How We Learn That *It Depends* In Protective Relaying

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***Abstract*—Protective relaying is referred to as both an art and a science. The science of protective relaying is the philosophy, basis, and guidelines used as a starting point for settings design. The art of protective relaying is the application of those rules to a system that tends not to follow the rules. Generally, only the science is taught to young engineers, leaving them frustrated until they figure out on their own that the inability of senior engineers to reply with yes or no is the art or the "it depends" part of protective relaying. Learning the concept of "it depends" can take years for young engineers. This paper illustrates the concept of *it depends* and emphasizes the impact it has on protective relaying. Experienced engineers will benefit from a new perspective, or at least a reminder on mentoring young engineers. Young engineers will benefit from several illustrations of the *it depends* concept in protective relaying.**

***Index Terms*—It depends, mentoring, protection engineer, protective relaying, relay settings.**

I. Introduction

Protective relaying is referred to as both an art and a science. This description is so widely used in the field that an internet search for art and science with protection relaying yields too many books, papers, dissertations, and articles for one person to carefully examine in a reasonable amount of time. A couple of books and authors that are well known to the community can be expected to appear near the top: *The Art and Science of Protection Relaying* by C. Russell Mason and *Protective Relaying Principles and Applications* by J. Lewis Blackburn and Thomas J. Domin. Mason's seemingly self-evident title may be better understood by a quote in the preface, which reads, "Science is systematized knowledge. Art is knowledge made efficient by skill" [1]. Although Mason is indicating a need for learning and experience to move from a beginner to a skilled engineer, little else is revealed. Blackburn, on the other hand, provides a detailed explanation. "…This tends to make protection an art as well as a technical science. Because the personalities of protection engineers, as well as that of the power system as reflected by management, operating considerations, and historical development, are different, so is the protection that results. Although there is much common technology, protection systems and practices are far from standardized" [2].

Blackburn's description is what necessitates nearly every answer to a protection question to be prefaced by, "It depends." These answers tend to frustrate young engineers who are accustomed to working to arrive at singular correct answers. Eventually with experience, the young engineers learn what others in the field have known for decades: *it depends* is the result of the personalities referred to by Blackburn, but the connections between the responses and examples get lost along the way.

This paper has two audiences: the young engineers just starting to experience the challenges of learning protective relaying and the experienced engineers who are in a position to mentor those young engineers.

II. The Issues

A. Math Is Precise and Accurate

Engineers are trained for two or more years in advanced mathematics. That training is the foundation of future work and application. During that time, it becomes habit to properly use significant digits, strive to obtain the correct answers, e.g. 0.7 versus 0.6 Volts, and provide appropriate units of measurement. This is how schools train engineers to evaluate and work. Then upon entering the workforce, protection engineers are expected to think outside the box and accept ambiguous answers prefaced by, "It depends."

B. Academic Training and Preparation for the Workforce is Lacking for Protection Engineers

Electrical engineering school is the foundation for all electrical engineering disciplines. The education is meant to encourage thinking, problem solving, and arriving at correct answers. Educational programs are accredited by the Accreditation Board for Engineering and Technology (ABET) so that graduates "have a solid educational foundation and are capable of leading the way in innovation, emerging technologies, and in anticipating the welfare and safety needs of the public" [3].

What students are completely unprepared for is the reality that their training is abstract when they are introduced to relays. One could say that on the job orientation to a protection engineer should begin with, "Forget everything you learned in school except for Ohm's Law, Kirchhoff's Laws, and √3."

C. Professional Engineering Exam Formats

The National Council of Examiners for Engineering and Surveying (NCEES) develops and administers the licensing exams for engineers. Both the Fundamentals of Engineering (FE) and Principles and Practice of Engineering (PE) exam formats have right and wrong answers. This furthers the concept that was instilled in school where there must be a singular method to arrive at a singular correct answer. According to NCEES, system protection is 10% of the PE Power exam [4]. While the topics may be few in protection, the complexity and application of those topics is not, as this paper will demonstrate.

D. Protective Relaying Depends…

From possibly the very first relay an electrical engineer worked on, he or she discovered that there are often multiple "right" answers when it comes to applying relay schemes to a real power system. Specific system conditions and protection philosophy must be considered to point the engineer in the direction of the "best" right answer. So, *it depends*. Every protection engineer remembers approaching senior engineers a question that begins, "I just want a yes or a no!" Later, with some experience, it is clear that less experienced engineer's do exactly the same thing, with precisely the same sentiment. Seeing their frustration and recognizing the importance of remembering how those seemingly vague and defeating answers felt, one thing is evident: there are a scarce number of protection schemes or concepts that are clearly defined for repeated application. Those schemes are not addressed in this paper.

E. Aging Workforce Replacements and Transfer of Knowledge

In 2011, a paper was presented at the Texas A&M Conference for Protective Relay Engineers titled *Today's Aging Workforce – Who Will Fill Their Shoes?* [5]This is a critical topic for protection engineers and correlates directly to the intent of this paper with the impending transition of knowledge out of the workforce. Along with the importance of the transfer of knowledge, the concept of *it depends* presented herein is critical to teach new engineers <u>as soon as they enter the profession</u>. The answer, "It depends," has always been a part of the language and discussion; the explanations, details, and a fundamental understanding of *why* has been missing.

III. Protection Philosophy Challenges.

Protection is referred to as part art and part science. The basic rules and concepts or *rules of thumb* (typically derived from experience, research, and/or analysis) are the science. The *science* is the first area of training for protection engineers in how to create schemes and settings. Every aspect of protection has to have a place to start, a guide to follow so that the attempts at creating settings are reasonable. Although the rules have a valid scientific and/or theoretical base, they do not apply equally to all cases, and might not apply to certain cases at all. Science will bring the application close to where it needs to be; art will refine it to where it has to be in order to perform as intended.

Art is the variation or deviation from the science that gives life to the *it depends* cases. Nearly every application, except current differential schemes, tends to deviate from a standard rule of thumb, thereby forcing the use of "It depends" in practically every question asked, every answer given, and ultimately every protection scheme installed.

The reasons for deviation from the rules vary greatly, including physical and electrical topography, climates, adjacent relaying and communications, interconnections, generating stations, and much more. A few examples will be discussed with the impact to relaying provided in detail.

A. Hot vs. Cold Climates

Relay settings can be impacted by the climate in which they are applied. The North American Electric Reliability Corporation (NERC) Protection and Control Reliability Standard, PRC-023, *Transmission Relay Loadability* [6], states that "load" responsive relays are to be set so that they do not operate at or below a percentage of the highest seasonal Facility Rating of a circuit. The highest seasonal Facility Rating is usually the winter emergency rating, which is based on the winter ambient temperature for a geographic region. In the northern United States, winter ambient temperatures can be around 0 degrees Celsius (C), but in southern states, winter ambient temperatures can be above 25 degrees C. This difference in temperature significantly affects the "loadability" of a transmission circuit, and can greatly impact the relay settings applied to transmission line terminals. When the winter ambient temperature varies from 0 to 25 degrees C, the facility rating at 0 degrees C will be around 15% higher than the rating at 25 degrees C. Relay settings, governed by NERC PRC-023, are impacted by cold climates in the following ways:

- Forward or Reverse over-reaching elements may have to be reduced.
- Load encroachment logic use is more likely.
- Power Swing Block (PSB) and Out-of-Step Trip (OST) outer blinder settings have to be set closer to the inner blinders, making it more difficult to achieve correct operation at desired slip rates.

Other Hot/Cold Climate Challenges:

- Cold climates are generally further north in latitude, so geomagnetic effects have to be considered for ground relaying.
- Hot climates may be in arid or mountainous regions with higher ground resistances, resulting in overall higher zero sequence impedances. This may require the use of sensitive ground overcurrent (OC) elements in communications assisted tripping schemes as opposed to using phase and ground distance or directional ground overcurrent elements only.

B. Biology – Plants and Animals

Occasionally, trees in high voltage rights-of-way contribute to major outages. On the afternoon of July 2, 1996, a 345 kV line in southwestern Wyoming sagged into a tree, initiating a fault. This fault resulted in a major blackout and breakup of the electrical system from California east to Nebraska and north to British Columbia into five separate islands. The following day, the same 345 kV line sagged into the same tree, but the system disturbance was contained due to manual load shedding by the operator working in the Idaho control center. A few weeks later, on August 10, 1996 three different 500 kV lines sagged into trees in Oregon, initiating another major disturbance in the same area. The 1996 outages were minor compared to August 14, 2003. On that day, several 345 kV lines in Ohio sagged into trees over a period of a few hours, ultimately initiating a major blackout affecting about 50 million people in the northeast US and eastern Canada. Events like these and major storms, such as Hurricane Sandy in 2012 or those delivering heavy snow and ice, commonly result in many tree-involved outages. The more common events are at lower voltages, where individual feeder-scale outages also have significant contributions from trees and other vegetation.

Line-to-tree faults do not usually initiate major blackouts; for those events, often *it depends* on multiple things going wrong. The July 1996 outages included several relay misoperations following the initial fault, along with generator excitation systems which did not respond as models predicted. A major contributor to both the August, 1996 and 2003 blackouts was a lack of control room operators' situational awareness – the electric system was already in a precarious condition just before the initiating faults.

However, line-to-tree faults do provide another *it depends* situation at all voltages. Trees are not good conductors because high resistance faults result in low fault currents with delayed clearing compared to what the engineer might otherwise expect. Actual resistance is unpredictable because *it depends* on the tree type, its health, soil conditions, or other factors such as recent rainfall.

Although trees in rights-of-way can be expected in specific locations, animals in search of shelter cannot. While the specifics of individual cases depend on the local wildlife and utility practices, animals frequently and successfully find vulnerable hiding places in a power company's facilities. Raptors and other large birds nest on utility poles and substation structures occasionally causing outages due to their nesting material (e.g. pieces of wire), large wingspan, or "streamers" as they attempt to take off.

Substation control buildings provide shelter for not only relays and controls, but may ultimately serve as a safe haven to local mice, squirrels, insects, and other wildlife. Mice will periodically chew through control wiring insulation, which can cause operating errors. The type of error, immediate or delayed, depends upon whether the wires are normally energized (e.g. dc control voltage or ac potential circuits) or not (e.g. trip circuit).

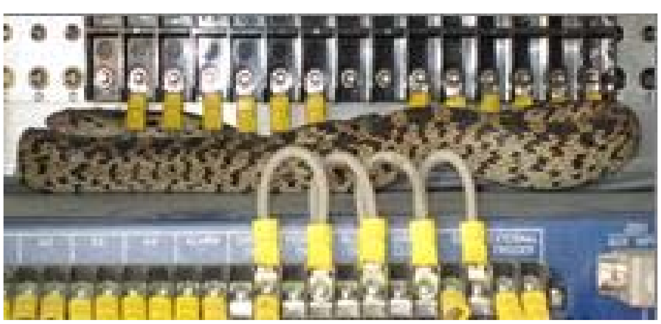

Fig. 1. Bull Snake Staying Warm on top of a Relay

C. Forward and Reverse Over-reaching Zones

In distance relaying, directional zones are used to look an estimated "reach" down a line, into or through a transformer, or into multiple bus and terminal configurations. The reaches are estimated because they can vary slightly with changing conditions of system impedance, which the relay measures to detect faults. The general rule of thumb is that forward reaching Zones 1 and 2 are set to 80% and 120% of the protected line, respectively. Additional over-reaching zones are where things get interesting. There are two distinct philosophies on the use of these zones – one looks reverse and one looks forward for remote back up protection of relays at the adjacent terminals. The use of one over the other depends on local philosophies, the perception of risk of tripping multiple terminals for a single fault, and which application is more comfortable to the user(s). Both approaches have advantages and disadvantages.

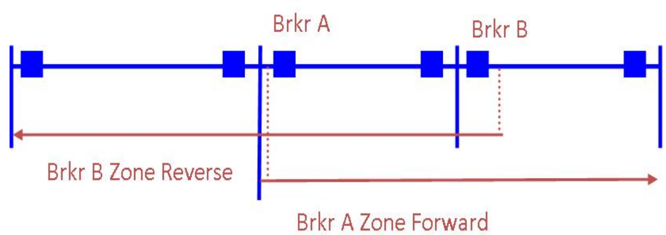

Fig. 2. One Line of Forward and Reverse Over-reaching Zones for Relays at Breaker A and Breaker B

For both over-reaching zones, the primary advantages are remote back up coverage and the ability to serve as a type of remote breaker failure protection. This enables faults to be cleared if there is a relay failure, a Potential Transformer (PT) or Current Transformer (CT) failure, or a communications or a local dc failure. These failures will not initiate breaker failure relays because the line relays will not detect the fault(s). Thus, the over-reaching zones provide a true back up because they are totally independent from the failed system or component.

The disadvantages of over-reaching zones are the complexity involved in designing settings and the large number of terminals that may need to trip, and coordinate, to clear a fault. The reaches of both zones must be substantial in order to cover the desired terminal(s). There can be far reaching zones due to multi-terminal substations with large amounts of infeed. Increased infeed is typically a result of multiple sources connected to the remote bus. As such, it may not be possible to set an over-reaching zone as far as needed. Large zones can result in "relay loadability" or coordination issues when remote buses or distribution transformers are over-reached. Proper settings require experience, some art, and finesse. There is not one sure method of tackling this challenge – *it depends* on the electrical topography and impedances of the surrounding lines and equipment.

In addition to the zone reaches, coordinating the timers for each of these zones is another challenge. One method of coordination is to use the same time delay on all overlapping relays. For example, if the longest possible Zone 2 time delay allowed by philosophy is 0.65 seconds, then all over-reaching zone relays in the area can be set at 0.9 s or greater (providing a 0.25 s margin – which is another *it depends*). Alternatively, individually coordinating each relay as it looks at the terminal, such that some relays will be faster at 0.5 s and others may be

0.9 s or slower, is an option dependent on the equipment to be coordinated with.

D. Dependability, Security, and Reliability

In protective relaying, two fundamental premises guide the practice – dependability and security. By definition, these premises are at odds with each other when creating settings. *Dependability* is the intent to have a relay successfully operate as desired during fault or other conditions. *Security* is the intent to have a relay successfully withhold operation as desired during fault or other conditions. Put simply, trip when it should; don't trip when it should not. As settings are created, the balance between dependability and security warrants careful consideration. If a scheme tends more towards tripping (appropriately), some security must be sacrificed, and vice-versa.

Historically, there has been a tendency to design settings to be more dependable than secure. Many utilities leaned toward tripping, which could result in more or longer outages. The tendency to trip more often when a fault is detected, sacrificing some security, was one of the factors that contributed to the cascading during the 2003 blackout. As a result, recommendations followed, to have the NERC Reliability Standards become enforceable. Soon after, the regional entities, e.g. Western Electric Coordinating Council (WECC), Southwestern Power Pool (SPP), and NERC were restructured and given the authority to enforce, audit, and penalize for violations of the Reliability Standards for all Registered Entities. Registered Entities are power system asset owners and/or operators meeting criteria that must register with NERC [7]. Since that time, reliability has become a major focus of NERC's efforts and enforcement.

Reliability is the combination of security and dependability such that relays will both successfully operate and withhold operation as desired. For a successful balance between the two, operations and non-operations should be correct during faults, non-fault, and other conditions, like heavy loading, which was present during the 2003 blackout. Other things (situational awareness, communication protocols, operating procedures) still may have caused the affected lines to trip. However, had the Reliability Standards been in effect and complied with prior to the event (PRC-023 Loadability specifically), the blackout may have been much smaller in scale. When creating settings for relays, the balance between security and dependability to achieve reliability is a significant *it depends* case.

Most transmission lines with voltages above 100 kV are part of interconnected circuits, also known as the Bulk Electric System (BES), which NERC regulates and enforces Reliability Standards upon. These requirements have many focal points with reliability at the center. Although the requirements for each individual standard are specific, the methods to meet them vary as discussed in Section III C. All BES line protective relays are now evaluated for Relay Loadability based on the standard, which makes them more secure.

When looking at the approach taken for distribution settings, however, the situation becomes less defined. Local philosophies, fault location, and even individual customers (hospitals, emergency services) can impact the decisions made with settings choices. Before one approaches the challenges of climate, plants and animals, the type of protection, and other factors…*it depends*…

On a distribution circuit, relay fault location is difficult due to the topology of the circuit. One circuit will normally have multiple taps, above or underground, significantly altering the apparent impedance of the circuit at a given point. A common method of fault location within relays uses impedance measurements to calculate fault distance from the relay. When faults are difficult to locate for inspection by crews, power restoration is delayed. Distribution circuit protection has a vast array of options to choose from. Of those choices, fuses are the most economical, simple interrupting device, and can be installed virtually anywhere additional protection or interrupting capability is desired. Because of the economics and simplicity, in addition to fault location and fault isolation benefits, fuses are used on most distribution lines with load taps off the main feeder.

There are two basic protection philosophies associated with fusing circuits: fuse-saving and non-fuse-saving. These two fusing philosophies are opposing in methodology, dependability vs. security, and implementation. Each method has advantages and disadvantages, yet the choice of which method is most appropriate varies greatly from one company (or even one engineer) to the next. A change between these two philosophies impacts fault isolation, outage duration, and power restoration.

Fuse-saving schemes lean toward dependability and away from security. Substation feeder instantaneous overcurrent elements are set to reach beyond fused taps, and will usually cover the entire main feeder. The substation feeder breaker typically has a fast (no intentional delay) reclose followed by additional time-delayed recloses. After the first fast reclose, the instantaneous overcurrent elements are "blocked" from tripping for subsequent faults until the reclosing relay resets to start another cycle. If a temporary fault occurs beyond a fused tap, the fuse will not blow as it was "saved" by the substation feeder breaker's instantaneous operation. Fuse-saving schemes will "blink" the lights of everyone fed by the feeder more frequently than a non-fuse-saving scheme, due to the greater reach of the instantaneous overcurrent elements.

However, if a permanent fault occurs beyond a fused tap, the fuse will blow after the substation feeder breaker recloses the first time, resulting in two voltage dips (lights dim) seen by all feeder customers and a sustained outage to the fused tap customers. Using a fuse-saving scheme allows temporary faults to be quickly extinguished while outage durations to the fused tap customers are minimized.

Alternatively, non-fuse saving schemes lean toward security. Substation feeder instantaneous overcurrent elements are set short of the first fused tap and are not blocked from operating after the first fast reclose. Instantaneous tripping will only occur for faults close to the substation. Faults beyond the instantaneous reach will trip on the time-overcurrent characteristic, which results in slower tripping and a more noticeable voltage dip to the affected feeder customers. A fault beyond a fuse will allow the fuse to blow whether the fault is temporary or permanent, resulting in more frequent outages to the fused tap customers. Additionally, substation instantaneous elements may not be used at all. These feeders have taps in close proximity to the substation such that setting an instantaneous element cannot be accomplished reliably. Lacking an instantaneous element, faults will trip on the time-overcurrent characteristic, which results in slower tripping. Though the outages to the fused tap customers may be more frequent, the impact to the rest of the feeder customers is minimized. This scheme also makes fault location easier since breaker operations are for main line faults and fuse operations are for fused tap faults.

These alternatives must be weighed when determining protection schemes for distribution circuits, and all circuits may not be protected with the same philosophy. There are many factors to be considered, which makes protection with fusing and the associated relay settings a significant *it depends* case with regard to dependability and security.

IV. Examples Where *It Depends*

NOTE: The following technical examples are not recommended or best practices. They are drawn from accepted practices based on philosophies learned over time and may not be appropriate in any one specific application.

A. Distance Relaying

Impedance-based distance elements are widely used as primary and backup protection on transmission lines, but also prove useful as backup protection for other systems including tapped distribution and generator step-up transformers. Phase and ground distance elements can be implemented as stepped-distance protection schemes, or they can be used with the aid of communication between line terminals in pilot protection schemes.

Variations in distance element settings will depend on one or more factors such as:

- application
- relay type(s)
- system topology and configuration
- number of terminals
- mutual coupling
- series compensation
- tapped distribution loads on the line
- adjacent lines
- transformer(s) connected to a terminal
- transformer protection schemes and settings
- and individual philosophies (the art)

Other factors to consider which will not be addressed here (discussed in detail in several other papers) are:

- length of the line
- source impedance ratio
- load carrying capacity of the line
- fault arc resistance
- infeed currents
- capacitive voltage transformer transients in measured voltage
- local pilot schemes
- availability of breaker failure protection, etc.

In applications employing distance elements, the use of mho (circular impedance) characteristics is adequate for a majority of cases. The use of other impedance-based characteristics, such as lenticular (lens shape impedance) or quadrilateral characteristics, will depend on the protection coverage desired. The quadrilateral characteristic is useful in providing better coverage for higher resistance ground faults, while a lenticular characteristic is better suited to avoid areas where a mho element encroaches into a load region during heavy load conditions. However, modern microprocessor-based relays offer load encroachment settings that block operation of distance elements when the measured impedance is inside the load region [8].

The number of distance zones available and/or implemented not only depends on philosophy, but also the type of relay used. Some electromechanical relays are three-phase, single zone units; some are single-phase units with up to three zones. Both types require three duplicate units to protect all three phases of a line for three zones of protection. More modern microprocessor-based relays having up to five zones of distance protection are available. Some are designed with forward and/or reverse distance element(s) for use in pilot schemes as well as a separate set of distance elements for time-delayed backup or stepped-distance protection. This design allows flexibility in setting forward and reverse elements. Since there is little risk of misoperation of pilot elements, the forward and reverse reaches can be extended without worrying about coordination challenges with adjacent systems; it can be implemented using any microprocessor-based relay with up to five distance zones.

The following summarizes typical zones and challenges used in distance protection applications:

1) Zone 1 Phase and Ground Distance:

Under-reaching (less than the full line length) Zone 1 distance elements are generally set to trip instantaneously and reach 80%–90% of the protected line impedance to ensure no undesired tripping occurs outside of the protected line. Zone 1 is also used in under-reaching pilot schemes such as Permissive Under-reaching Transfer Trip (PUTT) or Direct Under-reaching Transfer Trip (DUTT).

2) Zone 2 Phase and Ground Distance:

Over-reaching (greater than the full line length) Zone 2 distance elements must be set greater than 100% of the protected line impedance, and are typically set at 120%–150%. Application philosophies can depend on the engineer’s preferences and training, among other things, resulting in varied practices for Zone 2 reaches. For example, one method is to set Zone 2 to 100% of protected line impedance plus 50% of the shortest adjacent line impedance. That is provided this coverage is sufficient for the protected line and it does not over-reach a Zone 1 element from the next line. This philosophy often eliminates the need to perform time-delay coordination with adjacent downstream device distance elements. The typical time delay is 15–30 cycles or set to coordinate with adjacent systems. They are also used in over-reaching pilot schemes like Permissive Over-reaching Transfer Trip (POTT) or Directional Comparison Un-Blocking (DCUB).

3) Zone 3, Zone 4, and Zone 5 Phase and Ground Distance:

Over-reaching Zone 3, Zone 4 or Zone 5 distance elements are used as local and/or remote backup protection (forward or reverse) with longer time delays. Typical settings cover the longest adjacent line or adjacent transformers but are limited to the load capacity of the line as established by NERC Reliability Standard PRC-023 or operator established line loadability limits. The time delays must be set to coordinate with adjacent protection components. Reverse elements are often used in pilot schemes as blocking or unblocking elements such as DCUB or Directional Comparison Blocking (DCB).

4) Distance Relaying Challenges

Although Zone 1 distance elements follow a simple and somewhat hard and fast rule of always under-reaching and operating instantaneously, there are a few *it depends* cases. As an example, short lines present a risk of Zone 1 over-reaching caused by errors in current and voltage measurements and inaccuracies in model data and minimum settings available in a relay. In this case, the best solution is to disable instantaneous Zone 1 distance elements and use pilot protection instead [8].

Additionally, mutual coupling in parallel lines poses another *it depends* case for Zone 1 as well as Zone 2. The zero-sequence mutual impedance introduced between parallel lines can lead to over-reaching Zone 1 and under-reaching Zone 2 for phase-ground faults. Mitigating this issue can depend on the relay properties, line topology, and setting preferences. Modern microprocessor-based relays provide a zero-sequence compensation factor setting that can be used to account for mutual coupling effects on Zone 1 and Zone 2 reaches. One can opt to use this function and maintain settings at 80% and 120% of the protected line impedance for Zone 1 and Zone 2 ground distance elements. Another option is to perform a fault analysis to determine reach settings; using two cases, find the worst-case apparent impedance as seen by the relay for phase-ground faults. One case is with the line in its normal service configuration, and the other case is with the parallel line open and grounded at both ends. The minimum apparent impedance from these is then used to determine Zone 1 ground distance reach and the maximum apparent impedance is used to establish Zone 2 ground distance reach [10]. With good knowledge of the system, one can also opt to reduce Zone 1 reach to less than the recommended 80% (e.g., 60%–70%), and increase Zone 2 reach above 120% (e.g., 130%–150%), as long as coordination is not compromised and 100% protection of the line is still achieved.

Impedance variations are the primary factor in determining zone reach. Other factors, such as line design and connected equipment, will impact the settings as well. Three terminal lines will need to include infeed current effects from the other terminals. Series-compensated transmission lines will impact the reactive component introduced by switching capacitors when calculating apparent impedance. Settings calculations also depend on the location of coupling capacitor voltage transformers on either side of the capacitor bank for those compensated lines.

When protecting transmission lines with tapped transformers, one needs to consider apparent impedance seen by the relay for faults on the low side of the tapped transformer. Coordination with transformer protection or distribution level protection will need to be checked when over-reaching distance elements see through to the low side of tapped transformers and/or loads. Distance elements on transmission lines terminated with a transformer will depend on the transformer design and overall protection system principles. For example, if there is dedicated transformer protection, fast operation can be achieved independent of the line protection to isolate transformer faults. Otherwise, the transmission line relays will have to protect the transformer as well. The reach settings from the transformer end will depend on transformer winding configuration and location of the PTs and CTs [9]. Distance zone reaches depend on all of these factors, which will regularly alter them from one application to another.

Once reaches are established, time coordination between overlapping components must be evaluated. Here, challenges may exist depending on protection schemes used on adjacent circuits. For example, the presence of only overcurrent ground protection on an adjacent line may pose a limitation in the use of over-reaching ground distance elements (forward or reverse) on the protected line. If the delay needed to achieve coordination is not practical, it may be necessary to eliminate over-reaching ground distance elements (with delays), and only use them in communication-assisted fast tripping. In the absence of over-reaching time-delayed distance elements (forward or reverse), it is important to ensure adequate breaker failure protection exists for remote systems.

B. Breaker Failure Relay Settings

Breaker Failure (BF) protection is used as a local back up when the breaker fails to clear a fault after a trip is issued by protection schemes. There are advantages and disadvantages to the configuration that must be considered in the design of the system. The chosen design depends on many variables. Things such as cost, existing/new equipment, bus configuration, topology, redundancy requirements, communications equipment, and system stability will affect design decisions. Specifically, a straight bus with a single-sourced transformer could be a configuration where breaker failure relays are not always deemed necessary. Instead, another protection relay, component, or scheme could be used as a backup.

Once the physical design is chosen, including the relaying equipment, the settings for the BF relays and the tripping/blocking configuration (lock out relays) must be considered. How many breakers need to trip for failure of a specific breaker to clear a fault? What will trigger the relay? How will settings be designed?

With BF relay settings, certain considerations must be made before settings can be created:

Critical Clearing Time (CCT) – the amount of time a fault can be present on the system before any connected generators may become unstable.

Fault Detectors – the amount of current necessary for a trip to be issued by the relay.

Trip Timer – the time before the relay will issue a trip.

Active Control Timer – the length of time a trip command is active.

Retrip – a secondary trip command sent to the breaker after the initial trip has been issued before a BF trip is sent.

Breaker Failure Initiate (BFI) – the external trigger or other means to tell the relay that a trip has been issued by the protective device and to be ready to trip if the breaker fails to clear the fault in a specified time.

Reset – when the BF relay is no longer ready to trip.

The CCT is determined based on the system condition. The method and use of External Triggers, Retrip, BFI, and Reset are all decisions that are made based on local practices and philosophies and are relevant to the settings process.

To provide additional security, it is common practice to use Fault Detectors and/or breaker status monitored through auxiliary contacts. Then, the Fault Detector must be set. One rule of thumb is to set the phase detector above load current and the ground detector above any imbalance currents. Also, in some cases using a lower value than the rule of thumb may depend on the system; there might not be enough fault current in a particular area to set the relay at those desired values. In these cases, judgment must be used for the most appropriate settings. However, *it depends* on one's philosophy. There has been a trend toward setting BF Fault Detectors to a minimum value and relying solely on the external trigger (protective relaying). This minimum current setting ensures there is current present on the line. The Trip Timer setting depends on the CCT, breaker trip time, the location of the BF relay, and whether or not the scheme uses Retrip.

Even a BF relay, one of the least complex relays to set, has many variables one must consider, and the resulting settings depend on the system, physical and electrical topographies, and the local philosophy [11].

C. Load Encroachment and PRC-023 Requirements

Many major blackouts, at least since New York City in 1965, involved major contributions by relays that tripped transmission lines due to heavier than normal load, but non-fault conditions [7]. These offending relays were primarily phase distance, since these relays often provided the most common form of transmission line protection, with some overcurrent relays tossed in the mix. Overcurrent relays (directional or not) are less often used for line protection, especially at higher voltages, but can also be vulnerable to non-fault operation at higher than expected load levels as well.

Following the recommendations resulting from the August, 2003 blackout, NERC instituted new standards to address this relay loadability issue. The first phase of this standards development process was legally in place by mid-2007. Additional standards addressing generator relay loadability (PRC-025 approved) and stable power swings (PRC-026 pending regulatory approval) should also be reviewed as needed for appropriate relay settings. However, as early as 2005, transmission owners were effectively required to review relay applications on all transmission lines and transformers rated 200 kV and above to identify applications that would be vulnerable to tripping under heavy load conditions and determine a schedule for remediation. These initial results were reported to NERC through the Regional Reliability Organizations (WECC, SPP, etc.) and updated in 2006 and early 2007.

When the PRC-023 Relay Loadability Standard was created, the drafting team recognized that system configuration, equipment types, and system stressed conditions (such as low voltage) have an influence on how much load can be experienced by relays protecting each line, transformer, or other elements. Emergency load carrying ratings can vary for different equipment, and duration of the heavy load conditions should also be considered because relay operate times are almost always significantly faster than emergency loading time limits. Therefore, the drafting team settled on the philosophy that any of the various factors can be used to identify acceptable load-tolerant relay settings to coordinate with the protection settings (distance or OC pickups). Having coordinated relay settings that account for loadability means that the load and distance relay tripping characteristics do not overlap, and that any OC trip pickup settings are higher than the equipment loadability rating or are otherwise supervised by the relay's loadability characteristics.

The most commonly used method [12] to determine relay loadability is based on the thermal capacity of the line. This calculation usually takes the most limiting component from either the conductor or connected equipment, such as: breakers, jumpers, switches, or other equipment, including wave traps when applicable. In 2006, protection engineers used this method for approximately seven out of every eight lines reported to NERC. It is usually an easy calculation and can be readily applied to most short and medium length lines, as well as longer lines connecting strong systems without having to modify distance settings. Even here, *it depends* on the how the rating is defined. The standard merely says that the rating should be the highest seasonal rating "closest to 4 hours" [6]. But if a utility uses a single, rather than seasonal rating, or does not use a separate emergency rating, that is okay. If the component manufacturer's overload ratings for a wave trap end at a two hour interval, then that value is also acceptable for calculations.

Then, there are eleven other loadability calculation methods for lines, transformers, and other facilities. Three separate methods address connections of remote load or generation centers to the main grid. Three more address transformers and series capacitors. There is even a loadability rating method that is essentially a "build your own." One must ensure it provides at least a 15% margin above the maximum load before tripping is allowed. But perhaps the most notable method is essentially a stability-based method that uses both line and system equivalent impedances at each terminal; this method is most useful for long lines and weak transmission sources.

Then again, the biggest *it depends* part of the loadability requirement is that the standard allows the engineer to use any one of the many rating methods to prove settings are coordinated and in compliance. Often, several methods could provide acceptable coordination with distance and/or OC elements. This leaves the choice up to the user, their equipment loading and relay settings philosophy, ease of calculation and documentation, as well as the specific application. In other words, *it depends* on many inputs in addition to the Reliability Standard being followed.

D. Current Turns Ratio Selection

The one choice on which all other current driven protective elements depend is the Current Turns Ratio (CTR) selection for the device. Choosing the proper CTR is critical to ensure the relaying equipment can function without overloading (saturating) the CTs under normal loading conditions. Also of note is that in transformer differential devices, the CTRs will be sized differently to accommodate the high and low side voltages, and subsequent maximum load and fault currents on t each side of the transformer.

First looking at equipment, the class of Current Transformers can impact the CTR chosen. Class C is the most commonly used CT on new equipment today and will be assumed to simplify the discussion. However, if other classes of CTs are included in the equipment already installed, additional care must be taken (these details are discussed in most literature on protective relaying). Then the relays being used must be considered. Relays are intended to be used at either 1 A or 5 A secondary continuous load. There are also specific CTRs available to be used with each CT; this data is available from the manufacturer or from industry standards based on the maximum available CT ratio. Compared to microprocessor and solid state relays, electromechanical relays tend to have a higher resistive burden. This value can be calculated and should be considered.

Next the philosophy used can impact the CTR selection. This also depends on the type of relay or element being used. For distance relaying, there are two basic rules of thumb: either choosing a CTR that matches the maximum line and equipment loading or setting the CTR to the maximum possible value. Both methods are acceptable, depending on the system. In both situations, the minimum fault currents that the connected relay(s) are expected to see must be checked. If those values are too low on the secondary side, then the CTR must be lowered. For example, when dealing with transmission elements, a full CT ratio can often be used without adjustment due to high fault currents. However, on distribution elements, low voltage capacitor banks, or tertiary or neutral connected components, fault currents can be very low, making the full CTRs unsuitable for protection.

As an example, suppose there is a microprocessor distribution relay using both overcurrent phase and ground elements on a 24.5 kV line. The expected loading on the line is about 675 A primary. This relay uses a 5 A secondary (A_{sec}) value. The maximum available CTR is 1200:5 and the philosophy is to use the highest available ratio (tap setting). Phase and ground faults at the end of the line being protected are 313 A and 117 A primary, respectively. The minimum tap setting of this relay is 0.5 A_{sec}. Using the maximum CTR of 240 (1200:5) to check all the tap settings we have the following:

Line loading (continuous load) → 675/240 = 2.81 A_{sec}
Phase faults → 313/240 = 1.30 A_{sec}
Ground faults → 117/240 = 0.49 A_{sec}

Assuming a 2:1 confidence margin of tap setting to fault current, the CTR is too high because this relay's minimum tap setting is 0.5 and must be lowered. To obtain a tap of 0.5*2 = 1*117 = 117 A, the minimum possible CTR is 600:5, checking again:

Line loading (continuous load) → 675/120 = 5.62 A_{sec}
Phase faults → 313/120 = 2.61 A_{sec}
Ground faults → 117/120 = 0.98 A_{sec}

All of these values are within the tolerances of the relay and settings parameters. However, the adjusted phase pick-up for end of the line faults is below load, upon which the relay could issue a trip for a non-fault condition. A possible solution would be to evaluate installing an additional interrupting device further downstream from the relay. With additional protection device(s) on the line, the relay phase pick-up could be raised as it may not have to "see" end of the line faults. Then, that device and the relay would have to be checked for coordination. Any mitigation method would depend on local practices and philosophies.

When considering the CTR selection, *it depends* on several factors. There is not one correct answer or rule of thumb that can be used to apply settings. In addition to knowledge of the equipment, local philosophy, and desired protection, a test and check is required on the individual application and relay(s) to ensure that the selection and settings will be appropriate for the circumstance.

V. "It Depends" is a Valid Answer

In protection engineering, unlike some other engineering specialties, there is rarely a straight forward answer to a question without obtaining multiple data inputs for each specific situation. Furthermore, there are often many correct answers and methods to apply settings for a single scheme or element. For new engineers, this is a frustrating dilemma, one that takes a long time (up to several years) to adjust to. Experienced protection engineers learned *it depends* with the same frustration, but fail to emphasize the lesson when it becomes their turn to teach. We can improve by taking the fundamental concept of *it depends* to the forefront and focusing on it with concrete examples from the first day with new engineers. Though it will still take time transitioning away from singular definitive answers, as we were taught in school, to “It depends,” removing some of the frustration will help the engineers concentrate more on what they need to learn as opposed to what they are failing to understand.

Protection is called both art and science for good reason. *It depends* is the art part. Why shouldn’t we be teaching the art from the beginning? To be sure, no settings are complete without a little bit of art. Teach young engineers the reason why from the beginning. They will be grateful and feel rewarded and empowered when they understand the art as they learn the science.

Mentor the art daily.

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VII. Biographies

Heather R. Malson received her BSEE degree with a minor in mathematics in 2008 from the University of Nevada at Reno, Reno, NV and her AA degree in Liberal Arts, Cum Laude from Western Nevada Community College in Fallon, NV in 2001. She has a range of both distribution and transmission system protection experience. Ms. Malson served in the United States Navy from 1992 to 1996, stationed at the former Naval Air Station Miramar. Beginning with a student internship, she worked for Sierra Pacific (now NV Energy) for three years in System Protection. During the following five years with Xcel Energy, she worked in the System Protection Engineering department and later in the Transmission and Substation Standards department as the Commissioning Standards Engineer for all of Xcel’s operating territory, covering ten states. She is a Senior Settings Engineer with Power Grid Engineering, LLC in Amarillo, TX. Heather is a Member of IEEE and is an active participant of several working groups within the IEEE Power System Relaying Committee (PSRC). She is serving as chairman of the C29 Working Group for the PSRC.

Gene Henneberg received his BSE degree from Walla Walla College in 1973 and an MSEE degree from Washington State University 1977. He has broad experience in the field of power system planning, operations, and protection at NV Energy, a division of Berkshire Hathaway Energy (previously Sierra Pacific Power Company) in Reno, NV. Mr. Henneberg is vice-chairman of the C subcommittee of the IEEE Power System Relaying Committee, is active in several technical work groups in the Western Electricity Coordinating Council (WECC), is chairman of the NERC Standard Drafting Team for PRC-012-2, Remedial Action Schemes and has authored or co-authored several conference papers. He is a Professional Engineer in the state of Nevada and a Senior Member of IEEE.

Kevin W. Jones received his BS degrees in Electrical Engineering and Computer Engineering from the University of Missouri in 1989. He has broad experience in the field of power system protection, operations, and maintenance. Upon graduating, he has served over 26 years at Southwestern Public Service Company (now Xcel Energy), where he worked in various departments, including Distribution Design, Substation Commissioning, Transmission Operations, and System Protection Engineering. Kevin specialized in high-voltage transmission line relaying, event analysis, and system stability relaying. He is the vice-chairman of the IEEE Power System Relaying Committee D29 Working Group, and was the vice-chairman of the NERC PRC-026-1 Standard Drafting Team titled: Relay Performance During Stable Power Swings. Kevin is a registered Professional Engineer in the state of Texas and a Member of IEEE.

Munira Masoud was born in Arusha, Tanzania, and began her undergraduate studies in Manipal, India. She eventually received her BS and MS degrees in electrical engineering from University of Minnesota, Twin Cities, MN USA, in 2007 and 2010 respectively. While pursuing her master’s degree, she interned with Xcel Energy in Minnesota, where she first gained exposure to power system protection. Upon graduating, she secured a position as a Substation Design Engineer at HDR, Inc., but her interest, along with her prior experience in protection, led her to subsequently transition to a protection engineer. She joined Schweitzer Engineering Laboratories in 2012, where she currently holds the position of a Protection Engineer in the engineering services division in St. Louis, MO.

Pratap Mysore received his BE and ME degrees from Indian Institute of Science, Bangalore, India in 1974 and 1976. He is with HDR, Inc. as the Director System Protection in Minneapolis, MN. He has vast experience in the power system industry in the areas of substation protection and control design, short circuit and transient studies, maintenance and commissioning. He is the vice-chairman of IEEE Power Systems Relaying Committee and a member of the Capacitor T&D committee. He is an adjunct professor at the University of Minnesota teaching a Protection course and is involved in developing modules for the Consortium of Universities for Sustainable Power (CUSP) as part of a Department of Energy sponsored program led by University of Minnesota. He is a Senior Member of IEEE and has authored or co-authored several papers for IEEE transactions and regional conferences. He is a Professional Engineer in the state of Minnesota.

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