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Challenges, Industry Practice, and Research Opportunities for Protection of IBR-Rich Systems

May 2024

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U.S. DEPARTMENT OF ENERGY

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Executive Summary

The objective of this technical report is to outline the challenges of protection design for power systems rich in inverter-based resources (IBRs), synthesize current industrial practices, review new approaches from recent literature, and explore future opportunities in protection.

IBRs are experiencing widespread adoption across both transmission and distribution systems. When present in significant quantities, IBRs challenge the performance of many traditional protection functions due to their low inertia, fault current characteristics, negative sequence, and complex interactions with grid dynamics (Section 2.0). To address these issues, the industry has developed sophisticated protection schemes that involve advanced relaying techniques, such as directional overcurrent, distance protection, and differential current, and extensive coordination studies in highly engineered pilot projects (Section 3.0). However, these schemes are expensive and time-consuming to develop, build, and test (Section 4.0). Researchers have proposed a number of new approaches for protection in IBR-rich distribution systems. These approaches include dynamic adaptive protection, as well as data-driven, short-term, transformation-based protection (Section 5.0). Despite their potential, these new approaches do not address some major shortcomings of industry approaches stemming from complexity, practical requirements, and reliability (Section 6.0).

The essential findings of this report are as follows:

- The protection methods currently being used to protect IBR-rich microgrids can also be applied to IBR-rich distribution systems and provide good performance if modern design methods are employed. Compared with traditional distribution protection schemes, microgrid protection generally makes greater use of transmission-oriented protection algorithms and communications.
- Industry microgrid protection approaches are not economical for large-scale distribution systems. This is because they rely heavily on high-speed communications, complicated system-specific logic, detailed models of IBR behavior, and electromagnetic transients modeling (EMT). Thus, there is significant value to new protection techniques that reduce reliance on these factors.
- Researchers have proposed a variety of new protection approaches for IBR-rich distribution systems. Some show promise for protection schemes that will scale more economically to distribution systems at large. Approaches based on unbalanced incremental quantities, such as incremental negative-sequence impedance, provide accurate fault detection and directional indications even in IBR-rich networks. Data mining approaches, such as random forest classification, provide a statistical framework for designing effective protection features while retaining transparency and determinism.
- Approaches that are purely data-driven or those that rely on dynamically adaptive protection are unlikely to scale economically. In addition to requiring extensive studies to design, these approaches are difficult to integrate with established and trusted approaches for protection system testing.

Based on these findings, Pacific Northwest National Laboratory has identified several avenues for further research. The use of modern data mining techniques for designing robust, reliable, and transparent power system protection algorithms (Section 5.5) should be explored. Modern directional elements are a promising line of inquiry for improving protection algorithm robustness against system operating conditions and IBR fault controls (Section 5.3). There is a need for

design strategies to confirm IBR protection elements are immune to uncertainties in IBR fault controls or variations in system operating conditions (e.g., microgrid vs. islanded operation) (Section 4.0). Design strategies are also needed for IBR protection based on short-circuit programs rather than EMT (Section 4.0). For a more complete discussion of these opportunities, refer to Section 7.0.

Acknowledgments

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Acronyms and Abbreviations

BESS	battery energy storage system
CT	current transformer
DER	distributed energy resource
DT	decision tree
EHV	extra-high voltage
EMT	electromagnetic transient
HIF	high-impedance fault
IBR	inverter-based resource
IEC	International Electrotechnical Commission
LR	logistic regression
L-L	line-to-line
ML	machine learning
MTBF	mean time between failure
NERC	North American Electric Reliability Corporation
PNNL	Pacific Northwest National Laboratory
POTT	permissive overreaching transfer trip
RF	random forest
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SLG	single line-to-ground
SVM	state vector machine
TOC	time-inverse overcurrent
TW	traveling wave
VSC	voltage source converter

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1.0 Introduction

Many forms of renewable energy, such as solar and wind energy, rely on inverters to deliver electrical power to the grid. These resources are known as inverter-based resources (IBRs) and have significantly different dynamic behavior than traditional generators. These differences in dynamics are challenging for conventional approaches to power system protection because they were originally designed for use with traditional generators. This is particularly difficult for IBRs that connect to the distribution system because traditional distribution protection systems are designed for simplicity and economy.

In industry, system protection in IBR-rich distribution systems has primarily been accomplished by making greater use of transmission-oriented protection algorithms and modern communications architectures. This results in significant cost increases when applied at the distribution level, which could significantly hinder the further proliferation of distributed energy resources (DERs). Most new protection approaches proposed in literature do not address these major sources of cost. This presents an opportunity for future protection research to better address the shortcomings of the existing state-of-the-art methods.

In this work, a review is given of challenges with protecting IBR-rich distribution systems and how industry has addressed them so far. Based on industry solutions, major sources of cost in protecting IBR-rich distribution systems are presented and discussed. The essential characteristics of a cost-effective solution are identified. Next, new protection approaches proposed in literature are reviewed, and their ability to provide a cost-effective solution is evaluated. Finally, next steps for productive research are described based on the gaps identified in this analysis.

2.0 Protection Challenges for IBR-Rich Distribution Systems

The presence of a significant quantity of IBRs in a distribution network introduces a variety of challenges related to power system protection. These can be classified as either technical challenges or operational challenges.

Technical challenges are mostly an issue related to the limitations of the protection technology that is used in traditional distribution systems today. The technical challenges discussed are well understood in literature and have been studied for the past two decades [1]. As will be discussed in Section 3.0, industry has developed some solutions for these challenges. However, these solutions have significant drawbacks that will hinder further adoption of IBRs.

Operational challenges are related to how this technology is applied when the protection system is designed and operated. These challenges are emergent and are often more related to shortcomings in governing standards, testing practices, and specific implementations of existing technologies. Operational challenges have been responsible for multiple GW-scale generation outages over the past several years [2]. These challenges have appeared primarily at the transmission level, but the underlying issues are applicable to distribution systems as well.

2.1 Technical Challenges

2.1.1 Multi-Source Distribution Networks

The vast majority of distribution networks in service today are fed radially. This results in a single source of fault current and a single direction of power flow. Compared to the networked power systems that are widespread in transmission systems, this has allowed much simpler and cheaper protection systems to be used. The presence of IBRs at the distribution level causes problems for traditional protection simply because the existing protection system assumes the utility power source is the only source in the network. Thus, the multi-source issue is not specific to distribution IBRs but is relevant for any kind of DER.

Figure 1 illustrates a basic scenario where the presence of a DER on a distribution feeder can cause coordination issues. In the traditional case, a fault at the end of the feeder causes the closest recloser (REC2) to operate. However, when a DER is introduced, the additional fault contribution can cause the next recloser upstream (REC1) to operate as well.

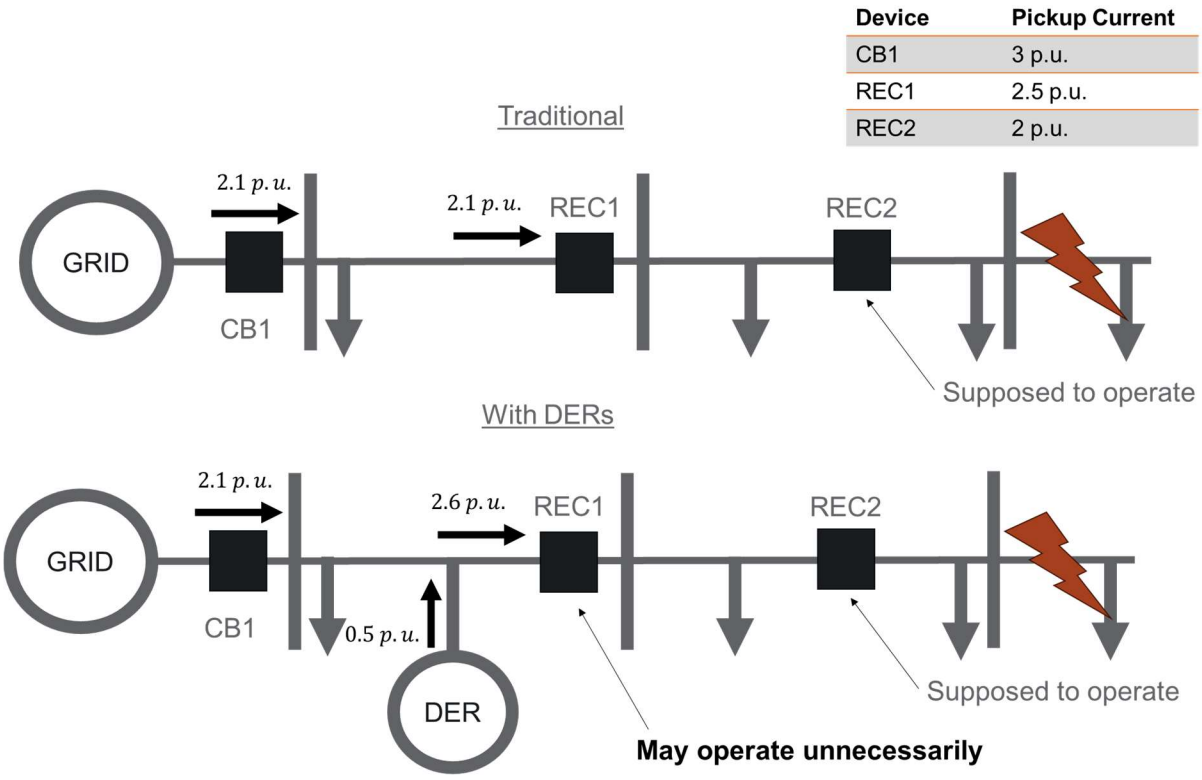


Figure 1: Fault Currents in a Network without (Top) and with (Bottom) a DER. The DER's fault contribution may cause REC1 to operate incorrectly due to the increased fault-current levels.

The protection logic shown in Figure 1 is much simpler than most feeder protections, which often involve more sophisticated coordination. A simple example has been used for the sake of brevity. However, the fundamental issue—that DERs introduce additional sources of fault current that challenge coordination based on current magnitude—remains the same in more realistic protection schemes.

As will be explained in Section 3.0, existing protection schemes are capable of protecting networked distribution systems. However, such schemes are more expensive to design, build, and test. Additionally, the case shown in Figure 1 is somewhat exaggerated—coordination issues typically only arise for very high levels of DER penetration (e.g., 100%) [3]. Regardless, distribution protection engineers must still consider the possibility of miscoordination during protection studies. This makes the study more time consuming. These factors support the primary finding of this literature review: existing protection methods can function in IBR-rich systems, but the presence of IBRs makes the protection system significantly more expensive to design, build, and test. In Section 5.0, research approaches for reducing this cost are discussed.

2.1.2 Constant-Current Fault Response

Unlike a traditional rotating machine, IBRs interfaced with a power converter must limit their current during voltage faults to avoid potential hardware damage. From a converter design perspective, this is beneficial and necessary to protect the converter, which has significantly less short-term overload capacity than an equivalent rotating machine. However, at a high IBR

penetration, this behavior can defeat the current magnitude-based coordination that is commonly used in distribution systems.

Time-inverse overcurrent (TOC) is by far the most widely used protection element in traditional distribution systems. A TOC element detects overcurrent events with a variable time delay—the length of the time delay is approximately inversely proportional to the magnitude of the overcurrent.

Figure 2 illustrates a simplified distribution feeder with some loads and key protective elements identified. Figure 3 illustrates some TOC characteristics that could be applied to protect this feeder. The lower TOC curves, which operate more quickly, are applied to protections nearest the loads, such as the fuses shown in Figure 2. The middle curve could be used for the circuit breaker or the recloser, with the higher curve being used for the next device upstream.

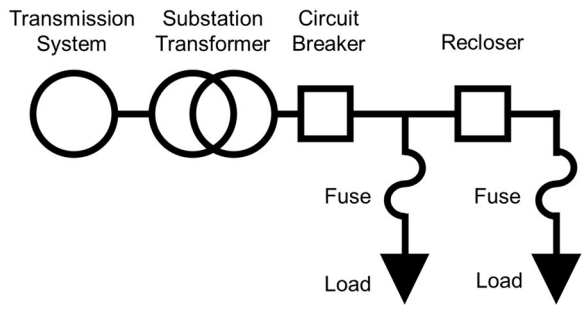


Figure 2: Simplified Distribution Feeder with Major Protection Devices Identified.

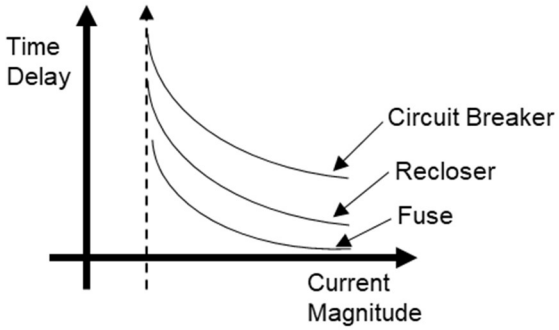


Figure 3: Typical Time-Inverse Overcurrent Operating Characteristics.

In a traditional power system, the generators behave like an ideal voltage source, and fault-current magnitudes are lower for faults closer to the end of the distribution feeder. Thus, TOC-based protection remains coordinated. However, in an IBR-dominated system, the fault current is relatively constant with respect to fault location.

More generally, current-limiting behavior can challenge the sensitivity of some kinds of protection because the limits commonly used (e.g., 1.2 to 1.5 per-unit) are relatively close to load current and much lower than the fault currents commonly seen in traditional distribution systems (e.g., 3 per-unit or more). However, this challenge is not necessarily new, and many of the industry protection elements that will be discussed in Section 3.0 can overcome this issue.

Figure 4 compares some typical current and voltages for a fault in a traditional (left) and IBR-dominated (right) distribution system. All values are given in per-unit. Consider the placement of a protective relay at Bus 1, which implies that the relay measures the voltage at Bus 1 and the current flowing through it.

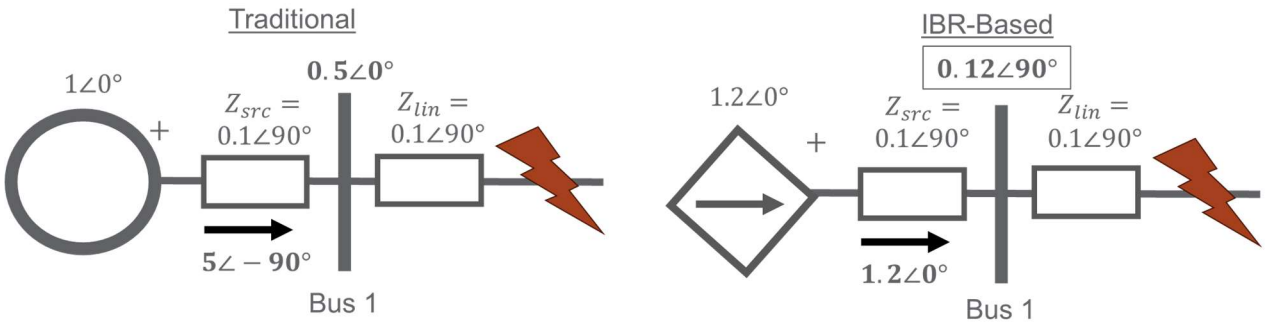


Figure 4: Typical currents and voltages for voltage- (left) and current-sourced (right) distribution systems.

In the traditional system, overcurrent is an obvious choice for coordination because the current magnitude is both large (5 per-unit) and will decrease as the fault is moved further away from Bus 1 (due to the increase in ($|Z_{lin}|$). However, in the completely IBR-based system, undervoltage becomes a more attractive option—for more distant faults, $|Z_{lin}|$ will be greater, and thus the voltage at Bus 1 will increase. This is simply a result of the dual relationship between current and voltage sources, and the reason why some approaches to IBR protection use voltage-based coordination in the absence of communication [4]. However, this approach is only easy to apply in radial networks with a single current source. IBR-dominated systems often still have significant fault-current contribution from traditional sources, and the amount of contribution is highly variable depending on the availability of the IBRs.

Traditional transmission systems are seldom coordinated based on current magnitude. While current-limiting behavior is not traditionally encountered, fault-current magnitudes at the transmission level vary significantly depending on which transmission lines and generators are in service. Referring back to Figure 4, observe that, in accordance with the fundamentals of circuit theory, the driving point impedance measured at Bus 1 is the same for both cases (Equation 2.1):

$$\frac{0.5\angle 0°}{5\angle -90°} = \frac{0.12\angle 90°}{1.2\angle 0°} = 0.1\angle 90° = Z_{lin} \tag{2.1}$$

Operation based on driving point impedance is the fundamental idea behind distance protection, a traditional protection element that is ubiquitous in transmission systems. The relationship shown in Equation 2.1 holds true irrespective of the source behavior, which has led some to develop distance-based approaches for protecting IBRs in distribution systems [5]. However, this approach is prone to some complexities that increase cost. Distance protection is discussed more in Section 3.1.2.

2.1.2.1 Current-Limiting Behavior of IBRs: AC vs. DC Systems

The hardware design commonly used for voltage source converters (VSCs) allows the converter to control and limit fault currents for faults that occur on the AC side of the VSC. However, faults on the DC side of the converter cause uncontrolled rectification of the freewheeling diodes, which leaves the VSC's IGBTs unable to control the current. This results in high fault currents, and the protection system must clear DC-side faults extremely quickly (e.g., less than a millisecond) in order to protect the diodes [6]. In AC-based distribution systems, the only DC-side faults are internal converter faults. Such faults are handled at the device level and thus are not a concern for the distribution protection system. In DC-based distribution systems, the situation is quite different—most faults occur on the DC side of the converter, and DC faults are

the primary concern for system-level protection. Rapidly detecting and isolating such faults is a major technical challenge and an area of ongoing research [6].

There are VSC topologies that can perform current limiting for both AC- and DC-side faults (e.g., a full-bridge multi-level modular converter) [7], but these are not commonly used due to their higher capital cost and lower efficiency compared to other designs.

2.1.3 Negative-Sequence Current Control

On a phasor timescale, traditional generators behave as a positive-sequence voltage source behind a series impedance. As a result, the negative-sequence current that flows during a fault is primarily determined by the fault type (e.g., line-to-line vs. line-to-ground) and system sequence impedances. Many protective relays are based on this negative-sequence behavior, and a great many protection elements rely on negative-sequence currents in order to detect and locate short circuits. The negative-sequence behavior of IBRs is determined by the IBR control strategy and varies significantly by make and model, causing a variety of issues for traditional protection [8] [9].

Most IBRs either synchronize to the grid's positive-sequence voltage (grid following) or generate a positive-sequence reference internally (grid forming). The grid-following IBR's current control loop is designed to regulate the converter currents to a current reference that is constant in the positive-sequence reference frame. From a protection system perspective, an unfortunate consequence of this behavior is that the converter tends to regulate the negative-sequence currents produced by unbalanced faults to zero (Figure 5).

A simplified way to view this behavior in the phasor domain is to say that an IBR's negative-sequence impedance is infinite [9]. However, this simplification can be somewhat misleading. Negative-sequence currents have a frequency of twice the power system frequency in a positive-sequence reference frame (e.g., 120 Hz in a 60 Hz system). The phase-locked loop and current regulators used in many IBRs perform poorly when regulating such currents. Thus, the observed IBR behavior is often quite different from an ideal, infinite negative-sequence impedance. It is likely for many manufacturer implementations to exhibit a variety of unusual and distorted waveshapes during unbalanced faults [3].

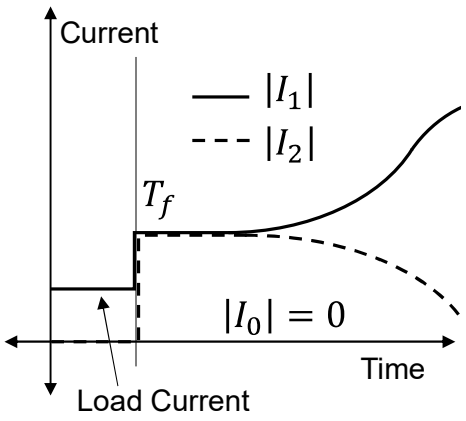


Figure 5: IBR response to unbalanced fault—negative-sequence current is initally present but is regulated to zero.

Some work has been done to modify existing protection to reduce its dependence on negative-sequence current [10] [8]. Meanwhile, some works propose improved IBR control strategies to regulate their negative-sequence current response [11]. Some converters now offer a constant impedance operating mode, wherein the converter produces negative-sequence current during unbalanced faults in a manner more similar to a traditional positive-sequence source (Figure 6).

Even though some IBRs are beginning to implement negative-sequence behavior such as that shown in Figure 6, this behavior is far from standardized. Even once standards (e.g., IEEE 2800-2022 [12]) are implemented by utilities and vendors, legacy IBR installations will likely need to be supported for some time (e.g., 20 years). In a distribution application, it will likely be impractical for a protection engineer to study the behavior of every IBR on the distribution network. Thus, protection schemes that are effective regardless of the converter's negative-sequence behavior are of great practical use for IBR-dominated systems.

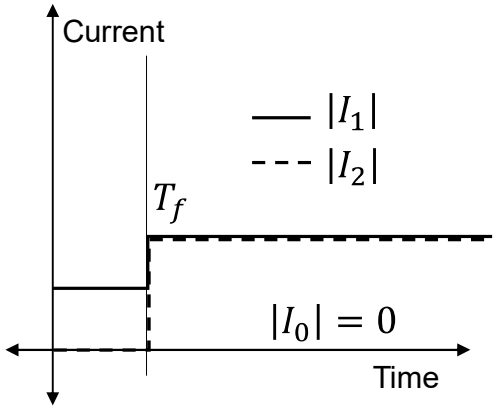


Figure 6: IBR response to unbalanced fault—constant impedance mode added to provide negative-sequence current.

2.1.4 High-Impedance Faults

A full discussion of challenges and solutions for high-impedance fault (HIF) detection is beyond the scope of this report, but a brief discussion is presented in this section due to the topic's importance.

Usually, when an energized component in the power system experiences a shunt fault (e.g., due to vegetation touching a transmission line), the additional resistance of any foreign object is generally negligible and can be treated as an ideal ground. Such faults are called bolted faults. However, some faults do have a significant resistive component. Small resistances (e.g., up to 10 Ω) are generally handled by the engineering margin built into existing protection schemes, with occasional amendments such as quadrilateral distance elements. However, faults with a high impedance (e.g., 10 to 100 Ω or more) occasionally occur and are of significant concern to utilities. Common HIF scenarios include a broken conductor that falls onto a concrete pad or very dry pile of soil or brush—soil and vegetation moisture content is a major factor affecting fault resistance [13]. HIFS are also generally of more concern at lower voltages, where the fault resistance is much closer to the load resistance.

HIFs are difficult to detect because in electrical terms, they have a small impact on the voltages and currents in the power system. However, they are extremely hazardous. Anyone physically near the site of an HIF is at serious risk of fatal shock. Moreover, HIFs are more likely during dry conditions where wildfire risk is high. Utility concern over this topic has only grown in response to the 2018 Camp Fire in California, which was sparked by a transmission line and resulted in the deaths of over 80 people [14]. Legislators judged utility Pacific Gas & Electric liable for the fire, with liabilities potentially exceeding $30B, bankrupting the utility. Thus, both ethical and fiscal incentives for utilities are extremely strong. This has led to the greater use of Public Safety Power Shutoffs, a policy by which electric utilities pre-emptively de-energize portions of the grid during times of high wildfire risk, only re-energizing once the lines have been inspected [15].

Even in traditional power systems, HIFs have long been an area of active research. Existing mitigation strategies include specialized grounding systems (e.g., resonant grounding) or algorithms that detect current signatures peculiar to arcs (e.g., high noise levels, interharmonics, and odd-numbered harmonics) [13]. Many of the theoretical approaches that have been more recently proposed for IBR protection (e.g., decision trees or wavelet analysis—see Section 5.0) have been previously suggested for HIF detection. However, these techniques have seen little industry adoption, and practical solutions generally take the form of proprietary algorithms

based on power quality metrics (e.g., [16]). Even so, these algorithms are known to be challenged by non-HIF sources of interharmonics such as arc furnaces and large, intermittent motor drive loads.

The presence of IBRs makes HIF detection more difficult, primarily because of the uncertainty they add regarding the signatures of currents flowing in the system. Inverters can produce harmonics and high-frequency noise, which can affect the performance of traditional HIF detection algorithms. HIF detection algorithms usually require some form of tuning to typical system behaviors and harmonic levels, which is made more difficult by the significant intermittency of DERs. That said, the proliferation of IBRs is also incentivizing the use of additional sensors and communications in distribution systems, which may help justify the wider use of more sophisticated HIF detection algorithms.

2.2 Operational Challenges

As frequently happens when a new technology begins achieving widespread adoption, significant and unexpected challenges have emerged following recent IBR installations. Starting in 2016 [17], the protection systems used in transmission-level IBRs have increasingly been the source of gigawatt-level interruptions in power generation during system disturbances [2]. Many of the observed operational challenges with transmission-level IBRs are applicable in distribution systems as well, making it useful to review them in this report.

Either by incorrect settings management, a misapplication of the study, or an unintended side effect of the inverter's signal-processing design, a significant quantity of transmission-level IBRs do not remain connected to the system during power system disturbances that they are required (by North American Electric Reliability Corporation [NERC] reliability standards) to ride through.

Figure 7 illustrates the voltage ride-through behavior required by NERC PRC-024 [2]. The region within the envelope of the orange lines is forbidden. For example, for an undervoltage that is below 0.9 per-unit and above 0.75 per-unit, generators are required to remain connected for at least 3 seconds. NERC found that roughly 2.2 GW of BES-connected solar farms violate this characteristic, tripping prematurely for under- or overvoltages.

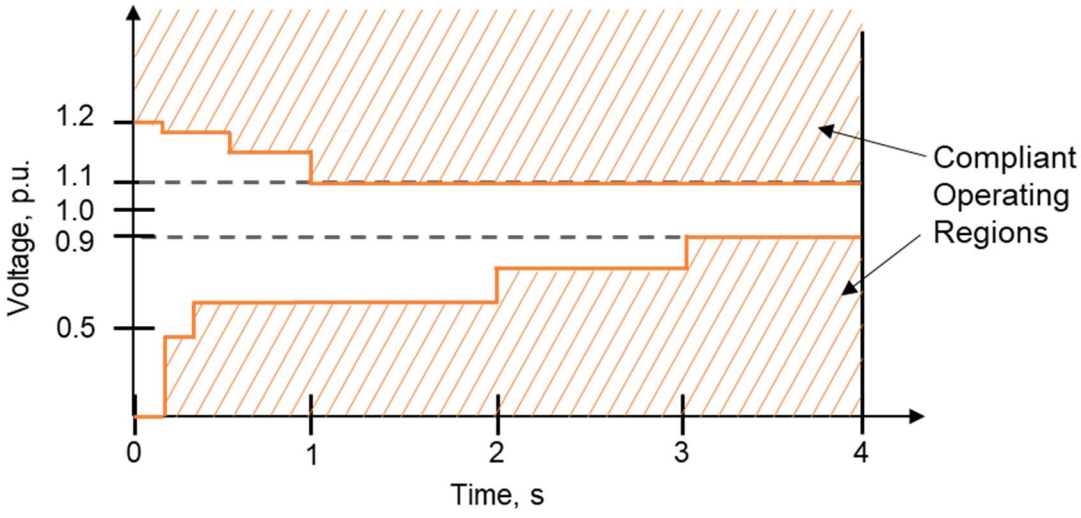


Figure 7: Voltage Ride-Through Behavior Required by NERC PRC-024 [2].

In addition to the significant quantity of generation that is noncompliant, a significant number of sites are set directly on the orange lines, meaning there is no engineering margin provided. In these cases, sensor errors or small differences in signal-processing design are likely to cause inconsistent compliance with ride-through requirements. Similar issues are present in the frequency ride-through data as well [2].

NERC is particularly concerned that the ride-through behaviors of these IBRs are being set "for compliance" rather than based on the IBRs' actual capabilities [2]. In other words, IBRs are not being configured to support the grid to their full capacity, even in scenarios where it does not impede the generation site's ability to generate revenue. As IBRs continue to proliferate, this will increase the overall cost of electricity because grid operators will need to install additional devices such as synchronous condensers and static VAR compensators in order to provide sufficient voltage and/or frequency support during disturbances.

Another issue that transmission-level IBRs are experiencing related to disturbance ride through is a delayed return to normal real-power product after a disturbance. NERC recommends IBR controls be set to resume operation within 1 second, which is well within typical IBR control capabilities. However, many IBR facilities do not follow this recommendation and are set in the range of 2 to 20 seconds, with some outliers being delayed as much as 300 seconds.

Many IBR performance issues are discovered only after the IBR facility has been studied, commissioned, and put into service. Given the rather basic nature of some issues (e.g., noncompliant settings), this raises questions about the accuracy and thoroughness of the model and test processes. In some field events, IBRs have exhibited dynamic performance that differs significantly from the vendor-provided models. In NERC's assessment, "these modeling errors are not minor issues regarding parameterization; they are vast modeling errors or gaps where the plant control modes and interactions are not captured with sufficient fidelity [18]." Groups such as the Western Electricity Coordinating Council Modeling and Validation Subcommittee (MVS) are developing improved models, and Pacific Northwest National Laboratory (PNNL) is involved in these efforts.[1] However, much work is still needed to develop trusted models and validate that manufacturer implementations reflect model behavior.

Reports of similar events in distribution-level IBRs were not found in literature. However, distribution-level IBRs are not subject to the same reporting requirements as transmission-level generation, and such information is less likely to be publicly available. The IEEE standard governing the requirements for DERs (IEEE 1547) does not currently require that distribution-level IBRs remain connected during system faults [19]. That said, some U.S. utilities are adopting measures that would require this support and have begun testing the fault-ride-through capabilities of distribution IBRs [3]. Initial results from these tests suggest that distribution IBRs are likely to exhibit emergent issues similar to those seen in transmission-level IBRs.

[1]PNNL members of the Western Electricity Coordinating Council MVS at the time of writing include Wei Du, Xiaoyuan Fan, and Slaven Kincic.

3.0 Industry Solutions for IBR Protection

Industry efforts toward protecting IBR-dominated systems have focused on exploiting recent advances in distribution automation and sensing technologies to make existing methods more flexible and economical.

In this section, a selection of industry protection technologies that have been commonly applied or recommended for use in IBR-dominated distribution systems is reviewed (Section 3.1). Some related technologies that play an important supporting role are reviewed as well (Section 3.2). Lastly, several real-world installations and case studies are presented to demonstrate how existing industry technologies are being put into practice (Section 3.3).

3.1 Protection Algorithms

3.1.1 Directional Overcurrent

An (non-directional) overcurrent element operates only based on the current's magnitude. Directional overcurrent elements also use the current's phase angle, usually in relation to some voltage measurement, to determine the direction of current flow. This results in greatly improved selectivity in multi-source systems, because a directional overcurrent can be set to only trip for faults in a single direction. As an example, consider the two-source system shown in Figure 8. Relays REL1 and REL2 are set using directional overcurrent and used to protect the line with impedance Z_L. The green arrows indicate which direction has been set as the relay's "forward" direction.

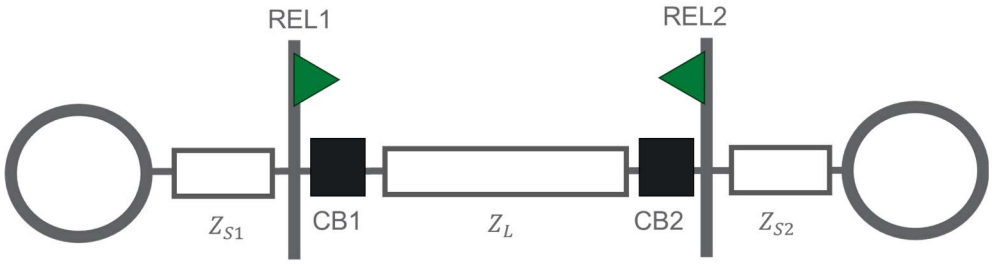


Figure 8: Placement of Directional Overcurrent Relays REL1 and REL2 to Protect Z_L.

A fault in Z_{s1} may have a fault-current magnitude very similar to a fault in Z_L that occurs close to REL1. However, the direction of the current flowing through CB1 will be opposite. In this way, REL1 can be set to only trip for faults that occur on Z_L or Z_{s2}. If communications are available, multiple directional overcurrent elements can be used to further improve selectivity. This is commonly done in transmission systems and is discussed more in Section 3.1.3.

As a reference for the measured current's phase angle, directional overcurrent elements primarily use negative- or zero-sequence voltages for ground or neutral overcurrent elements and positive-sequence voltage for phase directional elements. However, modern implementations have a great deal of supervisory logic intended to handle edge cases associated with close-in faults (which result in nearly zero voltage at the relay), untransposed lines, and resistive faults [20].

Directional elements also account for the fact that the main source of impedance in most short circuits is the impedance of the power system lines and transformers, and are therefore highly

inductive. The inner workings of this approach are quite similar to those underlying distance protection, which is the focus of the next section.

Directional overcurrent elements are a common choice when seeking to improve a distribution system's protection beyond simple TOC. Most modern relays that support TOC also support directional overcurrent, and no additional sensors are needed. Directional overcurrent can solve many of the challenges associated with IBR protection when combined with even very lightweight communications [11].

3.1.2 Distance Protection

A fundamental drawback of current-based protection is that it is based on both the location of the fault and the behavior of the source providing the current. This is particularly problematic in parts of the power system where the fault-current levels vary significantly depending on which generators and transmission lines are online. Distance protection, which is based on measuring the driving point impedance of the system as measured at the relay location, is much more robust against changes in fault-current levels. Distance protection can also be used to identify the location of faults on a transmission line with reasonable accuracy (i.e., to within several hundred meters), which provides valuable time savings during the restoration process. For these reasons, distance protection is the most common form of transmission line protection used today.

The basic operating principle of step distance is Ohm's law (Equation 3.1):

$$Z = VI \tag{3.1}$$

When no fault is present, the measured impedance is primarily determined by the load, which results in a relatively high impedance magnitude and a power factor close to one. When a short circuit occurs, the measured impedance magnitude is primarily determined by the series impedance of the power system equipment, which results in a low impedance magnitude and a power factor close to zero.

As discussed back in Section 2.1.2, distance protection is an appealing choice for IBR-dominated distribution systems because its operating principles are based on the electrical properties of the short circuit itself, rather than those of the source. For example, consider the application of distance relay REL1 to a traditional distribution feeder (left) and one where a current-limited IBR source is present downstream of the fault (right).

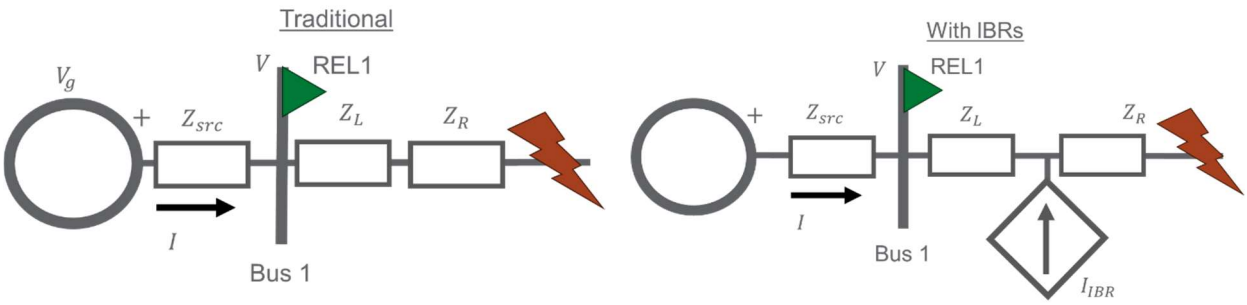


Figure 9: Sources of Fault Current in Traditional Distribution Systems (Left) and Those with IBRs (Right).[1]

Through inspection, we see that the impedance measured in the traditional system is $REL1$. The system with distribution IBRs is solved by transforming the Norton equivalent defined by I_{IBR} and Z_R into a Thevenin equivalent, from which Equations 3.2 and 3.3 are obtained:

$$I = \frac{V_g - Z_R I_{IBR}}{Z_{src} + Z_L + Z_R} \tag{3.2}$$

$$V = \frac{Z_L + Z_R}{Z_L + Z_R + Z_{src}} \left(V_g - Z_R I_{IBR}\right) \tag{3.3}$$

Dividing Equation 3.3 by 3.2, we obtain the expression for the driving point impedance (Equation 3.4):

$$Z = \frac{\frac{Z_L + Z_R}{Z_L + Z_R + Z_{src}} \left(V_g - Z_R I_{IBR}\right)}{\frac{V_g - Z_R I_{IBR}}{Z_{src} + Z_L + Z_R}} = Z_L + Z_R \tag{3.4}$$

Thus, in this somewhat idealized case, the presence of a current-limited IBR has no effect on the distance calculation of REL1. While many particulars have been simplified, this example illustrates how impedance-based protection is more robust in the presence of IBRs than current-based protection: the fault-current contribution of the IBR (I_{IBR}) reduces the current supplied by the substation source (I). Depending on the system impedances and level of IBR penetration, this could very feasibly result in overcurrent protection failing to detect faults further down the feeder.

Distance elements determine whether they should operate using a closed contour, defined in the complex impedance plane. If the measured impedance is within this contour for a specified time period, the distance element operates. The most commonly used characteristic is a mho circle (Figure 10). The mho circle provides good sensitivity and selectivity while being easy to configure and implement in firmware.[2] The line that defines the circle's diameter and orientation

[1]The IBR is shown as a current source here (rather than a voltage source) because it is assumed that Z_R is small enough to cause the IBR to limit its output current.

[2]Checking if a point lies within the circle can be done with a simple analytical expression using trigonometry.

about the origin has the same angle as the series impedance of the protected device.[1] In other words, faults in the protected device should, ideally, result in an impedance that lies directly on the line defining the operating characteristic.

Figure 11 illustrates the application of a relay protecting a line (Z_{L1}) with step-distance protection. Let m be a coefficient between zero and one, indicating the fault's location along the line.

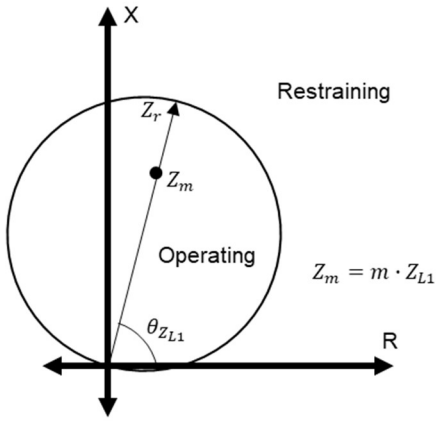


Figure 10: Operating Characteristic of a Mho Distance Element.

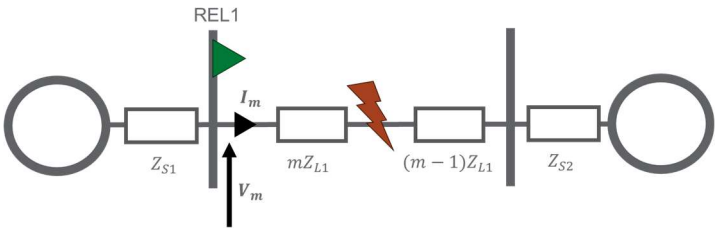


Figure 11: Single-Line Diagram of Network for Relay Protecting a Line Using Step Distance.

A fault occurring at location m causes the relay to measure impedance $Z_{L1} \cdot m$. In other words, the measured impedance provides an indication of how far down the line the fault is.

The width of the mho circle characteristic (Z_r) defines the furthest away fault for which the distance element will operate and is referred to as the element's "reach." Reach is usually described as a percentage of the protected line's impedance (i.e., 100% reach implies that $Z_r = Z_{L1}$). The concept of reach is used in transmission systems to provide communications-free backup protection.

For example, the relay shown in Figure 11 might have three different zones of reach, each with a different reach setting and time delay. It is common to set the first zone to have 80% reach and no added time delay. The second zone then has 120% to 150% reach and, say, 500 ms of time delay. The third zone then has 210% reach or more and 1,500 ms of time delay. The idea behind this arrangement is that faults are quickly cleared by the relay closest to them using Zone 1. Zone 2 and Zone 3 are present to provide backup protection.

Choosing a reach for Zone 3 is often one of the more difficult decisions in a protection study because other lines in the system might be shorter than the protected line. There is also a risk that the set Zone 3 might reach into the coverage of another relay's Zone 3, causing a race condition. However, modern transmission line protections often feature multiple layers of redundancy, which should act before a Zone 3 trip, and the actual operation of a Zone 3 distance element is an extremely rare and serious event. Zone 3 protection is often regarded as an emergency measure, intended to guarantee that a fault does not remain on the system—even at the cost of potentially tripping extra transmission lines unnecessarily.

[1]Ground distance elements use a compensation factor to account for differences in a transmission line's positive- and zero-sequence impedance.

The concept of reach is effective in transmission systems where the protected lines are long and relatively few. However, step-distance protection is seldom applied to distribution systems (regardless of whether IBRs are present). There are several reasons for this. The most basic is simply that distance requires both current and voltage to be measured—overcurrent protection does not require voltage measurements and is therefore cheaper. However, there are technical challenges as well.

Reach-based coordination is challenging in distribution networks because of how short distribution lines tend to be [21]; the difference between 80% and 120% reach in a distribution network may be only tens or hundreds of milliohms. Keep in mind that an impedance measurement is less accurate than a current- or voltage-only measurement because it is a derived measurement and inherits error from multiple sensors. Fault resistance is also a more significant factor at lower voltages because the system impedances tend to be lower. In fact, because system X/R ratios are lower at lower voltages, the mho characteristic (refer back to Figure 10) is more difficult to use. As the X/R ratio of the protected system decreases, the circle is tilted toward the positive real axis, which is the operating region for normal loads. This makes the distance element less secure.

These drawbacks do not mean that distance is entirely unsuitable for distribution systems—work has been done to show that distance protection is useful for protecting distribution systems with DERs [5]. However, the aforementioned drawbacks make it more expensive or even impossible to use in some situations.

For the sake of brevity, the operating principles of modern distance elements have been simplified here. Modern distance elements do not simply calculate the driving point impedance but use adaptive sensitivities and memory-based polarization logic [22] [23] to achieve much greater robustness than the naïve approach.

3.1.3 Current Differential

Current differential is a robust and widely used protection scheme that is based on Kirschoff's current law: all of the currents flowing into a protected device are measured and summed. In the absence of a short circuit, these currents generally sum to zero. However, if there is a shunt fault (i.e., an electrical connection between two objects that are supposed to be electrically isolated from one another), current will flow on this errant path and the measured currents will no longer sum to zero. Rather, they will sum to equal whatever current is flowing on this errant path. The nuance to applying this apparently simple concept in practice lies in accounting for erroneous sources of differential current such as measurement error, magnetic saturation, and shunt capacitance.

The most used form of current differential protection is the restrained differential, which is based on operating current (I_{OP}) and restraint current (I_{RT}). These two quantities are computed using Equations 3.5 and 3.6:

$$I_{OP} = K_1 \left| \sum_{n=1}^{N} I_n \right| \tag{3.5}$$

$$I_{RT} = K_2 \sum_{n=1}^{N} |I_n| \tag{3.6}$$

where:

- N is the number of terminals on the protected device.
- I_n is the complex phasor current measured on the nth terminal.
- K_1 and K_2 are constants that vary by manufacturer—these are not critical to the protection's qualitative behavior but generally convert the measured currents into per-unit quantities.

Operating current is also called the differential current and is ideally zero unless there is a shunt fault in the protected device. The restraint current is intended to serve as a quantitative measure of the overall current magnitude being measured. The overall current magnitude is closely correlated with erroneously measured operating current; this fact is used to make the differential protection more secure.

Most restrained differential protection uses a dual-slope characteristic such as the one shown in Figure 12.

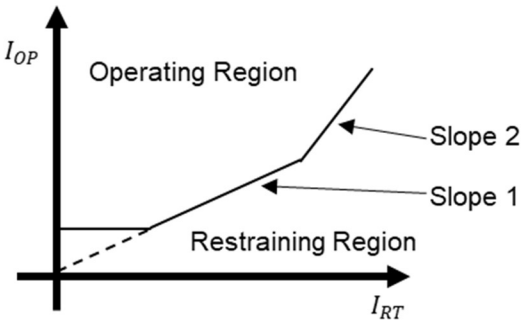


Figure 12: Dual-Slope Restrained Differential Characteristic

Observe that, as the restraint current increases, so does the amount of operating current required for the differential protection to operate.

The dual-slope characteristic uses a much more aggressive second slope (Slope 2) at high restraint currents, which is intended to provide security in the case of external faults that cause current transformer saturation. Other notable common features of differential protection include compensation for transformer winding connections and harmonic-based detection of transformer magnetizing inrush. The latter feature is used to prevent false tripping of the differential element during transformer energization.

Modern differential relays provide other implementations of a restrained differential such as an adaptive slope differential [24]. Other refinements include waveshape-based logic for fast detecting the magnetizing inrush that evolves into an internal fault [25], an alpha-plane current differential for a communications-based line current differential [26], and a negative-sequence current differential for sensitive detection of turn-to-turn faults in generators [27].

Conceptually, current differential is an appetizing solution for IBR-dominated distribution systems. Differential protection usually does not rely on source behavior to operate correctly,[1] and it is easy to understand how the protection system scales with network size and complexity.

[1]Practical exceptions to this include high fault currents that can cause current transformer saturation or low fault currents in systems where some branch currents are not measured.

If real-world constraints regarding cost and logistics are discounted, most power system protection problems can be reduced to simply breaking the system up into small subnetworks and applying current differential to each subnetwork. This is a useful point to keep in mind when considering the cost and complexity of a new protection approach—if a new approach has implementation requirements similar to those of current differential (e.g., high-speed time synchronization, measurement of all or most branch currents), then the approach is unlikely to compete with industry solutions in terms of cost.

In practice, current differential is generally a high-cost, high-performance solution. From the perspective of maintaining cost efficiency, distribution networks are particularly challenging, although digital substation technology is reducing these costs somewhat (Section 3.2.1). In the context of distribution networks, current differential protection has two important limitations:

1. The cost of using current differential increases significantly (compared to other protection methods) with the number of nodes and branches in the network.
2. Current differential protection does not provide backup protection for faults outside of the measured zone.

To better understand limitation (1), compare current differential protection to TOC protection. In a traditional protection system, a single current measurement, taken at the head of the distribution feeder, can often be used in conjunction with TOC protection to detect short circuits anywhere on the distribution arterial. To apply current differential, on the other hand, one must measure not only the current at the feeder head, but most of the lateral currents as well. A restrained differential (Figure 12) provides a security margin for allowing some lateral currents to be neglected, but the amount of margin available depends on the fault-current levels. In IBR-dominated distribution networks, fault levels are low and thus most of the lateral currents will need to be measured. This is also a serious issue from a measurement accuracy perspective—individual sensor errors due to calibration error, noise, time-synchronization error, etc. accumulate when the currents are summed together. In a system with high fault-current levels, this is accounted for by desensitizing the differential protection (e.g., increasing the minimum operating current and using a steeper slope on the restrained differential). However, this is a less feasible option in an IBR-dominated system where fault currents are near nominal.

Limitation (2) is a result of current differential's inherently selective operating mechanism—current differential protection is explicitly designed to avoid operating for faults external to its protection zone. Thus, a protection system that is entirely based on current differential is not very resilient—if a relay fails to protect its zone, relays protecting neighboring zones will not operate. Thus, it is necessary to supplement current differential with some backup protection of a kind other than current differential. However, it is acceptable for this other protection to be less selective.

One method to reduce the need for other protection elements to perform backup protection is to duplicate the entire current differential protection system (sensors, communications, controls, relays, etc.). However, not only is this prohibitively expensive, it also does a poor job of improving resilience compared to traditional distribution protection. Existing protection systems use either time- (e.g., TOC in distribution systems) or reach-based (e.g., step distance in transmission systems) coordination for backup protection. This verifies that, even if several protection system components fail, several other protective relays will operate. These approaches make sure that faults are detected even in highly unusual contingencies (e.g., $N-3$) and at low additional cost. Redundant current differential, on the other hand, doubles the cost

of the protection system but only allows the system to detect faults in contingencies up to $N - 2$.[1]

3.1.4 Traveling Wave Detection

Most protection elements are based on the lumped-parameter approach to power system modeling, in which the spatial distribution of components is disregarded and the physical propagation of electromagnetic waves is assumed to be instantaneous. Traveling wave (TW) protection elements differ in this regard because they operate by detecting the reflections launched from a short circuit when it first occurs. While this concept originated in the late 1970s [28], it has only been in the last 10 years that improvements in relay processing power and the invention of new signal-processing techniques have allowed this concept to become an off-the-shelf commercial product [29].

TW protection has two unique advantages compared to protection elements based on lumped-parameter models. First, TW protection is extremely fast—commercial TW protection can achieve detection times of roughly 100 μs [30]. Second, TW protection can provide extremely precise fault location (e.g., within 100 m, even on multiterminal lines [31] [32]).

In recent literature, there has been interest in applying TW protection to IBR-dominated distribution systems [1]. However, there are significant drawbacks to applying TW protection to distribution networks, as follows:

- The propagation velocities of electromagnetic waves in overhead lines and underground cables range from 50% to 100% of the speed of light. In short line segments (e.g., 10 km), this necessitates sampling at 10 MHz or more and operating based on less than 10 μs worth of data. These requirements are 10 times more onerous than those achieved by the fastest protective relay available today [33].
- Distribution systems have impedance discontinuities (e.g., laterals, arterial splits, voltage regulators, fuses, reclosers, etc.) at regular intervals. These discontinuities create additional reflections. The TW protection must be able to differentiate between reflection patterns in order to locate faults in real time.
- Because of the large number of impedance discontinuities present in distribution systems, a TW-based solution will need to process reflections to achieve selective operation. In field events on extra-high voltage (EHV) transmission lines, it is usually possible to measure two or three reflections following the initial propagation of the TW [31]. Distribution systems are more lossy than transmission systems. Thus, TW in distribution systems will be more attenuated and distorted, making processing of TWs more difficult.

Drawbacks (2) and (3) make assume that single-ended fault location is being used to some extent. However, this is a necessary assumption for TW protection to be remotely comparable to other protection methods in terms of cost: a TW-based relay can cost as much as 18 times more than a typical feeder relay [34] [35].

[1] Here, N is the number of component failures. There are feasible real-world scenarios where a single event causes multiple components to fail (e.g., a leaky roof exposes all the relays in a single equipment rack to water).

3.1.5 Pilot Protection

Pilot protection schemes combine traditional protection elements (e.g., directional overcurrent or distance), communications, and Boolean logic. Compared to traditional protection elements alone, pilot protection generally significantly improves protection system performance in all respects. The main downside of pilot protection is the extra cost of the communications. The most common use case for pilot protection is transmission line protection, where it is ubiquitous above 100 kV and fairly common at the sub-transmission levels.

Consider the simple distribution line shown in Figure 13. This line could be protected using traditional time-inverse overcurrent. However, pilot protection can provide much faster tripping. Let relays REL1 and REL2 be set with some sensitive directional protection (e.g., directional overcurrent or distance) that will detect any faults along the line. Without communications, this provides good sensitivity but poor selectivity. However, when used for pilot protection, REL2 can send a blocking signal to REL1 whenever it detects a forward fault, preventing CB1 from being opened.

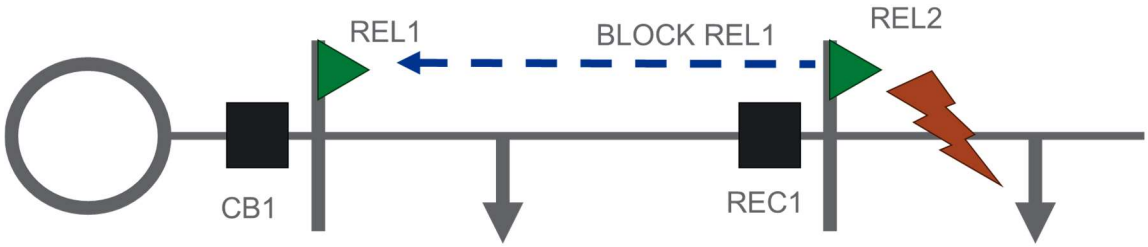


Figure 13: Use of Blocking Signal as a Basic Form of Pilot Protection

The example given in Figure 13 is known as a blocking scheme: the default behavior in the event of a lost or missing communication signal is for the sensitive protection to operate. The other option is a permissive scheme—REL1's sensitive protection might be instead set to wait for permission from REL2 before operating. In either case, some slower, time-coordinated protection is used as a backup. The terms permissive and blocking simply indicate the default behavior of the fast, sensitive protection that operates when no protection system failures are involved.

Permissive schemes tend to be favored at the transmission level, where tripping more slowly is preferable to taking assets out of service unnecessarily. Conversely, blocking schemes are favored in distribution schemes—it is preferable for some additional customers on a single feeder to experience an outage than to risk that an entire distribution substation will need to be tripped.

Directional comparison blocking (DCB) and permissive overreaching transfer trip (POTT) are two commonly employed pilot protection schemes. DCB uses either directional overcurrent or distance elements and is based on comparing directional indications from multiple terminals (e.g., Figure 13). POTT schemes use reach-based elements, such as distance.

In a POTT scheme, multiple distance elements with overlapping zones are set. Figure 14 illustrates the protection of a transmission line with impedance Z_L that could use a POTT scheme. Relays REL1 and REL2 both use distance elements set with a reach of 120%. This extra 20% margin allows for fault resistance, uncertainty in line parameters, and sensor error.

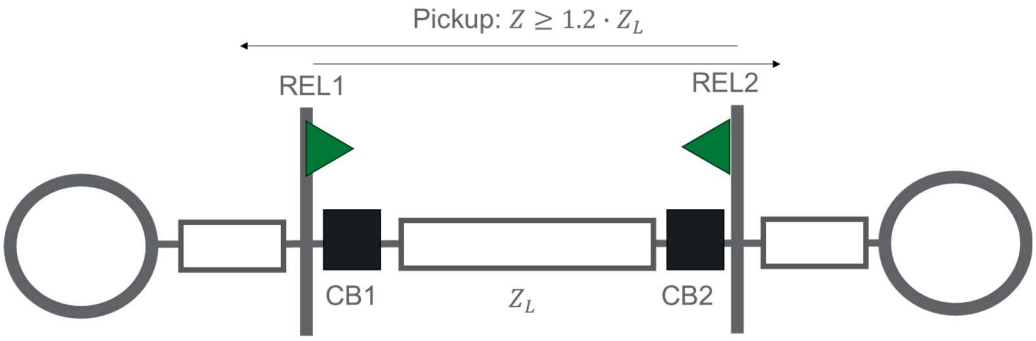


Figure 14: Use of Overlapping Distance Zones for a POTT Scheme

If either REL1 or REL2 detect a fault, they send a permission signal to the other relay. If one relay has detected a fault and has permission from the other, the relay trips its local circuit breaker. In such a case, the relay sends a trip signal to the other; this is the “transfer trip” portion of the POTT scheme.

If the relay does not receive a permission signal or a transfer trip, the relay then waits for a set time delay (e.g., 500 ms) before acting. This gives other relays in the system time to act in the event that the fault is indeed external but provides backup protection if the lack of communications is due to a communications failure.

Transmission-level pilot protection usually makes use of fiber optic communications installed along transmission towers, and the communication architecture is designed to provide redundancy through multiple fiber paths if the fiber on a particular tower is damaged.

3.1.6 Load Encroachment

At EHV, it is common for fault currents or impedances to have a magnitude that is relatively close to the load impedance magnitude. In such a case, a kind of supervisory element called load encroachment is used. Load encroachment uses the same underlying methodology as distance protection—the relay measures the system’s driving point impedance and compares it to a user-defined characteristic. However, instead of tripping a circuit breaker, load encroachment is used to block other protections from operating when an impedance within the operating characteristic is measured. Figure 15 illustrates a typical load encroachment characteristic—the hashed region indicates the ranges of load impedance that are expected.

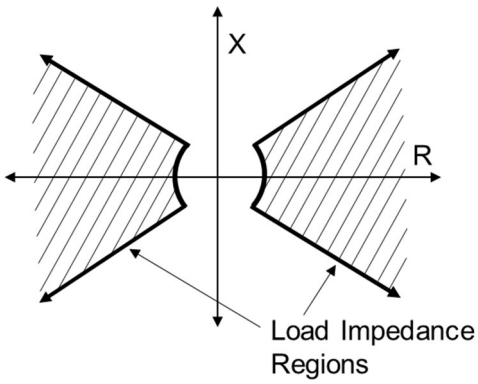


Figure 15: Typical Load Encroachment Characteristic.

Load encroachment is a very useful tool for improving the security of protection elements in fault-current-limited systems. Even if an IBR limits the fault-current magnitude, it does not alter the fact that the short circuit is far more reactive than typical loads.

3.2 Supporting Technologies

3.2.1 Digital Substations

Electric utilities are beginning to use networked communication protocols more, which has made it much more cost-effective to implement protection schemes involving cooperation between multiple protective devices. While not directly related to IBR protection, the changes occurring in the substation automation realm have been critical to enabling some of the IBR protection schemes that are in service today [11].

In a traditional substation, the role of communications in protection is relatively limited and consists almost exclusively of point-to-point connections. Control logic is primarily implemented using low-voltage DC (e.g., 125 V) connections of electromechanical relays and contacts. In a digital substation, almost all of these connections are replaced with networked communications.

Vendor-specific solutions for digital substations do exist, but industry has been pushing to adopt a central architecture and suite of protocols so that interoperability between vendors becomes achievable without extensive engineering. International Electrotechnical Commission (IEC) standard IEC 61850 covers these standard protocols [36].

Figure 16 illustrates a typical network connectivity diagram for an IEC 61850 compliant digital substation.

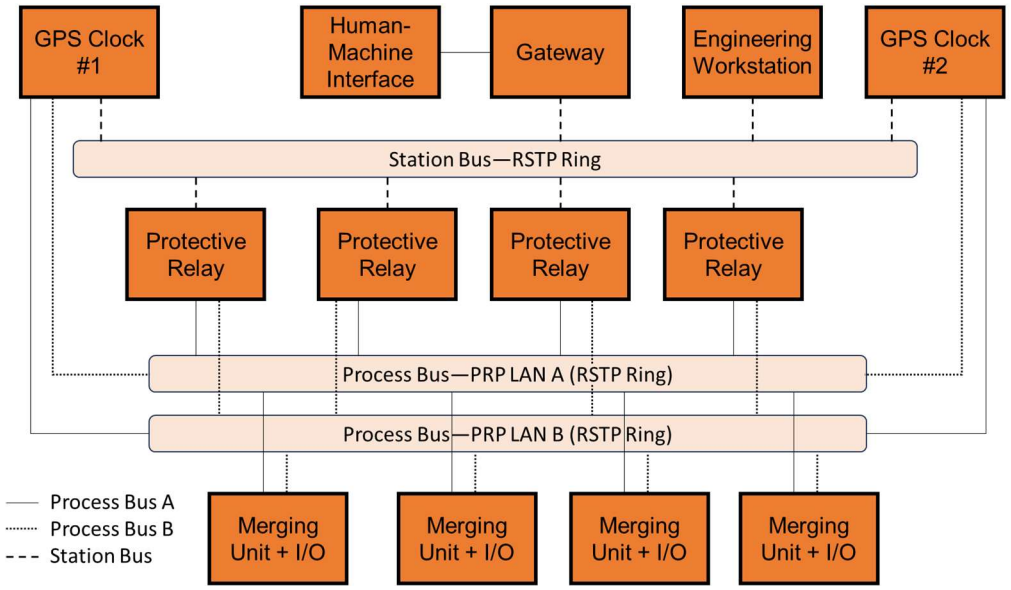


Figure 16: Network Connectivity of Devices Typically Present in a Digital Substation.

The station bus (top) is a network used for supervisory control and data acquisition (SCADA). This network supports external access to or from the substation and supports functions such as engineering access and operator controls. The station bus network is generally similar to the SCADA communications networks in place in many substations today. The process buses are unique to digital substations; they are redundant networks used to support the exchange of information between protective relays and merging units. Merging units are used to collect sensor data and publish it for protective relays. The relays then process measurements and take protection and control action as necessary.

Even with redundant networks in place, it is still considered best practice by some for protection functions to be directly implemented on merging units. In other words, the “Merging Unit + I/O” and “Protective Relay” blocks in Figure 16 are the same hardware. For example, a line protection relay would be used to measure line currents and voltages, and then also publish those measurements to the process bus for other relays to use. This confirms that, even if the substation network fails entirely, the protective relays still have the measurements necessary for backup protection.

Communications on the process bus generally have a latency of less than 5 ms, which is insignificant for most distribution protection applications. Measurements from different merging units are synchronized and timestamped using high-precision (e.g., 1 µs) time sources.

3.2.2 Distribution Automation

Utilities have received significant funding to upgrade their distribution systems in the last 20 years, and they have invested a significant portion of this funding into distribution automation. As with digital substation technology, distribution automation is not intrinsically related to IBRs. However, it has also played an important role in making it more economically feasible to use tools such as pilot protection in distribution systems.

Distribution automation generally involves adding more switches, sensors, and communications to a distribution network so that it can be controlled more flexibly and monitored more thoroughly. The primary goal of this additional control and monitoring is to speed up restoration (e.g., by allowing for automatic reconfiguration of the feeder or replacing a fuse with a remote-controlled switch) and reduce the number of customers affected by a given outage (e.g., by adding more switches and splitting the feeder into more protection zones).

Key devices for distribution automation (in the context of power system protection) include reclosers, sectionalizers, and fault indicators.

A recloser is essentially a light-duty circuit breaker that is primarily used to clear temporary faults and isolate permanent ones. Reclosers are generally pole-mounted and installed along the feeder arterial. They usually use TOC protection, coordinated with upstream protective relays and downstream reclosers or lateral fuses.

Modern reclosers are controlled using fully featured microprocessor protective relays (e.g., [38]) and can generally be treated as circuit breakers for the purpose of protection system design. Recloser controllers invariably measure line currents. Line voltage measurements are not always used but are commonly available. Recently, some recloser controllers have started supporting anti-islanding and ride-through functions as defined in IEEE 1547 [38]. This indicates some industry interest in performing DER control at the recloser level.

Total installation cost for a recloser varies from $75,000 to $150,000, depending on geographical location and the necessary current and voltage ratings [39] [40] [41].[1] Utilities will generally justify this cost based on how much of the lost revenue they can reclaim (in the form of reduced outages) or by presenting a rate increase case to the public utilities commission (e.g., “We will improve our reliability indices by a specified amount if you allow us to recover this much extra cost from consumers”).

[1]Cost data from this source has been adjusted for inflation due to its age (16 years).

A sectionalizer is a disconnect switch that has some automated opening capabilities. Sectionalizers are less flexible than reclosers and cannot interrupt fault currents but are generally two to three times cheaper [39]. Unlike recloser controls, sectionalizer controls are generally limited to simple current-based logic.

In addition to adding sectionalizers and reclosers, utilities have been adding remote-control functionality to many of the normally open (N.O.) disconnect switches present in distribution feeders. These N.O. switches are primarily used to provide customers with utility service from another substation or transformer if a portion of the feeder or distribution substation is out of service. Traditionally, these disconnects required manual operation by line crews, but many are now being motor operated and may have some SCADA connectivity. However, similar to sectionalizers, these switches are intended to be a lower-cost alternative to a recloser, and generally have limited or no protection-related capabilities.

As indicated in the discussion of disconnect switches and sectionalizers, there is still significant industry interest in affordable devices that can supplement or partially replace recloser functionality. Distributed current sensors and/or fault indicators are another popular option.

Traditionally, a fault indicator is small, relatively lightweight, and is hung on a distribution line or installed in a cable vault and uses overcurrent to detect faults. A fault indicator does not control any switches but provides a visual indication or radio signal when a fault has been detected. This indication is used by line crews during the restoration process to physically locate the fault more quickly. This is especially valuable for locating faults in underground cable systems where cable vault access is time consuming.

Fault indicators are drastically cheaper than reclosers (e.g., $300 each) and so are a cost-effective way to improve the selectivity of simple current-based protection. With the recently increased interest in distribution automation, fault indicators capable of integrating with protection systems during the fault (rather than simply aiding post-fault analyses) have become available [42].

Modern fault indicators provide a very affordable means for implementing simplified pilot protection schemes. Some practical examples included simplifying coordination in high-density recloser applications or blocking reclosing attempts for faults located on underground cable sections. Communication latencies for fault indicators are on the order of 10 ms and make it feasible to meet the speed requirements of distribution systems.

Modern fault indicators are a promising avenue for economical distribution protection for IBRs. However, they have some shortcomings. Fault indicators have no inherent directional capability; they use only simple overcurrent protection, do not measure voltage, and do not have the processing capabilities for any advanced logic or signal processing. This simplicity is what makes fault indicators so affordable. Thus, fault indicators are viewed mainly as a supplementing technology for IBR protection rather than the primary method for fault detection.

3.3 Real-World Installations and Case Studies

There are few reports documenting real-world distribution protection systems that accommodate high levels of IBR penetration. Existing installations of IBRs in distribution networks generally fall into one of two categories:

1. Traditional distribution networks where DERs simply disconnect during fault conditions and have no significant reported effects on traditional protection performance.
2. Facilities or small distribution feeders that support microgrid operation under the design and supervision of a single entity.

Systems in category 2 are of interest in this paper and the primary focus of this section—many microgrids are dominated or even supplied solely by IBRs. This is because, commercially, microgrid technology is frequently used to provide facility- or feeder-scale backup power when the utility source does not meet reliability requirements. Common reasons for this include the distribution network's criticality (e.g., a hospital or military base) or geographical factors (e.g., a town in a remote and/or economically underdeveloped region). In such a case, battery energy storage systems (BESSs) and renewable energy sources (wind, photovoltaic, and hydroelectric) are attractive alternatives or supplements to traditional microgrid generation (diesel generators or gas turbines). This is because they do not rely on fuel, which is logistically intensive to procure and maintain. Because modern BESS, wind, and photovoltaic systems are all IBRs, microgrid applications have been among the first to have to deal with the practical challenges of IBR protection.

3.3.1 Cape Cod Battery Storage Facility

The Cape Cod Battery Storage Facility is a recently designed microgrid that is entirely served by IBRs during microgrid operation and provides a useful illustration of the modern industry approach to protection in IBR-dominated distribution systems [11].

The Cape Code facility is a 38 MWh BESS installation that uses grid-forming inverters and serves approximately 11,000 customers [11]. The BESS can operate in both grid-connected and islanded modes and is expected to improve distribution reliability indices by a factor of roughly five. The local grid is a modernized distribution network with 17 reclosers in total (Figure 17).

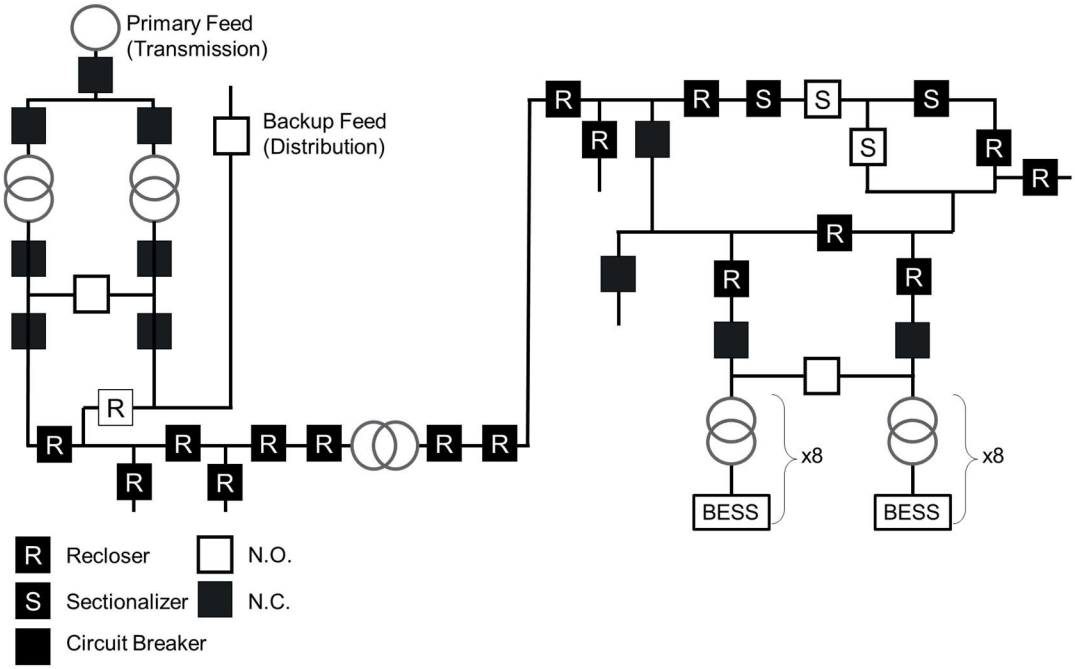


Figure 17: Single-Line Diagram of Cape Cod Distribution Network and BESS [11].

Nearly all of the technologies discussed in Section 3.1 were used in this project—directional overcurrent, pilot protection, load encroachment, and digital substation technology—and are all central to the protection scheme. Verifying the selectivity and performance of the scheme required detailed modeling in multiple electromagnetic transient (EMT) programs as well as hardware-in-the-loop testing involving the protective relays and BESS controllers.

While the modern protection, modeling, and testing practices used in the Cape Cod BESS were responsible for its success, they also represent a significant increase in protection system costs compared to a more conventional distribution system. In the case of Cape Cod, this cost is justifiable due to geographical difficulties associated with additional feeder construction and the reliability issues caused by weather conditions [11]. However, these are unusual conditions, and typical distribution feeders are unlikely to provide similar cost incentives.

The complexity of the interlock logic required for the Cape Cod BESS indicates that this approach is unlikely to scale to systems where generation is more distributed. Operator and designer knowledge of BESS status and operation was critical to the protection design process—designers created adaptive protection logic based on known BESS plant operating conditions. A typical distribution feeder with consumer-owned DERs is unlikely to have this kind of information available with the necessary reliability. All these factors suggest that industry's current approaches for protection in IBR-dominated distribution systems will result in massive cost increases when applied to DER-based distribution feeders.

3.3.2 Other Real-World Microgrid Protection

The Cape Cod BESS facility provides an example of modern distribution protection practices applied to an IBR-based distribution grid. However, there are numerous other real-world microgrid projects that have had their protection systems reviewed in literature [43]. Not all of these microgrids use IBRs, but even microgrids without IBRs can pose challenges related to multi-source distribution networks (Section 2.1.1).

Table 1 summarizes some approaches used or proposed for real-world microgrids. Observe that all the approaches either require costly communications infrastructure or are difficult to coordinate. In practice, a protection scheme that is difficult to coordinate is also costly—a large amount of engineering labor is required to identify settings that are coordinated, and additional supervisory logic must often be developed and tested.

Table 1: Approaches Used in Real-World Microgrid Projects and Their Drawbacks [43].

Approach	Drawbacks	Example Application
Directional overcurrent	• Requires complex coordination. • Can give incorrect directional indications for some IBR responses.	Cape Cod BESS, IIT
Current differential	• No backup protection for neighboring zones. • Requires high-performance communications. • Poor scalability with electrical network complexity.	BCI, IITT
Voltage-restrained protection schemes	• Difficult to coordinate. • Insensitive to high-impedance faults or high fault-current levels.	Borrego Spring

Approach	Drawbacks	Example Application
Adaptive overcurrent protection	• Requires complex logic to be designed for all system configurations. • Requires communications to monitor and update protection logic based on system configuration.	Boston Bar, Oncor & Irvine Smart Grid

In the current state of the art, microgrid protection consists of highly customized solutions, with no clear best practices that suit all cases. Much of this complexity transfers to IBR-dominated distribution networks as well.

3.3.3 Feeder Conversion Studies

Recently, several studies have been carried out to assess the coordination issues associated with converting traditional distribution feeders to IBR-dominated microgrids [44] [45] [46]. These studies have considered relatively small distribution systems (e.g., <50 nodes) having a low number of DERs (e.g., three). Figure 18 illustrates a simplified layout of protection devices for a real distribution feeder that was considered for conversion to an IBR-based microgrid [44].

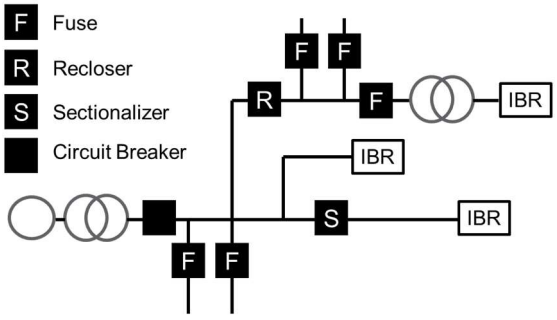


Figure 18: Single-Line Diagram of Distribution Feeder Considered for Conversion to IBR-Based Microgrid [44].

Researchers found that traditional protection or some of the simpler microgrid protection schemes could be effective in small distribution networks with simple topologies and a low number of DERs (e.g., the system shown in Figure 18). However, they also found that these techniques were unlikely to scale well to the size of modern distribution systems. Comparing the quantity of protection devices in Figure 18 to those present in the Cape Cod distribution system (Figure 17) clearly indicates that there are real-world applications in need of protection techniques that scale more effectively to more complex distribution systems having a high penetration of IBRs.

3.3.4 Southern California Edison IBR Fault Response Testing

In 2023, Quanta Technology, LLC and Southern California Edison (SCE) performed power hardware-in-the-loop testing of a variety of photovoltaic converters in order to evaluate their short circuit and grid ride-through responses [3]. As mentioned back in Section 2.1.4, California utilities are beginning to require distribution-level IBRs to provide grid support during disturbances. This will result in more IBRs remaining connected to the distribution grid during faults and thus make the issues discussed in Section 2.0 more likely to occur.

When discussing fault controls, it is common to categorize inverters as either smart inverters (which ride through system faults and provide voltage and/or frequency support) or legacy inverters (that try to participate in system disturbances as little as possible in order to protect themselves). Figure 19 qualitatively illustrates the difference in response between these two inverter control strategies to a single line-to-ground (SLG) fault.

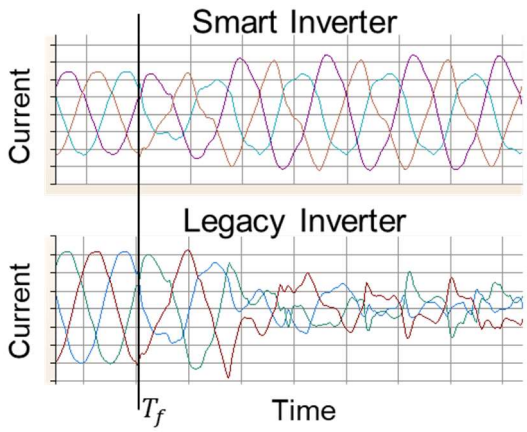


Figure 19: Smart vs. Legacy Inverter Currents During Single-Phase Fault.

Observe that the smart inverter increases its output slightly in response to the fault, whereas the legacy inverter currents are regulated to much smaller values. Neither inverter entirely succeeds in maintaining a sinusoidal output—this is due to the high level of voltage unbalance. More sophisticated controls than those used to generate Figure 19 can provide a less distorted output, but the general difference between controller strategies is unchanged, and the exact behavior varies by vendor.

The authors of [3] tested a range of inverters, and their findings correlated with the operational challenges described in Section 2.1.4. One of the tested smart inverters exhibited current-limiting behavior. However, the other smart inverter behaved abnormally, produced an unusual current waveform, and was deemed noncompliant with standards. This kind of issue is similar to those documented in NERC reports [2] and suggests that the operational issues seen in transmission-level installations (Section 2.1.4) are likely to occur at the distribution level as well.

The authors also found that TOC miscoordination issues did not occur in their system until the IBR capacity installed on the feeder reached 150% of the peak load. However, the system under study was a very small and simple feeder, and very few fault scenarios were considered. Thus, this finding is not necessarily generalizable to real distribution feeders.

4.0 Shortcomings in Industry Solutions

Industry has demonstrated that modern protection principles and communications technology have the performance required to protect IBR-dominated distribution systems [11] [43]. However, the resultant protection systems are far more cost- and labor-intensive to produce than traditional distribution protection. This is a serious barrier to the further proliferation of DERs in traditional distribution systems.

Industry challenges for protection in IBR-rich distribution systems can by summarized in three findings:

1. Evaluating protection system performance requires knowledge of IBR short-circuit behavior.
2. Evaluating protection system performance requires detailed EMT models.
3. Achieving coordination requires either high-speed communications (e.g., current differential) or complex and custom interlock logic (e.g., adaptive protection).
4. The decision to support microgrid operation contributes significantly to protection system cost and complexity.

Finding 1 is concerning because industry experience so far indicates that IBR behavior is inconsistent even at the bulk electric system level. Both the operational challenges for transmission-level IBRs (Section 2.1.4) and the variance observed in SCE's testing (Section 3.3.4) suggest that accounting for variances in IBR short-circuit behavior at scale is impractical in the near term. Some industry experts have come to this same conclusion [10]. Thus, there is a need for distribution protection schemes that are robust against significant uncertainties in source behavior. In transmission systems, this can likely be achieved using distance and traveling-wave based protection schemes [10]. However, as discussed in Sections 3.1.2 and 3.1.4, these approaches are ill-suited for distribution systems.

Finding 2 is concerning because EMT analysis is much more costly and time consuming to perform than short-circuit analysis. While EMT analysis has long been a tool used by protection engineers, its use has been confined to specialized transmission applications that can economically justify significant study (e.g., HVDC or series-compensated lines) [47]. Even aside from the significant training and software costs involved, maintaining and verifying an EMT model of a utility's entire distribution network will be an order of magnitude more expensive than the cost associated with the short-circuit models in use today. Thus, there is a need for distribution protection schemes that can be set selectively without the use of EMT models.

Finding 3 is concerning because these techniques scale poorly with network node count and DER penetration. Current differential scales poorly because each new branch in a protection zone requires a new sensor—this issue is exacerbated in IBR-dominated systems owing to the lower fault-current levels, which require that the differential element be set more sensitively. Adaptive protection scales poorly because it relies on a study of each possible system operating condition. The number of feasible operating conditions grows exponentially with the network size. Thus, there is a need for distribution protection schemes that do not require large-scale, high-speed communications or adaptive logic.

Finding 4 is not inherently concerning but suggests important topics for further research. Recent literature on protection of IBR-dominated distribution systems sometimes proceeds with the assumption that, if a distribution feeder has sufficient generation capacity to island, it should be

operated as a microgrid. Microgrid operation is desirable because it increases system reliability. However, as with all reliability-improving technologies, a cost analysis is necessary.

Most existing microgrid cost analyses focus on whether new generation should be installed, in which case the capital cost of the generation and distribution power equipment (e.g., circuit breakers and underground cables) becomes the primary source of cost [48] [49] [50]. Operating IBR-dominated distribution systems as a microgrid generally requires the addition of a BESS, which significantly hampers the microgrid's cost-effectiveness, even before considering the additional protection costs highlighted in this paper [49] [51]. Remote or difficult-to-reach power systems are a notable exception to this [11].

In further research on protecting IBR-dominated distribution systems, it would be helpful for researchers to more clearly identify how much microgrid operation increases the protection system's complexity (or decreases performance). In practice, it is reasonable to expect that many distribution systems will achieve a high penetration of IBRs without integrating the additional controls and energy storage systems needed for microgrid operation. Thus, there is still significant value to new protection schemes that accommodate high IBR penetration, even if they do not support microgrid operation.

Now that the industry state of the art has been discussed and important challenges identified, some performance goals for new protection schemes can be determined. These are listed in Table 2 and classified as either low, medium, or high priority. These goals were determined partially based on the findings from Section 4.0 and partially based on cost-related concerns that are common to all protection system designs. In Section 5.0, the new protection approaches proposed in literature are benchmarked against these goals. In Section 7.0, avenues for designing new protection schemes that better meet these goals are suggested.

Table 2: Goals for New Distribution Protection Methods and Their Relative Importance

No.	Goal	Importance
1	Higher speed than existing protection (e.g., 200 ms primary, 1.5 s backup).	Low
2	Reduce reliance on voltage sensors.	Low
3	Reduce reliance on lightweight communications.[1]	Medium
4	Reduce reliance on high-speed communications (e.g., current differential).	**High**
5	Uses relatively simple supervisory logic.	Medium
6	Requires minimal logic changes between applications.	**High**
7	Uses a predetermined list of setpoints once in service (i.e., new setpoints are not dynamically determined).	**High**
8	Computational burden comparable to modern protection algorithms.	Medium
9	Function in both grid-connected and islanded systems without change.	Medium
10	Eliminate reliance on EMT modeling to design.	**High**
11	Eliminate reliance on large datasets to design.	**High**
12	Maintain robustness against uncertainties in IBR response (e.g., fault ride-through, current limits, negative-sequence behavior).	**High**
13	Eliminate reliance on accurate (e.g., better than 10%) measurements or knowledge of network parameters.	**High**

[1]In this context, lightweight communications tolerate high latency (e.g., 50 ms) and use low bandwidth (e.g., >1 kb/s).
[2]In this context, high-speed communications require low latency (e.g., 1 ms) and/or time synchronization.

Some academic sources claim a need for fast (e.g., several milliseconds) protection in the distribution systems of the future [52], citing the need to protect distribution equipment against damaging fault levels. However, this claim is not reflected in industry literature and appears to contradict the fact that a transition to IBRs decreases fault-current levels, as discussed back in Section 2.1.2. While advances in communications and distribution automation could be used to increase speed, utilities instead use the solutions discussed in Section 3.0 to make their protection more selective [53], cheaper to build and maintain [54], and to reduce the duration and number of customers affected by outages [55]. Thus, improving protection speed is a low priority (Goal 1).

Foregoing the use of voltage measurements (Goal 2) is considered a low priority due to the relatively low cost of potential transformers, the wide range of useful functions provided by voltage measurements (e.g., power quality monitoring, synchronism check), and the importance of voltage-based protection in grids with significant current-source behavior.

Lightweight communications (Goal 3) add cost, but many vendors now offer relatively simple communications implementations [38] [56]. Even basic pilot protection can make some coordination issues much simpler, and communications provide other useful benefits such as increased operator awareness and quicker restoration times (because of a reduced need to physically visit devices to collect data from them). The main reason that the need for lightweight communications is seen as a moderately important drawback (as opposed to low importance) is because of the need for backup protection—there must be some reasonably performant option in the case of a communications failure.

High-speed communications (Goal 4) are a more significant drawback because they generally require more significant infrastructure (e.g., fiber-optics-based networks, GPS clocks, etc.) that is useful solely for the protection scheme.

Use of relatively simple supervisory logic (Goal 5) is beneficial because it reduces time spent designing, building, and testing the protection scheme. It also reduces the chances of user error. However, what is more important for a distribution application is that the protection logic is applicable to a broad variety of distribution systems (Goal 6). This is because many utilities rely on the use of internal design standards to make their designs homogenous across their service territory. This significantly reduces the time required to design, build, and test their protection schemes. Needing to pilot and test a complex new protection scheme is not a major drawback, as long as that same scheme can be repurposed for other systems without too much extra effort.

The use of dynamically determined (i.e., determined by the protective relay while it is in service) protection settings (Goal 7) is highly undesirable because of the large testing burden incurred. This is discussed more in Section 6.2.

Limiting new protection functions to those that can feasibly be implemented on existing protective relay hardware (Goal 8) is important to allow for timely adoption of DER technology. Hardware refreshes represent major costs for equipment manufacturers and consequently require very strong market pressures to justify them.

It is valuable but not imperative that new protection schemes are robust in both microgrid and grid-connected applications (Goal 9). Microgrid operation in IBR-dominated systems introduces other significant costs such as those associated with a BESS, and there will likely be many distribution systems where the reliability improvements associated with microgrid operation do

not justify the extra costs. Thus, there is still considerable value in protection systems that function well in IBR-rich distribution systems even if they do not support microgrid operation.

Goals 10 through 13 are all meant to obviate the need for design studies that will be vastly more costly and time consuming for an IBR-rich system than the studies used to design protection for distribution systems today. Even at the transmission level, industry leaders are calling for protection methods that are robust against uncertainties in source behavior [10]. Scalability and cost are vital concerns to utilities when designing distribution systems. Thus, reducing the effort required to apply a protection scheme to a particular distribution feeder is paramount from a practical perspective.

5.0 Theoretical IBR Protection Concepts

Industry solutions for protection of IBR-dominated distribution systems, along with their drawbacks, have been discussed. In Section 4.0, a collection of goals were summarized and assigned priorities. In this section, new protection approaches proposed in literature are surveyed, and a discussion of how well they meet the goals given in Table 2 is provided.

Much research on power system protection has focused on entirely new concepts for protection, and there has been significant interest in data-driven protection techniques (e.g., machine learning [ML] or optimization methods). These techniques are often paired with signal-processing techniques designed for analyzing signals that are compact in time, such as wavelet analysis, traveling-wave analysis, and the short-time Fourier transform.

Figure 20 gives an overview of industry solutions for IBR protection, as well as theoretical solutions, that will be discussed in the following subsections. A distinction is made between solutions that are currently largely theoretical and those that draw considerably from existing industry approaches. From a practical perspective, the level of development required (both in terms of research and modification of protective relay software and hardware) is lower for approaches that are not entirely theoretical. However, this does not necessarily make them more promising for further research—PNNL's findings on future research opportunities, as well as an evaluation of all the approaches shown in Figure 20, are given in Section 7.0.

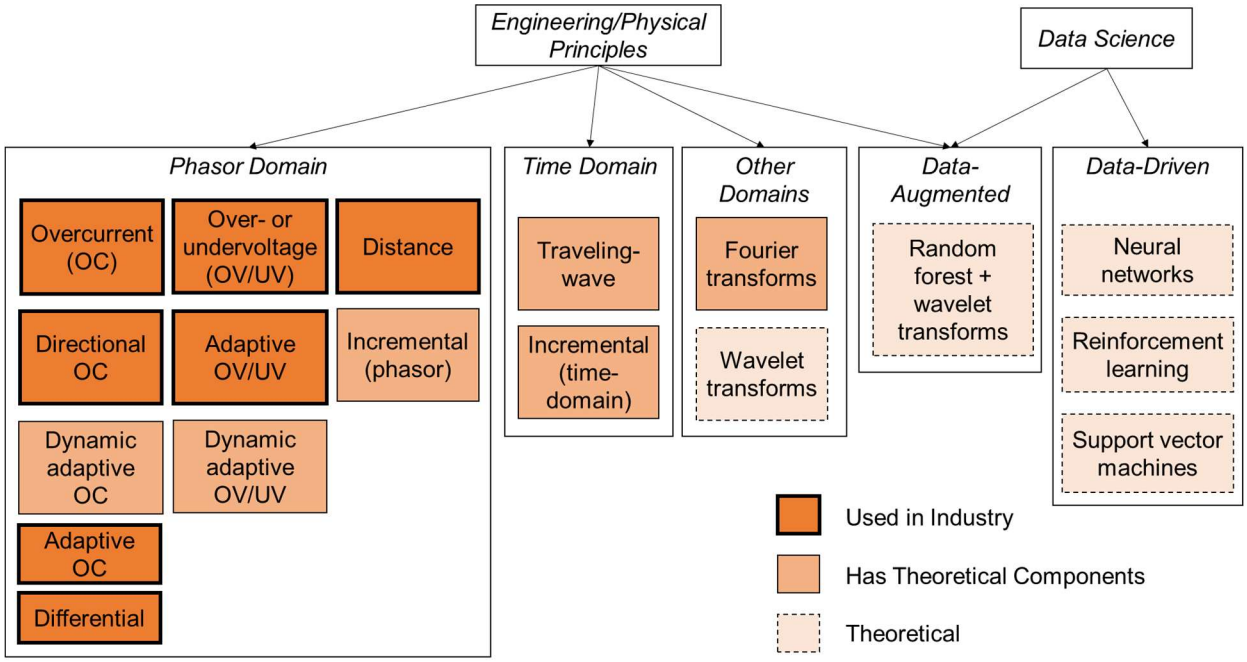


Figure 20: Overview of Distribution IBR Protection Approaches.

In the following subsections, the protection approaches not currently used in industry are introduced and discussed.

5.1 Dynamic Adaptive Protection Elements

Adaptive protection, in its basic form, refers simply to a protection scheme that varies its logic based on system conditions, such as whether the distribution network is operating in grid-connected or islanded mode. This is commonly done in industry for microgrid protection (refer back to Table 1). However, this approach requires custom logic and a detailed coordination study for each distribution system it is applied to. As a potential solution to this issue, some researchers have proposed adaptive protection approaches wherein the protection settings and logic are automatically determined by an optimization [57] [58] [59]. This approach is referred to as dynamic adaptive protection in this report to distinguish it from the approach currently used in industry.

In [57], researchers developed a dynamic adaptive protection scheme based on TOC protection and multiagent system (MAS) control. High-performance computing resources are used at the central processing level to perform real-time (~100 ms) optimization of TOC settings. In order to support this communication scheme, all protection devices use high-speed communications via IEC 61850. However, the authors do not consider the use of this communications channel for industry-standard protection techniques such as pilot protection. Rather, the MAS control is used to compute TOC curves. The proposed approach provides selective protection at a speed comparable to traditional TOC protection.

A significant amount of research on dynamic adaptive protection has been done [1] [60]. Other recent work for dynamic adaptive protection involves optimizing directional overcurrent settings based on DER status [58] and extending problem formulation to consider additional factors such as phase unbalance [59]. Dynamic protection schemes have been designed using many of the optimization algorithms commonly applied to power system problems such as genetic algorithms, particle swarm optimization, and mixed-integer programming [1]. Optimization with respect to protection system speed, operating costs, and the number of relays has been considered.

Dynamic adaptive protection research generally assumes that high-speed communications and time synchronization are used. Some dynamic adaptive protection research claims that communications-aided protection for distribution schemes will require latencies of 20 ms or less [60] [61], citing a need for distribution systems to isolate fault currents within 100 ms. Modern high-speed (magnetically actuated) distribution circuit breakers take up to 50 ms to interrupt a fault [62]. At a requirement of 100 ms fault interruption time, this leaves 30 ms for fault detection. This is an order of magnitude smaller than values reported in real-world protection systems, even in microgrids with high penetrations of IBRs [11] [43] [55] [44] [45] [46]. In real-world distribution systems, fault detection times of 500 ms or more are regularly tolerated to verify reliable and selective protection.

5.2 Protection Elements Based on Short-Time Transforms

Phasor-based protection essentially operates on a power system signal's frequency component. Considering a power system signal's full frequency spectrum provides more informational content but is seldom used for fault detection. This is because transient disturbances, such as the incidence of a fault, are not compactly represented in the frequency domain. This makes it difficult to design effective protection algorithms. As a solution to this, researchers have proposed the use of short-time transformations, such as Fourier transforms and wavelet transforms, to create features more suitable for fault detection.

The most basic variation of the Fourier transform researched for protection systems is the short-time Fourier transform, but most research focuses on the use of wavelet transforms. Wavelet transforms are similar to the Fourier transform in that they decompose a signal into orthogonal components by projecting the signal onto a series of basis functions. However, wavelet transformations may use any of a wide variety of basis functions. Most of these basis functions have a high crest factor, and thus yield high coefficients for step changes. For this reason, using wavelets to remove noise from a signal (e.g., an image or audio) is a common signal-processing technique [63].

Figure 21 illustrates the wavelet coefficients (bottom plot) produced using a Daubechies-4 mother wavelet in response to a simplified fault-current waveform (top plot). Observe that the different wavelet coefficients all tend to produce a maximum around when the fault occurs. A sampling rate of 10 kHz was used, and the signal has a signal-to-noise ratio of 50 dB.

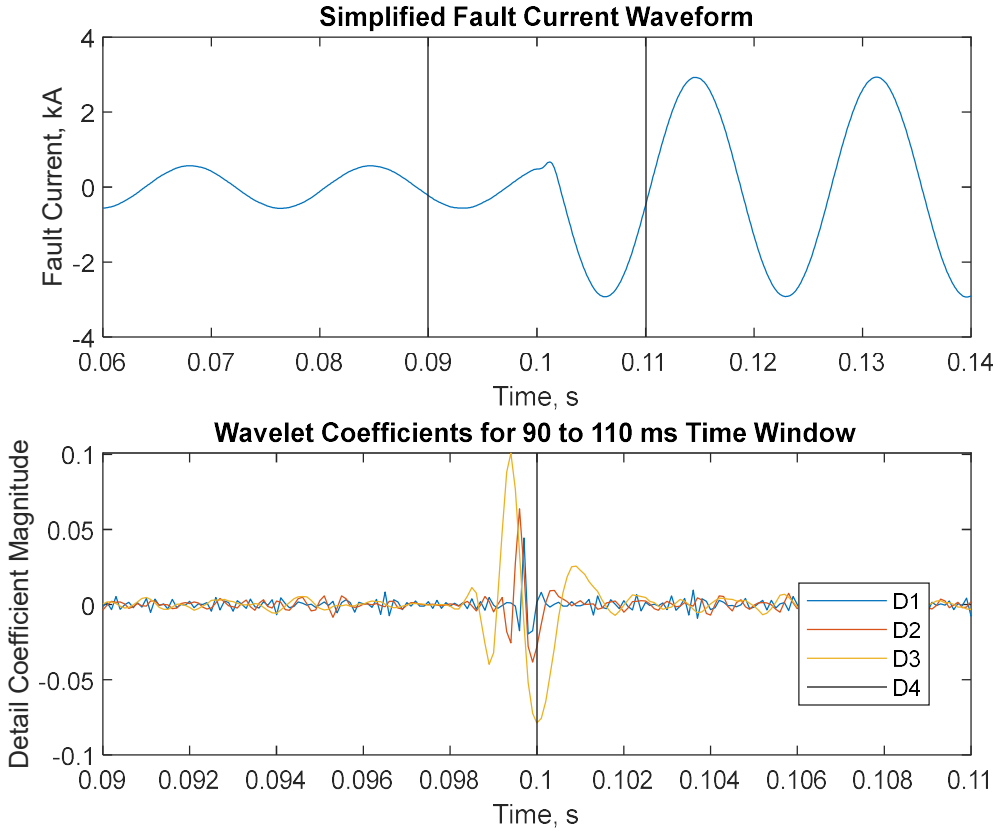


Figure 21: Exemplar Fault-Current Waveform and the Wavelet Coefficients it Produces for a Third-Order Daubechies-4 Mother Wavelet.

Wavelets are effective at identifying and extracting both noise and step changes such as faults—the difficulty lies in distinguishing between the two. Wavelet transforms generally consider a wider bandwidth than phasor-based protection and can issue false positives in response to normal switching operations or external faults. Potential solutions to this problem include a combination of pilot protection [64] and directional logic [65].

While short-time transforms were primarily used in combination with more traditional protection logic in the early 2000s [64] [65], more recent work has used these transforms primarily to

generate features for use in data-augmented protection schemes for microgrids [66] [67]. This is discussed more in Section 5.5.

5.3 Protection Elements Based on Incremental Quantities

Protection elements based incremental quantities (also called superimposed quantities) were originally conceived of in the 1970s but have become available in commercial protective relays [68] [35]. These elements were originally discussed alongside TW-based protection as an option for high-speed transmission line protection. However, unlike TW-based protection, incremental quantities are well-suited for use in distribution systems.

A time-domain signal, $x(t)$, is transformed into an incremental quantity, $x_\Delta(t)$, by taking the cycle-to-cycle difference according to Equation 5.1:

$$x_\Delta(t) = x(t) - x(t - T) \tag{5.1}$$

where T is the reciprocal of the system frequency.

The signal $x(t)$ is generally filtered to a maximum bandwidth of several kilohertz to mitigate the effects of transients involving parasitic capacitances. Incremental quantities can be used to design selective and sensitive directional protection that overcomes some of the limitations of phasor-based protection such as directional overcurrent or step distance [8].

Some work has been done to study the suitability of incremental quantities for microgrid protection [4] [69] [8]. These approaches commonly operate based on incremental negative-sequence impedance (Z_Δ^-), which is computed using Equation 5.2:

$$Z_\Delta^- = \frac{V_\Delta^-}{I_\Delta^-} \tag{5.2}$$

where V_Δ^- is the incremental negative-sequence voltage and I_Δ^- is the incremental negative-sequence current.

This relatively simple operating quantity combines characteristics of several different traditional protection elements in a way that has many benefits for IBR-rich distribution networks. Similar to step distance, Z_Δ^- provides good immunity in the case of low fault-current levels. Being an incremental quantity, the element is robust in cases where either the current or voltage are low before or during the fault. It also provides good immunity to uncertainties in the negative-sequence behavior of any IBRs in the network.

The Z_{Δ}^{-} element provides a directional indication, and Figure 22 illustrates the operating characteristic used to make directional declarations. The angle and boundaries of the reverse fault region are determined using system studies. The authors of [8] use a detailed EMT model. However, the large security margins available suggest that it could be feasible to design a methodology based on a sequence-domain model.

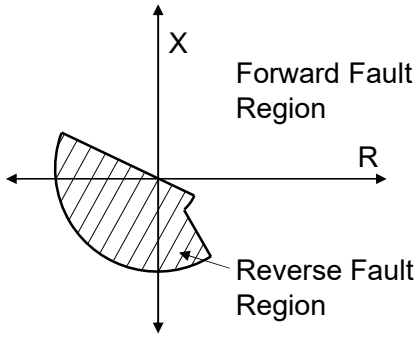


Figure 22: Directional Characteristic for Z_{Δ}^{-} Protection [8].

A Z_{Δ}^{-}-based protection is unsuitable for three-phase faults because negative-sequence quantities do not produce a reliable directional indication in such cases, so modification is required. The authors of [8] propose a solution based on the positive-sequence incremental impedance (Z_{Δ}^{+}) and several quantities from traditional directional elements. However, the resulting logic is relatively complicated. Given the comparatively simple dynamics of balanced faults (to unbalanced faults), it is reasonable to posit that a simpler logic could be developed.

Interest in the Z_{Δ}^{-} concept has continued. Recent contributions include addition of time-coordinated backup protection [70] and pilot protection [69]. New works frequently introduce novel variations on the Z_{Δ}^{-}, but there is still room for important research to be done in the space of establishing the concept's ability to meet the important goals highlighted in Section 4.0.

5.4 Data-Driven Protection Elements

A significant amount of research has been done on the topic of applying data-driven methods such as ML to the detection of power system faults [1] [71]. Given the availability and thoroughness of recent literature reviews, the review given here is brief.

Most modern ML and statistical tools have been applied to the problem of power system protection including hidden Markov models, many kinds of neural networks, reinforcement learning, support vector machines, decision trees, data clustering, and naïve Bayes [72] [73] [74]. Authors generally use synthetic data that was created using a detailed EMT model and use datasets consisting of several thousand events, although some approaches have been validated with real-world data [72]. Accuracies of up to 99%[12] for moderately noisy datasets are reported [75] [72].

A good demonstration of an ML-based solution is one for busbar protection that was published in 2016 [75]. The authors considered a three-terminal bus zone (Figure 23). Buses of this kind are usually protected with restrained current differential.

[1]The datasets used are generally too small for authors to claim greater than 99% accuracy; outcomes of 100% accuracy are not unusual but may indicate a dataset too small to sample the error rate accurately.
[2]Some accuracies above 99% were observed in the complete absence of noise. However, even relatively low levels of noise were shown to degrade performance for the studies in which it was considered.

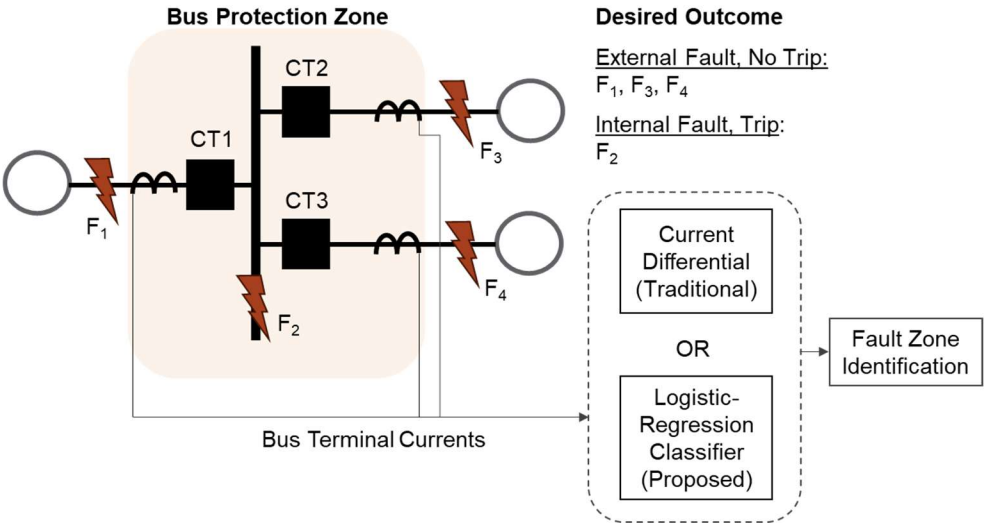


Figure 23: Test System Used for Designing ML-Based Busbar Protection [75]

The authors' motivation for ML-based protection is a security issue related to current transformer (CT) saturation. At high currents, CTs can enter magnetic saturation, which results in a significant portion of the CT primary current flowing through the CT magnetizing branch instead of the CT secondary winding (which is connected to the protective relay). This can cause false tripping in differential protection. This challenge is particularly common in bus protection because external faults typically cause one terminal to measure far more fault currents than the others. For example, in Figure 23, a fault at F_1 will cause CT1 to measure significantly more current than CT2 or CT3. Thus, there is a risk that a fault at F_1 will cause CT1 to saturate and cause an incorrect current differential trip. This is an established industry challenge, and commercial solutions are available (e.g., high-impedance current differential protection [76]).

A synthetic dataset of 38,400 fault events was generated using an EMT model of the system shown in Figure 23, 9,600 of which were used for training (the remainder are used to test the performance of the trained model). The goal for the ML algorithm was to determine whether a fault was internal or external. The authors used a single cycle of 1 kHz data—this is a good approach because it allows for typical protective relay data acquisitions to be used and allows for a reasonably fast detection time (23 ms).

A binary logistic regression (LR) classifier is used to distinguish between internal and external faults. LR is a well-established statistical model that is used to estimate the probability of one event (from a finite set of options) occurring [77]. The authors also implemented a multi-layer perception (MLP) model and a state vector machine (SVM) model as a basis for comparison.

The LR obtained an accuracy ranging from 99.6 to 99.91% without noise; performance primarily depended on the source impedances and fault connection. There was no intuitive reason or explanation for the variation with respect to source impedance. Performance was worst for SLG faults and best for three-phase faults. This makes sense because a three-phase fault strongly affects currents in all three phases, whereas an SLG fault affects the current in only one phase.

The MLP and SVM models achieved accuracies of 95.64 and 96.23%, respectively. However, others have obtained classification accuracies of over 99% using vector-machine-based approaches for similar studies [78]. It is not clear whether these different outcomes are

indicative of inherent limitations in the kind of classifier used or are caused by variations in implementation (e.g., selection of kernel and activation functions).

The authors did test the performance of a laboratory prototype data acquisition system (20 cases in total). However, feature construction and classification was done offline in postprocessing. Thus, this hardware prototyping did not address challenges related to realistic noise and sensor accuracy or real-time processing.

5.5 Data-Augmented Protection Elements

The protection approaches given in Section 5.4 involve little engineering analysis of the system under study and rely almost entirely on an ML algorithm to characterize the relationship between the measured signals and fault circuit type and/or location. In this sense, these approaches are data driven. However, there are other approaches that implement tools from data science while still relying on an understanding of the system's physical behavior and producing a human-understandable protection algorithm (i.e., not a black box, such as a neural network). These approaches are referred to as data-augmented, rather than data-driven. As will be discussed, a data-augmented approach circumvents many of the drawbacks associated with data-driven protection design. There is also some evidence to suggest that it can offer comparable or better performance.

Existing literature on data-augmented protection system design is limited. It mostly consists of using simple wavelet transforms and sequence components to generate features and then applying random forest classification to produce protection logic. The authors of [66] demonstrated a microgrid protection scheme where wavelet transforms are used to derive features based on energy, entropy, and variance. Decision trees (DTs) are used for fault detection and classification (Figure 24).

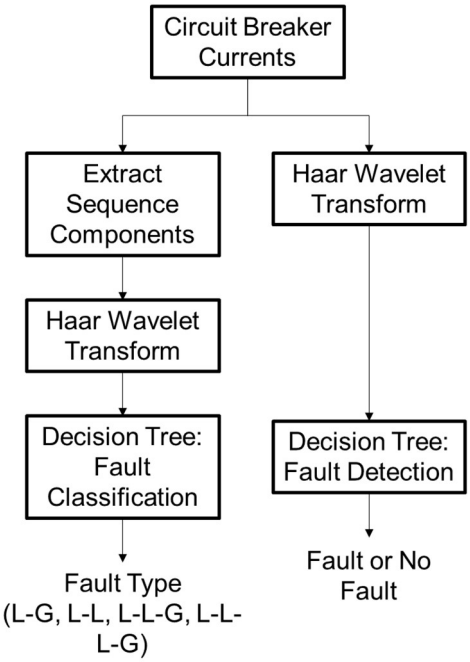


Figure 24: Application of Wavelet Transforms and DTs for Fault Detection and Classification [66].

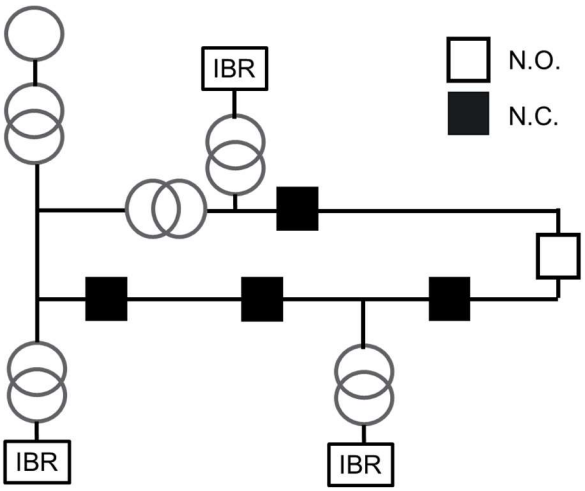


Figure 25: Test System Used to Evaluate Protection Performance [66].

The proposed scheme is solely based on local current measurements (e.g., CB4 tripping is determined only based on the currents measured by R4). Data is sampled at 6.66 kHz, which is within the sampling capabilities of modern commercial protective relays.

The proposed scheme uses the Haar wavelet, which defines a basis of relatively simple square waves. This generates relatively simple features that are easy to predict and interpret—each wavelet coefficient can be related to a specific frequency band. The energy, Shannon entropy, and standard deviation of the wavelet coefficients are computed. These result in useful features that have clear physical and statistical links to system events, which is invaluable for studying the algorithm's robustness.

DTs are used both individually and collectively in the form of random forests (RFs). DTs and RF classifiers provide much better transparency in their decision-making than models such as neural networks. Figure 26 illustrates a portion of the DT produced for fault type classification (e.g., SLG fault vs. three-phase fault). The features used in the tree are derived by taking the energy, entropy, and standard deviation calculations and applying them to both phase- and sequence-domain quantities. For example, $\Delta E(I_0)$ is the cycle-to-cycle change in the energy of the zero-sequence current.

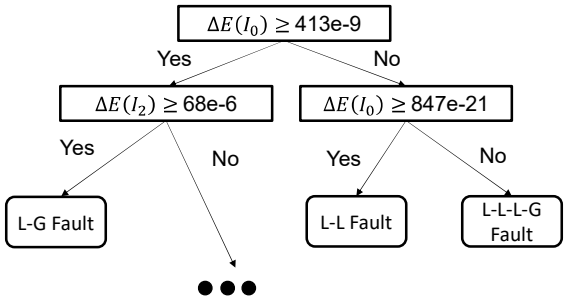


Figure 26: Portion of Decision Tree for Fault Classification [66].

Observe that $\Delta E(I_0)$ is used to distinguish between faults that involve significant ground currents and those that do not. Furthermore, observe that a very small value of $\Delta E(I_0)$ is being used to distinguish between line-to-line (L-L) and three-phase faults. In the simplified models traditionally used for fault analysis, L-L faults are said to produce no zero-sequence current. However, unbalances in more detailed power system models (primarily in lines and cables) do result in some coupling between sequence networks. This could explain why the DT is using zero sequence to differentiate between L-L and three-phase faults. However, given that this behavior is highly dependent on cable and line construction, it also suggests that this particular part of the DT is less likely to be robust against uncertainties in power system parameters. One way of solving this issue is to use many DTs, which is the basis of RF classification. However, the ease with which the DT can be analyzed (as just demonstrated) suggests that DTs are a powerful protection system design tool, even for applications where the final protection scheme is not necessarily intended to be an RF or DT.

Interest in the combination of wavelet analysis and RF classification has continued and even been shown to outperform more black-box methods such as SVM in some cases [79]. For example, RF classification has been shown to be orders of magnitude more robust than SVM in the presence of noise. While there is still significant work to be done in order to meet the goals identified in Section 4.0, the transparency offered by simple wavelet functions (e.g., the Haar wavelet) and DTs provides a promising framework for refining the RF-based approach for easier design and testability.

6.0 Limitations to Theoretical Protection Concepts

Many of the protection approaches discussed in Section 5.0 fail to meet several of the most important goals identified in Section 4.0. These drawbacks primarily relate to complexity, testability, data availability, and reliability. For some approaches (primarily dynamic adaptive protection and black-box type data-driven approaches), these limitations are inherent in the methodology. Yet for others (primarily methods that combine short-time transforms and white-box data-driven methods as well as methods based on incremental quantities), there are significant opportunities for improvement. For these other methods, there are promising paths open for further research.

6.1 High Design Complexity Reduces Reliability

For approximately the last 100 years, reliability has continued to be the most important goal for those who design and apply protective relays [80] [81] [82]. Moreover, for two protection schemes that meet protection system requirements, the more complex of the two is inherently the less reliable [81]. Despite this important relationship, the surveyed approaches paid little explicit attention to mitigating the complexity of their proposed implementations.

Industry leaders have found that protection systems have become exponentially more complex over the last 100 years (Figure 27).

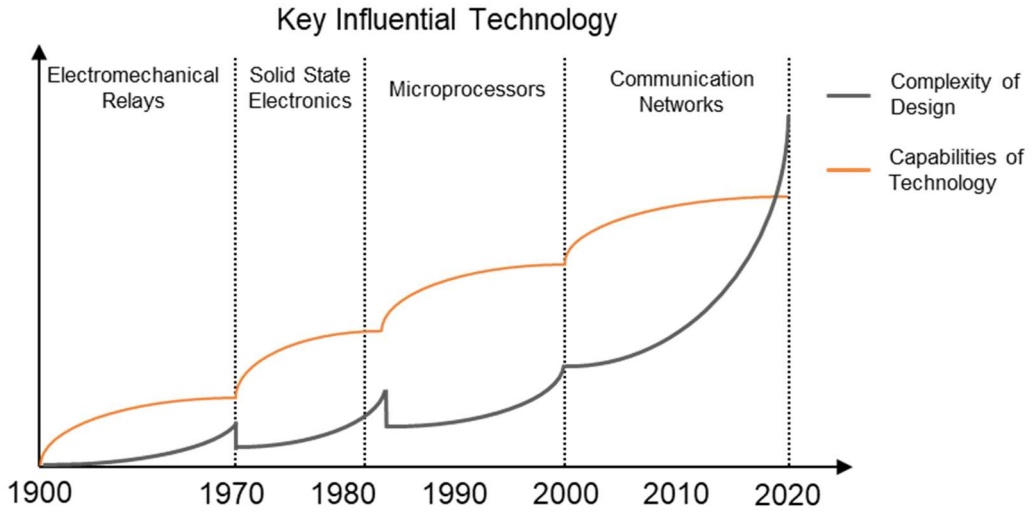


Figure 27: Industry Assessment of Complexity and Technology Development for Power System Protection [81].

This growth in complexity has been somewhat kept in check by advances in technology that make existing solutions easier to apply. However, recent advances in protection system communications (primarily digital substation technology) have shown a concerning potential to significantly decrease protection system reliability [81].

In the surveyed literature, new approaches seldom considered increased complexity as a drawback. For example, authors might present one or two simulations showing a commercial solution misoperating and claim that a better approach is needed. However, little consideration is given to the fact that the complexity of the proposed approach requires order-of-magnitude

increases in modeling, testing, and hardware performance. While it is not expected that experimental research provides solutions for addressing this complexity, it should be considered whenever authors claim that their algorithm is promising for practical use with today's technology. In the case of purely data-driven approaches, comparison with existing solutions sometimes involves an implementation of the existing solution that is too simplified to provide a realistic indicator of performance [66]. In other cases, a data-driven solution is shown to be feasible but consideration is not given to whether basic engineering principles could also work [54] [74].

6.2 Compatibility with Industry Design and Test Requirements

The significant effort required to design and test the protection scheme is a major issue associated with most of the new protection approaches reviewed in this paper. In particular, dynamic adaptive protection and data-driven protection appears to be significantly limited in this regard.

One factor that is frequently overlooked when considering the transparency of data-driven protection elements is its importance to mechanisms relating to engineering ethics. Protection systems are in place not solely to protect electrical equipment but to protect utility personnel and the public as well. Thus, when a protection system is installed, the utility must be willing to accept responsibility for the protection system's actions. In the event of a fault or outage, the utility must be able to explain and justify the protection system's actions. This is important evidence when regulating bodies evaluate legal liability and corrective actions in the wake of serious events such as wildfires. Transparency in the operating mechanisms of protection systems is critical in the decision-making processes in these situations.

The need for transparency has important implications for dynamic adaptive protection and data-driven protection. Because it can alter its behavior in the field, dynamic adaptive protection would require far more extensive testing and analysis than a traditional element to establish confidence that it will not become too desensitized over time. Purely data-driven approaches such as classification based on neural networks are even more challenging. Establishing approaches for building trust in black-box artificial intelligence approaches is an emerging area of research, the scope of which extends far beyond power system protection [83]. Moreover, none of the surveyed literature indicated that black-box approaches yielded better performance than transparent approaches.

The effects of noise and sensor error are seldom considered despite the fact that data-driven approaches show significant susceptibility to even low amounts of noise [84] [79]. While signal noise is considered more of a practical issue for traditional protection elements, its role is vital even at the theoretical level for statistical approaches. To neglect noise is to assume that all the variance in the measured signal is caused by deterministic factors. This assumption is strong and introduces a significant risk of fitting the model to features that cannot be accurately simulated or measured in practice (as demonstrated by the reduction in model performance). Given that signal noise is easily added in postprocessing, there is little reason to neglect its consideration.

For the foreseeable future, data-driven approaches will need to continue relying on synthetic training data. This translates to a continued need for detailed EMT studies and a lengthy design and test process, and more importantly the validation of an EMT model against the real system model. Data-driven methods developed based on EMT simulation data will have limited practical values unless the EMT simulation fully captures the real systems' performances in various tests.

This is because system disturbances such as short circuits are relatively rare. For example, southeast China's extra-high-voltage system, which comprises roughly 20,000 km of lines, experiences an average of 140 faults per year. Data-driven approaches require a large number of test cases. For example, an SVM took 20,000 events for a relatively simple 123-bus feeder model [74]. The authors of [75] used a set of 10,000 events. Collecting this many fault events from southeast China would take over 70 years. Some work has been done to demonstrate that models trained on synthetic data can perform classification on real-world faults [85]. This work is valuable, but a much broader scope is required to establish best practices for training.

6.3 Reliability (Accuracy) Relative to Industry Performance

Data-driven approaches, upon achieving an accuracy in the range of 98 to 99.9% in the presence of noise, are sometimes recommended for use in practical systems. However, available data suggests that the reliability of existing protection systems, which data-driven approaches must at least meet, is more on the order of six sigma (99.9997% accuracy) [86] [81].

In 1998, protective relays used in transmission systems had an all-cause mean time between failure (MTBF) of 10,000 years—this includes hardware failures, protection algorithm failures, and failures due to user errors such as improper use of protection functions or typographical errors [86]. For the sake of taking a pessimistic view of the reliability of industry approaches, assume for the moment that all these failures are caused by protection algorithms issuing either false positives or false negatives.

A rigorous comparison of the reliability of commercial protection devices as compared to ML solutions is beyond the scope of this report. However, a rough comparison can be performed because the power system is operating at some relatively steady-state condition (from the standpoint of power system protection) most of the time, and it would be unduly pessimistic to consider every processing interval an opportunity for failure. As a simplistic but fairer metric, consider every fault an opportunity for failure.

EHV power lines in southeast China (about 19,000 km of line in total) experienced 1,610 faults from 2007 to 2018 (roughly 140 faults/year). In this case, if the protective relays in the system have an MTBF of 10,000, the chances of a specific traditional protective relay misoperating for a fault are less than 1 in 1,400,000 (99.99992857% accuracy). Note that the chance of *any* protective relay misoperating is likely an order of magnitude or two higher than this because tens or even hundreds of protective relays might be close enough to the fault to measure a disturbance.

As a point of contrast with industry protection reliability, the disturbance detector in [84] achieves an accuracy of 98.9% with a signal-to-noise ratio (SNR) of 30 dB (a reasonable SNR for modern hardware in a high-noise environment such as an electrical substation). In a system that experiences 140 faults per year, this results in an MTBF of 0.65 years, which is more than ten thousand times less reliable than the overall reliability of industry solutions. Thus, data-driven approaches must become several orders of magnitude more reliable to be considered viable options for power system protection.

In fact, the dataset used to measure probabilities on the order of six sigma (99.9997% accuracy) will likely need to consist of many millions of power system events. While work is ongoing to develop phasor measurement unit databases on this scale [87], utilities continue to face serious

issues with data quality [2]. Moreover, many of the surveyed protection approaches rely on more detailed waveform data than phasor measurement units can provide.

7.0 Opportunities for Further Research

Industry has developed approaches for extending traditional protection principles to IBR-dominated distribution systems, primarily in the context of microgrid protection. The recent proliferation of digital substation and distribution automation technologies have been key in enabling this. Industry solutions achieve satisfactory performance but at a high cost; significant investments in the form of detailed EMT studies, communications networks, and design and testing of custom protection logic are customarily required. This approach is suitable for specialized projects but scales poorly to the distribution system at large.

In Section 4.0, drawbacks from industry approaches were distilled into a summarizing table and assigned priorities (Table 2). These drawbacks were presented previously to provide the reader with context on areas needing improvement before discussing the theoretical approaches given in Section 5.0. Table 2 is reproduced below as Table 3 for the reader's convenience.

Table 3: Goals for New Distribution Protection Methods and Their Relative Importance (Reproduction of Table 2).

No.	Goal	Importance
1	Higher speed than existing protection (e.g., 200 ms primary, 1.5 s backup).	Low
2	Reduce reliance on voltage sensors.	Low
3	Reduce reliance on lightweight communications.[1]	Medium
4	Reduce reliance on high-speed communications (e.g., current differential).	**High**
5	Uses relatively simple supervisory logic.	Medium
6	Requires minimal logic changes between applications.	**High**
7	Uses a predetermined list of setpoints once in service (i.e., new setpoints are not dynamically determined).	**High**
8	Computational burden comparable to modern protection algorithms.	Medium
9	Function in both grid-connected and islanded systems without change.	Medium
10	Eliminate reliance on EMT modeling to design.	**High**
11	Eliminate reliance on large datasets to design.	**High**
12	Maintain robustness against uncertainties in IBR response (e.g., fault ride through, current limits, negative-sequence behavior).	**High**
13	Eliminate reliance on accurate (e.g., better than 10%) measurements or knowledge of network parameters.	**High**

[1]In this context, lightweight communications tolerate high latency (e.g., 50 ms) and use low bandwidth (e.g., >1 kb/s).
[2]In this context, high-speed communications require low latency (e.g., 1 ms) and/or time synchronization.

A range of new protection approaches have been proposed in literature and can be roughly categorized as dynamic adaptive protection elements, elements based on short-time transforms, data-driven protection elements, and elements based on incremental quantities. Dynamic adaptive protection elements do little to solve the cost challenges associated with industry problems. They generally require high-speed communications and a high-performance computing platform, and produce complex protection settings that need extensive testing. Data-driven protection elements also do little to compete with industry solutions in terms of cost or complexity. Aggregating data in a quantity and at a quality necessary for even human forensics

is an ongoing challenge, even at the transmission level [2]. Neural networks can encode a much wider variety of behaviors than man-made protection algorithms and therefore require much more testing.

Elements based on short-time transforms show good performance in laboratory settings, but scale poorly in practice: detailed EMT models and large test datasets are generally required to verify and tune element performance. However, the transparency offered by simple wavelet functions used in conjunction with data-mining approaches such as RF classification provide a promising avenue for using statistical methods to design white-box protection algorithms.

Elements based on incremental quantities provide a promising new feature set that meshes well with industry practices and requirements. In existing industry applications, incremental quantities have achieved good performance even when configured without EMT models. Initial study has shown that incremental impedance quantities can provide selective and coordinated protection at high IBR penetrations without the use of high-speed communications.

As a convenient summary, Figure 28 illustrates PNNL's evaluation of the utility of the different protection algorithms surveyed in the report. Key techniques are expected to be valuable for IBR protection in many cases. Supporting techniques bring value as well but are likely to be used primarily to support key techniques, rather than replace them. Ill-suited techniques may bring significant advantages to other applications but are not recommended for further investigation as methods for IBR protection in distribution networks. Significant advances in technology may make these techniques more suitable in the future, but near-term research should focus on key techniques.

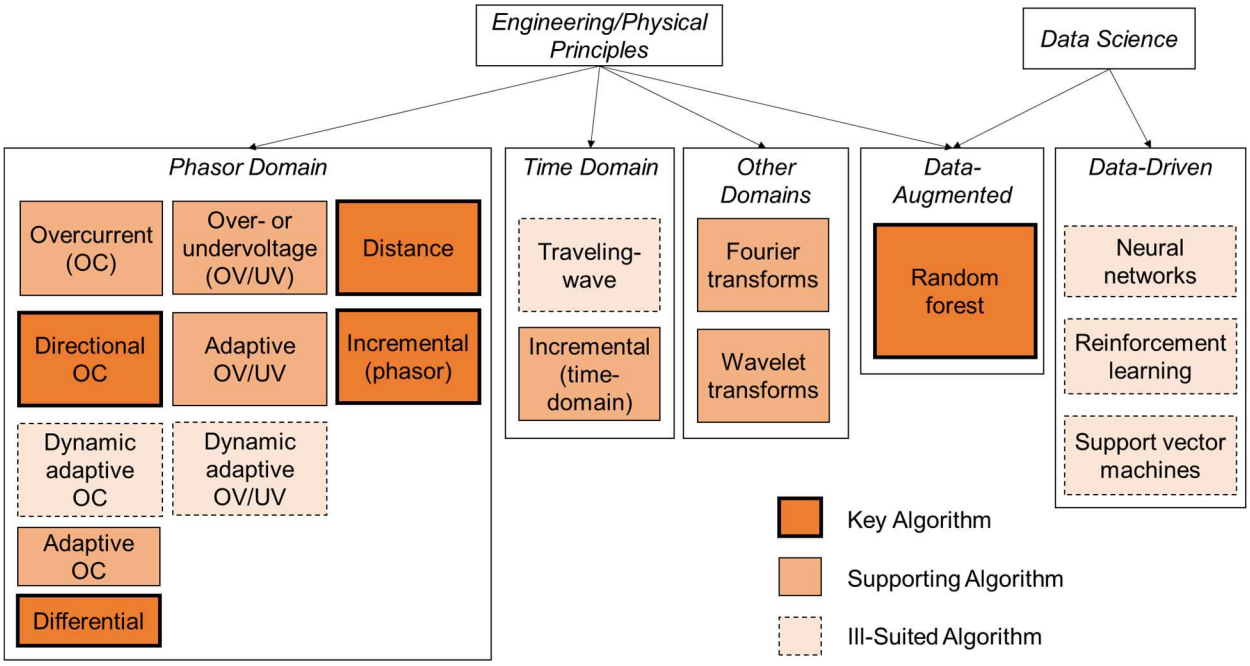


Figure 28: Summary of Protection Algorithms Reviewed and their Applicability to Protection of IBRs in Distribution Systems.

Current differential, directional overcurrent, and distance protection have all been heavily studied and are widely used in industry, and additional research in these areas will likely lead only to minor modifications. However, protection based on incremental quantities and data-

augmented approaches for protection system design are still underdeveloped, and there is much room for additional work to be done.

Based on these findings, PNNL has identified several thrusts for further research:

1. Use of modern data-mining techniques for designing robust, reliable, and transparent power system protection algorithms (Section 5.5).
2. Use of modern directional elements for improving protection algorithm robustness against system operating conditions and IBR fault controls (Section 5.3).
3. Development of design strategies to make sure IBR protection elements are immune to uncertainties in IBR fault controls or variations in system operating conditions (e.g., microgrid vs. islanded operation) (Section 4.0).
4. Development of design strategies for IBR protection based on short-circuit programs, rather than EMT (Section 4.0).
5. Coordination of new protection elements with traditional protection.
6. Detection of HIFs in IBR-dominated grids.
7. Use of simple and highly scalable protection schemes based on distributed sensors to simplify IBR protection (Section 3.2.2).

While contributions in these areas have been made (as discussed in Sections 5.3 and 5.5), significant improvements are still needed to achieve the goals identified in Section 4.0. Additional research that helps bridge these gaps will provide valuable progress toward enabling greater proliferation of IBRs at the distribution level.

8.0 Glossary

Table 4 lists some terms that are widely used by protection engineers in industry and have consistent definitions. Note that some terms, notably reliability and security, have a different definition in other power system contexts.

Table 4: Glossary of Common Protection Engineering Terminology.

Term	Definition
Reliability	A protection system's ability to detect faults repeatability and consistently.
Sensitivity	A protection system's ability to detect minor or subtle faults (i.e., robustness against false negatives).
Selectivity	A protection system's ability to determine which protection zone a fault (or other anomaly of interest) is in.
Security	A protection system's ability to reject faults or other disturbances that it is not supposed to detect (i.e., robustness against false positives).
Shunt Fault	An electrical connection that ought not to be present, usually between two points operating at different electrical potentials (e.g., a conductor and the earth or two conductors from different phases). Also called a short circuit, but the term short circuit can also apply to scenarios that are intentionally allowed (i.e., not regarded as faults). Most faults in power systems are shunt faults, not series faults.
Series Fault	The absence of an electrical connection that should be present (e.g., a conductor that has broken or a circuit breaker that has jammed in the open position). Also called an open circuit, but the term open circuit can also apply to scenarios that are intentionally allowed (i.e., not regarded as faults).
Speed	Unless otherwise noted, this is usually the time between fault initiation and detection time by the protective relay. Does not usually include circuit breaker operating time or any intentional time delays (e.g., in time-coordinated protection schemes).
Supervision / Supervisory	Additional device functionality or logic added to a protection scheme for the purpose of making sure that another function behaves as intended. Typically used to improve security. (E.g., "supervisory logic was added to block the distance calculation if the current magnitude is too low for an accurate measurement to be made").

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