Line Protection Solutions for Multiple IBR Interconnections With Unfavorable Conditions in an Incumbent Utility Infrastructure

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Abstract— **The introduction of inverter-based resources (IBRs) has created challenges with weak infeed on its interconnection bus and fault current contributions that differ from traditional sources. Traditional solutions for line protection for such systems rely on a strong source from the grid-connected network for dependability and advanced logic for security. Incumbent utility infrastructure often consists of a mix of technologies, designs, and configurations. This paper outlines the challenges with legacy protection schemes along with solutions implemented on recent interconnections.**

A current standard protection scheme of the authoring utility is evaluated against increasing IBR penetration within the incumbent transmission system. The paper summarizes how this traditional scheme is modified for use near IBR sources but also identifies limits of applicability for this scheme as IBR penetration increases. New relay technologies are also evaluated for inclusion into the utility's practices to protect transmission lines where IBR penetration is increasing.

I. Introduction

As part of climate action, Entergy Services LLC, an energy utility, is committed to achieving net-zero greenhouse gas emissions by 2050 [1]. The utility expects to grow renewable capacity to 9 GW by 2031, nearly half of which is expected to come from inverter-based resources (IBR) sources. As more and more facility studies come for review, protection engineers are starting to see challenges faced by utility-level solar interconnects close to each other. The protection philosophy of the utility regarding these sites, has also evolved to tackle those challenges. Previously published papers [2] [3] [4] talk about the adoption of early phases of IBR interconnection. This paper focuses on protection challenges seen—as additional interconnections enter queue—on an incumbent utility system. It is further aimed to help with the business case justification for adequate protection and communication schemes on lines with a high volume of interconnection study requests.

The utility has roots that go back to 1913, and they now serve power needs for 3 million customers through operating companies in Arkansas, Louisiana, Mississippi, and Texas. As a result, the utility has a diverse spread of substation, transmission-line, and telecom-design infrastructure, along with even more diversity in protection equipment, including legacy electromechanical relays, various generations of microprocessor relays, power line carriers (PLCs), and nonubiquitous fiber circuits. Increased adoption of IBR sources—especially when close to each other—challenge the assumptions (referred to as favorable conditions) of manufacturer application guides and technical solutions developed by industry working groups.

In this paper, an actual system within the transmission network, of the utility, with multiple IBR cut-ins is shown in which favorable conditions are found not to exist for some faults during contingency operations. The paper further offers guidance for a growing network of renewables to explore technology enhancements that promise acceptable sensitivity and dependability even for the loss of favorable conditions. It also guides adoption of advanced logic schemes and weighs time-domain protective elements against the basic objectives of system protection.

II. Entergy's Protection Philosophy and Terminology

A. Definitions

- Unfavorable conditions—When favorable conditions mentioned in [4] are not present during a power-system fault. These are described in Section III, Subsection C.
- In-and-out station—Breaker substation where there are only two transmission feeds.
- Network bulk station—Site where there are at least two sources supplying fault currents at all times.
- POI station—First transmission substation after the point of interconnection (POI) where the IBR is being installed.

B. IBR Interconnection Relay Upgrade Philosophy

When the energy utility has a new IBR site proposed on the system, a facility study is implemented to identify what upgrades may be necessary to accommodate the new site with continued reliable operation of the power system. Protection systems are one aspect of this and are evaluated for fitness to protect transmission lines under a variety of contingencies. Of particular concern is the response of traditional relaying to fault currents contributed solely by an IBR. The scope of the system for which these evaluations are performed must also be determined.

The utility has determined three configuration scenarios that define the scope of the evaluations:

1. New POI station with network bulk station at Remote Ends—Fig. 1 shows an example POI station between bulk stations OPQR and WXYZ. Protection is upgraded for the lines between the POI station and the bulk stations to include dual primary design with current differential, permissive overreaching transfer trip (POTT), and direct transfer trip (DTT) schemes.
2. New POI station with in-and-out station at Remote Ends—Fig. 1 shows an example at POI station BCD. Facility studies will call for dual primary with current differential, POTT, and DTT schemes for all lines between network bulk stations. The decision ladder presented in [2] is used later during detailed scoping to identify the schemes that may be acceptable without upgrade. Advanced logic [4] is implemented where applicable during settings development.
3. POI connecting to a breaker at a network bulk station without a new POI station—Fig. 1 shows an example at Breaker Z. Line relaying between the network bulk station and collector station is commissioned as dual primary with current differential, POTT, and DTT schemes.

Overview of this energy utilities design basis for line protection and various contingency conditions is described in [3]. But the philosophy presented therein can be summarized as ensuring that under the loss of any one asset of the protection system, that a fault can still be cleared by local line protection so that the sensitivity of the remote backup protection need not be considered. But the current philosophy may not be sufficient as IBR penetration increases.

III. Protection Challenges Introduced by High Penetration of IBRs

Phasor-based elements may rely on phase quantities, positive-sequence quantities, negative-sequence quantities, or zero-sequence quantities. Regardless of the quantities used, traditional phasor-based protection solutions rely on the assumption that power-system sources provide fault current contributions at a similar frequency as pre-fault system voltage and that the phase angle of such fault current contributions will occur within a predictable window of phase shift from the system voltage. IBRs are known to exhibit positive-sequence current (I1) and negative-sequence current (I2) contributions to faults that are neither coherent with each other, nor with system voltage. Both contributions may exhibit frequencies and phase angles unique from each other and from the system voltage. Naturally, this challenges the assumptions upon which traditional phasor-based protection generally operates.

The solution presently employed by the utility, to ensure reliable operation of line protection for faults, which are solely sourced by an IBR, is to follow the guidelines in [5] as described in [4]. Reference[5] offers methods to enhance the security and dependability of traditional phasor-based distance (21), directional overcurrent (67), and line-current differential (87L) protective relay elements that may observe fault current contributions from both traditional and IBR sources.

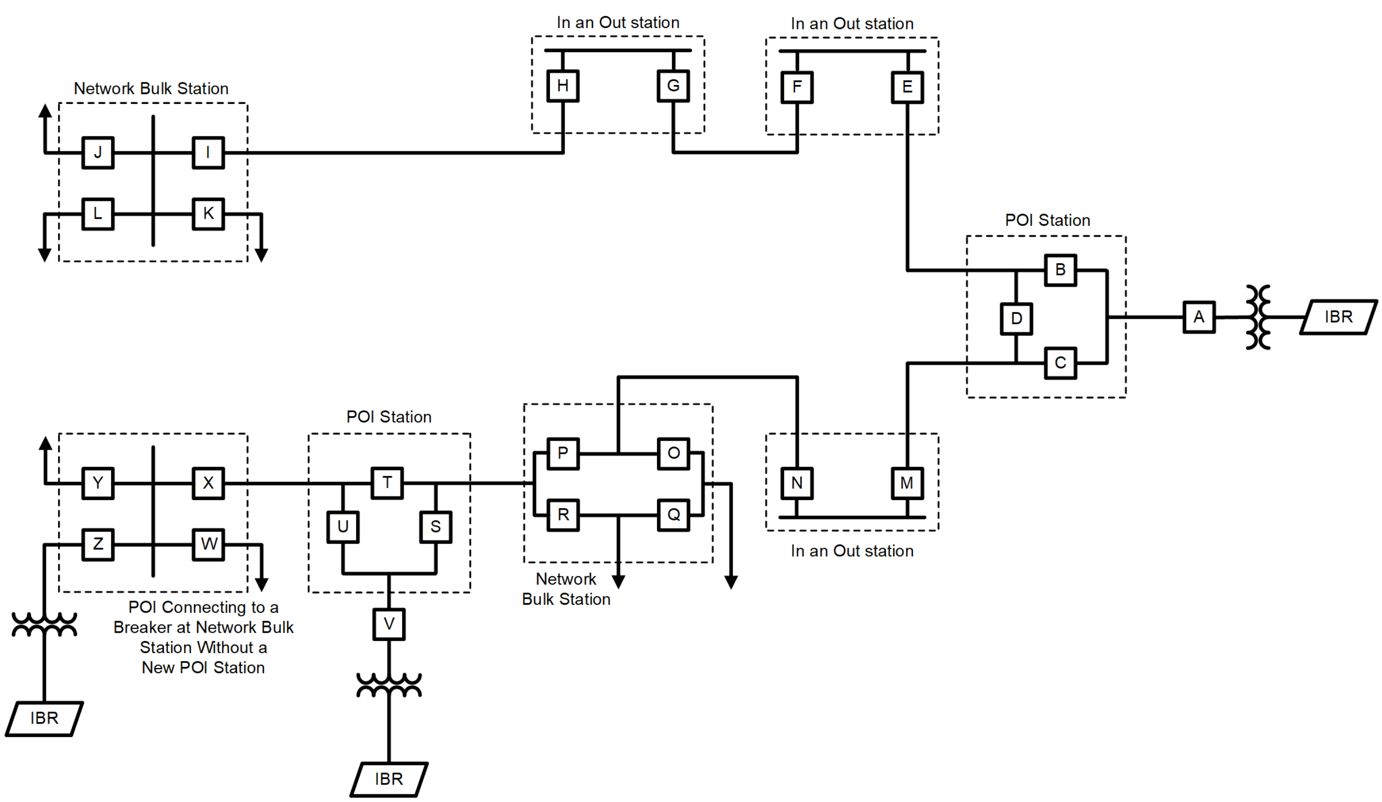

Fig. 1 Example Portion of a Utility System Showing the Three Configurations of IBR POIs.

One key aspect of the guidelines in [5] is the calculation of I_{MAX} (1) that is then used to desensitize directional overcurrent and distance element functions that are dependent on memory voltage polarization and negative-sequence current (3I2) contribution to the fault.

$$I_{MAX} = 1.3 \bullet \frac{(S_{IBR})}{\sqrt{3} \bullet V_{L-L} \bullet CTR} \quad (1)$$

where:

- S_{IBR} is the real power (W) rating of the IBRs.
- V_{L-L} is the transmission-line-to-line voltage.
- CTR is 600 based on the standard breaker CTs of the utility.

As more IBRs are installed between bulk stations, these additional sites must be considered in the calculation of I_{MAX} as well [5]. Where the actual inverter capacity is not known or where the site is expected to continually expand, the step-up transformer may be used as the IBR output capability. These considerations can result in further desensitization of the line protection to the point that unfavorable conditions may exist even for faults sourced by a network bulk station. 87L provides excellent sensitivity even in these conditions but may not always be an option if the existing infrastructure will not support the communication channels it requires [5].

A. Directional Overcurrent, 50FP and 50RP

To avoid misoperation on IBR-sourced fault currents, the directional overcurrent forward, 50FP, and reverse, 50RP, fault detector, are set to the following:

$$50FP = 1.25 \bullet I_{max} \quad (2)$$

$$50RP = 1.00 \bullet I_{max} \quad (3)$$

These settings provide security for unbalanced faults for distance (21P, 21G) and directional overcurrent (67P, 67G) elements at terminals, which may be supplied only by IBR contribution. Having the aggregate of IBRs installed on the same terminal could produce unfavorable conditions, such that the minimum fault current value contributed by the network could be less than the directional overcurrent security (50FP and 50RP) thresholds set according to (2) and (3). By desensitizing this fault detector shared by the negative-sequence directional decision (32Q) and the zero-sequence directional decision (32G), the step-distance (21P, and 21G), directional overcurrent (67G), and pilot (85) schemes using POTT or directional comparison unblocking (DCUB) methods may not pickup for remote or resistive faults, even at network-sourced terminals.

B. Line-Differential Negative-Sequence Element (87LQ)

87LQ is also desensitized, as shown in the following:

$$87LQ = \frac{1.25 \bullet I_{max}}{I_{nom}} \quad (4)$$

This provides security for external phase-to-phase faults being supplied only by IBR contribution. The pickup of the negative-sequence line-differential element (87LQ) needs to be increased by some margin above the aggregate contribution of all IBRs that might source a fault on the protected line. With the aggregate of IBRs installed on the same terminal, this could produce unfavorable conditions, such that the minimum fault current value contributed by the network could be less than the negative-sequence line-current differential threshold, (87LQ) set according to (4).

C. Favorable and Unfavorable Conditions Table

As mentioned above in Section I and in [3] [4], IBR fault contributions provide weak and incoherent fault current contributions that challenge phasor-based distance and directional overcurrent protection when an IBR is the only source feeding the fault. These effects are exacerbated in cases of higher IBR penetration or weak system conditions.

Reference [4] discusses three favorable conditions—listed in the following numbered bullets—for directional, distance, and differential elements to operate dependably when faults are being contributed by both Network and IBRs and when the guidance of (1)–(4) are employed:

1. I1 current is higher than I_{MAX}, with margin, for 3P faults
2. 3I2 current is higher than I_{MAX}, with margin, for line-to-ground, line-to-line, and double line-to-line ground faults
3. 3I2 current is lower than I_{MAX}, and voltage-based fault-identification selection (FIDS) is enabled, for line-to-ground faults (only available for the latest primary number-1 and number-2 standard relays of the utility).

Table I displays the quantity of IBRs with the same MW contribution being added on the same 230 kV line terminal, the supervisory directional overcurrent (50FP, 50RP) pickups, differential negative-sequence (87LQ) thresholds, and the minimum 3I2 fault current to cover, which is determined by short-circuit analysis. Additional IBRs were added to compare if the security thresholds were still less than the minimum 3I2 fault current to meet favorable conditions. This analysis assumes that the addition of these IBRs has no effect on overall system strength, but in the future, if IBR penetration begins to displace traditional synchronous generation, the threshold for favorable conditions could become even lower.

TABLE I
FAVORABLE AND UNFAVORABLE CONDITIONS

Number of 200 MW IBRs on same 230 kV Terminal	Differential Negative-Sequence (87LQP) Pickup Value	Directional Overcurrent (50FP / 50RP) Pickup Values	3I2 Minimum Fault Value on Transmission Loop (Line-to-Line)	Favorable or Unfavorable Condition per Differential Negative- Sequence and/ Directional Overcurrent
0	0.5 A (Secondary) Line Standard Minimum Pickup	0.5 A = 50FP (Secondary) 0.25 A = 50RP (Secondary) Line Standard Default	3 • I2 • 0.8 and CTR = Pickup 1.91 A (Secondary) Line Standard Criteria PU	Favorable (87LQ) Favorable (50FP and 50RP)
1	1.25 • I_{MAX} = 1.36 A (Secondary)	1.25 • I_{MAX} = 50FP 1.35 A (Secondary) I_{MAX} = 50RP 1.08 A (Secondary)	Same as Above 1.91 A (Secondary)	Favorable (87LQ) Favorable (50FP and 50RP)
2	(2) • 1.25 • I_{MAX} = 2.7 A (Secondary)	(2) • 1.25 • I_{MAX} = 50FP 2.7 A (Secondary) I_{MAX} = 50RP 2.16 A (Secondary)	Same as Above 1.91 A (Secondary)	Unfavorable (87LQ) Unfavorable (50FP and 50RP)
3	(3) • 1.25 • IMAX = 4.08 A (Secondary)	(3) • 1.25 • I_{MAX} = 50FP 4.05 A (Secondary) I_{MAX} = 50RP 3.24 A (Secondary)	Same as Above 1.91 A (Secondary)	Unfavorable (87LQ) Unfavorable (50FP and 50RP)

From the analysis shown in Table I, unfavorable conditions for both directional overcurrent (50FP, 50RP) and differential negative sequence (87LQ) will arise when two or more 200 MW IBRs are added to the same terminal. The directional overcurrent unfavorable condition will result in 21P and 85-POTT and DCUB not operating for minimum line-to-line faults. The same unfavorable condition also suggests that 21G, 67G, and 85 will be unable to detect minimum ground faults if dependent on a 32Q directional decision.

Based on the analysis previously stated, if enough additional IBRs are being installed on the same terminal, the utility protection will require upgrading all line protection relays to the utilities standard line differential (87L) or line protection not dependent on phasor-based relaying to maintain high-speed fault clearing. The line protection upgrades will need to be installed at all sites located on the 230 kV network between the network bulk stations. Teleprotection infrastructure will have to be installed if it does not already exist at these sites. This approach will satisfy the line protection criteria as well as provide a compelling business case justifying the more expensive solution.

IV. CASE STUDIES

The utility has already seen proposals for multiple IBR sites between network bulk stations. Presented below are two case studies based on proposals that drove the values in Table I that highlight the potential for IBR penetration to drive unfavorable conditions in the very near future.

A. Case Study 1 (Multiple IBRs Contributing From the Same Terminal)

Consider the first case study one-line diagram shown in Fig. 2. In this case study, multiple solar IBR sites and utility POIs are being evaluated on a 230 kV transmission loop. For faults between in-and-out stations on this loop, all of the IBRs will contribute fault current from the same terminal. Prior to this evaluation, when only one IBR was being evaluated, favorable and unfavorable conditions were assessed to verify if enhanced IBR protection could be implemented per [4]. Different line sections, along the 230 kV transmission section, have a mix of the latest standard and legacy line relays, which implement line-differential (87L), step-distance (21), pilot (85-POTT via digital channel, 85-DCUB via PLC), and undervoltage (27). With additional IBRs being added behind the same terminal, the value I_{MAX} is also increased, which also increases the chance of unfavorable conditions.

The ideal solution would be to upgrade all line relaying to dual primary with 87L and 85 schemes between the two network bulk stations, but this was not immediately deemed financially feasible due to telecom infrastructure (optical ground wire and all-dielectric self-supporting fiber), material (protection panels), and labor (design and commissioning) costs for this application. However, as demonstrated in Table I, the case study team's evaluation determined that the existing line step-distance pilot schemes (85-POTT via MB, 85-DCUB via PLC) would not pass the favorable condition criteria for the addition of the second IBR site. This result shows that regardless of the expense, an upgrade to dual primary with 87L and 85 schemes would be required to adequately protect these lines.

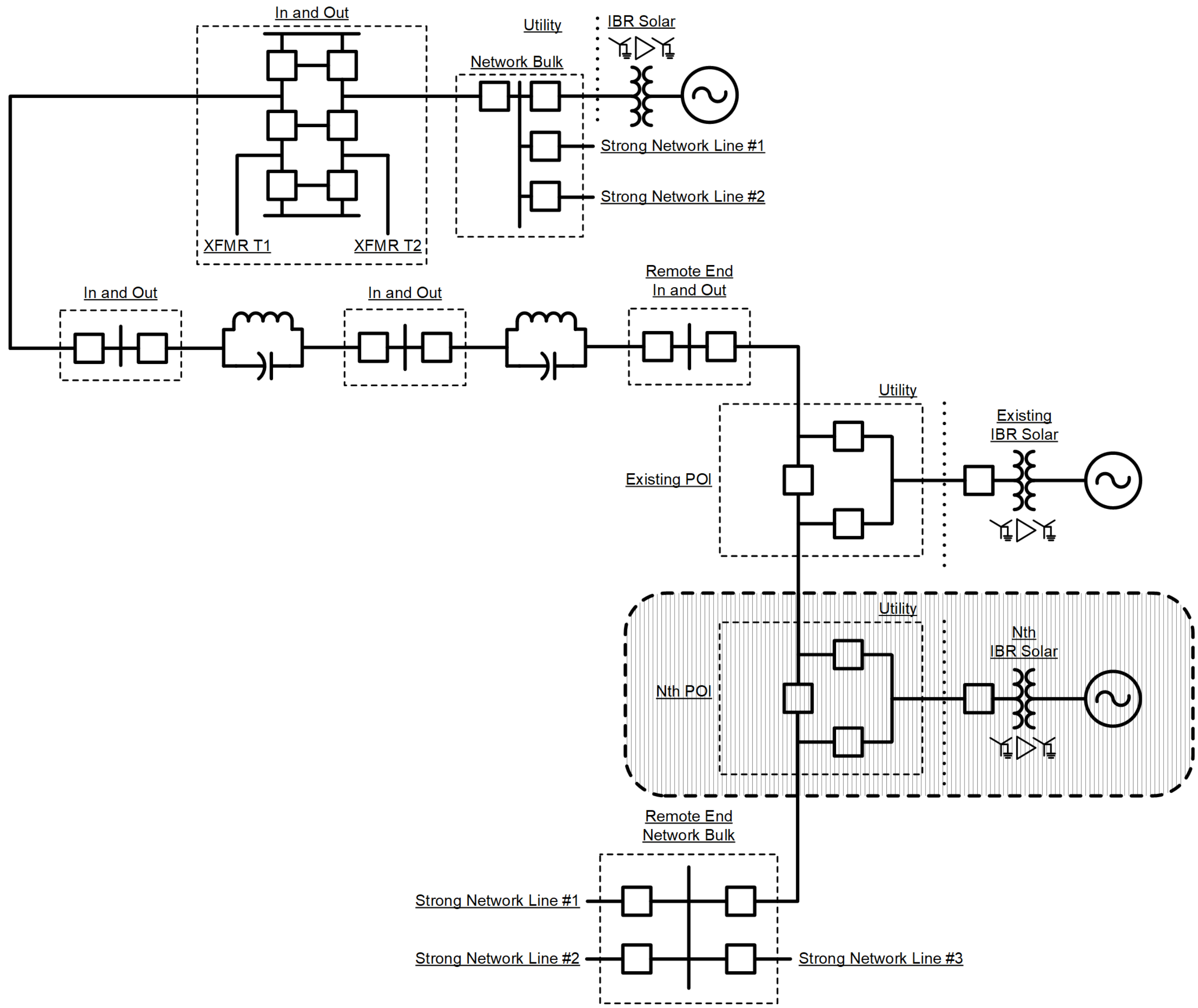

Fig. 2 Case Study 1: One-line Diagram

B. *Case Study 2 (Network N-1 and IBR Weak-Feed on Sending End and Only IBR Contributions on Receiving End)*

The directional overcurrent security threshold criteria is set to ensure that the line relay does not assess fault conditions, which are solely supplied by an unreliable IBR fault contribution. For such a contribution, the protection will behave just as it would for a weak or radial terminal. When the situation occurs—such that the system has a strong network source on one end and only a weak source on the other end—only the strong network terminal will see the fault.

For step-distance (21P, 21G), high-speed protection is achieved through pilot (85-POTT via MB, 85-DCUB via PLC) by using echo conversion to trip (ECTT). In the ECTT scheme, the relay at the strong terminal that detects the fault will issue a permissive signal to the weak terminal. The relaying at the weak terminal will not respond to fault current for a forward fault sourced only by the IBR, but it will detect a reverse fault that is sourced by the transmission network. If the weak terminal relay receives the permissive signal and does not detect a reverse fault, it will echo the permissive signal to the strong terminal so that it can trip high-speed. The weak terminal relay will also confirm the presence of a fault using phase undervoltage (27P) and ground overvoltage (59N) elements, and if it receives the permissive signal from the strong terminal, while 27P or 59N is picked up, it will also trip. The weak terminal relay used by the utility employs backup protection for phase faults through undervoltage (27P) and for ground faults using 21G and 67N. It is prudent to mention the undervoltage (27P) time delay is dependent on PRC-027 coordination with the IBR end user's ride-through requirements, which results in the undervoltage (27P) element clearing the fault in seconds, rather than cycles.

The case study team evaluated the possibility of having weak sources on both ends via a network or IBRs. Consider the second case study one-line diagrams, shown in Fig. 3 and Fig. 4. These present two different scenarios that result in weak and potentially incoherent sources on both ends of a line, should it become faulted while multiple other contingencies are present. This would be an unusual operating condition today, but it may soon become more common as grid-forming IBRs gain acceptance at the transmission level [6] in an effort to provide more reliable power under multiple contingencies.

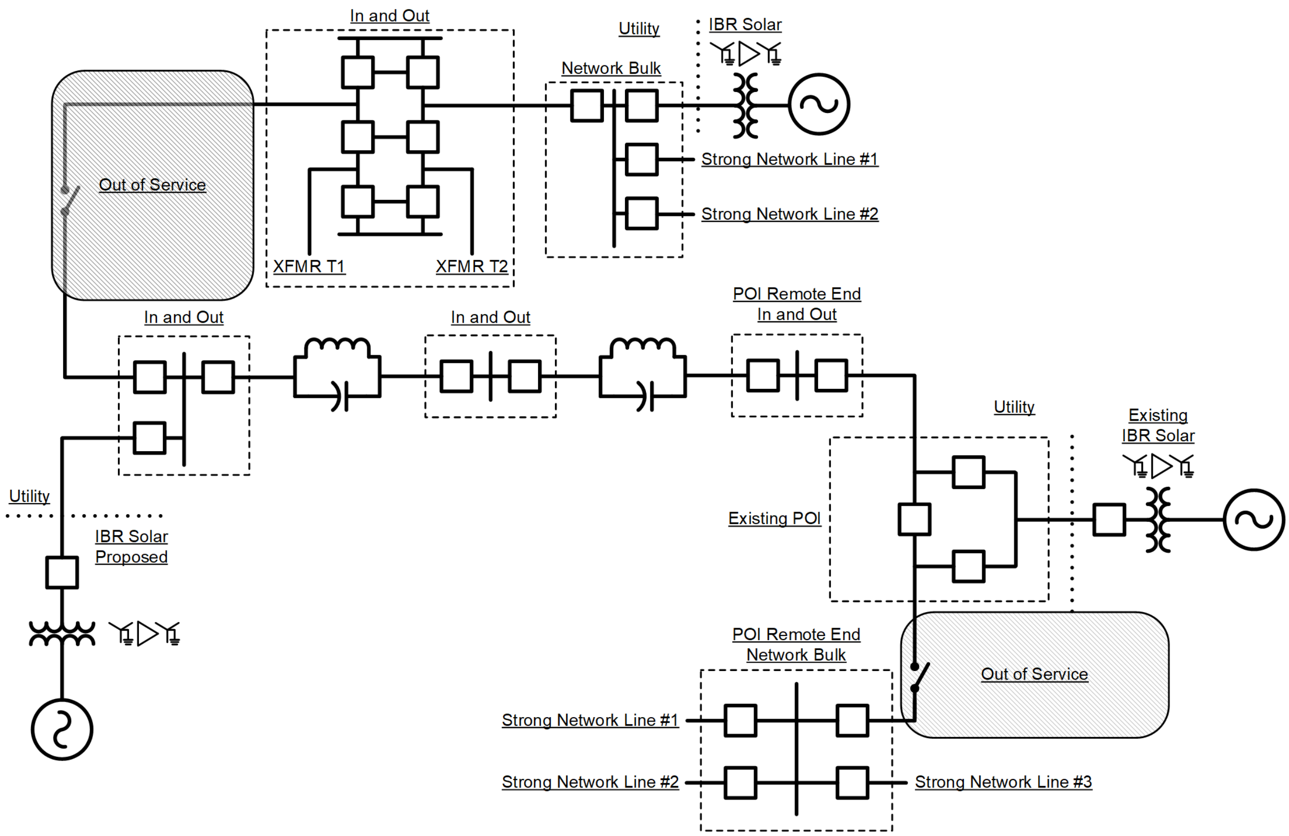

Fig. 3 Case Study 2: One-Line Scenario 1

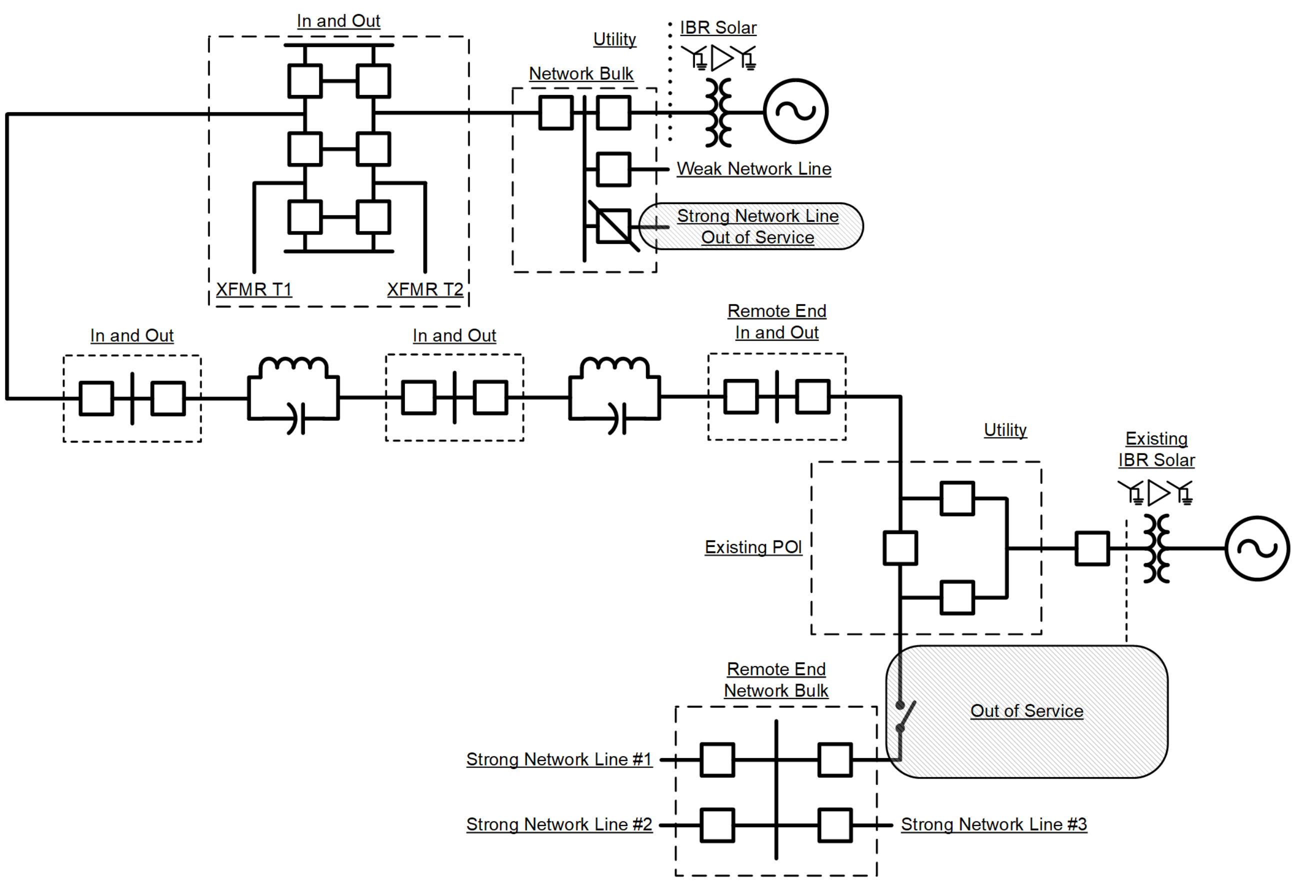

Fig. 4 Case Study 2 One-Line Scenario 2

If the utility transmission operations wish to operate with weak-feed conditions on both ends, the threshold for unfavorable conditions will become much lower, and the existing step-distance protection would need to be replaced by the standard line differential (87L) of the utility or protection not dependent on phasor-based relaying.

V. Transmission Protection Element Designs for Improved Reliability in Unfavorable Conditions

We can see now that with enough IBR penetration unfavorable conditions may exist under realistic contingency conditions, resulting in unacceptable sensitivity of the line protection. For ground faults, the step-up transformer at an IBR site typically isolates whatever zero-sequence contribution an IBR could provide and serves as a strong source of zero-sequence current (3I0) that is coherent with zero-sequence voltage (3V0). We can use this to our advantage to recover some sensitivity using traditional zero-sequence phasor-based protection such as 67G or 21G. Of course, mutual coupling is a well understood challenge to using 67G and 21G [7] [8] [9], and so it must still only be applied judiciously.

All of this means that the settings engineer has choices to make when protecting transmission lines that may be solely sourced by IBRs during a fault. The ideal solution would be to employ protection principles that inherently provide the required sensitivity and dependability without consideration for characteristics of the power system beyond the protected line. The remainder of this section details principles of 21, 67, and 87L element designs that can be employed to ensure reliable performance when observing fault contribution solely from IBRs, including phasor-based and time-domain principles. The complexity of applying these principles is also evaluated for use in the transmission-line protection standards of the utility when upgrading protection in response to IBR projects. The time-domain principles are all known to offer a high-speed response as well, but the discussion in this paper is more focused on security, dependability, sensitivity, and simplicity when applying these and phasor-based elements.

A. Directional Overcurrents (67) Used in Directional Comparison Schemes

Phase (67P) and ground (67G) directional overcurrent elements can be used in directional comparison schemes, such as POTT, directional comparison blocking (DCB), or DCUB schemes. The utility employs all three of these types of directional comparison schemes using phase (21P) and ground (21G) distance elements along with a time-delayed 67G for optimal sensitivity. This section also evaluates time-domain protection that responds to fault contributions occurring before IBR dynamics become apparent. The security gained by operating so quickly allows for settings that improve simplicity and sensitivity [10] [11].

1) Phasor-Based Ground Directional Overcurrent Element (67G)

Because of the typical step-up transformer design at an IBR site, it is possible to recover sensitivity to ground faults using ground directional overcurrent (67G) elements that compare 3I0 and 3V0, and a threshold set below the calculated I_{MAX}. This type of directional comparison is known as 32V. However, in a transmission network where lines may be mutually coupled, 32V can provide incorrect directional decisions in the presence of ground faults on or passing through the coupled line under certain bus arrangements and system contingencies. This is well documented in industry literature [7] [8] [9]. Additional guidance is offered in [7] and [9] for the practical implementation of 32V in the presence of mutual coupling, but following this guidance requires detailed modeling of each fault scenario and may result in unique settings calculation methods for each line in a transmission network.

A common solution in traditional transmission networks is to use 67G elements supervised by a comparison of negative-sequence current (3I2) to negative-sequence voltage (3V2) referred to as 32Q, since the mutual coupling has little effect on negative-sequence quantities. 32Q, especially when applied as guided in [12] [13], performs well for mutually coupled lines without any additional consideration for the coupled lines, source strength, or network impedances. For the majority of transmission lines, the advent of 32Q meant that setting a line protective relay can be performed with simple repeatable steps and even automatically generated thresholds, helping to eliminate human error. But since IBR sources may provide 3I2 fault contributions that are incoherent with the 3V2 developed by the fault, 32Q must be desensitized for lines that may observe fault contribution solely from an IBR.

The use of 67G then leaves the settings engineer to make a decision that may be unique for each line in the incumbent utility system as IBR penetration increases. 32Q offers repeatable simplicity but may not provide adequate sensitivity due to unfavorable conditions. 32V can provide adequate sensitivity, but at the cost of added complexity since it must be set with unique methods for every line. Since the utility already has a practice of considering mutual coupling in their fault study models when evaluating minimum pickups for 67G, the use of 32V, instead of 32Q, at least adds no new complexity to the practices of the utility.

2) Incremental Quantity Directional Overcurrent Element (TD67)

The incremental quantity directional element (TD32), described in [11], responds to the change in voltage and current when a fault occurs by removing the previous cycle of pre-fault information from the total faulted-state information. This effectively filters out the steady-state load and source information. While IBR sources do exhibit a dynamic response to the fault, the response during the first few milliseconds of the fault is more like a weak inductive source. The TD32 element is able to determine the direction of the fault within this window [10], and therefore, it makes the same determination whether the observed fault contribution is delivered by a traditional source or an IBR. This means that the TD32 element does not need to be desensitized for IBR sources, because it makes the correct decision even under unfavorable conditions. The TD32 decision can then be used in conjunction with an incremental quantity overcurrent (TD50) to develop an incremental quantity directional overcurrent element (TD67) suitable for use in POTT, DCB, and DCUB schemes.

Settings guidance for TD32 found in [14] offers a straightforward settings methodology. But the loop quantities used by TD32 and TD50 exhibit the effects of zero-sequence currents and voltages and so are not immune to mutual coupling. Following the guidance in [14] results in secure and dependable TD67G settings for modeled fault conditions rather than setting the element for maximum sensitivity, which reduces the risk of false operation due to mutual coupling. For lines that are not at risk of mutual coupling, more sensitive settings can be considered for TD67G. Migration to relays that employ the TD67 element offers improvements in sensitivity near IBR sources, but setting it for a balance of sensitivity and security does still require some knowledge of the system and an ability to simulate fault conditions on the system. Since the utility already has a practice of considering mutual coupling in their fault study models when evaluating minimum pickups for 67G, the practice of maximizing sensitivity of TD32 adds no new complexity to the general practices of the utility. Where automatic thresholds can be used with 32Q and 32V, the calculations recommended for TD32 require a small additional step to model apparent source impedances for strongest system configuration.

3) Traveling-Wave Directional Element (TW32)

The traveling-wave directional element (TW32) described in [11] responds to the traveling wave initiated by the fault itself and has no dependency on the type of source contribution to the fault at all. It is therefore an excellent indicator of the direction of the fault at an in-and-out substation terminal sourced solely by an IBR and can be used advantageously in a POTT scheme specifically to provide a high-speed permissive or blocking signal.

TW32 responds correctly even under unfavorable conditions since it responds to the traveling wave from the fault, rather than the contribution of the source to the fault. However, a traveling wave on one conductor does couple with adjacent conductors and adjacent transmission lines to create traveling waves on unfaulted conductors, to which TW32 may respond. TW32 must only be used for a permissive or blocking signal. In order for a relay to trip with this permissive signal or in absence of a blocking signal, it must also locally declare a forward fault with a TD32 or 67 element. Because TW32 uses such a different principle than other directional elements, it may return a different decision than other directional elements. For this reason, the permissive or blocking signal driven by the TW32 decision should be transmitted separately from the general permissive or blocking signal [15].

Directional comparison schemes using TW32 provide an improvement in speed over the use of phasor-based 21 and 67 elements. But these traditional phasor-based elements must still be secured for proper restraint for at least the duration of the relay operation, including the breaker operation during external faults. The use of TW32 elements requires no additional complexity beyond ensuring a dedicated signaling channel for the TW32 apart from the general permissive or blocking signal.

B. Distance Elements (21)

The design of distance elements has evolved quite a bit over the years [16] to include principles beyond the basic concept of Z = V/I. The familiar mho, compensator, and quadrilateral characteristics all measure the difference between the measured voltage drop across a faulted loop (V) and the voltage drop due to the measured current flowing through an impedance equal to the set reach of the distance relay (IZ), to create an operating quantity (V-IZ). This operating quantity is then compared to a polarizing quantity (either voltage or current) using an angle comparator to develop the shape of these distance elements in the fault loop impedance plane. This is well described in [16] [17] [18].

Modern microprocessor relays typically include some additional techniques and supervision to ensure the reliable operation of a complete distance relay for all fault types, but of note to this discussion are the polarizing voltage mentioned above and faulted loop identification. Distance elements in modern relays may also be supervised by 32Q or 32V for unbalanced faults and so will follow the 32Q and 32V responses for unfavorable conditions. The following sections focus on the additional effects of polarization voltage and faulted loop identification for faults sourced solely by an IBR.

1) Self-Polarization Vs. Memory Polarization

In [19] we can see the behavior of self-polarized mho distance elements compared to memory-polarized mho distance elements. Memory polarization is required to ensure reliable operation for close-in three-phase faults that develop little to no measurable loop voltage. Memory polarization also provides favorable expansion characteristics to improve resistive coverage for all fault types. However, if a memory-polarized distance element measures the fault current contribution from an IBR—which may not occur at the nominal system frequency—while being polarized with a pre-fault memory voltage exhibiting the nominal system frequency, the apparent impedance can oscillate impacting reach accuracy, and more severely, the distance element can lose directionality, especially if the fault is allowed to persist [10]. In the current practice of the utility, a time delay is used to secure the Zone-1 distance element, while a dropout timer is used to ensure the dependability of a time-delayed Zone-2 distance element. The utility additionally desensitizes the phase distance (21P) element for three-phase faults to ensure that memory-polarized distance elements do not operate for three-phase faults that are small enough that they could be sourced by the IBR.

A self-polarized distance element does not offer the advantages of dynamic expansion and reliable response to close-in faults of a memory-polarized distance element. But by being self-polarized, such a distance element only combines voltage and current signals from the faulted loop that are occurring simultaneously, and as such, it measures a stable and linear faulted loop impedance [10]. Coverage of close-in faults can be achieved by applying a small reverse offset. The reverse offset sacrifices some selectivity for close-in reverse faults, but a time delay can be used to ensure all other adjacent bus and line protection elements have a chance to operate first. This then becomes a useful method for protection on the IBR tie lines to detect the presence of a network fault and trip the tie line to separate the IBR from the transmission network, since the protection on the remaining lines in the transmission loop may not be responsive to the IBR fault contribution. In this way, if teleprotection on the faulted line were completely unavailable, it is possible that only the strong sourced end of a faulted transmission line may trip, but the IBR contributions to the fault will be cleared by protection at the IBR tie lines. This is accomplished today in the protection design of the utility through the use of a time-delayed undervoltage (27) element on the tie lines. The use of a self-polarized distance element instead offers some improvement in selectivity during unfavorable conditions. Because it is an accurate reach-limited element, even as a backup element it may be set with a shorter time delay than a 27 employed as a backup element.

2) FIDS

Mho and quadrilateral distance elements are designed to respond to specific fault loops. For three-phase transmission systems this results in six fault loops that need to run concurrently (AB, BC, CA, AG, BG, and CG). Three-phase, line-to-line, and double line-to-ground faults are covered by the AB, BC, and CA distance elements. But more specifically, an AG distance element is designed to respond correctly to an AG fault, but being responsive in general to current and voltage on A-phase, it can also respond incorrectly to an ABG or AB fault. Of more specific concern, the AG element could overreach for an ABG fault with fault resistance. FIDS can be used to only enable the correct distance elements for a given fault type based on other indicators of the most likely faulted loop.

The weak and unpredictable contribution of IBRs can lead to incorrect decisions when using FIDS methods [17] [20] that are dependent on the 3I0 and 3I2 of the fault current contribution alone. But voltage can be an excellent indicator of faulted phases as well, and it can be used in lieu of current based FIDS or along with current to enhance FIDS [21] during ground faults. Migration to relays that employ voltage in FIDS provides the utility the opportunity for more dependable usage of distance elements at weak sources [10].

C. Line-Current Differential Schemes

87L is known to be a secure and dependable solution for protecting challenging transmission lines. Other traditional solutions for protecting transmission lines rely on information from only the local end of the line or on the exchange of directional decisions made using that local information only. This puts the relays at a disadvantage of never really having a complete picture of the protected line. 87L offers the opportunity for a local relay to make decisions based on a complete current measurement of the protected line by having access to remote terminal current information. The technique inherently removes most effects of source and load for external faults, but it allows all 87L protected terminals to observe the total fault current of internal faults even if contributed from only one terminal.

1) Alpha-Plane Line-Current Differential (87L)

Alpha-plane 87L relays have long been considered the most superior form of line protection at the utility. The technique has been used to provide secure and dependable protection for challenging transmission lines and, in general, wherever the infrastructure allows it. Even as newer technologies are evaluated and adopted, 87L is expected to remain the preferred protection method of the utility for any transmission line, especially those that may be solely sourced by an IBR [2]. Out of the current standard protection schemes of the utility, 87L provides the best reliability during unfavorable conditions, even as IBR penetration increases on the incumbent utility system.

References [4] and [22] provide guidance for secure and dependable 87L settings for lines, which may be solely sourced by an IBR. 87L, typically implemented as an A-, B-, and C-phase elements (87LA, 87LB, 87LC), along with a negative-sequence (87LQ) and a zero-sequence (87LG) element. Because of the high-harmonic content contributed by IBRs under certain conditions, it is advised to desensitize the 87LQ, much as other negative-sequence elements are desensitized. The 87LA, 87LB, 87LC, and 87LG elements do not require the same measure of desensitization, and in fact the 87LA, 87LB, and 87LC elements should be set even more sensitively than they have been traditionally [4].

Any 87L technique requires the exchange of analog information, which requires more bandwidth on a digital channel than a simple directional comparison scheme. Direct or multiplexed (MUX) fiber infrastructure is required for the secure and dependable operation of such a scheme, and where it does not exist, it must be installed. Utilities are motivated to minimize system protection upgrade costs in response to any independent power producer (IPP) project, including renewable energy providers that use IBRs. Utilities are also motivated to ensure adequate protection for their systems and must identify the costs associated with necessary upgrades so that these costs are borne by the IPP who wishes to invest in a profitable project and not by the ratepayers who already have access to electricity with or without the presence of a new IPP. Oftentimes the new infrastructure cost required by 87L is avoided in an effort to minimize costs to the IPP, especially if multiple transmission lines will be affected by the installation of an IBR site. While a transmission line can be protected without 87L, there is no solution that offers the same combination of security, dependability, and simplicity. This must be considered when scoping the protection upgrades that are truly required to ensure reliable power-system service to all utility ratepayers when the protection is challenged by increased penetration of IBRs.

The other consideration here is redundancy. Once the infrastructure is in place to support one digital channel for 87L, it is a minimal additional cost to also provide backup channels. However, care must be taken to avoid single points of failure for all channels. For instance, a utility may install a dual primary-line protection panel with two 87L relays, each with their own primary and backup 87L channels. But if all four channels are routed through the same MUX access, then failure of the one access device could disable all 87L protection. It is also still necessary to employ the techniques outlined in [4] to ensure that there is still complete protection for the loss of 87L communications and for correct remote backup operation for uncleared external faults.

2) Traveling-Wave Differential (TW87)

The traveling-wave differential element (TW87) described in [11] responds to the traveling wave initiated by the fault itself and has no dependency on the source contribution to the fault at all. It is therefore an excellent solution to provide a high-speed detection of an internal fault and can securely restrain for external faults. It is unaffected by the unfavorable conditions referenced earlier in the paper.

Unlike 87LQ, there is no need to desensitize TW87 for IBR contributions since it responds to the traveling wave from the fault, rather than the source's contribution to the fault. However, a traveling wave on one conductor does couple with adjacent conductors and adjacent transmission lines to create traveling waves on unfaulted conductors. The TW87 element described in [11] is secure against mutual coupling because it responds only to the alpha and beta components [23] of the Clarke transform, applied to the phase signals.

The TW87 element is designed to observe the first arrival of the traveling wave launched by the fault and determine its polarity and arrival time, using a differentiator-smoother filter, as described in [23]. As long as no other reflections arrive during the filter delay, the element will have an accurate measurement of the arrival time and polarity of the wave. However, if any reflections do arrive at the breaker, associated with the relay, during the same filter window, the output of the differentiator-smoother filter may not be accurate enough for the TW87 element to use. The element is designed to recognize this and prevent an operation. For faults occurring on overhead lines about 5 miles and shorter, or for faults occurring between taps that are within 2.5 miles of each other or the line terminations, such reflections may be observed within the same filter time window as the first arrival of the wave and may reduce the dependability of the TW87 function. The element is not designed to be dependable under these conditions but does remain secure. The overall concern is minimal as these faults comprise a minority of most transmission systems.

TW87 provides an improvement in speed and simplicity over a traditional phasor-based 87L and is an excellent addition to any line protection scheme. On IBR-sourced lines TW87 may operate before traditional phasor-based elements are challenged by the contribution of the IBRs. But with the TW87 exhibiting less dependability for some short and tapped lines, a phasor-based 87L is still desired to operate in parallel. Because the breaker may not clear the fault before a phasor-based 87L is challenged by the contribution of the IBRs, it will still need to be desensitized. TW87 also requires a higher bandwidth channel that cannot practically be provided with acceptable determinism using traditional time-division or packet-based multiplexing. A direct fiber channel is required for the utility to take advantage of TW87.

VI. Conclusion

Electric power systems are evolving to an extent where underlying assumptions of design basis and canned solutions are being challenged. This paper focuses on protection problem statements exacerbated by increased penetration of IBRs. Initial sections of the paper present Entergy's approach to IBR interconnection protection schemes. Section III dives into the details on how with the addition of IBRs, unfavorable conditions are created. In Section IV, through case studies, the recent project examples within the system of the utility are presented—where challenges from unfavorable conditions are evaluated. In Section V, the adoption of recent solutions by the utility are described. Section V details both phasor and time-domain based principles that can be employed to mitigate challenges presented in Section IV.

Engineering the right protection scheme is often a balance of project needs, regulatory requirements, and industry standards, while delivering the best value to stakeholders. This paper is aimed to help with the business case justification for adequate protection and communication schemes on lines with a high volume of interconnection study requests. Operations, planning, and design engineers have to collaborate proactively to align on solutions in early phases of the projects. Some of the key points are summarized in the following:

- Many traditional line protection elements are dependent on an unbalanced fault contribution that contains 3I2 coherent with 3V2. IBRs do not contribute 3I2 coherent with 3V2, and so these elements must be desensitized to the unfavorable conditions of IBR fault contributions.
- Increasing penetration of IBRs will exacerbate these unfavorable conditions to the point that relays may be unresponsive even for network-sourced fault currents.
- 32V may be used to provide a more sensitive 67G function for detection of ground faults but must be set carefully with regard to the effects of mutual coupling.
- Self-polarized distance elements offer improved dependability and security during unfavorable conditions at the expense of selectivity and are best used as time-delayed backup elements at the IBR tie line.
- Voltage-influenced FIDS improves the security and dependability of distance elements near IBR sources during ground faults.
- TD67 elements do not need to be desensitized for IBR fault contributions, but TD67G must still be set carefully with regard to the effects of mutual coupling.
- TW32 does not need to be de-sensitized for IBR fault contributions and it offers speed at no cost to simplicity. But it is not dependable for all transmission lines and so does not preclude the use of traditional protection elements and the other techniques discussed in this paper.

- TW87L does not need to be desensitized for IBR fault contributions, and it offers speed at no cost to simplicity. But it is not dependable for all transmission lines and so does not preclude the use of traditional protection elements and the other techniques discussed in this paper. It also has the most stringent teleprotection communications requirements of any element discussed in this paper.
- Alpha-plane based 87L—even when 87LQ is desensitized—offers excellent security, dependability, and sensitivity with little more complexity required of an IBR-sourced transmission line, compared to any other transmission line. Because 87L is dependent on teleprotection communications, which may become unavailable, it does not preclude the use of the other techniques discussed in this paper.
- Superior performance of 87L and time-domain principles provide a compelling business case, especially when unfavorable conditions exist, and thus, it needs to be strongly considered along with the scoping of the necessary teleprotection infrastructure.

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VIII. Biographies

Keith Gaffney has a BSEE from Louisiana State University. He is a licensed engineer-in-training and has Project Management Professional certification. He has been supporting P&C design and engineering roles for 14 years at Entergy. As a senior lead, he supports P&C with training, compliance, design basis, workforce development, quality assurance, project portfolio support, and other business initiatives.

Tu Nguyen has a BSEE from the University of New Orleans and has over 35 years of experience with Louisiana Power & Light and Entergy as a commissioning engineer, relay design engineer, and protection application engineer. He has been an IEEE member since 1990.

Ram Viswanathan has a MS degree in electrical engineering with a specialization in electric power and energy systems. He is an active member of IEEE and the North American Transmission Forum. He has over 10 years of experience in relay protection working for Entergy Services, LLC in various engineering roles.

Jeremy Blair, PE, earned his BSEE from Louisiana Tech University and his MSECE from Georgia Institute of Technology. He joined Schweitzer Engineering Laboratories, Inc., (SEL), as an application engineer in 2013, authoring conference papers and application guides and assisting customers with relay and distribution automation solutions. Previously, he worked for Entergy Corporation as a distribution planning engineer with responsibilities in distribution system plans, protection, power quality, and automation. He also managed Entergy's Automatic Load Transfer and Sectionalization Program over its four-state territory. He is a licensed professional engineer in Louisiana.

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