930s, a pilot wire system of protection consists of a twisted wire pair for transmitting an analog signal between terminals. Originally, telephone pairs were used as pilot wires [1]. As a phase-comparison scheme, this differential protection typically operates by converting the three-phase currents to a single-phase voltage, which is applied to the pilot wires. Under normal conditions, voltages at each end of the line cancel each other out, which results in no current flowing through the protective relay's operate coil located at both ends of the line. A simplified schematic is shown in Fig. 2.

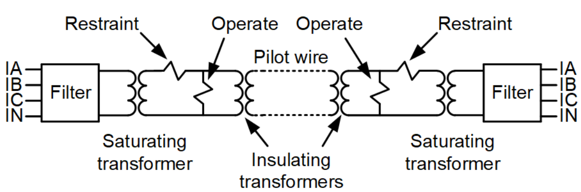

Fig. 2. Simplified pilot-wire differential scheme schematic—typical.

While pilot wire differential technology allows for instantaneous fault detection, it should be emphasized that any open circuit in the pilot wire pair will render the protection inoperable. Thus, pilot wire protection is often used in conjunction with pilot wire monitoring relays or monitoring functionality that will alarm if the pilot wire circuit has opens, shorts, or grounds. These typically operate by circulating a small dc current (on the order of 1 mA) through the pilot wire pair and using sensing relays and equipment at each terminal that are designed to not interfere with the 50 to 60 Hz pilot signal. The same monitoring equipment can be appropriated to perform direct transfer trip (DTT) in either direction; generally, the dc polarity for this circulating signal is reversed and the voltage increased for remote tripping.

The use of pilot wires is more economical than running current-transformer secondary wires between the terminals; however, the application of pilot wires is still limited to short lines (usually less than one mile) because of cost and increased physical exposure at longer distances.

III. New Protection Physical Layout

The existing electromechanical line differential relays had a vertical panel-mount form factor; at some substations four separate line relays were mounted side-by-side in one panel, as shown in Fig. 3.

Fig. 3. Previous panel-mounted 138 kV line relays.

The pilot wire monitoring relays were typically mounted directly underneath each respective line relay. A protective relay with similar construction could be mounted on a metal plate that could fit over openings left by cutting holes in the panel around the electromechanical relays. Preferably, there would also be room for relay test switches.

The selection of the new protective relay, used for both primary and backup replacements, was based on:

1. A vertical panel-mount option, which has a very similar form factor to the previous line relays.
2. Its history as a modern solution using supported technology.
3. Its cost, relative to other options.

4. Its capacity for multiple channels of pilot protection, namely line current differential.

For each previous line relay replacement, the new design included one line relay with two test switches mounted to a stainless-steel plate that could fit over the opening left after the demolition of the old relay and its corresponding pilot wire monitoring relay. For efficiency in design and installation, the relays and test switches were templatized as much as possible and prewired with a 15-foot whip for ease of installation. Each wire had a label that corresponded to its destination on the relay plate's associated Issued for Commissioning (IFC) wiring diagram.

The breaker control for the 138 kV line breakers, handled by the front panel and the existing hardwired remote terminal unit (RTU) system, was not changed within the scope of this project. Although the 87L relay has the communications infrastructure to implement supervisory control and data acquisition (SCADA) operations, the existing breaker control RTU equipment was not yet designated for upgrade. However, as a part of the design, the primary relay for each terminal included input wiring to perform trip coil monitoring for local alarm, which was not previously being done on the single trip coil for the 138 kV circuit breakers.

The steel mill's management made the decision to install new overhead 1300 nm single-mode fiber between each substation to accommodate the upgraded 138 kV line relay communications-assisted protection because the existing #12 American wire gauge (AWG) solid copper pilot wires played a role in the 2019 incident. Because of their design, protection, and maintenance requirements, pilot wires are a very common problem point of protection systems [1]; thus, low-bandwidth pilot wires are generally not recommended in modern power protection designs. Using fiber-optics provides immunity from electromagnetic noise interference and is commonly used for new applications of microprocessor-based relays.

IV. Protection Philosophy

A. Redundancy

Primary and backup relays maintain the redundancy requirement. As for the protection itself, is it necessary for both relays to use pilot protection, which would be commensurate with the old dual 87L protection? There are many considerations factoring into this determination, but ultimately it boils down to whether time-delayed tripping would be acceptable under contingency failure [2]. A closer look at the steel mill's power system indicates that there would be some issues with time-delayed tripping, specifically the fact that it is a loop system with short lines (all less than one mile long) where overcurrent coordination may be impossible [1]. Critical plant operations should stay online, if possible, for out-of-zone faults. The fact that the old protection did not use any other elements further implies that line current differential may be one of the only options for secure protection. Plus, once the fiber infrastructure is in place, there is little incremental cost in adding one more channel. Therefore, dual-pilot was chosen for the application.

It is important to consider actual real-life contingencies when determining whether protection systems are truly redundant. Both relays may have pilot protection, but are the communication channels themselves independent? If the fiber is routed together from substation to substation and directly connected relay-to-relay, they are not independent. Consider the possibility of a crane in the plant accidentally severing an entire overhead fiber strand from its support. This would essentially be a single contingency (N-1) resulting in a loss of communication for both primary and backup relays, rendering both pilot schemes inoperable. The old pilot wire protection had this same disadvantage with pilot wires running together in conduit, which could have contributed to the incident described in Section I.

One way to implement independent communication channels is to introduce a multiplexed network capable of routing communication along another path if the direct-fiber route is severed. If this multiplexed network connected each of the five 138 kV substations in a ring topology, local and remote line relays could communicate with each other using channels configured for communication along either side of the ring. Thus, a multiplexed optical network was introduced that used synchronous optical network (SONET) technology, which complies with IEEE C37.94 [3] and its implementation at the steel mill consisted of one module installed at each of the five outdoor substations. Multiplexed rings like this also have information technology (IT) capability to allow IT network accessibility at the substations for a segregated or converged network, if desired.

With independent communication channels, dual-pilot can be considered redundant. A straightforward solution common in dual-pilot schemes is having direct-fiber communications in the primary relay and multiplexed fiber communications in the backup relay. However, it has already been suspected that, because of the characteristics of the plant's 138 kV lines, secure protection elements will be at a premium. Typically, pilot protection is supplemented by protection in the form of step-distance or overcurrent elements. A diverse set of active relay elements essentially combines different protection algorithms in one package, allowing full protective coverage for various types of faults on the line [2]. If this type of diversity is limited, it would be advantageous to have some additional communications channels. In other words, if our means of providing comprehensive fault coverage is limited, we can make up for it to a limited extent by adding more of the means that we do have, namely pilot protection channels. As mentioned, the incremental cost of adding an additional channel is low. Thus, the design specified direct fiber on channel X for each relay and multiplexed fiber on channel Y for each relay. Fig. 4 illustrates the relay communications scheme between each line terminal.

Having independent communication channels within the same relay does not address each single-contingency because the relay itself is only one device; however, having pilot still in service under channel-specific contingencies in both primary and backup relays makes the protection scheme cumulatively more dependable and robust.

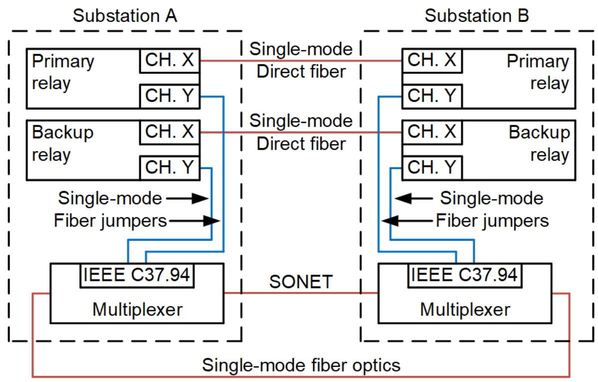

Fig. 4. Communications channel configuration for each new line relay.

B. 87L Elements

A helpful exercise when evaluating prospective protection elements is classifying the electrical length of the line, which can be characterized by the source impedance ratio (SIR). This ratio is a measure that provides the voltage seen by the relay for an out-of-zone fault [4] [5]. Using the methods outlined in [4], it is possible to obtain this ratio for each transmission bus on the steel mill's 138 kV system. A low voltage (resulting in high SIR) for an out-of-zone fault increases the impact of error and transient overreach [6]. This calculation was made easier by modeling the 138 kV system and placing the faults as described. SIR values greater than 50 were calculated for all 138 kV line terminals, which is firmly in the range at which it is necessary to disable underreaching Zone 1 and instantaneous overcurrent elements [6]. The lines are too short for the relay to distinguish between an in-zone and out-of-zone fault using traditional step-distance and overcurrent elements.

Unfortunately, the story is not much better when it comes to overreaching elements because of the coordination problems associated with short-line loop systems. Time-overcurrent curves for each relay need to be spaced relative to each other for sufficient coordinating time interval (CTI), which typically ranges from 0.2 and 0.5 seconds depending on the application [1]. Even with a very low CTI, it is not possible to space the time-current curves to coordinate all the way around the low-impedance 138 kV loop. It is the same situation with step-distance elements; the zones for the multiplicity of electrically short lines around the 138 kV loop have too much overlap to simply keep adding time delays to achieve coordination.

Because of the very limited selectivity of current and distance functions, the relays must rely predominantly on pilot assisted schemes. Line current differential elements were chosen for the steel mill's 138 kV lines because this type of protection has the significant advantage of being independent from voltage, which, as demonstrated, can collapse considerably for out-of-zone faults. Like all differential protection, it works by using Kirchhoff's Current Law to compare current into one line terminal with current out of the remote terminal. Under normal conditions for a two-terminal line, the phasor current measurements at the terminals are equal in magnitude and opposite in angle, resulting in operation within the "restraint" region of the differential relay tripping characteristic. As the line terminal phasors start to disagree in magnitude and agree in angle, as they would during a line fault scenario, operation moves into the "trip" region and each line terminal's relays will initiate a high-speed breaker trip to isolate the detected line fault.

The 87L tripping is characterized by an "alpha plane" representation to illustrate and algorithmically compare the complex ratio of remote-to-local currents. There is a separate alpha plane for every current (phase, negative-sequence, zero-sequence, etc.) [7]. Accordingly, the line relays at the steel mill have three separate differential elements enabled: phase, negative-sequence, and zero-sequence. These elements were reviewed for dependability and security. For example, the phase differential pickup was set with margin above the maximum line rating to avoid tripping for a current transformer (CT) open condition at one terminal, while being sensitive enough for the minimum applicable fault under single contingency to be greater than three times the pickup.

C. Backup Phase and Ground Overcurrent

The challenges associated with traditional step-distance and overcurrent elements were established in the previous section. Is there anything that can be realistically done to back up the pilot differential channels, or is it even necessary? The point of redundancy is to ensure that the failure of a single component (N-1) does not affect the ability of the protection scheme to detect and isolate faults [1]. However, this level of contingency is typically a bare minimum, especially when dealing with transmission assets. Often, standards dictate that the power system protection maintains reliability for "high-probability" double contingencies (N-2) as well [3]. While it can be debated whether any relevant double contingencies at the steel mill would constitute as high-probability, a dc outage at a remote substation (disabling remote relay protection) would indeed have a deleterious effect on protection that is solely communications-based.

Even though overcurrent elements cannot effectively coordinate with other overcurrent elements for this application, they can coordinate with high-speed differential protection, and relay logic can be programmed to only enable these backup elements when all 87L communications for the line terminal are lost. Under such a condition, the relays that have lost communication with the remote end can continue to protect the line, and this is exactly what was implemented at the steel mill. A programmable output contact from each primary relay was wired to an input on the backup relay, and vice versa. This output notified the other relay when it had lost communication with the remote station. Relay logic was then configured to enable the overcurrent elements as described when *both* relays have independently found that 87L protection is inoperable because of fiber channel failures. See Fig. 5 for an illustration of this logic in each 87L relay.

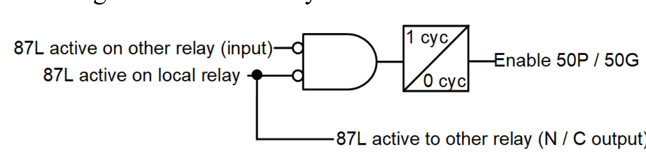

Fig. 5. Definite-time overcurrent element supervision logic.

For this application, the overcurrent elements were chosen to be non-directional and therefore biased towards dependability. Typically, overcurrent elements for looped systems will have directional elements to supervise their operation for only forward faults, but these elements at the steel mill are enabled only during extreme backup scenarios, and they will still coordinate with out-of-zone 87L protection, provided the time delay is sufficient. A 30-cycle definite-time delay was chosen to coordinate with breaker failure schemes at the remote substation and with the protection for the incoming parallel lines from the local utility. The enabled overcurrent elements included phase overcurrent (50P) and residual ground overcurrent (50G) elements, which were each set for security (above emergency line loadability with margin) and dependability.

D. Breaker Failure

Most substations had existing breaker failure protection for the 138 kV line breakers. All existing breaker failure protection used older electromechanical relays roughly the same age as the legacy pilot wire line relays. The existing scheme typically involved the issue of a DTT over the pilot wire to the remote 138 kV breaker using the pilot wire monitoring relays. Instead of trying to interface with existing legacy technology, it was decided that the primary 87L relay for each line breaker would have additional built-in breaker failure logic. Existing electromechanical line breaker failure relaying was either removed or abandoned in place.

Essentially, the two faults for which the breaker failure elements needed to be operable, i.e., faults for which the line breaker is tripped, were line and local bus faults. The former are faults cleared by the local line relaying, so the breaker failure timer can be simply initiated with logic inside the primary relay itself for protective trips. However, existing bus differential relaying solely clears local bus faults. To notify the primary relay to start breaker failure timing for these faults it was necessary to hardwire a breaker-fail-initiate (BFI) input to the primary relay. For this, a spare contact was used from one of the bus lockout relays tripped by the bus differential relaying. See Fig. 6 for the breaker failure initiate logic implemented inside the primary 87L relays.

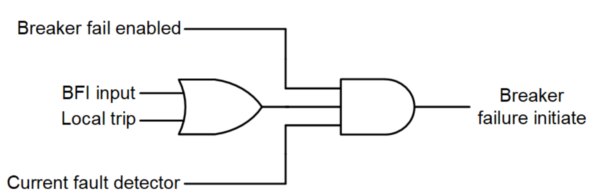

Fig. 6. Breaker failure initiate logic in each primary 87L relay.

Breaker failure timer initiation is supervised by a current fault detector, and this logic is latched until the current drops out. Using auxiliary contacts alone is not recommended because these may not be a reliable indicator of an adequate breaker opening, particularly in failure-to-clear scenarios [8]. The breaker failure initiate logic is also supervised by a local toggle switch using relay logic to allow the operator to enable or disable breaker failure protection using the relay front panel, if desired. The relay front panel displays text to indicate when breaker failure is disabled to help minimize the likelihood of a detrimental human performance impact on breaker failure dependability. The breaker failure timer itself was set at 12 cycles, which provided sufficient margin for the current detector to reset for normal breaker clearing. The breaker failure assertion in the primary relay (and associated breaker failure trip output) was set with sufficient drop-out time to trip all local bus lockout relays.

An important inclusion of this scheme involved retaining breaker failure DTT to allow the failed breaker to also be quickly isolated by the remote end of the line. This was easily accomplished using programmable logic in the 87L relays, which allows for binary data to be communicated over the same fiber media being used in the 87L scheme. Upon breaker failure of a local breaker, the primary relay asserts and latches a breaker failure transmit signal, the receipt of which at the remote end is used to trip its line breaker with a short security delay (1 cycle, in this case). This latch is only reset by acknowledging the breaker failure trip on the primary relay front panel that asserted breaker failure.

One limitation of the breaker failure scheme worth mentioning is the fact that only one of the line relays performs breaker failure. If a separate dedicated relay is not used for breaker failure and the breaker failure element is instead part of the protection suite of the protective relay itself, this element is sometimes added to both primary and backup relays to gain similar redundancy [8]. If the primary relay fails, this will disable breaker failure protection for the line breaker. However, with the end user monitoring the health for each relay, this was considered a low-probability N-2 scenario (breaker failure with a relay failure), and the tradeoff was made for considerably reduced wiring and complexity.

V. Installation and Commissioning

A. Plan and Prework

Close collaboration and careful planning were crucial to successful isolation, installation, testing, and commissioning. It was determined that this work should be divided by each 138 kV line so that only a single line outage would be needed. As mentioned, the plant typically runs with the 138 kV loop closed for reliability, so minimizing the length of each line outage (which opens the 138 kV loop) was key to minimizing the risk of disrupting plant processes. Critical tasks that did not require a line outage were identified and performed early when possible. Some examples are:

1. Construction and early testing of the optical fiber network communications loop and fiber jumpers was done prior to the first line outage. The steel mill either procured enclosures or found sufficient panel space at each substation to house each new multiplexer module. Fiber pairs were connected and tested to prove the ring network communications. For direct-fiber connections, fiber jumpers were also run early, when possible, and tested with an optical power meter.
2. The new line relays had settings files loaded and most of their protective elements and logic tested with a

secondary injection test set prior to installation. To test the 87L element, the remote end relays do not need to be communicating when the relay is temporarily configured in loopback mode, in which the relay received current is vectorially programmed to be equal to the local current [7]. This early testing meant that the outage commissioning could be predominantly focused on functional verifications, such as the breaker and bus lockout relay trip circuits.

3. At a few substations, the line terminal relaying did not have a dedicated panel; the primary relays for two different line terminals on a particular bus were mounted together on a panel while the backup relays were mounted together on another panel. This complicated the demolition and install process because panel space was very tight (see Fig. 2) and between the outages for each of these line terminals, only some of the panels would be upgraded while the others remained in service. A free-standing steel frame was used for this temporary period to house the new relays. When the second line terminal was upgraded, the wire slack could be simply pulled back through the opening. The relays were all panel mounted as designed.

B. Commissioning

With as much prework completed as possible, demolition with demo drawings and installation with the IFC drawings was performed. Initially, the plan was to install and commission primary relays first and then return after a short period of having primary "new" and secondary "existing" in service together. Two sets of demo and IFC drawings (Phase I and Phase II) were issued so that this could occur. However, it was determined late in the project that this would be inefficient and unnecessary. A lesson learned was that it is important to fully discuss and collaborate early on about the design implications of the commissioning strategy so that unnecessary complexity in design and installation can be avoided.

Ideally, the bus connecting to each of the line terminals being commissioned could be de-energized so that the breaker trip and bus lockout relay circuits could be verified relatively easily, but the plant often had reasons to keep these buses energized during commissioning. Thus, the line terminal breakers for the line terminals being commissioned were opened and locked out. For these situations, it was decided that breaker trips should be verified by measuring trip voltage going out to the breaker yard cabinet with a meter, and bus lockout relays were functionally verified with very careful secondary isolation of in-service equipment. All other functional checks were performed, which included:

- Single-point ground verification on CT and potential transformer (PT) circuits.
- Secondary injection on CT and PT circuits at furthest point of disruption.
- Trip coil monitoring.
- Hardwired input/output (I/O) between primary and backup relays to indicate status of disabled 87L elements.
- Relay alarm outputs.

Remaining protection and logic testing was performed with a commissioning engineer situated at the substation on both ends of the line communicating over the phone. Accurate receipt and transmission of relevant data between relays, including DTTs, over all fiber channels was confirmed.

C. Restoration

Upon the conclusion of installation and testing for each line, all secondary restoration was completed, and switching was performed to restore the 138 kV loop. In-service checks were performed to verify that phasors and all applicable relay quantities were as expected. These include, but are not limited to:

- Checking that the positive-, negative-, and zero-sequence metering at each terminal and for all channels look accurate within the relay.
- Triggering an event in the relay and observing correct phase rotation.
- Verifying that alpha plane values used for the 87L element are very close to $1 \angle 180°$ in the line relay, which indicates normal load current [7].
- Observing no alarms or relay targets, except for LEDs indicating relay enabled status.

As-left settings and field marks for all drawings were collected after the commissioning trip for each 138 kV line. Once all lines were restored, the field marks were used to record the as-built condition.

VI. Conclusion

Ultimately, the project was a success from the standpoint of meeting the requirements outlined in Section I while insisting on complete safety and quality, which were maintained as the two highest priorities throughout its duration. The protection for all seven of the plant's internal 138 kV lines was upgraded with the lines returned to service in a timely manner. The facility can operate with peace-of-mind knowing that another line fault incident like the 2019 blackout is not lurking around the corner.

The phrase "dual-pilot" generally has a positive connotation among protection engineers, but this paper demonstrates that real-world implementations need to be evaluated on a case-by-case basis to ensure that power protection systems using dual-pilot schemes are both dependable and secure. Additionally, legacy line protection schemes that have been in service for decades may have hidden vulnerabilities that can prove hazardous just when they are needed most. This demonstrates the possible need for proactive modernization and upgrading of not just protective relays, but their communications media as well, particularly in the case of pilot wire. The plant discussed in this paper is simultaneously a cautionary tale and an encouraging retrofit story; in fact, less than a month after the 138 kV loop was put fully back in service, the new protection quickly cleared a line fault between two substations on differential. If a similar shortcoming had been hiding for that line protection, it is not an exaggeration to say the total project largely paid itself off with this fault clearing alone.

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VIII. Biographies

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