Case Study: Application Considerations for Local and Remote Breaker Failure Protection From a Utility's Perspective

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***Abstract*—Reliability is a critical factor in the design of protection systems. This paper explores the reliability challenges that protection engineers must address to ensure dependable operation in the event of failures, such as those involving relays, circuit breakers, instrument transformers, or dc station batteries within a transmission substation, while also maintaining system security under varying load and transient conditions.**

Since the era of electromechanical relays, forward overreaching distance elements, commonly referred to as Zone 3 or Zone 4, have been used to provide remote backup protection for adjacent circuit faults in the event of protection system failures at neighboring substations. The remote backup distance element protection has been identified as a contributing factor in several major power system disturbances in North America since the 1965 blackout [1] [2]. This underscores the critical importance of carefully balancing dependability for faults on adjacent circuits with security under high load conditions when applying remote backup distance elements. In some system configurations, it may not be feasible to set the reach of this distance element to simultaneously satisfy both dependability and security requirements, while maintaining acceptable fault clearing times. To mitigate reliance on remote backup distance elements, utilities implement local breaker failure protection and direct transfer trip schemes.

This paper revisits the principles of local breaker failure and remote backup protection, discusses typical application considerations, and presents the protection philosophies of Xcel Energy and Great River Energy, highlighting how these two utilities apply such schemes within their systems.

I. Introduction

Reliability is a fundamental consideration in the design of protection systems. A protection system is made up of various critical components, such as relays, instrument transformers, dc station batteries, communications equipment/channels, and merging units, which function to detect and isolate faults by operating circuit breakers/interrupters. For a protection system to be dependable, each component must operate correctly under all fault conditions, which is why it is common to implement redundancies in the protection system design.

It is impractical to design a protection system capable of reliably operating under all possible simultaneous failure scenarios. As a result, industry practice generally focuses on the N-1 criterion, where the system is expected to handle a single component failure or contingency, with protection systems continuing to operate in the intended sequence during faults. The precise definition of N-1 differs depending on the protection systems in use and the protection philosophies of individual utilities, and certain utilities may also pursue levels of system reliability that exceed the standard N-1 criterion.

Appendix A of this paper provides a high-level overview of various protection system redundancies implemented to accommodate N-1 scenarios at both Xcel Energy (hereafter referred to as Utility 1) and Great River Energy (GRE) (hereafter referred to as Utility 2). The components of a protection system that are not commonly implemented with redundancy include the dc battery system and the circuit interrupting device. At extra-high voltage levels, utilities like Utility 2 have a standard for redundant battery systems, while Utility 1 applies dual battery systems only for critical substations. A failure in the dc battery system can result in the loss of protection across the entire substation, while an issue with a circuit interrupting device or associated circuitry may allow a fault to persist on the system for an extended duration. For utilities like Utility 2, the complete failure of the dc battery system is considered a rare event and an acceptable risk. As a result, their local and remote backup protection schemes focus primarily on breaker failure (BF). In contrast, utilities like Utility 1 may choose to account for both the complete loss of dc supply and BF, shaping their backup protection philosophy accordingly.

In this paper we revisit the principles of local BF protection followed by remote backup protection application considerations and setting methodologies. The protection philosophies of Utility 1 and Utility 2 will also be discussed throughout the paper, highlighting how these two utilities apply such schemes within their systems.

II. Local BF Protection

The benefits and methods of local BF protection are well documented [3] [4] [5]. In summary, if a trip command is issued to a breaker, and the breaker fails to interrupt the fault current within a specified time frame, it should be considered a BF. In such cases, alternative isolation methods must be employed to ensure fault clearance. Today, local BF protection is implemented by nearly all utilities, including Utility 1 and Utility 2, at both transmission and subtransmission voltage levels.

Local BF protection not only monitors the trips to the circuit breaker (via BF initiation [BFI]) but also tracks the breaker status by monitoring the breaker current magnitude (50BF). If the breaker fails to open before BF timer pickup delay (BFPU) times out, a BF trip (BFT) signal is issued to a lockout relay that trips the adjacent breakers at the substation and, in some cases, remote breakers to isolate the fault.

There are two common BF protection schemes. In the first scheme, shown in Fig. 1, the BF timer starts timing only when the BF is initiated and the current has exceeded the fault-detector pickup threshold at the same time. This scheme is most suitable for straight bus, single-breaker configurations, where fault current reliably flows through the breaker being monitored.

In the second scheme, shown in Fig. 2, the BF timer starts timing as soon as the BF function is initiated, regardless of the current level. However, the BF trip will only occur if the current exceeds the fault-detector pickup threshold. This method is useful in multibreaker bus arrangements, such as ring bus or breaker-and-a-half schemes, where unequal current distribution among breakers can delay the start of the BF timer in the scheme, as in Fig. 1.

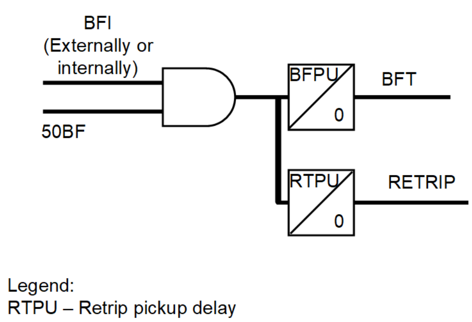

Fig. 1 BF timing when both BFI and the fault-detector pick up

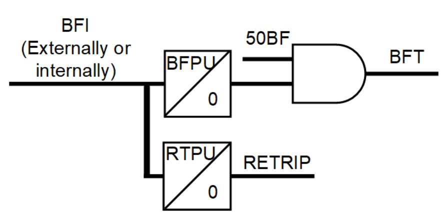

Fig. 2. BF timing when BFI picks up

The retrip logic allows the failed breaker an additional chance to operate and isolate the fault before the BF trip is issued. Typical BFPU falls within the range of *6 to 12 cycles*. At higher voltage levels, where fault clearing speed is more critical to maintain system stability and limit equipment damage, the BF timer is often set to a shorter duration based on having faster relays and breakers.

The following subsections cover the key factors considered by Utility 1 and Utility 2 when implementing local BF protection.

A. Standalone vs. Integrated BF Relay

There are two main approaches to local BF protection: standalone BF relays, which handle only breaker-specific tasks such as reclosing, synchronism check, and BF protection; and integrated BF functions built into main zone relays, such as line, bus, or transformer protection.

Utility 1 follows a standard approach that uses a standalone breaker relay. This BF philosophy is biased toward security and simplicity, as only a single relay is tasked with executing the BF function. It is also clear where the BF functionality is being performed with this approach. Utility 1 does not implement redundant BF relays, as the relay itself serves as a redundancy to the breaker (a failed breaker and relay failure would be N-2).

Utility 2 primarily implements the BF function within both their primary and secondary zone protection relays. Occasionally, a dedicated relay is used if the BF function is not available in the primary protection device. In multibreaker bus arrangements, Utility 2 implements BF protection in only one set of zone protective relays of the shared breaker. For example, in multibreaker bus arrangements, two transmission lines, Line A and Line B, share a common breaker. In such cases, the BF logic for the shared breaker is typically implemented in the protection relays of either Line A or Line B, not both. This highlights one drawback to this philosophy: it is not always clear in multibreaker bus arrangements where the BF functionality will be performed. Utility 2 prefers to use the integrated BF functionality in zone relays because it reduces the number of relays that need to be maintained and minimizes panel space requirements. This approach also inherently provides redundancy and operational flexibility, because both primary and secondary relays incorporate BF protection.

B. BF Scheme Implementation

Utility 2 uses the first scheme, as shown in Fig. 1, for all bus configurations. Utility 2 has not observed any issues with unequal current distribution among breakers in multibreaker bus arrangements within their system. As a result, they consistently implement the scheme shown in Fig. 1 across all bus configurations.

Utility 1 uses the combination of both schemes, as seen in Fig. 3, for all bus configurations. The output of AND Gate 1 is similar to Fig. 2, and the output of AND Gate 2 is similar to Fig. 1.

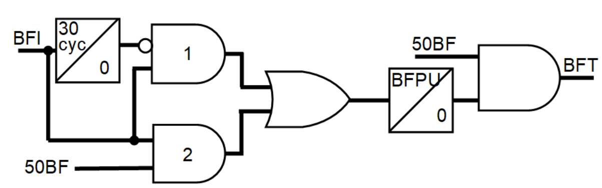

Fig. 3 Utility 1's BF logic

The philosophy of using a 30-cycle control timer originates from traditional solid-state BF relays. When the BFI signal is asserted, it triggers a timing window in which the BF timer starts timing. This approach is particularly beneficial in configurations, such as ring bus or breaker-and-a-half bus arrangements, where a parallel current path may exist. In such cases, the current measured by the BF relay might fall below the threshold set for the BF fault detector. Using this control timer narrows the window during which only the BFI signal initiates BF timing. This approach accommodates scenarios where the BFI signal is permanent, such as one triggered by a bus lockout relay, a method historically used to overcome the limited output contacts available in electromechanical relays.

After that first 30 cycles, it requires both BFI and 50BF to start the BF timing.

C. BF Initiation

BF schemes must be initiated primarily by protective elements that attempt to trip the breaker in response to shunt faults. Control operations typically do not trigger BF logic, to avoid the ramifications of operating the BF lockout relay when the system is in a healthy state. Utility 2 uses a combination of internally generated BFI signals and external BFI inputs to the primary zone relays. This includes receiving BFI signals from adjacent protection zones. In contrast, Utility 1 employs dedicated BF relays where all BFI signals are externally initiated via discrete input.

One potential security risk in BF schemes is the false assertion of an external BFI signal. BF fault detectors need to be picked up along with a BFI assertion for BF logic to operate, adding a layer of security to the logic. However, the philosophy of setting BF fault detectors varies significantly and settings are commonly set less sensitively than normal load levels to ensure reliable fault detection. To further enhance security, relay input debounce timers are used to prevent spurious signal assertions. Additionally, retrip logic can be implemented to minimize impacts of BF operation if BFI is sporadically asserted. The retrip logic trips only the protected breaker, unlike BF logic, which may trip multiple breakers on a false BFI signal.

Utility 2 implements the retrip logic represented in Fig. 1 without a retrip time delay, while Utility 1 does not implement retrip logic.

D. BF Fault Detector

A fault detector is the basic overcurrent supervision used to verify whether current continues to flow after a trip is issued to open a circuit breaker. Its primary purpose is to detect any persistent fault conditions. The fault-detector pickup settings should be sensitive enough to detect all fault types within the zones of the relays that provide a BFI signal. Ideally, the fault detector should be set sufficiently higher than the maximum load current level to avoid false BF operations. However, to achieve the desired sensitivity, it may sometimes be necessary to set the fault detector below the maximum load current level.

The following subsections cover the two types of fault detectors that are typically employed by Utility 1 and Utility 2.

1) Phase Overcurrent Fault Detector for Phase Faults

Utility 2 sets the fault detector to pick up at the *minimum* of the following two thresholds:

- 120 percent of the NERC PRC-023 load limit
- 30 percent of the minimum fault current observed for in-zone faults during an N-1 contingency

If the fault current is too low to ensure reliable detection, Utility 2 supplements the BF logic with the 52a auxiliary contact in parallel with 50BF. This contact provides an additional layer of dependability by acting as a *no-current* indicator, especially useful in scenarios where the current-based supervision is unavailable or unreliable. The drawback is that the 52 contacts may fail closed, inadvertently arming the BF logic and reducing the security of the BF scheme.

Utility 1 applies a slightly different approach. Their fault detector is set to the *minimum* of the following two thresholds:

- 150 percent of the maximum established FAC-008 current rating of the facilities fed by the breaker
- 60 percent of the lowest fault current for an in-zone phase fault during an N-1 contingency

In systems where the maximum load current level is significantly lower than the fault current, this scheme provides better sensitivity while ensuring security.

2) Ground Overcurrent Fault Detector for Ground Faults

Utility 2 configures their ground overcurrent fault detector based on 30 percent of the minimum fault current observed for an in-zone fault during an N-1 contingency.

In contrast, Utility 1 sets their ground overcurrent fault detector to be the minimum of the following two values:

- 10 percent of the maximum established FAC-008 current rating of the facilities fed by the breaker
- 60 percent of the lowest fault current for an in-zone ground fault during an N-1 contingency

E. BF Delay

The BF logic should allow sufficient time for the breaker to interrupt the current and for the 50BF to drop out before declaring a BF state. Utility 1 and Utility 2 use the following equations when setting the delay:

$$\begin{aligned}\text{BFPU (Utility 1)} &= 2 \bullet \text{Breaker interrupt time} \\ &+ \text{Margin (1 cycle)}\end{aligned}$$

$$\begin{aligned}\text{BFPU (Utility 2)} &= \text{Breaker interrupt time} \\ &+ \text{Current dropout time} \\ &+ \text{Margin (4 to 8 cycles)}\end{aligned}$$

The breaker interrupt time is a characteristic of the breaker that is typically listed on the breaker nameplate. For Utility 1 and Utility 2, 345 kV breakers generally have a two-cycle interrupt time while breakers at other voltage levels typically interrupt in three cycles. The current dropout timer refers to the time it takes for fault detectors to reset after fault isolation. Subsidence current may remain in the CT secondary for a few cycles after the breaker opens, extending the dropout time. Modern relays mitigate this concern by incorporating subsidence logic, which detects that the breaker poles are open and resets the fault detectors in less than a cycle [5]. Utility 1 specifies a minimum BF delay of 7 cycles and a maximum BF delay of 12 cycles.

III. Bus Arrangement Considerations

The effectiveness of local BF relaying depends heavily on the bus and breaker arrangement at the local substation. The defining characteristic discussed here is whether each line terminates on a single breaker or on multiple breakers. This section highlights backup protection strategies across various bus arrangements at both subtransmission and transmission voltage levels.

A. *Straight Bus and Single-Breaker Terminal Bus Arrangements*

This type of bus arrangement is commonly used by both Utility 1 and Utility 2 at subtransmission voltage levels and is like the configuration shown in Fig. 4. In such arrangements, local BF protection is sufficient to fully isolate faults within this configuration, due to the fact that the breakers for the adjacent zones are local.

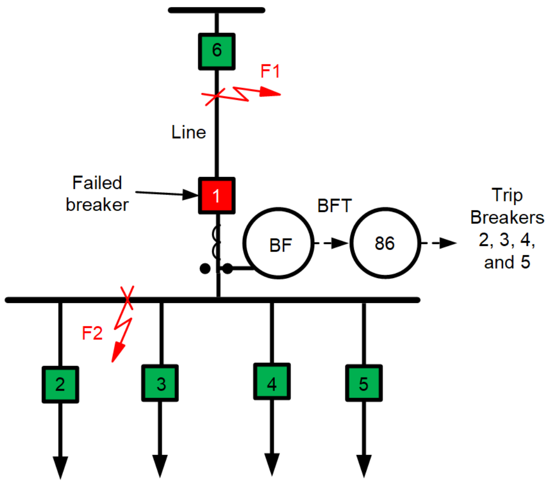

Fig. 4 Failed Breaker 1 for a line fault/bus fault

For example, if Breaker 1 fails for a fault (F1) on the line, Breakers 2, 3, 4, and 5 are all operated by the local BF relay to isolate the fault.

If Breaker 1 fails to clear a bus fault (F2), Breaker 6 must operate to isolate the Breaker 1 fault contribution. In this configuration, step distance Zone 2 (Z2) in the Breaker 6 relay provides remote BF backup, and typically trips within 14–30 cycles. Both utilities, Utility 1 and Utility 2 accept the delay associated with allowing step distance element Z2 to operate. Communications schemes would be implemented if faster clear times were required for system stability, which is not generally the case at subtransmission levels.

B. *Multibreaker Terminal Bus Arrangements*

The multibreaker terminal ring bus and breaker-and-a-half bus arrangements are commonly used at transmission voltage levels by Utility 1 and Utility 2.

Fig. 5 illustrates breaker-and-a-half and terminal ring bus configurations. In these arrangements, a transmission asset is sourced through two breakers, enhancing reliability and operational flexibility.

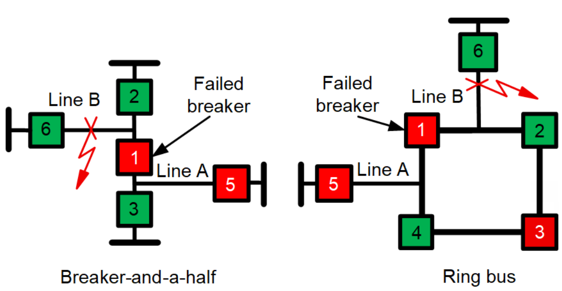

Fig. 5 Multiterminal bus arrangement

In Fig. 5, for a fault on Line B, where Breaker 1 fails, the local BF relaying will trip the adjacent local breakers. However, this action alone does not fully isolate the fault. To achieve complete fault isolation, the remote breakers of Line A must also be tripped. This can be accomplished either through a direct transfer trip (DTT) signal or via remote backup distance protection elements. The benefits and drawbacks to each option will be discussed in further detail in the following sections.

IV. DTT

As discussed in Section III, local BF relaying alone is insufficient to fully isolate a fault in the event of a BF for multibreaker bus arrangements. The preferred method for isolation in these scenarios is to send a DTT signal to the remote substation to open the breakers there. DTT requires a communications channel between local and remote line terminals, which has historically been cost prohibitive and only applied as necessary, particularly on systems with tighter stability limits that require faster clearing and operational flexibility. DTT provides significantly faster fault clearing as compared to the alternative remote backup protection discussed in Section V. An additional advantage of DTT over remote backup protection is that its reception at the remote relay is used to block reclosing during a local BF condition. Since remote forward overreaching zones can operate for a local BF, it is not feasible to block remote reclosing for a local BF without implementing DTT. In such cases, where a forward zone is set specifically for remote backup, Utility 2 would exclude the remote backup zone from the reclose initiate logic to reduce the likelihood of reclosing in a failed breaker.

Utility 1 has a standard practice of applying DTT on transmission lines operating above 100 kV. Since communications channels are generally unavailable at lower voltage levels, the application of DTT in these cases is evaluated on a case-by-case basis. Utility 1 has few 69 kV multibreaker bus arrangements where they apply DTT. Additionally, Utility 1 requires redundant DTT schemes on transmission lines rated at 345 kV and above to enhance system reliability and ensure faster fault clearing for system stability during disturbances. They use fiber-optic, power line carrier (PLC), and, in some cases, microwave communications channels to transmit DTT signals. Utility 1 typically sends the local DTT signal from the BF relaying to a dedicated transceiver to transmit the signal to the remote substation. For PLC-based schemes, Utility 1 employs a dual-transmitter setup, one dedicated to transfer trip and another shared with the pilot channel that has a designated DTT frequency. The relay is allowed to trip only upon receiving the DTT signal from both transceivers, thereby improving scheme security and minimizing the risk of false tripping due to channel noise/transients. Utility 1 calls this the two-out-of-two voting scheme for PLC-based DTT. Utility 1 does not have this voting scheme for fiber optics as they have not seen many false DTTs with fiber optics.

Utility 2 has a standard practice of applying DTT on all multibreaker bus arrangements. For voltage levels of 345 kV and above, dual DTT channels with fully redundant equipment are required to ensure high reliability. While Utility 2 initially did not require communications channels on their 69 kV lines, their standards now include the installation of communications infrastructure via optical ground wire on all new 69 kV lines, making pilot schemes feasible at 69 kV, in some cases. Utility 2 primarily uses fiber and PLC for communications. Utility 2 implements DTT in a variety of ways based on coordination with the remote entity. In single-pilot systems, Utility 2 typically uses a dedicated transceiver to ensure that the DTT signal remains available even when a relay is taken out of service. In contrast, for dual-pilot systems, Utility 2 allows the DTT signal to be transmitted over the communications channels of each relay, reducing the number of devices that need to be maintained, as well as the number of fiber-optic strands needed for communication with the remote substation.

BF DTT schemes supplement local BF protection by using communications channels to the remote substation. A failure in the DTT communications path is considered an N-2 contingency and should be promptly identified and resolved to prevent further reliability risks. For this reason, continuous monitoring of the communications channel is critical, and any detected failure must be addressed without delay.

V. Remote Backup Distance

A cost-effective option to address all reliability concerns of protection components at transmission and subtransmission voltage levels is to implement a forward-looking overreaching distance element in the remote line relays to back up the local substation [6]. This mitigates the concern of equipment failures at local substations, such as circuit breaker problems or loss of dc control power. While remote backup protection is considered a cost-effective solution for addressing reliability concerns at transmission and subtransmission voltage levels, it has been known to misoperate on several occasions [1] [2].

The dependability requirement for this remote backup protection is to provide coverage for 100 percent of faults on all circuits of the remote substation. One security requirement is governed by loadability limits defined by NERC PRC-023 standards [7]. Additionally, the protection engineer must set an appropriate time delay for this element to ensure the relay maintains selectivity. This delay is influenced by how far the remote backup element overreaches into the system. In some system configurations, it may not be possible to set the reach of this distance element to simultaneously satisfy both dependability and security requirements while maintaining acceptable fault clearing times.

Configuring remote backup protection requires two key settings: reach and time delay. From a coordination perspective, protection engineers can ensure proper operation by either adjusting the reach or by modifying the time delay. This flexibility may allow for the remote backup protection to be effectively coordinated with other protection elements in the system. Various philosophies exist for setting the remote backup distance zone reach to provide coverage for remote substations. Typically, the time delay for this zone ranges from 45 to 90 cycles. However, if reach coordination cannot be achieved and the desired level of dependability is not met, this time delay may need to be increased to ensure proper backup protection.

For example, Fig. 6 displays a remote backup Z3 distance element at Substation A and is set to back up the entirety of the Substation B line up to Substation C. When A-Z3's reach is set as shown by the green dashed line in Fig. 6, it does not overreach B-Z2, thereby achieving proper reach coordination. In this case, A-Z3's time delay is based on B-Z2's delay. However, when A-Z3's reach is extended, as shown by the green solid line, it overreaches B-Z2, resulting in miscoordination. To resolve this, the protection engineer can either reduce A-Z3's reach to match the dashed line, maintaining coordination and a shorter delay, or retain the extended reach and coordinate using B-Z3's time delay, resulting in a longer delay.

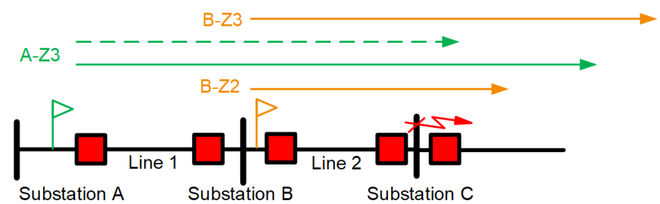

Fig. 6 Stepped distance protection zones

Utility 1 applies remote backup protection on both transmission and subtransmission lines, even when local BF protection and a communications channel for DTT are available. Their philosophy is to set the remote backup phase distance protection to provide time-delayed clearing for high-impedance multiphase faults on circuits out of remote substations. Protection engineers at Utility 1 aim to maximize the remote backup coverage within reason, which may, in some cases, provide full coverage for complete dc system failure at the remote substation, as explained in Section V.C.3. Utility 1 also uses directional ground time-overcurrent as remote backup for ground faults. Ground time-overcurrent elements provide better fault resistance coverage compared to ground distance elements.

In contrast, Utility 2 only implements remote backup protection when a communications channel for DTT is not available in multibreaker bus arrangements or in three-terminal lines. This approach prioritizes security and simplicity in terms of setting the relay and avoiding potential coordination challenges. Utility 2 implements both phase and ground distance elements as the remote backup protection as well as ground time-overcurrent elements. Utility 2 recognizes the importance of remote backup protection, particularly in the event of a dc station battery failure, but they consider this an acceptable risk given the rarity of a complete dc station battery failure and the benefit of maintaining simplicity in relay settings where human error-related misoperations are far more common.

A. *Consideration for Remote Backup Zone Reach*

The factors discussed in the following subsections influence the setting of the remote backup protection distance reach.

1) Infeed

When an additional source of current exists between the relay location and the fault location, the relay measures an apparent impedance value that is higher than the actual impedance between the relay and the fault. This is known as the infeed effect, which causes the distance protection element to underreach, if not accounted for. The presence of infeed is common at transmission and subtransmission voltage levels.

To illustrate the impact of infeed, consider a simple example in Fig. 7 and Fig. 8. All the impedances considered here are equal to 1 Ω. The dependability requirement of remote backup distance zone in the relay at Bus S is to operate for 100 percent of Line B faults. Z_S represents the source impedance behind the relay, and Z_{INFEED} represents the combined source impedance on adjacent circuits at Bus I.

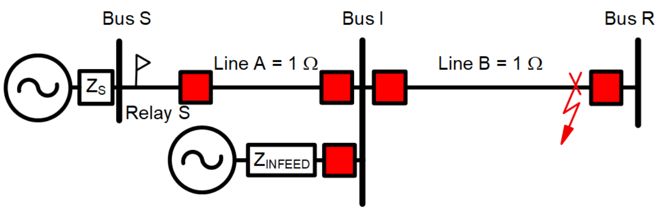

Fig. 7 One-line illustration of infeed impact

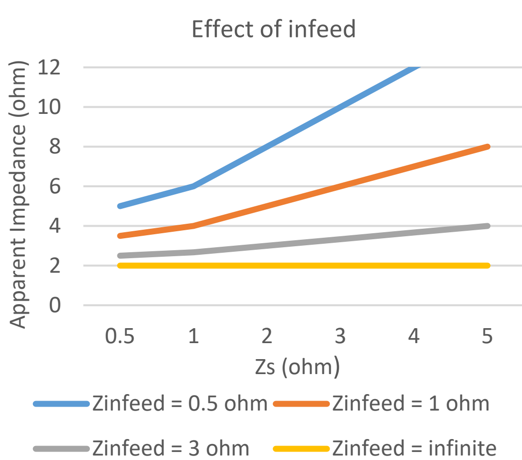

Fig. 8 Effect of infeed on apparent impedance

On applying a bolted fault at remote Bus R, the impedance value between Relay S and the fault is equal to 2 Ω. However, due to the presence of infeed (Z_{INFEED}), the apparent impedance measured by the relay at Bus S will be higher than the actual value. As seen in the plot of Fig. 8, the apparent impedance measured by the relay increases for the remote Bus R fault when the remote infeed source (lower Z_{INFEED} value) is stronger and the source (higher Z_S value) behind the relay is weaker. Therefore, an N-1 contingency behind the relay (the higher Z_S value) requires long reach settings for both phase and ground distance elements.

To ensure dependable remote backup distance zone reach settings, protection engineers must identify the contingency scenario that results in the highest apparent impedance for a remote-end fault on the adjacent circuits. For Utility 2, the complexity of setting this remote zone is a significant concern when considering the implementation of remote backup distance zones across their system. They prefer to keep relay settings as simple as possible to reduce the risk of human error.

Given this long reach requirement for certain system configurations, the remote backup zone of the relay at Bus S can overreach into lines adjacent to Line B as well. If there are additional lines, especially those longer than Line B or lines with strong sources connected to Bus I, then the required reach setting at Relay S needs to be even greater. This large reach increases the risk of misoperation. This situation presents a tradeoff: either reduce the reach of the remote backup zone at Bus S, compromising its dependability to cover 100 percent of faults on Line B, or increase the time delay to maintain coordination, resulting in slower fault clearing for faults on Line B in the event of a BF at Bus I.

2) Mutual Coupling

Mutual coupling primarily affects the zero-sequence network; therefore, protection elements that rely on zero-sequence quantities, such as ground distance and ground overcurrent elements are affected [8]. The apparent impedance measured by a ground distance element is calculated using (1).

$$ZnG = \frac{Vn}{(In + k0 \cdot IG)} \quad (1)$$

where:

n is A, B, or C

Vn is the phase-to-ground voltage

In is the phase current

k0 is the zero-sequence compensation factor

IG is the ground current

Due to mutual coupling, the apparent impedance measured by ground distance elements may increase or decrease, depending on the direction of current flow in the mutually coupled lines. If the fault causes currents in both lines to flow in the same direction, mutual coupling leads to a larger apparent impedance measured at the relay. Conversely, if the currents flow in opposite directions, mutual coupling results in a lower apparent impedance measured at the relay.

The most challenging scenario for remote backup distance protection occurs when both mutually coupled lines share common buses at both ends, creating parallel lines, as illustrated in Fig. 9. Building on Fig. 7, Fig. 9 introduces an additional Line C , which is mutually coupled with Line A and shares the same terminal buses, S and I. For this analysis, it is assumed that Line A and Line C are mutually coupled along 100 percent of their length.

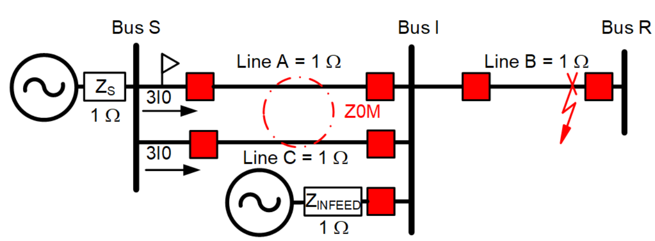

Fig. 9 Line A and Line C are mutually coupled lines

For a bolted single-line-to-ground fault at the remote Bus R, both mutually coupled lines experience current flow in the same direction. In Fig. 10, it is evident that the presence of mutual coupling significantly increases the required remote backup distance reach to maintain dependability as compared to Fig. 8 for $Z_{INFEED} = 1\ \Omega$. In remote backup distance applications, this long reach setting means the remote backup ground distance element is overreaching farther into the system when the mutually coupled line is out of service, which may introduce coordination challenges that necessitate longer time delays for the remote backup zone to avoid misoperation, as was seen with the infeed effect. Therefore, an N-1 contingency in front of the relay (i.e., a mutually coupled line out of service) can cause the ground distance element to reach significantly farther, introducing coordination challenges. The phase distance element is unaffected in terms of reach by an N-1 in front of the relay.

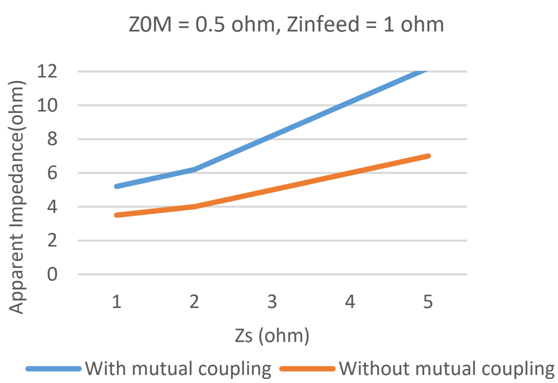

Fig. 10 Apparent impedance in presence of mutual coupling

One of the key advantages of distance protection elements is their fixed reach, which remains unaffected by variations in the source impedance behind the relay. This assumption holds true in the absence of infeed and mutual coupling effects. However, when mutual coupling or infeed is present, the apparent impedance measured by distance elements becomes sensitive to changes in the source impedance behind the relay, as seen in Fig. 8 and Fig. 10.

This is an important consideration for the utility, as the frequency of setting maintenance depends on evolving system conditions. Over time, the addition of new lines and generation can alter source impedance, infeed levels, and the effects of mutual coupling, necessitating periodic coordination checks to ensure the remote backup reach settings remain accurate.

This analysis highlights that in certain weak systems—particularly those with significant infeed at remote stations and mutual coupling—it may not be feasible to apply remote backup protection while still meeting dependability requirements and ensuring timely fault clearing for in-zone faults for all system contingencies.

3) Line Ratings and Loadability

Following an August 2003 blackout event [2], NERC mandated that load-responsive relays, such as distance elements applied to transmission lines that are part of the bulk electric system (BES), must be configured to avoid operation during heavy or transient loading conditions. This ensures that protection schemes do not misoperate under non-fault conditions, preserving system stability and reliability. Therefore, protection engineers must ensure that the relay reach settings comply with the NERC PRC-023 standard for transmission loadability [7]. According to the standard, the loadability criteria can be calculated using (2) for the following conditions: 0.85 per unit system voltage, a power factor angle of 30 degrees, and 150 percent of the circuit's highest seasonal facility rating (I_{RATING}).

$$Z_{PRC\_LOAD} = \frac{0.85 \bullet V(LL)}{\sqrt{3} \bullet 1.5 \bullet I_{RATING}} \quad (2)$$

where:

V is system voltage (LL)

I_{RATING} is the circuit's highest seasonal facility rating

Z_{PRC_LOAD} is the PRC load impedance value

Equation (3) defines the security requirement for the remote backup zone reach in primary ohms. If the distance zone reach is set beyond this threshold to meet the dependability requirement, then additional supervision—such as load encroachment logic—must be used to block the distance elements.

$$Z_{PRC\_MAX} = \frac{Z_{PRC\_LOAD}}{\cos(MTA - 30)} \quad (3)$$

where:

MTA is maximum torque angle

Z_{PRC_MAX} is maximum PRC reach for a given PRC load impedance value (Z_{PRC_LOAD})

Load encroachment defines a designated load area within the mho characteristic, effectively preventing tripping for conditions that fall within this region, as shown in Fig. 11 and mentioned in [6].

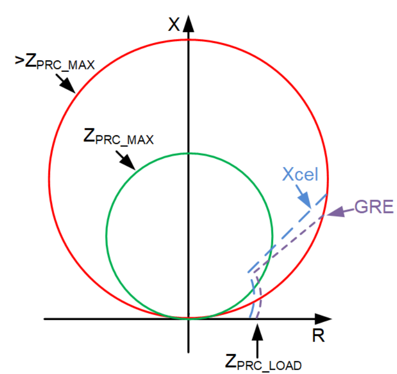

Fig. 11 Load encroachment characteristic

When properly configured, load encroachment settings eliminate security concerns with distance element loadability. However, it is important to note that load encroachment can desensitize the resistive coverage of distance elements. To maintain effective protection, engineers should avoid overly conservative settings and instead align with realistic PRC-023 load levels.

The Utility 2 philosophy follows (3), where load encroachment would only be enabled if distance element reach was set higher than Z_{PRC_MAX}. The load angle and load impedance values are needed to set the load encroachment element to define the load region. Utility 2 sets the load angle at 30 degrees with the load impedance setting set equal to the PRC load impedance value, Z_{PRC_LOAD}. These settings maximize dependability within the limits set by PRC-023.

Utility 1 takes a slightly different approach, enabling load encroachment in all lines for simplicity. Additionally, supervising memory-polarized mho elements with load encroachment adds security during frequency excursions [9]. Utility 1 sets load encroachment using a 35-degree load angle, with the load impedance setting configured to 90 percent of the PRC load impedance value, denoted as Z_{PRC_LOAD}. These settings offer a higher level of security compared to Utility 2's philosophy, though they come with a slightly reduced level of sensitivity.

4) Fault Resistance Coverage

Fault resistance is another factor that can impact the performance of remote backup protection. Higher fault resistance leads to higher apparent impedance estimates, making fault detection more challenging. During coordination studies, protection engineers not only evaluate different system contingencies, to identify the highest apparent impedance for remote-end faults, but also adhere to internal standards that specify minimum fault resistance coverage. These standards help ensure that protection schemes remain dependable even under high-resistance fault conditions. Both Utility 1 and Utility 2 use mho distance elements for the remote backup zone; neither employs quadrilateral distance elements.

Utility 2 protection engineers do not directly account for a specific fault resistance coverage. Coordination checks are run for faults with up to 5 Ω of resistance to identify any coordination issues resulting from high-resistance faults.

At Utility 1, the remote backup phase distance zone is required to provide coverage for multiphase faults on external circuits out of remote bus, accounting for 200 percent of the maximum estimated arc-resistance coverage under both N-0 and N-1 system conditions. This occurs because, in the case of a phase-to-phase fault with an arc resistance of R, the mho phase distance element will only detect R/2 as the effective arc resistance [10]. Therefore, to ensure that the remote mho phase distance element provides adequate coverage for the desired arc resistance during a fault, the remote phase distance zone must be set to detect at least twice that resistance value.

There are different ways to calculate the arc resistance. Utility 1 calculates the arc resistance using the Warrington empirical formula [10]. As shown in (4), arc resistance is inversely proportional to fault current. In weak systems or during system contingencies, if the source impedance behind the relay increases, effectively weakening the source, the available fault current decreases. This results in a higher minimum arc-resistance value that must be accounted for, thereby increasing the required reach of the remote backup protection zone. Therefore, in weak systems, it is difficult to meet the arc-resistance requirements.

$$R_{ARC} \cong \frac{8750 \bullet \mathrm{Lpp}}{I^{1.4}} \tag{4}$$

where:

R_{ARC} is the arc-resistance value

Lpp is the weighted spacing of the three-phase conductors over the course of the line

I is the minimum phase-to-phase fault current for a remote-end fault with remote breaker open under N-1

5) Transmission Line With Tapped Loads

When applying distance protection to transmission lines with tapped loads, the dependability requirement is that the relay must operate for faults on the transmission line. The security requirement is that the transmission line relay must not operate for faults on the low-voltage side of the tapped distribution transformer [11]. The transmission line owners rely on the local protection at the tapped stations to clear faults beyond the high side of the tapped transformer and into the distribution system.

If the tapped load is located near one end of the transmission line, there is a risk that overreaching elements in the step distance scheme from that line terminal may operate for faults on the transformer low-side. In step distance schemes, security may be maintained by:

- Reducing the distance reach
- Coordinating with low-side protection relays

Reducing the distance reach may not be possible while maintaining dependability for transmission line faults, so often the only solution is to increase the time delay of the distance element to coordinate with downstream distribution overcurrent relaying. This coordination is inherently challenging, as it involves coordinating two fundamentally different protection elements: a distance element and an inverse-time-overcurrent element. As a result, the distance elements that reach into the distribution system may require significantly longer time delays, which can impact overall system clearing times.

Both Utility 1 and Utility 2 require that distribution faults at tapped stations be cleared locally by the substation's own protection systems. They intentionally do not set protection elements to back up tapped stations. This approach ensures that transmission-level protection does not operate for faults that should be isolated at the distribution level.

As a result of attempting to coordinate with tapped stations, Utility 1 and Utility 2 implement remote backup distance protection that may need to be set with time delays of up to a few seconds, depending on the coordination with the tapped substation protection elements. The remote backup philosophies for phase and ground elements may differ depending on the tapped load transformer winding configuration. The most common tapped transformer configuration is delta-wye grounded, which behaves as an open circuit in the zero-sequence network, preventing transmission line relay ground elements from detecting low-side ground faults. This prevents overreach into the distribution system for remote backup ground distance elements, allowing ground distance elements to operate with relatively shorter time delays compared to those set for phase distance elements.

Uncleared faults on the high side of a tapped transformer or within the transformer itself present a notable protection challenge. If the high side is protected by a fuse, fault clearing is generally reliable. In cases where a circuit interrupter is used, a motor-operated disconnect (MOD) may also be operated. The MOD acts as a sacrificial switch to isolate the fault in the event of a circuit interrupter failure. In the event of a failure of a high-side circuit interrupter without a disconnect switch at the tapped substation for a fault within the transformer and without a DTT, the fault may persist for an indefinite amount of time. This is considered an acceptable risk by Utility 1 and many of Utility 2's member distribution cooperatives.

If the tapped substation owners determine that a transfer trip is necessary, they must install the appropriate communications equipment and send the transfer trip signal to the transmission line relays. Otherwise, the fault may persist until it escalates into a transmission line fault, at which point the line protection relays may eventually operate.

While rare, Utility 2 has seen a failure of a high-side switching device that took minutes to clear after the fault significantly evolved. As a mitigation option, Utility 2 offers their member cooperatives a lower-cost backup in the form of DTT over the Utility 2 SCADA network, provided Utility 2 owns both remote line terminals. Local BF relaying may be installed at the member's distribution site, which is then connected to Utility 2's internal network. This BF relay would isolate the remote breakers by sending a remote open command to those breakers through SCADA. This method typically results in slower clearing times, up to 15 seconds, which is preferable to the indefinite time mentioned above.

B. *Sequential Tripping*

Sequential tripping refers to the process of clearing a fault by progressively disconnecting the sources of infeed contributing to the fault. Sequential tripping usually causes longer, less desirable clear times. This may be acceptable in subtransmission systems where system stability does not require faster clearing, but it is not acceptable at higher voltage levels where fast clear times are critical.

Given the previous considerations on infeed and mutual coupling, it may not be feasible to set backup distance elements to pick up on the large apparent impedances observed for remote faults on adjacent circuits while the system is intact. To reduce the impact of infeed, it is generally accepted that local BF relaying will operate to remove local sources of infeed in the event of a local BF. This would reduce the apparent impedance measured at the remote backup relay, allowing it to sequentially clear the fault, without an excessively long reach. Fault clearing times are inherently longer in these scenarios, as remote backup protection may only operate after infeed sources have been removed. This approach is generally acceptable for rare BF scenarios at the subtransmission level, which are considered N-1 events. At transmission voltage levels, remote backup distance elements typically operate only under even rarer N-2 conditions, such as a BF combined with a communications channel failure for DTT. In these cases, the delay in fault clearing by remote backup protection is considered acceptable, especially if it allows avoidance of overly long reach settings in the remote backup distance zone. It is crucial for protection engineers to fully understand how the system will operate for various faults when setting remote backup elements. If the sources contributing to remote infeed are not disconnected as expected, the remote backup protection may fail to operate dependably.

Utility 2 incorporates sequential tripping into their BF protection strategies in various ways as needed for dependability. In contrast, Utility 1 does not account for sequential tripping when configuring remote backup distance elements.

C. *Remote Backup Distance Reach Setting Philosophies*

As discussed above, several factors influence the reach setting of remote backup protection, all centered around the balance between dependability and security. Dependability ensures that the remote backup element reliably operates for faults located at the remote end of the longest adjacent circuit. On the other hand, security aims to prevent unnecessary relay operations by ensuring protection elements do not respond to normal system loading and trip selectively only for faults for which they are intended to operate.

With factors affecting remote backup distance reach as discussed in Section V.A., three options for setting a remote backup reach are discussed.

1) Sequential Tripping BF Backup

This option offers the simplest method for calculating the reach setting, using (5):

$$(Z_{\mathrm{LOCAL}} + Z_{\mathrm{ADJACENT}}) \bullet \%\mathrm{DF} \qquad (5)$$

where:

Z_{LOCAL} is the local line zone impedance

Z_{ADJACENT} is the largest adjacent circuit impedance

%DF (dependability factor) would be a typical 125% to ensure sufficient overreach

This method requires that all sources of infeed are sequentially removed at the remote substation by the local BF relaying (as shown in Fig. 12), maximizing the security of the remote backup element.

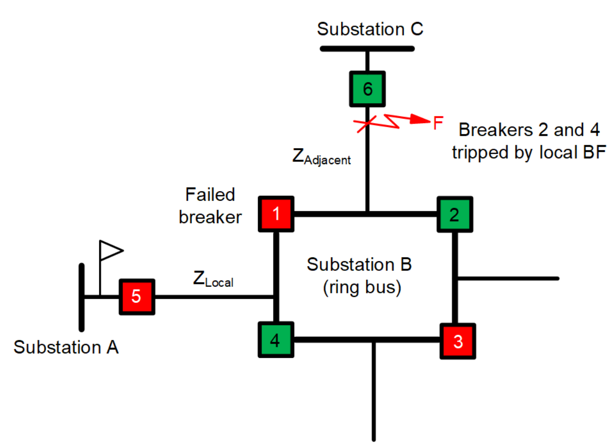

Fig. 12 Local BF relay removes infeed

This implies that fault clearing time for the remote backup protection will be equal to the sum of the local protection system operating times, the local BF fault clearing time, and the remote backup time delay. Utility 2 prefers this option for remote BF backup as it satisfies the N-1 design criterion while maximizing security. This philosophy was designed to provide backup for remote BF. However, it may not offer full coverage in the event of a complete loss of protection, such as complete dc battery system failure at the remote substation. Utility 2 will enable the load encroachment if the reach settings exceed the Z_{PRC_MAX} value.

The primary advantage of this philosophy is that impedance values only change when equipment is replaced or line configuration changes, ensuring that the settings remain stable and reliable over time.

If the local line is a three-terminal configuration or includes tapped generation, a modified setting philosophy may be applied. In this approach, the traditional sum of local and adjacent impedances (Z_{LOCAL} + $Z_{ADJACENT}$) is replaced by an apparent impedance value, Z_{APP} as shown in (6). Z_{APP} is determined by simulating a remote bus fault on the adjacent circuit which has the highest impedance with the remote breaker open and all sources of infeed at the local Substation B removed, as shown in Fig. 13. This may require manual adjustments to the short-circuit model, as the transmission assets between Breakers 4 and 3 and Breakers 2 and 3 are electrically isolated at the bus level but remain connected to the transmission system. Since system configurations can evolve over time, this setting should be periodically reviewed to ensure continued reliability and accuracy.

$$Z_{APP} \bullet \%DF \tag{6}$$

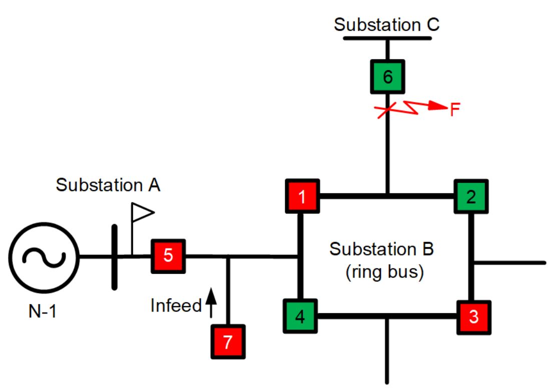

Fig. 13 Finding Z_{APP}

2) Adjacent Circuits Backup

This method requires more detailed system analysis and results in a larger distance reach setting. Instead of using the line impedance value, the remote backup distance zone reach is set based on the highest apparent impedance value, $Z_{APP\_ADJACENT\_MAX}$ in (7), observed during a remote-end fault on an adjacent circuit under N-1 conditions, with the strongest source at the local terminal removed as shown in Fig. 14. Only faults on adjacent circuits are evaluated in this case.

$$(Z_{APP\_ADJACENT\_MAX}) \bullet \%DF \tag{7}$$

This method requires all infeed sources to be left in service during fault simulations, resulting in a significantly larger distance reach setting. It does not rely on sequential tripping, which enhances dependability and can lead to faster fault clearing times in certain scenarios.

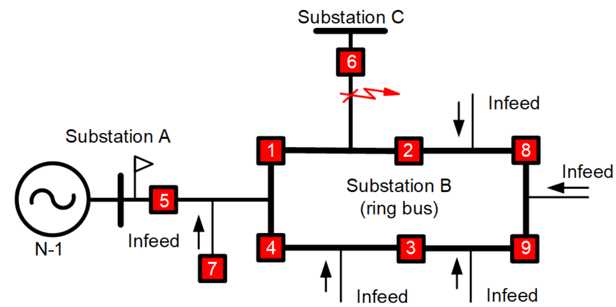

Fig. 14 Finding $Z_{APP\_ADJACENT\_MAX}$

Utility 2 may choose to apply this philosophy if the resulting reach is not excessively long, although it generally prefers Option 1. This philosophy is primarily intended to provide backup for remote BF of the adjacent circuit (i.e., network element connected between Breakers 1 and 2 and between Breakers 3 and 4), and does not guarantee full coverage in the event of a complete loss of relaying at the remote substation. However, it does offer more coverage than Option 1.

Unlike Option 1, the effective reach of this setting may vary over time due to changes in system topology or configuration, necessitating periodic review to maintain reliability and coordination.

3) Full Substation Backup

In contrast to Option 2, which provides remote BF protection only for adjacent circuits, Option 3 applies remote backup protection to both adjacent and non-adjacent circuits. This includes network elements between Breakers 1 and 2, 2 and 8, 8 and 9, 9 and 3, and 3 and 4, offering more coverage in the event of a remote BF as seen in Fig. 15.

This option requires identifying the highest apparent impedance observed during a remote-end fault on any circuit within the substation, under N-1 conditions, with the strongest source at the local terminal removed, as seen in Fig. 15. In this approach, faults on both adjacent and non-adjacent circuits are evaluated. This comprehensive coverage enhances system dependability, especially in rare but critical dc battery failure scenarios.

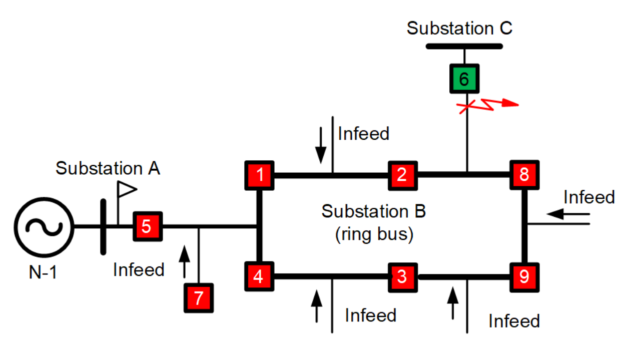

Fig. 15 Finding Z_{APP_MAX}

This method requires all infeed sources to be left in service during fault simulations, resulting in a significantly larger distance reach setting as compared to Option 1.

Utility 1 uses (8) to define the maximum allowable reach for remote backup protection, setting the dependability factor at 110 percent.

$$(Z_{app\_max}) \bullet \%DF \tag{8}$$

The minimum allowable reach at Utility 1 is determined using (9).

$$Z_{MIN} = MAX\left((Z1 + 1.1 \bullet Z1_{FWD}), 1.5 \bullet Z1\right) \tag{9}$$

where:

Z_{MIN} is the minimum allowable remote back up protection reach

Z1 is the local line impedance

$Z1_{FWD}$ is the line impedance of the longest line out of the remote substation

Protection engineers at Utility 1 have the discretion to select a value within the defined range between the minimum and maximum remote backup reach. PRC loadability requirements are consistently met, as Utility 1's standard philosophy includes enabling load encroachment on all transmission lines.

A total loss of relaying, such as caused by a complete dc system failure, is exceedingly uncommon, especially with advanced battery monitoring systems available today that can detect potential failures by monitoring dc output voltage, charger circuitry, rectifier diode health, battery cell health, and battery ground detection [12]. As such, neither Utility 2 nor Utility 1 explicitly design their protection schemes to cover this scenario. In the event of such a failure, the affected substation would typically be isolated or taken offline to maintain system stability and safety.

The options described in Table I are general settings philosophies. Many times, the philosophy used falls somewhere between Option 1 and Option 3, depending on the full settings intent and system parameters. Only Option 3 offers full dependability in the event of a dc control power loss at the remote substation. In contrast, Options 1 and 2 offer only partial coverage under such conditions.

TABLE I REMOTE BACKUP REACH SETTING

Option	Reach Setting
1	$(Z1_{LOCAL} + Z1_{ADJACENT}) \bullet \%DF$
2	$(Z_{APP\_ADJACENT\_MAX}) \bullet \%DF$
3	$(Z_{APP\_MAX}) \bullet \%DF$

To accommodate larger distance reach settings, CTs occasionally need to be tapped, reducing the CT ratio to accommodate the maximum allowable reach setting threshold of the relay. In most 5A microprocessor-based relays, the maximum secondary reach is limited to 64 Ω. In weak systems with strong remote infeed and long adjacent circuit impedances, the calculated reach setting may exceed this limit. To address this, the CT ratio must be lowered so that the effective secondary ohm reach falls within the settings threshold of the relay. In strong systems, CT saturation can become a concern by tapping the CT. This adjustment also has impact on the circuit load ratings and must be carefully evaluated. Utility 2 has encountered such applications in their system.

D. Remote Backup Protection Time Delay

Timely fault clearing is essential to limit thermal and mechanical stress on electrical equipment during fault conditions and to maintain system stability at higher voltages. At the same time, selectivity in protection systems is equally important, preserving system stability and minimizing service disruption.

The remote backup protection is typically delayed coordinating with main zone relaying of adjacent circuits, allowing sufficient time for remote BF protection to operate and clear the fault, sometimes leading to delays in the 45–90 cycles range.

At Utility 1, fault clearing times for remote backup phase distance protection are based on the following formula: longest overreaching remote-end Zone 2 time delay + BF time delay + breaker interrupt time + DTT time + lockout relay (1 cycle) + margin (2 cycles). This formula is valid only when the remote backup zone does not overreach Zone 2 of the circuits at the remote substation. If the remote backup distance zone is set with an extended reach, the associated time delay must be adjusted accordingly to maintain proper coordination.

Utility 2 prefers to keep remote backup fault clearing times under 60 cycles but accommodates slower fault clearing times up to 90 cycles on subtransmission systems. In some cases, it may be possible to speed up fault clearing by leveraging the principles of sequential tripping and implementing additional logic, as shown in Fig. 16.

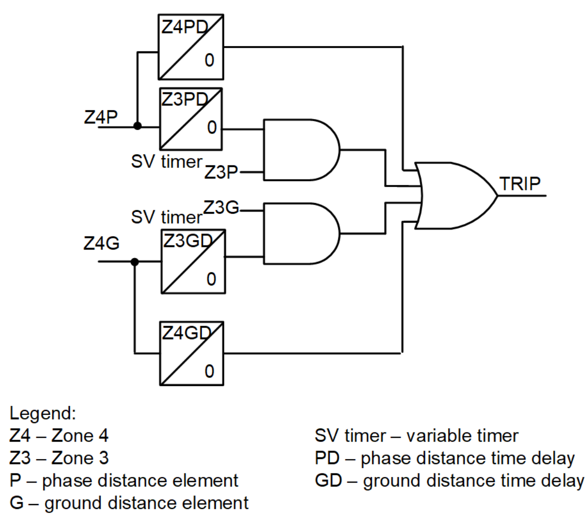

Fig. 16 Logic implemented by Utility 2 to improve remote backup distance zone's fault clearing times

For example, at Substation A, Relay R5 in Fig. 17:

- Distance Zone 3 was set per Option 1 with a shorter reach and subsequently shorter delay of 30 cycles (Z3PD/Z3GD); this assumes that the Z2 time delay in Line 2 relays was 15 cycles

- Distance Zone 4 was set per Option 3, with a longer reach and substantially longer delay of 120 cycles (Z4GD/Z4PD)

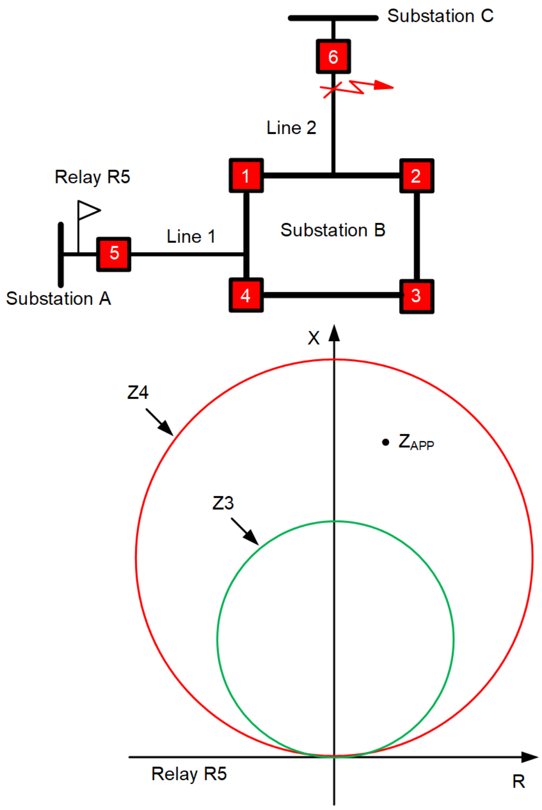

Fig. 17 Fault on Line 2 near Breaker 6

In Fig. 17, we placed a fault on Line 2 near Breaker 6. The Relay R5 sees a fault in Zone 4 with infeed observed at Substation B. The Zone 4 element in Relay R5 will clear the fault in 124 cycles, assuming it took 4 cycles for breaker(s) to open. The Line 2 relay at Substation C operated on Zone 1, and the Line 2 relay at Substation B operated on step distance Zone 2 in 15 cycles, followed by a local BF relay of Breaker 1 operation (8 cycles) due to failed Breaker 1. Following this sequence, the system transitioned to the diagram shown in Fig. 18 approximately 27 cycles after fault initiation, at which point the measured apparent impedance (Z_{APP}) enters the Zone 3 reach.

Without the additional logic scheme, Zone 3 began its 30-cycle delay after the system transitioned to Fig. 18, resulting in a total fault clearing time of approximately 61 cycles (i.e., 15 + 8 + 4 + 30 + 4). While this is faster than the Zone 4 delay of 124 cycles, it may be undesirable in high-speed protection applications.

Instead of waiting for the Zone 3 time delay to initiate tripping after transitioning to Fig. 18, the proposed scheme started a separate Sampled Values timer shown in Fig. 16 as soon as Zone 4 picked up. This timer pickup delay is set to match the Zone 3 delay of 30 cycles. Three cycles after the 27-cycle system transition, both the timer and the Zone 3 element inputs asserted, triggering the trip. This resulted in a significantly faster fault clearing time of 34 cycles (i.e., 30 + 4-cycle breaker interrupting time). This scheme leverages the ability to dependably detect all forward faults, while quickly and securely tripping after the sequential operation, greatly improving clear times.

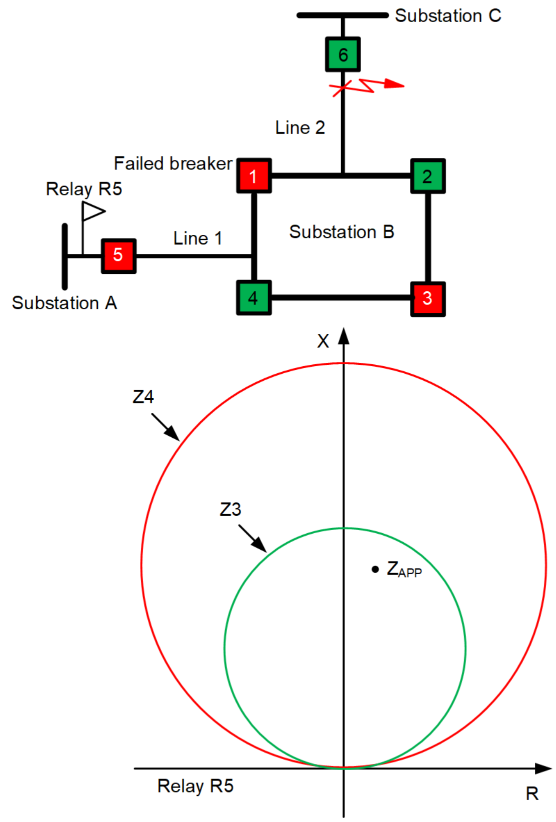

Fig. 18 BF relay at Substation B removed infeed

VI. Additional Application Considerations

Currently, Utility 1 and Utility 2 do not have dedicated standards for implementing local BF and remote backup protection on transmission lines connected to inverter-based resources (IBRs) or for digital secondary system (DSS)-based substations. However, we share preliminary insights in the following subsections on the evolving nature of electric grid technology and its effect on remote and local BF protection.

A. *IBR Connected Lines*

When only IBRs are present behind the relay, the performance of distance protection elements, particularly those that use memory voltage as a polarizing quantity, can be compromised. Under such conditions, the relay may experience oscillating impedance measurements during IBR-fed faults [13] [14]. These oscillations in impedance can lead to the dropout of remote backup distance elements, even for in-zone faults, thereby reducing the dependability of the remote distance protection element. To address the issue of oscillating impedance measurements, utilities should consider using self-polarized distance elements, which are better suited for such applications [14].

Most IBR facilities connect to the existing transmission system using a ring bus arrangement, which offers operational flexibility by allowing the IBR facility to be isolated without tripping the transmission line. Since IBRs are weak sources, and due to the infeed from the other line connected to the ring bus, this application can result in high remote backup distance reach without local BF relay. Even though the local BF relay removes infeed sources at the ring bus, relying solely on remote distance backup is not viable due to the IBR sources' response to the fault. Therefore, implementing DTT is the preferred solution.

In the context of local BF protection, a key concern with IBR facilities is the insufficient fault current contribution from the IBRs to reliably assert the overcurrent fault detector. Since IBRs typically provide limited and controlled fault current [13], the traditional current-based logic may not be dependable in such applications. To maintain BF protection dependability, it may be necessary to incorporate a 52a contact status or use voltage elements to supplement current-based detection. This ensures that the BF scheme can still operate effectively, even in low- or no-fault-current scenarios typical of IBR-fed systems.

B. Digital Secondary System

Many utilities, including Utility 1 and Utility 2, are exploring the implementation of DSS in their substations. In DSS technology, a key component is the merging unit which is installed near the primary equipment in the substation yard. This unit is responsible for performing analog-to-digital conversion and sending that digitized data to the zone protective relays installed in the control house via fiber optics. They also act as a remote I/O module. To ensure the reliability of the protection system, it is essential to install two merging units per protection zone.

For local BF protection, intelligent merging units used in the DSS-based method often include built-in phase overcurrent and BF elements. Utilizing the BF function within the merging unit is functionally like installing a standalone BF relay directly in the substation yard and offers the simplest and most reliable solution. The BF initiation still originates from the zone protective relays. The BF protection can also be implemented in DSS-based zone protective relays or dedicated BF relays installed in the control house.

In both cases, it is crucial for protection engineers to understand the implications of losing fiber-optic communications with the merging unit. Without this communications link, the BF function loses access to real-time current measurements, BF initiation signal, or the ability to trip the adjacent breakers, all of which are essential for a BF scheme. Fiber redundancy is possible in certain DSS systems. Additionally, the DSS-based relays continuously monitor the integrity of the communication link and triggers an immediate alarm upon detecting any issues. Protection engineers must carefully consider these factors when designing and configuring local BF schemes in DSS-based systems to ensure both dependability and security are appropriately balanced.

In applications where one end of a transmission line is connected to a traditional substation and the other end to a DSS-based substation, configuring the remote backup distance zone at the traditional substation can enhance system dependability. This approach provides a layer of dependability in scenarios where BF and other protection functions at the DSS-based substation become inoperative due to the loss of fiber-optic communications with the merging unit especially in the absence of fiber redundancy.

VII. Conclusion

This paper presents the protection philosophies of Xcel Energy and GRE, focusing on their approaches to remote and local BF protection schemes.

Today, utilities including Xcel Energy and GRE commonly apply local BF protection to provide backup protection in the event of a BF. BF protection can be implemented either through a dedicated standalone relay or integrated within a zone protective relay(s). In straight bus and single-breaker applications, a local BF relay is typically sufficient to fully isolate the fault in the event of a BF. In multibreaker terminal applications, a local BF relay alone is insufficient to fully isolate the fault upon BF. To ensure complete backup protection, local BF protection must be supplemented with either a DTT or a remote backup distance zone element. DTT provides significantly faster fault clearing. It is common for the utilities to install DTT at transmission voltage levels.

When setting the remote backup distance reach, it is essential to account for factors such as infeed effects, mutual coupling, loadability limits, and tapped load lines. Sequential tripping helps to eliminate infeed affecting the local substation remote backup relay, which in turn facilitates smaller remote backup distance reach settings. Longer reach settings for remote backup distance zones can lead to extended tripping times due to the need for coordination with adjacent protection zones.

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IX. Appendix A

In this section, we provide a high-level overview of various protection system redundancies implemented to accommodate N-1 scenarios at both Utility 1 and Utility 2.

A. Relay Redundancy

To mitigate the risk of a relay failure, it is standard practice to implement redundant protective relays commonly referred to as primary (or system/Main A) and secondary (or system/Main B) relays at transmission and subtransmission voltage levels. Both Utility 1 and Utility 2 implement redundant protective relays. Utility 1 even prefers hardware diversity between primary and secondary relays to address a common-mode failure concern. As a result, relay failure is generally not a significant concern at transmission and subtransmission voltage levels.

B. AC Instrument Transformer Redundancy

At higher voltage levels, it is often feasible for each relay to be equipped with its own dedicated set of CT circuits, and this redundancy is also required by NERC [15]. This configuration reduces the risk associated with CT failures. Utility 1 and Utility 2 follow a standard practice of providing each protective relay with its own dedicated set of CTs. However, there are a few exceptions in legacy systems where CT circuits may be shared among multiple relays protecting adjacent zones or shared between the primary and secondary relays protecting the same zone on equipment in non-BES systems. Additionally, it is not uncommon for standalone local BF protection to share CT circuits with one or more protective relays. Some utilities incorporate low- or no-current detection into their BF schemes to enhance dependability, particularly in scenarios involving a failed CT or when the fault current is below the threshold of the fault detector [3] [16].

It is not practical for each relay to have its own dedicated VT circuits due to space limitations and cost considerations [17]. In multibreaker terminal applications, both the primary and secondary line protection relays typically share the same set of three-phase VTs, installed on the line side of breaker. In straight bus/single-breaker applications, three-phase bus VTs are typically shared among multiple distance relays associated with different transmission line zones. Many utilities, including Utility 1 and Utility 2, use VT circuits with multiple secondary windings, one for primary protective relays and another for secondary relays. However, this shared setup creates a risk: failure in that the VT primary can affect the reliability of voltage-based protection elements such as distance and directional relays. A shunt fault on the VT primary windings is treated as a primary system fault which will be detected and cleared by the primary protective relay. The main concern with VT failure lies in a series fault in the VT primary winding which can compromise protective relay operation.

During such failures, current-based non-directional overcurrent relays (50/51) can still maintain dependability using loss-of-potential schemes. The line current differential (87L) relaying also continues to provide reliable performance, even without dependable voltage measurements. However, at subtransmission voltage levels, communications channels are often unavailable, which renders the use of line current differential (87L) protection impractical in these scenarios.

C. DC System Redundancy

Similarly, installing fully redundant battery systems in every substation is impractical due to cost and space constraints. Utility 2 has established a standard requiring redundant battery systems for voltage levels of 230 kV and above, while Utility 1 installs dual battery configurations for selected critical substations identified by their operations team. When dual battery systems are implemented, it is common practice to connect the primary protection relays to one battery circuit and the secondary relays to the other, thereby enhancing protection system resilience against dc supply failures. At a minimum, in substations with a single battery system, utilities monitor dc voltage and report it to SCADA [12].

Complete failure of a battery system is uncommon today, especially with the availability of advanced battery monitoring systems that can detect potential failures by monitoring dc output voltage, charger circuitry, rectifier diode health, battery cell health, and battery ground detection [12]. The voltage monitoring is effective when the charging circuit is interrupted (open-circuited) and the battery is required to support station load. Modern battery chargers address this by briefly reducing the charge voltage to confirm that the battery can pick up some station load without a significant voltage drop, indicating the system is healthy and ready for service. In substations with a single battery system, the reliability of dc control power can be enhanced by installing a redundant power module [18] which integrates multiple available power sources within the substation to provide source diversity and improve overall protection system resilience. Issues in the DC control circuit are sometimes human-induced during maintenance activities. These risks can be mitigated through proper documentation, standardized procedures, and comprehensive training [19].

D. Merging Units Redundancy

An additional consideration in recent times has been the adoption of DSS. Unlike traditional systems where protective relays receive analog current and voltage signals directly from instrument transformers, DSS uses merging units installed near the primary equipment in the substation yard. These merging units digitize the analog and binary signals and transmit them to protective relays via fiber-optic connections. To ensure protection system reliability and availability, merging units like protective relays are deployed redundantly.

E. Circuit Breaker and Interrupter Redundancy

Installing redundant circuit breakers/switches/interrupters is not practical due to their high cost and significant space requirements within substations. Circuit breakers can fail to operate when required, particularly during fault conditions due to issues such as mechanical malfunction, loss of dielectric medium, trip coil failure, or faults in dc control wiring [3]. To enhance reliability, circuit breakers are often equipped with multiple trip coils, providing some redundancy in the tripping mechanism [17] but there remains a concern that a BF could prevent it from opening its contacts during a fault or interrupting the current once the breaker main contacts have opened. Utility 1 and Utility 2 have established a standard requiring the use of two trip coils in their circuit breaker design. Rather than installing a second interrupting device, full redundancy for breakers is generally obtained through the implementation of local BF relaying, DTT, or remote backup schemes.

X. Biographies

Adi Mulawarman (Senior Member, IEEE) is the senior manager of NSP System Protection Engineering at Xcel Energy, Minneapolis, MN. He has more than 25 years of experience in substation protection, design, and engineering, including compliance management, resource allocation, and technical leadership. Adi holds a Master of Electrical Engineering and a Bachelor of Science in Electrical Engineering (with Distinction) from the University of Minnesota, with minors in industrial engineering, operations research, and mathematics. He is a licensed professional engineer in Minnesota and an active member of the IEEE Power and Energy Society, serving in various leadership roles within the Power System Relaying and Control Committee.

Andrew Arndt is a principal engineer in the Substation Field Engineering (SFE) group at Xcel Energy. Before joining SFE in September 2025, Andrew served as a system protection engineer at Xcel and American Electric Power (AEP) since 2007 and prior as an intern at AEP and Electric Power Products (EP2). Andrew has a Bachelor of Science in Electrical Engineering–Power Systems Emphasis from Iowa State University and is a registered professional engineer in state of Minnesota.

Tyler Porter, P.E. is a senior engineer at Great River Energy, working in the Transmission Division's Substation Engineering group, with a focus on system protection. He joined GRE in 2019 and has more than ten years of experience in the power industry. Tyler began his career in 2015 at HDR as a system protection and studies EIT, following internships at Xcel Energy and Blattner Energy starting in 2013. He holds a Bachelor of Science in Electrical Engineering from the University of St. Thomas in St. Paul, Minnesota, and is a licensed professional engineer in the state of Minnesota.

Yash Shah received his BS in electrical engineering from Maharaja Sayajirao University in 2017. In 2019, Yash received his MS in electrical engineering from Arizona State University. Yash worked at a mining company, Freeport-McMoRan, as an electrical engineer. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2020 and is currently a field application engineer in the SEL office in Plymouth, Michigan. His responsibilities include providing application support and technical training for protective relay users. Yash is a member of IEEE.

Josh LaBlanc received his BS in electrical engineering from the University of North Dakota in 2011. After graduation, Josh worked for an oil and gas pipeline company, Enbridge Energy, then an electric power utility, Minnesota Power. Josh has most recently spent 6.5 years working as an application engineer for Schweitzer Engineering Laboratories, Inc. (SEL). His primary roles are providing application and technical support and training on power system protection topics. Josh is a registered professional engineer in the state of Minnesota.

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