Adaptive Protective Relay Settings – A Vision to the Future

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***Abstract*— Adaptive relaying utilizes the continuously changing status of the power system as the basis for online adjustment of the power system relay settings. Fundamentally they are protection schemes that adjust settings and/or logic of operations based on the prevailing conditions of the system. These adjustments can include, but are not limited to, the logging of data for post-mortem analysis, communication throughout the system, as well as changing relay parameters. Adaptive relaying considers the fact that the status of a power system can change. These include system configuration changes, load effect, cold load pickup, end-of-line protection, transformer protection, and automatic reclosing. In this research, the author focus on the need for a secure, selective, and reliable system for adaptive overcurrent protection in T&D and Distributed Energy Systems. Various types of adaptive methods are presented and explained along with some pros and cons of each.**

Index Terms*— *Adaptive, artificial intelligence, group settings, high impedance, machine learning, , model driven, self-setting

I. INTRODUCTION

Adaptive Protection is a philosophy which permits and seeks to make adjustments in various protection functions automatically in order to make them more attuned to prevailing power system conditions. Adaptive relaying inherently considers the fact that the status of a power system can change. The underlying concept is that settings of relays will change adaptively to accommodate system state and configuration changes without human interference. The load current in a system is can fluctuate greatly. In such a situation, a protection system must be used such that it can adapt to these changes. The adaptive protection checks the existing information in the network and the status of the circuit breakers, calculates the load flow again if a change is detected, it then should automatically change the relay settings accordingly. Over the years concern for classical protection settings has risen, primarily driven by pre-set fault conditions as more numerous inverter-based generation assets get integrated into an interconnected and distributed grid. There are several reasons why adaptive relaying is getting traction in the industry. For example, increased fault current contribution from inverter-based generation on a radial distribution feeder may be unknown to pre-set relay settings. This implies that operating margins, relay settings and tripping or reclosing schemes that were once commonplace are no longer acceptable. Adaptive protective relaying schemes are needed to address the wide range of short-circuit contributions related to distributed generation and alternative configurations of the grid. These protective relays must adaptively coordinate for multiple contingencies and configurations of the power system they are protecting. With routine fixtures such as forest and brush fires, hurricanes, floods, ice storms and cyber-attacks, the need to adaptively set relay protection is critical to the resilience of any electric grid or microgrid. Another major concern is high impedance fault detection. High-impedance faults are often encountered when phase conductors are downed and contact the ground or other objects typically encountered in a power line right-of-way. High-impedance faults are a challenge for utilities due to the low-magnitude fault current. The fault current levels of highimpedance faults can be significantly less than peak load current and therefore undetectable by typical protection schemes. However, these fault types often have unique signature characteristics such as arcing and flashing, and several methodologies have been developed to detect faults based on these signatures. Multifunction relays have the ability to switch to other predefined protection settings stored in multiple selectable setting groups. These setting groups are typically limited to between four and eight static setting groups per relay. Each of these setting groups requires individual setting calculations, depending on the differences between the type of operating configurations for the system. Line impedance relays may, for example, have two setting groups that can be switched, depending on the particular season of the year (e.g. summer and winter) [1]. In this case, predetermined settings may be selected based on the specific seasonal line rating. For live-line work, circuit breaker relays sometimes use alternative setting groups that use a hot-line-tag group, which reduces the instantaneous protection element set point and blocks all reclosing for the circuit while this work is being performed. Many other operating configurations could be contained in the individual setting groups for a quick transition to the new operating constraints.

II. METHODS OF INITIATION FOR RELAY SETTINGS

The goal of protective relaying technologies is to protect a utility's investment in generation, substation, transmission, and distribution assets. When done properly, protective relaying achieves this goal while also limiting outages to as few customers as possible and in such a way that the system is restored quickly and safely when outages occur. These protections result in more resilient system operations. Protection schemes are a balance of four main concepts: dependability, security, sensitivity, and selectivity. These concepts are described below [2].

• Dependability: The facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly.

• Security: The facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly.

• Sensitivity: Sensitivity refers to ensuring that the relays that are intended to operate for a given condition have a stronger propensity to operate for that condition than other (usually remote) relays. This ensures that no matter what the magnitude of the fault or the location of the fault on the protected power system element, the intended relays will “see” the fault more strongly.

• Selectivity: Selectivity, which also is sometimes referred to as timing coordination, refers to analysis to ensure that the relays intended to operate for a given condition will operate faster than other relays that may provide backup protection for the condition. Selectivity is obtained when a minimum amount of equipment is removed from service for isolation of a fault or other abnormality.

A. *System State or configuration*

The state of a system determines configurations and adaptive settings. This drives the initial state of topology and its power flow. Assume that power system statuses are unknown and communications to substations, plants and various field equipment is unavailable and a comprehensive description of the initial state of the system is also not available. The classical relay would only then know the location of the fault by calculating the distance using voltage and current received by the CTs and PTs (mho/distance/impedance relay concept). The changed topology of a system is what an adaptive relay is basing its decisions on. Having an inaccurate or incorrect circuit topology within an adaptive relay is a risk that must be investigated. If the topology in the adaptive relay has changed or if the circuit topology in the adaptive relay is incorrect, then it can be safely assumed that the fault current calculated by the adaptive relay will be different from the measured fault current from the recloser/circuit breaker CTs and PTs [3] [4].

B. *Communication assisted Automation*

RTAC, wide area communications, pre to post system state, least squares reduced state of the system are ways that can possibly be used to determine an adaptive state upon loss of grid driven communication. Loss of communication can help engineers use signature outputs, pre state, or post state snapshots in a N-X contingency state. For instance, various communications and pilot assisted line differential protection schemes exist and are commonly used in Transmission Line protection systems. Another example, Microgrid systems inherently have small line impedances and widely varying short circuit capabilities (i.e. grid connected or islanded). In order to identify a change in fault current, a key piece of information that is going to be needed by let’s say an overcurrent relay is the actual location of the fault. The actual location of the fault can be compared to the calculated location of the fault. If these two locations differ substantially, then there is a possible difference between the circuit topology and the actual circuit.

C. *Sequence Components of fault to select relay settings*

Real-Time Detection methods of negative sequence have been developed in traction systems and provide an opportunity for use of negative sequence current sampling, filtering, and calculation to securely differentiate islanded or grid connected unbalanced fault conditions. Furthermore, several negative sequence control methods have been developed for control of doubly-fed induction generators commonly used in modern Type III Wind Generators which provide secure and reliable negative sequence control of inverters in wind turbines. When grid connected, it is assumed that the utility fault current contributions will be several magnitudes higher than that of the contributions from distributed energy resources or microgrid generation sources. This situation allows for determination of faults associated with the utility contribution by using an instantaneous phase element which is set above the contribution from the microgrids system and below the time overcurrent reach of the utility relays which are typically set to a value between 150% to 200% of the maximum expected full load current [5]. Typically, the setting is set above maximum expected inrush of the circuit upon energization and reclosing events. The microgrid sources will have a limited supply to inrush and energization and can therefore be set significantly lower for the time overcurrent pickup of around 110% of maximum expected load. Faults that occur when grid connected can provide a wide range of short circuit contributions from maximum contribution of the distributed energy resourcesto maximum utility contribution. When faults occur in the island mode the magnitude of short circuit is limited to the capabilities of the distributed energy resources, which provides lower magnitudes, and narrow range of contributions.

D. *Transient initiation*

Transient initiation happens when a system fault occurs and there are no negative sequence flows (a source is unidentified). When grid connected, the short circuit contributions to faults are larger in magnitude and typically consist of characteristic positive, negative, and zero sequence currents [6]. If the system is grid connected or islanded, and unbalanced faults occur, numerical relays can easily discriminate between negative sequence current or voltage. During a fault on a grid connected Microgrid one can expect to see high magnitude negative sequence flows. However, in islanded mode and during a fault condition the inverter based Microgrid will see very low negative sequence currents. This information can allow protective relays to use appropriate settings at the time of fault initiation.

E. *Island detection and communications to select relay settings*

Inverters typically know when a microgrid is islanded from utility grid. They can initiate relay changes based on this information through communications or novel ideas such as a small negative sequence contribution to the Microgrid to tell relays to change to islanded settings.

III. ADAPTIVE SETTING METHODS

Adaptive protection methods can be classified into static relay setting groups, multiple relay setting groups, programmable relay setting groups, model-driven relay setting, machine learning protection setting, algorithm protection setting, multi-agent protection setting and automated or self-setting protection method.

A. Static relay setting groups

The static relay group setting method is based on placing a unique and fixed setting group with definite/inverse time overcurrent, over/under voltage, over/under frequency, directional profiles and others protection functions. The directional profile settings allow the protection devices to be used in non-radial power systems, a main characteristic of microgrids that could be connected on grid and islanding modes for the reverse and forward direction profiles, respectively. In the static relay group setting method, the protection device settings are not modified, and they remain always the same for the grid and islanding connected modes. An example of where this method can be used is in small microgrids, that have two circuit paths that could be set with the forward and reverse directional profile settings. In that case one setting group is activated and the other setting groups are not used. In the static relay group setting method, primary and backup protection functions could be implemented in the same setting group. An inverse time overcurrent and over/under voltage protection function could be implemented as primary and backup protection, to protect the grid and islanding connected modes, respectively. This method doesn't require the protection relay setting groups to be switched, resulting in the protective relays being deactivated for a short period of time, also no communication between protective devices is necessary because of the static relay setting group is fixed for the microgrid operation [1].

B. Multiple relay group setting method

The multiple relay group setting method is based on using more than one setting group with different definite/inverse time overcurrent, over/under voltage, over/under frequency and/or other protection functions in a protection device. These individual setting groups are not modified, and each setting group could be applied for different operation states. A typical application is a line impedance relay that may have two setting groups that can be switched, depending on the particular season of the year (e.g., summer and winter), then, predetermined settings may be selected based on the specific seasonal line rating. Another example is for a live-line work, in which circuit breaker relays sometimes use alternative setting groups that have hot-line-tag groups, to reduce the instantaneous protection element set point and block all reclosing for the circuit while this work is being performed. In small and medium microgrids, the multiple relay group setting method is applied, while one relay setting group is used in the utility-grid mode, another relay setting group is used in the islanding mode. In complex microgrids, more than two relay setting groups could be used, because distributed energy resources could be located at different bus sites, configuring several circuit paths that require a variety of protection setting alternatives. Then complex microgrids have multifunction relays that contain several setting groups and have the ability to switch to other predefined protection settings stored in multiple selectable setting groups. These setting groups are typically limited to between four and eight static setting groups per relay. In addition, each of these setting groups requires individual setting calculations, depending on the differences between the type of operating configurations for the system. Also, when the setting groups are switched, the multifunction relays are disabled for a short period of time, typically one second. In the multiple relay group setting method, the communication among the multifunction relays is needed to pick up the setting groups, based on the circuit paths established by the breaker states along the microgrid. Many other operating configurations could be contained in the individual setting groups for a quick transition to the new operating constraints. However, in a dynamic operating environment setting groups are insufficient because they are static, limited and cannot account for many situations that may present themselves. Then, the option of a programmable relay setting group method and/or model driven relay setting method could provide a much wider range of operation and maximizes the protection settings for changing conditions.

C. Programmable relay group setting method

The programmable relay group setting method is based on using a written programmable logic instead of setting groups for protective devices. In this case the definite/inverse time overcurrent, over/under voltage, over/under frequency and other protection functions are programmed into the multifunction relay. In this method, the written programmable logic settings are fixed, and the number of settings could be increased because the settings are not limited by the number of setting groups of protection device. In microgrid and/or feeder cases, the programmable relay group setting method was applied with inverse time and differential overcurrent protection functions, and impedance protection functions. In the programmable relay group setting method, there is no need to disable the protective devices for short periods of time as with the setting groups method. In this case the protection relays are always enabled since the switching of setting groups is it not necessary. Also, the programmable relay group setting method improves the capacity of multifunction relays, which could be used in other protection setting applications, because the protection functions are programmed into one setting group for each relay. Then, the programmable relay group setting method allows more free setting groups than the multiple relay group setting method, improving the capacity of relays for seasonal (winter and summer) and other operation adaptive protection settings that could be required [7]. While the multiple relay group setting method is limited by available relay setting groups provided by the manufacturer, the programmable relay group setting method allows you to implement the protection functions with the programmable logic and math operators, increasing the number of protection function settings respect to the resident setting groups of relays. Therefore, the programmable relay group setting method could be more suitable than the multiple relay group setting method for complex microgrids. In addition, complex microgrids require adaptive overcurrent protection that could set a great number of circuit path situations, and the programmable relay group setting method and multiple relay group setting method could be integrated into one method, to increase the number of protection function settings by the multiplication of available setting groups and control inputs provided by each relay. It is possible that an adaptive overcurrent protection method that does not require the relay engineer to write a specific program could be more desirable. However, in the multiple relay group setting method, the setting group changes disabled the relays for a fixed amount of time, reducing the relay availability. An adaptive overcurrent protection based on a programing alternative results in a better solution for microgrids, but it requires that relay engineers to be trained in relay programing techniques. In complex microgrids with distributed energy sources located at different bus sites, more than eight relay setting groups could be needed. Then, the programmable relay group setting method could be the best option, since it allows to optimize the capacity of multifunction relays.

D. Model Driven Relays

Adaptive protective relaying schemes are needed to address the wide range of short-circuit contributions related to distributed energy resources and alternative configurations of the grid. Incorporating an internal power system simulator within the local relays can automatically calculate protection settings and adjust coordination with both local and remote terminals. These protective relays can adaptively coordinate for multiple contingencies and configurations of the power system they are protecting. Oak Ridge National Labs has developed a field-programmable (FPGA) gate array–based model-driven adaptive protection relay that can calculate settings in real time and coordinate protection with other relays on the system to provide increased reliability, security, speed, and selectivity [7]. These relay schemes need more research, but preliminary results have shown promise to fill many gaps for future protective relaying schemes. The model-driven setting method is based on creating an adaptive protection software that focuses on using different domain models, which are conceptual models of all possible scenarios related to the specific adaptive protection problem. This model can include specific circuit elements (busses, feeders, transformers and power lines) or the total electrical circuit (microgrids and power grids). The model driven relay setting method creates different abstract representations of the knowledge and activities that govern the application domain, rather than computing algorithms. The model-driven relay setting method usually depends on dynamics functions, and power system real time simulators provide the scenarios to calculate the settings of protection devices [8]. Then, voltage and current values between the real and simulated power system are collected to evaluate simple and complex scenarios and calculate the relay settings automatically. An effective scheme for real-time operation and protection of microgrids based on the distributed dynamic state estimation was presented, by using the dynamic state estimation on a component under protection with real-time measurements and dynamic models. Another scheme proposes an adaptive reclosing approach for restoring the interrupted feeder operation and maintaining the dynamic security with low inertia microgrids, based on collecting and forecasting data, to calculate the state variables for reclosing. In the model-driven relay setting method, adaptive protective relaying schemes are needed to address the wide range of short-circuit contributions related to distributed energy resourses and alternative configurations of the grid. Incorporating an internal power system simulator within the local relays can automatically calculate protection settings and adjust coordination with both local and remote terminals. The model driven protective relays can adaptively coordinate for multiple contingencies and configurations of the power system they are protecting. The model-driven relay setting method could have simple scenarios (radial power systems) or more complex scenarios (non-radial power systems) such as a system reconfiguration that can include the injection of distributed energy resources onto the circuit, islanded situations, and others. In the simplest scenario such as a circuit with no distributed energy resources the adaptive relay only needs the load current that is presently on the circuit. The load current is multiplied by a scaler value called the Adaptive Pickup Factor (APUF). The result is the Adaptive Pickup (APU) [9]. The APU value is compared to the rating of the equipment on the circuit. The equipment may include the substation transformer the wire along the backbone and laterals of the circuit etc. If the APU value is calculated to be greater than the rating of the circuit equipment, then the rating of the circuit equipment is chosen to be the pickup value. The relay receives current readings from the Current Transformers (CTs) built into the circuit breaker or recloser that the relay is associated with. The current being read from the CTs will be at a load level during normal operating conditions and at a fault levels during a fault. If the pickup value is being calculated in real time, then during a fault the adaptive relay will calculate a pickup value that's greater than the fault current and a trip will never be issued. Therefore, the pickup value calculation needs to be delayed by 5 minutes so that the real time current readings will be compared to amp readings in the recent past.

E. Machine Learning Protection Setting Method

The machine learning protection setting method is based on using artificial intelligence that provides to the power grid and protection system the ability to automatically learn and improve from experience without being explicitly programmed. The machine learning process focuses on the development of computer programs that can access data and use it for learning from themselves. The process of learning begins with data observations, in order to look for microgrid or power grid patterns in data and make better decisions in the future based on the past and actual scenarios that are provided. The machine learning protection setting method allows the computers to learn automatically without human intervention or assistance and adjust actions accordingly. In microgrid protection schemes, before calculating the protection device settings, it is necessary to detect the circuit topology (circuit paths) to know if the microgrid is working on grid or islanding mode, and what distributed energy resources have been connected. The machine learning protection setting method could be applied at the circuit topology detection step of microgrid protection schemes. A rule-based adaptive protection scheme using machinelearning methodology for microgrids with extensive distribution automation was presented, based on using uncertain elements in a microgrid, and perform a first quantitatively analysis by Pearson correlation coefficients from data mining, to recognize circuit topologies by a support vector machine model, that uses the growing massive data streams from the microgrid. In the machine learning protection process, the circuit state recognition and the adaptive reconfigurations can be implemented with enhanced decision-making to modify the protective settings and the network topology to ensure the reliability of the intelligent operation. However, the machine learning protection process in complex microgrids or power systems, it is usually applied as a partial (circuit topology detection) solution instead of being a full-integrated adaptive protection solution. Then, the machine learning could be used to detect the circuit topology, and the calculation of the protection setting devices could be implemented by using a more accurate way, based on algorithms. However, the application of machine learning could minimize the number of measurement devices installed in complex microgrids, to detect circuit topologies for adaptive protection schemes.

F. Algorithm protection setting method

The algorithm protection setting method is based on a finite sequence of well-defined instructions, that are created to detect the circuit paths in microgrids, and/or calculate the pickups for the overcurrent, over/under-voltage and - frequency settings in microgrids. The algorithms are specifications that perform calculations, data processing, automated reasoning, and other tasks. In the algorithm protection setting method, the variables (currents, voltages, frequencies, impedances, etc.) of protection functions are expressed with finite values that represent the boundaries for a specific breaker trip and/or close state condition. The algorithm protection setting method is a well-defined formal language for calculating the protection function settings, starting from an initial state/s with initial input/s, and it is based on detailed list of instructions that describe the computation process that when protection devices trip or don't trip their breakers. The process of the algorithm protection setting method is usually written as a flow-chart diagram. The algorithm protection setting method is one of the most common adaptive protection schemes used to calculate the settings of protective relays, and it is because this method is easy to be implemented. In addition, the majority of static, multiple and programmable relay group setting methods are based on algorithms that represent equations and flow-chart instructions. The algorithm protection method has been applied in adaptive protection schemes for microgrid project based and research-based applications, using ANSI/IEEEd dynamic protection functions. The applied ANSI/IEEE protection functions were the differential current, impedance, over/under voltage, inverse overcurrent, instantaneous overcurrent, phase directional zero, positive and negative sequence overcurrent. In addition, the applied dynamic protection functions were the transient voltages/currents, harmonics and d-q wavelet packet transform. In microgrid adaptive protection schemes, the algorithm protection setting method could be combined with other methods. Then, the machine learning and algorithm protection setting methods could be used to detect the circuit topology and calculate the directional overcurrent and distance settings of protection devices, respectively.

G. Multi-agent protection setting method

The multi-agent protection setting method is given by a computerized system with several interacting intelligent agents that may converge to an appropriate modelling approach. In microgrids with distributed energy resources, the multi-agents can solve problems that are difficult or impossible for an individual agent, such as the detection of low fault currents because of the contribution of PV inverters and/or the lack of selectivity coordination between fuses and relays for circuit paths with inverter based distributed generators. A multi-agent protection setting method for a microgrid operating in both grid-connected and islanding mode, using a variable tripping time differential protection scheme (VTDPS) is another approach. There, the agents are only coordinated with lateral fuses and each agent has the task of protecting a unique zone with several differential layers. The variable tripping time is used for the coordination with protective devices without the need for additional data transmission. Each agent is composed of primary, backup, and bus protection layers, with their relevant VTDPS, that achieves the main and backup protection for the microgrid. This VTDPS is implemented by using a multi-agent system approach where each agent gathers the required measurements for the VTDPS, and the agent checks the tripping rules according to the adjusted threshold for the lateral fuses. This VTDPS application like other multi-agent protection setting methods are based on a methodic, functional and procedural approach that works with algorithmic search and/or reinforcement learning, to find an effective solution for microgrid protection scheme needs.

H. Automated or self-setting protection method

The automated or self-setting protection method is based on using a technology process performed without human assistance for calculating, setting and operating protective devices. The automated or self-setting method for microgrid research-based applications can use inverse time, instantaneous, directional overcurrent and dynamic protection functions. Electrical utilities don't use full self-setting protection methods, because protection engineers need to run the power flow and fault analysis studies, calculate the protection settings, set and validate the protection devices, before installing them in electrical substation. The static, multiple, and programmable relay group setting methods are not self-setting procedures, because they require that protection settings were previously calculated. However, these methods could be integrated with the model-driven or machine learning setting methods to detect the circuit paths, run the power flow and fault analysis studies, calculate the protection settings, and set or select the relay setting groups. The automated or self-setting protection method requires artificial intelligent based on computers and/or real-time simulator applications with communication. The modeldriven and machine learning setting methods are crucial to develop a self-setting protection procedure. The machine learning protection setting method can use artificial intelligence that provides to the power grid and protection system the ability to being automatically programmed, focusing on the development of computer programs that can access data and use it for learning from themselves. On the other hand, the model-driven method uses different domain models based on creating all possible scenarios related to the specific adaptive protection problem. By using the model-driven and machine learning setting methods, the definite/inverse time overcurrent, over/under voltage or over/under frequency protection settings could be calculated, and placed on protection devices for specific situations, such as microgrid circuit path configurations, weather conditions, or inverter based distributed energy resource operations.

IV. PROS AND CONS OF ADAPTIVE PROTECTION METHODS

There are advantages and disadvantages of adaptive protection methods for the static relay group, multiple relay group, programmable relay group, model-driven relay, machine learning protection, algorithm protection, multiagent protection, and automated protection setting methods. The static relay group setting method requires protection engineers to have relay setting capabilities only, and this method is applicable for small microgrids that allow one setting group based on a forward and reverse directions. On the other side, the multiple and programmable relay group setting methods have a greater setting capacity than the static relay group setting method. The multiple and programmable relay group setting methods could be used for medium and large microgrids, respectively. In addition, the programmable versus the multiple relay group setting method mean that relays are not disabled since settings groups are not changed. The programmable relay group, model-driven relay, machine learning, and multi-agent setting methods for adaptive protection could be more adequate to use in complex systems and/or large microgrids that have different circuit paths that are connected to inverter based distributed energy resources. The currently available setting groups of commercial relays are not sufficient to cover all adaptive protection scenarios.

IV. CONCLUSION

Historically the changes in protective relaying involved the transition from electromechanical to digital relays which basically mimic the electromechanical functionality. Due to the changing landscape of the power system with things like automation, inclusion of inverter based generation and more variable loads and fault levels there comes a need for relays that are adaptive in nature and have expanded capabilities to make “on the fly” changes in settings. There are several options available now and in various stages of development that can accomplish this. Each have pros and cons and limitations in their usefulness and application should be carefully evaluated considering the current and future power system as the grid continues to evolve.

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