Development of a Systematic Approach for Wide Area Protection Coordination of Transmission Lines

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1 Introduction

Today's complex and interconnected power systems require sophisticated tools to simulate and analyze their behavior under faulted conditions. Given the increasingly tight fault clearing times needed to maintain system stability and the complexity of protective devices employed, traditional approaches to studying coordination between relay pairs on adjacent lines may not ensure the high level of system reliability and security required by modern electric utilities and their governing regulatory bodies such as NERC and FERC [1, 2].

The purpose of Wide Area Protection Coordination is to analyze and evaluate on a system wide basis, existing protective relaying equipment schemes and settings for system normal and contingency fault conditions. The intent is to determine how effective the relaying schemes are now and implement settings and/or equipment changes in order to optimize system protection and device coordination.

1.1 Background

National Grid has embarked on a large capital investment program to upgrade transmission infrastructure across its service territories and as such has anticipated a corresponding impact on significant parts of the protective relay system.

Protection coordination studies have historically been performed on a per project or per request basis where portions of the system under consideration are studied in great detail while adjacent areas tend to get less attention, the further from the affected area they are located. As infrastructure is added, upgraded or reconfigured, the result can sometimes be a system that is coordinated in an incremental fashion rather than on a system wide basis. In undertaking the “Wide Area Protection Coordination” project it is hoped that any unknown deficiencies in transmission system protection and device coordination can be identified and corrected. This will serve as a baseline from which to proceed with the aforementioned capital investment program. In addition, it will address increased national pressure from regulatory agencies and the public to insure that electric transmission organizations are utilizing sound utility practice regarding implementation, setting and maintenance of protection systems.

The Wide Area Protection Coordination project was initially intended to be applied to National Grid's bulk power and critical transmission facilities only, but it was subsequently expanded to include transmission lines at 69kV and above in order to achieve the expected outcome and benefits. In the end, over 500 transmission lines and 1300 power transformers along with their pertinent protective relay schemes and settings have been researched, modeled and analyzed.

To assure the studies were performed on a sound foundation, a completely new short circuit system model was constructed. All transmission line self and mutual impedances were recalculated from scratch. All transformer impedances and winding connections were verified against available test reports. The latest relay setting records and/or electronic setting files were scrutinized and provided the basis for relay settings included in the model. Due to the nature of the task and location of transmission line construction data, the data gathering and modeling segments of the project were labor intensive and done in a largely manual fashion.

Device sensitivity and coordination analysis was initially envisioned to be done in a manual fashion as well, using available short circuit analysis software. It soon became apparent however that a more systematic and automated approach would be required in order to efficiently and effectively handle the large amount of data, various protection schemes and the many system fault conditions. For these tasks, two automated macros were developed using an advanced protection system simulation program. The "sensitivity" macro first performs a system topology search in order to identify protection elements associated with targeted line terminals and load taps under study. It then applies a series of specified faults to determine the ability of individual protection elements to properly respond to normal and contingency fault conditions. The "coordination" macro performs a similar topology search, then applies a series of pre-specified faults and utilizes sequence-of-event analysis to determine the ability of protection schemes to properly coordinate with adjacent protection schemes, again under various normal and contingency fault conditions. Lastly, the study results are summarized based on pre-determined evaluation criteria and action categories. The sensitivity checks, coordination studies and evaluation criteria were developed based on a series of best practice seminars and protection criteria discussion sessions among the utility's protection engineers and the development team. As a result, a consistent set of guidelines and procedures were applied to determine protection philosophy and setting requirements as the basis for the development of sensitivity and coordination macros. This method and approach is explained further in the following sections.

1.2 Proposed protection coordination methodology vs. traditional approach

A line protection system must meet a number of challenges. These include having sufficient sensitivity and/or "reach" to detect faults on the protected line with some allowance for fault resistance and abnormal system conditions. These design requirements are also applicable when a remote breaker backup is intended to have sufficient sensitivity or reach to detect faults on adjacent lines. Further, the protective system must be able to carry the anticipated load as specified by NERC standards [3], and by regional standards. Since the loadability requirements tend to conflict with sensitivity requirements the conflicts must be identified and mitigated. Finally, the protective system must "coordinate" with other protection systems in the area such that fault clearing will be selective, yet reliable, while the extent of the resultant outage area is minimized.

Other design considerations include the impact of fault clearing time on system stability, damage prevention of conductors and transformers as well as maintaining an acceptable level of power quality. However, these considerations were outside the scope of this study and hence were not evaluated.

The first step in a wide area protection study is to evaluate the sensitivity of the relay elements that make up each line protection scheme. In this regard, the main question is whether relay elements can detect or "see" the faults for which they are intended. This step required initial specification of what is to be considered adequate sensitivity and/or "reach" to faults of various types, at various locations and under normal and abnormal conditions. To do this, it was essential to determine a desired target value as well as several ranges of deviation from that target. In this way it could be determined which settings required immediate corrective action and which could be addressed at a more leisurely pace. See Table 1.

In the case of over-current tripping elements, a variety of short circuit simulations are required at various locations and contingencies with a comparison being made between calculated current and the relay pickup. Likewise in the case of distance elements, faults are placed at pre-determined locations, again with specified normal and abnormal system conditions. Here, comparisons are made between the relay "reach" settings and calculated apparent impedances to verify that settings are appropriate. Elements intended to overreach or under-reach should be verified to do so based on desired margins. In addition, the sensitivity checks should also evaluate overcurrent fault detectors and other supervising elements associated with distance, directional and breaker failure elements.

The traditional method of protection coordination involves comparing a pair of protection elements. When coordination is done or verified manually, an engineer will first coordinate pickups or reaches of pairs of relays and then coordinate timers. The process often includes plotting time-current curves or mho circles to visualize the situation. Infeed or outfeed are factors included as part of the evaluation. The process might be repeated for a number of system conditions, both normal and abnormal. Automated coordination studies do not use this approach directly. Rather, for a given system condition, faults of user specified types are placed along a particular line under study. The time of operation of relay elements on that line is then calculated and breaker clearing time is added to obtain total fault clearing time. The time of operation of relays on adjacent lines, transformers or generators for the same fault is also calculated. From these two times the coordinating time interval (CTI) is calculated. If the CTI is less than the desired margin it is classified as a CTI violation and if it is negative it is classified as a miscoordination.

1.3 Paper objectives and organization

The main objective of this paper is to introduce a systematic and automated approach for sensitivity analysis and in-depth coordination studies of all primary and backup protection functions of transmission lines including pilot and non-pilot tripping and breaker failure protection. The proposed approach will ensure that the multitude of protection schemes applied over a large area of the transmission network is effectively and systematically coordinated with each other. The studies simultaneously analyze multiple protective devices while considering the effects of an evolving network topology. Adjacent lines, transformers and generator infeeds as well as mutually coupled lines are removed in sequence-of-event fashion as the protective schemes and interrupting devices respond to simulated fault conditions.

The paper describes a generalized study methodology and a comprehensive set of sensitivity tests and coordination studies that are normally applied by protection engineers on an individual basis as part of a line protection design and setting implementation. The proposed studies may be applied to new or existing transmission lines to investigate protection system performance according to pre-determined protection system evaluation criteria and coordination requirements typically derived from the utility-specific best practices, guidelines, and applicable protection design standards (NERC/FERC, IEEE).

The subsequent sections of this paper are organized as follows. The wide-area protection coordination approach is discussed in section II. Details of sensitivity checks and coordination studies are explained in sections III and IV. A representative case study based on parts of an existing transmission system, which is used as a benchmark to explain the iterative process of sensitivity study and coordination analyses, are outlined in section V. Concluding remarks are given in section VI.

2 Automated Sensitivity and Coordination Studies

The flowchart in Figure 1 describes the overall process of wide area protection coordination proposed and explained in this paper. The study approach is designed in two major steps. In the first step, the Sensitivity Analysis tool is used to investigate sensitivity of as-found protective relay settings. Protection functions modeled include phase and ground distance, instantaneous and time overcurrent, and fault detectors utilized for distance supervision, breaker failure, or carrier start/stop. Common pilot schemes are also included. To effectively test these functions, any logical association between elements is modeled as well (e.g. distance and fault detector elements). Functions are studied for a variety of fault conditions under normal and N-1 or N-2 scenarios. After initial results are reviewed, necessary setting changes are either fed back into the model to resolve critical sensitivity issues in the short term or set aside (if less severe) to be addressed in combination with coordination study results. Conformance with NERC-PRC-023 criteria for line emergency loading is also checked in Step 1.

In the second step, the Coordination tool is applied with revised settings from Step 1 to analyze coordination between relay schemes in a given area of the power system. This coordination study tool uses sequence-of-event analysis by applying multiple (pre-specified) faults to a line under study as well as all adjacent lines terminating at local or remote terminals along with lines mutually coupled to the main line under normal and N-1 or N-2 conditions. Protective relay responses and coordination time intervals are determined by comparing the fault clearing time of primary protective devices with the predicted operating time of the backup and breaker failure protection on the line under study as well as adjacent lines. Similar to the sensitivity study, protective device coordination intervals are reviewed and any necessary setting changes are fed back into the model to resolve critical coordination deficiencies.

The aforementioned two-step approach is proposed as an efficient and systematic analysis tool which greatly surpasses traditional methods of performing relay scheme sensitivity and coordination tests on complex transmission systems. The method applies a unified study methodology based on pre-specified design guidelines and evaluation criteria. It simultaneously examines numerous protection settings and multiple primary and backup protection schemes (including automatic reclosing and breaker failure) over a large part of the network.

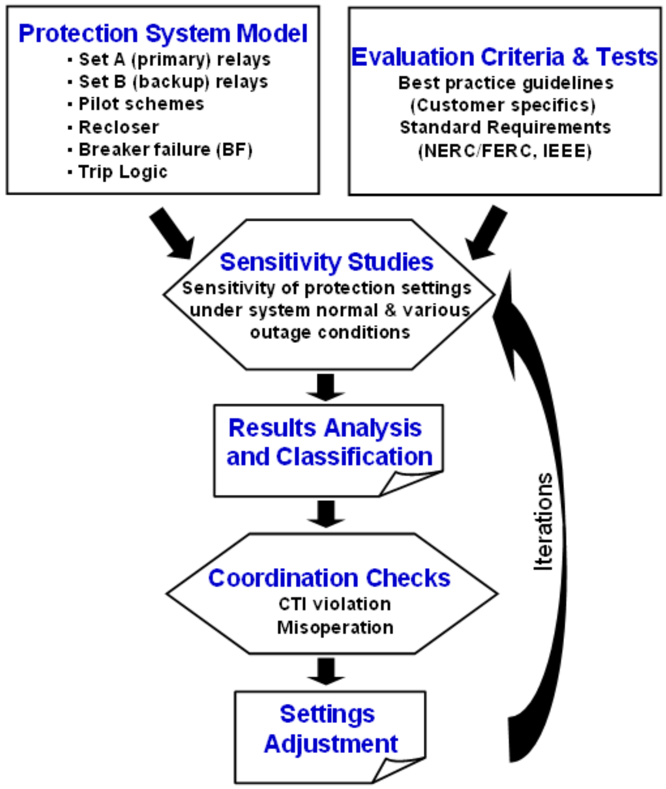

Figure 1 – Sensitivity and coordination study flow chart

Separate macros were written to automatically check sensitivity and to perform coordination tests.

3 Sensitivity Studies and Setting Evaluations

Sensitivity studies are used to evaluate the effective reach of protective relay elements during fault conditions to confirm appropriate coverage of the power system. The ratio of pick-up to fault current is measured for overcurrent elements. The actual reach of impedance elements is determined by applying faults with a "golden search" algorithm for each case of interest. Sensitivity evaluation parameters are user defined to allow for application flexibility. If sensitivity analysis results show relay elements do not meet setting parameters, setting changes can be made to correct these conditions prior to running coordination studies.

Relay sensitivities for each line are studied for system normal conditions (all sources in service) and with each local or remote bus source outaged one at a time (N-1 contingency), depending on the type of element being studied. Lines mutually coupled to the study line are also considered N-1 contingencies and are outaged during the evaluation of ground/neutral protection elements.

3.1 Sensitivity tests

Sensitivity tests are designed according to the types of protective elements in use and expected functionalities. Although the protection design methodology may widely vary from one utility to another, the following sensitivity tests can provide an overall outline of the variety of tests that can be applied to evaluate protection design sensitivity and requirements.

Time Overcurrent Elements: Time overcurrent elements (TOC) are most often applied to provide primary protection for the line section A-B and back-up protection for other sections connected to Station B (see Figure 2). Faults at Station B under system normal conditions and with sources at Station A outaged one at a time are used to determine the range of pick-up to fault current ratios. For faults beyond Station B the relays at Station A are performing a back-up function and faults at the end of each line section with the remote breaker open are calculated with no outages of sources behind Station A. If the line has three terminals, as in Figure 2, an end-of-line fault is applied at C (breaker open) with D in service, and an end-of-line fault is applied at D (breaker open) with C in service. Appropriate faults are applied for different element types; three phase and phase-to-phase for phase elements, line-to-line faults for negative sequence elements, and phase-to-ground faults for ground (zero sequence) elements. For ground overcurrent tests lines mutually coupled to the protected line are also considered as N-1 conditions and outaged one at a time as well. In most applications directional elements are being used to supervise the overcurrent protection. It is important that the computer models of the protective relays under study also include directional element characteristics to insure their performance is not a limiting factor.

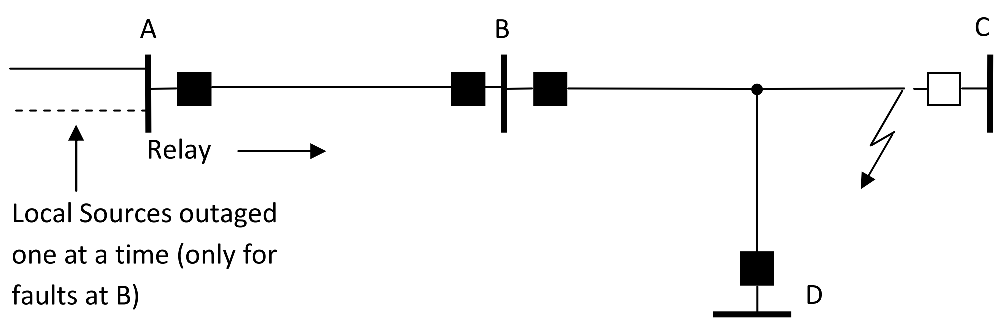

Figure 2 – Example line topology for time overcurrent tests

Instantaneous Overcurrent Elements: Instantaneous overcurrent elements (IOC) are generally applied to provide high speed primary protection for the line section A-B (see Figure 3). Actual coverage is less than the entire line section to insure coordination is not compromised with other line protection at Station B. The actual reach of the IOC element on the protected line is calculated for system normal and N-1 contingencies to determine if the element overreaches the remote bus. For these tests the lines removed are at Station B to maximize fault current at A. The element pick-up to fault current ratio is also determined for remote bus faults with and without contingencies. The program is able to recognize elements sensitive to DC offset current and automatically evaluate them at a higher pick-up/fault current ratio. Supervising directional element characteristics are also considered in a manner similar to TOC elements.

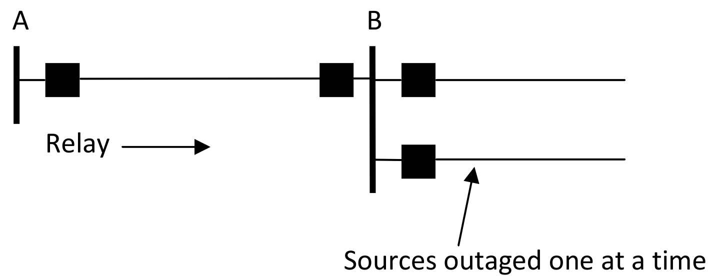

Figure 3 – Example line topology for instantaneous overcurrent and step distance tests

Breaker Failure Fault Detectors: Breaker failure sensitivity is tested by applying appropriate faults at the end of the protected line with the remote breaker open. Sources behind the relay are outaged one at a time. The pick-up to fault current ratio is calculated and compared to the desired value. Sensitivity tests are run with three phase, phase to phase, and phase to ground faults.

Distance Elements and their Associated Fault Detectors: Different tests are performed depending on the element's application. Any associated overcurrent fault detector(s) is checked simultaneously. Fault detectors may be an integral part of the distance relay or a separate device.

Zone 1 step distance elements: Zone 1 elements are applied in a manner similar to instantaneous overcurrent elements providing primary protection for line section A-B (Figure 3). The actual reach of Zone 1 is calculated for all paths to remote buses on the protected line (if a multi-terminal line). Local sources at the relay location (terminal A) are outaged one at a time for the fault detector test. Note that fault detector pick-up/fault current ratios are tested at the element reach point, not the remote bus location. Ground distance element evaluation includes outaging mutually coupled lines one at a time.

Zone 2 step distance elements: Zone 2 elements provide protection for the far end of the line section not covered by Zone 1 and remote back-up protection for bus faults at Station B (Figure 3). The zone 2 setting must be long enough to reach the remote bus but not over-reach the zone 1 settings of other lines originating from Station B. The ratio of the relay reach to apparent impedance measured by the relay for remote bus faults is evaluated under different outage conditions. To check for over-reach issues with remote zone 1 elements, the actual reach point of zone 2 along all lines emanating from Station B is calculated. Reach point determination is calculated for system normal and with each source connected to Station B outaged one at a time. Mutual lines are removed for ground distance element evaluation.

Zone 2 Pilot System Applications: Over-reaching distance elements are also part of directional comparison and permissive over-reaching transfer-trip pilot systems. If the remote end employs a reverse reaching blocking element, it is important to compare the relative reach of the local end forward and remote end reverse reaching elements. The actual reaches of the two elements are compared on each of the lines connected at Station B (Figure 3).

<u>Zone 3 step distance elements:</u> Zone 3 elements are most often applied as back-up protection for remote station line protection and as back-up for a breaker failure at the remote station. Figure 4 illustrates the failed breaker situation. Faults are applied at the end of each line terminated at a Level 2 station (e.g. Station C). Note that the Level 2 remote breaker is open and that no other lines are outaged for this test.

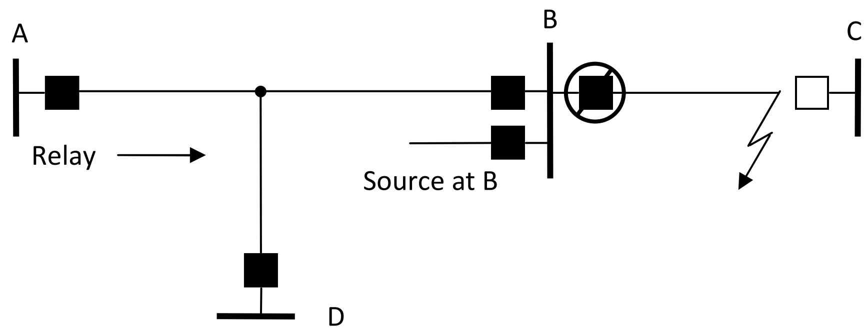

Figure 4 – Example line topology for breaker failure tests

<u>Distance Relay Loadability Tests:</u> Distance elements are tested to determine compliance with NERC-PRC-023 criteria for relay loadability, [3]. Load angle, normal line rating factor, and per unit voltage at the relay bus can be specified. Load encroachment functions, if part of the relay, are modeled as well. The loadability tests will determine when the basic reach test fails but operation is blocked by the load encroachment function.

3.2 Categorization and evaluation of the results

As mentioned earlier we specified target sensitivities or reaches as well as ranges of deviation from those targets and what kind of urgency for correction various amounts of deviation warranted. Categories included “Target”, “Act Now,” “Act Later,” “Possible Improvement” and “No Action.”

Table 1 shows an example of evaluation criteria and action requirements for three types of protective elements: directional instantaneous overcurrent elements (67NI type) and zone 1 and zone 2 step distance elements (21Z1 and 21Z2).

Table 1 - Evaluation criteria and action categories for three selected protection elements

Element	Value						Comments
	Target	Act Now (1 Yr or more)	Act Later (2 - 3 Yrs)	Possible Improve-ment	No Action	Condition	
Instantaneous Elements							
Minimum multiples of pickup (PU) current to operating current (digital and induction cup types)	PU ≥1.25	PU < 1.20	1.25 > PU ≥ 1.20	PU > 1.50	PU ≥1.25	Norm & N-1	Possible improvement for PU > 150% to improve coverage if practical
Minimum multiples of pickup (PU) current to operating current (solenoid/plunger/clapper types)	PU ≥1.50	PU < 1.40	1.50 > PU ≥ 1.40	PU > 1.75	PU ≥1.50	Norm & N-1	Possible improvement for PU > 175% to improve coverage if practical
Distance Elements							
Desired zone 1 reach (Z1) as multiple of the positive-sequence line impedance	Z1 ≤ .85	Z1 ≥ 0.90	.87 > Z1 < .90		.75 ≤ Z1 ≤ .87	Norm & N-1	Possible Improvement for Z1 < 75% to improve coverage if practical
Desired zone 2 reach (Z2) as multiple of apparent impedance for remote bus faults	Z2 ≥1.20	Z2 ≤ 1.15			1.15 < Z2	Norm & N-1	NOTE: Reach is over 115% of apparent Z for remote bus faults and under 50% of impedance remote line(s). If 50% test fails, verify longest Z2 does not reach more than 80% of the shortest adjacent apparent Z1 reach under system normal and N-1 conditions. (If there are pilot schemes on adjacent lines, then it is not an issue.)
Desired zone 2 reach (Z2) on lines adjacent to the remote bus as fraction of line impedance	Z2 ≤ .50	Z2 > 0.50 (further evaluate)			Z2 ≤ .50	Norm & N-1	

Although default target setting criteria, contingencies (outages), and coordination requirements for each element and protection action were hardcoded into the macros, the type of tests to be performed and evaluation criteria (element-type-specific parameters) are user-selectable/adjustable and can be customized during the initialization stage of a specific study.

4 Coordination Studies

The sensitivity studies described in the previous section evaluate the settings of individual relay elements against the criteria used to set them originally. For example, one of the tests performed was to ensure that instantaneous ground overcurrent elements (50N) do not over-reach the remote terminal of the line under different network contingencies. The results of these studies are used to modify relay settings, as described before.

The coordination studies described in this section are used to evaluate whether the protection system as a whole, with pilot (teleprotection) schemes, automatic reclosing, breaker failure logic and stepped-distance/overcurrent protection operates as intended.

To challenge the protection system, faults of different types, with multiple fault resistances, are applied at different locations on the line being studied. Contingencies like outage of lines, transformers, and mutually coupled lines, failure of pilot schemes and stuck breaker situations are evaluated.

The complete study of one line involves the application of a large number of faults under different contingencies (typically in excess of 500). To help the engineer perform the study in an accurate and expeditious manner, a high level of automation was introduced. Once the engineer has specified the line to be studied and the faults and contingencies to be evaluated, the automated process takes over and systematically tests each case. It evaluates relay operation, identifies situations where backup relaying is too close in time to primary relaying or even operates ahead of primary relaying, and gathers and reports the results to the engineer.

The engineer has to analyze the problems found, and decide what type of relay setting changes are needed to mitigate them.

The next few sub-sections provide additional details about the automated coordination study process.

4.1 Objective of coordination studies

The main objectives of the coordination studies are:

- Ensure that the protection system that has the primary responsibility for clearing a fault is indeed able to do so, under different contingencies.
- Evaluate the available time interval between the fastest primary and all backup protection operations – the Coordination Time Interval (CTI).
- Determine whether backup protection systems (those that do not have primary fault clearing functions for the given fault):
    - Are too close in time to the time of operation of primary protection. This type of issue is called a CTI violation. It may or may not lead to actual opening of a backup circuit breaker.
    - Operate at the same time as, or ahead of primary protection. This type of problem will lead to the opening of a backup circuit breaker, and is called a Miscoordination.
    - Are too far behind the time of operation of primary protection. This is also a CTI violation, but the effect is that of not having a backup to clear the fault promptly in the event primary protection is unable to do so.

It is important to note that fault clearing can take multiple breaker openings, even if primary protection is able to clear the fault successfully. CTI issues are typically seen once the first breaker(s) has (have) opened and the network topology changes.

The automated coordination tool uses a method called the “stepped-event technique” to evaluate the response of the protection system, [4, 5]. A series of steady-state calculations simulates the sequence of protective device operations and consequent circuit breaker opening from the moment a fault occurs until the operation of the last circuit breaker. At each breaker opening (event), the network topology is altered, and new voltages and currents measured by protective relays are computed. Allowance is made for the partial time-out of time-overcurrent elements during this process – they may operate slower or faster depending on the way in which currents in the network change. Protective elements that did not operate previously might now become sensitive to the fault condition on the system.

The process of evaluating protective relay operations and circuit breaker opening continues until the time the fault is cleared, or no more protective relays are predicted to operate.

With the ability to model pilot protection schemes, breaker-failure relaying and single-pole tripping and reclosing, the stepped-event technique has proven to be a practical and effective means for uncovering CTI and miscoordination issues.

4.2 Type of studies: CTI issues, Misoperations

Most of the transmission lines on the National Grid bulk power system utilize two protection packages labeled Package A and Package B. Each package uses direct tripping elements (both instantaneous and time-delayed) and pilot (teleprotection) elements.

National Grid's protection design philosophy requires each package to coordinate with backup relaying, entirely on its own. That is, having both packages in service might cause relays in one package to "save the day", and mask problems that might exist with the relays in the other protection package.

With regard to pilot protection, it was decided to consider a pilot outage as an N-1 contingency. That is, outage of pilots (on the protection package being evaluated) would not be combined with any other line, transformer or mutual coupling outage.

Further, use of one package or the other and attendant pilot outages are applicable only to the line being studied. On other lines (considered to be backup protection), all protection packages including pilot protection are in service and allowed to operate for the faults on the study line.

Thus, two sets of studies are performed during the evaluation of one transmission line – one set of studies for each protection package applied on the line, with the other package disabled. The N-1 network contingency cases to be considered are:

- System Normal with pilots out of service
- System Normal with pilots in service
- Outage of lines at the local and remote bus(es) with pilots in service
- Outage of transformers (including generator step-ups) at the local and remote bus(es) with pilots in service
- Outage of generators at the local and remote bus(es) with pilots in service
- Outage of other shunts (grounding transformers for example) at the local and remote bus(es) with pilots in service
- Outage of load tap transformers on the line, with pilots in service
- Outage of lines mutually coupled to the study line with pilots in service
- Outage of lines mutually coupled to the neighboring lines at the local and remote bus(es) with pilots in service
- Outage of the other terminal on multi-terminal lines with pilots in service
- Failure of the breaker to open at each end of the line, with pilots in service

It is to be noted that the pilot protection is in service during the outage of lines, transformers, etc. However, the engineer has the option of running the outage scenarios with pilot protection turned off. This would lead to four sets of studies for each transmission line with each protection package being evaluated separately with pilots in and out of service.

The engineer can also perform N-2 type of contingency studies; these are special outage situations under which the System Normal and each of the N-1 contingencies listed above are applied. Two types of such contingencies are of general interest: double- or triple-circuit tower loss and long-term generator outages.

(a) Double- or triple circuit tower loss. Only circuit pairs or triplets that sometimes share the same towers and that both terminate on one of the end buses of the primary line are considered.

(b) Long term loss of generator. In this scenario, each "important" generator is outaged one at a time. "Important" means that a particular generator outage affects fault current values at one of the ends of a particular study line according to pre-established criteria.

The N-2 network situations are only provided as options to the engineer at present. They are not routinely tested.

4.3 Reporting the results of studies

The complete study of a transmission line involves application and evaluation of faults routinely in excess of 500. Each of these faults will take two or more breaker openings to clear.

Not all the faults tested will result in a CTI violation or miscoordination of course. When a problem does occur, the engineer needs to be provided with sufficient information to quickly identify the offending relays.

For each transmission line that is studied, the automated study process produces three types of reports:

- **Summary of Results:** The summary report shows one line of output per fault that was tested. By looking at this report, the engineer can quickly tell whether a fault at a certain location, with a certain contingency in effect, was cleared properly by primary protection, or not, due to a CTI violation or miscoordination. An example of the summary report is shown in the next section.
- **Detailed Sequence-of-Events Report:** As explained before, it might take multiple breaker openings for a fault to clear. For each evaluated fault, and for each event (opening of breakers) in that fault, the automated test procedure records information about primary and backup relays that cause breaker operation (or are predicted to operate at a future time if conditions do not change).

  The detailed sequence-of-events report is made available as a single file, with details about each applied fault. The report is color-coded according to the level of severity of the problem. By studying this report, the engineer can see exactly which relays operated at what times during the fault clearing process. Section 5 contains an example of the detailed sequence-of-events report generated by the automated test procedure.
- **Offending Relay Panel Report:** If, for example, during the study of a transmission line, a particular set of back up relays, called a panel (with possibly multiple relays) shows CTI violations or miscoordinations for a number of faults that were tested. We call such a relay panel an "offending relay panel" because it shows one or more problems when serving as a backup.

The offending relay panel report is extracted from the detailed sequence-of-events report by the automated test procedure and stored as a file. The name of the file is specified such that the engineer can quickly tell where the relay panel is located, and the study-line for which the relay panel caused one or more problems.

5 Study Examples

The sensitivity study and coordination test results for an example line are outlined in this section to illustrate the macro output, report formats, and types of issues that may be identified in a typical wide area protection study. The selected line for this example is a 345 kV bulk power system (BPS) line (LN 345_39) with two protection packages at each end terminal. A schematic diagram of part of the study system illustrating the corresponding lines terminating at each substation is shown in Figure 5. Each line protection package uses a microprocessor relay. The line is also equipped with two pilot schemes: a POTT scheme in package A and a DCB scheme in package B.

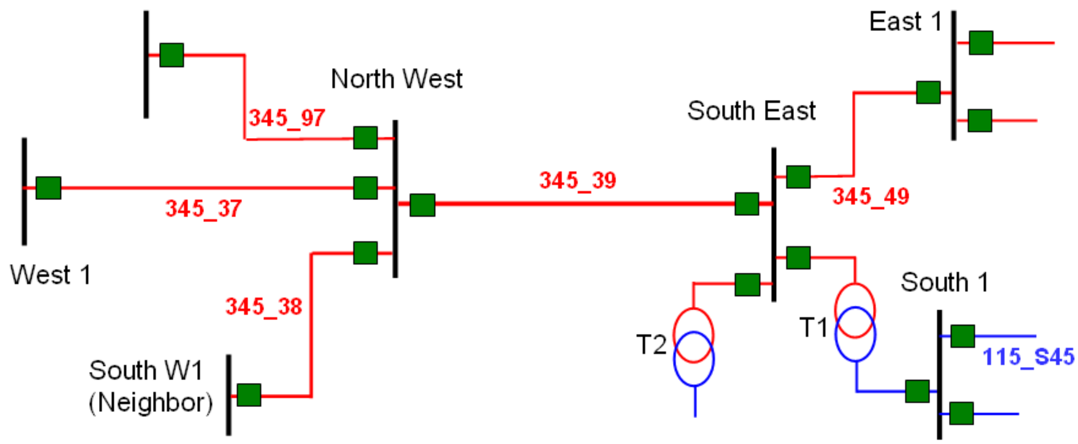

Figure 5 - Schematic diagram of part of the study system

5.1 Example sensitivity studies

The macro generated results of sensitivity studies for directional ground instantaneous overcurrent elements (67NI) and ground zone 1 step distance elements (21G1) at the South_East end terminal of line 345_39 are presented in Tables 2 and 3.

Table 2 - Sensitivity macro generated study results for a 67NI element

South_East TOC "IN>3" (P443K (5A)); Contact Logic Code: 67NI_B;
Testing sensitivity for remote bus faults

No.	Fault	Outages Considered	Fault Location	Pickup A,Prim	Meas. A,Prim	Act. Ratio	Des. Ratio	PASS FAIL	Oper. Cyc.
1	SLG	None	North_West	11200	8122.8	1.38	1.25	PASS	999.0
2	SLG	Line 345_37	North_West	11200	8205.1	1.37	1.25	PASS	999.0
3	SLG	Line 345_97	North_West	11200	8477.4	1.32	1.25	PASS	999.0
4	SLG	Line 345_38	North_West	11200	9581.6	1.17	1.25	FAIL	999.0
5	SLG	Mutual: 115_S45	North_West	11200	7623.7	1.47	1.25	PASS	999.0
6	SLG	Mutual: 115_T46	North_West	11200	7142.1	1.57	1.25	PASS	999.0

The sensitivity study results in Table 2 shows that the ratio of the pick up to the operating current for the studied 67NI element is 138% under the normal primary system condition and may vary in the range of 132 to 157% for most of the outage conditions. However, it has been also identified that this ratio drops to 117% under a specific contingency condition (outage of line 345_38 connecting to North_West substation). This case is highlighted in red by the macro. Considering the sensitivity requirement that the pickup to operating current ratio be more than 120-125% for directional IOC elements, the above condition qualifies the element as one of the "Act Now" situation.

Table 3 - Sensitivity macro generated study results for 21G1 elements on schemes 1 and 2

Ground Distance Elements Zone: 1;

Testing zone 1 reach on path **South_East** to remote bus **North_West** (LN 345_39)

Element	Details	Fault	Outages Considered	Line Imp. Ohms	Line Angle Degrees	Set Reach Ohms	Set Reach %	Act. Reach %
DIST Z1G 1	SEL-421_5A	SLG	None	8.58	86.74	7.31	85.	94.
DIST Z1G 1	SEL-421_5A	SLG	XFMR (T1)	8.58	86.74	7.31	85.	94.
DIST Z1G 1	SEL-421_5A	SLG	XFMR (T2)	8.58	86.74	7.31	85.	94.
DIST Z1G 1	**SEL-421_5A**	**SLG**	**Line (345_49)**	**8.58**	**86.74**	**7.31**	**85.**	**100.**
DIST Z1G 1	SEL-421_5A	SLG	Mutual: 115_S45	8.58	86.74	7.31	85.	93.
DIST Z1G 1	SEL-421_5A	SLG	Mutual: 115_T46	8.58	86.74	7.31	85.	90.
DIST Z1G 1	**P443K (5A)**	**SLG**	**None**	**8.58**	**86.74**	**6.45**	**75.**	**84.**
DIST Z1G 1	**P443K (5A)**	**SLG**	**XFMR (T1)**	**8.58**	**86.74**	**6.45**	**75.**	**84.**
DIST Z1G 1	**P443K (5A)**	**SLG**	**XFMR (T2)**	**8.58**	**86.74**	**6.45**	**75.**	**84.**
DIST Z1G 1	**P443K (5A)**	**SLG**	**Line (345_49)**	**8.58**	**86.74**	**6.45**	**75.**	**89.**
DIST Z1G 1	**P443K (5A)**	**SLG**	**Mutual: 115_S45**	**8.58**	**86.74**	**6.45**	**75.**	**82.**
DIST Z1G 1	**P443K (5A)**	**SLG**	**Mutual: 115_T46**	**8.58**	**86.74**	**6.45**	**75.**	**80.**

Table 3 provides macro study results for two ground distance elements on package A and package B. By investigating the results in Table 3, it can be noticed that the two elements are set differently (a set reach of 85% vs. 75%). Moreover, the present actual reach of the zone 1 ground distance element on package A violates the zone 1 setting requirement of less than 90% of the line impedance. As highlighted in red by the macro, for a specific contingency condition (outage of line 345_49) the zone 1 element can over reach the remote end terminal. The above situation classifies the element under the "Act Now" category.

5.2 Example coordination studies

Table 4 provides part of the summary report generated by the coordination study macro for the line under study (LN 345_39). The coordination studies are performed for package A in service (package B disabled). Due to space limitations, only a sample of the study cases is shown in this table. Each case has a case number (No.) to cross-link the summary report for the study cases to the detailed study report as explained before. The summary report can help a user to identify cases that may need further investigations. In the examples presented here, when pilot schemes are disabled, a remote close-in bolted line-to-ground fault has led to a miscoordination under normal primary system conditions.

However, the same case with pilot enabled condition (utilizing high speed tripping through pilot schemes) has only caused some CTI violations.

Table 4 - Summary report generated by the coordination macro

No.	Situation/Outages	Fault Type	Fault Location	Time(cyc)	Operation
1	Normal/Pilot Out	SLG Close-in	on LN 345-39 to North_West	4.60	OK
2	**Normal/Pilot Out**	**SLG Remote Close-in**	**on LN 345_39 to North_West**	**5.40**	**MISCOORDINATION**
37	Normal/Pilot In	SLG Close-in	on LN 345_39 to North_West	2.90	OK
38	**Normal/Pilot In**	**SLG Remote Close-in**	**on LN 345_39 to North_West**	**2.90**	**CTI VIOLATION**
39	XFMR : (T1)	SLG Close-in	on LN 345_39 to North_West	2.90	OK
40	**XFMR : (T1)**	**SLG Remote Close-in**	**on LN 345_39 to North_West**	**2.90**	**CTI VIOLATION**

Part of the detailed sequence-of-event report for Case 38 (CTI violation case in Table 4) is provided in Table 5 to illustrate the format and type of information outlined in this report. The information provided in this report is very beneficial for the root-cause analysis of any misoperation situation. As an example, in the selected case, although the pilot schemes are the primary protection and have correctly tripped the line and cleared the fault, the detailed sequence-of-event investigation has identified backup protection elements that may cause over tripping of the neighbor lines if the pilot schemes are not in service or their operation is significantly delayed by the corresponding communication system latency (more than normal). The predicted CTIs violate the coordination requirement of a minimum 18 cycle time margin between primary and backup protection elements.

Table 5 – An example of part of a detailed sequence of event report generated by the coordination macro

```
                              Package A in service (B outaged)
 No.   Situation/Outages   Fault Type          Fault Location             Time(cyc) Operation
 38      Normal            SLG Remote Close-in: on LN 345_39 to North_West 2.90 CTI VIOLATION

Event:  1 at  2.40 cycles;  0.040 seconds

                                                Primary  LZOP  Brkr  Total  Avail
 Substation              LZOP Name     TYPE   Backup   Time  Time  Time   CTI   Operation  Details

North_West    LN 39, 345 kv,        LINE  PRIMARY  0.44  2.00  2.44   N/A   NORMAL OPERATION
Element: 9745 DIST "Z1G" "1"; (SEL-421); Contact Logic Code: 21G1_A
Element: 9745 AUX "67G1"; (SEL-421); Contact Logic Code: 67NI_A
Element: 9747 AUX "TRIP"; (PILOT_WIZARD); Contact Logic Code: POTT_TRIP_A
  Supervisor: 9745 DIST "Z2G" "2"; (SEL-421);

South_East    LN 39, 345kV,         LINE  PRIMARY  0.94  2.00  2.94   N/A   NORMAL OPERATION
Element: 9781 AUX "TRIP"; (PILOT_WIZARD); Contact Logic Code: POTT_TRIP_A
  Supervisor: 9779 DIST "Z2G" "2"; (SEL-421);

North         LN 37, 345 kV,        LINE  BACKUP   1.44  2.00  3.44   -1.00 CTI VIOLATION
Element: 9600 DIST "Z1G" "1"; (SEL-421); Contact Logic Code: 21G1_A

North_West    LN S45, 115KV,        LINE  BACKUP   15.00 3.00  18.00  12.56 CTI VIOLATION
Element: 7283 TOC "51N"; (REL512); Contact Logic Code: 67NT_B

South         LN 97, 345 kV,        LINE  BACKUP   22.00 2.00  24.00  19.56 PREDICTED
Element: 9892 TIMER "Z4GD" "1"; (SEL-421); Contact Logic Code: 21G2T_A
Element: 9893 TIMER "tZ3G" "1"; (P44y); Contact Logic Code: 21G2T_B
```

6 Conclusions

This paper described a systematic and automated method for investigating sensitivity and coordination of protection systems in a vicinity of a targeted line. The automated approach allows the engineer to thoroughly test and evaluate sensitivity of protection elements and coordination between primary and backup relays for different fault types, fault locations, contingencies and protection schemes. The results of this exhaustive study are presented with different levels of detail, and problematic situations are clearly highlighted to draw the engineer's attention.

The decisions on which problems to mitigate and which ones to live with need to be made by the engineer. The automated test procedure does not attempt to do that, nor should it.

7 References

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