Multiple Setting groups based Adaptive Protection for Radial Distribution Feeder

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***Abstract*— Most existing midline electronic reclosers on radial distribution feeders support up to eight settings groups, some of which may already be in use. However, the setting groups that can be stored in these devices to accommodate and cater to numerous system configurations are limited. To configure each of the four available settings groups to provide the optimal response for all reclosers under all conditions presents a significant challenge. The proposed logic in this paper discusses the feasibility of selecting a standard set of settings groups which can be deployed to all electronic reclosers across a set of feeders out of a substation. These standard settings need to be calculated after extensive protection coordination studies which can also be automated. The implementation of this philosophy in conjunction with a standard Fault Location, isolation and Service Restoration (FLISR) scheme was tested in a Hardware in the Loop (HIL) environment.**

***Index Terms*—FLISR, Distributed Energy Resources, Hardware-in-the-loop, Multiple Setting Groups.**

I. Introduction

Distribution grid operations are becoming more complex and variable due to increasing deployment of distributed energy resources (DER), distribution automation (DA), and increasing electrification of customer load. There are scenarios where it is challenging to configure a midline recloser to provide optimal performance under all grid operation conditions and feeding arrangements.

Most existing midline electronic reclosers on radial distribution feeders support multiple (six to eight) settings groups. Generally, around four groups are available for use to implement various adaptive protection schemes which have been studied in the past [1]-[4]. These setting groups may correspond to multiple operating conditions of the system, ensuring proper selectivity and sensitivity of the relay with only one settings group (SG) being active at one time. Pertaining to numerous possible topologies of the system, suitable relay settings can be computed offline and stored as a separate, distinct setting group. To configure each of the four available settings group to provide the optimal response for all reclosers under all conditions, presents a significant challenge [5]. In the past, clustering techniques have been used to classify possible operating topologies of the network into clusters and hence calculating viable setting groups [6],[7]. Determining the best settings for each group in each recloser across all feeding arrangements and the various DER and short circuit level permutations could exponentially increase the complexity and engineering time required to configure a recloser. Such an approach would also be optimal at a single point in time and could potentially need revision as the grid evolves and changes.

As a counterpoint to this approach, it was considered whether a standard set of settings groups could be deployed to all electronic reclosers across a set of feeders out of a substation. Such an approach would significantly reduce the engineering effort and deployment strategy as each recloser has identical settings groups; the analysis is then reduced to an operational challenge to determine which settings group each recloser should use for a given distribution system/circuit arrangement. An adaptive protection system was developed based on this simplified approach. The logic enables the reclosers to adapt their protection characteristics in response to changes in grid configuration or short circuit current source. The proposed adaptive protection scheme was evaluated using power flow and short circuit fault simulation software such as OpenDSS-G. The scheme was implemented using a commercial, off-the-shelf protection relay and verified in conjunction with a Fault Location, isolation and Service Restoration (FLISR scheme) in a Hardware in the Loop (HIL) environment.

In conjunction with a utility partner, the methodology was applied to a set of feeders. The recloser settings and settings groups were configured based on the largest downstream fuse size and minimum fault level across a range of credible grid operating scenarios and feeder loading. Following the settings groups and logic design, the scheme was enhanced to enable automated transmission of the settings group change command by the Distribution Management System (DMS/SCADA) system in response to the system topology changes. This is performed without any manual operator intervention when the scheme is enabled. This approach entails the development of logic within the DMS to issue relay/recloser settings group change commands as switches open and close to transition from one circuit arrangement to another.

The rest of the paper is structured as follows: Section II discusses the proposed adaptive protection design overview. Section III outlines the network model considered for the pre-deployment testing phase of the adaptive protection scheme. Section IV illustrates the various test results that were carried out using HIL lab testing. The conclusions and ongoing as well as future work are summarized in Section V.

II. Multiple Settings Group based protection

A. *Adaptive protection success criteria*

While designing the scheme, it is imperative to define some important success merits to correctly identify key design aspects of the scheme. The success of the adaptive protection logic design for use on radial distribution feeder networks can be evaluated by the following measures. These success merits were translated to specific simulations and lab tests to validate the scheme.

- A centralized adaptive protection design which can dynamically respond to changing system operating conditions and enable the target feeder to be operated in multiple configurations without compromising protection sensitivity.
- A scheme which can be readily deployed to common protection and controller equipment already in use by distribution utilities.
- A design that detects and isolates all credible low impedance balanced and unbalanced faults during normal and abnormal grid configurations.
- Protection that trips in a timely and coordinated manner for faults during normal grid configurations.
- Protection that trips in a timely and coordinated manner for faults during abnormal grid configurations, respecting that available fault current and the number of series protective devices may mean coordination is not achievable for all devices in certain edge cases.
- Protection that trips in a timely and coordinated manner when cumulative DER installed capacity on the feeder results in the reverse flow of power up to conductor continuous rated current or the short circuit ratio falls below a utility defined value.

B. *Adaptive protection design overview*

Figure 1 presents a simplified example of how the adaptive protection scheme operates for a grid with two feeders arranged in a loop. Each feeder has two reclosers and the feeders are connected via a recloser in the normally open position. After considering the largest downstream fuse size and minimum fault level for this given set of feeders, a number of different standard settings can be considered. Table I presents the settings used for each settings group on all of the reclosers as an example in this case.

TABLE I. Example of Simplified multiple setting groups

Setting Groups	Pickup(A)
SG1	200
SG2	400
SG3	600
SG4	800

In the normal configuration shown on the left in Figure 1, the recloser nearest the substation uses settings group 4 with a pickup setting of 800A, while the downstream recloser uses settings group 3 with a pickup of 600A. The normally open recloser operates in settings group 5, which is a non-tripping settings group dedicated to operating the recloser as a sectionalizing switch.

If one recloser is opened, the normally open recloser is closed to re-supply the load. In this arrangement, there are two reclosers in parallel with the same setting of 600A and thus not coordinated. With the adaptive protection scheme, however, the normally open recloser changes to settings group 2, up on closing, with a pickup of 400A and the last recloser changes from settings group 3 to settings group 1 with a pickup current of 200A. All of the reclosers are now coordinated.

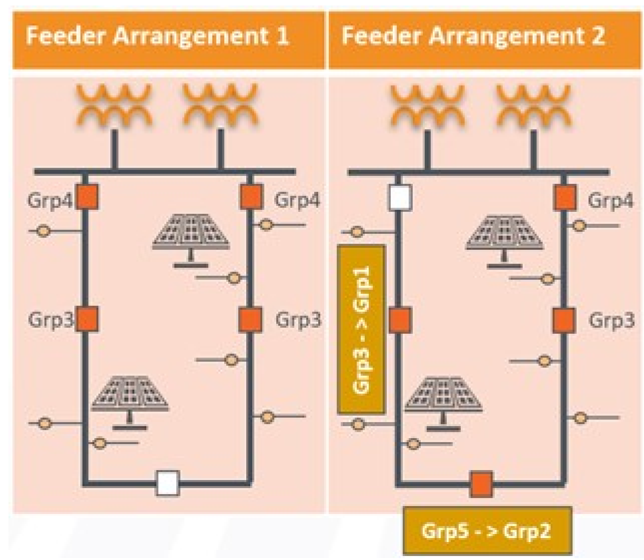


Figure 1. Setting group modifications based on various feeder arrangements.

Choosing the appropriate settings for each group typically requires an understanding of minimum credible fault current magnitudes and maximum load flow for normal and abnormal grid conditions. This can be achieved using planning and protection short circuit analysis tools.

It may not be possible to adequately protect the grid for every feeder configuration. The feeder may be so long that the fault level is comparable to the load current, so fault clearance is not guaranteed. For grids with many reclosers or normally open switches, it may not be possible to configure the protection for all credible system configurations.

C. *Distribution Protection Analysis Toolkit*

A tool that can automatically analyze grids to determine optimal settings groups may prove beneficial for these types of situations. The optimal settings may need feeder specific considerations – some feeder configurations may be more frequent or important than others and the choice of settings will reflect that.

Distribution Protection Analysis Toolkit (DPAT) [8] is a tool developed to run automated protection coordination studies for distribution systems which can help in identifying miscoordinated relays, fuses and reclosers along with automatically assessing protection under a wide range of scenarios including with/without DER, different feeding arrangements, etc. The toolkit's framework is integrated into common distribution grid Short Circuit and Power Flow Analysis tools and makes use of their available Application Programming Interfaces (APIs) to automate analyses and data extraction.

The framework is intended to execute numerous analyses on a single study, generating vast amounts of data which is then stored for historical performance checks as well as for report generation. The main goal of the framework is the generation of actionable suggestions from the collected data to enable engineers to quickly assess the protection system performance which would have been tedious and cumbersome to solve manually. Figure 2 illustrates the general framework of the toolkit.

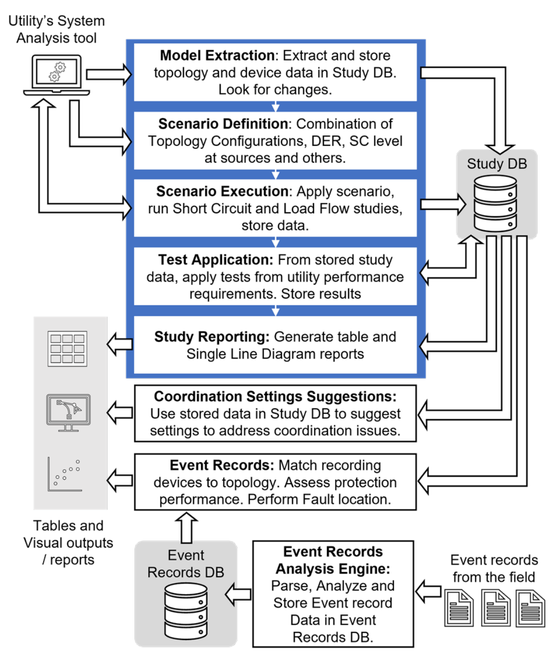


Figure 2. General Framework of DPAT [8].

The details of the general workflow of this framework can be found in [8]. Figure 3 shows the general parameters provided by the user to assist the tool for model extraction and scenario definition stages of the framework.

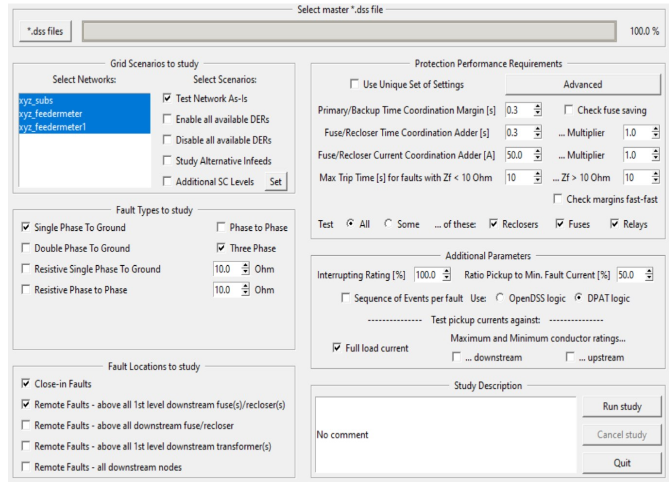
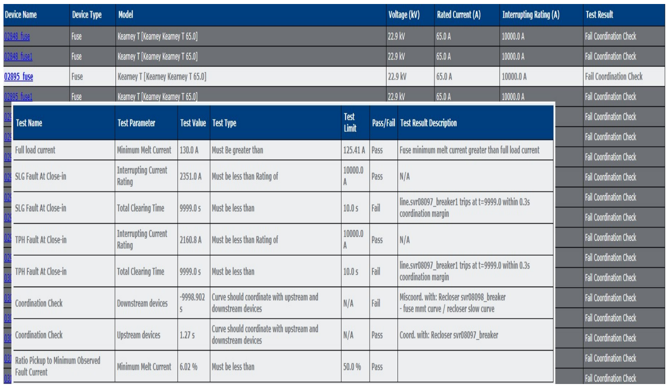


Figure 3. User defined test parameters provided in DPAT input GUI .

The Test Application stage of the framework makes use of stored analyses and results from the previous step (Scenario Execution) and topology data from Scenario Definition to perform some key tests as listed out below:

- Protection device Overcurrent pickup settings are checked against 1) Upstream and downstream conductor ratings which is intended to analyze loadability limitations against protection device overcurrent pickups; 2) Full load power flow currents to check if devices would trip for load current.
- Protection device observed fault currents against a percentage of the interrupting capability of devices defined by the user.
- Primary/backup protection coordination checks.
- Sequence of Operations. For each applied fault, the framework should be able to use the extracted data and TCC curves and device settings to recreate the sequence of trip and reclose events that might occur.
- Overcurrent pickup sensitivity: Compute ratio of minimum fault current in protection zone against overcurrent pickup.

After execution of all the tests and storing the results, the tool then generates relevant tabular and visual Single Line Diagram (SLD) reports that help protection engineers to quickly identify the location of protection devices with issues. Figure 4 illustrates the format of the tabular report generated by the toolkit. The user can hover over a particular row (corresponding to a particular protection device) and can observe a detailed pop-up table of all the associated tests for the device as shown in the figure for a particular fuse.



Device Name	Device Type	Model	Voltage (kV)	Rated Current (A)	Interrupting Rating (A)	Test Result
02848_fuse	Fuse	Kearney T [Kearney Kearney T 65.0]	22.9 kV	65.0 A	10000.0 A	Fail Coordination Check
02848_fuse1	Fuse	Kearney T [Kearney Kearney T 65.0]	22.9 kV	65.0 A	10000.0 A	Fail Coordination Check
02895_fuse	Fuse	Kearney T [Kearney Kearney T 65.0]	22.9 kV	65.0 A	10000.0 A	Fail Coordination Check
02895_fuse1	Fuse	Kearney T [Kearney Kearney T 65.0]	22.9 kV	65.0 A	10000.0 A	Fail Coordination Check

Test Name	Test Parameter	Test Value	Test Type	Test Limit	Pass/Fail	Test Result Description
Full load current	Minimum Melt Current	130.0 A	Must Be greater than	125.41 A	Pass	Fuse minimum melt current greater than full load current
SLG Fault At Close-in	Interrupting Current Rating	2351.0 A	Must be less than Rating of	10000.0 A	Pass	N/A
SLG Fault At Close-in	Total Clearing Time	9999.0 s	Must be less than	10.0 s	Fail	line.svr08097_breaker1 trips at t=9999.0 within 0.3s coordination margin
TPH Fault At Close-in	Interrupting Current Rating	2160.8 A	Must be less than Rating of	10000.0 A	Pass	N/A
TPH Fault At Close-in	Total Clearing Time	9999.0 s	Must be less than	10.0 s	Fail	line.svr08097_breaker1 trips at t=9999.0 within 0.3s coordination margin
Coordination Check	Downstream devices	-9998.902 s	Curve should coordinate with upstream and downstream devices	N/A	Fail	Miscoord. with: Recloser svr08098_breaker - fuse mmt curve / recloser slow curve
Coordination Check	Upstream devices	1.27 s	Curve should coordinate with upstream and downstream devices	N/A	Pass	Coord. with: Recloser svr08097_breaker
Ratio Pickup to Minimum Observed Fault Current	Minimum Melt Current	6.02 %	Must be less than	50.0 %	Pass	

Figure 4. Tabular report generated by DPAT.

Figure 5 depicts the SLD representation generated by the tool. The various protection elements in the system model are highlighted with various color codes after DPAT analysis for the convenience of the user to easily identify protection issues.

- *Red:* indicates the short circuit current rating has been exceeded or fuse minimum melt current is lower than load current
- *Orange:* indicates the protection device misoperates during faults
- *Magenta:* indicates fuses or reclosers are not coordinated or a protection setting limits feeder loadability.
- *Gray:* indicates the fuse or recloser has no issues.

The user can hover over any protection device which will bring up the TCC curve coordination results between the selected protection device and its relevant upstream and/or downstream devices as shown in Figure 5.

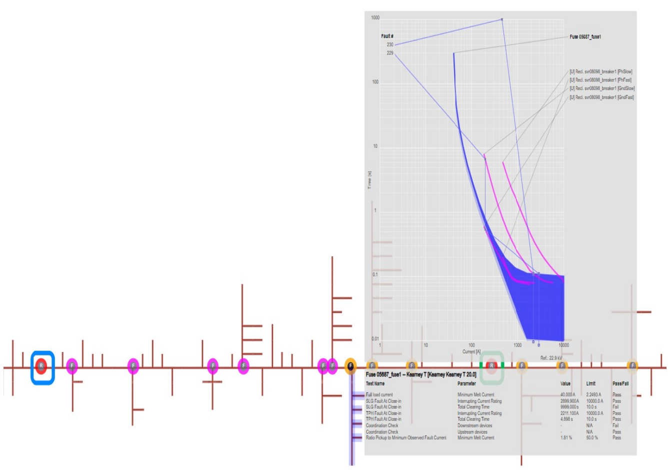


Figure 5. SLD report generated by DPAT .

Finally, the user can decide appropriate setting groups based on the suggestions made by the tool.

III. NETWORK MODEL

A double radial feeder network model was used to test out the switching of settings groups of the relays [9]. This model was built in the OpenDSS-G platform. The Open Distribution System Simulator (OpenDSS) is a comprehensive electrical system simulation tool for electric utility distribution systems. The program supports nearly all rms steady-state (i.e., frequency domain) analyses commonly performed for utility distribution systems planning and analysis. In addition, it supports protection system simulation and fault study analysis. The OpenDSS single line diagram (SLD) plot of the test setup network is shown in Figure 6.

Each radial feeder consists of a feeder breaker and 3 midline reclosers. The specifications of the DERs and loads included in the model are specified in Table II. Based on the DPAT analysis as explained in Section II, appropriate setting groups were defined for each recloser and a particular midline recloser was chosen to be tested in the HIL setup.

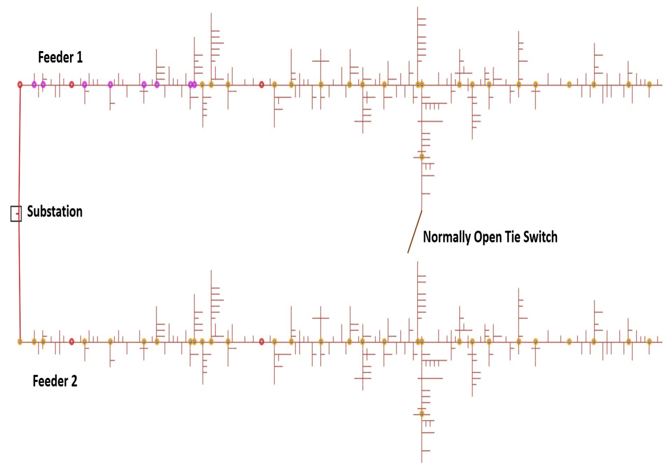


Figure 6. Feeder models under test.

TABLE II. SPECIFICATIONS OF RADIAL FEEDER NETWORK

Description	Value
Line-Line voltage	13.2kV
PV systems/DER included	Yes
PV specs	0.38 kV, 360 kVA each
Total PV generation	1.7 MW
Total load on both feeders	2.24 MW + 0.94 MVAr

IV. HIL TESTING

To validate the proposed approach, comprehensive testing was conducted. The test setup consisted of four key components, as shown in Figure 7. The first component was a prototype implementation of the control logic that simulated an Advanced Distribution Management System (ADMS) performing Fault Location, Isolation, and Service Restoration (FLISR) and issuing control commands to modify protection settings as needed. The second component was an off-the-shelf protection relay that represented a field device involved in the dynamic adjustment of protection settings groups. The third component was a real-time power system simulation that used the network model shown in Figure 6 to perform continuous power flow calculations, emulating the behavior of protection devices and other power system components in response to incoming commands. The final component was a set of co-simulation tools used to provide bi-directional Distributed Network Protocol (DNP3) data streams with the relay controller.

This setup was designed with the objective of enhancing the practicality of testing control routines in a laboratory environment. The use of a hardware controller and simulated systems mirrored the operational requirements of field implementations at the device level, while the continuous simulation of the power system provided the flexibility to study system-level effects.

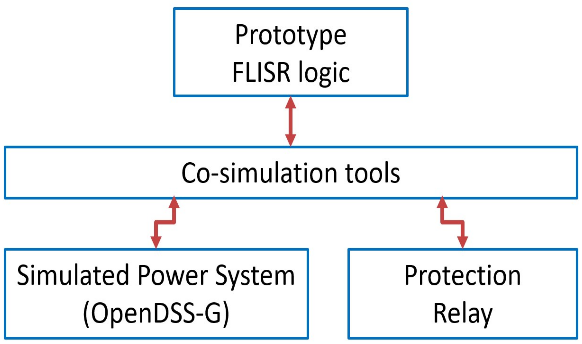


Figure 7. Key components for HIL testing in lab environment.

An electrical fault was simulated in the area closest to the feeder head of Feeder 1 to initiate a sequence of operations to evaluate the effectiveness of the proposed approach. During the test, the prototype implementation of the FLISR logic continuously monitored the state of the emulated power system. Upon detection of the electrical fault and corresponding protection device operation, the FLISR logic identified the location of the fault and the protection devices defining the faulted area. The faulted area was then isolated by opening the downstream protection device as shown in Figure 8.

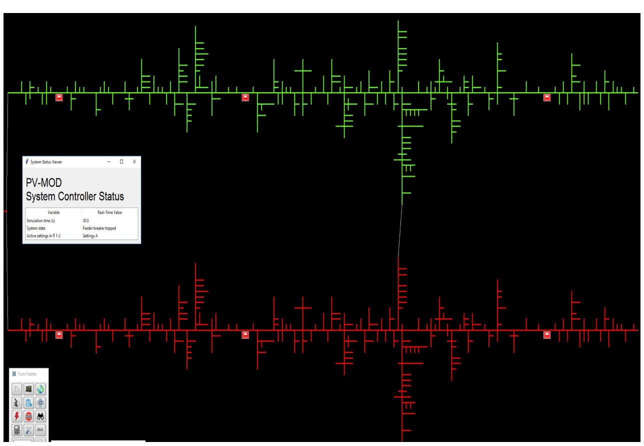


Figure 8. Isolation of the fault by FLISR logic.

Thereafter, DNP3 commands were issued by the FLISR logic to change the protection setting group in the relay control unit associated with one of the non-faulted protection zones. This change of settings was achieved by a combination of commands to change the state of binary points in the relay controller and the logic configured in the relay controller to issue a change of internal protection settings based on the combination of binary points received. The successful change of settings was confirmed by the relay controller to the FLISR logic by a corresponding change of binary points reflecting the currently active protection settings groups. With this confirmation, the FLISR logic could proceed with recovery actions. Finally, unaffected protection zones were reconnected by closing a normally open tie with Feeder 2, restoring power to as many customers as possible while the fault was cleared as shown in Figure 9.

Additionally, to test the feasibility of sending settings group change DNP3 commands over a LTE network, lab tests were performed where the commands were sent to a microprocessor relay located in a laboratory a little over 2 miles away from the utility control center by an operator. The tests showed that the latency inherent to public LTE networks did not pose a challenge to the scheme. The test was repeated multiple times and, in each case, the relay received the command and successfully changed its active settings group as instructed by the control center. Since this is a low bandwidth application, if such a scheme were to be deployed in the field the associated costs will be lower when compared to schemes that may require optical fiber communication channels to the associated relays and reclosers.

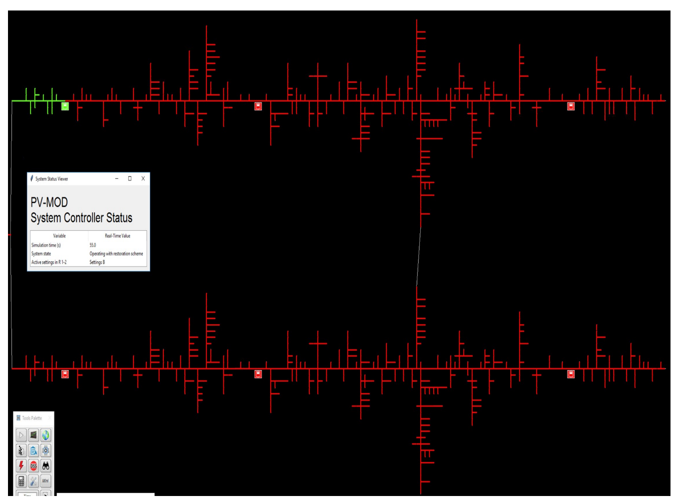


Figure 9. Reconfiguration of the system by FLISR logic.

V. Conclusions and Future Work

In conclusion, this scheme, can present other issues which might warrant consideration. For the scheme to be effective, a reliable communication channel is essential to deliver the commands from the control center to the individual relays and reclosers. If no communication channels currently exist, it may be an expensive scheme to implement since communication is essential to the operation of the scheme.

A thorough analysis of the system in which this scheme is to be implemented is needed to ensure that the right set of standard settings can be used for each settings group in the protection device. Based on the nature of various sections of the distribution system, different regions within the utility may need different standard settings. If on the other hand an optimization approach is preferred some form of automation tools will be beneficial to perform the multitude of coordination studies needed to determine the appropriate protection settings for the numerous possible system configurations. These configurations can arise as the topology changes with the operation of various normally open and normally closed switches in the circuit or the DER output fluctuates.

Future work on this topic involves research on automating the sending of the settings group change command by the DMS/SCADA system as real-time DER output changes. This may entail the development of logic within the DMS to issue relay/recloser settings group change commands as DER units come online or are taken offline.

Another aspect to look at is to determine the right order in which relays/reclosers are issued the settings group change command when multiple devices need their settings groups changed on account of topology changes. Since it takes some time from when the command is issued to when the relay activates the new settings group, there exists a non-zero time interval when the relay/recloser in not performing its protection functions. To account for any faults that may occur during that time interval, it is essential to ensure that the backup protection device is active and ready to provide the necessary protection during that time window.

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