A Practical Guide to Performing Wide-Area Coordination Analysis

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***Abstract* -- A wide-area coordination study systematically reevaluates protective relay coordinated elements with standardized protection coordination criteria to identify means to improve protection performance. The scope of the study can range from an entire utility transmission and distribution system to a smaller subset that may only include a few terminals.**

Some unique challenges that may arise when performing a wide-area coordination study are described in this paper. These challenges include: defining what parts of the electrical system to include in the wide-area coordination study, system operations and contingencies to consider, relays/protection elements to include in the study, and what data is needed for the study. Defining a systematic approach to the coordination study can also be a challenge in itself. The study can be performed on a protection element-by-element basis or be divided into system subsets such as operating voltage levels or geographic areas.

This paper serves as a guide for developing a systematic approach to performing a wide-area coordination study. It presents considerations and choices the protection engineer may be faced with, and gives examples of trade-offs made when coordination cannot be met. The paper also discusses specific topics such as utilizing engineering software tools for automated coordination checking and strategies for resolving coordination time margin violations in looped systems under tight coordination guidelines.

***Index Terms*--Protection, Coordination, Transmission, Relay, Wide-Area Coordination, Guide, Coordination Time Interval**

I. Introduction

Most electric utility protection schemes are a system of relays that rely on localized information (voltage & current) to detect power system faults or abnormalities. These relaying schemes are based on a stepped-style time setting principle to coordinate as to avoid a greater outage area. The relays are often set to operate under a "worst-case" scenario and then checked to see if the schemes operate adequately under other scenarios.

Today, protection engineers are faced with the challenge of assuring that their systems remain coordinated to provide reliable power to their customers by reducing the risk for unintended outages. The following contribute to the complexity of maintaining a coordinated system:

- New system operating scenarios (i.e., deregulation) that did not exist when relays were installed may impact the performance of the protection schemes.
- For economic reasons, electric utilities are being pressured to maximize the utilization of their system closer to component limits (transformers, lines, etc.)
- Increased reliability of electricity is becoming more important to customers while wide-area blackouts are becoming more costly.
- Increased concern for power system security due to acts of coordinated sabotage is resulting in more power system grid planning to avoid wide-spread disruption [1].

Verifying the performance of a protection system over a wide-area isn't trivial. Checking for relay sensitivity and selectivity of protective relays over an entire service area of a utility can be complex; however, the results of the study may help the utility increase power system transmission capability while improving power system reliability.

Wide-area coordination (WAC) analysis is the evaluation of protective device selectivity and sensitivity at a system level (multiple layers of adjacent terminals) with a goal of improving system reliability. This paper will discuss the following topics:

- Determining the boundaries of the study
- How to approach modeling the system under study
- Management of data used for short-circuit model development and analysis
- Identifying a systematic approach to coordinating all the relays under study
- Guidelines and approaches for selectivity and sensitivity analysis when performing a WAC study

This paper is not intended to discuss the analytics behind fault simulation or component modeling or how to set specific relay element types (distance, overcurrent, etc.). It is assumed that the reader has an understanding of power system protection concepts. This paper provides a high level guide for the WAC analysis process and discusses some potential challenges that may be encountered, but not all. It is important to distinguish the difference between coordination analysis and a full protection evaluation. A protection evaluation includes all aspects of the protection including equipment ratings, relay hard wiring, relay logic, and element settings for all protective elements enabled in the relay, as well as, coordination analysis. A coordination study assumes equipment is properly rated for system conditions, protective devices are properly wired and internal logic is configured correctly. The coordination study only focuses on evaluating the protective elements that require coordination with other protective devices. This paper is a guide for coordination analysis and does not cover all the aspects of a protection evaluation.

Figure 1 below shows the recommended approach to conducting a WAC study. Some of the steps can be performed in parallel while others are sequential. Each of these steps will be discussed in greater detail in the following sections of the paper.

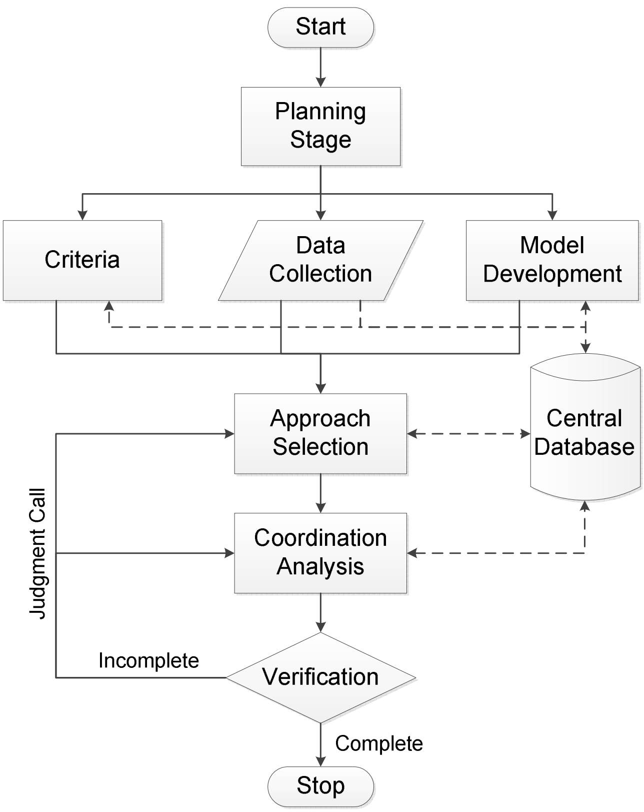

Figure 1: Wide-Area Coordination Methodology Flow Chart

II. PLANNING STAGE

Before any analysis work is performed, it is important to do some high-level planning in order to best determine the scope of the analysis. Consider the following questions during the planning phase to help identify the scope of the project:

- What are the boundaries of the system that will be studied?
- What system operating conditions need to be considered when performing short-circuit analysis and coordination?
- Which relays and protective elements need to be considered in the study?

A. Identify System Boundaries to Establish Scope of Analysis

Will the study cover an entire transmission system, or just a portion of the system? Are there multiple voltage levels in the system being studied? Are there neighboring systems owned by other entities that form boundaries? If there are neighboring systems, find out early on if the other entities are willing to adjust their relay settings to improve system coordination. Knowing whether boundaries are hard boundaries or soft boundaries will influence how the study is approached. Hard boundaries have protective devices where no setting adjustment is allowed. Soft boundaries allow for setting adjustment to achieve coordination. Keep in mind that any adjustment to protective devices at soft boundaries will require further analysis to ensure coordination is maintained with adjacent protective devices beyond the boundary. To establish the boundaries of the system, first print out the system one line diagram or system map and highlight the parts of the system that will be included in the study. As parts of the system are highlighted and the questions above are considered, the individual will start to question which parts of the system should be included in the study and seek input from the stakeholders. This process will help to solidify the scope.

B. Evaluate System Operating Conditions to Determine Controlling Scenarios

After identifying the boundaries of the system, the next step is to identify the operating conditions to include in the study. Are there different system loading conditions to consider? Is there local generation, and if so, is it operated all the time or infrequently? More often than not, there are many possible system operating configurations driven by factors such as seasonal load changes, import/export power agreements, available generation, etc. To ensure the study is performed efficiently, the engineer should identify all the plausible operating scenarios for the system and then narrow down the list to the most extreme/controlling configurations; typically configurations that result in minimum and maximum fault currents.

C. Tabulate Protective Relays and Elements to Refine the Scope of the Analysis

After establishing the system boundaries and operating configurations, the next question is: What protective devices will be considered in the study? If there are multifunction devices, what protective elements within the devices will be evaluated? The elements that are typically evaluated in a coordination study are distance elements and overcurrent elements. Other protection schemes such as differential protection and communication based schemes have near instantaneous (2-5 cycle) trip times and only detect faults within a restricted protection zone. Therefore, these protection schemes are not included in the coordination analysis. At the start of the analysis, tabulating all the relays (and their enabled elements) that will be included in the study is a good exercise for gaining familiarity with the system, further establishing scope, and this tabulated list can serve as a tracking tool for the duration of the study. Figure 2 gives an example of a tracking spreadsheet format.

Station	Prot. Device	Relay Type	21P	21G	50P	51P	50G	51G	...
Hawk SS	L101-21		3	3	-	-	-	1	...
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	...
Raven Sub	T2-87T		-	-	1	2	1	2	...
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	...
Sparrow SS	L205-21		2	2	-	-	-	1	...
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	...

Figure 2: Example Relay Tracking Spreadsheet

III. Short-Circuit Model Development

It is strongly recommended that a short-circuit model is used for coordination analysis and to take advantage of any automation tools the software has to offer. Whether using an existing short-circuit model or creating one from scratch, it's important that the model be reviewed to make sure it includes all the components that can impact system fault currents prior to starting the WAC study.

During the planning phase of the study, it should be determined if a short-circuit model of the electrical system exists. Commercially available software packages significantly improve accuracy and efficiency of the coordination analysis, particularly when dealing with large and/or looped systems. If a short-circuit model does exist for the system, does it have the entire system that will be studied included in the model? Has the model been maintained and updated as changes and upgrades have been made to the electrical system and protection system within? It's important at the beginning of the study to gain an understanding of the state of the short-circuit model and if an audit of the model is warranted.

If a short-circuit model needs to be created or one exists but needs to be updated, here is a list of data that will be needed for the model:

- Protective relaying single-line and three-line diagrams
- Source Equivalents for System Boundaries: This is typically given as positive and zero sequence impedance Thevenin equivalents.
- Transmission Lines: Maximum continuous rating, emergency rating, positive- and zero-sequence impedance. If parallel lines exist, the mutual impedances of the lines will be needed.
- Generators: positive- (synchronous, transient, subtransient), negative- and zero-sequence impedance data
- Transformers: Ratings, impedances, winding configurations, and grounding type (solid vs. resistive)
- Series/Shunt Reactors and Capacitors: Ratings and Impedances
- Station Bus Configurations
- Current and Voltage Transformer Ratios
- Protective Relay Settings: Best to get as-left settings uploaded from in-service relays and/or relay test reports.

In addition to the information listed above, the following information is recommended for performing the study:

- System Wide One Line Diagram
- Latest AC elementary drawings for stations and equipment within the scope of the study. Station drawings provide details of how equipment is oriented and connected. Station drawings also provide current and potential transformer tapped ratios and connections to protective devices.

Many software packages offer built-in coordination checking tools to save the engineer time and effort. An existing short-circuit model will typically dictate what software package is used for the analysis. It is important to have a clear understanding of the automated tools with the software package being used prior to creating/updating the model. Some tools require equipment data to be entered in a certain way or may require additional data. Review software manuals prior to building/updating a model to ensure a clear understanding of what data is required and to avoid rework.

V. Data Management

It is recommended that data acquisition be performed in preparation for creating or assessing the short-circuit model. An accurate WAC study is largely based upon the accuracy of the information needed to build the short-circuit model and to evaluate relay settings. Acquiring, storing and maintaining the data for the study in a central database during the life of the coordination study is critical to maintain the quality of the analysis.

When performing a WAC study, there is significantly more data needed compared to a typical protection study. There could be many stations involved in the study, each having drawings, equipment data, relay settings files, photos, etc. Furthermore, the required data may not all become available at one time but rather be delivered in pieces through the course of the study. Not establishing a system for organizing and managing the data up front can lead to wasted time, lost data, and potential rework.

A variety of document control software is available to assist maintaining the data needed to perform the analysis. The benefits of document control software include:

- A common platform for multiple users
- Simpler means of synchronizing concurrent activities
- Revision tracking and ability to revert back to earlier versions
- Improved efficiency during verification of the results from the analysis.

Establishing a file/folder structure at the start of the project can also help with keeping data organized through the duration of the analysis. Figure 3 is just one example of how to organize data for the coordination analysis.

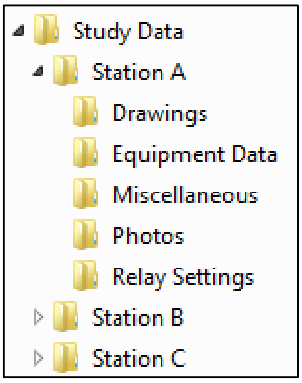

Figure 3: Example Folder Tree

Additional folders can be created to track and maintain calculations workbooks, coordination criteria documents, model updates, results and reports from the analysis as the coordination study takes the desired approach. Establishing naming conventions for files, documents, graphs, etc. at the start of the study can help to finish the analysis with more consistent and orderly results and documentation.

VI. Coordination Criteria

Prior to starting the coordination analysis, it is recommended that criteria be defined to assist in evaluating the sensitivity and selectivity of the relay elements. Criteria can be based on best practice guidelines (utility standards), industry guidelines (IEEE) and/or standard requirements (NERC). A criteria document forms a basis that can be shared with and agreed upon by all the stakeholders. Additionally, defining coordination criteria at the start of the analysis allows for the development of calculation tools used to automate the evaluation of each element resulting in time saving when performing the analysis. Spreadsheets with calculation capabilities or mathematical programs are tools that can help streamline evaluation of existing relay/element settings against the established coordination criteria. The coordination criteria document generally addresses the following:

- Description of study boundaries, operating configurations, and contingencies that will be considered
- Description of selected approach to coordination analysis
- Coordination criteria for evaluating each type of protective device/element included in the study
- Critical notes and assumptions

The coordination criteria document discusses what contingency conditions that will be considered in the study. Contingency conditions refer to unplanned outages of equipment in a system. These conditions are considered when evaluating coordination of protective devices. For example, an N-1 contingency would be the outage of a single piece of equipment. Loss of the strongest source contribution is typically used as an N-1 contingency for coordination analysis.

Typically, phase and ground distance and overcurrent elements are evaluated in a WAC study. If negative-sequence elements are present, these will also need to be evaluated to ensure they coordinate with ground and/or phase elements.

In the coordination criteria document, establish acceptable minimum coordination time intervals (CTI) between protective devices. IEEE 242-2001 Table 15-3 provides industry accepted minimum CTIs. [2] To take it a step further, define trip timing ranges for underreaching (zone 1), overreaching (zone 2), and extended overreaching (zone 3 or 4) elements. For example, the following timing ranges could be used: underreaching as instantaneous, overreaching as 0.2 - 0.5 seconds, extended overreaching greater than 0.8

seconds. Defining timing ranges will provide a rule of thumb for knowing whether elements are tripping too fast or too slow.

Defining criteria in terms of acceptable setting ranges instead of absolute criteria is a suggested approach because it allows for flexibility in the analysis and simplifies the evaluation of the relay/element settings. Defining criteria in terms of a minimum, maximum, and preferred setting is a practical way of setting up the coordination criteria. For example, the coordination criteria can be defined for a zone 1 distance element to have a minimum reach of 60% of the line impedance, maximum reach of 80% of the line impedance (or tap point), and preferred reach of 70% of the line impedance (or tap point). When evaluating existing settings, if a setting falls within the defined range, then the setting is acceptable. If the setting falls outside the range, then the element will require further evaluation to determine if it coordinates with adjacent protective devices. If the element needs adjustment to fix coordination, the preferred setting criterion provides a starting point on what the setting should be changed to. A word of caution: sometimes given the established criteria and system characteristics, the calculated minimum setting will be greater than the calculated maximum setting. A couple of common scenarios where this occurs are when a long transmission line is followed by a short transmission line or with three-terminal lines with infeed conditions. In these situations, evaluating how the element settings best coordinate with adjacent protective devices can help in determining an appropriate setting.

A WAC study serves as a platform for auditing an electrical system to ensure compliance with regulating agencies, if necessary. When defining the coordination criteria for the study, review applicable North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC), coordinating council and Independent System Operator (ISO) requirements to include in the coordination criteria, as required.

VII. Selecting an Approach to the Analysis

To efficiently perform a WAC study, it is important to identify a systematic approach to doing the work.

A. Controlling Factors that Drive Approach Selection

System topology and schedule constraint to complete the study are two main factors that drive the selection of approach to conduct the study. Operating scenarios, protection schemes, protective elements and their dependencies are the system characteristics that are also viewed as variables. Figure 4 shows the relationship of the variables and the controlling factors to consider while deciding on an approach to the coordination study.

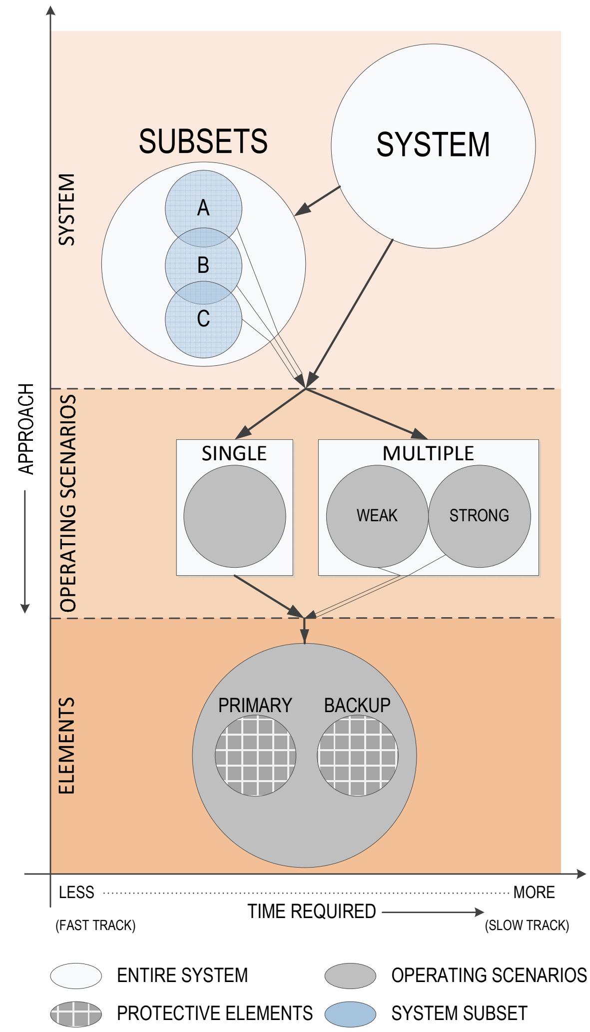

Figure 4: Approach Selection Chart

Figure 4 is a representation of the relationship between the primary factors (system topology and schedule constraint) and the variables (operating scenarios and protective elements) for approaching the coordination analysis. The large discs at the top layer represent an entire power system which can be further divided into subsets overlapping each other at the point of interconnection, such as a power transformer. The alignment of the subsets within the superset (system) against the X axis (Time Required) in a vertical line indicates the coordination can be performed in parallel by multiple people, hence taking less time.

The middle layer represents situations where there could be single or multiple operating scenarios. The block with multiple operating scenarios represents that there could be weak and strong source conditions that need to be studied. Coordination analysis will need to be evaluated for each operating scenario. The number of scenarios that need to be analyzed may not be limited to just two.

The single disc at the bottom layer represents two subsets where protective elements are categorized as primary and backup for analysis. Coordination analysis will need to be performed for the primary elements followed by the backup elements for each operating scenario.

Depending upon the paths selected to analyze the coordination of the system, there could be multiple approaches which are time-variant. The subsections below provide examples of the considerations and choices taken based on the variables for determining the desired approaches for the coordination study along with their advantages and disadvantages.

B. Establish System Subsets to Gain Efficiency

Dividing a large and/or complex system into subsets allows for simultaneous analysis that can lead to improved efficiency. The system can be divided into geographic areas, voltage levels, or a combination of both. For a large transmission network consisting of multiple operating voltages, power transformers can serve as a boundary marker to divide the system into subsets for performing the analysis. Distance elements are not typically set to reach through the transformer and the transformer damage curve serves as a coordination boundary for overcurrent elements. One of the challenges with dividing the system into subsets is ensuring coordination at the subset intersections (i.e. transformers). If not thought out ahead of time, there is a potential for rework to achieve coordination across the system. Coming up with a plan for how protective devices should be coordinated at subset intersections will help to avoid potential rework.

For example, a 345/115 kV system can be divided into system subsets by voltage level with power transformers acting as the subset dividers. A plan for making sure the two subsets coordinate where they meet at the transformer is to establish the criteria that overcurrent devices protecting the transformer will be set to hug the transformer damage curve with one CTI of separation and that distance protection will not reach through the transformer. Therefore, the overcurrent protection on the 115 kV system will need to have at least two CTIs of separation from the transformer damage curve to ensure coordination. Note that this example is not intended to work for all transformers, but rather explain the concept of establishing criteria for subset boundaries.

C. Strategy for Maintaining Selectivity across Multiple Operating Scenarios

Operating scenarios pose additional challenges to the coordination analysis. In many cases, all potential operating configurations cannot be considered. The operating scenarios chosen for the analysis should be representative of the controlling and/or extreme conditions of the system. How long the operating scenarios last and how they affect the fault currents needs to be measured and compared against the normal scenario.

For example, a transmission system may have three operating scenarios categorized as normal, maximum and minimum based on the generation that the protection scheme is expected to perform within. While, the normal system is prevalent most of the time, the maximum and minimum scenarios produce higher and lower fault currents, respectively, during non-normal operating conditions. The desired approach would be to first achieve coordination taking into account the infeed for N-1 contingencies. This is achieved by first analyzing the normal scenario followed by the maximum scenario. The reason being that there is a high likelihood of the minimum scenario fault currents falling within the ranges of the normal scenario with N-1 contingencies (removing the strongest source). Hence, once the normal scenario with N-1 contingencies and maximum scenario are coordinated, the minimum scenario will also be coordinated.

The advantage of considering the normal scenario first with N-1 contingencies is that it will maintain sensitivity of all the protective elements and it will maintain selectivity of distance elements throughout all the three operating scenarios. The challenge is that the overcurrent elements will speed up during the maximum scenario. The likelihood of the maximum scenario needs to be analyzed and if it results in miscoordination, then an engineering judgment needs to be made.

For distribution systems that are generally protected by overcurrent elements only, evaluating operating scenarios discussed in the above example will be approached differently. The maximum scenario with N-1 contingencies is initially considered for attaining coordination instead of the normal scenario. The key is selectivity of the overcurrent elements in all the scenarios has to be maintained equally while speed at the minimum scenario can be sacrificed.

E. Strategy for Maintaining Selectivity between Primary and Backup Elements

Once the area has been divided into system subsets and the operating scenarios have been determined, the next step is to closely examine the subset in order to separate out the substation equipment and lines into groups. Protective elements like distance and overcurrent are further examined for selectivity and sensitivity.

Consider a transmission line that is protected by differential and stepped distance schemes where both schemes are backed up by directional overcurrent elements. An approach to coordinate these elements is to follow a sequence based on the priority of the elements to trip. First coordinate the distance elements followed by the overcurrent elements. The stepped distance zone reaches and their respective timers will serve as boundaries when coordinating the overcurrent elements. The goal is for the overcurrent elements to have a delayed trip once the stepped distance elements have timed out.

The advantage of following the sequential approach is that selectivity and security between the primary elements and backup elements can be achieved without running into conflicts. The disadvantage is this process is tedious since the fault analysis for the primary elements exhaustively considers the N-1 contingencies in evaluating each element for sensitivity. The fault analysis would need to be repeated for the backup elements while also securing them to meet the defined CTI.

Coordination analysis is simpler for medium voltage systems that are radial. For distribution systems, load and topology are dynamic and constantly changing in comparison to transmission systems. Developing distribution feeder relay settings specific to each feeder based on its current loading and downstream protective devices is impractical, because the settings will need to be constantly re-evaluated and possibly changed every time something changes on the feeder. A more effective approach is to try and standardize the distribution feeder protection design. Standardizing the size of pole mounted fuses, reclosers, and getaway cable sizes to a few options can greatly simplify the protection scheme. Then predefined feeder coordination sets can be developed and applied based on feeder loads and standard fuse/recloser sizes.

VIII. ANALYSIS

The flowchart shown in Figure 5 below provides steps on applying the approaches discussed earlier in reference to Figure 4.

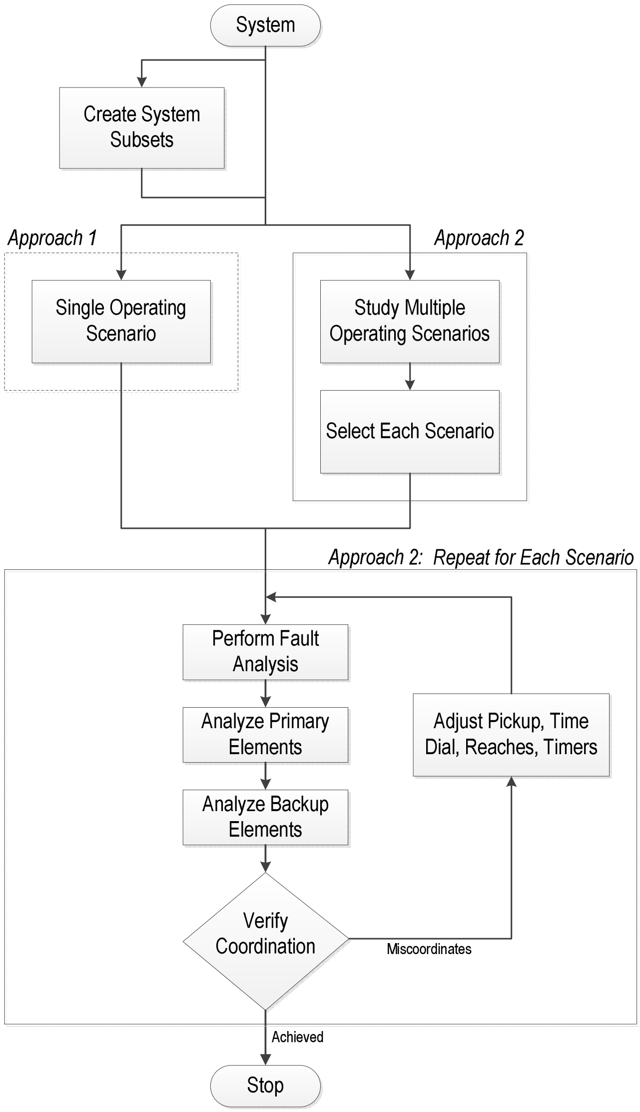

Figure 5: Coordination Analysis Flowchart

The following subsections provide a high level guide for performing activities like arranging data, streamlining fault placements, and using automated tools to complete the coordination study efficiently and effectively. The last subsection provides two examples illustrating challenging coordination issues.

A. Utilize Calculation Spreadsheets to Automate Coordination Analysis

Most short-circuit programs allow exporting component information into other software so that it can be easily manipulated in spreadsheets. Also relay settings can be exported and directly placed into spreadsheets or be imported directly into modeling software. The benefit of arranging the data in a tabular format and maintaining it is realized during the evaluation process. Once the short-circuit model is updated with the desired source, line, and apparatus (transformers, capacitors and reactors) impedances and distance and overcurrent settings of each protective device have been modeled, the following steps can be taken to set up the calculation sheets before proceeding with the fault analysis.

Step 1. Separate equipment data (ratings, impedances, voltage, etc.) into separate tabs by equipment type (transmission line, transformer, capacitor, reactor, generator). For example, arrange the transmission lines by terminal numbers and bus numbers with their positive-, negative- and zero-sequence impedance and line rating information entered.

Step 2. Populate each row with the CT and PT ratios for protective devices protecting each line, transformer, capacitor, reactor or generator. Also tabulate existing protection settings including underreaching, overreaching distance elements with definite timers; overcurrent settings along with the pickup, time dial and curve type.

Step 3. Separate out the groups of data based on the type of element being coordinated. For example, prepare separate tables, each dedicated for (i) phase distance element (ii) ground distance element (iii) ground overcurrent element.

Figure 6 gives an example of arranging input data per the above-mentioned Steps 1-3.

Relay ID	Protected Line Name	kV	CT Ratio	PT Ratio	2-hr Line Rating (A pri) from database	Line Rating (A sec)	Z1 Line (Ω-pri)	Z1 Line Angle (degrees)	Z0 Line (Ω-pri)	Z0 Line Angle (degrees)	Relay MTA	
L151-21	…	138	…	…	…	…	…	…	…	…	…	
L247-21	…	138	…	…	…	…	…	…	…	…	…	
L109-21	…	138	…	…	…	…	…	…	…	…	…	

Figure 6: Example Calculation Spreadsheet

Step 4. Once the existing data is assembled, now start applying the criteria for each element setting. Prepare the calculation sheets by programming in the equations.

Step 5. Start the fault analysis and apply the results to the equations.

Step 6. Once all the settings are calculated, evaluate the existing settings against the new settings. Analyze and make judgment calls to finalize recommended settings.

Figure 7 gives an example of calculated output data arrangement per the above-mentioned Steps 4-6.

	Minimum Zone 2 Reach Calculation (Ω-sec)	NERC Loadability Maximum Zone 2 Reach (Ω-sec)	Apparent Z to end of shortest remote recommended Zone 1 (with N-1) (Ω-sec)	Maximum Z for Coordination with remote Zone 2's (Ω-sec)	Preferred Zone 2 Reach Calculation(Ω-sec)	Is Minimum Calc > Maximum Calc?	Existing Zone 2 Reach (Ω-sec)	Recommended Zone 2 Setting (Ω-sec)
	…	…	…	…	…	…	…	…
	…	…	…	…	…	…	…	…
	…	…	…	…	…	…	…	…

Figure 7: Example Calculation Spreadsheet (cont.)

The next section leads into fault analysis mentioned in the above steps.

B. Ways to Streamline Short-Circuit Analysis

Careful thought of fault placement and contingencies while performing short-circuit analysis is important to the quality and efficiency of the coordination analysis.

For example, forward overreaching distance elements can underreach their intended zone of protection if the effects of infeed are not considered. It is recommended to select the largest apparent impedance seen by the relay while further evaluating the zone 2 element against the coordination criteria. In order to select the largest apparent impedance seen by the relay, N-1 contingency situations are considered. This is accomplished by placing balanced and unbalanced faults at the end of the shortest remote zone 1 element reach while the largest source of fault contribution at the remote bus is removed.

Another example is the forward overreaching zone 3 or zone 4 distance elements which generally trip for an N-2 contingency situation. N-2 contingency conditions are generally indicative of a catastrophic event. N-2 contingency could be for a combination of failures like (i) when primary and secondary protection fails, (ii) when cascading trips open adjacent lines, and (iii) a combination of relay device failure with a line outage or breaker outage. Sensitivity is a key to the setting of such distance elements providing backup protection. Traditionally, most stepped distance schemes have forward overreaching zone 3 or 4 elements set to trip with a definite-time delay providing backup protection to remote lines. Hence, this zone covers the longest remote line. Placing unbalanced and balanced faults at the end of the longest line with no contingencies will help in evaluating the apparent impedance seen by the relay. The apparent impedance seen should be less than the selected zone 3 or 4 reach. The selected reach should not see past transformers connected at remote buses.

Other than the distance schemes that can potentially consume large amounts of time in fault placement, evaluating coordination of substation apparatus overcurrent protection with the adjacent transmission line protection can also require multiple fault placements. This can be streamlined by placing close-in balanced faults for phase elements and close-in single line-to-ground faults for the ground elements on both lines and apparatus. This will verify coordination of apparatus overcurrent elements with adjacent transmission line protection for line faults and coordination of over-reaching line distance elements with apparatus overcurrent elements for apparatus faults.

C. Use Automated Tools to Gain Efficiency

It can get very tedious to manually coordinate time overcurrent elements by stacking curves to analyze the CTIs. A more efficient means to approaching a large study is to take advantage of the automated coordination tools offered by many short-circuit programs. These automated tools can simulate multiple faults for each device and report violations of minimum CTI criteria.

The coordination checking tools offer options where the primary/backup coordination can be checked by placing a close-in fault of the type selected while applying it to the primary group with the remote end of the branch open. Another option is to check the coordination by placing faults at multiple points along the feeders.

In order for these automated tools to give the correct results, each relay group needs its backup selected and programmed. Also, the desired CTI needs to be entered. Both options of coordination that can be exercised are: (i) check coordination of the selected relay against all the relays that serve as backup, and (ii) check coordination of the selected relay group against relays that it backs up.

The report generated by the automated tool clearly flags the elements that did not meet the CTI requirement, margin of violation, and the fault type. This helps in determining the miscoordinated elements. Such elements can be adjusted as needed and further evaluated by the automated tool.

D. Examples of Coordination Challenges

Every system has its own challenges to achieving coordination based upon the complexity of the system and the criteria applied. This section provides specific examples of coordination challenges and the strategies and trade-offs to overcome them.

One common issue when analyzing transmission network overcurrent coordination is that protection engineers may run into coordination conflicts when trying to meet NERC’s loadability criteria [3] while maintaining sensitivity and speed. In such cases, disabling of phase overcurrent elements is recommended to provide security against emergency load situations. If overcurrent elements are still needed for sensitivity and speed, use of negative sequence and/or ground overcurrent elements are recommended alternatives.

Example 1: Overcurrent Coordination of a Tightly Looped System

While analyzing the time delayed overcurrent coordination of transmission systems, specifically with tightly looped lines, achieving tight CTIs may be challenging. If found that there is miscoordination between adjacent line overcurrent elements, settings adjustments are required with a primary focus on achieving the minimum CTI between the primary and backup and then trying to reach the desired CTI. An initial strategy is to select a predefined time for the time-delayed overcurrent elements of each line to trip for the remote bus fault (smaller fault current of the N-0 or N-1 condition). This action sets the pickups and time dials which can be adjusted when checking the coordination. Again the focus is to achieve the minimum interval and then if possible reach out for the desired interval.

The intent of the following example is to show how the above strategy was utilized in achieving coordination among the time-delayed directional ground elements in the adjacent lines. Figure 8 shows a one-line representation of a 138kV tightly looped system. The figure shows a fault occurring close to Breaker C1. There should be coordination such that time-delayed directional ground overcurrent elements in the relays at Breakers C1 and C2 operate and clear the fault before their backups at Breakers B1 and D2 operate. Similarly, for every fault around the loop, a set of backups need to be coordinated with a minimum time interval of 30 cycles. Automated tools were applied to check the coordination in order to avoid confusion and conflicts in trying to coordinate all the elements for ground faults around the loop since there were multiple short and long lines in the loop (all lines are not shown in the figure).

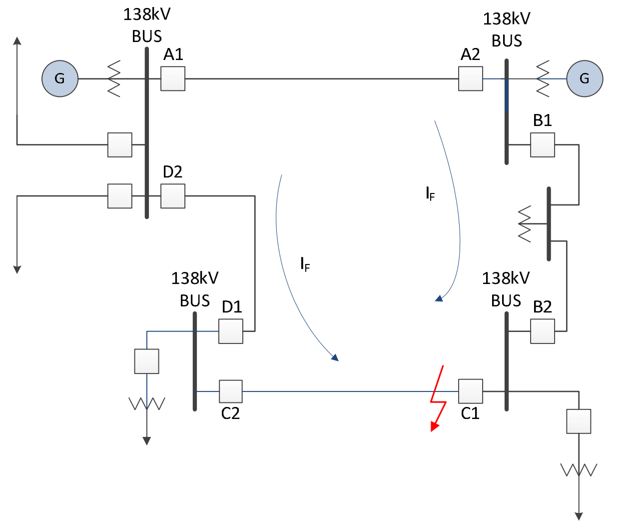

Figure 8: Single-Line of a Tightly Looped System

The automated tool was selected to check coordination by placing close-in single line-to-ground faults at each breaker with the remote-end of the branch open. The report showed miscoordination among the existing time-delayed directional ground overcurrent elements throughout the loop. It was hard to select where to start in order to fix the miscoordination since there was a mix of generation and load. Trying to only adjusting the elements closest to the generating sources did not resolve coordination issues. Finally, a strategy where the pickups of all the time-delayed directional ground overcurrent elements in the loop was selected at 30% of the smallest ground fault at the remote bus (system intact or removing the highest source). Time-dials were chosen such that the element initially trips after 0.65 seconds (longest overreaching distance timer) when using the automated coordination checking tool. There were significant troubles achieving a CTI of 30 cycles. A compromise was made to accept the time interval of 15 cycles as the minimum CTI.

In this example coordination was achieved by increasing the time-delayed ground overcurrent element operate times. This was possible since the overcurrent elements were intended as the last elements to trip. Selectivity and security of the newly achieved coordination was further evaluated by placing faults at the end of the overreaching distance zones and adjusting the pickup/time dial ensuring that the time-delayed ground overcurrent elements trip after the overreaching distance elements.

Example 2: Distance Coordination of a Multi-Terminal Line

Coordination becomes more challenging for lines with three or more terminals. Infeed conditions must be considered and more fault cases must be analyzed to ensure coordination. In this example, parallel lines connect two substations. These parallel lines are tapped part way by a distribution substation. The bus topology at the distribution substation results in the two parallel lines being tied together at the tapped substation creating a large 4-terminal line. Figure 9 gives a one-line representation of the system topology.

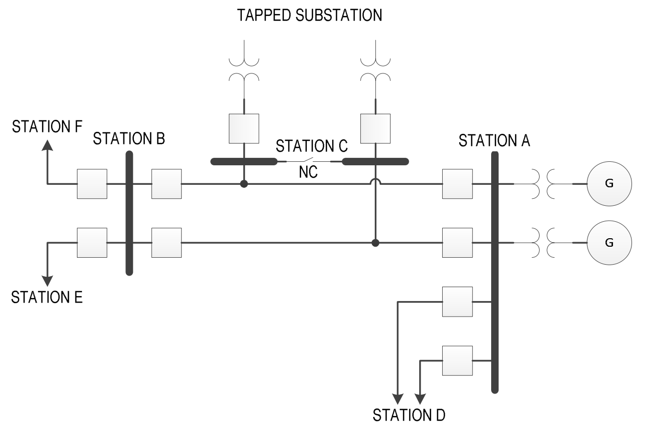

Figure 9: Single-Line of a Multi-Terminal Line

The real challenge with this configuration was that no communication based protection was in place and the lines were protected by a step distance scheme. The zone 1 elements were set to reach short of the tap to avoid miscoordination with the tapped substation transformer protection. For zone 2 elements, the first attempt at the protection was setting the reach to provide full protection of the line with the system intact and the presence of infeed. When contingency conditions were evaluated, it became apparent that the far reaching zone 2 elements would reach past the remote bus and miscoordinate with the protection of the lines leaving the remote terminal. Therefore, to achieve coordination, the zone 2 reach was reduced and the protection scheme relied on sequential tripping to clear the fault. Due to long fault clearing times and concern for system stability, this transmission line was flagged as having a major protection issue and was brought to the system owner's attention. A few options were presented for solving the problem which included changing the normal operating position of the transmission bus tie switch at the tapped substation and/or installation of communication based protection. This example shows that the goals of protection and coordination cannot always be solved by simple settings adjustment and system modifications/upgrades may be required to resolve identified issues.

X. CONCLUSION

Performing a WAC analysis can be a complex yet a rewarding exercise. The results of the analysis can lead to a more reliable system by improving selectivity of the protection system and therefore limiting the outage area of system fault. However, without careful planning and a systematic approach, the WAC analysis can be time consuming and complicated.

Upfront planning to determine the scope of the analysis, which operating scenarios to consider and what relays/elements to evaluate prior to any analysis being performed is key to saving time and effort during the study. Obtaining the right data for the short-circuit model and a means to methodically organize the information will make the analysis more efficient while reducing the likelihood of error. A coordination criteria developed at the front-end of the analysis will allow for better consistency across the system when coordinating relays/elements and will provide direction when judgment needs to be applied.

A successful WAC analysis depends on so many factors that aren't directly associated with coordinating relays. Planning ahead about what boundaries of the system to include, what contingencies to consider and how the analysis can be broken into subsets will result in a time savings and a quality end product.

XI. REFERENCES

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XII. BIOGRAPHIES

Bipasha Barman received her MS degree in Electrical Engineering from Michigan State University in East Lansing, Michigan in 1997, and her bachelor's degree from The Maharaja Sayajirao University of Baroda, India in 1992. She earned her Power System Protection and Relaying Certificate from the University of Idaho in 2007. She started her career as a trainee engineer in Asea Brown Boveri Ltd., India for 2 years. She worked for General Electric Company as a dry type transformer product engineer in Fort Wayne, Indiana for 3 years and as a substation engineer for about 5 years in Boise, Idaho. She joined POWER Engineers Inc. in Boise, Idaho in 2007 as a senior engineer in the SCADA and Analytical Services Department. Ms. Barman is presently a project engineer with extensive experience in protective relaying and electric power system analysis through planning studies. She is currently registered as a Professional Engineer in the states of Idaho and Texas. She is an IEEE member.

Jason Clack is a substation engineer for POWER Engineers Inc. and is based out of Meridian, ID. He earned his bachelor's degree in Electrical Engineering from Boise State University in 2009. He earned a Power System Protection and Relaying Certificate from the University of Idaho in 2012. Mr. Clack started working for POWER Engineers Inc. in the SCADA and Analytical Services Department as an intern in 2007 while finishing his bachelor's degree and then came on full time as a studies engineer after graduating. Mr. Clack is currently registered as a Professional Engineer in the state of Idaho. He is an IEEE member.

Vernon Padaca has over 20 years of experience in system protection and relay settings development, operational analysis, communication systems and maintenance practices for transmission, distribution and generation protection applications. He also has knowledge of the latest technology, communications/protocol, and techniques used in the system integration of protection, control, and monitoring systems. He received his BS in Electrical Engineering from Washington State University in 1992 and has also taken several graduate courses in power system analysis, protective relaying and machine design from the University of Idaho. Prior to joining POWER Engineers, Inc. in 2004, he has had careers at Idaho Power Company, Stellar Dynamics and General Electric. Mr. Padaca presently is a Department Manager and Senior Project Engineer in the SCADA and Analytical Services Department at POWER Engineers, Inc. He is currently registered as a Professional Engineer in the states of Idaho and Texas. He is an IEEE member.