OPERATED DEVICE ESTIMATION FRAMEWORK

A Thesis

by

JANARTHANAN RENGARAJAN

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2008

Major Subject: Computer Engineering

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Approved by:

Co-Chairs of Committee,	Billy Don Russell, Jr.
	Narasimha Reddy
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ABSTRACT

Operated Device Estimation Framework. (December 2008)

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Co-Chairs of Advisory Committee: Dr. Billy Don Russell, Jr.
Dr. Narasimha Reddy

Protective device estimation is a challenging task because there are numerous protective devices present in a typical distribution system. Among various protective devices, auto-reclosers and fuses are the main overcurrent protection on distribution systems. Operation of a protective device in response to a particular fault condition depends upon the protective device's operating behavior and coordination of various such protective devices.

This thesis presents the design and implementation of a protective device estimation algorithm which helps in identifying which protective devices have operated to clear a short circuit condition. The algorithm uses manufacturer's device details, power quality data measured from substation monitoring devices and power system event features estimated using existing DFA algorithms. The proposed technique can be used to evaluate coordination of these protective devices and helps in locating a fault in a distribution system feeder. This approach is independent of feeder topology and could be readily used for any distribution system. The effectiveness of this algorithm is verified by simulated and actual test data. Suggestions are included for future research and application by electric utilities.

To my family and friends

ACKNOWLEDGEMENTS

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NOMENCLATURE

A	Amperes
AI	Artificial Intelligence
C	Cooling factor
C_k	Cooling factor for k^{th} reclosing time interval
CB	Circuit Breaker
DFA	Distribution Fault Anticipator
EPRI	Electric Power Research Institute
F	Fast
I	Current
I_{device}	Magnitude of fault current seen by protective device
I_{in}	Input current
I_{out}	Output current
kA	Kilo-Ampere
MM	Minimum Melt
OC	Overcurrent
P	Reduction in melting time of fuse due to preloading effect
PSAL	Power System Automation Laboratory
PQ	Power Quality
S	Slow
SCADA	Supervisory Control And Data Acquisition

SQL	Structured Query Language
t	Time
t_{device}	Duration for which fault current is seen by the protective device
$t_{fuse\text{-}clear}$	Estimated clearing time of fuse
$t_{fuse\text{-}melt}$	Estimated melting time of fuse
$t_{recloser\text{-}fast}$	Estimated matching time on recloser fast curve
$t_{recloser\text{-}delayed}$	Estimated matching time on recloser slow curve
T_l	Point on the maximum equivalent lockout curve of recloser
T_{Rj}	Maximum clearing time at the chosen current for the j^{th} operation
TC	Total Clearing
TCC	Time Current Characteristic
V	Volts / Voltage

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CHAPTER I

INTRODUCTION

Electrical power distribution system feeders are susceptible to different kinds of faults caused by a variety of situations like weather conditions, equipment failures, disturbances caused by animals, etc. Most of the power distribution feeder systems in the United States are built over radial methodology. Associated with these distribution systems, there exist many ancillary systems which assist in meeting the requirements for safety, reliability and quality of supply. Among them, protection systems are the most important one. The objective of the protection system is to mitigate the harmful effects of abnormal events on the components of distribution system. The radial distribution systems typically have overhead distribution lines which are protected based on the well known radial philosophy - reclosers on the main feeder and fuses on the lateral feeders. These conventional protection devices have been proven to be reliable, secure and dependable as they operate only when there is a fault in the system. Most faults on the lateral feeders are temporary in nature and therefore require a recloser's instantaneous trip operation to de-energize the system and allow the fault to clear prior to any fuse operation in a typical fuse saving scheme. If the fault fails to clear and becomes permanent, the fuse will then operate to isolate the faulted section from the network resulting in loss of power supply for that portion of feeder. Such kinds of power outages are highly undesirable and utility companies do their utmost to keep the outages

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This thesis follows the style of *IEEE Transactions on Power Delivery*.

to minimum possible level by quickly locating the cause of the disturbance and implements necessary measures to restore service to the end customers. Nevertheless, these kinds of disturbances and fault conditions are inevitable. This calls for efficient and intelligent identification of faults and root cause of the fault.

For any fault occurring in this kind of radial distribution systems, we need only a single interrupting protective device to clear the fault. But in a typical radial distribution system, there exists many such protective devices and the device that operates to clear a fault is determined by coordination of these protective devices based on their ratings and operating behavior. These protective devices include circuit breakers, reclosers, relays, sectionalizers, and fuses [1]. They appear in series along a feeder in order to sense the fault current and interrupt the fault. Proper coordination of these protective devices is impeded because of the differences in protective device time-current characteristic curve slopes and coordination of multiple devices at a time. Improper coordination of these devices results in device misoperation resulting in more frequent and longer duration of voltage disturbances thereby impacting the overall power quality of the system. Recognition of this kind of device misoperation might be undetectable until a major event occurs in the system.

As a part of Distribution Fault Anticipator (DFA) project, utility companies are installing feeder monitoring devices at substations to monitor the power data. Whenever the monitoring device identifies any current or voltage variation that is outside the preset threshold, it records all phase current and voltage waveforms. This data is transferred later to the database server in Power System Automation Laboratory (PSAL) at Texas

A&M University. Many algorithms developed by researchers at PSAL, Texas A&M University, currently analyze these power data using extensive signal processing methods and generate detailed reports that include classification and identification of various disturbances. Even though the reports estimate device operations like “breaker operation”, “recloser operation”, “capacitor switching”, current algorithms do not quantify and qualify the exact device that operated during the fault conditions. This calls for the development of an operated device estimation framework.

This thesis describes the work performed to implement automated estimation of protective devices that operate during fault conditions in a radial distribution system using the approach described in [22] in combination with modified coordination strategy as described in [26]. This operated device estimation framework utilizes relevant information and data available from the distribution system database & records of electrical quantities from substation monitoring devices, results from existing fault classification and feature estimation algorithms developed in PSAL, Texas A&M University and/or simulated data. Chapter II of the thesis briefly reviews previous work done on the protective device monitoring and estimation methods. Chapter III outlines the description of protective devices, generic modeling approach and co-ordination strategy. This is followed by the problem formulation and operated device estimation framework in Chapter IV. Chapter V presents the software implementation. The results and case studies are presented in Chapter VI. Concluding remarks and scope for future work is provided in Chapter VII.

CHAPTER II

REVIEW OF PROTECTION DEVICE MONITORING USING PQ DATA

With the development of computers, many artificial intelligence methods such as expert systems, neural networks, etc., emerged. These methods provide a way to capture the experience of operators or engineers, and can help people to do much laborious work. Many artificial intelligence solutions & algorithms have been published about fault location, disturbance classifications using data from power quality monitoring devices and estimating the protective device that operated, for example [2] and [3]. The most primitive of these identification methods is visual inspection by utility personnel upon receiving trouble calls from the customers, which is time consuming and needs lot of man power. Most of the algorithms developed use the protective device information and feeder topology to estimate the accurate device that operated during the fault conditions and identify the faulted section to locate the fault. These methods mostly employ artificial intelligence methods to process the data. One such method uses the topology information updated manually or by Supervisory Control And Data Acquisition (SCADA) systems and the information gathered from switch activations and protective device information as inputs to an expert system that estimates the device that operated and identifies the faulted section [4]. Another method uses an expert system to estimate the faulted section by using dynamic inference of protective device coordination [5]. Some algorithms have been proposed for systems equipped with SCADA, that use an expert system and various machine learning techniques to analyze different possible sequence of events caused by differences in operation of protective devices for a fault diagnosis [6], [7].

Another artificial intelligence technique, fuzzy logic could be used to account for uncertainties in the input data of distribution system faults. One such method uses feeder topology for fault diagnosis by employing fuzzy rules [8]. Another method employs feeder topology information, pre-fault and post-fault system configuration information to identify the fault islands, and assigns possibilities to different devices in sections [9]. Many other methods that employ fuzzy logic uses information like feeder topology geographical information, utility personnel's expertise, short circuit calculations, post-fault system configurations has also been proposed [10] – [12].

With computer programs that simulate the behavior of human experts in solving a complex problem, expert systems have received considerable attention for developing fault location methods. Many researchers used rule-based expert systems based on topology information and protective device information. Ypsilantis et al. proposed a rule based expert system that also used the status of protective devices [13]. This method was different from other methods due to its consideration of sequential information in the network. Teo developed a rule-based diagnostic system that used feeder topological information and real time data from SCADA systems [14]. The system used two types of rules. A set of core rules using breaker trips and bus status was normally enough to cover a majority of fault conditions. In the cases where the core rules failed, exception rules were generated by interaction with system operators. These exception rules used breaker trip information and the islands formed in the faulted network. Rule-based expert systems have a powerful capability to mimic human experience. However, a number of rules are needed to describe various devices. The tasks of knowledge-acquisition and maintenance of knowledge base are often laborious and tedious, and the development of an expert system is often a costly and very lengthy process. Hence, the portability of expert systems is very important. Instead of representing the operator's expertise as complicated rules, Hadjsaid and Bretas presented a special knowledge based system that captured the post-fault network state, and recorded it as a pattern [15]. When linking to a distribution network simulator, the diagnostic system was trained. When a new fault happened, a matching mechanism was used to compare the network state with records to identify the fault location. If no one matched, the system would consider it as a new fault condition and prompt the user to enter the faulted element.

Some of the approaches use a neural network for estimation of the device that operated based on information about the states of different protective devices on the circuit and phasor measurements at the substation [16], [17]. Neural networks were used as the knowledge base, instead of heuristic rules. The feeder fault voltage, circuit breaker status, real power of feeders during the normal condition, and real power of feeders during short circuit, etc, were used to train the neural network. Yang et al. presented distributed neural nets diagnosis system constructed by the training database that associated the protective scheme using the individual sections [17]. By using the distributed processing technique, the burden of communication between the control center and substations was alleviated. In order to implement an on-line estimation system, Bi et al. employed a multi-way graph partitioning method based on weighted minimum degree reordering to partition a large-scale power network into some sub-networks [18], [19]. Then a radial basis function neural network and its companion fuzzy system were used to identify the device that operated and isolate the fault section based on information available from SCADA systems. The speed of this method made it possible to use it as an on-line system. Glinkowski and Mohammed presented different algorithms that uses neural network to identify the device operations and faulted section based on pattern recognition [20], [21]. Some measurements uniquely defined a fault pattern, and a neural network was used to recognize the pattern to identify the fault conditions.

An operated device identification module using fuzzy resolver was developed by researchers in PSAL of Texas A&M University as part of three stage fault location system [27]. But even this approach uses feeder topology information and assigns possibility values to the devices based on fuzzy rules.

Most of methods mentioned above estimated the protective device that operated and faulted section based on the information obtained from SCADA systems and feeder topology information. However, there are uncertainties in these data as feeder topology might change over time and it’s a very tedious process to get accurate update of feeder topology. The focus of ongoing work is to develop a new approach and software framework for best possible identification of the protective device that operated during fault conditions using relevant data that are independent of feeder topology information.

This chapter presented the review of various methods on protective device estimation during fault conditions. The next chapter will describe various protective devices used in a typical distribution system, generic modeling approach and the co-ordination strategy with the influence of thermal behavior of protective devices.

CHAPTER III

BACKGROUND OF PROTECTIVE DEVICES

Protective devices are used in the electrical power distribution systems to minimize the duration of faults and the effects of the faults. Commonly used protective devices in distribution systems are fuses, reclosers, and circuit breakers, which are usually controlled by relays. The generic structure of the protective device model is shown in Figure 1 [24].

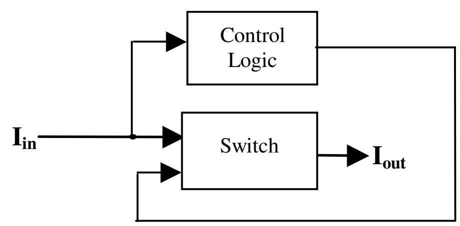

Figure 1. Generic structure of protective device.

In the Figure 1, I_{in} is a current flowing in the system. To simulate Time Current Characteristic (TCC) based protective devices programmatically, the control logic to determine the control signal status is the key element. The TCC curves for all types of devices are stored in the logic. Each of the commonly used protective devices and coordination strategies are presented below.

FUSES

"Fuses are overcurrent protective devices and can operate only once. They use a metallic element that melts when overload current passes through them. The metallic element must be replaced before a fuse can be used again. A fuse is designed to blow within a specific time for a given value of overcurrent. It has two TCC curves: the minimum-melt (MM) curve and the total-clearing (TC) curve. MM curve represents the relationship between the overcurrent value and the minimum time needed to melt the fuse; TCC is the relationship between the overcurrent value and the maximum time to melt the fuse" [24].

"The advantage of fuses is their low cost. To install them only needs a small investment. The disadvantage is that they are one-time operating devices. When a fault happens, even a temporary fault, they will blow and interrupt power supply. However, most faults (80-95%) on distribution and transmission lines are temporary faults" [34]. "Using too many fuses will jeopardize the continuity of power supply; hence automatic reclosing devices like reclosers are used" [24].

RECLOSERS

"Reclosers are overcurrent devices that automatically trip and reclose a preset number of times to clear temporary faults and isolate permanent faults. Reclosers also have two types of TCC curves: instantaneous curve (fast curve) and time-delay curve (slow curve). The operation sequence of reclosers can vary. For example, the sequence can be two instantaneous operations followed by two time-delay operations (2F+2S), one instantaneous operation plus three time-delay operations (1F+3S), one instantaneous operation and two time-delay operations (1F+2S), etc. Usually the number of operations is set at three or four (up to five times)" [24], [34].

"The advantage of reclosers is that they clear temporary faults before they lock out. This improves the continuity of power supply significantly. The shortcoming of reclosers is they are more costly than fuses" [24].

CIRCUIT BREAKER / RELAY COMBINATION

"Usually Circuit Breaker's (CB) operation are controlled by relays and their characteristics are determined by overcurrent relays and reclosing relays. Overcurrent relays have two types: instantaneous trip relays, which operate instantaneously when currents are larger than the setting, and inverse time relays, which have inverse, very inverse, or extremely inverse time-current characteristics. Generally the relay used to open CB's is the second type [34]. CB's can operate once or reclose several times" [24].

SECTIONALIZERS

Sectionalizers operate after it senses a predetermined number of overcurrent surges in the distribution line. Operation of sectionalizer isolates the faulted section from the main feeder.

COORDINATION OF PROTECTIVE DEVICES

In this work, the fault overcurrent phasor value and fault time duration is compared with protective devices' TCC curves to decide which device operates in response to a fault. The assumption of this method is that protective devices are coordinated correctly. Therefore before coming up with any inference, device coordination needs to be done. The protective devices used in this work are fuses, reclosers and CB's. The coordination between them will be discussed.

A. Fuses protecting reclosers

There are two different situations when a fuse is used to protect a recloser. One is the recloser clearing temporary faults and the fuse clearing permanent faults. The other one is the fuse clearing both temporary and permanent faults. Obviously the first one is better, because it reduces the outage time of the distribution circuit and saves the time to exchange fuses. But when a lateral carrying a rather small current goes away from the primary feeder with a rather large current, the first kind of coordination is unrealistic. Then the second coordination method is needed. Two kinds of coordination are shown in Figure 2 [30], [31].

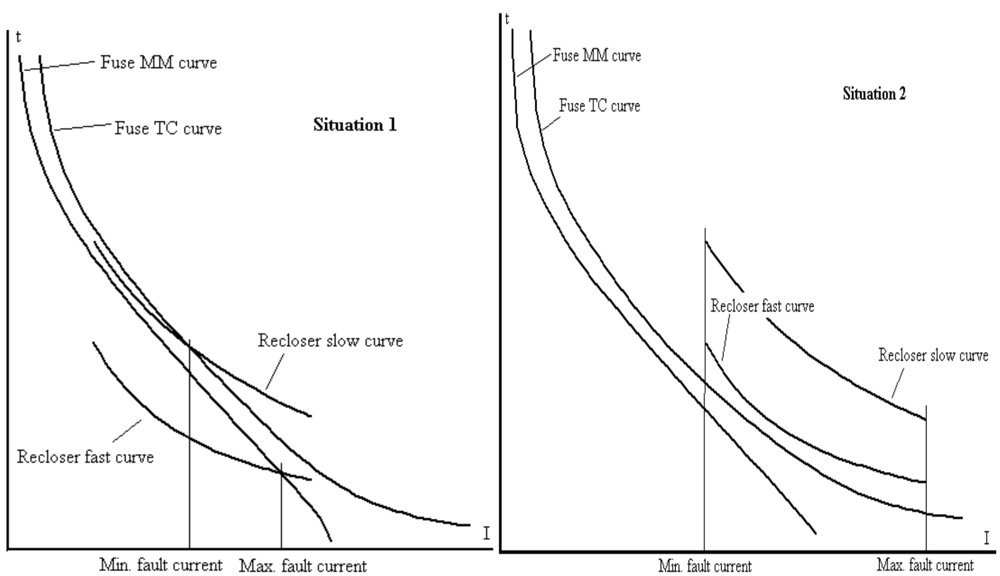

Figure 2. Fuses protecting reclosers.

For the first situation, the correct coordination is achieved if the minimum fault current is larger than the intersection of the recloser's slow curve and the fuse's TCC, and the maximum fault current is less than the intersection of the fuse's MM curve and the recloser's fast curve.

For the second situation, the correct coordination is that the fuse's TCC is always below the recloser's fast curve, which means the fuse always operates faster than the recloser.

To achieve the correct coordination, some factors such as preloading, ambient temperature, accumulated heating and cooling of the fuse should be taken into account.

B. Fuses protecting fuses

Because fuses are much cheaper than reclosers, some distribution systems use a large fuse (protected fuse) as the backup device of a small fuse (protecting fuse), instead of using a recloser. These two fuses should be coordinated appropriately, so that the outage areas would be limited as small as possible. To ensure these two fuses are coordinated correctly, the protecting fuse's TCC should always be located lower than the protected fuse's MM curve during the fault current range [30]. To eliminate the effect of load current, ambient temperature, etc., usually an adjustment factor of 75% is used on the protected fuse. Correctly coordinated fuses' curves are shown in Figure 3.

Fuse coordinating with other fuses can also be identified using a coordination table such as Table 1. This enables quick confirmation of coordination between two fuses in series at particular values of fault current. The table lists the maximum available fault current that will permit coordination. Such tables are available from manufacturers of fuses.

Table 1. Fuse to fuse coordination table for T type fuses.

Protecting fuse current rating	Protected fuse current rating									
	6	8	10	12	15	20	25	30	40	50
3	225	360	550	780	1050	1400	1750	2250	2900	3600
6		140	400	690	990	1350	1750	2250	2900	3600
8			220	560	900	1300	1650	2250	2900	3600
10				300	710	1200	1600	2200	2800	3600
12					400	910	1450	2000	2700	3500
15							1200	1800	2550	3400

C. Reclosers protecting fuses

Usually this kind of coordination is used at substation transformer primary side and secondary side. The fuse provides protection for the transformer against a fault in the transformer or at the transformer terminals and also provides backup protection for the recloser. The recloser should clear all kinds of downstream faults (temporary & permanent), and the fuse only protects the transformer [30]. The correct coordination is that the recloser's slow curve should be below the fuse MM curve. There is also an adjustment factor depending on the number of fast and slow trips and the reclosing time of the recloser. Figure 4 gives an example of this kind of coordination.

D. Reclosers protecting reclosers

While downstream smaller reclosers protect upstream larger reclosers, the correct coordination is achieved by the requirement: the maximum fault current is less than the intersection of the upstream slow curve and the downstream slow curve plus several cycles (usually 12 cycles) [30], [31]. This requirement illustrates in Figure 5.

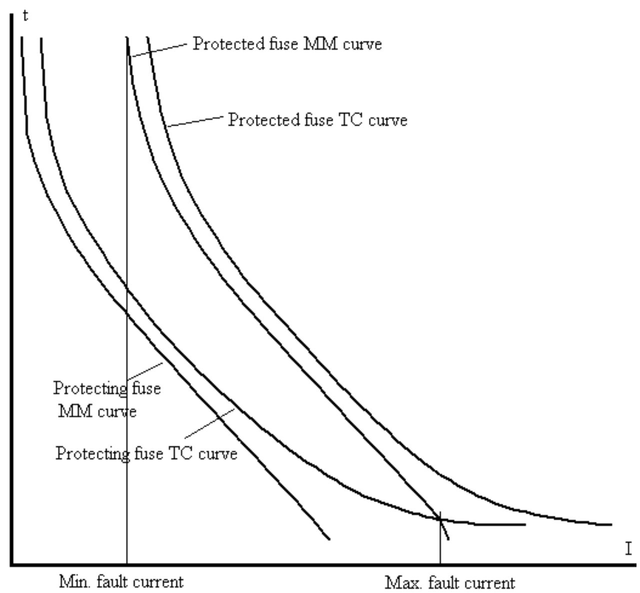

Figure 3. Fuses protecting fuses.

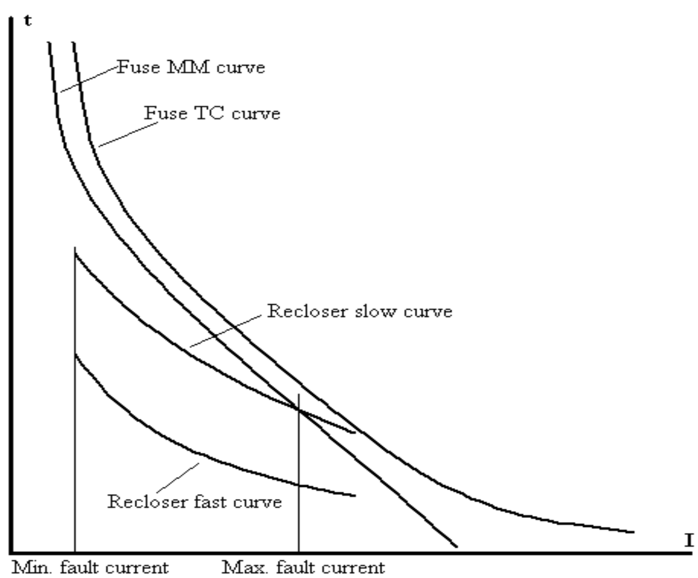

Figure 4. Reclosers protecting fuses.

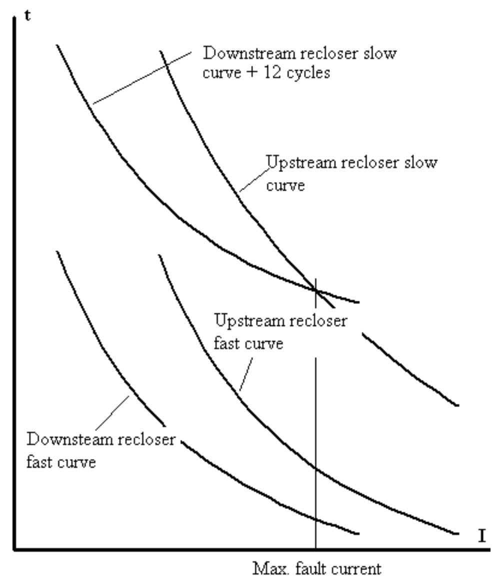

Figure 5. Reclosers protecting reclosers.

E. Coordination between fuses and CBs

The coordination between a fuse and a CB (overcurrent relay) is somewhat similar to the coordination between a fuse and a recloser. The main difference is that the reclosing time of CB's is larger than that of reclosers, so that there is no need for heating and cooling adjustments. When the fuse is used as the protecting device, the coordination is achieved if the relay operating time is 150 percent of the total clearing time of the fuse. When the fuse is used as the protected device, the coordination is achieved if the minimum melting time of the fuse is 135 percent of the combined time of the CB and related relays [34].

F. Coordination between reclosers and CB's

A CB is the backup protective device of a recloser. The CB's TCC's should be higher than those of the recloser. A crucial factor to achieve the coordination is the reset time of overcurrent relays during the tripping and reclosing sequence. The coordination must ensure a mechanical relay cannot accumulate enough movement in the trip direction during recloser successive operations to trigger a false tripping. Digital relays must also be protected from false tripping through proper coordination.

G. Coordination between sectionalizers and reclosers

Better coordination of sectionalizers with other protective devices depends on three factors. The first factor is that only overcurrent surges resulting from load side fault current are to be sensed. This means that sectionalizer's actuating current must be less than the upstream device minimum trip settings. The second factor involves setting the number of overcurrent counts to trip open. Sectionalizer setting should be one less than lockout setting of upstream protective device. The third factor is that sectionalizer's memory time must be no longer than the cumulative tripping and reclosing time intervals of the upstream protective device.

INFLUENCE OF TEMPERATURE IN COORDINATION OF DEVICES

"The combinational presence of fuse and reclosers in the feeder increases the temperature effects on the coordination of these devices. The application of reclosers on electrical distribution systems requires them to be coordinated with both source side and load side fuses. In either case, fault current through the fuse will be interrupted by the recloser and then restored as the recloser progresses through its operating sequence. At the start, the temperature of the fuse element is determined by the pre-fault load current and by the ambient temperature. When there is a fault, the temperature of the fuse element increases towards its melting point value. If the recloser open occurs before the fuse elements melting value, temperature of fuse will cool down during the reclosing time interval. This cycle will continue until the fault is cleared prior to the next reclosing operation, fuse melts and clears the fault or the recloser operates to lockout" [25]. Figure 6 illustrates the heating and cooling effect of the fuse element".

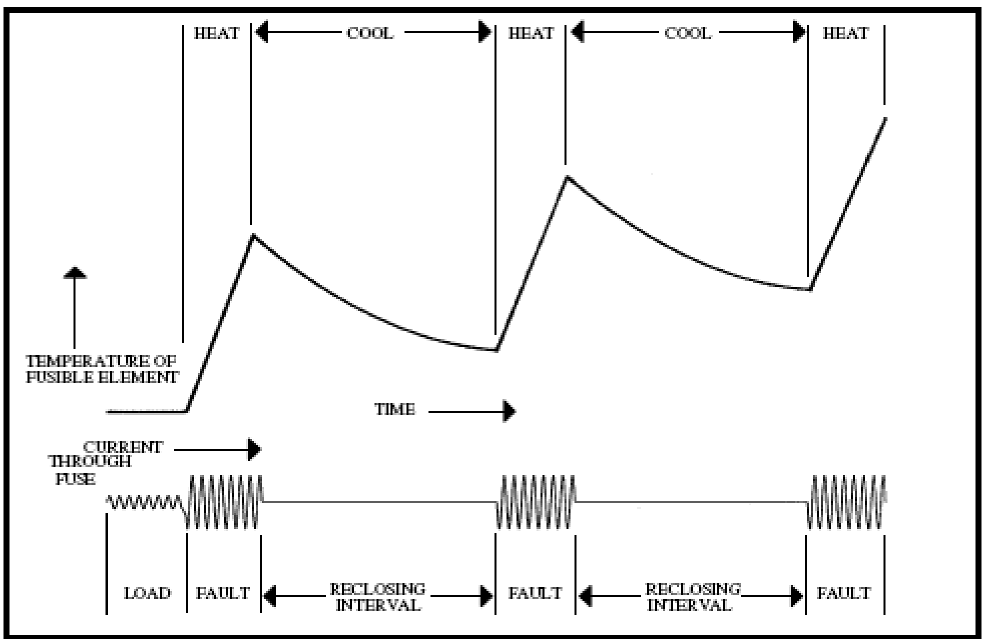

Figure 6. Heating and cooling of fuse during recloser's operating sequence [25].

"This repeated heating and cooling effects of fuse element is to be considered while coordinating the protective devices. We need to make necessary adjustments of TCC curve data to include the influence of this heating and cooling effect. When we include both the heating and cooling effects, recloser curves can be precisely adjusted to reflect these and equivalent recloser TCC curves seen by the fuse. Effects of heating and cooling for fuses can vary substantially" [25]. This is illustrated by Figure 7. In this figure, after a reclosing time interval of 2 seconds has elapsed, the slow speed fuse 20 T has lost 13 % of its heat input as compared to that of very fast speed fuse 40 N, which has lost 92% of its heat input.

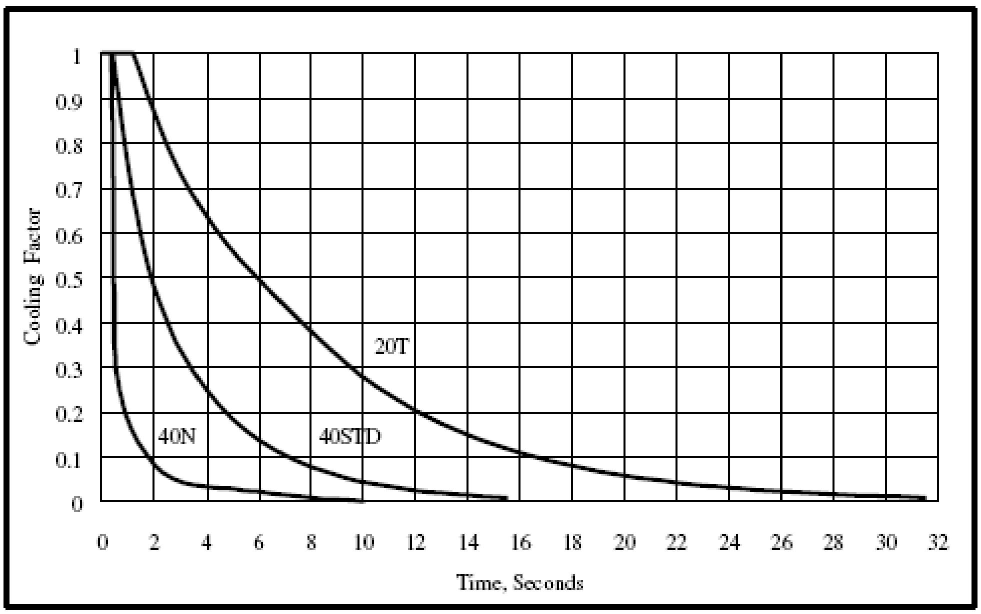

Figure 7. Cooling factors versus time for different fuse links [25].

"In source side fuse and load side recloser case, the maximum current up to which accurate coordination occurs is determined by lower of maximum interrupting rating recloser or fuse and the intersection of minimum melting curve of the fuse and maximum equivalent operating TCC curve of the recloser. For better coordination, heat stored in the fuse needs to be compensated when the recloser contacts are closed and the heat lost when the contacts are open. At a particular chosen current value, the heat stored in the fuse when recloser contacts are closed is directly proportional to recloser's clearing time. So the necessary adjustments can be made to fast and slow curves of recloser by using cooling factor C to the clearing time" [25]. Hence the maximum lockout curves for the recloser, for various operating sequences are obtained as,

For one operation of recloser,

$$T_l = T_{R1} / (1-P) \tag{1}$$

For two operations of recloser,

$$T_l = (T_{R1}C_1 + T_{R2}) / (1-PC_1) \tag{2}$$

For three operations of recloser,

$$T_l = (T_{R1}C_1 C_2 + T_{R2} C_2 + T_{R3}) / (1-PC_1 C_2) \tag{3}$$

Similarly for four operations of recloser,

$$T_l = (T_{R1}C_1 C_2 C_3 + T_{R2} C_2 C_3 + T_{R3} C_3 + T_{R4}) / (1-PC_1 C_2 C_3) \tag{4}$$

These equivalent lockout curves and manufacturers TCC curves for fuses are used in conjunction in this work to estimate the coordination between the protective devices [25].

In this chapter, description of different protective devices, their basic modeling approach, coordination of these protective devices during fault conditions and influence of temperature effects were presented. Following chapter will introduce the device identification problem, authors approach and details of operated device estimation framework implementation.

CHAPTER IV

PROTECTIVE DEVICE ESTIMATION FRAMEWORK

PROBLEM FORMULATION

An electric power distribution system is that part of an electric utility system between the bulk power source and the consumers' service switches [34]. Figure 8 shows a simplified diagram of a typical distribution system. Distribution systems can be divided in various parts, namely, sub-transmission circuits, distribution substations, distribution or primary feeders, distribution transformers, secondary circuits and service drops. Each distribution substation serves its own load area. The area served by the distribution substation is subdivided and a primary feeder, usually operating in the range of 4.6 to 34.5kV, supplies each subdivision. The primary feeder normally consists of either a three phase, three wire or a three phase, four wire main that runs from the substation to the load center where it branches into three-phase sub feeders and single-phase laterals. The distribution transformers are connected to the primary feeders, sub-feeders, and laterals usually through fused cutouts, and supply the secondary circuits to which the consumers' services are connected [34].

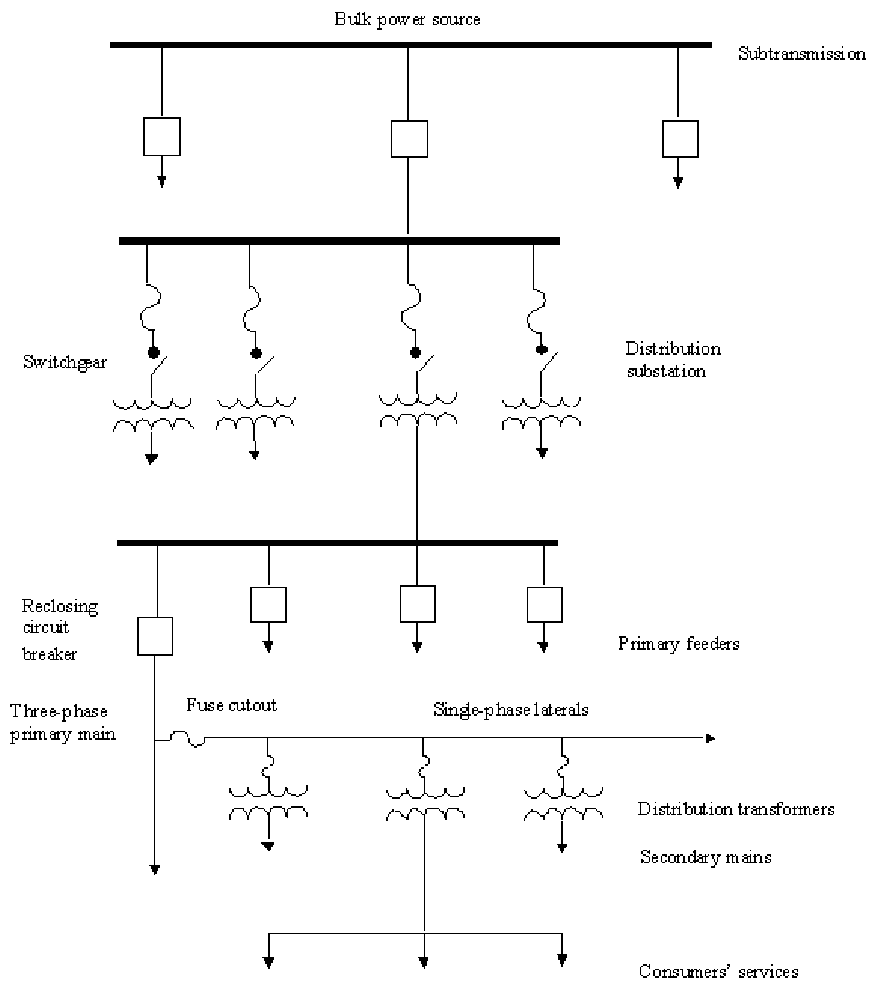

Figure 8. One-line diagram of a typical distribution system.

Most feeders in the distribution system are radial, which means that the electricity flows only through one path from the source to each customer [32]. A feeder may consist of a three-phase primary feeder, laterals (three-phase, two-phase or single-phase), loads, transformers, shunt capacitor banks, and protective devices. These equipments age over time, and this may lead to defects. Furthermore, most distribution systems are overhead systems, which are easily affected by changing weather conditions, animals, and traffic accidents and hence power system faults and other abnormal events are inevitable. Any such power system events are interrupted by a protection device to isolate the faulted section and minimize the impact on the overall system. Ultimately only one of the protective devices interrupts the short circuit condition. But many such protective devices connected in the system senses the fault and the operation of particular protective device is determined by the coordination of these protective devices, such as fuse to fuse coordination, recloser to fuse coordination and recloser to recloser coordination [33], [34].

The power monitoring devices installed in the substations as a part of DFA project, gathers various phasor voltage and current data whenever any abnormal power system event occurs. The voltage variations provide the main data in terms of the power quality problems the customers will see on the feeder, which are usually the voltage sags and interruptions. However, for our diagnostic purposes, i.e., to determine what happened, the Over Current (OC) waveforms provide more information [30]. One of the major diagnostic analyses involves the identification of the protective devices operated as a response to a disturbance. It is also important to detect any equipment failures or coordination problems. This is very tedious and challenging because

- To perform proper analysis the substation personnel need to have complete knowledge about the protection devices installed on the system, protection scheme utilized and coordination of each feeder.

- A typical power system disturbance might create multiple data records. Hence manual screening of these records is time consuming and needs dedicated substation personnel.

Many AI-based methods published usually estimates the device that operated and locate faults based data fed from SCADA systems, fault detectors, and communication channels. Due to economic constraints, the communication between protective devices and the substation are limited to some important substations. For many systems, measurements are only available at the substation and the operation status of feeder protective devices is unknown. For such systems, these methods are not feasible. Also, many expert system-based methods locate faults by using information obtained from SCADA systems, the network map and the dispatcher's past experience. Therefore, these methods are customized to one particular system and difficult to apply to different distribution systems. This calls for development of algorithm for estimating the device that operated independent of data from SCADA systems and experts involvement.

In order to overcome the problems mentioned above, this work presents development of a new device estimation framework for radial distribution systems that utilizes relevant data from substation measurements.

PROTECTIVE DEVICE ESTIMATION APPROACH

Power quality monitoring devices in the substation capture both the current and voltage waveforms of each phase whenever the monitored feeder values falls outside their predefined threshold settings. Figure 9 shows typical event record captured using the DFA monitoring system. Overcurrent events are captured if the current values exceed the predefined thresholds. The aim here is to use the OC event records to determine which protection device has operated in response to an observed OC event using these data capture record and device TCC data.

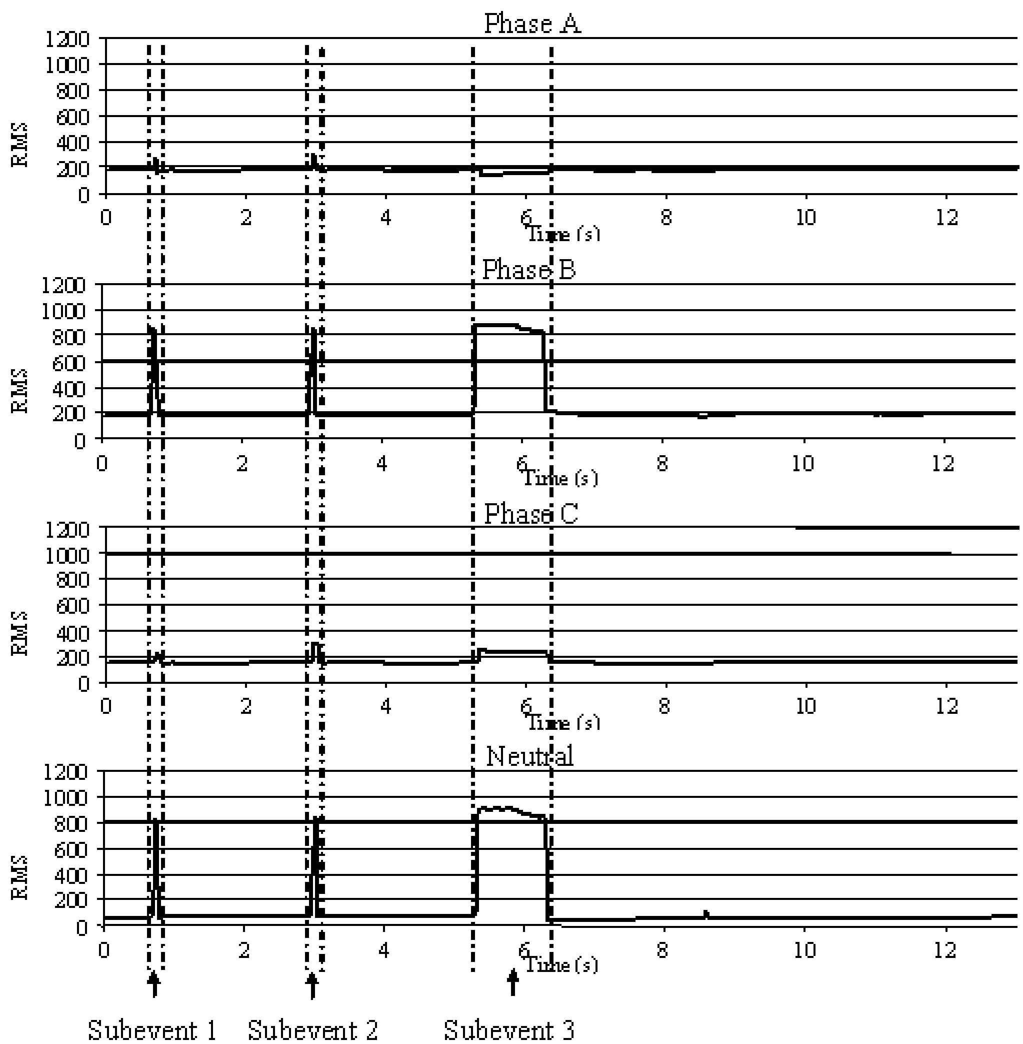

Figure 9. Typical power system event data capture record.

Figure 10 shows a typical three phase voltage and current waveform during a current induced disturbance. If the utility employs fuse saving scheme, using the authors approach one can determine the midline recloser that clears the fault and identify the downstream fuse that coordinated with the recloser.

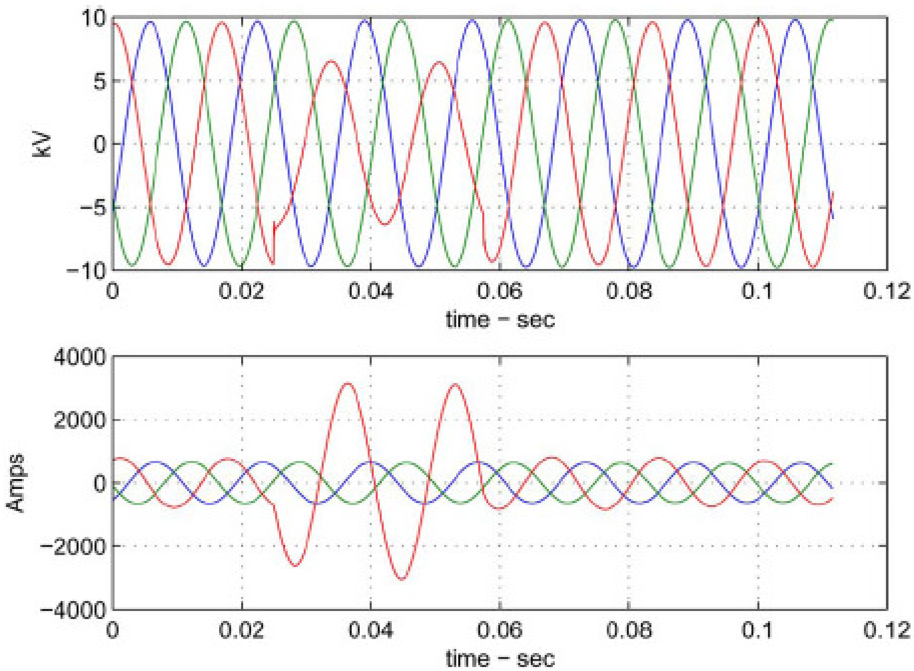

Figure 10. 3 Φ voltages and currents during OC fault observed at substation [22].

The existing algorithms developed as a part of DFA project can be used to recognize the OC event and extract the features for device estimation. The existing algorithms are used to estimate the following features,

- Magnitude of fault current seen by the overcurrent protective device, I_{device}

- Duration for which the fault current flows through the device, t_{device}

- I^2t of fault event

"These parameters will then be compared with the device TCC data. The device operating point (I_{device}, t_{device}) must be with in the fuse's minimum melting time and maximum clearing time in the case of a fuse operation or on the recloser's fast or delayed curve in the case of recloser operation. In addition, the I^2t of the fault event must be higher than the specified by the device manufacturer. The protective device which satisfies the above criteria is the one that operated to clear the fault" [22].

A. Estimating fault duration seen by protective device

"TCC curves of a protective device specify how fast the device responds to the OC fault condition. Most distribution protective devices have inverse time–current curves and hence higher the current magnitude faster the device reacts to it. The time duration during which the fault current flows in the device can be estimated directly from the faulted voltage and current waveforms. It is the duration of the voltage sag or the duration during the high current magnitude" [22]. The exact duration is determined by using existing feature estimating algorithms developed as part of DFA project in PSAL, Texas A&M University.

Figure 11 shows voltage and current waveform data in which fault current flows in the protective device between 0.024 and 0.057 seconds, which is 0.033 seconds.

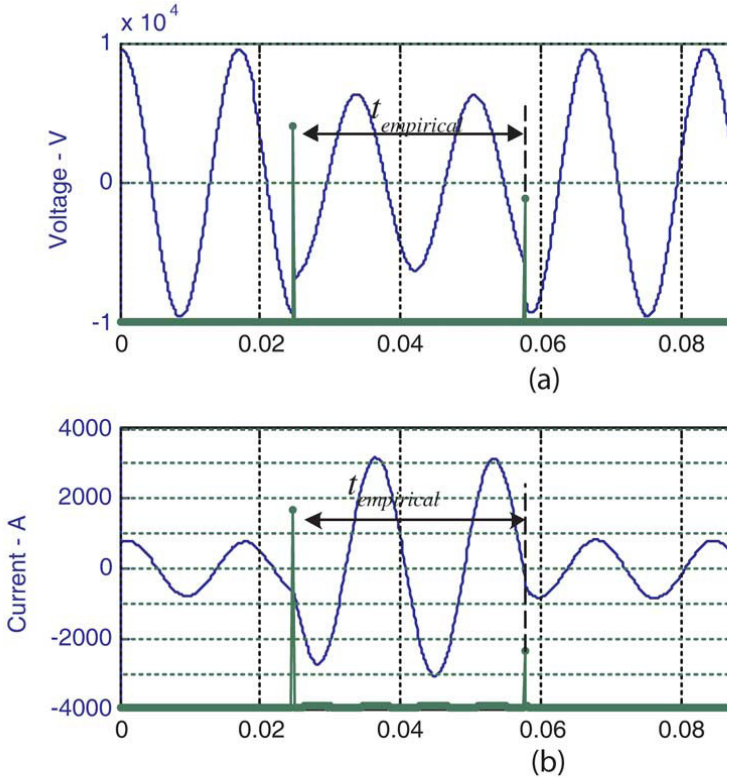

Figure 11. Voltage (a) and current (b) waveform for OC fault [22].

B. Estimating fault current seen by protective device

"Any protective device operation is directly proportional to fault current seen by the device. Since the voltage and current waveforms are measured at the substation, the current seen by the protective device needs to be estimated. But if measurements are at the bus level, the load current can be sizeable relative to the fault current. Hence we need to separate the load current from fault current" [22]. Our existing algorithms developed as a part of DFA project accurately estimate the fault current, which is seen by the protective device during an abnormal event.

C. Estimating fault I^2t feature

"The minimum melting I^2t feature of fuse could be estimated from the above estimated current and duration of fault features as,

$$I^2t(\text{device}) = (I_{\text{device}})^2 \times t_{\text{device}} \quad (5)$$

This estimated feature needs to be higher than the minimum I^2t value specified by the manufacturer for a given fuse to have operated in response to a fault. The manufacturer value can be computed from MM curve data of the fuse" [22].

IDENTIFICATION OF RECLOSER OPERATIONS

"In a fuse saving scheme, a recloser operates to save the fuse from melting in case of a temporary fault. But for a permanent fault, the fuse blows and clears the fault. The recloser operations can be identified by comparing the device operating point estimated as above to the recloser fast and delayed TCC curves. This can be done by determining the time corresponding to the fault current seen by the protective device using an interpolation technique. Due to the inverse relationship nature between the current magnitude and duration, the TCC curve can be easily approximated using an exponential function where the argument of the function is a fourth-order polynomial function of the natural logarithm of the current flowing in the through the device, which is,

$$t = \exp\left(\sum a_n (\ln I)^n \right) \text{ where } n = 0 \text{ to } 4 \quad (6)$$

Here both I and t are obtained from manufacturer specified TCC curve data. The $t_{\text{recloser-fast}}$ is point on the recloser fast TCC curve data. Given the many recloser details for a utility, this $t_{\text{recloser-fast}}$ is computed for all the reclosers. The minimum difference that a

$t_{recloser\text{-}fast}$ computed from the actual t_{device} estimated as above is the actual recloser operated in response to the fault. The similar procedure is followed for slow curve when the recloser operates in delayed curve region. The time of operation of a recloser in slow curve is denoted as $t_{recloser\text{-}delayed.}$ Fuses that coordinate well for a given recloser are chosen based on identified recloser's TCC curves. The TCC curve of the fuse should be with in the reclosers fast and delayed curves" [22]. Figure 12 shows the fuse coordination with recloser. If the fuse's estimated operating point on MM and TC for this operating current are between the reclosers' fast and delayed curves, then that indicates the match for fuse that coordinates with recloser. 10% to 12% adjustment needs to be done on TCC of fuse before the matching to account for any tolerance errors of the device.

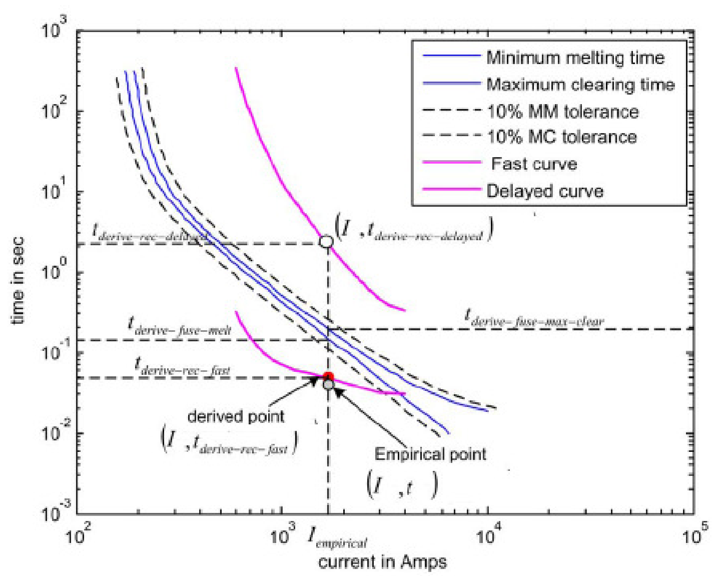

Figure 12. Coordination of downstream fuse with upstream recloser [22].

IDENTIFICATION OF FUSE OPERATIONS

"Whenever a permanent fault occurs, a fuse should blow to isolate the faulted section from the rest of distribution network. The t_{device} estimated should be with in the fuse MM and TC time for the given I_{device}. This matching is verified by estimating the $t_{fuse-melt}$ and $t_{fuse-clear}$ for the given fault current. Figure 13 shows such a match.

$$t_{fuse-melt} <= t_{device} <= t_{fuse-clear} \quad (7)$$

When we have many fuses satisfying the above criteria, especially for high value of fault currents due to overlap of TCC data of fuses, both the match using equation (7) and match with I^2t criteria estimates the exact operation of fuses" [22]. Even then some of the fuses overlap and thus cannot be accurately identified by this approach. In future work, the author plans to implement fuzzy logic to give weights for each fuse and develop fuzzy rules for exact identification.

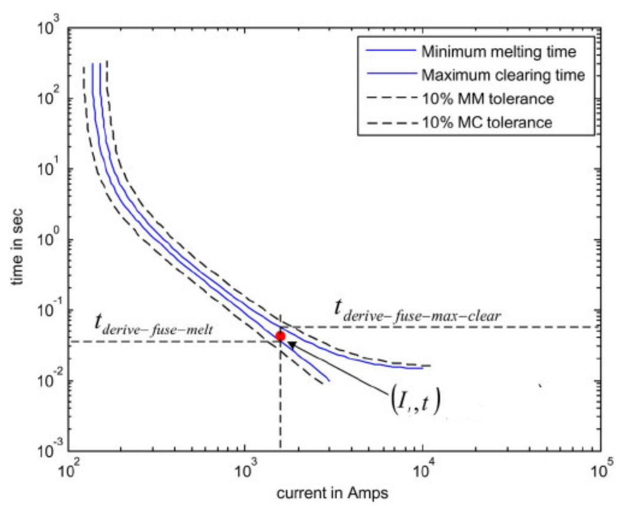

Figure 13. Matching fault point to fuse operation [22].

In this chapter, importance of device estimation and author approach in identifying fuse and recloser operations during overcurrent fault conditions was presented. In the next chapter, software implementation of the algorithm is presented.

CHAPTER V

SOFTWARE IMPLEMENTATION

Software systems developed for power systems are much complicated because of use of function-oriented development methodologies. In these methodologies, the emphasis is given to functionality and hence overall application is built over by many application modules which makes the software system to be unmanageable and necessitates expensive maintenance. But the use of object oriented design methodologies has proven track record of supporting future enhancements and ease of maintenance [35]. In this methodology, development consists of three different stages - analysis, design and implementation. During each of this stage, we use three different kinds of models to represent the system: object model, dynamic model and functional model. The static structure of objects in the system and their relationships are represented by the object model, aspects that change over time are represented by dynamic models and functional model presents the data transformation of the system. Although the complete description of software requires explanation of all the three models, only the object modeling is addressed here which forms the basis of implementation. The primary purpose of object modeling is to represent objects, which binds data and behavior in to single entity. The objects with similar properties, operations and relationships to other objects are grouped in to a class. Table 2 presents the “BranchDevice” class. There exits three different types of relationships among the different objects namely, inheritance, association and aggregation.

Table 2. Class with attributes and operations.

BranchDevice
fromBus toBus current Impedance PowerLoss

Inheritance provides powerful abstraction while sharing similarities among classes but preserving their individual differences. Inheritance represents the relationship between a class (base class) and its one ore more refined versions (sub classes) [35]. For example, "BranchDevice" class is the base class "Line" class which is further inherited by "OverheadLine" class. Attributes of "BranchDevice" class like fromBus, toBus, and current will be shared by the sub classes. Association represents the conceptual physical connection between the classes. This is the one that will be represented in database as one – one, one – many relations. Aggregation is special form of association that represents the "part-whole" relationship [35]. For example, "Substation" is composed of "Bus", "CircuitBreakers", "Reclosers", "Fuses" and other objects. The class diagram of "Device" class is illustrated in Figure 14.

Relational model used in this framework is combination of exiting relational databases of DFA project and few new tables to represent the device data. Table 3, Table 4 and Table 5 illustrate symbol definition table, device table and curve table added in addition to existing database to model the protective devices. Data for various protective devices like fuse, reclosers and circuit breakers are stored in these tables. The fuses have one-one relation in both device table and curve table, where as reclosers have one-one relationship with device table but one-many relationship with curve table.

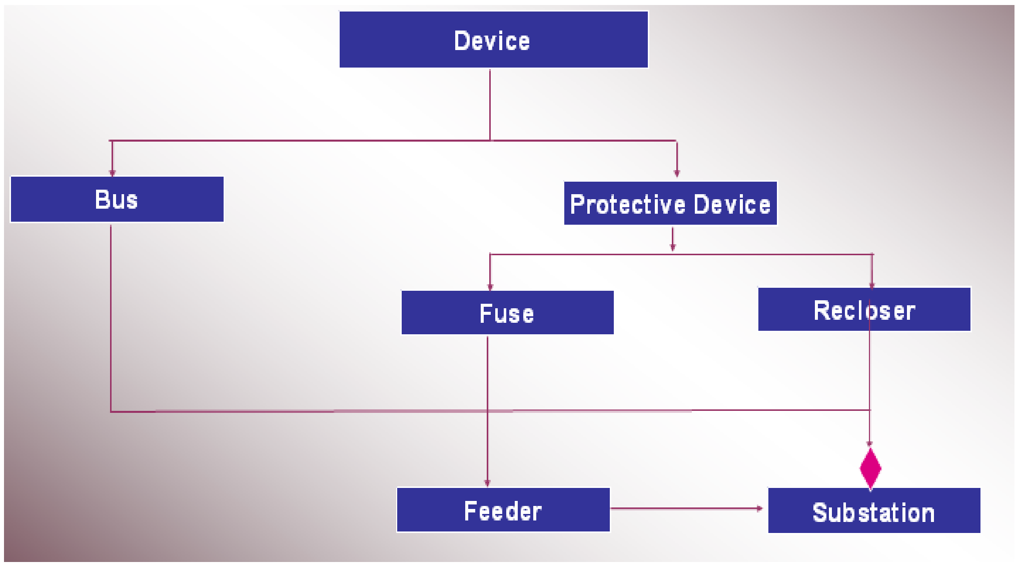

Figure 14. Class diagram of developed object model.

Table 3. Symbol definition.

Symbol	Definition
P	Pointer to object of type component
s_curve	Pointer to an object of type protective curve
s_device	Pointer to an object of type protective device

Table 4. Device table.

Variable	Definition of column content
Code	User defined name
DeviceID	Unique identification of protective device
Type	Whether device is relay, recloser, or fuse
Family	Associated family of curves
Curve	Number for starting row in curve table that has the curves associated with the device
Current	Continuous current rating
Interrupt	Interrupting rating

Table 5. Curve table.

Variable	Definition of column content
Selector	Name used in curve selection
CurveID	Unique identification of device curve
Type	Whether device is relay, recloser, or fuse
Family	Associated family of curves
Lower	Number of points in first curve stored
Upper	Number of points in second curve stored
CT[i,j]	Two dimensional array that stores the data points of the curve

The details of protective devices used in the distribution network are obtained from utility companies. The manufacturer's curve data for these devices are stored in this relational database in Microsoft Structured Query Language (SQL) Server. The fault data captured in DFA project are stored in the existing databases in Microsoft SQL Server. The existing algorithms developed by researchers in PSAL, compute the necessary parameters like fault current, fault duration and writes them in to existing DFA database. The algorithm presented in chapter IV was implemented in Microsoft C# using object models described above and uses the features written by existing DFA algorithms as input parameters and tries to match with curve data by computing minimum distance for the operating point identified as explained in Chapter IV. Implementation is a two tier model where the data resides in SQL data tier and business tier written in Microsoft C# performs the necessary computation based on device coordination and fault operating point. Results will be written to a text/log file. The use of Microsoft C# helps in future enhancement to web based application.

In this chapter, object oriented software implementation of device estimation was presented. In the next chapter, some of the test cases and results obtained by using the authors approach will be discussed.

CHAPTER VI

RESULTS AND DISCUSSIONS

The device estimation algorithm was implemented in object oriented software framework and evaluated using simulated and actual test data. “Simulation data are generated using Matlab with 12-MVA substation transformer (115/12.47 kV) that serves three 12.47-kV main feeders. The voltage and current measurements are taken at the secondary of the transformer. Therefore, the measured current is the total load current of all the three feeders. The total load on each feeder is approximately 3.2 MVA with a power factor of 95%” [22]. The device models are developed using the approach discussed in [31].

CASE A

“In this case, recloser operation will be simulated in which phase ‘A’ pick up element recognizes the fault. With assumption that there exist fuse saving scheme, a temporary single line to ground fault is simulated on single phase lateral tap off the main feeder. The lateral is assumed to be protected with 65 T fuse link and recloser on the main feeder. The recloser (three-phase trip and three-phase lockout) has phase and ground pickup currents of 560 A and 280 A, respectively. The recloser operating sequence is 2-fast and 2-delayed. In the simulation, the 560-A phase pickup relay was chosen to clear the temporary fault in two fast and one delayed operations. The simulated fault current flowing in the recloser was 2.1 kA, and it tripped after 0.04 s for its first fast-trip operation” [22].

Using the approach discussed in Chapter IV, analysis was carried out. "Duration and magnitude estimates of the fault current are t_{device} = 0.041 s and I_{device}= 1.95 kA respectively. These quantities match reasonably well with the values obtained directly from the simulation. These quantities are then used to determine the recloser operating point and compared to the recloser TCC curves. The results indicate the recloser that matches the device operating point is a recloser with a phase pickup current of 560 A. Further analysis clearly shows that fuses that coordinate well with the reclosers are 65 T, 80 T, 100 T, and 140 T respectively. But we used only 65 T in the simulation and hence we get the match to 65 T fuse link" [22]. Figure 15 shows recloser and fuse estimation.

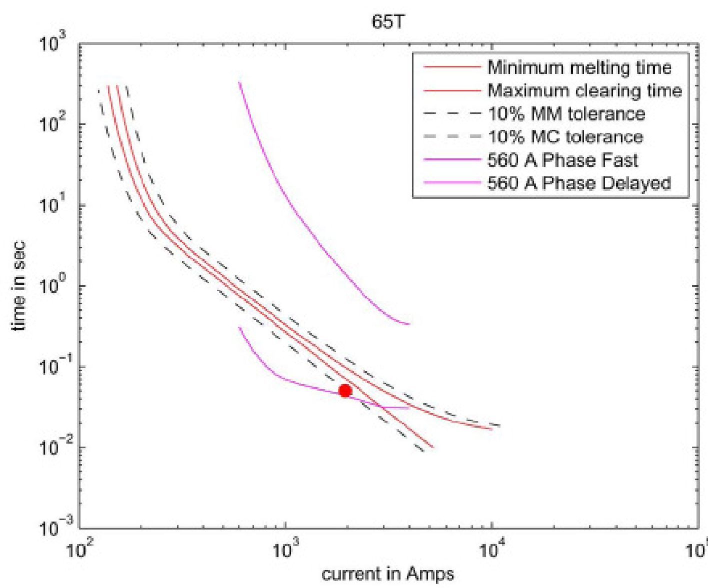

Figure 15. Recloser estimation with 65 T fuse coordination [22].

CASE B

“We assume there is fuse blowing scheme and a permanent fault occurs on the single phase lateral feeder which is protected by 65 K type fuse link. The actual current flowing through the fuse is 1.96 kA and blows after 0.032 s according to its 65-K TCC curve” [22]. Using the approach discussed in Chapter IV, the estimated current magnitude and duration seen by the fuse are 1.99 kA and 0.0325 s. “The analysis reveals that the device operating point can lie between TCC curves of more than one fuse. If the manufacturer’s tolerance is not included in the TCC curves, one of the following fuses would operate: 50 K, 65 K, 30 T, and 40 T. When the manufacturer’s tolerance is included, two additional fuses 40 K and 25 T are also possible. We have only 65 K connected and hence the device is identified correctly in our case” [22]. Figure 16 shows all of these fuses with device operating point.

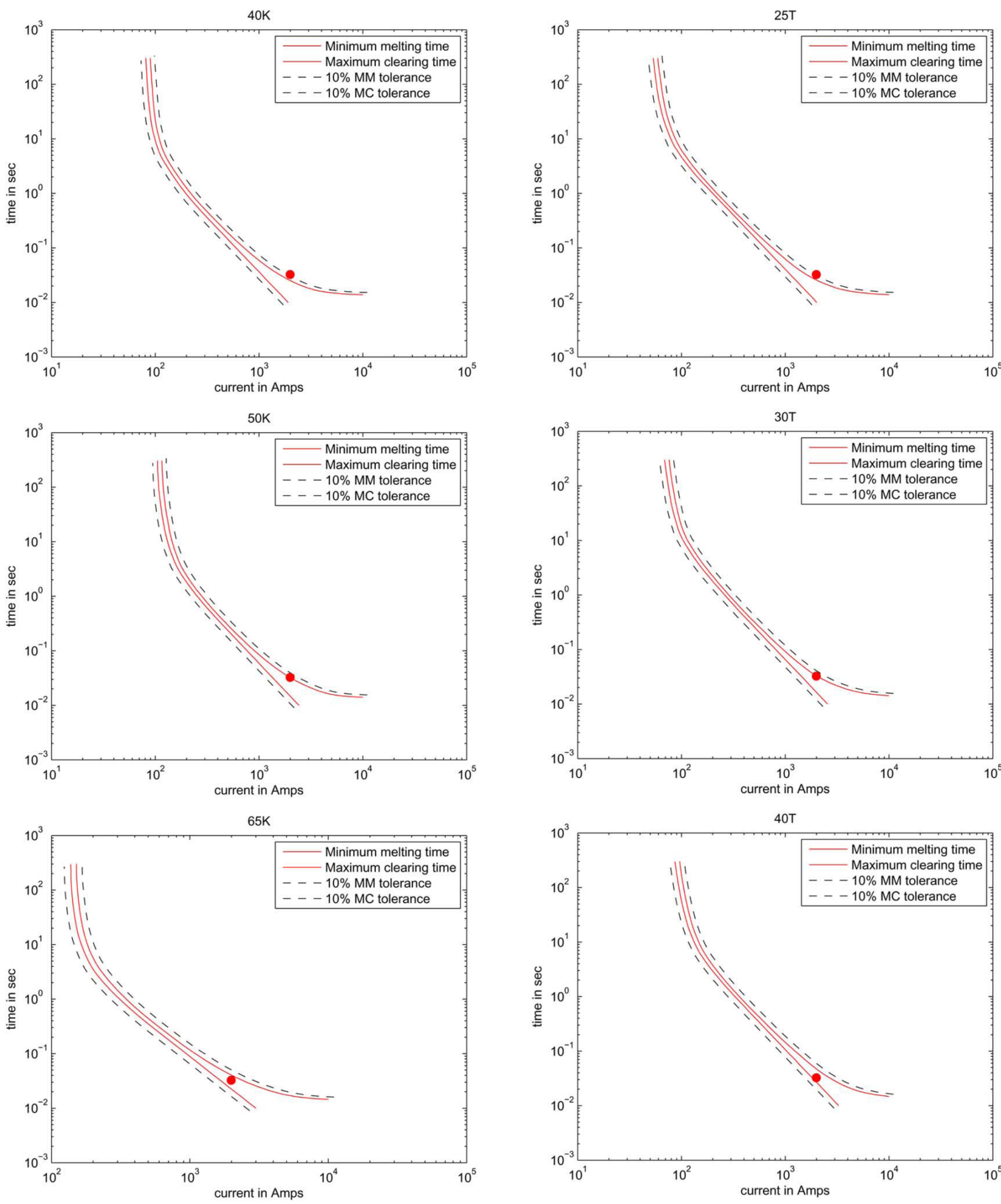

Figure 16. Fuse estimation [22].

CASE C

Several actual disturbance data collected from the utilities are analyzed using this method of estimating the devices. Table 6 shows the number of events analyzed and results obtained in device estimation using this approach.

Table 6. Actual OC fault data captures – Device estimation analysis.

Utility	Substation	Number of OC faults analyzed	Number of exact matches of devices
Northeast Utilities	Bloomfield	40	33
	Long hill	7	5
Keyspan	Commack	22	16
Southern company	Clairmont	24	16
TVA/Pickwick	North Adamsville	24	19
Oncor electric delivery	Hackberry	15	14
BCHydro	Whiterock	20	16
	McLellan	30	22
MidAmerican energy	SubQ	50	38
ConEd	Port Richmond	10	10
	Woodrow	10	7

In this chapter, several simulated and actual test scenarios and results were presented. The results are encouraging and show opportunity for improvement in the algorithm's for better estimate before deployment to the field. The next chapter presents conclusions and the scope of future research.

CHAPTER VII

CONCLUSIONS AND FUTURE WORK

A protective device estimation framework has been developed using protective device manufacturer's data and features estimated during fault conditions to identify the operation of protective devices in response to faults. Estimation and analysis techniques are proposed to detect and identify fuse and recloser operations on distribution feeders. These techniques are intended to further evaluate performance coordination of overcurrent protective devices and help locate faults on the feeder. This diagnostic framework needs waveform data collected from the substation, feature estimates during fault conditions, the utility fault-clearing scheme, and TCC's of the different protective devices. Feeder topology is not needed for analysis. As the analysis is only based on the current and voltage measurements at the substation, this new scheme can be used for almost all distribution systems. Also, the different test cases presented show the effectiveness of the technique. Results are promising and show that further improvements to the algorithms could lead to real world use. However, there exist uncertainties in identifying closely related devices when all of their operating points match the calculated operating point. These uncertainties can be modeled by fuzzy membership functions which should be considered in future research.

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VITA

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