A Systematic Approach to Meet NERC PRC-027-1 Requirements – Beyond Compliance

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***Abstract*—Over the years, the electric power grid in the United States has experienced several wide-area disturbances that, at times, have resulted in blackouts. According to the North American Electric Reliability Corporation (NERC), one of the leading factors for such undesired operations is incorrect relay settings in different zones of protection. Therefore, NERC established the PRC-027-1 Standard to maintain the coordination of protection systems on bulk electric system (BES) elements by detecting and isolating faults, such that the protection system operates in the intended sequence. However, many electric utilities lack mature processes to meet the requirements of PRC-027-1.**

This paper provides a step-by-step guide to comply with NERC PRC-027-1 by exploring the following areas: an introduction and purpose of the standard, a systematic approach to developing processes and protection settings, common and unique coordination challenges, and methods to automate repetitive tasks. Furthermore, the process put forth in this paper was used as the basis of the PRC-027-1 compliance program for the Metropolitan Water District of Southern California (MWD). Real-world challenges associated with this process from an end-user point of view are also discussed.

I. Introduction

The North American power grid experienced one of its largest blackouts on 9 November 1965, which affected nearly 30 million people in Connecticut, New York, Rhode Island, Massachusetts, parts of Pennsylvania and northeastern New Jersey, and a large area of Ontario, Canada. One of the major reasons was incorrect relay settings that caused a heavily loaded 230 kV transmission line to open. Losing the transmission line caused an overload of several other 230 kV and 115 kV transmission lines as well as generation units, which resulted in a blackout of the Northeast region [1]. In response to the 1965 blackout event, the National Electric Reliability Council was formed in 1968, which subsequently became today's North American Electric Reliability Corporation (NERC). North America continued to experience wide-area outages periodically even after the formation of NERC. Although NERC was formed, it was a voluntary organization and could not set mandatory or enforceable standards. In August 2003, North America experienced the worst blackout recorded leaving approximately 50 million people in Ontario, Canada, and the northeastern United States without power. In response, the US Congress passed the Energy Policy Act of 2005 to authorize the creation of an audited, self-regulated electric reliability organization. This would span the United States with oversight from the Federal Energy Regulatory Commission (FERC). In 2006, FERC certified NERC to serve as the Electric Reliability Organization, giving the organization the power to create mandatory and enforceable standards as well as propose methods to enhance the reliability of the North American electric grid. Consistent with NERC's charter, the NERC Planning Committee formed a Protection System Misoperations Task Force group in 2012 to analyze the possible root cause of misoperations and address reliability issues. The research showed that approximately 65 percent of misoperations were caused by incorrect settings, logic and design errors, relay failures or malfunctions, and communication failures [2].

In 2018, NERC introduced a new Protection and Control Standard titled "PRC-027-1 Coordination of Protection Systems for Performance During Faults," and the standard came into effect on 1 April 2021. This standard replaces Reliability Standard PRC-001-1 and addresses protection system coordination issues through its requirements and measurements. The standard requires entities to maintain coordination on bulk electric system (BES) elements, such that protection systems operate in the intended sequence during faults [3].

PRC-027-1 is divided into three main requirements, which are Requirements R1, R2, and R3.

Requirement R1 involves maintaining an accurate short-circuit model, establishing a process for developing new and revised protection settings, and outlining requirements for collaborating with neighboring entities for BES elements under study.

Requirement R2 provides three options to perform a partial and/or a full system coordination study. A wide-area protection analysis comprises sensitivity, selectivity, and speed of operation. To limit the detrimental effects of cascading outages, PRC-027-1 emphasizes the selectivity requirement. Achieving the trifecta of perfect sensitivity, selectivity, and speed of operation can be difficult. Furthermore, attaining proper coordination also relies on several other factors, including the accuracy of the system model, evaluation of contingency scenarios, BES owners' operational practices and protection philosophy, compliance with other NERC PRC standards, etc. Protection engineers are often required to make several subjective decisions, which makes the process more of an art than a science. This paper explores and lays out some unique coordination scenarios that entities can document in their coordination philosophy.

Requirement R3 ensures the processes established in Requirement R1 are utilized in a systematic way for developing new protection settings and revising existing settings. Even though implementing the processes from R1 may be laborintensive, templates can be developed to streamline compliance procedures and automated tools can be created to reduce the burden on the BES entities.

The goal of this paper is to provide a step-by-step approach to comply with all three requirements of NERC PRC-027-1. This paper also shares the perspective of a small electric utility, Metropolitan Water District of Southern California (MWD), on real-world challenges and solutions regarding compliance.

II. Requirement R1

Many electric utilities or BES element owners do not have well-established processes to maintain an accurate system model or a well-documented protection philosophy, perform periodic reviews of system fault currents and relay settings, and collaborate with interconnecting entities prior to deploying protection relay settings. As a result, inaccurate information may be propagated during the development of settings and possibly cause unintended circuit breaker operations. To mitigate potential human errors and ensure that the protection system operates in the intended sequence, PRC-027-1 Requirement R1 emphasizes that all electric entities must establish a process for the following new and existing equipment:

- Review and update of short-circuit models.
- Review of the developed protection settings.
- Collaborate with interconnecting entities to exchange all required information and resolve all coordination issues.

The standard is applicable to BES owners and operators for "all Transmission Elements operated at 100 kV or higher, and Real and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electrical energy," unless included or excluded by Application of Inclusion, Exclusion [4].

This section provides a methodical approach for electric entities to streamline the internal process. Potential challenges faced by smaller entities that lack dedicated resources for this effort are also presented.

A. Maintaining an Accurate Short-Circuit System Model

The validity of short-circuit calculations and protective relay coordination set points are dependent on the accuracy of the power system model. It is therefore very important to ensure that all sources, impedances, and protection elements are modeled accurately. Maintaining an accurate short-circuit model has been one of the major challenges for electric entities, especially those that have been in operation for a long time. It can be difficult for these entities to obtain original equipment manufacturer data sheets or verify the accuracy of transmission line, transformer, or generator parameters. Another commonly observed problem is when different versions of the system model are maintained by multiple groups within the same entity. For example, one version of the system model is maintained by a transmission planning group whereas a different version of the system model is owned and maintained by a team of protection engineers. Another example is when an entity may have a current system model, a next-year model for a temporary upgrade, and a five-year model for planning purposes. Since virtually all bulk electric systems are interconnected regionally, maintaining an accurate system model can be challenging. Not all changes in the neighboring systems are known due to delays or gaps in communication. To address these issues, it is recommended that entities establish a process to update their short-circuit model and the time interval when internal teams should collaborate to exchange updates made to the system model before integrating updates to the existing model.

Furthermore, it is recommended that the following information be verified for a new or an existing short-circuit system model:

- The protection one-line diagram and system layout maps must be consistent with the short-circuit system model.
- The equipment parameters in the system model must match with the parameters from equipment manufacturers' nameplate information and equipment test reports, such as generators and transformers (generator step-up transformers, unit auxiliary transformers, autotransformers, and power transformers).
- The line impedance parameters must be verified for overhead transmission lines and/or underground cables. Obtaining these parameters can be challenging especially for older lines in service. There are tools available that can assist protection engineers with calculating the line parameters if information such as tower structure data, line length, phase and ground conductor size, and right-of-way data are available. The accuracy of zero-sequence and mutual coupling impedance values is critical in the case of mutually coupled lines. This will be discussed in further detail in Section III, Requirement R2.
- The protection settings for the BES elements entered in the system model must be validated with the relay-settings calculation sheet for both new and existing protection devices, including accurate tapped current transformer (CT) and potential transformer (PT) ratios.
- Protection engineers must be careful and reasonable with their assumptions in situations where equipment parameter information is not available. All assumptions must be properly documented in the system model or protection setting calculation sheets.
- An understanding of the system operations is necessary to determine which equipment is in or out of service. This has a significant impact on the calculation of fault currents and coordination of protective devices under evaluation.
- Event reports obtained from in-service relays can also assist in fault current analysis when compared with the short-circuit model.

Managing different system models can be challenging. Once the electrical system has been modeled in a power system software, it is important for the model to be periodically verified to maintain its accuracy through configuration changes or future upgrades. This process may entail the following:

- Implement a policy to use only the approved system model from a centralized secured network directory. This decreases the chance of different groups having different local copies of the system model. Establish a check out process for the applicable model.
- Identify owners who maintain the latest versions of the system model and equipment parameters. Save the most recent test data reports in a common network directory that is easily accessible to the system modeling engineer.
- Maintain a tracking document of any revisions made to the applicable system model, along with the name of the responsible engineer, a description of the change, and the date the changes were applied. Power system modeling software may provide some form of version tracking with the ability to add notes. This feature can be leveraged to maintain and document revisions made by authorized personnel. Additional information, such as three-phase and single phase-to-ground fault currents, existing protection relay settings, and system topology should also be captured.
- Develop a process to ensure that engineers always obtain the correct source of documentation when any updates are made to the equipment parameters or protection relay devices in the system model.
- Identify reviewers who can perform quality checks when updates or modifications to the system model are necessary. Peer review of model updates is crucial to ensure that the integrity of the model is maintained. Data entry can be prone to errors with different units of measurement used across different software vendors. Establishing a peer review feedback process can help mitigate error propagation.
- Use version control of the system model with the latest date, and archive the old files. This minimizes confusion when obtaining the latest file from the specified secured network directory.
- Add security measures and/or backup methods to prevent unauthorized users from purposefully or accidentally deleting, modifying, or overwriting important information.
- Conduct periodic internal meetings or exchange updates via written communication in situations where multiple groups maintain the system model. A good communication plan can help minimize system model divergence.

B. *A Review of Developed Protection System Settings*

The first electrical protective devices were deployed over 100 years ago. Throughout most of electrical power history, engineers would perform protection setting calculations using a pen and paper. While this method may be adequate for smaller systems, it may not be practical for larger entities with multiple engineers working on a variety of protection schemes and applications. For example, different engineers may have different approaches in developing protection settings for multiterminal or mutually coupled transmission lines. To achieve consistency between different engineers, the first step is to establish a standardized and well documented protection scheme and coordination philosophies for all equipment and applications.

The protection philosophy document can include the type of protective relays, the protection elements used, and the criteria on how to set each of the protection elements for the equipment under evaluation. Additionally, it is recommended that a coordination philosophy is developed to include the type of contingencies, operating scenarios, the boundary of the study, type of fault currents to be simulated in the system model, minimum required fault clearing times, and other requirements. Even though PRC-027-1 does not make it mandatory to develop protection and coordination philosophies, having these well-documented standards offers several advantages, such as:

- Acting as a guideline document for developing new or revising existing relay protection settings.
- Serving as a knowledge transfer document for training new protection engineers on relay setting calculations.
- Reducing the effort of replacing experienced engineers who leave or retire.
- Helping maintain a consistent approach for developing settings for all enabled protection schemes.
- Addressing the issue of security and dependability, and critical clearing times for protection devices.
- Assisting in identifying knowledge gaps and areas of improvement to comply with new requirements for grid modernization.
- Serving as a reference and a quality control document for reviewers.
- Serving as a basis for limiting liability in the event of life safety impacts, property damage, and/or economic damage to interconnected systems.

Furthermore, the protection and coordination philosophy documents must be maintained and updated when modifications to the protection scheme and coordination goals are needed. While protection and coordination philosophy documents are meant to aid engineers in developing or reviewing protection settings, it must be emphasized that no philosophy is applicable for all special situations and corner cases. The protection engineer must still proceed with due diligence when developing or reviewing relay setting calculations. The following are some of the important considerations that one must account for:

- Relay setting calculations must use accurate equipment and system parameters, and the fault currents must be obtained from the owner maintaining the latest short-circuit system model.
- Protection setting calculations must account for all applicable system configurations under normal, alternate normal, and contingency scenarios.
- Updates to the protection philosophy or settings that directly impact the BES elements under study must be evaluated.

- Any amendments to existing system operational practices must be documented.
- The protection settings should meet coordination requirements.
- The developed protection set points must comply with other NERC PRC standards such as:
  - PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection.
  - PRC-023-4 – Transmission Relay Loadability.
  - PRC-025-2 – Generator Relay Loadability.
  - PRC-026-1 – Relay Performance During Stable Power Swings.

Applicable system configurations, BES elements, and coordination requirements are discussed in Section III. After the protection calculation sheets are developed and reviewed, it is important to save the signed documents in a proper network location with a document owner assigned.

C. Collaboration With BES Neighboring Entities

The BES is formed by the interconnection of multiple functional entities, such as transmission owners, generator owners, and distribution providers [3]. It is important for neighboring entities to collaborate and communicate their latest system information such as short-circuit model updates, maintenance or changes in system operation schedules, and planned outages that have an impact on system coordination. Communicating in advance gives the other entity an opportunity to plan the resources and address action items in a timely manner.

A communication plan must be established to exchange information with neighboring entities when any changes in the system operation impacts the short-circuit model and/or protection settings. One of the major challenges is having agreement on protection philosophies between all involved entities. For example, transmission owners from separate entities may use dissimilar relays for transmission line protection. This may cause coordination difficulties due to different operation principles of these protective devices, resulting in different fault clearing times [5]. It is recommended that interconnecting entities plan and collaborate in early stages to understand each other's philosophies. To mitigate these issues, the process should include communication of all the updates to the neighboring entity with proper documentation. This exchange of information between different entities must be written and may include:

- Updates to the system model, including Thevenin equivalent impedance model and/or additional generation sources.
- Comparison of the fault currents obtained at the station buses with the interconnecting entity. This is to ensure that all entities obtain similar fault current values.
- The most recent protective relay settings and test reports.
- Protection and coordination philosophies used.
- Contact information of all entities involved.
- Reason(s) for the exchange.
- Expected completion dates.
- Documentation of the acknowledgment received from all parties involved.

Additionally, when neighboring entities share their system models and/or protection settings, all parties involved must properly document, review, and file the information. The process required to maintain the documentation can be followed from the process discussed for the short-circuit model, as explained earlier in the section.

Once the communication plan is established and all entities possess an accurate system model and protection settings, a coordination study can then be performed. Continuous communication and collaboration are required between the entities involved until all coordination issues, if any, are resolved. The final calculations report should be reviewed by a designated reviewer as an additional layer in the quality control process. Lastly, the latest system model and protection settings must be properly saved in a network folder, and both entities must approve via written communication for complete record keeping purposes. Keeping documentation is required per PRC-027-1 Requirement R3, which will be discussed in Section IV.

D. Conclusion on Requirement R1 From End User's Perspective

MWD owns and operates approximately 300 miles of 230 kV transmission facilities, located in southern Nevada and eastern California, which are primarily used to deliver power to its pumping plants along the Colorado River Aqueduct (CRA). As part of the CRA 230 kV system, MWD owns four substations. Each substation includes transmission line terminals, operating buses, transfer buses, circuit breakers, and transformer banks. Each non-BES transformer bank is used to serve MWD's radial pump loads.

Many of MWD's systems were designed in the early 1930s when codes, standards, and engineering methods were substantially different than today. Additionally, many of the original equipment manufacturers are no longer in business, and obtaining required data can be extremely challenging.

Prior to the implementation of the NERC PRC-027-1 Standard, MWD's protection philosophy was only informally documented. Since MWD's 230 kV system was small, the need for extensive documentation was seemingly not required as generally only one engineer was responsible for the design, maintenance, and coordination of protection settings. For record keeping, hard copies of settings calculation were stored in binders at the MWD headquarters facility. Electronic copies of calculation records, along with the study models, were typically saved in the computer or file folder by the engineer who performed the study. There was no central location for electronic copies of calculation records and system models, which made it challenging to manage these documents. Additionally, when seasoned staff retired, a considerable amount of knowledge was lost as documentation of design requirements, protection philosophy, and contingencies considered were not always thorough.

Furthermore, despite having good working relationships with its two neighboring entities, a lack of formal information sharing agreements meant MWD often did not have access to their up-to-date system information.

As NERC PRC-027-1 became an effective standard, it was clear that MWD would have to make significant changes to its internal processes. Additionally, internal electrical engineering resources or personnel are limited and do not always have the necessary experience with complex transmission systems. For example, MWD has a four-terminal line with a very strong source behind two terminals, and a very weak source behind another terminal with very long lines. As a result of these factors, MWD's engineers and compliance team determined that the best strategy to meet MWD's regulatory requirements was to enlist a qualified consultant.

The requirement for the qualified consultant was to demonstrate experience in both protection settings development and regulatory compliance. Other criteria included evaluating the consultant's track record of executing similar work and their availability to work with incomplete information or partially defined requirements.

By partnering with an experienced consultant, MWD was able to update and properly document its protection philosophy, system model, protection settings and calculations, as well as formalize the communication process with neighboring entities. Additionally, MWD created a formal two-step review process for quality control of all protection settings as well as a tracking process that not only documents change to settings, but why they were made. Lastly, a secure centralized network location was established that ensures relevant information is not stranded and accessible by all users with need.

Although compliance standards are frequently viewed as unnecessary or extra work, in MWD's case, this process generated significant benefits outside of just meeting the regulatory compliance goal. By embarking on this process, additional staff training needs were identified, quality control processes for non-NERC settings were greatly enhanced (as these are the majority of MWD's components), and documentation was collected and centralized for future reference.

III. Requirement R2

Modern power systems continue to grow in complexity due to the interconnected networks in the system. Economic pressure can force electric entities to maximize the use of their system close to the withstand capability of equipment such as transformers, lines, generators, etc. Operating the BES in this manner greatly increases the need for a reliable protection system as any misoperation of a protective device can easily lead into a wide-area outage. The reliability of a relaying scheme is defined by dependability and security. Dependability is the ability of a scheme to operate for any in-zone fault. Security is the ability of a scheme to not operate when there is no in-zone fault [6]. Protective relays and instrument transformers form the backbone of any protection system. The performance of a protection system is defined by sensitivity, selectivity, and speed of operation during abnormal conditions. Sensitivity refers to the condition where protective devices detect the minimum fault in their protected zones [7]. Speed of operation is the ability of the protection system to isolate a circuit in the shortest possible time once an abnormal event is detected. Minimizing the operating time of a protective device limits equipment damage and allows recovery of the power system to a stable operating state. Selectivity, which is also referred to as coordination, is the ability of the protection system to isolate a fault in the shortest time possible with minimal power loss to system components [8].

The NERC PRC-027-1 Standard places emphasis on selectivity for Requirement R2 and gives entities three options to comply with this requirement when performing a coordination study:

- Option 1: Perform a protection system coordination study within a time interval of six years.
- Option 2: Periodically review the available fault currents, and compare the present fault current value with an established fault current baseline. If the available fault current is greater than the established fault current value by more than 15 percent at a bus to which the BES element is connected, then a coordination study is required, within a time interval of six years.
- Option 3: Use a combination of Options 1 and 2.

The following section provides recommended steps for performing a coordination study using a systematic approach. The advantages and disadvantages for each option are also examined in detail. Subsequently, cases where attaining coordination is difficult are explored with examples. Finally, an end user's perspective in complying with NERC PRC-027-1 Requirement R2 is also discussed.

The recommendations for the process to perform a study are those of the authors and do not represent the NERC PRC-027-1 Standard. The standard only discusses the options that can be chosen by the entity to perform a study.

A. Process to Perform a Study

A coordination study requires planning, identifying the scope, and implementing the processes established in Requirement R1. The steps to perform a coordination study can be divided into the following stages:

- Define the network boundary of the system to be studied.
- Identify the relevant system scenarios and configurations.
- Ensure that the correct system model is used for fault analysis (Requirement R1). Collaborate with interconnecting entities, if applicable.
- Define primary and backup coordination pairs.
- Review or develop the protection philosophy and coordination guideline.
- Evaluate existing and/or develop new protection settings (Requirement R3).
- Update the short-circuit model with the latest protection settings.
- Determine the method of the study.

- Perform a coordination study using Option 1, Option 2, or Option 3.
- Collaborate with interconnecting entities, if applicable. Resolve and document all coordination issues as needed (Requirements R1 and R3).

1) Define the Network Boundary of the Study

Prior to performing a coordination study, it is important to establish a scope for the analysis. The first step is to identify the equipment, protective devices, and system boundaries based on the station one-line diagram. The network boundary can be divided into either a wide-area coordination, or a partial coordination study as shown in Fig. 1. A wide-area coordination study provides a comprehensive analysis of coordination and evaluates the sensitivity and speed of operation of protective devices for a large area or the entire system with an objective to increase system reliability. The boundary of a wide-area coordination study can be at a point of interconnection, a designated geographical area, or at a different voltage level through a power transformer. A partial study involves investigating only a limited number of protective relays within a system. The boundary of a partial study can be an internal entity, external neighboring entity, or an adjacent transmission line or substation. An internal entity can consist of a generator owner, transmission planning group, and a team of protection engineers within the same utility. An external neighboring entity requires collaboration with a different organization. An example of a partial coordination study could be providing protection relay settings for a new transmission line that has just been installed. The coordination analysis is limited to the new and adjacent relays instead of the entire transmission system.

Generally, transformers and open points (disconnect switches, open breakers, etc.) can serve as obvious locations for establishing boundaries. If the equipment interconnects with other entities, a communication plan must address the process of coordinating the protection elements, as established in Requirement R1.

2) Identify Relevant System Scenarios and Configurations

Once the boundary of the study has been clearly established, the next step is to identify the system's operation configurations. Each configuration is a way for power to be produced from a generation station, transmitted to an electrical substation, and then distributed to loads or other substations. For example, consider a system that has multiple generation sources. Identify which generators remain online or offline under normal, emergency, and other operating conditions. Multiple system configurations consider several factors, such as seasonal loading conditions, and import or export power agreements. Another example of this case is wind farms or peak power generation. Generation from windmills is the normal condition. If there is insufficient wind or if the source is taken offline, then it can be considered as an alternate normal [6]. Systems that operate for multiple configurations can have a significant impact on the coordination of protective devices depending on the path of the fault current. When performing the study, each system configuration must be evaluated. In a boundary-limited study, the adjacent system configuration of normally open breakers and lines normally out of service play a significant role in the study.

A commonly observed problem is when engineers run fault cases with different outages on a system model in an abnormal or incorrect state. Engineering effort can be saved if the system model is set to the normal state prior to performing a study and after the study is completed. Therefore, careful attention should be given to the normal state prior to running different fault cases.

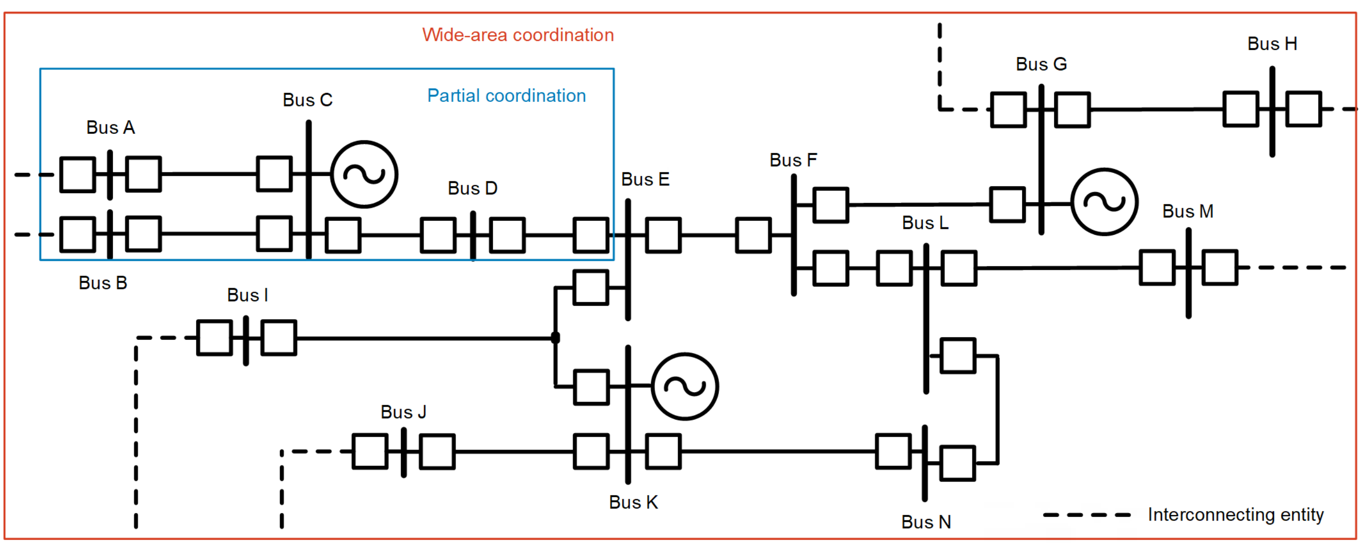

Fig. 1. Partial vs. Wide-Area Coordination Study Scope.

3) *Obtain or Develop an Accurate Short-Circuit Model*

The validity of the calculated fault currents is only as good as the accuracy of the short-circuit model of the system. It is critical that the protection engineer compares the existing model with the latest station one-line diagrams to ensure consistency. Furthermore, it is important to verify equipment parameters from manufacturers' data sheets, and review all data entered in the model. For both new and existing systems, the recommended checks discussed in Section II can be used to obtain an accurate short-circuit model.

If the scope involves collaboration with neighboring entities, a preliminary conversation to exchange required information such as system model, latest protection settings, and protection and coordination guidelines can also be initiated. This can help all stakeholders plan a schedule and identify the next steps.

4) *Define Primary and Backup Coordination Pairs*

The next step in the coordination analysis is to identify all the primary and backup protective devices for the equipment to be faulted. For every fault in a system, the closest protective device to the fault is considered the primary device. All primary protective devices should interrupt the faulted circuit first. Other protective devices that detect the fault are backup to the primary devices. Backup devices should operate only if the primary device fails to clear the fault. Refer to Fig. 2 for a visual description of primary and backup protective devices. The protective devices must be coordinated up to one tier level, with two tiers being preferable. In some cases, coordination may be required up to two tiers, such as with parallel lines or mutually coupled lines.

For this step, developing a spreadsheet is advised. The primary and backup coordination pairs can be defined by determining the faulted equipment. Typically, this includes lines, transformers, and buses. This spreadsheet can be further elaborated to include details such as different fault types, fault locations, system configuration, and contingencies to be studied.

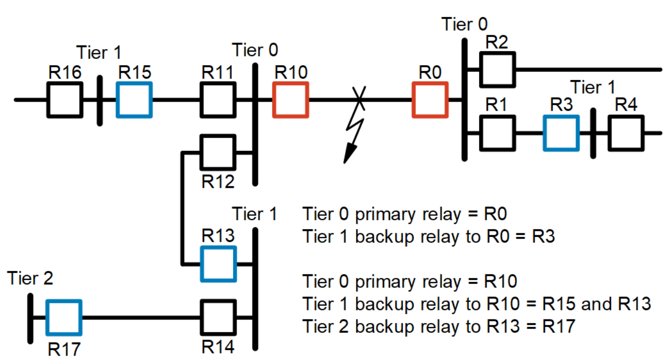

Fig. 2. Identifying Primary and Backup Coordination Pairs.

5) *Review or Develop Protection Philosophy and Coordination Guidelines*

As discussed in Section II, the NERC PRC-027-1 Standard does not explicitly call for entities to develop a protection philosophy or a coordination guideline. However, it is strongly encouraged that a well-documented philosophy be developed to ensure consistency in the design, development, and implementation of the relay settings. A protection philosophy provides evaluation criteria and guidelines for all the protection elements enabled in the relay for each application. As every entity has its own philosophy and operational practices, evaluating protection elements not related to coordination is beyond the scope of this paper. This section is intended for protection engineers to analyze and consider some important factors that a coordination guideline can entail.

The coordination study is performed with the expectation that all protection schemes with a predefined zone of protection (i.e., transformer and bus differential) are out of service. This is also referred to as a "unit protection scheme." Instantaneous clearing of a fault reduces the likelihood for backup relays to misoperate. The objective of a coordination study is to evaluate non-unit protection elements such that the faults can be isolated by the closest protective devices. In other words, the backup relay should not also attempt to clear the fault at the same time as the primary relay.

Furthermore, the power system must always be able to operate reliably under all N–1 conditions. A loss of any single component, such as outage of a high-speed protection scheme, is an N–1 condition. N–2 is when the power system experiences the loss of two elements. Loss of dual high-speed protection schemes may or may not be considered as N–2. For example, losing a shared coupling capacitor voltage transformer (CCVT) on a dual high-speed protection system is considered a single point of failure (N–1). The power system should be designed to survive both single contingency (N–1) and high-probability double contingencies (N–2) [6]. Therefore, the best practical solution is to assume that all the unit protection schemes are out of service.

Additionally, proper coordination is required for pilot protection schemes, such as directional comparison blocking (DCB) or permissive overreaching transfer trip (POTT), to operate correctly [6].

After determining the possible system configurations, and primary and backup relay coordination pairs, a coordination study guideline should define contingencies, fault types, and minimum coordination time interval (CTI) requirements. The response of the primary and backup protective relays can be evaluated for four types of faults:

- Three-phase fault.
- Single phase-to-ground fault.
- Phase-to-phase fault.
- Phase-to-phase-to-ground fault.

The three-phase balanced fault typically accounts for the maximum fault current the system may experience. The single phase-to-ground fault is the most common type of fault as shown in Table I [6]. Typically, it may be sufficient to evaluate three-phase and single phase-to-ground faults. However, if extensive study is preferred, other fault types can also be included.

TABLE I
FAULT TYPE DISTRIBUTION

Fault Type	Distribution (%)
Three-phase	5
Phase-to-phase-to-ground	10
Phase-to-phase	15
Phase-to-ground	70

The following fault locations should be simulated from the short-circuit model:

- Local bus fault.
- Close-in fault.
- Fault along a transmission line (as a percentage increment of the length).
- Line-end fault with end open.
- Remote bus fault.

Another factor to bear in mind when performing a study is the number of contingency scenarios to evaluate. A contingency scenario is defined as taking any one piece of equipment out of service. For example, faulted equipment may see lower fault current when a strong source is taken out of service. Evaluation of this scenario is critical in determining if the protective device closest to the faulted equipment is sensitive enough to detect, operate, and isolate the fault. Selecting contingencies can be simplified with a simple theory: minimize infeed and maximize outfeed.

Infeed is the presence of additional sources (a generation source, transmission line, or grounded transformer) of current between the primary (relay at CB B) and backup (relay at CB A) relays as shown in Fig. 3. In general, this aids the coordination efforts. For distance elements, infeed causes the fault to appear at a farther location than it is located. For overcurrent elements, infeed makes it such that the backup relay sees less current than the primary. The primary relay operates at a higher current point on the time current curve (TCC), allowing for faster operation. The lower current seen by the backup relay adds additional time delay. The objective of contingency selection is to evaluate the system under worst-case coordination by minimizing the infeed effect.

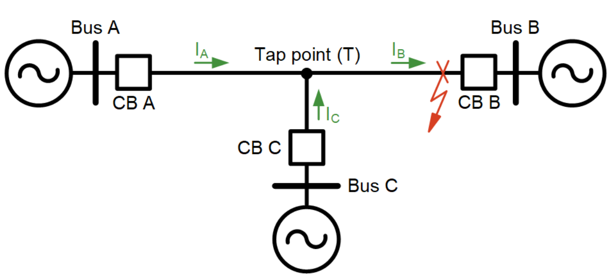

Fig. 3. Example of Infeed.

On the other hand, the effect of outfeed takes shape in two forms. A classical short-circuit study does not take load current into account. In a real scenario, the system continues to source some level of load current even during faulted conditions, as shown in Fig. 4. In multiterminal lines, a condition where current seen by the primary relay is not seen by the backup relay can arise. Another example of the outfeed effect is shown in Fig. 5. In this example, an alternate current path is established to the faulted location. This causes the fault to appear closer than it is for distance elements. For overcurrent elements, the backup relay could potentially time faster because it measures a higher fault current. Therefore, to evaluate for worst-case coordination situations, the outfeed effect should be maximized.

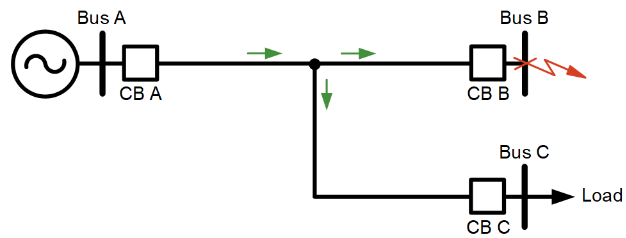

Fig. 4. Example of Outfeed – Load Condition.

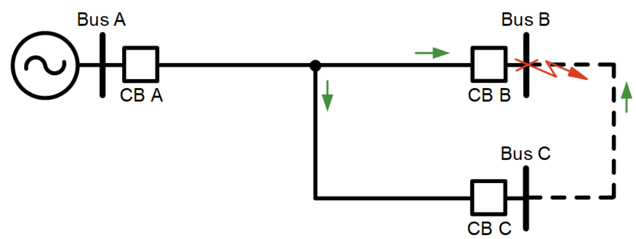

Fig. 5. Example of Outfeed – System Configuration.

As an example, a coordination case to be evaluated is shown in Table II. This table can be generated for different fault types as a record.

A coordination guideline should include the minimum trip time difference requirement between the primary and backup relays, known as CTI. The minimum desired time margin for a 5-cycle breaker is typically between 0.20 and 0.50 seconds (12 and 30 cycles) for digital relays [9]. This includes the circuit breaker interrupting time, relay tolerances, and setting errors.

The CTI for definite-time elements and for inverse-time elements differ. Delays introduced to definite-time elements are meant to coordinate with other relays and breaker failure schemes, or to ride through transient conditions. The CTI for definite-time elements can range from 0.13–0.2 seconds (8–12 cycles) for fault clearing, and 0.3–0.4 seconds (18–24 cycles) to coordinate with breaker failure schemes [6]. Inverse-time elements require a longer CTI due to small differences in measured current and protective system technology. For example, older electromechanical relays require precise calibration of their time dials, whereas modern microprocessor-based relays use a numerical input value to obtain a precise relay operating time.

TABLE II
EXAMPLE – SUMMARY OF SCENARIO

Scenario Number	Primary Relay	Backup Relay	List of Contingencies	Faulted Line
1	Line A (Relay name)	Line B (Relay name)	Line outage – Line C (66 kV out of service)	Line AA

All exceptions must be documented if coordination is not achieved. Furthermore, it is recommended to categorize the results based on the severity of worst-case CTI under all normal and contingency scenarios. This can assist engineers in addressing protection settings that require immediate attention. An example is shown in Table III.

TABLE III
EXAMPLE – RISK CATEGORY CLASSIFICATION BASED ON CTI

Risk Level	Color Code	Finding Category and Description
No risk	White	No coordination issues. CTI ≥ 0.40 s
Low	Orange	Marginal CTI between primary and backup protection relays. 0.20 s ≤ CTI < 0.40 s
High	Red	Potential for misoperation. Incorrect setting of a primary or backup element, resulting in CTI < 0.20 s

The coordination study evaluates the primary and backup relays’ response to each type of fault at every location for all configurations and for all applicable contingency scenarios within a defined boundary. Coordination is achieved if the operating time of the backup protective device is greater than or equal to the minimum required CTI of its associated primary device. Even for a small coordination study, a protection engineer may need to evaluate numerous cases.

6) Review or Develop Protection Settings

Once the protection engineers have reviewed the philosophy and obtained an accurate short-circuit model, the next step is to review the existing or develop new protection settings. The PRC-027-1 Standard requires the following BES elements to be coordinated [3]:

- Distance element (21), if infeed is used in determining the reach (phase and ground distance) or zero-sequence mutual coupling is used in determining the reach (ground distance),
- Instantaneous overcurrent element (50),
- Time-inverse overcurrent element (51), and
- Directional overcurrent element (67) if used in a noncommunication-aided protection scheme.

Systems undergoing upgrades must consider review and evaluation of protection settings based on the in-service settings obtained from the relays installed onsite. All the equipment parameters and fault currents used to determine the pickup set points must be properly verified with the existing settings. The pickup set points and delays must also align with protection and coordination philosophy, and all discrepancies must be documented. For systems where new equipment is added, protection settings will be developed based on the accurate short-circuit model, and protection and/or coordination philosophy. A review of existing or development of new protection settings must follow the processes established in Requirement R1.

7) Update the Short-Circuit Model With Latest Protection Settings

At this stage of the process, the latest protection settings can be updated to the latest short-circuit model. For all the other adjacent equipment in the vicinity, it is recommended to update the model with the latest protection settings up to two tiers of the network boundary. If interconnecting entities are involved, obtain their latest Thevenin equivalent model and protection settings from all the stakeholders, and verify the bus fault current values prior to performing a coordination study. All protection settings entered or automatically imported to the short-circuit model must be properly reviewed.

8) Determine the Method of the Study

A coordination study can be performed in two ways: static or sequential (stepped event analysis). The most widely used method for performing a study is the static method.

The static method of coordination uses TCCs and impedance (R-X) plots to study the system. In this type of analysis, the configuration of the breakers is fixed. As the fault is placed on the primary equipment, TCCs and R-X diagrams are checked for all types of faults and contingencies, and at different fault locations. For transmission lines, the static method must consider evaluating the CTI with remote breaker closed and remote breaker open. Generally, for overcurrent elements, a study performed with remote breaker open yields the minimum CTI and is considered the worst-case scenario.

The stepped event analysis or sequential method of coordination applies a fault on a line and examines the sequence of events. In this type of analysis, the configuration of the breakers is not fixed. The sequential study evaluates the operating time of the primary relay and the projected fault clearing time of the backup relays. Similar analysis can be performed for transmission lines with a relay at the remote end. However, this method has several drawbacks. The stepped event analysis or sequential method introduces a new variable, i.e., the operation of the remote relay. This method does not evaluate the sequence of events when the remote breaker fails to operate. In such scenarios, the breaker failure timing needs to be considered a part of the sequence. Additionally, when operating on time overcurrent elements, the relay measures different fault currents depending on the location of the fault. This leads to an operating time that cannot be accurately determined from the TCCs. Therefore, it is not possible to quantify and plot the TCCs.

The recommended philosophy is to use the static method for coordination followed by the sequential method to verify the operating times of the primary and backup relays. In certain cases, it may be necessary to solely rely on sequential clearing because of weak sources or system configuration causing outfeed. Details on this scenario are discussed later in this section.

The static option may not be a cost-effective solution for large systems performing a wide-area coordination study since it requires checking TCCs and R-X plots for multiple relays and system configurations. Therefore, entities may prefer to use a wide-area coordination study feature in the software for stepped event analysis or the sequential method.

9) Perform a Study Using Option 1, 2, or 3

Over time, the power system encounters changes that can cause variances in available fault current, impacting relay coordination of the BES elements under study. To minimize the risk, the NERC PRC-027-1 Standard requires entities to perform a coordination study from any of the three options.

Option 1 requires the entities to perform a complete coordination study of their system within a time interval that does not exceed six calendar years. This approach is simple in concept.

Option 2 allows entities to periodically check the available fault current against a baseline value at each bus to which a BES element is connected. A baseline is established when the fault currents are calculated at the time a short-circuit study is performed under the normal configuration. If, during a short-circuit review, the difference in fault current (either three-phase or phase-to-ground) exceeds an agreed upon threshold (maximum threshold of 15 percent) from a previously established baseline, then a coordination study needs to be performed. This option is the least understood and can be subject to different interpretations. For example, the standard does not specify the network boundary of the coordination study once a deviation of greater than 15 percent has been detected at a bus. A common interpretation is for the coordination study to evaluate only protective devices connected at that bus. If transmission lines are present, distance and overcurrent relays at the remote bus may also be impacted. When evaluating ground fault elements, the reliability of ground distance and overcurrent elements can be affected by the current flow on mutually coupled lines. Once a bus has been identified with a fault current deviation of greater than 15 percent, it is recommended that the coordination study includes all the relays at that bus, as well as BES element protective relays at adjacent buses up to two tiers away. This ensures that not only local relays are evaluated, but the relays at adjacent buses as well.

Option 2 has a fundamental assumption that the system is already in a well-coordinated state, which means that the entity has well-documented standards, practices, and an accurate short-circuit model. This is concerning because the initial baseline sets the framework for all future studies. If this assumption cannot be supported, then the state of the existing coordination cannot be justified. It may not be prudent to assume that coordination studies are warranted only when the system changes from the baseline.

Another thing to note with Option 2 is that the standard does not discuss which baseline value to use for the short-circuit review. For example, if there is a thermal or conventional generating station that has become uneconomical to operate because of a high penetration of solar inverter-based generation, it is typically still included as part of the study. This is deceptive because under most system conditions, the conventional generator is offline (alternate normal condition) and the system may no longer coordinate due to the lower available fault currents from inverter-based resources. Small changes in distribution of infeed can have a large impact on the apparent impedance. Since the standard does not define "baseline," it is easy for an entity to be misled into complacency even though their coordination has changed drastically.

The standard allows for a maximum fault current deviation of 15 percent; however, choosing a lower value is encouraged. An entity that decides to use Option 2 should have already established an initial baseline before 1 April 2021. Consider the following example as shown in Fig. 6.

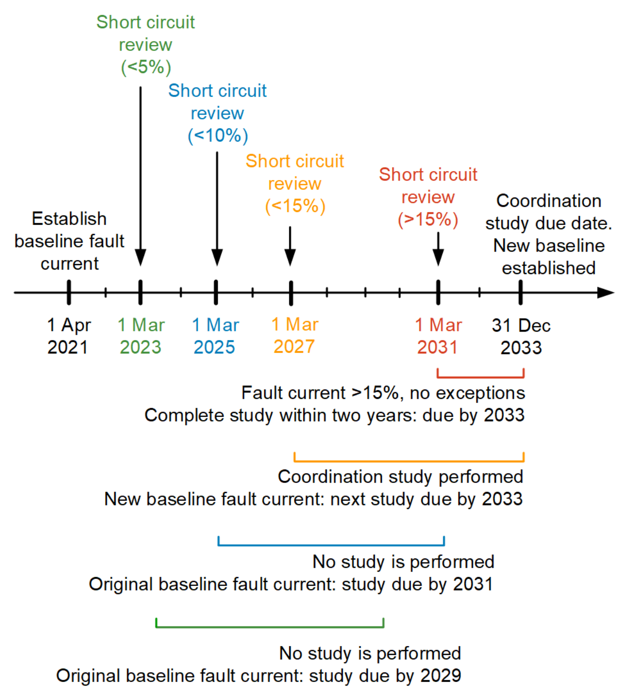

Fig. 6. Option 2 – Timeframe Example.

Assume that the short-circuit current calculated at a bus during the initial baseline was 10,000 amperes. If a short-circuit review performed on 1 March 2023 identifies 10,200 amperes (2 percent deviation from the established baseline), no coordination study needs to be performed since the increase in short-circuit current is below the maximum allowed deviation of 15 percent. The next comparison for the short-circuit review must be performed no later than six calendar years, i.e., 31 December 2029. However, it is to be noted that the baseline value for that bus remains at 10,000 amperes because no updated coordination study was performed. Similarly, a short-circuit current review performed by the entity two years later, on 1 March 2025, shows that the fault current increased to 10,600 amperes (6 percent deviation from the initial baseline). Once again, no coordination study is needed. On 1 March 2025, the entity will get another six years to perform a comparison review of short-circuit fault currents and a study, while the initial baseline fault current is still maintained at 10,000 amperes. This process continues until the fault current deviation between the next short-circuit current review and the initial baseline exceeds 15 percent.

Consequently, if an entity decides to perform the next short-circuit review on 1 March 2027 and observes a fault current of 11,200 amperes on that bus (12 percent deviation from the initial baseline), the entity has the option of performing a coordination study or doing nothing and waiting until the next short-circuit review. Should the entity decide to perform the study, the deadline will be six calendar years from the review date (31 December 2033). Once the study is complete, the fault current value of 11,200 amperes will be established as the new baseline on the study completion date. However, if the entity decides to do nothing, and a subsequent short-circuit review performed on 1 March 2031 identifies the fault current as 11,500 amperes (15 percent deviation from baseline), then the entity has only two years to complete the study. This is because the deadline was based on six calendar years from the date of the previous short-circuit review where the fault current did not exceed the 15 percent-threshold, i.e., 31 December 2033. Once the study is completed, the new baseline fault current will be established as 11,500 amperes at the study completion date.

A recommended time interval for a short-circuit review is one to two years, or any time a change is observed on the system. Categorizing the results based on percentage of fault current deviations may help entities plan in a timely manner when the next coordination study is required to be performed. An example is provided in Table IV. A color code system can be used to keep engineers appraised of the buses nearing the established deviation limit. Additionally, a sample table is also provided to track the baseline fault current value of a single bus, as shown in Table V.

Option 3 states that an entity can use a combination of Options 1 and 2 to comply with Requirement R2. One possible way to implement R2 is for an entity to perform a complete coordination study on 1 April 2023 (Option 1). The fault currents from this study can be used as baseline values. On 1 April 2025, the entity decides to compare the bus fault currents with those from the study. If the fault current deviation exceeds 15 percent, then a new partial study can be performed (Option 2 with a due date of 31 December 2029). Should the entity decide to perform a full coordination study at a future date, those results can then be used as the baseline.

TABLE IV
EXAMPLE – RISK CATEGORY IDENTIFICATION FOR % FAULT DEVIATIONS

Risk Level	**Color Code**	**Finding Category and Description**
No risk	Green	0–5% Coordination study is not required.
Low	Blue	5–10% Monitor the short-circuit currents periodically. Coordination study is not required but can be performed.
Medium	Yellow	>10% and <15% Initiate the process to inform the designated team members. Performing a coordination study is recommended at this stage.
High	Red	> = 15% No exceptions. A coordination study must be performed within the previously established six-year time frame.

Another way to implement Option 3 is that entities could choose to use Option 2 for areas where system upgrades such as addition and/or removal of sources, temporary changes to the system configuration, or integration with renewables are planned for future. Option 1 can be used on the remaining part of the system.

Entities can also implement Option 3 by using Option 1 for areas where frequent events or misoperations have occurred and using Option 2 on the remaining part of the system.

The main advantage of using Option 3 is the flexibility offered to the entity performing the coordination study. Since Option 3 is a combination of Options 1 and 2, the disadvantages are identical to those listed under Options 1 and 2. A summary of the advantages and disadvantages for each option is provided in Table VI.

TABLE V
A SAMPLE FOR TRACKING BASELINE FAULT CURRENT VALUES

Date	**Description**	**Bus Name**	**Initial Baseline Fault Current (Amperes)**	**Present Fault Current (Amperes)**	**Deviation from Baseline (%)**	**Due Date of the Study**
1 Apr 2021	Establish a baseline	A	10,000	10,000	NA	NA
1 Mar 2023	Short-circuit review	A	10,000	10,200	2.0	31 Dec 2029
1 Mar 2025	Short-circuit review	A	10,000	10,600	6.0	31 Dec 2031
1 Mar 2027	Short-circuit review	A	10,000	11,200	12.0	31 Dec 2033
1 Mar 2031	Short-circuit review	A	10,000	11,500	15.0	31 Dec 2033
1 Nov 2031	Perform a coordination study and establish a new baseline	A	11,500	11,500	NA	31 Dec 2037

TABLE VI
COMPARISON TABLE FOR PRC-027-1 REQUIREMENT R2 COORDINATION STUDY OPTIONS

	Option 1	**Option 2**	**Option 3**
Description summary	Perform a complete coordination study.	Perform a coordination study on buses where the fault current deviates by more than 15% or exceeds a predetermined value from the established baseline.	Combination of Options 1 and 2.
Scope	Broad, encompasses a BES owner's entire system.	Limited based on buses with a fault current deviation greater than defined value.	Periodically perform a full coordination study, or a partial study when the current baseline exceeds the initial baseline beyond a threshold (maximum 15%).
Advantages	Evaluates the coordination of all protective relays in the system on a fixed schedule. Allows entities to plan for the required resources ahead of time. Easy to maintain version control. Avoids ambiguity and minimizes human errors. Simplifies the coordination study process for protection engineers. No complex baselining requirements.	Fewer resource and time requirements since the study applies only to buses with a fault current over a defined margin. Collaboration with neighboring entities may not be required depending on the network boundary of the study. Ensures that relay settings are up to date if a short-circuit review is performed at a regular interval or during planned system modifications.	Offers flexibility to the entity when deciding which option to choose. Allows use of different options for different systems operated by the entity.
Disadvantages	System parameters and relay settings may not be up to date between coordination study intervals. Can become extremely labor- and resource-intensive since all changes and protective relays need to be evaluated, especially for large entities.	Higher probability of miscoordination where the fault current deviation threshold is close to the allowable 15% margin. Relying only on bus fault current deviation may not be sufficient. Individual branch currents may reflect a greater deviation. This may have an adverse effect on coordination of distance and overcurrent elements. Difficulty in maintaining a record of a baseline's fault current for all buses, especially for large systems. Impact on schedule and project execution when fault current deviation greater than 15% is identified during a short-circuit review close to the ending of six years calendar mark.	Depending on the option selected, similar to those given in Options 1 and 2.

Consider the following proposed alternative to comply with Requirement R2 Option 1. An entity with an accurate short-circuit model performs a full coordination study at a fixed time interval of every six years. At every planned system change, an entity should incorporate a partial coordination study as part of the organizational procedure. This method has several benefits:

- Does not require an entity to keep track of baseline fault currents.
- Minimizes the effort required during the full coordination study since all the required system changes within the entity's boundary should already have been accounted for.
- Is easy to plan resources for the study since it is on a fixed schedule, and part of planned system changes.

A noted disadvantage of this approach is that it requires strict adherence to the established process on when a full or partial study needs to be performed.

10) Collaborate With Interconnecting Entities and Resolve All Coordination Issues

All coordination issues must be resolved after performing the study. If coordination issues arise, any updates made to the BES elements being evaluated will require a study to be performed again until all coordination requirements are met. A flowchart to summarize all the recommended steps to perform a coordination study is provided in Fig. 7. If applicable, collaborate with interconnecting entities when performing the study and understand their philosophy to resolve all coordination issues. There could be cases when coordination is difficult to obtain. Communicate with neighbors and try to find an area of possible agreement to mutually resolve the coordination issues. The NERC PRC-027-1 Standard recognizes that there could be a possibility that the entities agree not to mitigate the coordination issues based on engineering judgment. The standard also recognizes that coordination issues may not be immediately resolved if the resolution involves system upgrades. Therefore, protection engineers should document all the results properly and follow the processes established in Requirement R1. Table VII documents an example of miscoordination.

The last step in this process is the deployment of protection settings in the field. PRC-027-1 encourages field engineers to document and communicate all issues that may have arisen during or after the commissioning stage. Analyzing the root cause and investigating misoperations assists protection engineers in identifying knowledge gaps and promotes learning for the team.

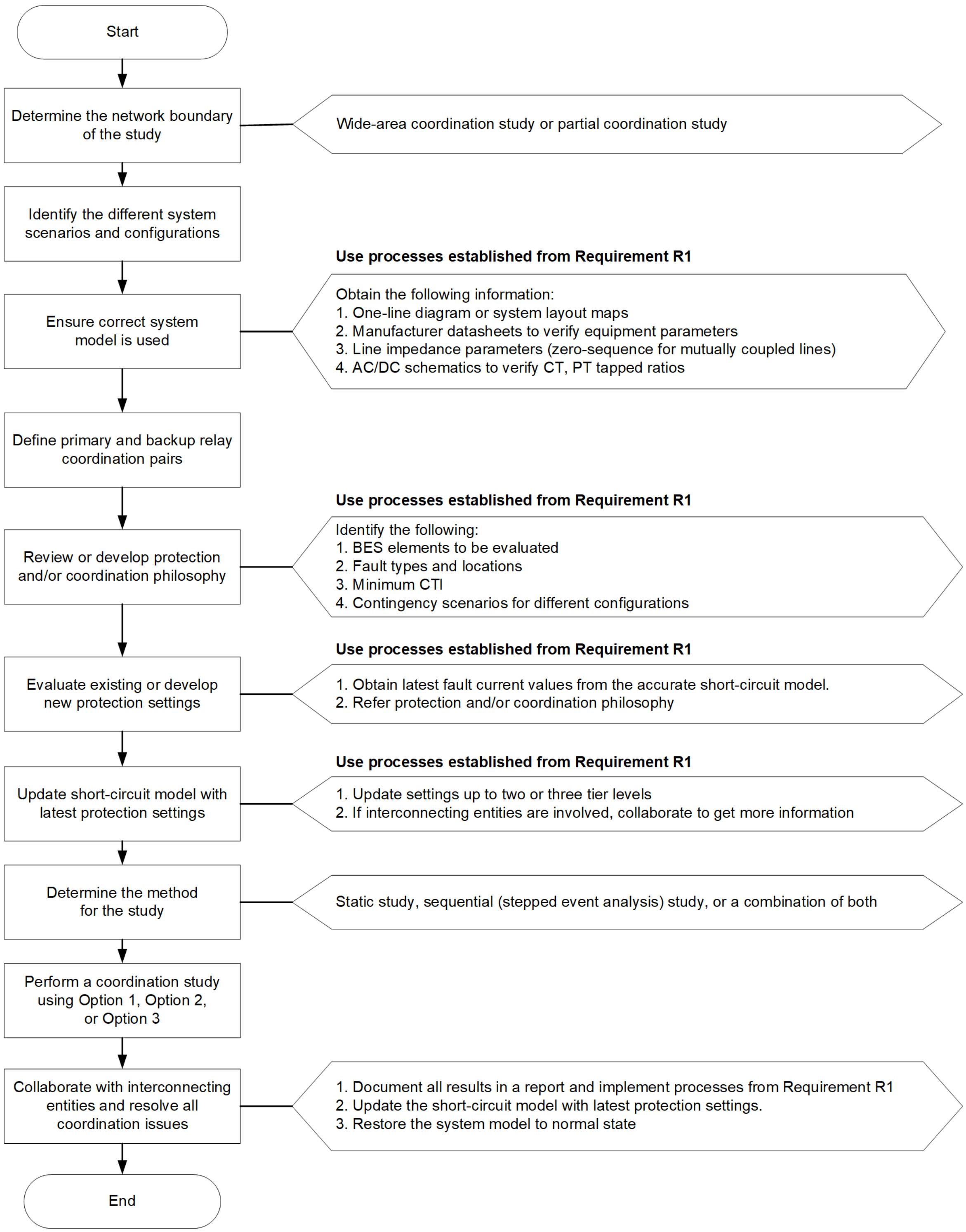

Fig. 7. A Summary of the Process to Perform a Coordination Study.

TABLE VII
EXAMPLE – DOCUMENTATION OF COORDINATION STUDY RESULTS – THREE-PHASE FAULT

Scenario Number	Substation	Primary Relay	Backup Relay	Faulted Equipment, Contingency, and Fault Location	Worst-Case CTI (Seconds)
1	Station X	Line A (Relay name)	Line B (Relay name)	Faulted equipment: Line A Contingency: Line C – out of service Fault location: at 30% of Line A	0.15

B. Discussion on Coordination Scenarios

The protection engineer is often faced with difficult challenges when performing a coordination study. Careful consideration should be given to the following situations.

1) Selection of Contingency Scenarios for Mutually Coupled Lines and Parallel Lines

Consider the single line diagram shown in Fig. 8. For a fault at location F1, the primary relays intended to operate are R1 and R2. The Relays R4 and R3 serve as a backup to the primary Relays R1 and R2, respectively. For a fault at F2 on the parallel line, the primary relays from the above scenario become backup relays and vice versa as shown in Fig. 9. It is not always possible to have R1 operate faster than R4 for a fault at F1 and R1 operate slower for a fault at F2. This is a classic case of a meshed network with sources at each side. Therefore, tradeoffs need to be considered when encountering this situation. Overcurrent elements are ill-suited for parallel lines. Distance elements should be the preferred choice. However, careful analysis must be performed to ensure that the elements are set correctly to prevent any miscoordination resulting from current reversal.

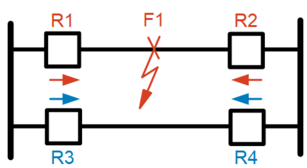

Fig. 8. Parallel Line – Fault Location F1.

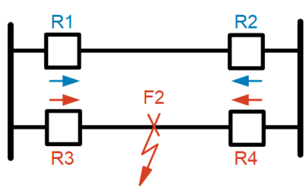

Fig. 9. Parallel Line – Fault Location F2.

Transmission lines that share the same tower structure or a common right-of-way experience a zero-sequence mutual coupling between the conductors [10]. Depending on the entity's coordination philosophy, the outage of one line along with grounding of both ends may need to be considered in the study. The grounding of the outaged line provides a path for the induced current to circulate. This may cause an increase in the zero-sequence current to the in-service line, which can impact ground fault detection elements. Ground distance elements are typically set using the apparent impedance for all zones. A mutually coupled line outaged and grounded at both ends results in a lower apparent impedance for the same fault with the line in service. Covering for these cases may necessitate desensitizing the relay by reducing the reach. However, the outage and grounding of the line is a planned event, and so temporary settings may have to be implemented for this configuration to improve sensitivity of the element under other conditions.

2) Three-Terminal Lines With Outfeed

Consider the system shown in Fig. 10. For a fault on the three-terminal Line L1, the primary relays intended to operate first are R1, R2, and R3. Based on the system configuration, Relay R5 serves as first-tier backup relay to R2 and second-tier backup relay to R3. A coordination study based on the static method requires the TCCs to be verified for a fault along the Line L1 with four different configurations:

- Remote breaker opens at Bus 1.
- Remote breaker opens at Bus 5.
- Remote breakers open at Bus 1 and Bus 5.
- All breakers closed.

The worst-case miscoordination is identified for the following scenario:

- The fault location is at 30 percent of the line from Bus 3 to Bus 5.
- Bus 1 breaker is open.
- Line L2 is out of service.

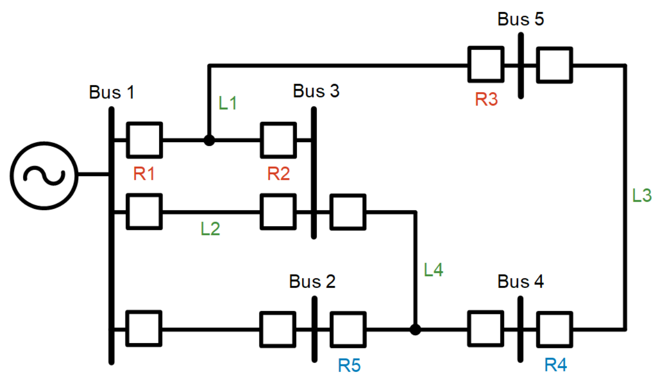

Fig. 10. Three-Terminal Lines With Outfeed.

For any fault on Line L1, an alternate path of current is introduced through Line L3. This causes significant outfeed, which is measured by R5 but not R2, resulting in overreaching distance elements or faster overcurrent trip times. This negatively impacts the distance and overcurrent coordination with the primary Relays R2 and R3. If the simulated fault location moves toward Bus 5, the outfeed will increase further, which exacerbates the miscoordination.

If the coordination study is performed using the sequential method, the primary Relay R3 will trip faster as the fault location progresses toward Bus 5. The sequential evaluation method significantly improves coordination as the alternate path of fault current is immediately eliminated when Relay R3 opens its associated circuit breaker.

Another interesting observation in this scenario is the interaction between the primary Relay R3 with the second-tier backup Relay R5. In an ideal condition, if the Relay R3 fails to clear the fault on Line L1, the first-tier backup Relay R4 should clear the fault followed by second-tier backup Relay R5. However, because Relay R5 serves both as tier-one backup to R2 and tier-two backup to R3, distance miscoordination is unavoidable in this circumstance.

If a breaker failure scheme is used, then breaker failure timers may need to be factored into the coordination analysis. By ensuring that the CTI includes time for the breaker failure protection to operate and clear the bus fault, this situation could be covered. For cases where the relay is defective and fails to operate, the settings would still overtrip for the contingency specified.

3) Miscoordination of Inverse-Time Overcurrent Curves

Several factors drive the setting criteria for determining the overcurrent pickup value, such as setting the pickup above nominal load, above a percentage of the highest seasonal Facility Rating of a circuit for a certain duration, or above the full load amperage of a transformer. For radial configurations, the overcurrent pickup element for the primary and backup relays should be set such that the downstream relay is more sensitive than the upstream relay. This ensures that for faults downstream of both devices, the downstream device trips first. However, in nonradial systems, different pickup set points can introduce the possibility of crossed time current curves, as shown in Fig. 11. The currents detected by the primary and backup relays are not identical; therefore, it is important to align the TCC based on current so that they can be compared. The relays may be coordinated for a certain range of fault currents but may not be coordinated for a different range of fault currents. For ground overcurrent pickup values, some entities may prefer having a fixed overcurrent pickup amperage for all their protective devices. Although this simplifies the setting process, it can cause miscoordination between primary and backup relays when there is an outfeed scenario. While some entities may consider this approach acceptable, it is important to understand the consequences of the decision and document accordingly. In an outfeed case, as shown in Fig. 12, when curves that have the same pickup are aligned, it is possible to have intersecting curves at lower levels of current. Lower levels of current may be a result of system unbalance or high-impedance faults, which are common for ground faults. Higher levels of current are typically associated with a bolted fault. Entities may decide that it is acceptable to have intersecting curves for lower levels of current by establishing a maximum fault impedance. Ensure that the curves do not intersect for higher fault current, and provide an appropriate CTI at that current value.

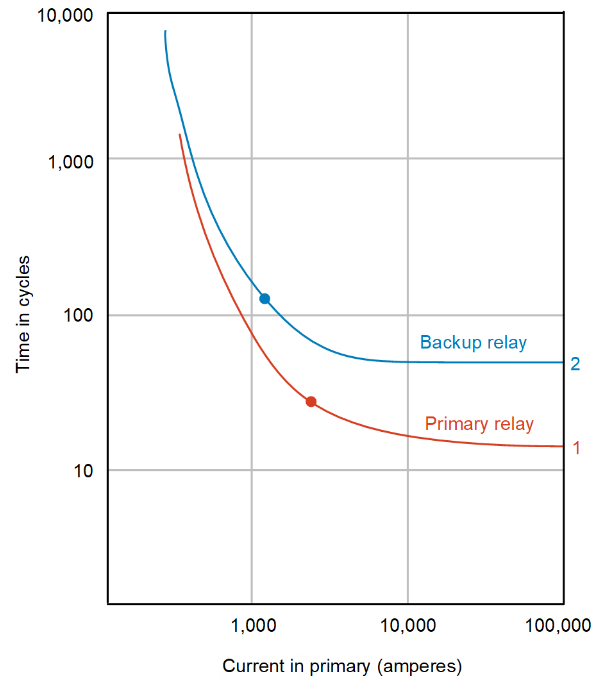

Fig. 11. Nonradial Scheme – Time Overcurrent Curves Under a No-Fault Condition.

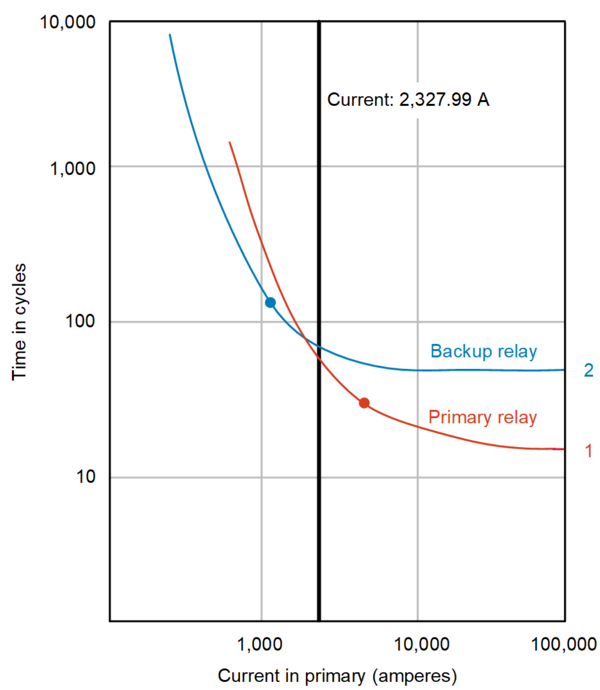

Fig. 12. Outfeed – Time Overcurrent Curves for a Fault Condition.

4) Distance Element Coordination

It is a common practice to set the overreaching Zone 2 distance element to 125 percent or more of the positive-sequence impedance of the primary protected line. The Zone 2 element may be coordinated by either reach or time. Coordinating by reach refers to altering the reach of Zone 2 element such that the Zone 2 element of the backup relay does not overreach the Zone 1 of the primary relay. Entities may choose to establish two methods for defining the reach of the Zone 2 element. The first method calls for the use of setting the reach equal to 100 percent of the primary protected line in addition to the 50 percent of the next shortest line (without infeed). The drawback with using only this philosophy is the possibility of setting a Zone 2 element with a reach that is not enough to cover the entirety of the primary protected line when accounting for errors from CTs, PTs, and relay measurements. The second method is to verify that the Zone 2 element is set to a minimum of 118 percent [10] or 120 percent [11] of the primary protected line's positive-sequence impedance. This ensures that the coverage exists through the end of the line. It is recommended that the method that gives a higher reach for Zone 2 is used. Mho circles are plotted with the assumption that they are 100 percent dependable for the region plotted on R-X diagrams. However, this may not be the case when CT, PT, and relay measurement errors are factored in. Therefore, the Zone 2 distance setting philosophy must include a safety margin between Zone 1 elements of primary relays and Zone 2 elements of primary and backup relays to preserve a region of nonoverlap. A minimum margin of 20 percent is recommended; however, lower percentages may be acceptable depending on the priorities of the setting engineer.

Consider an example where a long line (L1) is connected to a short line (L2) followed by a medium line length (L3), as shown in Fig. 13.

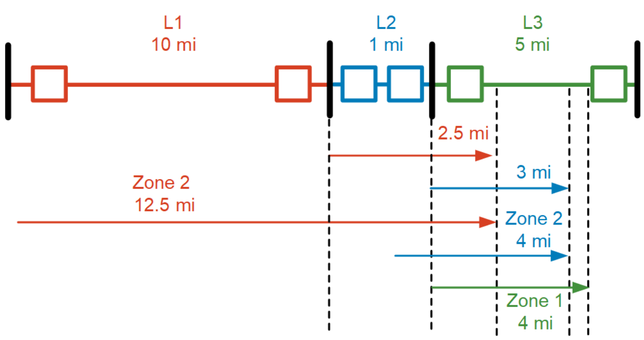

Fig. 13. Distance Element Coordination Example.

For faults beyond the reach of the Zone 1 element of Line L3, the sequence of relay operation should be L3, L2, and then L1. Depending on the length of lines, the Zone 2 elements may require coordination using a combination of reach and time. The protection philosophy typically considers setting the Zone 2 element to 125 percent of the positive-sequence impedance of the primary protected line. Using this scenario, if the distance relay protecting L3 fails to operate for a fault at Line L3, the relay at Line L1 could operate before the relay at Line L2. It can be observed that the relays do not operate in the desired intended sequence. Therefore, in such situations, a deviation from the standard protection philosophy is needed. In this example [6], coordination is only required between L1 and L2 relays. However, it may be necessary to time-coordinate the relays on all lines depending on the system configuration and topology, which may lead to long delays on backup elements.

5) Source to-Impedance Ratio (SIR) Consideration for Distance Elements

The source impedance ratio must be accounted for when protection settings are in the development or review stage. The SIR is the ratio of source impedance to the line impedance [12]. The IEEE C37.113, IEEE Guide for Protective Relay Applications to Transmission Lines [11] classifies the line length based on SIR as follows:

- Long line (SIR < 0.5).
- Medium line (0.5 < SIR < 4).
- Short line (SIR > 4).

In transmission lines with a high SIR, the security of the Zone 1 distance element may need to be analyzed for overreach if the settings were not set to account for a high SIR. In such cases, it is a common practice to either disable the Zone 1 distance element to avoid possible overreach or set fault detectors high enough to account for this. It should be noted that modern relays are often provided with specific settings to mitigate the effects of voltage transients associated with CCVTs due to transmission lines with high SIR values [13].

6) One Size Fits All?

It would not be uncommon for certain entities to take a one-size-fits-all approach. For example, an entity may prefer to set the Zone 1 element of all transmission lines to 80 percent of the line impedance, Zone 2 elements to 125 percent of the line impedance, and the residual inverse-time overcurrent to 120 A primary with a very inverse curve set to a fixed time-delay value. Even though this simplifies the protection relay's setting process, this practice is strongly discouraged. Relay settings must never be developed based on simple recipes from a cookbook without understanding how they are applied. To maintain security of the protection system, the standard mandates checking coordination for overreaching elements.

Coordination studies can have very different solutions or no solution at all, depending on the assumptions and priorities for the system under evaluation. In a complex meshed system, it may not even be possible to achieve coordination for all system configurations and contingencies. In these cases, engineering judgment must be used such that the developed protection settings satisfy coordination requirements for a majority of the system's operating conditions while also determining temporary settings for atypical situations.

C. Conclusion on Requirement R2 From End User's Perspective

Although many practiced engineers in the industry regularly perform relay coordination, bulk power system coordination presents some unique challenges. In MWD's case, prior to developing the PRC-027-1 compliance program, protection and coordination requirements were very subjective and not often well-documented. This led to different results depending on which engineer had performed the study. Although coordination is more of an art than a science, monitoring boundary conditions and documenting assumptions are required to set up a consistent framework. For example, when determining an end-of-line ground fault for a remote bus, the system configurations used to generate minimum and maximum fault current levels were not documented. As a result, when reviewing settings, it was not always clear which system conditions were reviewed to ensure proper coordination and it was sometimes not possible to repeat the calculations used by the engineer who generated the original settings. Additionally, during the compliance process, it was discovered that there were several areas where coordination was marginal under N–1 conditions caused by adjacent circuit outages. It was clear that the original settings engineers had not considered certain scenarios that could be problematic. Furthermore, it was discovered that a periodic review of settings was not conducted, and many settings had not been reviewed since scheme commissioning.

As mentioned in the previous section, due to the small size of MWD's system and informal documentation of coordination parameters, different engineers used different parameters. For example, if the CTI was not documented, it was hard to determine why certain coordination time intervals were selected.

By working with a qualified consultant, many of the key assumptions required to perform a coordination study including minimum CTI, N–1 worst-case scenarios, primary and backup coordination pairs, as well as remote backup protection philosophy were streamlined. This way, a baseline with a set of requirements for evaluating proposed settings was established. Overall, many marginal settings were identified, and mitigation strategies were established to improve coordination.

IV. Requirement R3

The objective of Requirement R3 is for the BES entities to use the process established in Requirement R1 to develop new and revised protection settings.

A. Gaining Efficiencies From the Process Established in Requirement R1

While it may seem like a daunting experience to implement all the processes, efficiency can be gained by standardizing and simplifying repetitive tasks using software tools. The following standardization methods were developed for various utility customers to assist with Requirement R1 compliance:

- A checklist summarizing all necessary steps when a review of the system short-circuit model and protection settings are required.
- An easy-to-follow, customized flow chart detailing an entity's specific processes.
- Creation of a relay-settings calculation template for reports in Mathcad.
- A communication plan when providing the BES system information to, or requesting information from a neighboring entity.
- A network directory on a common server for engineers to store and retrieve information related to PRC-027-1.

When performing a coordination study to meet Requirement R2, defining contingencies and running fault cases to find the worst-case coordination results under normal, alternate normal, N–1, and N–2 conditions can be a tedious task. Even experienced engineers may find difficulty in identifying miscoordination cases on complex meshed systems. Most modern short-circuit study programs allow engineers to run coordination scenarios between multiple tiers of protective devices automatically. Once properly set up, this brute force method tries to eliminate coordination scenarios the user may have inadvertently omitted. As an example of a useful feature, a user can run a script to automatically plot R-X impedance and time-aligned TCCs for the worst-case result in each coordination scenario for a particular software. A disadvantage of these types of automated running scripts is that they typically do not provide a lot of flexibility in terms of specific scenarios a user may want to study. A protection engineer may still need to manually adjust the statuses of various circuit breakers in the short-circuit model to the desired configuration prior to running the scripts.

Additionally, automatic coordination tools must only be used under careful scrutiny, with limitations and assumptions properly documented. Every coordination curve that may have been automatically generated still requires an explicit review. Complacency can eventually lead to an incorrect result, and ultimately, a protection system miscoordination.

B. Conclusion on Requirement R3 From End User's Perspective

Whether it be installing an upgrade in protection equipment, making changes in system configurations, or shortening the interval between coordination studies, Requirement 3 mandates MWD engineers to follow a developed process and steps outlined in requirements R1 and R2. In the past, when settings changes were required, the process of analyzing N–1 system conditions, maximum infeed or outfeed scenarios, and stuck breaker scenarios was solely up to the judgment of the engineer performing the settings development. Furthermore, it was possible to implement settings with no peer engineering review. With the newly implemented PRC-027-1 process, many of the boundary conditions that are required to be studied are clearly defined, and a formal peer review and setting sign off is required. Although sound engineering judgment can never be dismissed, a minimum number of cases that must be analyzed are now clearly documented along with primary or backup coordination pairs to be studied.

MWD's newly developed process established for Requirement R1 and the step-by-step procedure for coordination study performance in Requirement R2 have helped tremendously with respect to new and revised protection settings and in performing coordination study checks. An easy-to-follow, customized flow chart developed in the process dictates what events or changes trigger a review of protection settings and when a coordination study is required. Even with staff turnover or personnel changes, the documented protection philosophy remains in place as a guide to assist consultants and engineers with their calculations. Different N–1 configuration scenarios and acceptable CTI are now clearly defined, and that will help engineers evaluate coordination under different system configurations. Additionally, field test personnel and commissioning personnel can trace back if the protection systems are working as designed by referencing the centrally available setting calculation sheets. Another benefit of having ready access to the setting engineer's work is that the testing program can better comply with NERC PRC-005 testing requirements. One of the reasons to test is to ensure that the settings applied in the field match the setting engineer's intent. Calculation sheets not only include the core coordination information, but they also include a description of permissive blocking, and other logic functions along with their intended performance.

These documents are now located in a central network directory that guarantees engineers are using the latest study model and the study parameters are now defined. When followed, the results are significant improvements in efficiency and consistency for all future coordination studies and protective relay calculations.

V. Conclusion

The NERC Reliability Standard PRC-027-1 requires all BES owners and providers to ensure that the protection systems operate in the intended sequence during faults. Although the standard only calls for compliance with three requirements, there are significant challenges involved. Initiating the compliance process for Requirement R1 may force entities to considerably modify their existing workflow and procedures. The purpose of this standard is to identify coordination gaps in the protection system, minimize human errors, bring consistency to the relay setting process, and encourage engineers to avoid complacency.

Undoubtedly, the greatest complication in meeting this standard is complying with Requirement R2. It is quite possible that a coordination study has not been performed or the documentation has not been updated in years. The standard gives BES operators three options on how the study can be accomplished. While each option has its own advantages and disadvantages, this paper concludes that Option 3 gives the most flexibility to the BES operator. Performing a proper coordination study is never an easy endeavor. It may be possible that a significant portion of the BES protection system is evaluated under multiple system configurations, contingencies, and scenarios. The steps presented in this paper are not restricted to only complying with PRC-027-1 but can be used for all coordination studies.

The purpose of Requirement R3 is to collect, catalog, and maintain documentation to show that the processes developed under R1 are properly followed when developing new or revising existing protection settings. Failure to maintain proper documentation can result in out-of-date or inaccurate system modeling data. Furthermore, this documentation serves as evidence during audits. By following a systematic approach, and using automated tools where possible, the daunting challenges of complying with PRC-027-1 can be considerably reduced. As more methods are developed to improve efficiency in complying with PRC-027-01, it must be emphasized that no process or automation tool can replace sound engineering judgment. Protection engineers are expected to fully understand the reason behind each step taken to meet all requirements. Although it may seem that PRC-027-1 is yet another regulatory standard to adhere to, this paper presented a step-by-step approach on how to overcome the challenges associated with each requirement along with insight directly from a BES owner's perspective. If a sincere effort to improve protection system setting processes is made, rather than implementing steps simply to comply with the standard, significant operational, reliability, and efficiency enhancements for the subject entity can be made.

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