Substation Fault Analysis Requirements

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***Abstract*—Substation automation has critical role in power systems. Substations are responsible for protection, control and monitoring functions that allow robust routing of power from generators to loads through a complex network of transmission lines. With the latest technology development, many intelligent electronic devices (IEDs) available in substations today are capable of performing enhanced functionalities beyond what their basic function is. This brings an opportunity for adding new functionalities that go well beyond what the traditional substation automation solutions have provided.**

***Index Terms*—substation automation, expert system, fault location, genetic algorithm, intelligent electronic device, neural network, power system monitoring, substation measurement, sampling synchronization, asset management, alarm processing.**

I. INTRODUCTION

Various types of users in the utilities may benefit from substation automation: operations, protection, asset management, market operations, etc. In order to achieve such benefits, new concepts of substation automation have to meet the following expectations:

- Local protection concept needs to be enhanced to simultaneously improve dependability and security
- Substations need to be interfaced directly and through coordinating centers for better system-wide protection
- Data from IEDs needs to be merged with data from SCADA to enhance monitoring capabilities
- Condition based data from substation IEDs needs to be utilized for failure rate assessment of assets
- Local automated analysis needs to be coordinated with centralized analysis to cope with N-m cascades
- Control actions need to be defined hierarchically from substations to control centers for best outcome
- Monitoring and reporting of disturbances needs to be automated to meet recent NERC standards

This paper summarizes requirements for automated fault analysis functions that may be performed in substations in the future. Particular focus is on requirements for implementing a new concept of merging operational and non-operational data with a goal of improving fault analysis. The requirements are aimed at expanding the substation automation role in automated fault analysis towards better serving many utility groups: operations, protection and asset management.

II. BACKGROUND

To better understand the requirements for automated fault analysis in substations, several research efforts were undertaken, many of them still on-going:

- A solution for automated merging of data captured by digital fault recorders (DFRs), digital protective relays (DPRs), and circuit breaker monitors (CBMs) is developed [1-10]
- A concept for detecting, classifying and mitigating cascading events based on local and system-wide monitoring data is demonstrated [11-14].
- An optimal fault location algorithm that uses data from substation IEDs, as well as data from SCADA PI Historian and simulation data from short circuit program is implemented [15-25]
- A risk-based asset management methodology for maintenance scheduling taking into account condition-based data captured by substation IEDs is being developed [26-29]
- An intelligent alarm processor approach to take advantage of enhanced protective relay data in explaining cause-effect relationships between alarms is proposed [30-32]
- A Neural network based protective relaying scheme that enables simultaneous enhancements in dependability and security of transmission line protection is envisioned [33-37]

III. AUTOMATED FAULT ANALYSIS REQUIREMENTS

The conducted research resulted in several potential and demonstrated requirements brought forward by advanced substation automation and fault analysis solutions:

- *Operator efficiency*: automated fault analysis of events, which increases speed of drawing conclusions leading to better staff decisions, reduces time of restoration
- *Assessment accuracy*: fault location and asset management functions will increase quality of conclusions related to maintenance and restoration
- *Operator awareness*: intelligent alarm processor combined with optimized fault location gives more comprehensive view of the faults and consequences

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- *Equipment operations*: automated analysis of faults and disturbances as well as circuit breaker operation using IED data, can offer better monitoring than SCADA
- *Protective relaying*: new approaches based on pattern recognition and accurate fault location are more dependable and secure than distance protection
- *Regulatory compliance*: as regulatory requirements from NERC standards are increasingly becoming more stringent, new solutions offer much more details about disturbances than ever before

IV. SMART GRID AUTOMATED ANALYSIS

A. *Automated merging of IED data*

Proper substation data integration and information exchange are the main requirements to enable full IED data utilization. The Fig.1 shows substation data integration conceptual diagram. The benefits of the IED data integration can be found in [1, 2]. Assuming that all devices are synchronized using Global Positioning System (GPS) of satellites or some other time synchronization technique (IEEE 1588) the first steps towards substation data integration were introduction of standardized file format, COMTRADE [3], and standardized IEEE naming convention [4]. By converting all data to the same format and using file naming standard it makes data transparent to adding new analysis functions. Other requirements to make this concept possible are assumption that substation data are collected automatically and integrated into substation database with system configuration data. The developed applications for processing data from DFR (Digital Fault Recorder Analysis-DFRA), CBM (Circuit Breaker Monitor Analysis- CBMA) and DPR (Digital Protective Relay Analysis-DPRA) use the integrated data from the database so that the vendor and product model specifics do not affects their implementation and further extensions. The detailed system solution is described in [5].

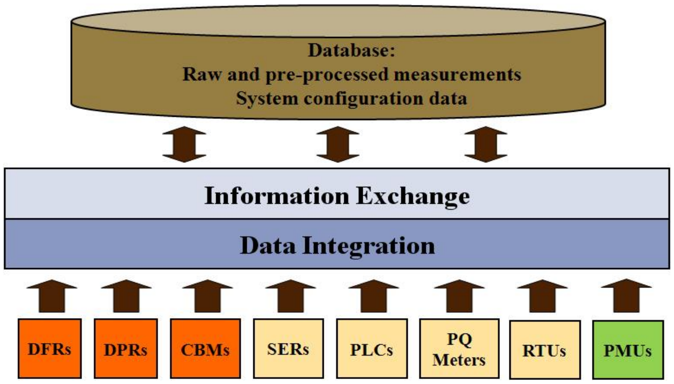

Fig.1. Substation data integration diagram

The following are examples of the automated analysis applications:

Digital Fault Recorder Analysis (DFRA) performs signal processing to identify pre- and post-fault analog values, statuses of the digital channels (corresponding to relay trip, breaker auxiliary, communication signals), fault type, fault location and faulted phases. It also checks and evaluates system protection, circuit breaker operations, fault location, etc [6, 7]. The software modules are shown in Fig. 2.

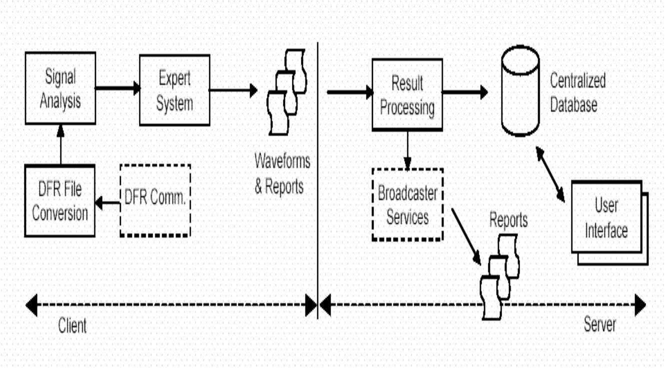

Fig. 2. Digital Fault Recorder Analysis

The Circuit Breaker Monitor Analysis (CBMA) performs analysis of data in COMTRADE format taken from the circuit breaker control circuit using a Circuit Breaker Monitor (CBM) and generates report in ASCII format that describes circuit breaker operating conditions and suggests repair actions [8, 9]. It enables protection engineers, maintenance crews and operators to quickly and consistently evaluate circuit breaker performance, identify performance deficiencies, and trace possible reasons for malfunctioning. CBMA software modules are shown in Fig. 3.

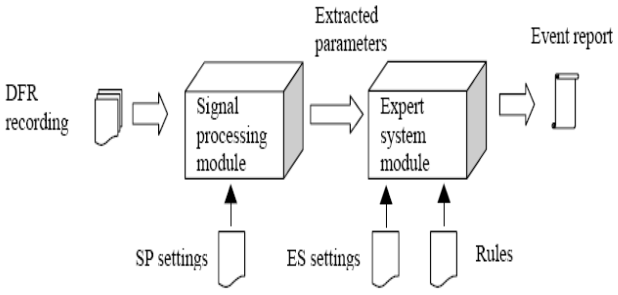

Fig.3. Circuit Breaker Monitor Analysis

The Digital Protective Relay Analysis (DPRA) is an expert system which automates validation and diagnosis of relay operation [5, 10]. It takes various relay reports and files as inputs and using embedded expert system generates a report on the results of analysis. Validation and diagnosis of relay operation is based on comparison of expected and actual relay behavior in terms of the status and timing of logic operands. DPRA software modules are shown in Fig. 4.

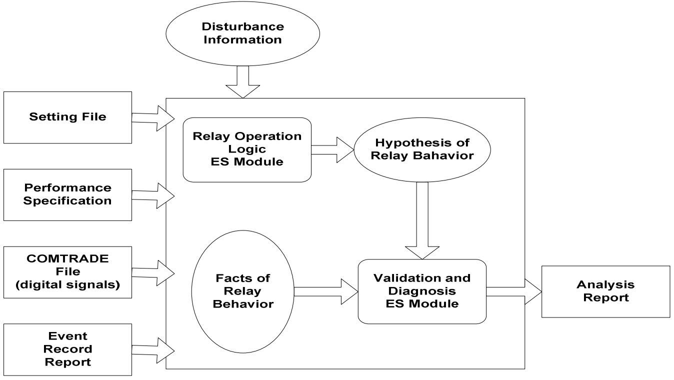

Fig.4. Digital Protective Relay Analysis

B. *Detecting and mitigating cascading events*

Power systems are exposed to many kinds of disturbances. Among those disturbances, cascading events draw special attention since they can cause great economic loss to utility companies and other businesses and devastating impact on people's life. Considering the large number of individual components it involves, the wide range of time scales of the event dynamics, and the different mechanisms of how the components interact, the detecting and mitigating of cascading events is extremely complex.

A new monitoring and control scheme for detection and mitigation of cascading events that coordinates the system-wide and local substation algorithms has been proposed [11]. The overall interaction is conceptually shown in Fig. 5.

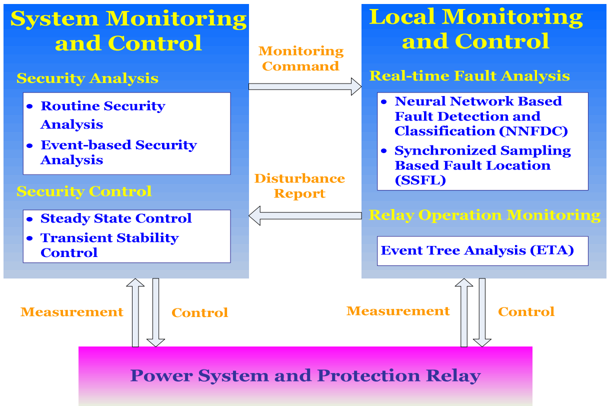

Fig. 5. Overall interactive scheme for protection

The system-wide monitoring and control tool can find the vulnerable elements and send request to the local tool for detailed monitoring. The vulnerability and security margin information can be obtained by Vulnerability Index (VI) and Margin Index (MI) [12]. Emergency control approaches for expected events can be found by the routine security analysis and activated when such events occur. Emergency control approaches for unexpected events can be found by event-based security analysis and activated to mitigate the disturbance and keep the system secure.

The local monitoring and control tool can find the exact disturbance information and make a correction if there is relay failure or unintended operation [13, 14]. Further information can be sent to the system-wide monitoring and control tool for better security control. The substation-based solution can provide the system-wide tool with local disturbance information and diagnostic support so that the system-wide tool can utilize local information to take better control action to ensure the secure operation.

C. *Optimal Fault Location Application (OFLA)*

Accurate location of transmission line faults is highly desirable to help find and repair the faulted line quickly. Traditional fault location techniques [15] require very specific measurements from one or both ends of the line to produce results with desired accuracy. In reality, measurements may be sparse as recording devices (DFRs or IEDs with DFR capabilities) are generally not installed at the ends of each transmission line (instead they are installed in critical substations only) and sometimes not all the DFRs installed may not be triggered by a fault. Although protective relays exist on every transmission line, most of them may still be electromechanical and they do not have capability to record measurements. Scarcity of measurements at the line ends require system-wide sparse measurement based fault location method [16], which may come from only some substations in the region where the fault has occurred.

An optimal fault location method which can obtain accurate fault location by selecting proper fault location algorithm from the following algorithms depending on the availability and location of the measurements is proposed: (1) Two or multiple-ended time-domain synchronized sampling [17], (2) Two-ended phasor-based asynchronized sampling [18], (3) Single-ended phasor-based [19] and (4) System-wide sparse measurement based [16] method.

1) *Implementation of the OFLA method*

The architecture of the OFLA scheme is shown in Fig. 6 [20]. Several commercial packages are used to implement this solution. The required data [21] are: (1) <u>System level data</u> which include power system model data (modeled using PSS/E^{TM} 31 [22]) and data reflecting real time changes in power system (SCADA PI-Historian data [23] at pre-fault) and (2) <u>Field data</u> which include event data recorded by different IEDs (DFRs) after occurrence of any abnormality.

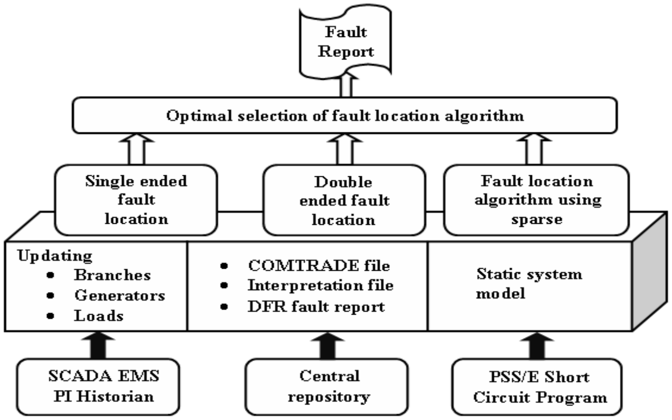

Fig. 6. Architecture of Optimal Fault Location Algorithm

The implementation of the software (using data captured by DFRs converted into information and integrated with system level data) should be done in the following step by step process [24]: (1) Extraction of phasors, (2) Synchronization of phasors, (3) Tuning the power system model with real-time power system conditions and (4) Choosing the appropriate algorithm to find accurate location of the fault.

2) *Evaluation of the OFLA method*

The software is implemented using Java programming language. To interact between PSS/E activities and Java programming language, IPLAN [25] language (part of PSS/E package) is used, which is able to modify the system topology, control the load flow and short circuit studies, and control the reporting of the results of the PSS/E activities.

The method was tested for real life test case provided by a utility where DFR data of two subsequent (5ms gap) phase to ground faults occurred in one circuit between two substations and PI Historian data (extracted in *.xls format) was provided for both of the substations for 10s time interval for a duration from pre-fault to post-fault. DFR triggered for only one substation for both of the faults. The DFR-resident algorithm could estimate the fault location for the 1st fault only while the new method estimated that accurately for both. The method is also robust as the same measurements may be obtained by multiple IEDs, which allows redundancy that can be explored to account for bad measurements. The method can be totally automated to perform quickly.

D. *Risk-based asset management*

For cost-effective maintenance scheduling of power system equipment, the problem may be formulated as follows: if it is the same availability of labor crews, and labor hours, and the given budget is constrained, how the maintenance decision needs to be optimized. A risk-based decision approach is proposed which suits best this kind of situation [26]. In this approach, the classic definition of 'risk' definition is adopted, which is the product of event probability and event consequence. Condition monitoring devices can be used to get informed about the equipment condition up to date, which plays major role in this approach. The 'Event probability' is updated after a specified maintenance action and risk is recalculated, and the difference is the direct result of that maintenance activity. Following are the definitions used to designate the risk in this section.

Event, E: 'Failure of a component or a group of components to operate properly'. Components can be line, breaker, transformer or bus bar.

Event probability, p(E): 'Probability that a component or a group of components fail to operate properly'.

Event consequence, Con(E): 'Impact of failure of a component of a group of the component on the system'.

Event risk, R(E): 'The product of event probability and event consequence'.

In order to evaluate the event probability, it is necessary to estimate the failure probability of all components involved in that event. The focus in this study is the circuit breaker but other components may be viewed the same way. The breaker data is basically a record of wave forms taken from the circuit breaker control circuit by using a portable or on-line recorder [27] while manually or automatically forcing a breaker operation. Signal processing and expert system modules developed in [28] can be used to extract the various features of the waveforms. Each of these extracted timing parameters is fitted with probability distribution and failure probability index is defined based on the probability distributions. The distributions and hence the failure probability index is updated using Bayesian approach as the new data comes.

First of all, define upper and lower limits for each timing parameters such that if new value of 't_i' falls in this range, then those part of breaker which cause the occurrence of time instant 't_i', operate properly. These limits are the expert settings used in developing automated analysis of CB operation as reported earlier [29]. Fig. 7 shows the probability distribution function of timing parameter t_2, result of Bayesian updating approach. The shaded area between the lower and upper limits is the probability that the breaker will operate properly.

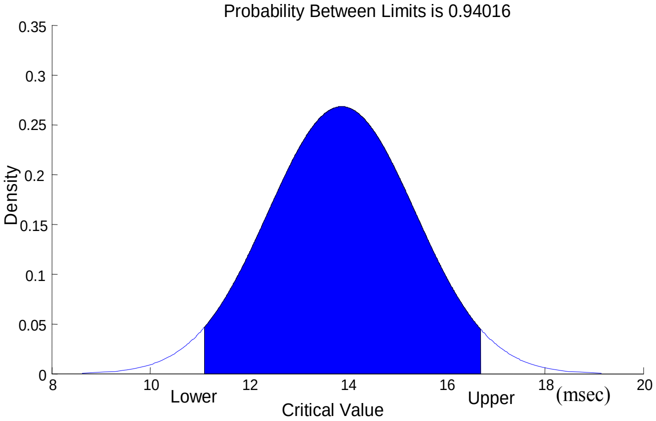

Fig. 7. Probability distribution function of timing parameter t_2

For the component to operate properly, all of the timings should fall into the specified interval.

$$P_f(B) = 1 - \prod P(t_i) \qquad (1)$$

Note that this failure probability is different from the failure rate or failure frequency often used in reliability index. Now, the event probability is computed as the product of failure probabilities of components involved in that event.

To illustrate the impact of the event on the system, two different scenarios are considered: single and multiple contingencies. Single contingency involves fault on bus bar, line, or breaker. Multiple contingency involves failure of more than one component. In conclusion, for both scenarios, the event consequence term can be divided into four parts: loss of load, loss of line, loss of generator and repair cost. The total consequence is the summation of their costs.

$$Con(E) = Con_{load} + Con_{line} + Con_{gen} + \text{RepairCost} \qquad (2)$$

Based on the risk concept associated with the product of event probability and event consequence, a maintenance scheduling is proposed. According to the risk number of components, a maintenance schedule for equipment can be defined.

E. *Advanced alarm processor approach*

A major power system disturbance could trigger hundreds and sometimes thousands of individual alarms and events [30]. For the case in this paper, there were 2125 alarm messages pop up within only 45minutes.

The alarm diagnosis algorithm and model have been illustrated in [31, 32]. The protection system configurations for sample test cases are shown in Fig.8 and Fig. 9 respectively.

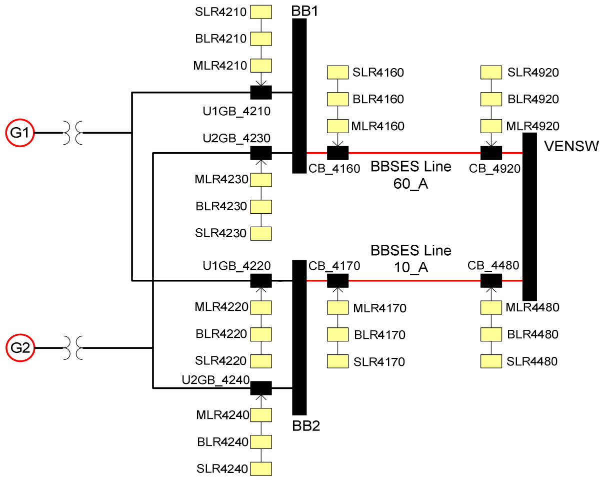

Fig.8. Protection System Configuration Diagram

The system consists of 9 sections, including 3 buses, 2 generators and 4 transmission lines.

The logic reasoning method uses the relay status obtained from the online-database to validate each candidate fault section. The strategy is to build one diagnosis model for each section of the power system. Each model establishes reasoning starting from a set of SCADA data to the conclusion of fault occurrence on its associated section with certain truth degree value.

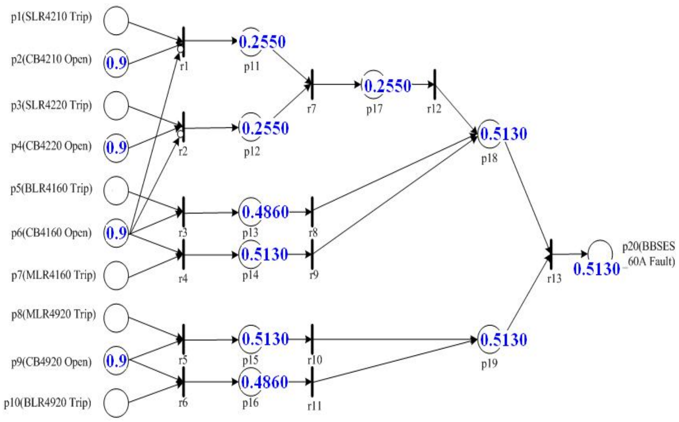

Fig.9. Model Analysis Procedure for Line BBSES_60A

<u>CASE 1</u>: No protective relay signals. Circuit breaker CB4210, CB4220, CB4160, CB4920 status changes are detected.

Diagnosis result: Line BBSES_60A is faulted, and its truth value is 0.5130.

<u>CASE 2</u>: The operation of the circuit breaker is caused by tripping by the associated relays, thus allowing the relay status to be obtained to validate the fault. The assumption is that the relay trip signals related to this case are available. All the devices worked correctly with no false signals. Circuit breaker CB4210, CB4220, CB4160, and CB4920 are detected.

Diagnosis result: Line BBSES_60A is faulted, and its truth value is 0.8550. With the input of the related relay signals, the fault certainness has been increased dramatically.

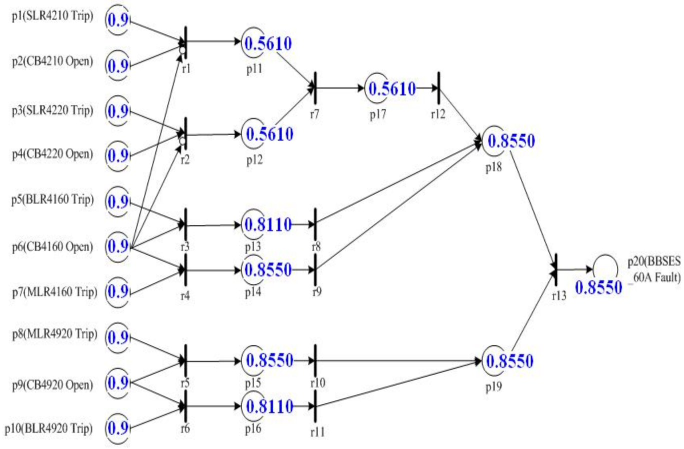

Fig.10. Model analysis procedure for Line BBSES_60A_with_assumed_relay_data

F. *Neural network based protective relaying*

The neural network based algorithm classifier is used to detect and classify the disturbances that require protective relay action [33, 34]. Comparing with traditional method, this neural network based fault diagnosis algorithms uses the time-domain voltage and current signals directly as patterns instead of calculating phasors. This neural network based protective relaying scheme compares the input voltage and current signals with well-trained prototypes instead of predetermined settings, which enables simultaneous enhancements in dependability and security of transmission line protection.

A self-organized, fuzzy ART neural network based fault detection and classification algorithm has been developed, which is conceptually shown in Fig 11. [35, 36]

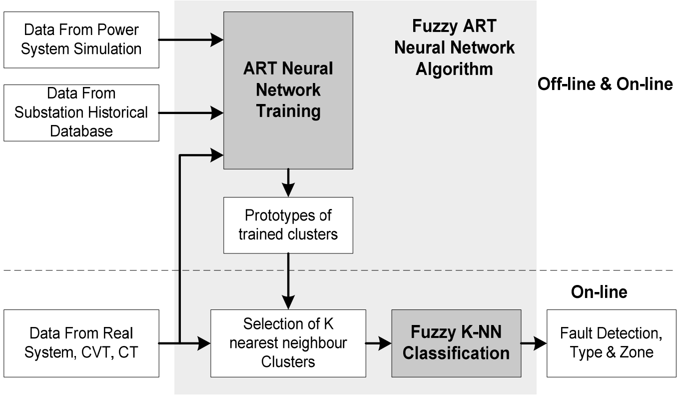

Fig. 11. Fuzzy ART neural network algorithm

The neural-network training uses a mechanism of clustering technique with combined unsupervised and supervised learning. Voltage and current signals from the local measurement are formed as patterns by certain data processing method. Thousands of such patterns obtained from power system simulation or substation database of field recordings are used to train the neural network offline and then the pattern prototypes are used to analyze faults on-line by using the Fuzzy K-NN classifier. The more details about this can be found in [36, 37].

V. ACKNOWLEDGMENT

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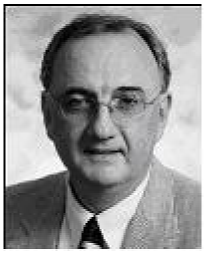

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