Adaptive Protection for Modern Distribution Systems: Approaches, Functional Requirements, and Challenges

J. Shiles, S. Rao, A. Johnson, M. A. Zamani, A. Gopalakrishnan, S. Ward, and F. Katiraei

***Abstract*— High penetration of distributed energy resources and utilization of advanced distribution automation applications have introduced a unique set of protection and control challenges to distribution systems. One of proposed solutions to these protection issues is to develop an adaptive protection scheme that can adjust to the changes in the power system configurations, conditions, and/or business rules. This paper investigates an adaptive protection solution for modern distribution systems. The definition, advantages, and implementation approaches of a distribution adaptive protection system are first discussed. Then, the paper defines functional requirements, identifies actors/players, and analyzes operational sequences for the adaptive protection function in modern distribution systems. Finally, the main challenges associated with the development of an adaptive protection system are described. Although the study considers a long-term perspective for the development of functional requirements, the focus is on determining short-term (3-5 year) specifications. The outcomes of this study can be used for the development of a comprehensive protection methodology for application in distribution grids of the future.**

***Index Terms*—Adaptive protection, distributed energy resource, distribution system, distribution automation, fault.**

I. Introduction

TRADITIONAL distribution systems are designed to operate radially, with substations providing power to dispersed customer loads. Since this design ensures that the power flows in one direction from the substation to the customer, the distribution system protection is normally achieved by non-directional overcurrent (OC) protective devices such as phase and ground relays, circuit breakers, reclosers, sectionalizers, and fuses. These devices are coordinated through proper selection of time-current characteristics, pickup settings, and melting/damaging curves such that the smallest possible area of the system will be de-energized in response to a fault. Remotely controlled switches (RCSs) may also be utilized to further reduce the number of customers impacted by a fault on the feeder.

With the proliferation of distributed energy resources (DERs) and the advent of advanced distribution automation (DA) schemes, conventional protection practices in distribution systems are challenged. This is mainly caused by the dynamic changes in the characteristics of modern distribution systems (topology, load, generation, etc.). In particular, direction and magnitude of fault currents will dynamically change in an automated distribution system dominated by DERs. For example, under light-load conditions, DERs may cause back-feed to sub-transmission or transmission systems which can potentially affect conventional protection and control (P&C) strategies in distribution systems.

The effect of expected changes in distribution system characteristics on the system protection is normally managed by determining the relay settings based on the worst-case scenario studies. However, this approach will no longer be adequate when the operating conditions and configuration of the distribution system are constantly changing. As a result, alternative protection solutions have been proposed in the literature to resolve this issue [1]. The proposed protection solutions can broadly be categorized into three groups:

- Conventional relaying with customized protection logic (examples include symmetrical-components-based protection, voltage-based protection, and directional OC protection)
- Communication-based protection schemes (examples include differential protection and directional comparison protection)
- Adaptive protection schemes

The requirements for performance improvement of the protection system under constant condition changes has particularly led to the idea of an adaptive protection system (APS) which can adjust to the changes in the power system configurations, operating conditions, and/or business rules. Based on the state of the switching devices and/or other changes in the system loading conditions, the APS will revise protective settings and/or protection functions/logics in one or more relays to adapt to the electric system changes.

Adaptive protection concepts have been tested for transmission lines and are showing potential for improving relaying reliability, enhancing power system security, and achieving better utilization of transmission facilities. [2]. The concept, however, has not been well developed for distribution systems. This study aims to define required functionalities, identify actors, and analyze operational sequences (step-by-step function) for adaptive protection in distribution systems of the future.

The rest of this paper has been organized in five sections. Section II briefly reviews the major protection issues in modern distribution systems. In Section III, the definition of an adaptive protection system (APS) is provided along with the possible approaches to implement such a protection

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system in distribution grids. In Section IV, it is explained how the APS can be integrated into the grid management and modernization platform of distribution systems. Sections V and VI provide the challenges associated with the APS development and the study conclusions, respectively.

II. Major Protection Challenges in Distribution Grids of the Future

This section briefly reviews the main protection challenges that modern distribution grids are facing.

A. DER Proliferation

As a part of network planning and design, utilities normally analyze fault current levels in their system to ensure (i) the design limits of various components are not violated and (ii) the protection coordination is preserved. Since DERs can change the fault current level and/or direction, interconnection studies are performed to analyze fault current contribution of newly connected DERs. The impact of the DERs on distribution feeder protection depend on several factors including but not limited to [3]:

- DER penetration level
- DER type (rotating-machine-based DER versus inverter-based DER)
- Configuration of DER interconnection transformer
- DER size (aggregate DER output rating)
- DER location (substation or feeder)
- Variability/Intermittency of DER output
- Availability of communications for P&C systems
- Availability of communication-enabled intelligent electronic devices (IEDs)

The presence of DERs can manifest itself as (i) change in the fault current range of feeders, (ii) multi-directional power flow in the system, and (iii) change in the fault current seen by protective devices in series. Consequently, the traditional protection systems will be impacted in the following ways:

- Protection mis-coordination issues
  - Nuisance fuse tripping (or fuse blowing)
  - Blinding of protection
- Sympathetic tripping on adjacent feeders
- Mis-operation of sectionalizers and reclosers
- Mis-operation of reverse-power and/or non-directional protection functions
- Exceeding equipment rating due to higher fault current
- Auto-reclosing failure
- Coordination of protection system with fault ride-through requirements of DERs

It is worth noting that, due to the increasing penetration of DERs, it would be difficult (if not impossible) to address all these protection issues by conventional protection functions and/or schemes. Therefore, it is essential to have a fresh look into traditional protection philosophies in distribution systems.

B. Advanced Distribution Automation

Distribution automation (DA) is a part of today's evolution of distribution systems. DA applications such as automatic load transfer, volt/var control, and fault location isolation and service restoration (FLISR) may reconfigure distribution circuits to optimize system efficiency or to enhance network reliability. This, in turn, can potentially affect fault current level/direction, especially if the system operates in a loop mode or embeds DERs.

Distribution circuit reconfiguration by DA applications can be done either proactively or automatically. Regardless, it may require protection settings to be changed (e.g., as a pre-programmed alternate setting group), and/or may need protection equipment to support reverse fault current. Therefore, the protective relaying of the affected circuits should be assessed under new system configuration [4]. The following are some of the protection challenges in the presence of DA applications:

- Change in the maximum loading condition caused by circuit reconfiguration (OC pickup may be exceeded)
- Change in the fault current level due to circuit reconfiguration or looping
- Reverse power flow caused by potential system looping
- Increased fault level due to close-transition switching
- Mis-coordination between the "automatic fault detection and isolation" and automatic reclosing that allows for self-clearance of temporary faults.
- Change in protection zones due to circuit configuration
- Potential setting violation if automatic on-the-fly setting adjustment is going to be implemented.

These challenges have motivated protection engineers to devise new protection schemes in distribution systems.

C. Microgrid Operation

Although protection of microgrids is not the focus of this study, the operation of (parts of) the distribution system as a microgrid should be taken into account when developing functional requirements for an adaptive protection system. One related challenge is the proper isolation of the microgrid system from the main grid when an external/grid fault occurs. In other words, considering microgrids as net loads or generators, protection at the point(s) of interconnection (POI) may need to be adapted based on the microgrid and/or grid operating conditions.

It should be noted that, due to the limited fault current capability of power-electronic DERs, it is not an easy task to differentiate between external (grid) and internal (microgrid) faults using conventional OC devices. Depending on the status (connected or disconnected) and type (inverter-based or rotating-machine-based) of DERs, the aggregate fault current contribution of a microgrid to an external fault can vary over a fairly wide range. This means that OC protective devices with fixed settings may no longer be able to fulfill sensitivity and selectivity requirements in detecting and isolating the faults within distribution grids.

III. Adaptive Protection Systems

As discussed in Section I, several techniques have been implemented/proposed in the industry or academia to resolve the protection issues associated with DERs and/or various operating conditions, either partially or entirely. Reference [5] has provided a comparative analysis of various protection solutions. One of the most elegant methods to deal with protection issues in modern distribution grids is an adaptive protection system. The following sections will focus on this protection solution and provide more details.

A. Definition

The definition of an adaptive protection system (APS) is still a matter of debate, with no general agreement. Based on the review of the existing technical literature, adaptive protection can generally be defined as a real-time, online activity that modifies the preferred protective response to a change in system conditions, business rules, or forecasted reconfiguration in a timely manner by means of externally generated signals or control actions [2]. The "preferred protection response" could potentially include a combination of proper protection setting group, optimal protection setting values, appropriate protective function, and correct switching sequence. For the purpose of this study, it is assumed that the APS will only determine recommended protection settings as well as switching sequence.

B. Implementation Approaches

The preferred protective response of an adaptive protection system (e.g., optimal protective settings) can be calculated in an either off-line (pre-calculated trusted settings) or on-line manner. Therefore, there are two different implementation approaches for adaptive protection systems, which will be briefly discussed in the following subsections:

1) Offline Pre-Calculated Settings

The off-line design of an adaptive protection system consists of the following three parts:

(i). Offline Analysis: In this stage, all the meaningful system configurations (operating conditions) are first identified and, then, fault analysis and protection coordination studies are conducted to calculate proper settings for each system configuration. Finally, all the possible system topologies/configurations and corresponding settings are arranged in an event (lookup) table.

(ii). Online Matching: The system topology is continuously monitored through monitoring the state of switching devices. Once a change in the state of a switching device(s) is detected changing system topology, proper relay settings are selected from the event table based on the current system topology. If the new topology is not defined as a meaningful configuration, the relay settings should remain intact.

(iii). Loading Relay Settings: Selected relay settings, if needed to change, are transmitted to corresponding relays through a reliable communication medium.

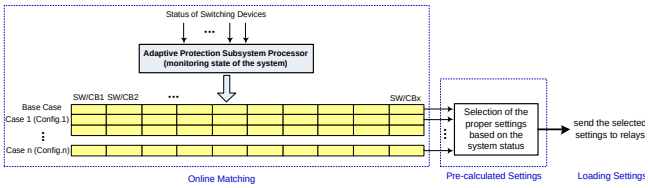

Figure 1 General concept for offline settings calculation in APS

Figure 1 shows the concept of an off-line adaptive protection system. It can be observed that as soon as a state change is detected, the adaptive protection system (APS) will select the corresponding pre-calculated settings to be sent to a relay(s). The main challenge associated with the offline APS is that the event table needs to be updated once the distribution system undergoes a new change (e.g., when a new system topology/configuration is allowed or a once new DER is added to the system). Moreover, since it is essential to conduct fault and protection studies for all the permitted topologies, the offline analysis will become a time-consuming and complicated task (particularly, in distribution systems).

2) Real-Time Setting Calculation

Another approach for an adaptive protection system is to calculate protection settings in a real-time basis, upon a change in the system topology including DER status. Similarly, this approach can be implemented in a central processor with continuous real-time measurement and monitoring of digital and analog signals originated from protection IEDs and/or other system components. Therefore, new system topology should be assessed, protection system coordination should be analyzed, and protection settings should be adapted if required.

Figure 2 shows a high-level sequence diagram for a real-time adaptive protection system. As can be observed in this figure, the APS comprises two modules, namely, (i) implementation module and (ii) operation module. The implementation module takes care of the setting calculations and changes if required (near-real-time module), while the operation module is responsible for fault detection and isolation (real-time module). It is important to note that protection coordination may not be achieved for all possible system topologies or configurations. Therefore, it may be needed to take some other corrective actions (e.g., system switching) by the APS or to compromise protection coordination to some extent (if business rules allows). To that end, a set of definitions has been developed for the APS as follows:

- Adequate Protection: A protection system that is capable of detecting and isolating all network faults (including end-of-line faults), even if in a non-coordinated manner, is referred to as an adequate protection system.
- Inadequate Protection: A protection system that fails to detect and isolate (some) network faults (including end-of-line faults) is referred to as an inadequate protection system.

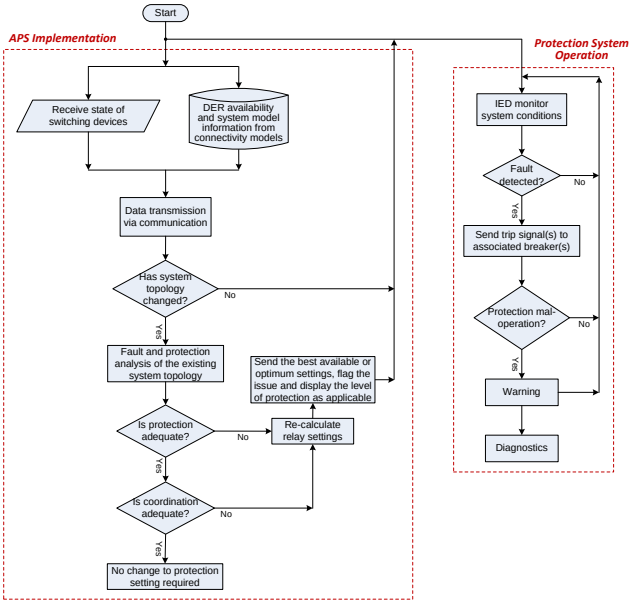

Figure 2 General concept for a real-time settings calculation in APS

- Optimum Coordination: It refers to a situation where Coordination Time Intervals (CTIs) are ideal values defined by business rules (e.g., CTI ≥ 0.5 sec).
- Accepted Coordination: It refers to a situation where CTIs are minimum accepted values allowed by business rules (e.g., CTI ≥ 0.3 sec).
- Violated Coordination: It refers to a situation where protection coordination is not preserved (e.g., CTI < 0.3 sec).

With these definitions in place, the rest of this paper will provide detailed requirements for an APS for the distribution system. It should be pointed out that the focus of the paper is on the real-time setting calculation approach as a more comprehensive solution.

IV. Adaptive Protection System as a Part of Grid Management Program

Figure 3 provides a high-level overview of the Adaptive Protection System (APS), as envisaged by Southern California Edison (SCE). As shown in this figure, the APS will only be a part of (or a subsystem in) an ambitious Grid Management System (GMS), a program undertaken by SCE for the modernization of its distribution system.

The APS embedded in the GMS will determine whether the forecasted or real-time distribution system conditions meet certain thresholds or match previous conditions where protection settings should change. The APS will then calculate the correct protection setting(s) to be changed based on the fault and protection analyses. It will also determine required modifications to the protection scheme and the conditions under which protections settings should be implemented. The APS will then send commands to the Device Setting Management System (DSMS) to change protection settings in the appropriate devices. The APS shall also provide verification and validation functions confirming

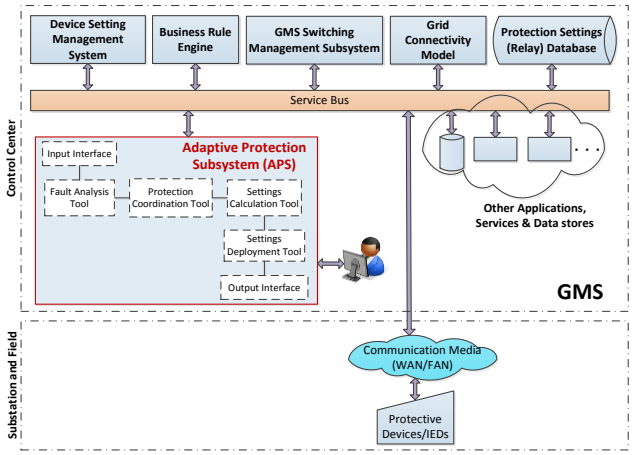

Figure 3 High-level overview of the adaptive protection function, as envisaged by SCE.

the receipt of protection settings by the intended devices, and support centralized training for system operators, distribution engineers, and protection engineers.

A. *Actors/Players*

An Actor/Player is defined as an entity (person, team, organization, department, device, system, subsystem, etc.) that plays a role in the operation of a function or application. This section describes the main Actors involved in the APS process; these actors are listed and defined in Table 1.

TABLE 1 ACTORS OF THE (REAL-TIME) APS

Actor Name	Actor Description
Protection Engineer	Individual (or team) who designs, tests, verifies, and analyses protection schemes.
Distribution Engineer	Individual (or team) who utilizes APS to determine protection settings for planning scenarios.
System Operator	Individual (or team) who interfaces with the system and approves/rejects non-automatic actions.
Protective device or IED	A device that monitors system parameters to detect and isolate faults within its protection zone. It also reports its status and settings.
GMS	A system that is a collection of applications designed to monitor and control the distribution network efficiently and reliably.
Switching Management System (SMS)	A Program within the GMS that calls the APS based on the real-time or forecasted switching actions.
User Interface (HMI)	It allows the operator to run applications, to view and analyze system status, and to run or disable the APS.
APS Processor (APSP)	When called upon, the APS processor receives the connectivity model information and protection setting, runs analysis (fault analysis, protection coordination, and setting calculation), determines the need for adaptive protection based on active settings, and requests changes to protection settings if needed.
Relay database	It contains the settings of each setting group and ranges for all protection IEDs included in the APS.
Connectivity Model	The electrical connectivity models contain system topologies, line data, power system component parameters, load data, DER parameters, etc.
DSMS	A system within the GMS that is used to read, create, send, download, and verify protection settings files.
Business Rule Engine (BRE)	A system that contains all business rules including those related to system protection and coordination.

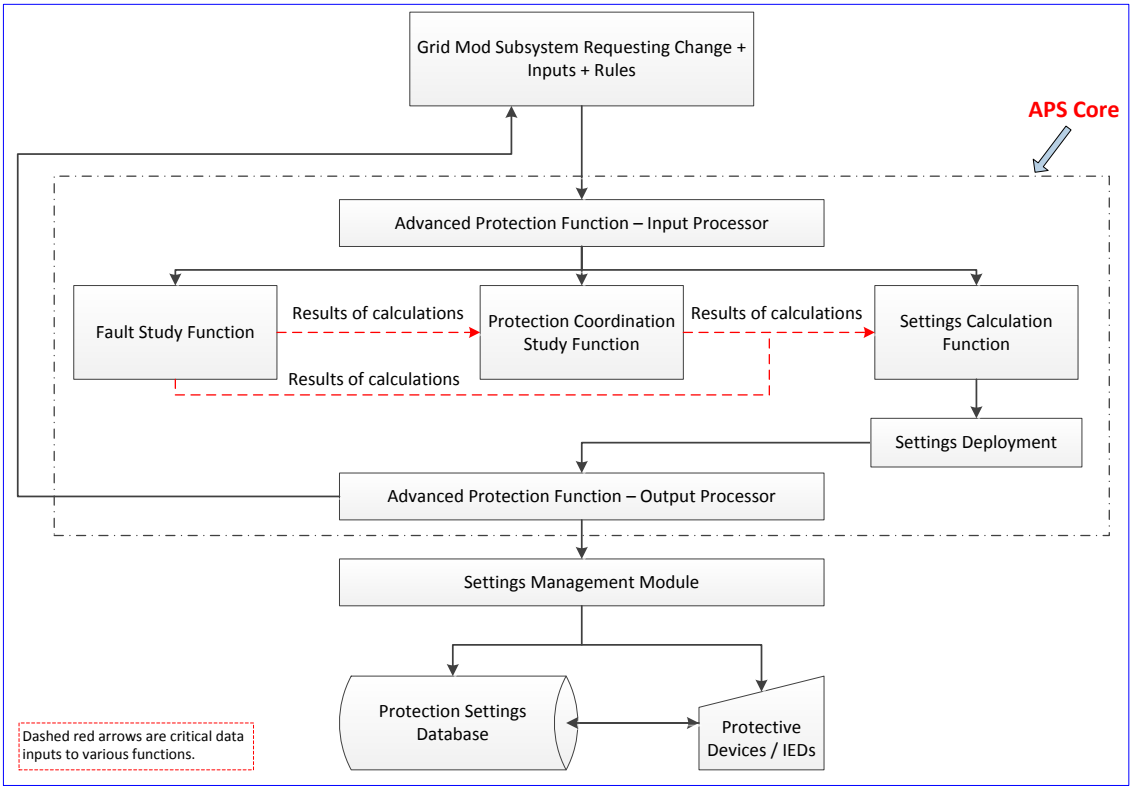

Figure 4 Building blocks and process flow of the APS

It should be noted that some of these actors should be created as a part of the GMS platform to enable proper execution of the APS function.

B. Step-by-Step Analysis of the APS Function

This section describes steps that implement the APS application. In particular, the normal sequence of events, with focus on steps that identify new types of information or new information exchange, is discussed in this section. The focus is less on the algorithms of the applications and more on the interactions and information flows between "entities", e.g. people, systems, data bases, etc. Table 2 provides the sequence of action for the operation of the APS application.

C. APS Detailed Requirements

The building blocks of the APS application are shown in Figure 4. The flow chart of Figure 4 is a 20-year plan, with full integration into the GMS as applied to distribution systems. A longer than 20-year scenario (long-term plan) will expand the APS to all voltage levels, including sub-transmission and transmission systems. In such a scenario, additional protection considerations may need to be examined. As Figure 4 indicates, the APS needs an external triggering input from a subsystem in the GMS platform, referred to as the Switching Management Subsystem (SMS). The SMS will detect any change in the system operating condition (feeder reconfiguration, load transfer, restoration sequence, etc.) and call upon the APS processor (APSP) to check protection coordination, identify the need for changing the protection settings, and provide new settings if needed.

TABLE 2 STEP-BY-STEP OPERATION OF THE APS

#	Primary Actor	Description of Process
1	Switching device	Switching device changes status
2	IED	IED detects and reports status change to the SMS
3	SMS	SMS updates the connectivity models
4	SMS	SMS calls APS and transfers the Connectivity Model information to the APSP.
5	APSP	APSP requests IED settings from DSMS
6	DSMS	DSMS sends protective device or IED settings to the APSP
7	APSP	APSP requests applicable business rules
8	BRE	BRE sends applicable protection-related business rules to the APSP
9	APSP	APSP requests fault and protection analysis based on the received connectivity model info and settings
10	APSP	APSP sends level of protection, trigger alarms, and/or flags issues, if applicable
11	APSP	APSP sends protective device or IED settings to device setting management system, if applicable.
12	DSMS	Device setting management system (DSMS) sends (updated) protective device or IED setting to protective device or IEDs
13	IED	Protective devices or IEDs confirm the receipt of updated settings, and report complete protective settings.
14	DSMS	DSMS informs APS about the successful implementation of (updated) protection settings
15	DSMS	DSMS sends complete protection settings to relay database
16	APSP	APSP sends the switching priority and location of (updated) protection settings to the SMS.

To perform its function, the APS should be provided with several inputs and (business) rules from external data sources. Some of this information includes:

- Online generation on the distribution system
- Power flow data
- Short-circuit model
- System configuration and topology
- Protection device characteristic models
- Protection settings from settings database or device
- Business rules for protection settings calculations (allowable CTIs, acceptable fault clearing times, etc.)
- Primary equipment characteristics and constraints (damage curves, thermal limits, etc.)

The APS trigger is recognized by its Input Processor block. The main functional blocks of the APS processor/engine are (see Figure 4):

- Fault Study Function
- Protection Coordination Study Function
- Settings Calculation Function

These functional blocks will interact with each other to create the following outputs, at the minimum:

- Flagging of potential coordination problems;
- "Optimal" or "Best-Available" protection settings to meet desired protection objective;
- The level of protection provided by new settings; and
- Switching sequence/priority.

The Settings Deployment block of the APS will gather all the settings that need to change, and pass them on to the Output Processor module in Figure 4. The Output Processor will provide acknowledgement to the SMS (Switching Management Subsystem), which has called the APS, once the calculation is complete. The Output Processor will also provide the new settings to the DSMS (outside the scope of the APS), which is responsible for transferring the settings to the protective devices and IEDs in the field, and to a settings repository (i.e., protection settings database).

In the following subsection, the requirements for the major building blocks of the APS will be discussed in more detail.

1) Grid Connectivity Model Requirement

As discussed in previous section, the APS function will be called by the SMS within the GMS platform. In other words, this subsystem will automatically recognize a change in the power system condition/configuration, and invoke the APS Input Processor block. At the same time, the SMS will provide certain data inputs and rules to the APS.

Inputs to the APS translate to requirements on the so-called Grid Connectivity Model that is developed for the entire suite of GMS applications. In other words, the Grid Connectivity Model Subsystem will provide the APS with the proper model needed for protection studies. The functional requirements imposed on the Grid Connectivity Model are to:

- Indicate the study mode to the APS:
  - "Real-time" study mode (present topology);
  - "As-built" study mode; or
  - "Planning" study mode
- Provide the source impedance at the appropriate substation(s) to the APS, based on the study mode.
- Provide an accurate model of the distribution system under study to the APS for fault and protection analysis:
  - Feeder/Cable impedances and damage curve data
  - Transformer impedance, winding configurations, and damage curve data
  - Load phasing
  - Instrument transformer information
  - Detailed switch and circuit breaker status
- Provide status, type, and accurate model parameters of distributed energy resources (DERs) for fault analysis.
- Provide in-service protective device and IED settings, status (On, Off, Disabled, or Failed), and fallback characteristics, as applicable.
- Provide information about the status of communications with devices in the system, as applicable.
- Provide power flow data (including load/generation profile) at the time the request for new settings is made.

2) Business Rule Engine Requirement

A detailed set of business rules must be provided to the APS for the distribution system under study. These rules define the framework under which the APS will determine protection settings. Some examples of business rules include:

- Coordination Time Interval (CTI) values, i.e., the time interval between devices that need to coordinate:
  - Ideal CTI for optimal settings, and
  - Minimum allowable CTI for acceptable coordination (to be discussed in Section IV.C.5); this value may vary based on voltage level or other parameters.
- End-of-line (EOL) fault current multiplier value for pickup settings (phase, ground, and sensitive ground):
  - Ideal EOL multiplier for optimal settings
  - Minimum acceptable EOL multiplier
  - EOL multiplier characterized by acceptable fault clearing time
  - EOL multiplier characterized by region (e.g., if fault duties are lower in certain areas)
- Minimum acceptable multiple of downstream load for pickup setting
- Standard protection settings for curve types
- Allowed number of reclosing attempts before the device lockout. Changes in circuit characteristics will require less or more reclosing attempts than the standard.
  - Majority of underground cable circuits will not use reclosing at all.
  - If circuit reconfigured to pick up additional load, one more reclosing shot may be required.
- Maximum number of iterations (or time) that the auto-coordination procedure can take before declaring that optimal or acceptable settings cannot be achieved (different values may be acceptable depending on the study mode).
- Guidance on when a temporary mis-coordination is acceptable (based on region, area, circuit type, etc.)

3) Input and Output (I/O) Blocks Requirement

The Input and Output Processor blocks of the APS interface with requests coming from various subsystems of the GMS platform (see Figure 4), and provide response(s) back to the same platform. The basic functional requirements of these blocks are:

- Receiving request from the GMS platform to perform an adaptive settings calculation
- Providing response to the GMS platform after the coordination/settings calculation is complete
- Communicating with protective Device Settings Management System (DSMS) to obtain device capabilities such as allowed range of pickup settings, curve types, reclosing shots, etc.
- Returning the changed settings to the DSMS, when settings calculations are completed.

4) Fault Study Function Requirement

The Fault Study Function serves as a data source for Protection Coordination Study Function and Settings Calculation Function. The function is capable of applying symmetrical and asymmetrical short-circuit faults as well as high-impedance and open-conductor faults based on pre-determined configuration settings for the network segment under study, and calculating fault currents and voltages. The function shall have the ability to:

- Model various types of DERs (wind, solar, energy storage, etc.) behaviors under short-circuit conditions, including their fault ride-through capability.
- Run fault studies by recall of previously stored network conditions.
- Sequential fault isolation (event-based analysis).

The Fault Study Function shall interoperate with the Grid Connectivity Model and receive data in real-time from the model. The Fault Study Function needs real-time data for:

- System configuration/topology
- Generation online, or generation to be online/off-line, after the requested change has been made
- Power flow data (e.g., via other GMS subsystems)
- DER availability data

The output from the Fault Study Function provides necessary fault data for the Protection Coordination Study Function.

5) Protection Coordination Study Function Requirement

Based on the results from the Fault Study Function, the Protection Coordination Study Function performs a coordination study on one or more distribution feeders or at the distribution substation. Thus, the Protection Coordination Study Function shall include accurate models of protective devices (characteristic models of relays, reclosers, fuses, etc.) and power system elements (damage curves of conductors, transformers and other equipment, as applicable).

The coordination study should take some factors into account during evaluation of protection coordination:

- Sequential fault clearing;
- Auto-reclosing capabilities of devices; and
- Pre-defined contingencies

TABLE 3 DEFINED PROTECTION LEVELS FOR THE APS

Level	Protection Adequacy	Protection Coordination
1	Adequate	Optimum
2	Adequate	Acceptable
3	Adequate	Violated
4	Inadequate	Optimum
5	Inadequate	Acceptable
6	Inadequate	Violated

The Protection Coordination Study Function shall identify cases leading to CTI violation and mis-coordination as defined by business rules. It will also flag potential problems and report them to the relevant GMS subsystems.

In the off-line mode, the Protection Coordination Study Function should be able to serve as a planning tool for system expansion. The function should also support recall of previously stored protection settings (historical data), and run coordination study for post-mortem event analysis. In a long-term plan, the Protection Coordination Study Function should also consider voltage and frequency requirements (low-voltage ride-through) and dynamic system behavior.

The functional requirements imposed on the Protection Coordination Study Function are summarized as follows:

- Performing coordination study on one or more distribution feeders or at the distribution substation.
  - If affected feeders are at different buses, all feeders in both buses need to be re-evaluated.
  - If affected feeders are at the same bus, only the affected feeders are to be re-evaluated.
  - If the fault duty at the bus changes, all feeders at the operating bus should be checked.
- Considerations for accurate models of protective devices as well as damage curves of power equipment.
- Considerations for sequential fault clearing (partial time out of inverse-time characteristic should be considered).
- Considerations for auto-reclosing capability of devices.
- Capability to model telecommunication protection schemes (e.g., direct transfer trip).
- Defining output level of existing protection provided (levels 1 through 6), as shown in Table 3.
- Considering N-1 contingencies during evaluation of protection coordination (planning study).
- Identifying cases leading to mis-coordination.
- Calling previously stored protection settings for running coordination study (planning function or post-mortem analysis). In this case, system model, setting information, and scenarios will be provided as input.
- Recommendation on the use of a particular type of relay or fuse (planning mode).

6) Settings Calculation Function Requirement

Based on the coordination study, if any mis-coordination or CTI violation is identified, the Settings Calculation Function (which could also be a part of the Protection Coordination Study Function) will determine if new settings can be found to resolve the issue. Thus, the Settings Calculation Function should be able to distinguish between “optimal” fully coordinated settings versus “best available” not-fully

coordinated settings that will still meet business rules. The Settings Calculation Function (along with the Protection Coordination Study Function) should also provide the level of protection achieved (see Table 3).

The Settings Calculation Function should calculate best possible settings for each network configuration/topology in a predetermined switching or restoration sequence. It should also determine the sequence of any setting change versus the time of switching. In other words, Settings Calculation Function will define if new settings should be applied before the switching operation or following the switching operation.

Depending on the functionality of the protective device (e.g., bus tie breaker in an operating/transfer bus arrangement), the Settings Calculation Function will need to calculate multiple settings groups since the protective device will potentially be responsible for protecting different primary equipment in various configurations. This type of service is most likely suitable for the "planning" study mode. The Settings Calculation Function requires data from the following functions/databases:

- Protection Coordination Study Function
- Protection settings database (relay database)
- Business Rule Engine (rules for protection settings)

The Settings Calculation Function generates a flag if settings will not meet business rules and warns if optimal settings cannot be achieved but "best available" settings still meet "minimum" requirements defined by business rules. This function also interfaces with the protective device setting software and initiates setting deployment to devices (sends request to Device Setting Management System, DSMS).

7) Protective Device and IED Requirements

In present-day protection systems, protective devices can store multiple, pre-calculated groups of settings. Then, under command from the operator, the device can be made to switch to another setting group. The adaptive protection function as envisaged in this study calls upon protective devices to receive and activate settings that are calculated on-the-fly by another algorithm or system.

The inclusion of adaptive protection functionality within the GMS platform's suite of applications imposes several unique and special requirements on the protective devices and IEDs to be deployed on distribution systems. Some the main requirements are described below:

- A minimum communication interface delay
- A minimum processing delay
- Ability to change settings or to switch to a different setting group in a real-time basis
- Number of setting groups
    - Primary and alternate setting groups
    - "Reserved" or "Validated" groups of settings that cannot be overwritten by outside applications
- Ability to accept settings through a standard communication medium/protocol (e.g., fiber/IEC61850)
- Ability to return active settings (or a full collection of settings files) to a calling function, through a standard communication medium/protocol, in a real-time basis
- Ability to test a setting file (playback)
- Ability to confirm that a requested settings change has been applied and is active, or there was a failure.
- Providing potential requested information (load data, status information, etc.) to other GMS applications.
- Support file transfer service of files (up to a few MB)

It is noted that all the requirements identified in this section will be further defined and tailored with more details during the pilot project of the APS, which is planned as the first step.

V. Adaptive Protection Challenges

From the discussions of Section IV.C, it becomes clear that the main concern associated with the application of adaptive protection schemes (APS), is the technical implementation in the field. The following is a list of the main challenges with regard to the APS implementation:

- Fuses, electromechanical relays, and standard solid-state relays do not provide the flexibility of changing protection settings (or tripping characteristics). Thus, the efficiency of the APS may be significantly limited due to the dominant use of these protective devices in distribution networks.
- Digital (microprocessor-based) relays with flexible protection settings as well as advanced communication capabilities are required in the APS. This is particularly important as some of these features are not fully supported by the existing products available in the market. This challenge manifests itself when the settings are planned to be adjusted, as compared to switching between different setting groups.
- Some of the digital relays need to reboot subsequent to the setting changes. This may leave the system unprotected for periods of time.
- The use of a reliable communication medium (PLC, fiber, etc.) and a standard communication protocol (DNP3, IEC6185, etc.) is essential for the development of an APS to monitor IEDs and switching devices in a real-time basis.
- Dependency on the communication system and/or a central processor may require redundancy which will further increase the implementation cost.
- Since bidirectional power flows can be experienced in distribution systems with DERs, the use of directional elements is essential for relays. Thus, the relays need different setting for forward and reverse directions (setting calculation function will need to provide settings for each energy flow direction).
- Considering DER status and availability, load status, state of switching devices, and application of distribution automation applications, there are several system topologies that need to be continuously evaluated in the APS. Moreover, any upgrade to the system may introduce new system configuration. In some cases, proper protection settings may not be achievable.

- It is very important to coordinate the APS function with other GMS applications. For example, potential setting violations may happen if automatic setting adjustment on-the-fly is going to be implemented (e.g., coordination with the fault location, isolation, and system restoration application is essential).
- Large-scale implementation of the APS shall address the concerns around possible deviation of safety aspects and maintenance routines from the traditional and established field relay testing practices in utilities.

All of these challenges can complicate the design of an effective APS. Therefore, it is important for utilities to have a strategic roadmap with short- and long-term plans that enable them to take the maximum benefits from an APS while their distribution system is going through modern changes.

VI. Conclusions

To address the protection challenges associated with high penetration of DERs and the deployment of advanced distribution automation devices and schemes, adaptive protection systems have been proposed and partially implemented. This study aimed to develop the requirements for an Adaptive Protection System (APS) envisaged to be embedded in a utility's grid management platform. Although the study has been performed based on the requirements of SCE's distribution system, this paper has provided the results in a generic form that are useful for other utilities.

The APS will support the continued safe and reliable operation of utility's distribution system by dynamically modifying protective device settings, functions, and/or logic in response to changing system conditions, with the goal of providing proper sensitivity and selectivity for short-circuit faults impacting the distribution system. However, strategic roadmaps with short- and long-term plans should be developed to enhance the effectiveness of the APS, considering the implementation challenges it is facing in the existing and future distribution grids. Moreover, a laboratory demonstration pilot is being planned to assess the feasibility of the APS prior to a subsequent field pilot and potential full-scale field deployment.

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