Case Study: Achieving Selectivity on a Critical Distribution Network

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Case Study: Achieving Selectivity on a Critical Distribution Network

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***Abstract*—In a metropolitan area, American Electric Power operates a complex, looped distribution network that consists of several parallel circuits between a single-source substation and two load-serving substations. The purpose of this loop is to maintain service reliability when a number of the parallel circuits are out of service. Because fault current contributions vary greatly depending upon fault location, this operating configuration presented a challenge to the design and setting of a protection system that was selective for faults on the network. This paper presents the advanced solutions implemented for the protection of this crucial network.**

I. Introduction

In a metropolitan area, American Electric Power (AEP) operates a complex, looped distribution network that consists of several parallel circuits between a single-source substation and two load-serving substations. The purpose of this loop is to maintain service reliability when a number of the parallel circuits are out of service. Although this network configuration is convenient from a load-flow perspective to maintain service reliability, it presented unique challenges to the design of a selective protection system.

Phase and ground time-overcurrent relays are typically implemented for the protection of distribution-level circuits or feeders. However, for looped networks like the one discussed in this paper, solely using time-overcurrent relays can result in a sacrifice of selectivity. A loss of selectivity, in turn, affects the reliability of service to the loads provided by the network. Another consideration when solely relying on time-coordinated overcurrent protection with a looped network is sequential tripping, because a weak terminal may not be able to detect a fault until the remote breaker opens and the fault current redistributes.

The AEP solution for increasing the selectivity of the network protection scheme was to install fiber-optic communications links between the three substations and to install microprocessor-based relays that included permissive overreaching transfer trip (POTT) and direct transfer trip (DTT) schemes between the two terminals of each circuit in the distribution network. The dependability and security of the protective elements in the POTT scheme were studied under two significant contingencies: 1) the loss of a single fiber-optic cable, causing the simultaneous loss of all of the communications channels for all of the POTT and DTT schemes in the network and 2) a blown fuse for the single bus potential transformer (PT), causing a simultaneous loss of potential for all of the relays at a particular substation.

Automatic reclosing was also implemented in the relays involved in the parallel circuits between the source substation and the two load-serving substations. Reclosing was not included on the tie circuit between the two load-serving substations. However, details of the reclosing operation are not discussed in this paper.

Microprocessor-based, percentage restraint differential relays were implemented for bus protection at each of the load-serving substations. The differential relays complemented the selectivity of the network protection scheme by isolating a faulted bus locally. However, varying current transformer (CT) ratings, large fault current magnitudes, and significant CT saturation on the breaker CTs involved in the bus differential schemes presented challenges to setting the slope characteristics for the differential element.

The purpose of this paper is to describe the protection scheme implemented for this network. Selectivity was regarded as the most critical requirement to ensure that none of the crucial loads in the metropolitan area would be affected by a fault on one of the parallel circuits. The discussion includes how selectivity was achieved for two significant contingencies and the bus differential scheme implemented at the load-serving substations, including the compromises that were required to use the selected relays.

II. Background

Before discussing the protection philosophy for the apparatus involved in the network, the history of the network is discussed to emphasize its importance. Fig. 1 provides a simplified one-line diagram of the network. The network is fed via a pair of 42 MVA transformers at Substation A. The tie breaker at Substation A is normally closed. Three parallel circuits between Substations A and B and three parallel circuits between Substations A and C form the network. The normally closed tie circuit between Substations B and C completes the loop. A 12.5/11.9 kV voltage regulator (REG) at each load-serving substation delivers power to two independent secondary networks via feeders labeled **Load** in Fig. 1. Also, note that there are tapped loads on Circuits 4, 5, and 6.

Substation C and its associated feeders were constructed in 1937 as the first underground electrical secondary network system in the area. In 1953, Substation B and its associated feeders were installed in response to downtown business development and expansion. The original design included single-conductor 4/0 copper paper-insulated, lead-covered

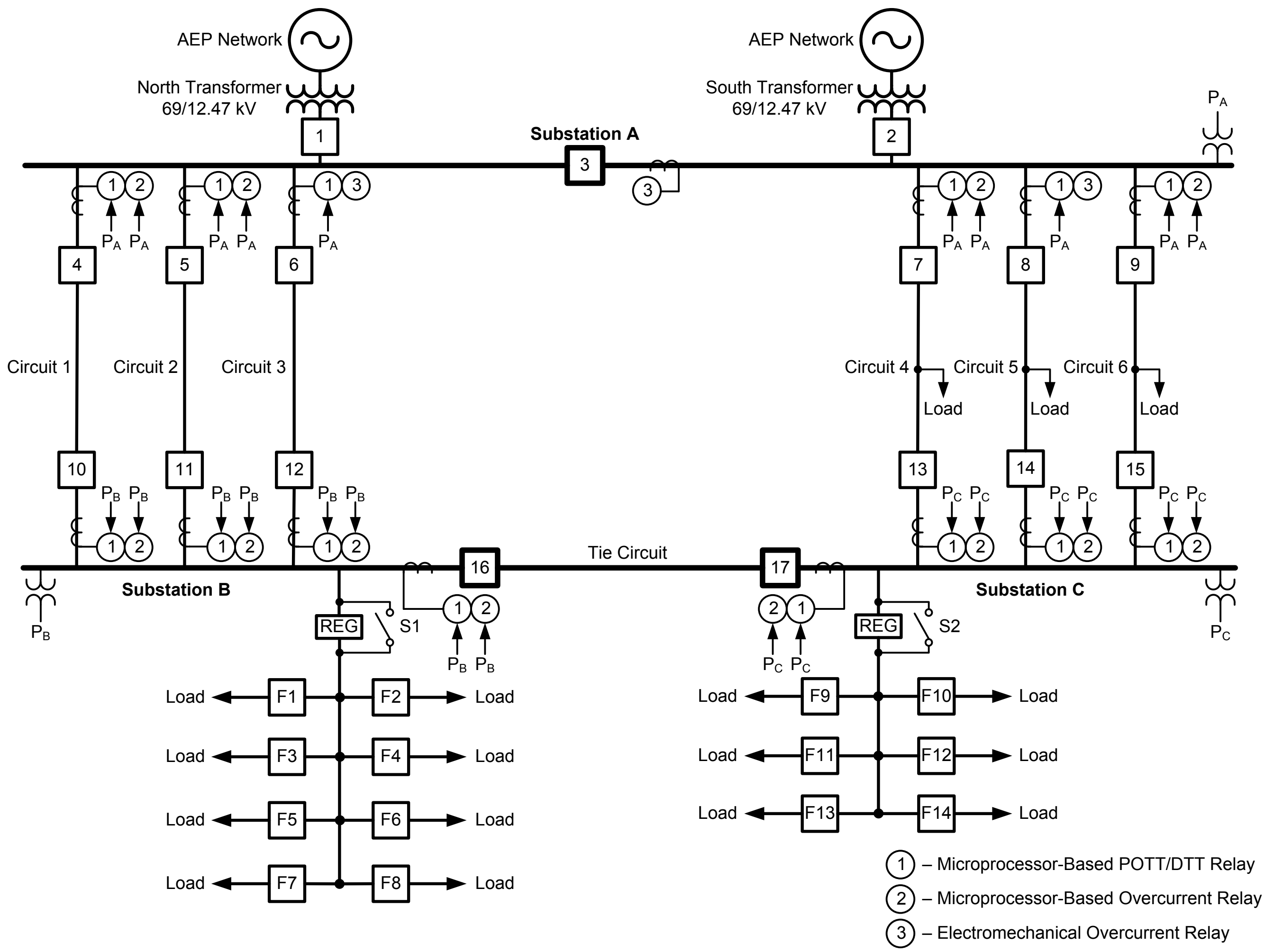

Fig. 1. Simplified one-line diagram of the network

(PILC) cable and 500 kcmil copper rubber-insulated cable for the primary and secondary components, respectively.

The distribution system covers 39 city blocks for a total area of 0.26 square miles. The 11.9 kV regulated output at Substations B and C serves a combined total load of 25.1 MVA. Substations B and C serve a total of 41 vaults, 114 manholes, and 116 transformers, with either a 208 V or 480 V secondary connection to the network. In addition to the variety of customers served by the 208 V grid secondary layout of each network, there are 19 major buildings served by several 208 V and 480 V secondary network transformers. Major customers on the distribution network include several important government buildings, an office center for AEP, and a major convention center.

To better understand the operation of the closed loop connecting Substations A, B, and C and how it provides improved reliability and continuity of service, a few scenarios are considered. If either of the transformers at Substation A is out of service, the transformer that is in service serves all of the loads at Substations B and C. When both transformers are in service and any one of the parallel feeders between Substations A and B or between Substations A and C is out of service, service continues to all of the loads at Substations B and C through the parallel circuits that are in service. If any two of the three parallel feeders between Substations A and B are out of service and the tie circuit between Substations B and C is closed, the remaining circuits provide continued service to the loads at Substation B. However, when the tie circuit is also out of service, the one circuit between Substations A and B is manually opened to prevent overload. It is, therefore, very important for the protective devices protecting the circuits to be extremely selective—that is, to isolate only the faulted circuit in order to maintain the continuity of service to the loads.

When this network was originally constructed, typical phase and ground electromechanical overcurrent relays were installed to protect the circuits. However, after years of service many of the distribution breakers were replaced. The breaker replacement process included an upgrade to standard microprocessor-based overcurrent relays in each circuit breaker cabinet to replace the original electromechanical relays. Note that some of the original electromechanical relays with the original circuit breakers still existed at the onset of this study, as shown in Fig. 1.

The implementation of the POTT/DTT relays for each circuit in the network began as a result of an unintended operation. A single-line-to-ground fault occurred on Circuit 1 after years of service. Ideally, only the overcurrent relays associated with Breakers 4 and 10 should have operated, resulting in the opening of only Circuit 1 and, importantly, no load loss. However, the overcurrent relays associated with Breakers 4, 5, and 6 at Substation A and the overcurrent relay associated with Breaker 17 at Substation C operated for this fault and tripped their respective breakers. This resulted in a loss of service to all of the loads at Substation B. AEP determined that the following actions needed to be performed to prevent the event from reoccurring and improve the selectivity of the protection schemes:

- Evaluate coordination of the existing inverse-time overcurrent relay settings (e.g., pickup and time dial).
- Discuss the feasibility of adding pilot protection on the parallel and tie circuits.

AEP decided to add fiber-optic links between the three substations and install a POTT/DTT relay at each terminal. The specific relay chosen for the POTT scheme was selected to be consistent with the microprocessor-based overcurrent relays that were already included with the replaced breakers. A DTT scheme was also implemented on the fiber-optic communications channel used by the POTT/DTT relays. Speed was improved with the addition of the POTT/DTT relays. Section V of this paper discusses the sacrifice of speed for the protection schemes during specific contingencies.

Naturally, the POTT/DTT relays (labeled **1** in Fig. 1) are the primary relays for the protection of each circuit on the network. Each primary relay also includes backup inverse-time overcurrent elements in addition to the POTT scheme. The microprocessor-based overcurrent relays (labeled **2** in Fig. 1) are the alternate relays for each circuit. The electromechanical overcurrent alternate relays are labeled **3** in Fig. 1.

Bus protection was included in the original design of the three buses (Substations A, B, and C). It was determined at the onset of the study that the original electromechanical bus differential relays at Substations B and C only would be replaced with microprocessor-based, two-restraint relays, which are typically used for transformer protection. The original electromechanical bus differential relay at Substation A remains in service. The bus differential relay includes the voltage regulator in its zone of protection. However, CT saturation presented a major challenge in developing settings that were both dependable and secure for the application. The challenges associated with setting the bus relays are discussed in depth in Section IV, Subsection C.

III. Design Challenges

The protection philosophy of distribution networks generally addresses radial feeders protected by simple overcurrent relays. However, the need for improved reliability and continuous availability of power to end users has resulted in the evolution of distribution networks from radial to mesh or looped configurations [1].

As discussed in Section II, while the loop configuration of this network improves the reliability of service to AEP customers at all times, it presents challenges for protection engineers. This configuration, with the normally closed tie breaker at Substation A (Breaker 3) and the tie circuit between Substations B and C, forms a dead loop between the two transformers at Substation A. Fault location plays an important role in the current contribution of faults along the circuits. For example, during a close-in fault in front of Breaker 4, there is no current contribution through Breaker 10. However, as interim faults slide along Circuit 1, the contribution through the parallel circuits around the loop increases significantly. The rapidly changing current magnitude based on fault location creates difficulty when trying to achieve selectivity and speed with simple overcurrent relays. Also, for a fault on the Substation A bus, none of the relays in the network measure fault current. This implies that the relays at Substation A are inherently directional because they do not see faults in the reverse direction.

Fig. 2 represents the fault currents measured by the relays associated with Breakers 4 and 10 on Circuit 1 with both transformers and all circuits in service.

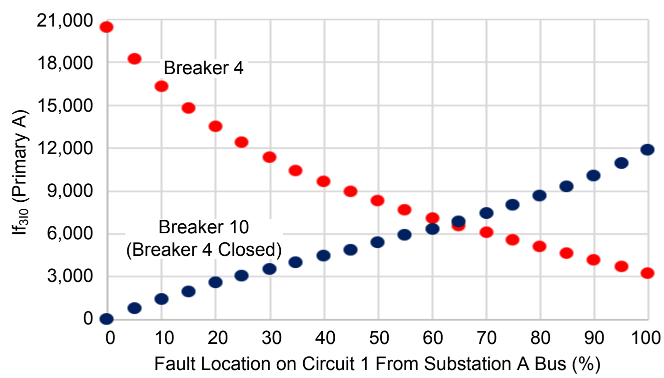

Fig. 2. Fault current variation seen by Breakers 4 and 10 for faults on Circuit 1

Using a short-circuit model of the AEP system, a close-in fault (with respect to Substation A) and interim single-line-to-ground faults were placed at every 5 percent of Circuit 1. This plot is helpful for visualizing the drastic change in fault current magnitude as the fault location varies. Though this plot depicts single-line-to-ground faults, similar results will occur for other classical fault types (i.e., phase-to-phase, phase-to-phase-to-ground, and three-phase faults).

The dependability of the overall network protection relies on the coordination of the remote backup phase and ground inverse-time overcurrent elements in the relays on the parallel circuits. Also, the security of the overcurrent relays is critical in preventing a reoccurring undesirable operation, as described in Section II. In order to provide reliable remote backup protection, it is necessary to analyze the variation of fault currents as measured by the relays on adjacent unfaulted circuits. Because the impedances of the parallel circuits are nearly identical, fault currents seen by the relays on the parallel circuits are also very similar. The tie circuit, however, sees the sum of the fault currents supplied by the parallel circuits in service behind the fault.

For the purpose of this study, only relays on Circuit 2 were considered when analyzing external faults because they measure the maximum fault current (and operate first) when compared with the relays associated with the other circuits.

Because faults on Circuit 1 are external with respect to the unfaulted circuits, the fault currents seen by both ends of Circuit 2 are the same. However, in Fig. 3 notice that the backup overcurrent relays associated with Breaker 5 measure less current when compared to the backup relays associated with Breaker 10. The relays associated with Breaker 5 sense a fault on Circuit 1 as forward, while relays at Breaker 11 declare it as reverse. Fig. 3 plots the fault currents seen by the relays associated with Breaker 5 for faults on Circuit 1 with both sources and all circuits in service. For easier comparison between the local and remote backup, fault currents as seen by both ends of Circuit 1 are also plotted.

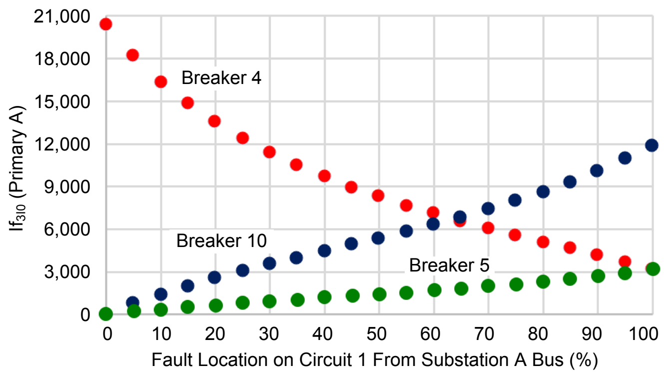

Fig. 3. Fault current variation as seen by Breakers 4, 5, and 10 for faults on Circuit 1

As seen from Fig. 3, for close-in faults on Circuit 1 with respect to the Substation A bus, the backup overcurrent relays associated with Breaker 10 and the backup overcurrent relays associated with Breaker 5 do not measure any fault current. However, in Fig. 4 notice that after Breaker 4 trips, the fault current redistributes and the relays associated with Breaker 10 rely on sequential tripping to clear the fault. Having analyzed the effect of fault location on the fault current values of both local and remote relays, it can be seen that this dead-loop configuration presents coordination challenges. In the case of radial feeders, the currents seen by the backup elements are the same. However, in looped systems, for each fault the currents seen by the overcurrent relays that overreach other relays are different from each other [2]. Section IV discusses the coordination of relays in this closed loop in greater detail.

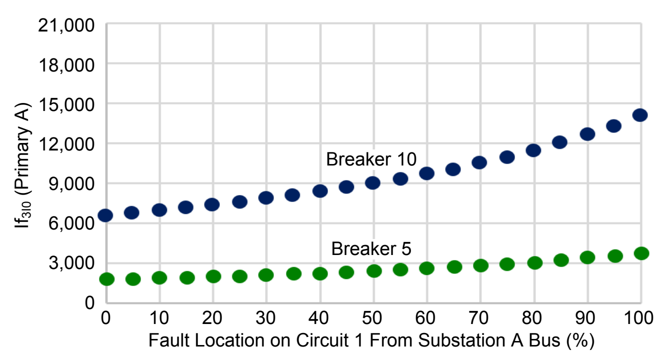

Fig. 4. Fault current variation as seen by Breakers 5 and 10 for faults on Circuit 1 when Breaker 4 is open

IV. Implemented Protection System

As concluded in Section III, achieving coordination for the looped network under study is complex. Because fault currents can flow in either direction around the loop, directional elements are applied on relays at Substations B and C, with each directional unit looking into the intended zone of protection (i.e., onto the specific circuit that the relay is protecting). The following is a general method for achieving coordination of the network around the loop in the counterclockwise direction:

- The relays at Breakers 4, 5, and 6 coordinate with the relays at Breaker 16 and the relays associated with the feeder breakers (F1–F8) at Substation B.
- The relays at Breaker 16 coordinate with the relays at Breakers 13, 14, and 15 and the relays associated with the feeder breakers (F9–F14) at Substation C.

The following is a general method for achieving coordination of the network Around the loop in the clockwise direction:

- The relays at Breakers 7, 8, and 9 coordinate with the relays at Breaker 17 and the relays associated with the feeder breakers (F9–F14) at Substation C.
- The relays at Breaker 17 coordinate with the relays at Breakers 10, 11, and 12 and the relays associated with the feeder breakers (F1–F8) at Substation B.

The relays associated with the breakers at Substation A receive three-phase voltage (P_A in Fig. 1) from a fused PT on the Substation A bus solely for metering purposes. These relays are set to be nondirectional because they do not operate for faults in the reverse direction (e.g., on the Substation A bus). This implies that the pilot tripping phase and ground elements used in the POTT scheme, as well as the backup phase and ground inverse-time overcurrent elements, are set to be nondirectional. However, because the relays at Substations B and C can see faults in both the forward and reverse directions, the three-phase voltage provided by the fused PTs on their respective buses (P_B and P_C in Fig. 1) are used for directionality. The pilot tripping elements, as well as the backup inverse-time overcurrent elements, are set in the forward direction to prevent operation during an external fault.

A. Pilot Protection

In a traditional POTT scheme, in order to high-speed trip the forward-looking pilot elements at both ends of the protected circuit must detect the fault. If either end fails to declare a forward fault, high-speed tripping will not occur and relaying on local and remote backup time-delayed overcurrent elements will need to clear the fault. However, in order to high-speed trip in a hybrid POTT scheme using echo logic, it is sufficient if either end (not both ends) measures the fault and both ends do not detect the fault in the reverse direction. Reference [3] provides more information regarding POTT schemes and echo logic.

Phase and ground directional overcurrent elements are used in the primary relays that operate in the POTT scheme. For security reasons, the pickups of the nondirectional phase overcurrent pilot elements in the relays at Substation A and the forward phase directional elements at Substations B and C were set at a margin above the winter emergency rating of the circuit. For dependability reasons, they were also set at a margin below the phase fault current seen by the relay to operate for a phase-to-phase or three-phase fault on the remote bus under a worst-case contingency. The pickups of the nondirectional and forward ground directional overcurrent pilot elements in the primary relays were set above the load unbalance, which was assumed to be 33 percent of the winter emergency line rating (usually an acceptable assumption for distribution systems) and below the fault current seen by the relays for a single-line-to-ground fault on the remote bus under the worst-case contingency.

As discussed in Section III, none of the relays in the network measure fault current for a Substation A bus fault. This implies that the relays at Substations B and C also cannot provide complete coverage of their applicable zone of protection (e.g., a close-in fault on a feeder terminal at Substation A). Therefore, high-speed fault coverage on the entire protected circuit via a traditional POTT scheme was deemed impossible. The devised solution was to use a hybrid POTT scheme with the addition of echo logic in the primary relays at Substations B and C to provide high-speed coverage of each circuit.

When implementing a hybrid POTT scheme, AEP typically prefers the coordination margin between the forward pilot tripping elements at one end and the reverse blocking elements at the remote end to be greater than 1.25 but less than 2. Echo logic was included in the POTT/DTT relays associated with Substations B and C. However, echo logic in POTT/DTT relays at Substation A was disabled because the relays at Substation A do not operate for reverse bus faults (bus faults are cleared by the bus differential relays at Substation A). However, custom logic was created to implement open breaker keying to allow high-speed fault clearance when the breaker at Substation A associated with the faulted circuit is open.

Because echo logic was enabled in relays at Substations B and C, reverse directional (phase and ground) overcurrent elements are necessary to block high-speed tripping for external faults. The pickups of these reverse pilot blocking elements at the Substation B and C terminals were set equal to half the pickup of the nondirectional (phase and ground) overcurrent pilot tripping elements at the Substation A terminal. This margin ensured adequate pilot coordination between the reverse directional overcurrent elements at Substations B or C and the nondirectional overcurrent elements at Substation A.

For the example discussed in Section III of close-in or interim (5 to 15 percent) phase and ground faults on Circuit 1 close to the Substation A bus, the nondirectional phase and/or ground overcurrent pilot element associated with Breaker 4 declares a forward fault and sends a permissive trip signal to the remote end. The forward directional overcurrent elements associated with the relays on Breaker 10, however, do not measure fault current that exceeds the overcurrent pickup setting. However, because the relay at Breaker 10 received a permissive trip signal, and echo logic is enabled, it echoes the permissive trip signal back to the relays at Breaker 4, tripping Breaker 4. Once Breaker 4 opens, a DTT signal is sent to the remote end, tripping Breaker 10 and selectively clearing the fault by isolating only Circuit 1 from the distribution network. The DTT scheme is therefore advantageous because it facilitates the high-speed tripping of the breakers at Substations B or C in spite of the low fault contribution seen by the relays for close-in or interim faults. If the DTT did not exist, the relay at Breaker 10 would trip semi-high speed because of the current redistribution following the opening of Breaker 4. Once the relay at Breaker 10 declares a forward fault following the current redistribution, it sends a permissive trip signal to the relay at Breaker 4. Because Breaker 4 is open, the open breaker keying logic also keys a permissive trip signal, allowing Breaker 10 to trip.

Depending on the location of the fault on Circuit 1, the forward pilot elements in the primary relays at one end of the unfaulted parallel and tie circuits may or may not pick up. However, because the reverse elements are set lower than the forward pickup, the security of the POTT scheme is ensured. Any time a forward element picks up, a corresponding reverse element must also pick up, which blocks high-speed tripping, resulting in secure and selective fault clearance.

Under normal conditions (i.e., all sources, circuits, and fiber-optic communications channels are in service), all faults on a circuit are cleared at a high speed by the pilot phase and ground elements.

B. Backup Time-Overcurrent Protection

Time-coordinated phase and ground overcurrent elements are used to provide reliable backup protection. These overcurrent elements are enabled in both the primary (POTT/DTT) and alternate (inverse-time overcurrent) relays. In order to simplify coordination but still be dependable, the overcurrent protection enabled in the relays is as shown in Fig. 5. For the purpose of simplifying the one-line diagram, only two of the six circuits between Substations A, B, and C are shown. Similar protection exists on the relays on the other parallel circuits.

At Substation A, the inverse-time overcurrent elements are set to be nondirectional because they do not measure reverse faults. Relays at Substations B and C incorporate directional overcurrent elements to provide backup protection. For security, the pickups for the phase time-overcurrent and ground time-overcurrent elements are set above the winter emergency rating of the circuit and the load unbalance, respectively. To simplify coordination with the downstream elements, directional elements are used in the relays at Substations B and C, as shown in Fig. 5.

The backup time-overcurrent elements operate faster with one of the parallel circuits out of service than with a normal system condition. Also, the time-overcurrent elements only operate if the POTT scheme is out of service. Therefore, this N – 2 contingency (i.e., a contingency in which two conditions outside of the normal operating conditions have occurred) was considered to be the boundary case to coordinate with relays

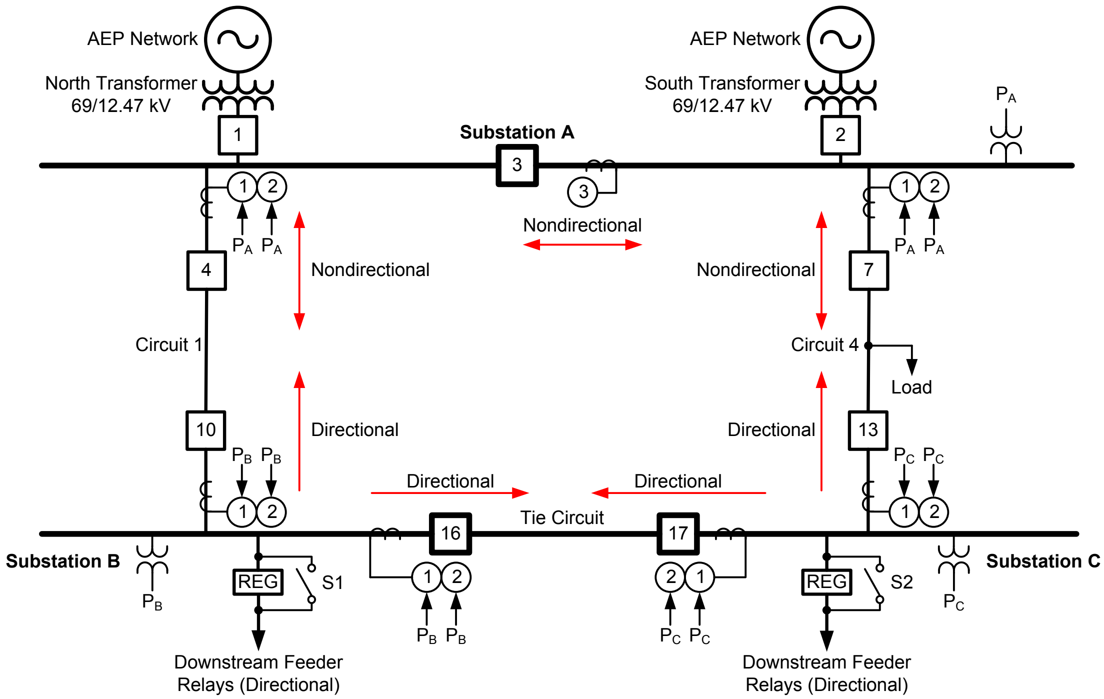

Fig. 5. Simplified one-line diagram showing the use of directional and nondirectional elements

on the remote bus. The recommended phase and ground time-overcurrent settings ensure a minimum coordination time interval of 0.3 seconds. Because the relays at Substations B and C do not see any fault current for faults on the Substation A bus, coordination with the tie breaker relay associated with Breaker 3 is not required. Therefore, the time dial is set to the minimum possible settings to allow for faster fault clearance. Section V provides more discussion about the coordination of relays in this looped system under contingency conditions.

C. Bus Differential Protection

During the addition of the POTT/DTT relays on the network circuits, AEP decided to also replace the electromechanical differential relays at Substations B and C with microprocessor-based, percentage restraint differential relays with dual-slope characteristics. The purpose of the differential relays is to dependably operate for bus faults at Substations B and C. Operation of the bus differential relays prevents the operation of the time-overcurrent relays at Substation A and also prevents the time-overcurrent relay at the adjacent load-serving substation on the tie circuit from tripping for a bus fault at either Substation B or C. Note that there are tapped loads between Substations A and C on Circuits 4, 5, and 6. The bus differential relay at Substation C complements selectivity by only isolating the breakers at Substation C during a bus fault and continuing service to the customers at the tapped loads.

The two-restraint relays used at the load-serving substations calculate an operating current (IOP) based on (1), where IW1 is the filtered current input from Winding 1, IW2 is the filtered current input from Winding 2, and TAP1 and TAP2 are values calculated from user-entered settings in the relays. Equation (2) calculates the restraint quantity (IRT) in the differential relay.

$$\mathrm{IOP} = \left| \frac{\mathrm{IW1}}{\mathrm{TAP1}} + \frac{\mathrm{IW2}}{\mathrm{TAP2}} \right| \tag{1}$$

$$\mathrm{IRT} = \frac{\left| \frac{\mathrm{IW1}}{\mathrm{TAP1}} \right| + \left| \frac{\mathrm{IW2}}{\mathrm{TAP2}} \right|}{2} \tag{2}$$

Because this was a two-restraint relay application, several CT circuits had to be externally combined before they entered the relay. Fig. 6 shows the CTs available for the bus differential scheme at Substation B and the existing CT connections that were used when the electromechanical relays were replaced. Substation C had a similar setup, the only difference being that Substation C has two fewer feeder breakers. The accuracy class (C-ratings) for the CTs involved in the differential scheme are also provided in Fig. 6. The C designation refers to the American National Standards Institute (ANSI) accuracy class of the CT, which requires a maximum ratio error limit into the nominal burden of 10 percent at 20 times the rated nominal current. The number following the C designation is the secondary terminal voltage that the CT can support while meeting the 10 percent error limit. See [4] for more details on the accuracy classes for CTs.

The goal of setting the bus differential relay is to provide dependable operation for internal (bus) faults while also preventing operation of the relay during external faults, during a normal system condition, or during a contingency. One of the greatest challenges to setting a bus differential relay is the unequal performance of the CTs involved in the bus differential scheme during CT saturation. Unequal performance results in a false differential current that can cause an undesirable operation of the scheme. Reference [5] provides a helpful discussion of CT basics and CT saturation fundamentals.

The fault study determined that bus faults resulted in large-magnitude fault currents at Substations B and C that caused excessive CT saturation. Mismatched CTs further complicated the problem. CT saturation simulation software [6] was used to analyze the CT performance during several internal and external faults in the short-circuit model of the network. After simulating several external faults with the existing CT connections shown in Fig. 6, a wiring change was recommended to improve security, as shown in Fig. 7.

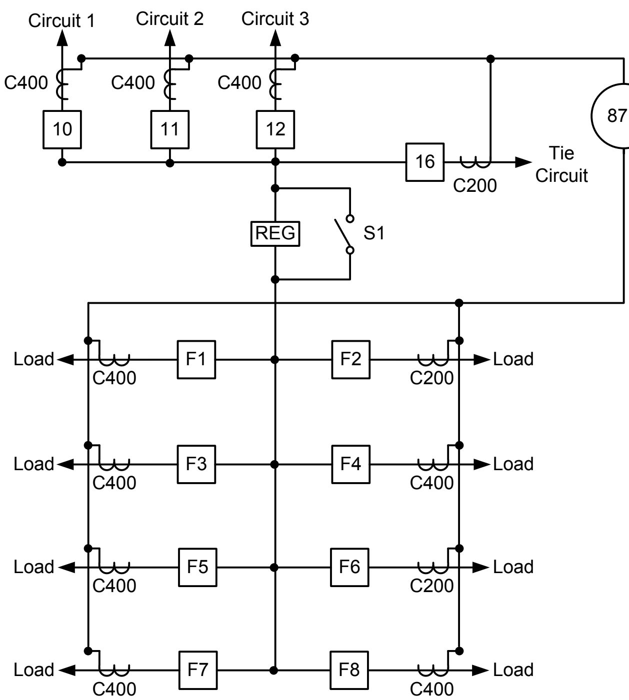

Fig. 6. Existing Substation B bus differential scheme CT connections

During the contingency that Circuit 6 is out of service, a three-phase, close-in fault on the tie circuit (with respect to Substation B) was simulated to test the performance of the differential scheme. This simulation included a primary current of 12.42 kA with an incident angle of 85.5 degrees and 0 percent remnant flux. The results indicated that the CT could saturate to approximately 75 percent of the expected output. With the existing connection, the IW2 input does not measure fault current because all of the feeders are loads and do not supply fault current. This implies that all the fault current seen by the relay is through IW1. When only one restraint measures current, (1) and (2) equal 1 per unit (pu) and 0.5 pu, respectively. However, with the original connection of the paralleled CTs, the only way restraint current is measured for an external fault on the tie circuit is if a CT saturates. IW2 measures zero current for any fault that does not exist on one of the feeders.

Fig. 7 presents a wiring change that was recommended to improve the restraint characteristic during this external fault. The wiring change parallels the CT on the tie circuit (Breaker 16) with all of the feeder circuits into Winding 2 and leaves alone the three source circuit CTs to Substation A entering Winding 1. Without consideration of CT saturation, the original wiring provided no restraint current seen by the differential relay for an external fault. With the recommended connections, restraint current is measured for all faults. Therefore, without consideration of CT saturation, the increase in restraint current between the existing and recommended connections is infinite.

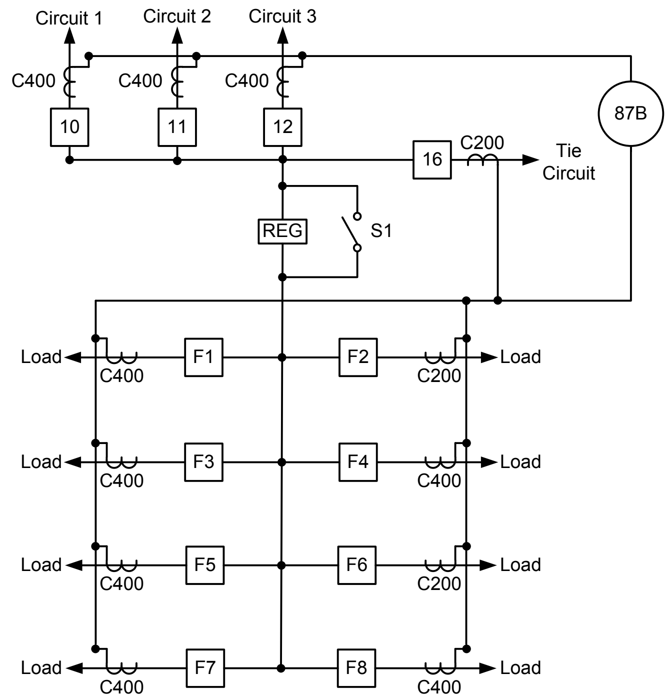

Fig. 7. Recommended Substation B bus differential scheme CT connections

Fig. 8 provides a visual depiction of the vast difference in the calculated restraint quantity between the original wiring and the recommended wiring. This plot is for a close-in three-phase fault on the tie circuit with Circuit 6 out of service. With the recommended differential settings for this scheme, notice that the fault plots in the operating region for the presented fault with the existing wiring connections; however, the same fault properly plots in the restraining region with the recommended wiring connections. Also, note that there are other possibilities for the connections of these CT circuits to provide the same level of security, but the recommended wiring connection was deemed the easiest change with respect to the existing configuration.

After analyzing several contingencies with the short-circuit model, it was determined that a single-slope characteristic would not be possible. The recommended settings resulted in a relatively high Slope 1 setting of 85 percent, a Slope 2 setting of 175 percent, a minimum operate of 0.3 pu, and a Slope 1 limit (or crossover point to Slope 2) of 1.5 pu. This solution provided the best balance of dependability and security. Fig. 9 provides a visual representation of the three-phase internal (bus) faults simulated in the fault study. The worst-case faults are depicted and correctly plot in the operating region. Also, Fig. 10 indicates that the relay is secure and will restrain for the worst-case external fault (i.e., a three-phase close-in fault on the feeder Breaker F2).

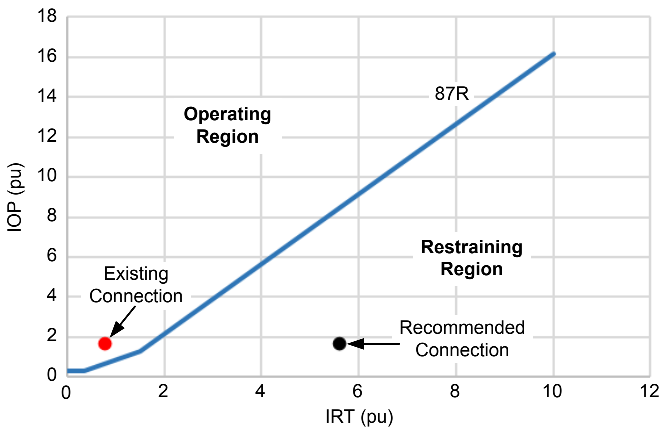

Fig. 8. Substation B bus differential characteristic (recommended versus existing connections)

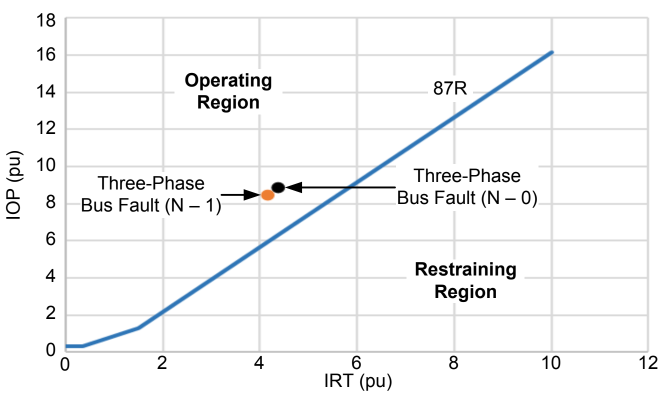

Fig. 9. Substation B bus differential characteristic and simulated internal (bus) faults

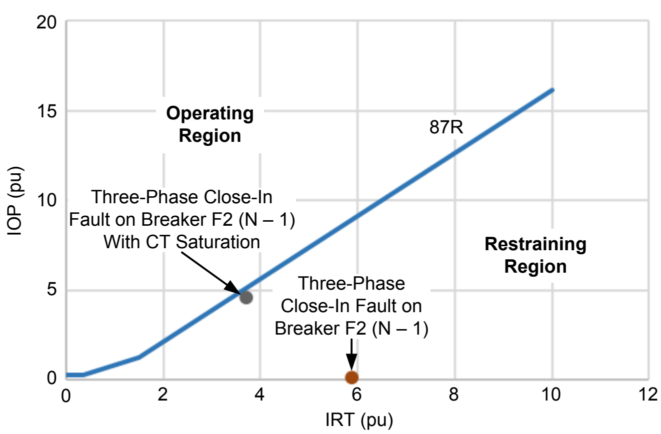

Fig. 10. Substation B bus differential characteristic and simulated external faults

Setting a relatively high slope characteristic resulted in certain compromises. As described in Section II, there is a voltage regulator in the bus differential zone of protection. Thus, the bus differential relay operates for faults on the bus and in the voltage regulator. Setting a larger slope characteristic results in decreased sensitivity for faults in the voltage regulator.

Setting a higher characteristic also decreases sensitivity for certain internal (bus) faults. For example, a highly resistive fault on the bus may not be cleared at a high speed by the bus differential relay because of the large slope settings. However, it was determined that during this situation, the backup time-overcurrent relays at Substation A and the remote end of the tie circuit between Substations B and C would clear the fault. Overall, it was determined that the recommended slope characteristics provide the best balance of dependability and security with the scheme that was presented. Also, selectivity was achieved for all of the scenarios considered in the study.

A better solution would have been to use a proper bus differential relay with multiple current inputs that does not require paralleling CTs externally to the relay. The higher cost of a multirestraint bus differential relay or a high-impedance bus differential relay would have been more than offset by the reduction in engineering studies that was required to determine compromise settings for the relay that was installed.

V. Contingency Analysis

When designing a protection scheme, it is a good practice to simulate every realistic contingency possible and evaluate how the scheme responds. The selectivity and speed of the protection scheme during the following contingencies are discussed in this section: (1) loss of fiber-optic communications, (2) loss of potential (LOP), and (3) loss of both communications and potential.

A. Loss of Fiber-Optic Communications

Fig. 11 represents the communications layout for the POTT and DTT schemes. The POTT scheme on each circuit between Substations A, B, and C communicates via a fiber-optic cable. This fiber-optic cable connection is made to a communications port on the microprocessor-based relays configured for the POTT scheme, and each individual cable is connected to a local fiber distribution center. The local fiber distribution centers at Substations A and C and at Substations B and C are then connected to each other via multifiber cables. If the fiber-optic cable between the fiber distribution center at Substation A and the fiber distribution center at Substation C is compromised, the POTT and DTT schemes for all of the relays at Substations A, B, and C will be disabled. This one fiber-optic cable out of service is the loss-of-communications contingency for this analysis.

Under the loss-of-communications contingency, a fault on the tie circuit or any of the parallel circuits between Substations A, B, or C is cleared by the local backup time-overcurrent elements. The result is a sacrifice in high-speed tripping. Due to the fault current variation, the location of the fault determines which breaker on either end of the faulted circuit operates first. For faults closer to Substation A, the time-overcurrent elements associated with the faulted circuit at Substation A operate first. Once that breaker opens, the backup elements at the remote end of the faulted circuit measure sufficient fault current and trip with a time delay, selectively isolating the faulted circuit from the rest of the network. Therefore, this contingency results in a slower relay response. Fig. 12 and Fig. 13 highlight the operating times of the POTT scheme, along with the backup phase and ground inverse-time overcurrent elements, respectively, for the relays associated with Breakers 4 and 10. Note that the POTT/DTT

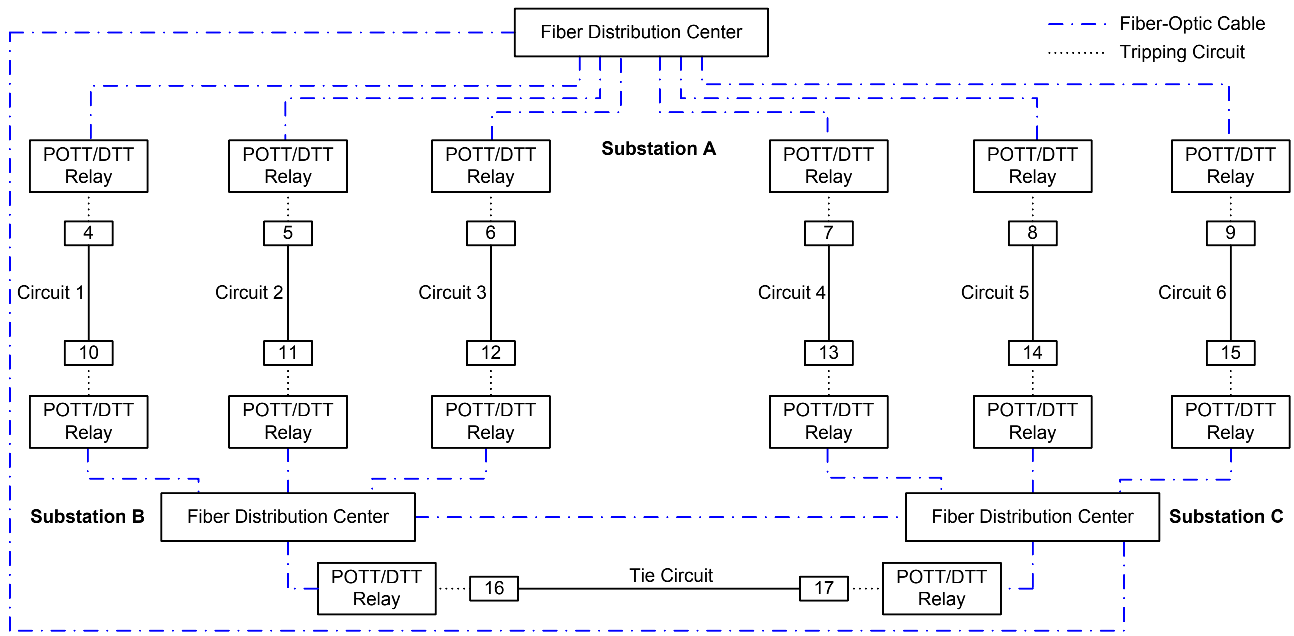

Fig. 11. Network communications layout for the POTT/DTT relay schemes

relays are delayed by the communications channel between the relays involved in the scheme. Because a fiber-optic channel is the communications medium for all of the POTT schemes in this network, this delay is minuscule. Fig. 12 and Fig. 13 highlight the speed benefit of having the POTT/DTT relays operate during a system normal condition; however, selectivity is still achieved even during this degraded mode of operation.

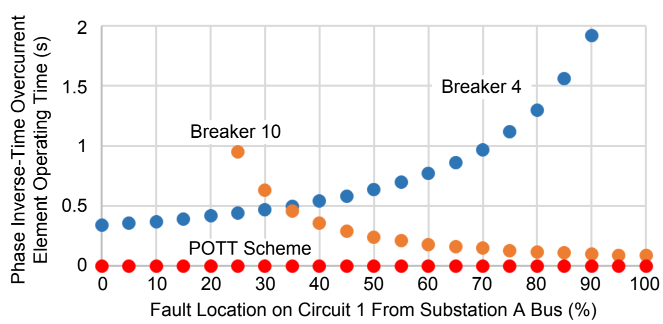

Fig. 12. POTT and phase inverse-time overcurrent element operating times as seen by Breakers 4 and 10 on Circuit 1

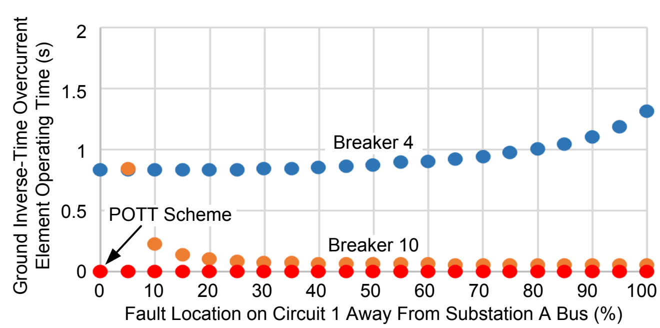

Fig. 13. POTT and ground inverse-time overcurrent element operating times as seen by Breakers 4 and 10 on Circuit 1

B. *Loss of Potential*

All of the relays at Substations B and C have LOP logic enabled. The LOP logic in these microprocessor-based relays is set to ensure that an LOP condition disables the pilot elements used in the primary POTT scheme and also disables any other directional elements. To selectively cover for faults during an LOP condition, nondirectional overcurrent elements are enabled in the relays on the parallel circuits at Substations B and C. The pickups of these elements are set to ensure that they do not see faults in the reverse direction, and due to the nature of the dead loop, it is impossible for these elements to see out-of-zone faults in the forward direction, making them inherently directional.

Because all of the relays in a particular substation receive potential from the same PT, a single contingency that all of the relays at a given substation experience LOP at the same time was considered for this analysis. However, the relays at Substation A do not have LOP logic enabled because these relays are nondirectional and do not have echo logic or reverse elements enabled. As a result, an LOP condition at Substation A has no effect on the selective POTT schemes on Circuits 1–6.

If an LOP condition occurs at Substation B, as shown in Fig. 14, the POTT scheme and the directional time-overcurrent phase and ground elements of the relays associated with the substation will be disabled. Under this contingency, for faults closer to Substation B, the instantaneous overcurrent elements will operate first to clear the fault. For faults beyond the reach of the instantaneous overcurrent elements, the time-overcurrent elements at Substation A associated with the faulted circuit will operate first. In both cases, once the local breaker trips, a DTT signal will be sent to the remote end, isolating the faulted circuit.

If a fault occurs on the tie circuit, with the communications in service and an LOP condition at Substation B, the time-overcurrent elements of the relays associated with Breaker 16 will be disabled and will not initiate a trip. The time-overcurrent elements of the relays associated with Breaker 17 will trip and send a DTT signal to Breaker 16. The location of the fault on the tie circuit determines how fast the fault is cleared. While this example considers Substation B, the results would be similar for an LOP at Substation C.

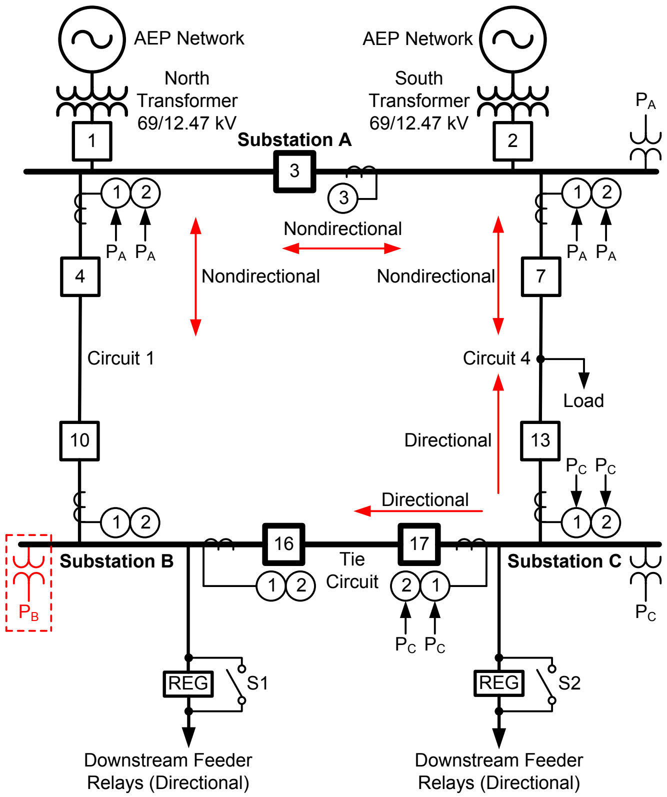

Fig. 14. An LOP condition at Substation B

C. Loss of Both Communications and Potential

Under the contingency of losing both communications and potential at Substation B, the directional elements in the relays at Substation B are disabled. Because the communications fiber is out, the DTT scheme does not work. For faults closer to Substation B, the instantaneous overcurrent elements will operate first to clear the fault. For faults closer to Substation A, which is beyond the reach of the instantaneous overcurrent elements at Substation B, the time-overcurrent elements at Substation A associated with the faulted circuit will operate first. In both cases, once the local breaker opens, due to current redistribution, the remote overcurrent elements will see higher fault current, resulting in faster and selective fault clearance. During this condition, if a fault occurs on the tie circuit, the directional time-overcurrent elements associated with Breaker 17 will trip first, but a DTT signal cannot be sent. In order to clear the fault, the remote backup overcurrent elements at Substation A, remote to Substation B, have to operate. However, because these backup time-overcurrent elements at Substation A are set the same as each other and these circuits see nearly the same fault current, all of the relays at Substation A, remote to Substation B, will operate around the same time, resulting in a loss of all loads at Substation B. While this example considers Substation B, the results would be similar for an LOP condition and loss of communications at Substation C. To prevent this, and to ensure selectivity during a loss of communications and potential at Substation B or Substation C, it was decided to directly trip the tie circuit.

D. Breaker Failure

Breaker failure was also considered for the breakers at Substations B and C. Because the primary POTT/DTT relays include programmable logic, breaker failure logic was easily implemented. For example, if the primary relay associated with Breaker 10 detects a fault on Circuit 1 and issues a trip signal, the breaker failure logic is also initiated. If Breaker 10 fails to clear the fault after a definite-time delay, the relay trips the bus lockout relay, which trips all of the adjacent breakers at Substation B. Also, if the fiber-optic communications channel is in service, a DTT signal is sent to the remote relay associated with Breaker 4 to isolate the failed breaker. The addition of breaker failure logic improves selectivity, especially for Circuits 4, 5, and 6, which have tapped loads. During a breaker failure on one of the breakers at Substation C, the only tapped load that is lost is the circuit with the failed breaker. Substation breaker failure logic was also recommended for Substation A and will be implemented as a future enhancement.

VI. Conclusion

The complex, dead-loop network discussed in this paper was designed to provide reliable service to AEP customers. However, the configuration presented a unique challenge to the design of a selective protection system.

The original protection system for this network consisted of simple phase and ground overcurrent relays. However, after an undesired operation on one of the circuits, coordination of the overcurrent relays was reviewed, and POTT and DTT schemes were added to improve speed and selectivity. Two significant contingencies were considered during the setting process: loss of communications and LOP. It was determined that selectivity would not be compromised, only speed, under either of these contingencies. Thus, another undesired operation is unlikely to occur with the scheme that was implemented.

Bus differential protection was also upgraded at the load-serving substations, and two-restraint, microprocessor-based relays replaced the original electromechanical relays. CT saturation presented challenges to setting a dependable and secure slope characteristic. A wiring change was recommended to significantly improve the security of the differential scheme. The fault study and CT saturation analysis yielded relatively high slope settings. Having large slope settings improves the security of the scheme; however, it also results in the following compromises:

- A lowered dependability margin for faults in the voltage regulator
- Less sensitivity for high-resistance faults

Further, a great deal of engineering study was required to determine settings for the two-restraint relays. Selecting a multirestraint relay for the bus zone would have provided better performance and security with a lower installed cost when the additional analysis required to set it is considered.

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VIII. Biographies

Jim Thomas has worked in Network System Engineering at AEP SWEPCO for the past 34 years, providing supervision for the completion of construction and operational projects for underground distribution network systems. He attended college at Louisiana State University and Michigan Tech University and holds a Master Electrician license in Texas and Louisiana.

Andrew K. Burich received his B.S. in electrical engineering, summa cum laude, from the University of Missouri, St. Louis, in 2012. He has been employed with Schweitzer Engineering Laboratories, Inc. as a protection engineer in the engineering services division since his graduation. He is a registered professional engineer intern in the state of Illinois.

Michael J. Thompson received his B.S., magna cum laude, from Bradley University in 1981 and an M.B.A. from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a fellow engineer in the engineering services division at SEL, a senior member of the IEEE, chairman of the Substation Protection Subcommittee of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book, *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

Sneha Vasudevan received her B.E. in electrical engineering from Anna University, India, in 2010 and an M.S.E.E. from Ohio State University at Columbus in 2011. Since graduating, she has been employed with Schweitzer Engineering Laboratories, Inc. as a protection engineer in the engineering services division. She is a registered professional engineer intern in the state of Missouri.

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