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New Trends for Automated Fault and Disturbance Analysis

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Executive Summary

This report deals with automated fault and disturbance analysis in power systems. It is assumed that utilities have intelligent electronic devices (IEDs) installed in most of their substations and that data corresponding to the faults or disturbances is recorded when the events occur. Automated analysis includes automated extraction of data, as well as the required processing to identify properties of the events: time, type, duration, location (for faults), impact, etc. The analysis also provides the understanding of cause-effect relationships between the events and automated reaction of the equipment. As an example, the analysis points out whether the event is a fault or not, and if it is a fault, whether the corresponding relays and circuit breakers operated correctly.

The report starts with a justification why automation may be needed. Multiple reasons are outlined: improving power system reliability, enhancing personnel productivity, providing faster response time, enabling efficiency in handling data, building better knowledge from statistics of historical data, meeting regulatory requirements, increasing return on investment, coordinating multiple utility personnel groups.

The report then focuses on three important questions: what is the present status, what are the future needs, and what are the requirements for future solutions. The discussion of the present status illustrates several disadvantages of manual analysis, points out some existing applications of automated analysis, gives description of the data needed for analysis, and defines various levels of automation. The future needs are focused on extending the protection system analysis, using expanded data from multiple IEDs, and engaging a variety of utility personnel groups. The requirements for future solutions point out that the level of automated analysis may be quite different starting from the equipment associated with the substation bay and then building up the complexity across a substation, across several substations in a given system, and finally across multiple power systems operating in an interconnection.

The final section deals with the implementation issues. Based on past experiences, many constraints in pursuing implementation are noted: personnel, equipment and project management. A deployment strategy that assumes several important features is suggested: time tagging and synchronized sampling of data, automatic collection of data from IEDs, and automation of the analysis tasks. The use of standards is highly recommended, but it is explained that the standardization of automated analysis requires development of new standards in addition to the use of the existing ones.

The conclusions indicate that automated analysis of IED data is feasible and desirable. The requirements for such systems to become a widely-used solution in the future are: The system deployment requires significant effort of diverse utility personnel groups to develop the best specification, it demands certain improvements in the wiring and communications for substation IEDs, and it imposes future maintenance efforts to keep it up to date and fully operational at all times. While the mentioned efforts require significant time and investment, the returns seem to be quite rewarding since many utility performance indices and business indicators may be positively affected. It is expected that such systems will be required in the future for the utility personnel to be able to deal with the “explosion” of data coming from the variety of IEDs that are being added to the substations across the world. The regulatory bodies may require the level of reporting for fault and disturbances that can only be efficiently met with the automated systems.

The report provides in the appendix three examples of the automated analysis systems recently developed by a utility company, a commercial firm and a university. Basic characteristics of each system are described.

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1 Objectives

1.1 Introduction

The goal of this report is to serve as a guide for the application of automated fault and disturbance analysis systems. The purpose is not to cover the design issues because it is understood that the technology may evolve making particular design solutions quickly outdated.

The complexity of power system operation is increasing and automated analysis contributes to more reliable and faster assessment of disturbances and faults, which is critical for improving power system performance [1]. The requirements of automated analysis systems should consider integration of data from many points in the power system and should call for standardization efforts to reduce the cost of future implementations.

Typically an analysis is performed after detection of a possible fault or disturbance in the power system. The analysis objective depends on the user's interest, but in general is aimed at understanding the causes of the events of interest and consequences related to power system operation. This understanding can improve practices through appropriate adjustments in the system operation or through identification of the equipment performance issues. The analysis of faults and disturbances is highly dependent on information that can be obtained from the power system recordings and models [2].

Automated fault and disturbance analysis is the ability of computers to correlate available data about faults and disturbances, yielding information that is more useful than raw data. The automated analysis is a step beyond automatic data gathering. Typically, data used for automated analysis comes from substation Intelligent Electronic Devices (IEDs) such as Digital Fault Recorders (DFR), Sequence of Event Recorders (SERs), Digital Protective Relays (DPRs), Phasor Measurement Units (PMUs), Power Quality Monitors (PQMs), etc. Data available from the field through Supervisory Control and Data Acquisition (SCADA) Systems, and Energy

Management Systems (EMS) is also used. The system configuration (switch positions, line compensation etc.) and system design (current and power limits, transmission lines impedance values etc.) data, as well as data from Lightning Detection Networks or Satellite Images may also be used. A variety of IEEE and IEC standards are used to support gathering of such data [3-6].

This report builds on results reported by various CIGRE Working Group such as B5-3 and B5-9 as a background for understanding the basic data recording and analysis requirements [7, 8].

1.2 Why automation?

As power systems' complexity increases under stressed power system operating conditions, the need for analysis increases. A variety of monitoring equipment may be used to facilitate the analysis results [9].

The complexity comes from ever increasing number of the measurement points of interest introduced by the monitoring equipment, as well as from the need to integrate such data.

Adoption of automated fault and disturbance analysis is driven by economic and regulatory needs for the following reasons:

- It improves system reliability due to better assessment of system performance
- It enhances staff productivity though reduction of analysis time
- It enables a fast and accurate determination of the fault cause due to automated means.
- It helps more efficient handling of data through integration
- It facilitates developing a better knowledge of the system through collection of statistical data
- It meets regulatory requirements concerning capture and explanation of field-recorded data
- It increases the return on investment in recording equipment due to multiple uses of data

- It emphasizes a need for cooperation of different personnel groups for joint uses of the solution

Adoption of such systems comes with costs that must be realistically evaluated against the many benefits.

1.2.1 *Improving power system reliability*

In general, reliability is the ability of a system to perform and maintain its functions in routine circumstances, as well as in hostile or unexpected circumstances. Also, reliability is defined as the ability of a system or component to perform its required functions under stated conditions for a specified period of time. Reliability in the context of power systems has a wide impact since it affects the reliability of all the processes that use electricity from the power grid. In terms of automated fault analysis, reliability can be improved by proper use of results obtained from the data available from various IEDs [10,11].

Fast and accurate detection and location of faults on power system components (transmission lines, power transformers) or control devices (protection relays and breakers) can reduce outage duration and in turn reduce power system vulnerability to other contingencies occurring while the outage remains. As an example, finding fault location on transmission lines quickly, which may result from using specialized algorithms applied to IED data, can benefit system reliability by reducing time to find the faulty section on long lines.

As another example, data coming from various IEDs, including digital fault recorders, digital protective relays, power quality monitors and other with capability to produce oscillography recordings, can be used to improve substation state estimation. The system state estimator can be made more robust and accurate by improved capability to detect incorrect measurements or topology status information in substations. Detailed monitoring of the loading and switching conditions, that are not possible through today's SCADA solutions, can be obtained through using dedicated algorithms applied to IED data.

As the complexity of the power system grows, it gets increasingly involved to keep track manually of all malfunctions in protective relays, potential transformers (PTs), current transformers (CTs) and other devices in a fast and accurate manner. Such difficulty may create a situation where a major fault occurs at the same time when relay malfunctions (for example, due to defective transducers), and all of this occurs during peak load times leading to many serious consequences. Automatic checking of the health of the IEDs based on available data could pinpoint many control device malfunctions before they coincide with a power system fault. During the first months after the commissioning of a controller, some problems like phase permutation, loose contacts in measurement channels and polarity inversion in PTs and CTs can also be detected by automated analysis systems.

System operators would, in the past, take all decisions based on SCADA data. Nowadays more elaborate conclusions are needed, and more complex EMS systems are being developed and implemented to meet such needs. The general idea is to take advantage not only from operational data collected through SCADA data but also from non-operational data from other IEDs. Synchrophasor measurements are a promising new technology that can yield valuable information if used, for example, in system state estimators. DFRs can generate information about distances to transmission line faults and, also, they can help in verifying the correctness of SCADA measurements. Quality monitors, if used online, can detect incipient quality problems evolving in some part of the grid, enabling operators to pinpoint the source and take proper actions before a line needs to be disconnected. Some of the equipment does not store and transmit data on a regular basis such as remote terminal units (RTUs) of SCADA and modern IEDs do, but in a great number of cases, they can generate data fast enough to make a difference in system operation. Integration of different sources of data is facilitated nowadays by a number of standards applied to each kind of data being dealt with and by the use of data sampling synchronization through GPS systems.

1.2.2 *Enhancing personnel productivity*

When fault and disturbance analysis is carried out, a large amount of information may have to be accessed to reach the final conclusions. This work involves not only a high degree of smart thinking, but also a lot of repetitive work, like retrieving files, converting file formats and making simple calculations. With the advances in the areas of monitoring, communications and computers, a large amount of data, which can be obtained in near real time, can be used to help accomplish this aim. The large size of many power grids added to the fact that the number of disturbances increases as the power system gets more and more stressed, creates an overwhelming situation for the personnel involved in such a job.

Although there are fault situations that are so intricate that only human expertise will understand it, automated analysis can make a big difference when one consider dealing with processing a large amount of data to extract information. An important advantage of automated fault analysis is to help the personnel responsible for disturbance analysis in getting focused in the most important events by not spending excessive time in accessing relevant data and performing repetitive tasks. Other benefits are coming from receiving results, like fault location along transmission lines, automatically.

Another example is in automated power quality analysis. Power quality analysis demands the gathering and processing of a huge amount of data, identifying phenomena like voltage sags and swells, which is a repetitive and intensive data handling task. Automation greatly enhances the efficiency of this task.

The automation has economic impact in many areas, not only in the productivity of the involved personnel but also in better overall performance of the system. This is due to correct actions resulting from better and faster diagnostic of the fault and disturbance causes being done automatically, which are less prone to mistakes caused by human errors in performing repetitive tasks.

1.2.3 ***Providing faster response time***

In general, adopting automated fault and disturbance analysis helps determining fault causes, location and characteristics faster and more accurately. This happens because most of the work of correlating information is done automatically. The automation is limited only by communication networks and computer speed, which are becoming less restrictive as the technology develops further. Also, automated fault and disturbance analysis systems can help in discovering an incipient equipment failure timely before it can lead to a fault.

This change in the time frame creates a competitive advantage that results in a direct benefit for the customer since automation reduces the power system interruption time. With the increasing dependability of our society on electrical energy, a fast recovery after a fault can change positively the public perception about the companies' responsibilities for power system operation, particularly at the time when we are witnessing an increasing number of large scale blackouts. During such events, attention to the utility response during emergencies is more intensive. and not using automated disturbance and fault analysis systems may make the company look less responsive to the public needs and concerns.

1.2.4 *Enabling efficiency in handling data*

In order to put an automatic disturbance and fault analysis system into operation, better organization of related data is needed. This in general may require a change in business process, as explained next.

One of the characteristics of human beings is the capacity to perform their tasks using implicit knowledge, i.e., using some knowledge available to them but not explicitly stated in the data. As an example a file name may identify a set of data because it is known, by someone or by some persons that such name relates to a specific source of data. Novice users of the same data would get lost unless they become aware of that knowledge!

When shifting to an automated analysis system, all the data has to be well organized; every file or database has to indicate clearly the origin and the characteristics of the data it contains. This knowledge is a key feature for data correlation and an imperative task if automated analysis systems are to be used. This also facilitates retrieving data in an automated way substituting manual process used in the past such as retrieval of data from digital fault recorders. Other data that has to be put into explicit electronic format relates to the system configuration (switch positions, relay settings, amount of line compensation etc.) and system design (current and power limits, transmission lines impedance values etc.). Generally, when organizing this data, a lot of mistakes are corrected and the capacity for understanding faults increases.

A consequence of adopting automation systems for disturbance and fault analysis is the change in business process since the system operation tasks and cooperation among personnel in different areas gets better defined. For example, if fault location is automated, protection engineers can be relieved from the task of collecting DFR files and running fault distance algorithms in short time periods, which may require working overtime. If relay settings are put into a database and downloaded automatically to the relays, malfunctions due to accidental changes in relay settings can be virtually eliminated, making fault analysis more reliable.

The most important consequence of the more efficient process is that taking the decisions automatically offers more timely and reliably actions while avoiding human errors.

1.2.5 *Building better knowledge from statistics of historical data*

A complete knowledge of power system operation includes defining, obtaining and keeping an up-to-date set of statistical data derived from historical data. Automated fault and disturbances analysis systems can obtain and maintain up-to-date statistics of the system operation as a by-product.

An example is the statistics used for strategic or long term fault analysis, where data from each event is aggregated over time to draw a picture of system fragilities (like transmission lines sections or phases more prone to faults) or equipment degradation (like I^2t calculations in circuit breakers). Such planning is needed to perform preventive maintenance, pursue timely equipment replacement and plan for system expansion.

Statistics are also important in power quality assessment. Statistics about the time and frequency of interruptions are used for calculation of reliability indices like SAIDI and SAIFI.

Also, statistics can be used in operation planning to keep system reliability at acceptable levels. For example, an area where ground fires are frequent in the dry periods may be detected by observing an elevated number of transmission line faults. Predicting a possibility of losing certain transmission lines based on past statistics may be helping improve planning for generation dispatch, power exchange among involved areas and equipment maintenance. In addition, equipment maintenance and replacement can be better planned if fault information is organized to reflect equipment stresses and aging.

1.2.6 *Meeting regulatory requirements*

Regulator demands for information from utilities are increasing. It is almost impossible to deliver all the requested information manually. Automated fault analysis can not only help in making data available, but it can also help in creating elaborated results while reducing the time of human involvement.

For example, some regulators ask for DFR files from utilities when major faults or disturbances occur. For larger utilities the number of files can be enormous, and some kind of smart filtering is needed before the files that should be sent can be identified. The role of smart filtering may be to separate recordings related to major faults from those generated by recording errors or events unrelated to faults.

Statistics about protection systems may also be required and used by system regulators to access quality of the utility’s design, operation and maintenance of protection system. Statistics like number of protection misoperations can be obtained by an automated relay operation analysis system if needed

Interchange of data among companies for cooperative tasks may also benefit from analysis automation. Use of automated fault analysis systems may be enforced by regulation in order to guarantee almost real-time availability of data to all interested parties.

1.2.7 *Increasing return on investment*

After examining the many advantages and opportunities that drive the adoption of automated disturbance and fault analysis systems, it is important to account for the investments needed. If the cost is too high, it may make it impossible to implement or if the desired functionalities may not be met, the expectations to make the decision to proceed may not be fulfilled.

Let us take the example of the use of Digital fault recorders (DFRs) for monitoring transmission lines. The voltages and currents stored show the pre-fault and fault events. They are used mainly to determine fault location and understanding protection behaviour during the fault. In this task, data from both line ends is necessary and, in the case of fault location, fast retrieval of data files is expected. The cost for integrating the devices can be, in simple terms, summarized as follows:

- Old devices must be updated or replaced to enable for network communication and GPS synchronization
- A fast and reliable network communication must exist between the substation and central office where the files are to be analyzed

The cost for fast retrieval of data can be very high if a company needs to implement a fast network linking its substations and central office just for this application. In this case, data files can be obtained using a dialled phone line connection. If fast determination of fault distance is imperative, sampling rate and length of the recordings must be kept low or local processing must be performed. If the sampling rates are low and files are short, other kinds of analysis will not be possible: harmonic components need a higher sampling rate to be analysed while protection system behaviour (like teleprotection and reclosing) cannot be observed if the recordings are too short. If local processing is performed, it means that a computer must be used for gathering DFR data and sending the fault distance calculated from only one terminal to a higher level. It makes the fault location calculation more prone to errors and does not enable more accurate analysis of fault location using files from two ends of the line.

The final solution will depend on analysis of the real needs against the available budget. The important thing to keep in mind is that even with the simplest approaches, some benefits become readily available.

In general, the shift for automated analysis is not done at once, but follows a phased plan, in which the benefits achieved in each phase are evaluated to decide whether further investments are justified or not. Each company may judge how much automation is desired using different criteria. Phased implementations can benefit from aspects like:

- A technology becoming mature and device costs decreasing (like DFRs and IEDs).
- Need for replacement of control equipment due to aging (old electromechanical relays being replaced by modern digital devices) creates new data recording enhancements for fault analysis.
- New substation automation facilities being built with new data collection and transmission capabilities (e.g. substations designed according to IEC 61850 standard) or old ones being refurbished.
- Regulatory needs driving equipment replacement and changing operation procedures may create new opportunities to pursue further fault analysis implementation.
- Governmental or internal utility financial resources for modernization get allocated based on the demonstrated need for more comprehensive fault analysis.

Great attention must be taken when preparing the specifications of new devices because sometimes advanced features comes at low or no cost in some devices but are difficult to be upgraded in others. A bad choice in the original data recording equipment specification can delay or even prevent automated fault analysis from being used, or future needs from being fulfilled.

As shifting from the traditional to an automated approach may generate savings that justify the investment, the benefits must be carefully justified when proposing the adoption of an automated system.

1.2.8 ***Coordinating multiple utility personnel groups***

The automated approach produces results that may be utilized by different utility groups. In the process of specifying the requirements, different groups need to find common means of agreeing how the solutions are going to meet their individual goals. This results in a need to coordinate group activities and discussions. This interaction is quite useful for setting broader goals of how the investments and returns are viewed from a global company strategic standpoint. This allows revisiting the business models for dealing with improvements in data utilization across the entire enterprise, a topic that may not be resolved unless different utility groups come together to a common point of view. Since this level of coordination is not a common practice today, one may say that the automation solutions are acting as an incentive for introducing new practice in the group coordination across the entire enterprise.

1.3 Report overview

After setting the stage for the report scope and rational in chapter 1, the report gives in chapter 2 an overview of the current status of automated analysis systems, the common analysis tasks and approaches, the data needed to perform the analysis, and examples of existing implementations.

This issue of missed opportunities is explored in chapter 3 where a list of expected future needs, including requirements for analysis and data aimed to specific users in the power system business, is discussed.

Chapter 4 is dedicated to describing the functional requirements that are necessary to fulfill these needs. Specific analysis solutions for different levels of hierarchy in the power system are outlined. The levels of hierarchy are defined by the equipment grouping selected for the analysis focus, which may start with substation bays and include substation equipment, and then extend to groups of substations, entire utility and eventually encompass group of neighboring utilities.

Implementation analysis cannot be complete without comments on implementation constraints, deployment strategy and existing standards that can be applied to analysis automation as well as suggestions for future standardization and/or standard harmonization needs. This very important issue is discussed in chapter 5.

The report ends with a set of conclusions and list of references. The report contains two appendices, one with definitions of terms usually referred to, and other detailing three examples of the present use of data for fault analysis.

1.4 Conclusion

Automated disturbance and fault analysis is a key issue in the modern competitive electricity business. If well done, it can make positive impacts on the reliability of the power system operation and in productivity, as well as in the efficiency and response time of the company personnel, allowing for a return on the investments. The automated disturbance and fault analysis systems also yield by-products that can improve knowledge on the operational statistics and fulfill regulatory needs for more comprehensive field data reporting.

2 Present Status

2.1 Introduction

It is a common belief in the power industry that disturbance analysis is of great importance. As one author writes, “Any relay engineer worth his salt knows the importance of good analysis” [11]. However disturbance analysis may (or should) affect more groups in a utility than just the protection department. The objective of this section is to discuss what the task of fault analysis comprises, where a semi-automated fault and disturbance analysis task has been useful, what type of data may be used, and what the levels of automation are.

2.2 Basic disturbance analysis tasks

When talking about disturbance and fault analysis, there are a number of concepts that need to be defined. The definitions are included in Appendix 1, and the definitions are based on existing standards and recommended terminologies ([12-17] and [3]) with some narrowing interpretations. A power system disturbance may affect more parts of a utility, and one or more (overlapping) investigations of the disturbance may take place. The timeline of a power system disturbance and related analysis is shown in Figure 2-1.

It may be noted from Figure 2-1 that not all listed power grid operating conditions have to be reached to have a disturbance. For instance, if an overhead line fault is not permanent, then the repair of components will not be necessary. It must also be noted that the output of the fault analysis is at the component/unit level.

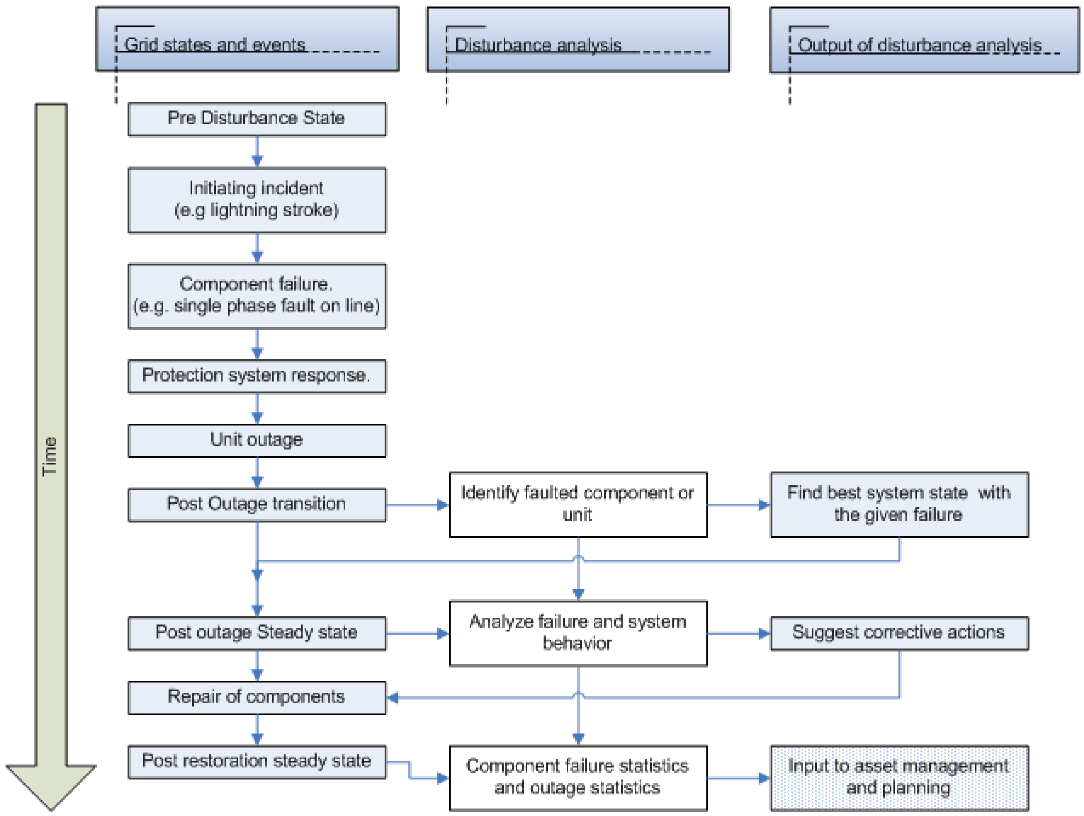

Figure 2-1: The timeline of power system disturbance and related analysis

Reference [7] states the fact that: "depending on the goal and on operational requirements, the processing of fault and disturbance data may take place in different time frames." Not only the time frames may differ, but also the wanted output of the analysis may differ as indicated in Figure 2-1, and the available input may also differ. Characterizing fault analysis along the time axis will give some additional insight for the users into desirable outputs of fault and disturbance analysis. It must be remembered that the separation between the different classes of analysis is not crisp, and there are a lot of borderline cases. In general, the analysis categories may be defined as follows:

- ***Operational (Short-term) fault analysis***

  This type of analysis is usually conducted by the operator in the control room. The purpose of this analysis is to decide what was a fault scenario or set of possible fault scenarios, thereby reducing the duration and the consequences of an event. The analysis may not have to be detailed. Identification of a "faulted component" may suffice to give the operator the needed input to decide on what may be the system restoration action. Up to now SCADA data has been used for this kind of analysis.

- ***Tactical (medium-term) fault analysis***

  This is what one usually refers to as "fault analysis". Protection engineers typically perform this analysis, and the purpose is to decide if primary and control equipment behavior related to a given event was correct. Protective relay and fault recorder data is typically used together with SCADA data. In some cases additional data gathering equipment like circuit breaker monitoring units, phasor measurement units or lightning monitoring system may also be used.

- ***Strategic (Long-term) fault analysis***

  This analysis involves aggregation of event data over time. For instance aggregation of distance to fault data for transient faults together with fault type may give input on where transmission line insulation and other construction elements may be improved. Another application may be to look at an I^2t energy integral for a breaker to give input to Reliability Centered Maintenance regarding the stress on circuit breakers. Outage statistics may be used for asset management to find the best choice for capital investment or operational expense. The strategic fault analysis depends on the results of the tactical fault analysis. If the tactical fault analysis does not store its results in a format that is usable for aggregation of strategic data, the strategic fault analysis will be difficult to perform and may result in guesswork.

It can be argued that an instant tactical analysis will make an operational analysis redundant. In the current context, the division in three "types" of analysis will give taxonomy of fault analysis which will be beneficial in discussing the different applications. In the next section the tactical analysis is discussed in more detail because of its importance to both operational and strategic analysis.

2.2.1 *Tactical fault analysis*

A dataflow of Tactical Fault Analysis as it is done by most utilities is depicted in Figure 2-2. It shows the many possible sources of data that can be recorded and transmitted for performing fault analysis. It must be noted that there are some cases where fault behavior is so complex that direct and close inspection of components and units is needed to verify assumptions based on available data, but such cases are out of the scope of automated systems and will not be considered herein. Figure 2-2 also shows the data resulting from the Tactical Fault Analysis.

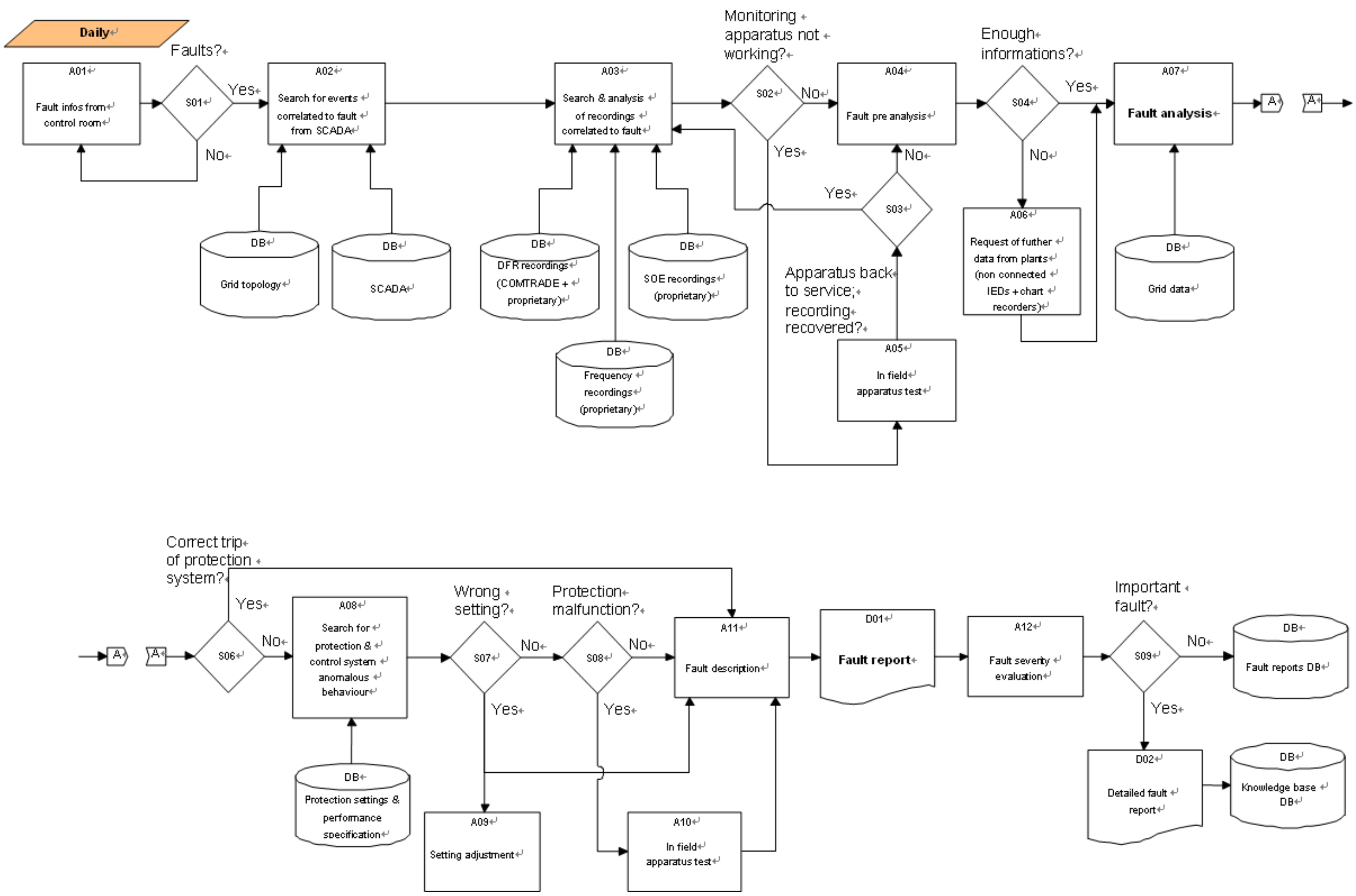

Figure 2-2: Dataflow analysis for an automated fault analysis system

Once the faulty condition is asserted, a search for field recorded data starts. The first place to search is the SCADA database. Also data from DFR recorders, frequency recorders and SOE recorders if available are used. One of the problems that can arise in the analysis is a malfunction in one or more recording devices, which can cause loss of key data needed for understanding the fault event.

Pre-fault conditions can, in some cases, explain the occurrence of faults. Examples are the presence of high level of harmonics, indicating a possible mitigating action due to the presence of harmonic components, or the presence of a power factor high enough to disrupt the system.

Fault analysis will help the understanding of the fault consequences, but to find the causes, it is sometimes necessary to look for a malfunction in power apparatus, as well as the protection and control devices.

Finally, the results are consolidated into a fault report that is archived. Prior to this, depending on the fault severity, additional reports may be generated for other types of actions. Examples are: a) to indicate when a piece of equipment needs maintenance, and b) to describe a protection malfunction to be sent to the manufacturer.

2.2.2 *Problems with manual fault analysis*

The process of fault analysis described in Section 2.2.1 has some weaknesses. First, only disturbances defined as "faults" are analyzed. Normally, a fault is associated with protective relay operation, so events, which do not lead to relay operations, do not get analyzed. This may lead to situations where latent faults may go unnoticed.

Example: Consequence of not analyzing all events

In this example, it was a "known fact" in the control room that if 420/132 kV Transformer 1 was the only component coupled to the 132kV busbar than "strange" voltages may occur. It was speculated that asymmetry in a long cable between the transformer and the busbar may be the cause. However the "strange" voltages did not lead to protective relay operation so the voltage fluctuations were not analyzed. The cause for the fluctuations was later found to be ferroresonance (missing dampening resistor) after two of the voltage transformers blew up (see Figure 2-3). The final fault led to blackout, and severe damage in the primary equipment.

Figure2-3: An example of a consequence of not analyzing all incidents

A second problem with manual analysis is that the task is demanding with respect to man-hours. For example a lightning strike causes a phase-ground fault on a 230kV transmission line [10]. Protective relays at both ends show zone 1 instantaneous targets. An "ideal" analysis of only the relay behavior comprises at least 5 levels:

1. Investigation of primary equipment response (breaker times, CT/VT response), and determination of faulted phase and distance to fault.

2. Investigation of control system response (Protective relay, relay signaling and measuring system, reclosing equipment) on the faulted line.

3. Investigations of control system response on all relays that have the faulted line as Zone 2 target with close investigation whether there is a protective relay "start" indication missing.

4. Investigations of control system response on all relays that have the faulted line as Zone 3 target with close investigation whether there is a protective relay "start" indication missing.

5. Investigations of control system response on all relays that have the faulted line as the “start” zone target with close investigation whether there is a protective relay “start” indication missing.

While checking one relay’s “start” indication may be a straightforward task, the sheer number of relays makes the analysis task described above overwhelming, and the task of analyzing the “start” indication for zones other than Zone I often is not done. The experience has shown that “Many incipient problems can be diagnosed and nipped in the bud” if a more thorough analysis is done utilizing all the data [11].

To sum up, the manpower demand of doing manual analysis often leads to a situation where a utility has to “sort out” which events get analyzed and to what depth. As a consequence, some incipient faults may exist in both primary and control equipment without being detected until the consequences of the fault becomes self-evident or catastrophic.

2.3 Common analysis approaches

The electrical transmission grids are well suited for automated diagnosis of fault and disturbances. Some of the reasons are:

- Good models of the transmission lines already exist
- An electrical grid is well instrumented compared to other application domains.
- The transmission grid usually is complex, and the benefits of enhanced fault and disturbance analysis may be substantial.

It is interesting to note that no common automated analysis approaches exist. The reason for this is (at least) twofold:

1. The different end-users may want different output from the analysis. This relates to the different time frames for analysis mentioned earlier

2. Up to now, data integration from all the different data sources has been difficult, and collection and integration of data has been a manual and time consuming task for the diagnostician.

Especially fact 2 mentioned above has been an obstacle for finding a common ground with regard to fault analysis. A big part of today's manual analysis task is data integration, and the automated diagnostic systems deployed today only use a part of the available data. Fortunately, the advances in electronics and the development of a number of standardization efforts, like COMTRADE [4-6], IEEE Recommended Practice for naming Time Sequence Data files, [3] and IEC61850 [17], are helping the data integration task, a topic, which will be closely discussed later in this report.

Instead of considering what diagnostic output is wanted, the deployed automated systems looks at what diagnostic output is possible to get with the given integrated data sources (SCADA, set of fault recordings or sequence of event recordings). The data sources to be used are also decided by the selection of the time frame of the analysis.

It appears that a top–down approach to fault analysis may be more comprehensive. Defining the output of the analysis from the view of intended use and users, and from there defining which data is necessary may be the best way to get the wanted output. In the following, a list of functionality needed from an automated system is made, and relationship to already deployed systems is established.

2.3.1 *Fault hypothesis generation*

Every automated diagnostic system has a span of possible fault hypotheses. This "diagnostic span" may be explicitly stated, like in a filter bank or neural net method, or there may be an inference process that generates possible hypotheses about the cause of the disturbance. The

diagnostic engine will then test the possible hypotheses. The hypothesis generator may serve as a reference for testing the hypotheses as recently discussed in a paper describing the Scottish Power's APEX/RESPONDD system [Appendix II]. As one can see, hypothesis generation is the heart of the diagnostic system, but may also be considered an application in its own right.
The reason why a hypotheses generation is considered important is because in some cases it will be useful for the operator to get a set of possible fault hypotheses presented. This is to prevent operators from getting tied up in one possible explanation and not seeing other possibilities [18]. Especially, a logic based system like GAAM described in [2], which ensures completeness in the set of generated hypotheses will be suited for such a task.

The application of hypothesis generation demands that it is fast since it is meant to serve the operator. Up to now analog disturbance data collection from substations has been time-consuming, so the applications for hypothesis generation had to rely on logical (status) data. This puts the existing hypothesis generation systems in the realm of alarm analysis.

The system-wide nature of hypothesis generation means also that it has to be centralized. A distributed agent system may also serve as a hypothesis generator. The FAFL system described in [10] is an example of such a new system, where some of the reasoning is decentralized, and IED data is used to build a disturbance hypothesis.

2.3.2 *Using redundancy to validate measurements/signals*

As said earlier, an electrical transmission grid is well instrumented compared to other domains. Hence there is a possibility to use redundant measurements and signals to perform integrity checks on the components. Hydro Quebec [19] reports on an automated system where Kirchoff's laws/component models are used over a set of measurements to detect inconsistencies. In addition the system computes steady state electrical quantities (harmonics, symmetrical components) and analyzes the measurements in the time domain. In this way both the performance of the measuring system and instrument transformers are verified. The work is underway to use crosschecking data over IED's that use the same measurements, both to discriminate between the sources of errors and to verify the IED's measuring system. In this way the need for maintenance testing of an IED's measurements may be greatly reduced.

2.3.3 *Using models to verify component behavior*

The deployed applications use signal measurements and/or quantities computed from signals together with models to verify the behavior of an individual component (relay, circuit breaker). The verification algorithms may be initiated by an algorithm for testing the hypotheses, or may be data driven [10]. The distinction here is significant as the data driven algorithms are self-contained, and can be implemented using distributed agents (maybe on-site). The data driven algorithms have also the advantage that an analysis is performed each time data is present (i.e. the component operates), and faults may be diagnosed before they have drastic consequences.

2.3.4 *Using automated calculations to improve computed quantities*

The main example here is the distance to fault calculation, which requires measurements from both (all) line ends to improve the accuracy of the computed fault location. This requires that measurements from IED's at all line ends have to be collected, time aligned and fed into the algorithm, which is a labor intensive task if done manually. Automation is a prerequisite to get the improved accuracy that this type of distance to fault calculation gives.

2.3.5 *Storing data*

Nearly all utilities have their own system for:

- Storing input data for the fault analysis.
- Storing the analysis reports.

What these systems often lack is the link between the input and output, namely a causal explanation between input (e.g. time series data) and output (causes). If an automated system is going to be accepted, it must be possible for the human operator to follow the line of reasoning of the system.

In the design of the data storage system, it must also be decided what queries the system should be able to handle. For example, if aggregation of breaker reclosing data is of importance, the analysis system must store this information.

2.4 Data used for analysis

2.4.1 *Dynamic data*

As pointed out in [7] fault and disturbance data may be gathered from a number of devices, or data sources. What these devices are and how these devices process their input data before storing it (i.e. data acquisition) is discussed in depth in [7].

If signals measurements from more devices are to be used for the analysis, the time synchronization of data sets is also an issue. A fully hardware-based synchronization of time-tagged data is desirable, as other methods have limitations that are not easy to overcome [7,19]. Furthermore, the time stamps across a power system can belong to different time zones or can be referred to GMT or can use daylight saving time convention; thus a further alignment may be necessary. The synchronization of data is a pre-processing function with regard to fault analysis and will not be discussed here further.

It will be beneficial to store the data in a common format for analysis when appending or merging the data. The common file format for transient data exchange (COMTRADE) [6] is a standard commonly used when it comes to storing disturbance records. As [20] mentions, COMTRADE files are not intended to carry much semantic information about the data source. File naming convention for time sequence data has been proposed by the IEEE [3]. A COMTRADE file does not explicitly indicate which physical signals the in data channels are related. This is because the use of the (optional) header file is not standardized yet. As a consequence, the application that reads and processes a COMTRADE record must access a static mapping between data series and data collection points in a substation. In the current context we will assume that the data is collected and stored in a machine-readable form.

2.4.2 *Static data*

The human fault analyst has a wealth of background knowledge about the grid that is used during a fault analysis. To make an automatic system work (at least partially), some of the static knowledge needs to be formalized and put into the system. This section will try to list and classify some of the information needed.

Grid model

To formalize a description of the grid so that it is suitable for automated reasoning, it will be beneficial to use a bottom up strategy. The goal must be to try to model the grid in such a way that the component models may be reused to minimize the modeling effort. The de facto standard in already deployed systems is that one of the basic modeling components is the bay [7,21]. A further division of the information may be represented as follows:

- ***Bay*** single line diagram***:*** This describes the physical outlay of bay's primary components like breakers, switches and instrument transformers.
- ***Bay*** configuration***:*** This provides mapping of signals/measurements to components in the one line diagram. This also maps signals/measurements over to the input channels on IED's with information on scaling. This provides the link between the physical components and IED naming convention.

- ***Bay*** function***:*** It describes the control functions associated with the bay such as protection, reclosing and measuring functions. The functions may be further split up as in the logical nodes described in [17]. Depending on the depth of the analysis, more or less elaborate models of the functions may be included.

Power system topology and connectivity

To perform an analysis at the unit level, a diagnostic system will also need information about grid connectivity together with models of the selected analysis unit. For example if one wants a system to do two-sided distance to fault calculation, a diagnostic system needs to know which two bays are connected by a line.

Component and its behavioral models

If a diagnosis of the behavior of the individual components within a bay is needed, behavioral models of the component must be included. If diagnosis of the behavior of units is needed, behavioral models of units are also needed. There is a plethora of modeling techniques for behavior; from black box models based on signal processing (e.g. neural nets) via rule based expert systems to crisp quantitative models.

If a modeling technique is to be useful for diagnostic purposes in an electric grid, the model must be reusable because of the high number of similar components/units in the grid. This implies that in the individual instance a model needs to be tuned for the specific component/unit.

It will be an advantage if the models are tuned by adding easily obtainable data as:

- Nominal breaker operating times.
- Relay operating characteristics and settings.
- Impedances

Naming conventions for power system components

Since the analysis may utilize information generated by different utility staff, it is quite possible that the notation about the same power system components or measured signals may be different. A typical example is the notation used by the planning groups in short circuit and load flow studies that may be quite different from the notation used by operators and even protection engineers. Therefore, if an automated system is to be deployed, there needs to be a naming convention for signals and components.

2.4.3 *Other Data*

Analysis of a disturbance includes also finding the root causes for a disturbance. Knowing that a phase to ground fault has been successfully cleared is only one step in the analysis. The cause of the disturbance may be:

- Harsh meteorological conditions (wind, icing, lightning).
- Damage caused by forest fire
- Design or construction flows
- Flow of geomagnetically induced current (GIC)

Data sources containing these data may be correlated with disturbance data to get a better understanding of the root causes. One example is analysis of one-phase faults on a 420 kV line in Norway. Correlation with meteorological, GIC and lightning data showed that the triggering factor was wind. A closer examination of fault location together with design data showed that wind induced faults often happened in or near the suspension towers. Based on this an inspection was carried out and the faults were shown to be caused by the conductor loop in the suspension tower. The example shows that correlation of more data sources may be needed to find root causes.

2.5 The levels of automated analysis

Fault analysis has different levels of aggregation: From analyzing the individual component behavior to analyzing overall system performance. With the level of aggregation the focus of attention shifts. Both the “nuts and bolts” at the component level and total system response have to be analyzed before one can decide if everything was working correctly. The hierarchical nature of fault analysis is discussed below.

2.5.1 *Bay level analysis*

If recorded data from one bay is given (currents, voltages and external protection signals) it will be possible to replay the data using a simulator for the primary and secondary equipment, thereby deciding if protection and breaker response was correct and computing fault data was accurate. If more signals are added, for instance from circuit breaker monitoring equipment, the behavioral models of equipment can be improved, as there are more observable states. Given more and better signals, a more comprehensive analysis can be performed. No topology or connectivity information is needed for this analysis.

2.5.2 *Unit level analysis*

If currents, voltages and external protection signals for one unit (e.g. transformer, busbar, line) are given, a unit level analysis may be performed. In verifying equipment behavior, the redundant measurements may be used for consistency checking both signals and model parameters, and perhaps a better assessing of fault state is possible. The protection system response for the unit can also be evaluated, based on the bay level analysis.

This level of analysis incorporates both a data aggregation of the bay level analysis, as well as new analysis functions. For this analysis, connectivity information is needed as one needs to know which terminals are connected to the unit.

2.5.3 ***System level analysis***

This analysis is primarily concerned with system response. It answers the questions such as: Did the system integrity protection schemes (SIPS) work as planned, is selectivity sufficient etc. This kind of analysis works on either signals measured from the unit and bay analysis, or from signals from the EMS/SCADA system. For this kind of analysis a good network topology model is vital.

2.6 Conclusion

This chapter focused on:

- Illustrating the shortcomings with today's manual analysis
- Pointing out some existing applications of automated analysis
- Giving a description of the data needed for analysis
- Defining various levels of automation

3 Future Needs

3.1 Introduction

The transmission system in many countries is being operated closer to the limits since consumption is growing faster than development of the networks. This imposes the requirements of reducing the outage and system restoration times while having a minimum impact on customers, extending the life of the equipment and preserving the system stability.

To achieve the above goals, the protection system performance should be further improved. The equipment performance also needs to be improved using predictive, preventive and corrective maintenances as necessary. Construction of new substations with state of the art technology enables capture of the data from all substation devices, and the processing of data in a quick way allows knowing the health of the primary and secondary equipment in a better way.

In this section future needs for automated fault and disturbance analysis are discussed by emphasizing the requirement to integrate data and have multiple uses of extracted information by different utility groups.

3.2 New protection analysis requirements

In many situations, the disturbance analysis may be done using only the information which clarifies whether the performance of the protection has been correct or not. In the case of wrong behavior, the inspection of the data needs to be more detailed. A more meticulous inspection of all the available data from all the bays (tripped or not) is required because it may reveal problems that can cause further misbehaviors. This may be time consuming if done manually, but if automated, it may be done in a very short period of time.

In this chapter we will differentiate between the data capturing capabilities of the different devices that are used in practice, and data that could be very useful if correlated with other data sources from distinct areas.

It should not be forgotten that to make analysis solution advances and to be able to extract more useful information from the available data, some new applications need to be developed.

3.2.1 *Protection analysis with existing data*

In the utilities there is a growing amount of data coming from IEDs located in substations. Most of these data are coming from fault data files and sequential events files, both produced by relays that have tripped and by relays located in bays and substations that have not been directly involved in the disturbances.

For the analysis purpose, if feasible, it is advisable to record the following quantities [2]:

- Bus phase voltages: Depending upon the station configuration, bus and/or line voltages (phase-to-ground) should be monitored. A minimum of three phases per voltage level should be provided.
- Bus residual voltage (derived from phase quantities)
- Line phase voltages
- Line phase currents: Currents from all three phases on each line must be monitored.
- Line residual current (derived from phase quantities)
- Breaker, station tripping, and blocking status data: Auxiliary contacts show when status points changed state. Breaker position, lockout relays position (differential and breaker failure) and pilot channel blocking or speeding up all aid in the assessment of both correct and incorrect operations.

- Control contact performance: Trip and close contact information is a must. Trip and close initiation helps to better define what happened and why (i.e. which relays initiated the trip or close).
- Alarm contacts.

For the protection staff, it is important to know if the protection system equipment has worked properly in correctly isolating all the fault related problems in the network. That's why the first items to be reviewed are whether or not:

- Opened bays are the minimum needed to isolate the problem
- Relays that have acted are all the ones that had to do it (neither more nor less)
- Reclosing has worked properly

In the case of a more detailed analysis, the other items to be checked are whether or not:

- The protection functions that have acted are the proper ones (no unintended operations)
- Breakers have opened when the trip was received (neither stuck nor slow breaker)
- CT and VT performance was adequate (impacts of saturation and ferroresonance)
- Communication channels worked properly (carrier transmission duration)
- Theoretical and real current and voltages match (consistency check)

For this purpose, the captured data from IEDs must be filtered and processed to extract the largest amount of useful information. With this information, using both automatic system and manual analysis, the protection staff should be notified of the devices that have not worked correctly, the devices that had worked correctly with required accuracy, and the disturbances that could not be fully analyzed using the automatic system and must be analyzed by an expert. With an automatic system, the analysis staff should have a quick and automated way of receiving the following protection related information without a need for human intervention:

- Identification of disturbances that have taken place in the network.

- Indication of which devices should be reviewed because of a malfunction or a questionable behavior.
- Determination of fault duration used in analyzing relay and breaker performance.
- Duration of the clearing time (all phases**)** used in determining breaker pole opening and fault clearing
- Calculation of fault location or magnitude of the fault current used in determining which relays should have operated
- Classification of fault type (single phase, multiphase, evolving***)*** used in analyzing faults, which depends on knowing how faults evolved,
- Selection of phases involved in the fault used in locating faults and analyzing relay system performance
- Assessment of protection behavior used in analyzing duration of fault clearing, including automatic re-closing,
- Characterization of system condition prior to fault***:*** used in analyzing fault causes
- Detection of VT and CT malfunctions, DFR malfunction, or loose contacts used to determine problems with equipment connections

It is also interesting to cross-check data from different IEDs, or even from a single source, to ensure the validity of it, to detect problems in the data sources. For instance, by comparing the voltages of different VTs on the same bus bar at the same instant of time, it is possible to detect the deterioration in performance. Due to the difficulties in synchronizing the recording devices, one possibility is to use the start of a fault as a time reference. Another thing that could be checked is the behavior of VTs during an extended period of time.

With an automatic analysis, these and many other checks can be executed quickly and without human intervention.

3.2.2 *Protection analysis with enhanced data*

When protection data is correlated with data from other sources, it is possible to get more benefits from the protection system data, as explained next:

- Control center data: if these data are correlated, it is possible to develop a system that automatically detects the disturbances in the network and captures the data from the different devices involved in the disturbance to extract useful information for the operation center staff. For example, distance to fault, fault phase and magnitude, etc.
- Planning data: when correlating protection and planning data, it is possible to get an accurate fault location distance by comparing the fault impedance and the impedance of the sections of the line used to obtain it. Even for mixed overhead/cable lines, it could be possible to calculate whether the fault is in the underground section or in the aerial one. In the last case, it could be possible to reclose the line to check if the problem has disappeared (most of the faults in aerial lines are temporary). It could also be possible to run a simulation with the obtained data (distance to fault, type of fault, currents, etc) in several bays of the network to validate the planning data or identify incorrect data.
- Maintenance data***:*** data captured from protection relays or DFRs could be useful for the maintenance department. For example, the number of openings of a breaker and magnitude of interrupted current (depending on the type, age, voltage level, area, etc) could be used to start a predictive maintenance action. Delays in the breaker opening time, which can be detected from relay data, can be highlighted as well.
- Climate and fire data***:*** Data about lightning, weather and ground fire can help in the analysis to clarify the causes of the disturbances, and can provide information to aid the operators' decisions. As an example, when a lightning stroke generates a permanent fault, data about its location (obtained by triangulation of lightning RF detectors output) could be used to improve fault location.

3.3 New User Requirements

The protection staff is not the only one that can benefit from the automated fault and disturbance analysis. The analysis can provide information of interest to many other utility groups.

Figure 3-1 shows an example of a flowchart of the main flow of the data and information from the devices, as well as from the analysis department to the rest of the departments in the utility.

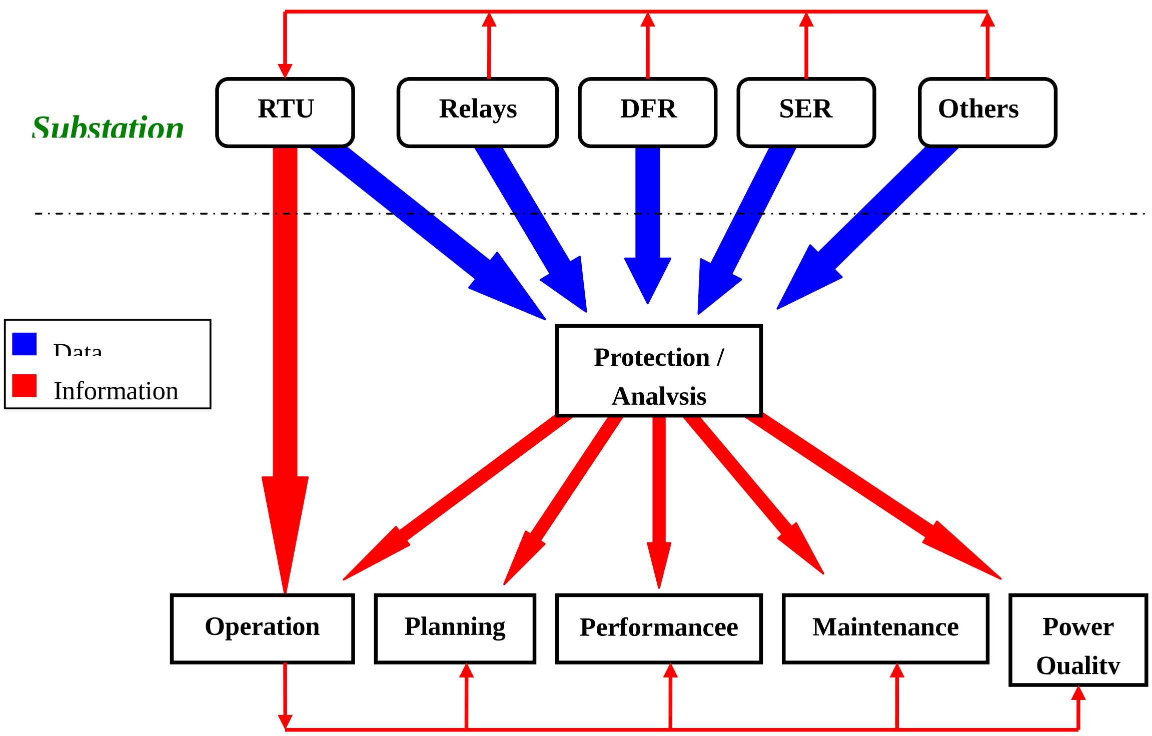

Figure 3-1: Use of data and information by different utility groups

Further discussion points out to other utility groups that may be interested in the information obtained from automated analysis or relay and other substation IED data.

3.3.1 *Operation*

The operation department is mainly concerned with real time monitoring and control of the power system. It needs to be informed instantaneously about faults and needs to receive the analysis data in a short time to restore the network as soon as possible.

For this purpose, the useful information from the substations devices, besides control signals provided through RTUs, are:

- End of automatic restoration time: this could indicate to the operators the moment from which they must start the manual restoration
- Confirmation of real fault location and extent: this information is useful for the dispatchers to know the risk of closing tripped elements
- Faulty element and, therefore, bays that have incorrectly tripped: with this information, the bays that have been tripped unnecessarily could be quickly restored
- Distance to fault calculation and determination of affected phases: such data is very useful when permanent faults occur in the network and field people need to get involved to solve the problem

Besides the information that is useful at the moment of the disturbance, there is more information that could be interesting for the control centre staff for determining off-line settings, such as the overload limits of switchgear and transformers. The load current limits that could be reached may be obtained from the automated analysis of real events.

3.3.2 *Planning*

For the planning department, statistical data obtained from automated disturbance analysis is useful to decide about further expansion and improvements in the network. For instance, some of these statistical data of interest could be:

- The number of faults in a given location, which may indicate an area prone to lightning strokes or short-circuits caused by trees, fire on the ground or wind.
- Equipment progressive deterioration, which can help predict circuit breaker failures and instrument transformer failures.
- Errors in component and unit commissioning, which point to phase permutation, phase inversion and loose contacts [19]

- Main causes and evolution of transformer trips, which can help decide what extent of damage the transformer has suffered

Other useful information, although not only of interest to the planning staff, is the actual data about aerial lines and cables. This data is used for simulations during planning, before carrying out switching actions and for the protections settings calculations. Today, the theoretical data are used, but when the disturbances take place, mainly in cable areas, some differences can be noticed between the expected currents and voltages and the real ones. This information is very useful in correcting the results of the planning studies.

3.3.3 ***Performance Analysis***

Due to new rules introduced by regulators, some utilities are forming internal teams related to monitoring and reporting of system performance. The focus is to develop detailed descriptions of how the system has performed during a system disturbance. This may include description of the disturbance, the expected performance of the secondary equipment, such as relays and control system during a fault clearing sequence, and actual performance of the primary equipment and system. This data may be used to report the reliability indices or to improve maintenance practice, or both. The data could also be archived and used to develop various statistical means of expressing equipment and system performance over a certain period of time.

3.3.4 ***Maintenance***

The maintenance staff may benefit from the information extracted from protection and other devices in the substations.

For example, interesting data for this department is:

- Behavior of breakers: Opening duration, number of openings and cleared current, stuck breaker, failure to trip all three phases, breaker re-strike and loss of synchronism. This information is useful for the maintenance of the primary equipment.
- Status of breaker closing and opening coils: It is important to know if some of the coils are burnt and therefore the breaker will not execute some of the orders.

3.3.5 *Power quality*

Power quality analysis demands gathering and processing a huge amount of data, identifying phenomena like voltage sags and swells, and making an elaborated set of statistics. It is a highly repetitive task. Power quality studies may take days, weeks or continue permanently, once an area is found prone to power quality problems.

An Automatic Power Quality Management System can be built in order to achieve [20]:

- Monitoring of power quality compliance with contractual terms.
- Collection of statistical information.
- Power system's equipment failure analysis.
- Monitoring of power supply conditions and its compliance with equipment manufacturers warranties.
- Monitoring of industrial power system aimed at reaching specific operation and maintenance objectives.

The most important phenomena to be studied are transients (impulses or oscillations), RMS variations (sags, swell and interruption) and harmonics. A database can store information about disturbances, monitoring sites and field occurrences, used to generate the reports and provide data correlation.

3.4 Conclusion

The new requirements discussed in this section emphasize the need for improved protection analysis, as well as expansion of the automated analysis in serving other utility groups. As a result, the following needs are identified:

- Extension of protection analysis
- Uses of expanded data
- Engagement of different utility groups in the analysis

4 Functional Requirements for Future Solutions

4.1 Introduction

This section describes generic functional requirements for future solutions for automated analysis of field-recorded data coming from Intelligent Electronic Devices (IEDs) located in substations. This description helps understanding future implementation and deployment requirements. It also helps understanding how a full range of expectations and benefits may be achieved including the design of the information technology infrastructure to support such solutions in the future. The solution requirements are classified into four broad categories starting from the analysis that can be performed on the data coming from a single substation to the analysis that includes data from multiple substations, the entire utility, and even from multiple utilities. This classification is not made to suggest that the analysis should be implemented this way, but to differentiate among the various hierarchical levels where distinct information is available and distinct categories of analysis procedures can be performed.

To illustrate the requirements and benefits of the automation, a discussion of fault and disturbance analysis applications is presented in this section.

4.2 Intra-station analysis

This section discusses requirements based on field-recorded data coming from a single substation. The discussion focuses on different analysis requirements trying to identify some generic steps needed in any analysis irrespective of how it may be eventually implemented and/or deployed.

4.2.1 *Intra-station data integration and pre-processing*

Field data needs to be collected and integrated. The pre-processing functions are needed to organize data and extract features needed for the analysis. It is expected that effective solutions in the future will have a way of integrating and pre-processing data that is transparent to what exactly the analysis applications that may be implemented using the data are. In other words, the data will be organized and saved so that any application may be added in the future without the need to make any major changes to the data integration and pre-processing. In order for this to happen, the following important implementation criteria will need to be observed:

- Selecting a common IED data file format and utilizing proper file naming conventions
- Implementing and verifying data sampling time synchronization
- Providing substation and system configuration data

4.2.2 *Detection and classification of disturbances*

In any of the analysis approaches, the first step is related to detection and classification of a disturbance. This step sets a stage for defining a hypothesis of what is the disturbance that is taking place, and hence what may be the cause-effect consequences. For example, if the detected disturbance is a transmission line fault, then it is expected that corresponding relays at two ends of the line will operate causing subsequent operation of related circuit breaker(s). Further classification of a detected disturbance allows for definition of the details of the analysis. Following the previous example of a transmission line fault event, as soon as we confirm that the event took place, it becomes interesting to know the zone of protection where the fault has occurred, the type of fault, as well as the equipment responsible for clearing that fault. Further implementation details will need to focus on the algorithms that will allow the best outcomes for the following aspect of the analysis:

- Determination of the disturbance location
- Classification of the disturbance type
- Selection of the equipment affected by the disturbance

4.2.3 *Performance of relays and other IEDs in a given substation*

Depending on the type of disturbance, several IEDs may be expected to operate. Certainly in the case of faults, protective relays may be activated. In such circumstances, when some IEDs are expected to operate, the focus of analysis becomes the performance of such IEDs. They are all expected to operate within certain performance criteria such as speed, selectivity, dependability, security, etc. If such performance criteria are well defined, one can set up the automated analysis to perform checks if such criteria have been met in a given circumstance. The analysis outcomes need to focus on the following issues:

- Identification of IED functions that may be affected by the disturbances
- Definition of the performance criteria for IED operation
- Specification of the analysis goals for IED performance analysis

4.2.4 *Performance of circuit breakers in a given substation*

Besides IEDs, the substation equipment that may operate as a consequence of certain events (in particular faults) are circuit breakers. They are operated automatically by protective relays as a part of a fault clearing sequence. They can also be switched by operators in the case disturbance mitigation requires operator action. In either case, circuit breakers are expected to operate within certain performance criteria. Most common criteria are operating time, and final operating status that is intended for a given disturbance. Further details of the analysis need to focus on the following aspects:

- Definition of the operating criteria for a single circuit breaker operation
- Specification of the criteria for multiple operations of a single circuit breaker
- Establishment of the operating criteria for a sequence of circuit breaker operations

4.2.5 *Single-ended fault location*

In the case of faults, it becomes very important to determine the fault location as accurately as possible. In the case the data is collected only in one substation, accuracy of transmission line fault location may be constrained by the type of data and a related algorithm used to determine the location. Further implementation needs to focus on the following issues:

- Why a particular algorithm is selected over other available algorithms? How the data needed for such an algorithm will be provided?
- What are the limitations of the selected single-ended fault location algorithm?
- What information about the line model is needed?

4.2.6 *Analysis of fault clearing performance by the equipment in a given substation*

This discussion focuses on integration of all the analysis steps and related requirements presented in this section. An example used to illustrate the complexity of automated analysis that can be performed based on the data collected in a single substation is analysis of faults and related equipment operations aimed at fault clearing. The following summary implementation outcome needs to be accomplished:

- Selection of the best data sources and related data integration and pre-processing
- Availability of needed substation configuration data
- Definition of the analysis criteria and related reporting requirements

4.3 Inter-station analysis

This discussion is similar to the discussion of the analysis performed in a single substation except in this case it is assumed that data from adjacent substations are made available for the analysis as well.

4.3.1 *Inter-station data integration and pre-processing*

In addition to the intra-station data integration and pre-processing, the following implementation steps need to be accomplished to have the required data ready for inter-station analysis:

- Specification of what is the data coming from different substations that needs to be integrated
- Outline of a technique for proper lining up of the data using the same time scale
- Definition of how to group the recorded data corresponding to the same events

4.3.2 *Double-ended fault location*

Major improvements in the accuracy of fault location calculation comes from the use of data from two (or multiple) ends of a transmission line. The assumption is of course that the fault has occurred on the transmission line connecting two substations where data recordings are available. To proceed with the implementation, several new issues need to be resolved when compared to the single-ended fault location:

- Whether to use the synchronized or unsychronized phasor algorithm, and if so, which one?
- Is it possible to use a synchronized samples algorithm, and if so, which one?
- What are the data communication needs and transmission line model requirements?

4.3.3 *Performance of communication channels and the relaying schemes*

Since most of the transmission line protection solutions today assume existence of a communication scheme, the analysis of protective relay operations requires monitoring of the communication channel performance. For this analysis, the following implementation issues need to be addressed:

- Definition of a particular communication scheme logic
- Expected performance characteristics of the scheme

- Synchronization of the communication channel signal records at two ends of a transmission line

4.3.4 *Synchronization of circuit breaker opening/closing*

In some high voltage substations multiple breakers may be used to clear a fault. This is certainly the case for the breaker-and-a-half substation layout commonly used in the USA at the voltage levels over 110kV. In such cases, four circuit breakers, two located at each line end, are responsible for opening a transmission line. As a part of this analysis, the following implementation questions need to be considered:

- What is the temporal relationship in the fault clearing sequences performed by equipment at two ends of the line?
- How the performance of individual breakers affects the switching sequence?
- When and how breaker failure cases affect the related switching sequence?

4.3.5 *Analysis of fault clearing sequences involving equipment at neighboring substations*

As the fault gets cleared, equipment in multiple substations may be involved. This requires that the analysis of data for each individual substation gets merged to come up with a conclusion about the overall fault clearing sequence. The following implementation topics are of interest in that case:

- How the time-synchronization and time stamping of recorded files from multiple substations is done?
- What are the most efficient mechanisms for merging the data files from multiple substations?
- How the configuration files representing multiple substations need to be organized and maintained?

4.4 Utility-wide focus

The automated analysis may be performed for the benefit of a particular group of utility staff, or it can be performed for the benefit of multiple groups. For example, an automated analysis of fault clearing sequences has definite benefits for the protective relaying staff that are responsible for making sure the fault clearing sequences are executed as expected. At the same time, the data collected from substation IEDs can be used to perform the analysis of interest to other utility groups such as dispatchers, maintenance crews and asset management staff, as well as staff responsible for system performance.

4.4.1 *Topology verification and advanced state estimation*

It is important to recognize that whatever the fault analysis criteria and functions may be implemented, most likely it will be very important to know the current switching state of the system prior to the occurrence of the disturbance. This knowledge translates in the following implementation requirements:

- Availability of SCADA information regarding topology status and state estimation
- Ability to correlate the times of the events recorded by SCADA RTUs with the events recorded by other substation IEDs
- Possibility of correlating system models and related notations with the configuration files of the substation IEDs

4.4.2 *Sparse allocation of substation IEDs*

While it is anticipated that IEDs will be widely spread across power systems in the future, it is still feasible that for a foreseeable future there will be parts of the systems that will not have a dense population of IEDs. In such instances, disturbances or faults may occur on the system components that are not directly monitored due to a sparse allocation of IEDs. For example, the fault can be “seen” by a DFR or DPR as being beyond the zone of protection (two three buses down the line). Being able to identify such faults based on measurements from several stations located away from the fault might make it possible to actually locate an area (island) where the fault might be even though recorded data is not readily available at every bus. A good example is the ability to better locate faults in the systems that heavily use tapped lines at the transmission level.

4.4.3 *Analysis of system-wide switching sequences*

Analysis of system-wide switching sequences has multiple benefits. In the case of faults, one can get an assessment of the performance of related switching equipment involved in the fault clearing. In the case of dispatchers and system operators, the analysis of switching sequences is used to verify final topology of the system. Maintenance groups and asset management staff are interested in the circuit breaker performance and can get the assessment through the analysis of the same data. The following implementation issues are of particular interest:

- What are the requirements for switching sequence performance analysis for different utility groups?
- How the system-wide topology verification is performed and what are additional benefits of alternative approaches over doing it using SCADA?
- What are the benefits of monitoring the history of breaker performance and how the performance criteria are defined?

4.4.4 *Analysis of cross country faults and related fault clearing sequences*

In rare occasions, fault events can occur simultaneously across different parts of a given power system. Analysis of such complex fault events is pretty involved. An automation of the process that can identify the events and determine if they are mutually correlated is a pretty important task in the analysis. The following analysis criteria related to this implementation needs to be well defined:

- What is the consequence of multiple fault events occurring at approximately the same time?

- What is the required system performance of multiple relay operations occurring simultaneously?
- What is the expected final outcome of multiple relay operations related to clearing simultaneous or evolving faults?

4.4.5 *Analysis of system-wide disturbances and related protective relay actions and clearing sequences*

System-wide disturbances are difficult to analyze since they may involve n-m contingencies. The on-line tools for analysis of such events are almost non-existent, and the expected system performance under such events is very hard to predict. While it is not expected that totally automated analysis will be developed for handling such cases, it is expected that the analysis of different important steps in such events will be feasible. The following are the most relevant steps of the analysis that need to be implemented for such circumstances:

- Ability to detect wide-area disturbances
- Possibility of providing information for taking actions aimed at correcting relay miss-operations or unintended operations
- Capability to perform an analysis leading to mitigating actions aimed at preventing such events from unfolding

4.4.6 *Statistics of the disturbance occurrence and protective relaying performance*

Lately, standardization and regulatory bodies in various countries and regions are more and more interested in reporting historical performance of protective relaying equipment. It is expected that such requirements may request timely reporting of all the disturbance events with clear indication of the equipment performance during the events. In this light, it would be beneficial that the following statistics can be extracted through an automated analysis of a series of events:

- Indication of the most common (frequent) disturbances in a given system or section of the system on an annual basis
- Calculation of performance indices for the equipment involved in fault clearing, as well as the reliability indices for the power delivery to the customers
- Determination of the equipment, particularly relays, that have caused major concern in the performance assessment undertaken in a given time interval

4.5 Inter-utility focus

In the case the utilities are part of an interconnection, events in one utility may affect operating conditions in the neighboring utilities. In that case, the analysis needs to incorporate interconnection-wide data that may be collected from substations belonging to more than one utility.

4.5.1 *Analysis of data from multiple utilities*

Getting data needed to analyze events from multiple utilities is rather difficult for many reasons. To be able to make this happen, several implementation issues need to be resolved:

- Inter-utility practice for analyzing data related to disturbances needs to specify what data is needed and how this data is transmitted should an interconnection-wide disturbance occur
- Time synchronization method for data files as well as harmonization of data format standards used in various utilities need to be specified
- Security of data that needs to be preserved by indicating the mechanism for data exchange and related responsibilities of the utility staff involved in the exchange

4.5.2 *Analysis of impacts of faults in one utility on the neighboring utilities*

In some instances, the faults may be occurring in an area close to an interconnection with the neighboring utility. As an example, the fault may be occurring on the transmission line that connects two utility systems. In such cases, the following implementation issues will have to be addressed:

- On-line integration of data from neighboring utilities needed for the analysis
- Time stamping and data format solutions required for the integration
- Representation of the results to the utility personnel in both utilities

4.5.3 *Analysis of the propagation of system-wide disturbances (cascades)*

In some instances, a fault in one utility can propagate to some or all interconnected utilities. This is particularly the case when a cascade of relay operations and fault clearing sequences started in one utility spreads across multiple utility systems. In that case the following ability needs to be included in the analysis:

- Detection, classification and verification of the starting event
- Identification of the subsequent events across neighboring utilities
- On-line integration of data required for analysis and representation of the results across the utilities affected by the cascade

4.6 Conclusions

This section of the report gives generic discussion of the requirements for the future automated analysis solutions. The emphasis was given to the possible levels of the analysis and the link between the analysis levels and available data. It was noted that the analysis may be structured along the organization of the power system equipment starting from the substation bays and then building up the complexity across a substation, across several substations in a given system, and finally across multiple power systems operating in an interconnection.

5 Implementation issues

5.1 Introduction

This section is devoted to implementation issues that are important for successful development and deployment of an automated analysis system. Recognizing the criticality of some of the implementation issues, one may prevent failures or may eliminate unnecessary burdens of a deployment. The reality of the automated analysis deployments across the world is that there are currently very few systems that are fully operational and have demonstrated clear benefits. On the other hand, the expectations from deployment of automated systems are ever increasing. To narrow the gap, the deployment issue needs to be well understood.

5.2 Implementation constraints

There may be multiple constraints, some seemingly unrelated. The constraints may be related to the people involved, equipment and infrastructure required, or management priorities established at an earlier stage.

5.2.1 *Personnel constraints*

For example, personnel that are performing manual analysis may not find the reason for urgency of deployment of an automated system that will eliminate their manual tasks, and may create a passive resistance to the implementation process. Another extreme is where the personnel wants to implement the system themselves and insists on doing it with internal resources, which sometimes may not be sufficient to have a successful completion of the work in a pre-described time period.

5.2.2 *Equipment and infrastructure constraints*

The current status of the IED equipment and recording capability may be such that the automation may not be feasible unless major investments are made, which may be prohibitive in some instances. A typical infrastructure constraint is the availability of the communication resources and database designs to support data integration required for the automated analysis.

5.2.3 *Project management expectation constraints*

Last but not least is the short term priority of the management which focuses on fast results and immediate gains. An automated fault analysis may need some time to implement and may not offer immediate returns. This may require a change in the business model to account for long-term investments to be able to efficiently implement such complex systems and gain full benefits.

Existing business models where each utility group develops its own infrastructure for system monitoring may not be conducive to developing data integration projects that will benefit many groups simultaneously. This approach may have some limitations, and a business model that does not aim at removing such limitations may be considered a constraint.

5.3 Deployment strategy

The belief that fault analysis is of importance has led most grid owners to conduct fault analysis in some form or another. The flow chart at the beginning of the report (Figure 2.2) depicts the current situation with manual fault analysis in most companies. The goal of automating (or semi-automating) the fault analysis task is aimed at getting a more efficient analysis. The problems with manual analysis were discussed in Section 2.2, and this discussion gave an incentive for considering (semi-) automation. The return of investment must be well defined ahead of the development and deployment effort. A firm commitment of all the involved parties is required to make the deployment possible. The implementation of an automated system typically comes in phases as discussed below.

5.3.1 *Time tagging and synchronized sampling of data*

Time tagging is vital when it comes to disturbance analysis. The analysis of the 2003 Northeast American blackout was heavily delayed because of the lack of proper time tagging of data [22], which led to considerable time spent on correlating times of different records. Knowing which event happened first is vital when trying to identify the cause and effect sequences. Another important, and yet not fully recognized issue, is data sampling synchronization. This does not have anything to do with time tagging but has everything to do with the way the sampled data may be aligned. For both requirements the use of the Global Positioning System (GPS) of satellites allows the time reference, either through a pulse per second (PPS) sampling clock reference or through the absolute time code, both readily available from the GPS receivers.
{However, if only intra-station analysis is needed, the requirement of data sampling synchronization can be relaxed to using a local synchronization source.}

5.3.2 *Automatic collection of data from data sources*

Collection of data from IED's can be a time consuming task. If the data is available to the analyst when needed, man-hours can be saved and restoration time shortened. The automated data "gatherer" should also check if the IED is available at certain intervals, and give notice if equipment is out of service. The use of standard formats for data storing is discussed in Section 5.4.

5.3.3 *Automation of analysis tasks*

The reasons for automating the analysis are given in Section 1. If the data is available in a standard format and time tagged, a lot of the obstacles for an automated analysis are overcome. As pointed out in Section 2.5, both the level of aggregation and the focus of attention shift for different parts of the analysis. To get payback on the analysis, the most time consuming parts (i.e. bay level analysis) should be automated first.

5.4 The role of standards

5.4.1 *Existing standards*

Existing standards provide a good start for analysis implementation. Since they were not implemented with integration and automation in mind, an automatic system may be difficult to build because of different conventions regarding databases, communication, data formats, etc. In general, lack of good standards for implementation of automated analysis systems is an issue that needs to be resolved before such systems become everyday practice.

Furthermore, various versions of the standards evolved in the years and sometimes manufacturers have extended them. The following are examples of standards issues that need to be addressed in the future:

- There are three slightly different implementations of COMTRADE (1991, 1999, 2001), and sometimes products do not fully comply with the standard), so an automated system should read all the formats [4,5,6];

- IEC 60870-5-103 defines a basic set of signals, but most manufacturers have extended versions with added functionality: the system should cope at least with the common implemented extensions;
- IEEE C37.232 defines the guidelines for COMTRADE file naming, but the utilities implementations can be quite different.
- Harmonization between IEC 61850 and IEC 61970, which requires additional data model definition for virtual analysis points in the CIM database created through automated analysis at the substation level

- Extension of Synchrophasor standard IEEEC37.118 to accommodate integration of PMUs into a monitoring network.

Defining file format is not enough: file naming convention and file organization containing configuration data must be defined too [3,16]. Although most IED products on the market can import and export COMTRADE files, chances are that if the files are not stored in an organized repository, automatic import may be difficult to achieve.

There is no standard to deal with a malfunction of an IED or a loss of the transmission channel between the DFR and the user application, so a problem can arise. Most manufacturers have implemented proprietary solutions to cope with this, but this implies the use the custom manufacturers products for each IED model installed. Communication to devices directly connected through Ethernet can be easily diagnosed although it does not assure that the device is working correctly.

There are various programs that can facilitate retrieval of data using IEC 60870-5-103 from DPRs. Once this data is retrieved, since the standard data format for DPR files is not established, storing and retrieving data in an automated way for analysis purposes is not straightforward.

The same applies to SER and lightning data: there must be a well documented data format.
But that is not enough, because if the configuration data to correlate information to physical objects (breakers, lines) is missing, automated analysis cannot be done.

Also, relay setting data, grid parameters, grid topology data and lightning systems data are usually available in some proprietary format.

IEC 61850-8-1 and Goose should overcome a few of the shortcomings depicted before; in fact they define a base set of data types for describing objects and define how to allow detection of device failure.

5.4.2 *Internal utility conventions*

The convention used to designate configuration data within a utility can simplify or complicate the work. For example, for DFR, if all the feeders use the same sequence of signals or the same labels for the same signals, this greatly simplifies the configuration of the system. The utility internal conventions play a key role in the successful implementation of the automatic diagnosis system.

Time tagging may be in GMT, local time with or without automatic DST changeover, so that time tags must be adjusted in order to correctly correlate events.

Data from SCADA, SER and lightning systems can be acquired, for example, from the ASCII text files produced by the log of that system. To successfully integrate this data, the naming convention within the utility must be well defined, and chances are that every system has its own internal format because they were specified and bought by different departments and at different times, so one or more cross reference tables ("Rosetta Stone") need to be defined in order to be able to correlate the data. The recent IEEE standard C37.232-2007 is addressing those issues, but further definitions may be needed to accommodate the variety of requirements imposed by automated analysis systems.

Integration of data from different utilities is also a challenging task because of the different conventions for naming the same object.

5.5 Conclusions

This section discussed the issues that are important for successful development and deployment of an automated analysis system. Several major implementation constraints are pointed out. The focus is on the deployment strategy and the standards. It should be noted that existing standards provide a good start for analysis implementation, but it also requires the cooperation from different departments within utilities and standards organizations.

6 Recommendations

In general, the report points out many advantages of implementing the automated analysis. The following recommendations are discussed throughout the report:

Benefits. For successful deployment of the automated analysis it is highly recommended that the benefits for embarking on the project be quantified. Recommended areas of the focus are:

- Automated analysis contributes to more reliable and faster assessment of disturbances and faults, which is critical for improving power system performance. The measure of improvements should consider the cost of the power not delivered and reduction of the restoration time.
- The requirements of automated analysis systems should consider integration of data from many points in the power system and should call for standardization efforts to reduce the cost of future implementations. The cost of obtaining data as it impacts quality of analysis should be well defined
- Automated disturbance and fault analysis can make positive impacts on the efficiency and response time of the company personnel. The savings in personnel time should be clearly indicated by providing the difference between the manual and automated analysis in the time spent on the analysis vs. quality of the outcome.
- The automated analysis yields by-products that can improve knowledge on the operational statistics and fulfill regulatory needs for more comprehensive field data reporting. The specific statistics and their value when used in the internal asset management tasks and reporting to the regulatory bodies should be identified.

Users. To take full advantage of the automation, it is critical that multiple staff get involved in the project requirements specification. The following are recommendations what staff should get involved and why:

- The operation department is mainly concerned with real time monitoring and control of the power system. It needs to be informed instantaneously about faults and needs to receive the analysis data in a short time to restore the network as soon as possible.
- For the planning department, statistical data obtained from automated disturbance analysis is useful to decide about further expansion and improvements in the network.
- Due to new rules introduced by regulators, some utilities are forming internal teams related to monitoring and reporting of system performance, and they have need for quick assessment of disturbances and faults
- Power quality analysis demands gathering and processing a huge amount of data, identifying phenomena like voltage sags and swells, and making an elaborated set of statistics. The results of automated analysis can help gather the statistics.

Deployment. Several recommendations regarding system deployment are discussed in detail and illustrated in the report:

- The deployment constraints may be related to the people involved, equipment and infrastructure required, or management priorities established at an earlier stage. It is important to define such potential barriers early on so that they may be removed before the project starts
- Personnel that are performing manual analysis may not find the reason for urgency in deployment of an automated system that will eliminate their manual tasks, and may create a passive resistance to the implementation process. Before the deployment starts the personnel to be affected should be briefed on their role once the system is installed.
- In some instances the personnel wants to implement the system themselves and insists on doing it with internal resources, which sometimes may not be sufficient to have a successful completion of the work in a pre-described time period. Internal resources and knowledge to complete such a complex project in-house have to be carefully assessed.

<u>Barriers. The automated analysis is still a new concept for many utilities and hence it may encounter several barriers which need to be defined early on. It is strongly recommendation that the following issues be discussed to identify whether they may create a major barrier:</u>

- The current status of the IED equipment and recording capability may be such that the automation may not be feasible unless major investments are made. A typical infrastructure constraint is the availability of the communication resources and database designs to support data integration required for the automated analysis.
- Existing business models where each utility group develops its own infrastructure for system monitoring may not be conducive to developing data integration projects that will benefit many groups simultaneously. A business model that does not aim at removing such limitations may be considered a constraint.
- In general, lack of good standards for implementation of automated analysis systems is an issue that needs to be resolved before such systems become everyday practice. Not recognizing standards that will allow future expansion of the solution may be a major obstacle since it is expected that the solution will be enhanced over the years.
- To successfully integrate the data, the naming convention within the utility must be well defined. The chances are that every data gathering system has its own internal format because they were specified and bought by different departments at different times. This issues need to be assess to see whether it may become a major obstacle for timely implementation.

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Appendix 1: Definition of Terms

1.1 General definitions

First, we shall begin by defining a disturbance. In [1], disturbances are defined as an unplanned event that produces an abnormal system condition or as any perturbation to the electric system. In [2], disturbances which need to be studied and understood are those that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions.

So it can be understood that a disturbance is any deviation in the power system parameters (voltage, current, frequency, phase etc.) that are out of nominal values. Disturbances may lead to no serious consequences or it can cause a faulty condition. For example, the presences of harmonics flicker or unbalances in the grid are disturbances that do not necessarily cause faults.

According to [1], a fault is an event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection. In [4] a faulty condition means that one component or unit is in an outage state, as explained later.

The definitions below are taken from [1], which in large measure builds upon the IEEE standard [4], with some narrowing interpretations, and [5], where the terms are discussed in detail.

Component

A component is a device which performs a major operating function, and which is regarded as an entity when analyzing data.

Unit

A unit is a group of interconnected components that can be isolated from the system as a unit to clear a fault on any of the components in the group.

Terminal (Bay)

A functional facility (substation, generating station or load centre) includes components such as bus sections, circuit breakers and protection systems, and where transmission units terminate.

State

A component or unit state is a particular condition or status of a component or a unit, which is important for outage reporting purposes

In-Service state

The component or unit is energized and fully connected to the system

Outage state

The component or unit is not in the in-service state, that is, it is partially or fully isolated from the system.

Outage Occurrence

One component or one unit changes from the service state to the outage state.

Failure

One component fails to perform its required function.

1.2 Data and measurement definitions

Digital fault recorders – DFR's

The modern DFR's are highly accurate recording instruments providing sampled waveform and contact data using relatively high sampling rate (typically above 1 KHz). Their use in the analysis is quite appropriate since they provide recordings of the waveforms that were also "seen" by the protective relays [6]. The digital fault recording function can also be found inside digital protection relays, power quality monitors and IED's.

Digital Protective Relays – DPRs

The digital protective relay, also called a numeric relay by some manufacturers and resources, refers to a protective relay that uses an advanced microprocessor to analyze power system voltages and currents for the purpose of detection of faults in an electric power system. Further attributes are described in [9].

Sequence-of-events function – SOE

The capability of a supervisory system to recognize each predefined event, associate a time of occurrence with each event, and present the event data in order of occurrence of the events [7].

Sequence of Event Recorders – SER's

The modern SER's are complex recording instruments implemented today using programmable logic controllers (PLC's) and analogue waveform data acquisition subsystems. The SER's are capable of monitoring changes in the switching equipment status with high precision due to a high data sampling rate. Combined with measurements of analog signals, the SER's can record the status change for a variety of controllers including the ones that are based on analog set points. Most of the SER's can also be set to provide control function through a number of control outputs [6].

Remote Terminal Units – RTU's

The entire complement of devices, functional modules, and assemblies that are electrically interconnected to effect the remote station supervisory functions. The equipment includes the interface with the communication channel but does not include the interconnecting channel. During communication with a master station the remote station is the subordinate in the communication hierarchy [7].

The modern RTU can be a very sophisticated recording instrument that may have a recording performance of a DFR, and at the same time may be producing a variety of pre-calculated quantities. In addition, some advanced RTUs will provide an extensive SER and some limited digital protection relay functions. Due to the fact that RTUs are a part of the Supervisory Control and Data Acquisition (SCADA) system, the data is readily available for the analysis at the centralized location through a SCADA database [6].

Intelligent electronic devices – IED's

The modern IED's are available today for variety of applications ranging from simple stand alone controllers and dedicated data recording systems to pretty complex integrated devices for monitoring, control and protection of the entire substation bay. The main issue with IED's, when used for the analysis, is the "open" communication architecture and data recording performance [6].

Supervisory Control and Data Acquisition – SCADA

A system operating with coded signals over communication channels so as to provide control of RTU equipment. The supervisory system may be combined with a data acquisition system by adding the use of coded signals over communication channels to acquire information about the status of the RTU equipment for display or for recording functions [7].

Phasor Measurement Units – PMU

A generic device that calculates phasors from voltage and/or current inputs [8].

Synchrophasors

A phasor calculated from data samples using a standard time signal as the reference for the measurement. In this case, the phasors from remote sites have a defined common phase relationship [8].

Alarm condition

A predefined change in the state or condition of equipment or the failure of equipment to respond correctly. Indication may be audible or visual, or both [7].

Alarm SCADA function

The capability of a supervisory system to accomplish a predefined action in response to an alarm condition [7].

1.3 References

[1] NERC Board of Trustees, “Glossary of Terms Used in Reliability Standards”, May 2, 2006, available at ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_01Nov06.pdf.

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Appendix 2: Example Systems

2.1 SINAI: INTEGRATED INCIDENT ANALYSIS SYSTEM

IBERDROLA, Spain

Nowadays, there is a general concern in most of the utilities about improving its profitability and efficiency by diminishing its costs. As a consequence of that, utilities are interested in reduction of maintenance and capabilities that offer the new technologies to reach this goal. The application of microprocessor technology in substation protection and recording equipment has significantly improved the monitoring of power system. It has brought the possibility of accessing from remote analysis centers a higher level of information about incidents occurred in the power network. Growing requirements in quality of supply demand exhaustive analysis of power system disturbances and data bases that allow statistical management of that information.

Digital protection and control devices generate a lot of data during the disturbances that occur in the electrical network. The analysis of these data provides very useful information about the system operation and the condition of the primary equipment, protection and control systems that can be used to monitor all these devices. The main problem is how to collect, store and analyze such as great amount of data, without increasing the staff. This fact, joined to the high and increasing amount of digital devices installed, leads to the need of an efficient system for getting, handling and storing information collected by all possible sources being nowadays: numerical relays, event recorders, digital fault recorders, and control centers.

SINAI is a computer system that collects stores and analyses the data generated by SCADA, protection and recording equipment and makes possible the corporate access to that information. The system favors the advantages that digital technology offers by means of the automatic access to the information generated during incidents in the network by the SCADA and by digital recorders, fault recorders and digital relays. All the information is stored in a common format and afterwards is analyzed, simplifying the analyst job.

SINAI offers the following innovations:

- Integration of Communications (via Switched Telephone Network, GSM and Ethernet), providing access to equipment supplied by different manufacturers in a single phone call by substation, and showing the information in a single environment.
- Standardized data storage format that facilitates the development of future analysis applications.
- Automatic incident analysis algorithms.
- Data storage in relational and distributed data bases and corporate access to them via Wide or Local Area Networks. It makes easier a decentralized management of protection maintenance.
- Generation of COMTRADE format records of real faults that can be reproduced on relays.
- Statistical analysis of incidents information.

SINAI has been prepared to analyze completely the disturbances that affect the electrical network. To do that, it collects periodically, according to the cycles defined by the user, the information available at control centers and in digital protection and recording equipment in substations.

SINAI is also prepared to classify and analyze all the collected information giving more information about:

- Behaviors of each affected circuit breaker (opening time, reclosing cycle, ...)
- Fault characteristics (type, duration, impedance, distance from line extreme, ...)
- Performance of protection relays
- Behaviors of electrical bays
- Warnings about anomalies of the protection system performance during incidents.

The goal of SINAI is to release the analyst from routine tasks related to data collecting and to communications monitoring, and also the automatic incident analysis allows to give less time to analyze simple incidents. So it is possible to get a better analysis, giving more time to analyse deeply the complex incidents.

Looking into the future, new system features as on-line analysis to provide information about fault location to the control centers, linkage with the tools used to calculate settings, comparison of real and theoretical relay performances, and automatic checking of network models have been considered as possible future improvements.

SINAI is also being expanded to capture data from 61850 IED's, that is, the communication protocol is been implemented and the data-base structure is been adapted for this purpose.

2.1.1 ***System description***

SINAI was developed by a consortium of four companies (IBERDROLA,S.A., ELIOP,S.A., ZIV Aplicacionesy Tecnología and UITESA) in two years, having been subsidized by the European Economic Community under the ESPRIT P7506 PASO framework.

Before SINAI development, the only solution to manage all the information generated by an increasing number of digital protection and recording equipment was to handle different and peculiar to each manufacturer programs, what obliged to separate the information into different working environments, and it made impossible to automate not only the processing, but even such simple procedures as data collection. In that perspective IBERDROLA felt the need to simplify the management of that information. SINAI presents a unique environment that makes it easy to handle all the information generated by digital protection and recording equipment. The system collects, off-line, all the data through the Switched Telephone Network (STN), GSM or Ethernet.

SINAI is a powerful tool that promotes the protection maintenance centers, providing at low cost very useful information about the performance of the electrical network and its protection system, which is used to design new substations and relays, and to plan and do the maintenance. It contributes to increase the efficiency of an important activity of the company.

In addition to the stated advantages, SINAI will incorporate the automation of the data analysis procedure. To perform the automatic analysis, SINAI will combine an inventory of the network facilities and equipment data base with a disturbances data-base, where analysis conclusions will be stored.

SINAI has a distributed hardware architecture, and modular software architecture that permit to combine the decentralized management of the Protection System Maintenance with the centralized statistical analysis of the overall information, and with the corporate access to that information. Both, hardware and software architectures are described below.

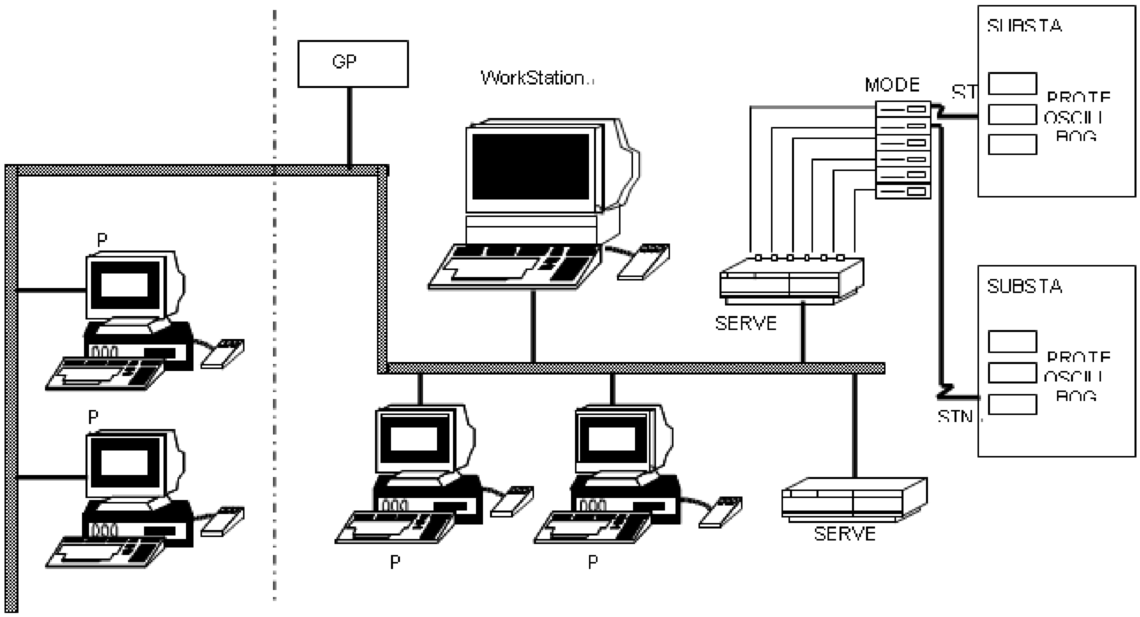
A. Hardware description

SINAI consists of a DEC WorkStation interconnected by a Wide Area Network (WAN) extended to the main company facilities. All processes and data of the system can be accessed in a few seconds from any PC connected to the WAN thanks to a client-server structure.

There is also a DEC SERVER 90M peripheral with several modems, for simultaneously handling several telephone lines.

The WorkStation has access to a GPS receiver in order to be synchronized, checking and correcting time deviation of relays and digital recorders.

The hardware drawing in shown in the next figure:

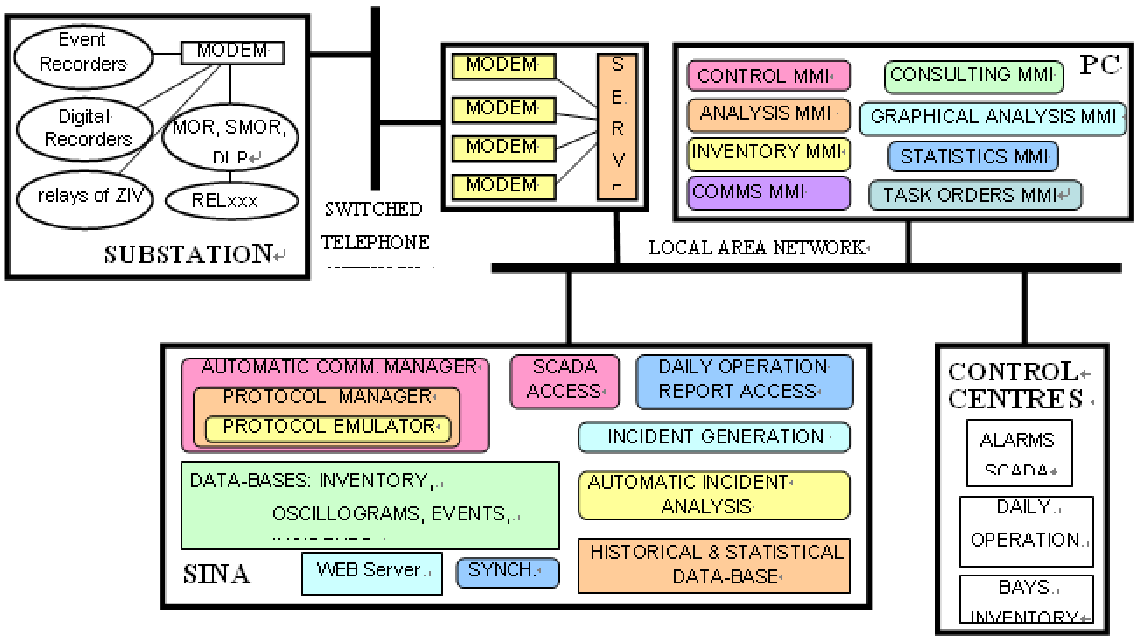


B. Software description

SINAI was designed on modular architecture, where each module will perform specific functions being linked to the others via defined and well-structured data-bases. This fact simplified its development and allows the end product to be available with various scopes in its functionality, depending on the ratio of units installed.

In order to make the best use of its processing and storage capabilities, software architecture has been adapted to the system hardware architecture. Thus, there are modules and processes that are executed in the workstation, although in certain cases they can be launched in accordance with the client-server structure from a PC connected to the WAN. Software that is executed in the PC is available in the WAN servers, and is loaded into the PC memory for execution, that makes easier to handle peripherals such as printers whose outputs can be personalized by each user and be obtained locally.

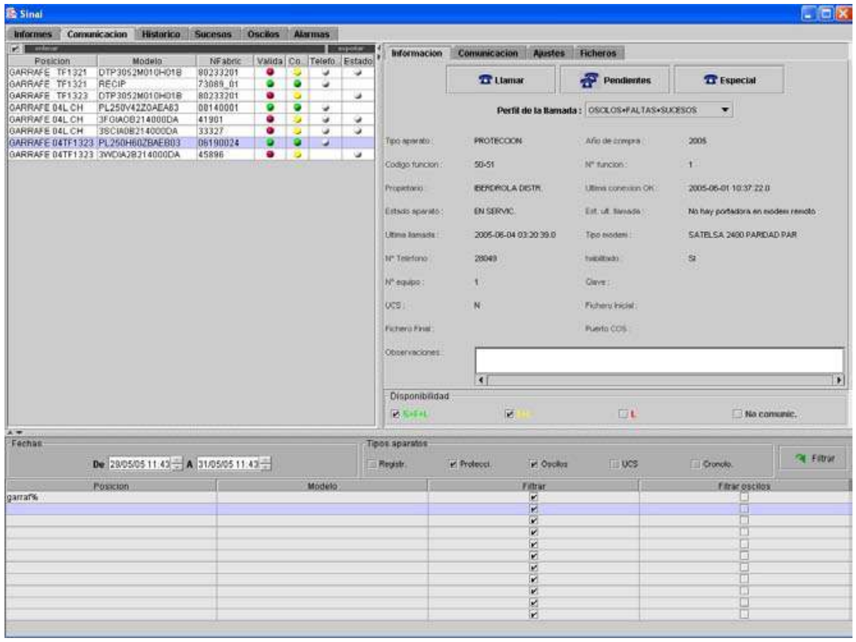
The modules what SINAI is made up and their functions are as follows in the next figure:



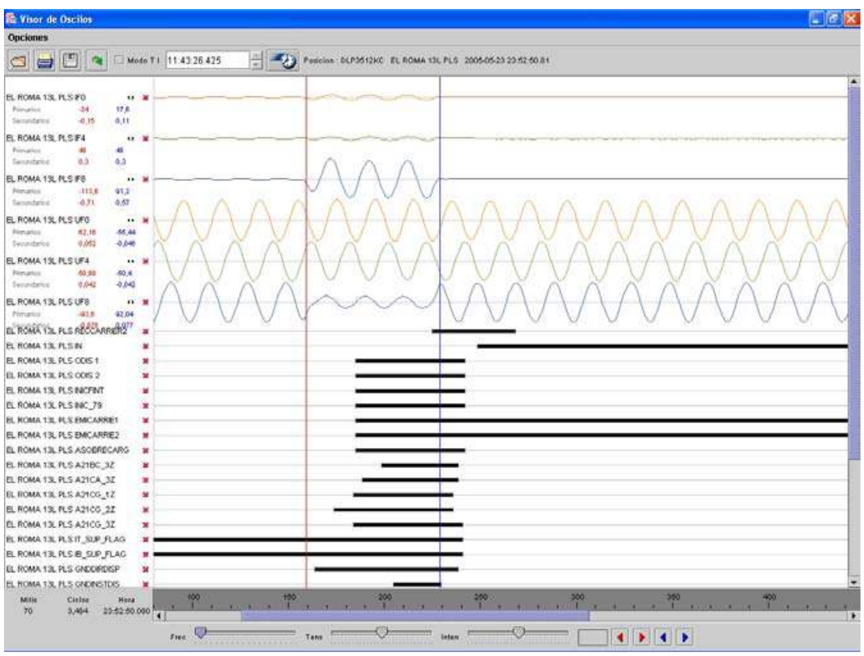
- Control Man-Machine Interface (MMI) Module. It allows to the system manager of SINAI to perform the maintenance tasks of hardware and software resources and to define new users' profiles. Additionally, this module presents the SINAI welcome menu that is different according to the user profile.
- Inventory MMI Module. This module allows to access to the plant and equipment inventory data-base either in edit mode, or view mode.
- Data-bases Consulting MMI Module. It allows accessing to inventory and disturbance data-bases in view mode.
- Analysis MMI Module. It allows accessing to incident and event data-bases either in edit mode, or in view mode. This module allows to access to the Graphical Analysis MMI Module.
- Graphical Analysis MMI Module. It allows the user to analyse manually the oscillograms, offering a complete set of analysis tools like magnitudes measurement, two records display, manual synchronization of records, new analog channels calculation, harmonic analysis, and exporting records to COMTRADE format.
- Statistics MMI Module. It allows the statistical analysis of historical data stored in the inventory and incident data-bases.

- Automatic Communications Manager Module. It is in charge of constructing communication queues.
- Protocol Manager Module. This module performs communication control at one of the communication ports. These are running as many modules as communication ports exist.
- Protocol Emulator Modules. Each type of device requires a module in charge of executing the requests received from the Protocol Manager Module. It emulates the corresponding protocol.
- Synchronization Module. This module synchronizes workstation with a Global Position System (GPS) time signal. This enables equipment time deviation to be monitored and corrected.
- SCADA Access Module. It allows, in an off-line mode, to collect and incorporate SCADA information into basic data for incident analysis purposes.
- Daily Dispatching Operation Report Accessing Module. It allows the Computerized Daily Operations Report issued by Control Centers to be accessed. This facility enables the System to detect incidents that have affected non-remote controlled substations, and also the information that the Daily Operation Report provides on the substations involved in incidents allows a selective list of piece of equipments to be interrogated in the communications cycle.
- Incident Generation Module. Module's function is to identify incidents from the available collection of data, and to associate each incident with its relevant data.
- Automatic Incident Analysis Module. Module for performing automatic analysis of data associated with each incident.

In the next figures, some screen captures of the application and of the web access are shown:



Devices Management Application



Oscilograms viewer

Relays data web access

2.1.2 *Communication management*

The information generated by all the digital protection and recorder devices that exist in substations is collected by workstation. The workstation links with the devices installed in the substations, being able to hold up simultaneously several connections with devices installed in different substations.

The SINAI includes two different communication hardware configurations at the substations:

- The first communication hardware configuration is a multipoint communication scheme with an absolutely transparent multiplexer.
- The second communication hardware configuration has a Code Operated Switch that lets the selection of any of its communication ports.

The configuration relevant to each substation is established in the inventory data-base.

The communication software is structured in three levels:

- At the first level, the Automatic Communications Manager Module selects the devices and substations that must be called and allocates the calls over the different available communication lines.
- At the second level, the Protocol Manager Module performs the operations related with the devices and the substations connections/disconnections and load the third level software.
- At the third level, a specific Protocol Emulator Module has been implemented for each different device and protocol. This level performs an important normalization task in order to keep data in the standard data-bases.

The devices supported by SINAI at this moment are:

- Digital relays: MOR, MCP, DLP from GE-GEPCE, RELZ100, REL5xx from ABB, IRD, IDN from ZIV and PL from Team Arteche.
- Digital Fault Recorders: SOREL EPC from ARTUS, RECIP from Ingelectric TEAM.
- Event recorders: SIGNATEAM from Ingelectric TEAM.

In addition to these devices that have a very specific communication protocol, SINAI will be able to link with any device that uses the PROCOME protocol. This is a protocol used by national manufacturers to communicate protections and local control equipment.

As mentioned before, SINAI is also been modified to communicate with 61850 IED's substations via GPRS or Ethernet.

To make the system able to link any other device, it is enough to develop the corresponding Protocol Emulator Module, without having to modify the actual software. It is possible because of the modular design of SINAI.

The Generation of Automatic Calls (GAC) Module generates a call cycle based on three criteria:

- Manual call. When the operator decides to call some devices, can include them in the communication queue.
- Automatic call. Every device is assigned to a call cycle. There are several cycles with different period and different starting date.
- Incidental call. The Automatic Communications Manager Module establishes the devices involved in each incident occurred in the electrical network and includes them in the communication queue.

The communication subsystem performs an exhaustive control on the results of tried connections, presenting to the expert reports about successful and failed attempts, diagnostics of unsuccessful attempts, devices and substations involved, and statistic information about these topics.

2.1.3 *Data-bases*

SINAI presents a data-base structure that has been adapted to the system hardware architecture, in order to make the best use of its storage capabilities. Thus, the structure of the data-bases is relational type, as it is the present trend in developing data-bases. In this data-base, the inventory is stored, and collects stores and analyses the information of disturbances.

SINAI includes the following ORACLE data-bases:

- Inventory data-base. It holds data about the principal elements of the power system (lines, generators, transformers, breakers.) and the equipment belonging to the protection and recording systems (current and voltage transformers, relays, communications system, digital fault recorders, event recorders,). This data base accounts for the network configuration because it wants to be used to analyse the incidents. It also includes the relationships between relays and breakers, and relays and main components of the power system. The structure of the data-base gives a great flexibility to the user. He decides and establishes in a library which settings of each relay model are going to be stored by the system. This feature lets it handle simultaneously both conventional relays, very simple, and new digital ones with a big number of settings. The history of each relay is kept also. The MMI that handles this data-base includes some powerful tools as copying data from a bay to a new one, what saves a lot of time when a new substation or a new bay has to be added to the data- base.

- Events data-base. This data-base stores the events recorded by any information source of the System, it is, protection and recording devices and SCADA alarms. It has the special feature that all the events have the same structure regardless where they were recorded.
- Disturbances data-base. It holds all the useful information about the incidents, analysis results included. Data such as time, location, cause, duration and kind of the fault, main equipment involved, tripped breakers, affected relays and valuation of its performance are stored in this data-base. It is possible to find out here the history of the performance of a relay or the description of all the faults occurred in a line from its commissioning for instance.
- Oscillograms data-base. The oscillograms are stored in an ORACLE data-base after to compress COMTRADE (IEEE Standard Common Format for Transient Data Exchange) format files. COMTRADE format has been chosen in order to rely in a known standard for information exchange between the different sources and end receivers of data. However, a compressed form of that format is used in order to save storage space.
- Historical and Statistical data-base. It consolidates the oldest Incidents data-base information, making possible to remove this information from the Incidents data-base in order to free hard-disk space.

The System includes all the corresponding MMI for data-base maintenance and consultation. The access to all this data-bases has a corporate character, and it means that any end user connected to the corporate communication network of IBERDROLA can consult the stored information. It is possible to define several user levels through the Control MMI Module in order to restrict data access.

2.1.4 *Automatic incident analysis*

Although this module was planned to be carried out from the beginning of the system, it's being developed nowadays.

The analysis of the incidents that affect the electrical network is going to be performed off-line. Once the communication subsystem collects all the necessary data from the different sources, the Incident Generation Module will start in order to group the information corresponding to each incident. Among the tasks that this module accomplishes, are the following ones:

- Synchronization of each event recording, fault recording and SCADA data.
- Identification of each incident, according to criteria depending on the voltage level of the affected area.
- Association of data to the corresponding incident.

Once all the information is classed, the Automatic Incident Analysis Module will process the data, according to several algorithms, and depending on the available information in the Incident data-bases, it will proceed to the analysis of the incident on such characteristics as:

- Performance of each affected circuit breaker (opening time, reclosing cycle, ...)
- Fault characteristics (type, duration, impedance, distance from line extreme, ...)
- Performance of each involved protection relay
- Behaviour of each implicated electrical position primary equipment.
- Sending of different warnings to the analyst.

The described process will be completely automatic, with no need of user mediation. The results will be presented to the analyst when he demands them through the Analysis MMI Module. This module will allow the user to manually modify or complete the analysed data (to add new events, to change the synchronization time of events, to associate events to another incident,...), when the results of the analysis are not satisfactory, in order to restart the Automatic Incident Analysis Module and obtain new results.

Relating to the oscillograms processing, the automatic incident analysis of SINAI will include the automatic oscillograms analysis that will generate more information about the fault characteristics and its location. Additionally, the Graphical Analysis MMI Module will allow the user to analyse manually the oscillograms saved in COMTRADE format in the oscillograms data-bases. This module will offer a complete set of analysis tools that include:

- Magnitudes (RMS and instantaneous values) and times (absolute and relatives) measurement.
- Manual synchronization of recordings.
- Calculation of additional analogical channels according to arithmetic operations over the registered channels (i.e., to calculate zero sequence current and voltage).
- New analogical signals calculation according to edition and manipulation of registered channels (i.e., to extend fault conditions along postfault period).
- Comparison between registered and calculated channels.
- Harmonic analysis.
- Conversion of recordings to COMTRADE protocol (IEEE Standard Common Format for Transient Data Exchange) or to another format, having the possibility to include different signals to the registered ones.
- A complete interactive help, that offers information about all the terms of the interface.

Of course, this module will allow to recalculate impedance and distance to the fault from the line extreme according to the modified or calculated channels from the MMI.

Obviously, the higher the number of digital protection and recording devices is, the SINAI becomes more efficient. However, SINAI accesses the SCADA event recording information what makes the system very useful even in those networks that have few digital relays but a sufficiently extended SCADA.

2.2 SUBSTATION ASSISTANT: DATA WAREHOUSE AND ANALYSIS AGENTS

M. Kezunovic, Texas A&M University, T. Popovic, TLI Inc

Fault and disturbance data analysis is an important issue in any utility company [1-3]. The importance is related to the impact that fault analysis may have on the speed of a system restoration, quality of a troubleshooting effort, deployment of a given maintenance strategy, risk analysis associated with the asset management, customer satisfaction, etc. With the utility business going though restructuring, deregulation, liberalization, privatization and other similar transformations around the world, it becomes critical that the above-mentioned impacts are realized at full extent while not exceeding a reasonable level of investment.

Finding suitable solutions to the fault and disturbance analysis leads to developing systems for automated analysis of data needed to explain cause-effect relationships between events and consequences. The solution reported in this section has been developed over the last 15 years where the first decade was spent on research and concept demonstrations [4-10] and the last five years on field deployment of commercial solutions [11-21]. The commercial solutions are now in operation at several utilities with projects ranging from single substation application to system-wide uses.

Integrating data where a substation contains several IEDs of different type may be a challenge. A single occurrence of an event can initiate recordings of signals from the same events captured by different IEDs. One approach to the IED data integration is to solve the main issues such as how to handle use of different types of IEDs, different vendors, different software support tools, different communication channels, different data formats, different methods for time synchronization, etc. Even in the cases when dealing with only the data coming from a single IED type but using different IED brands or IEDs from different vendors can pose a problem. This approach usually brings out the issues related to communication protocols and data file formats. To some extent handling of the configuration information is also identified as an issue, but primarily when handling IED specific functions.

Another approach to integration of substation data is to consider how the integrated data will be used [12]. Main difference in this approach is not only to consider the issues related to the substation equipment, but also to anticipate how the information gathered from substations would be utilized. This approach is broader and helps to better understand the requirements such as what substation data needs to be available to support as many different applications as possible. First, it is interesting to understand the actual need for monitoring and recording information in substations and how can the integrated data coming from substations can be used by end users.

A. Common problems with existing IED systems

It is important to note that a lot of power utilities are in some transitional states and are currently introducing new IEDs to their substations. This section identifies common problems users experience with their existing substation IED systems. Some of the problems related to user experiences with existing IED systems are:

1. IED data records cannot be efficiently analyzed manually due to an overwhelming number of records captured in a moderately sized system.
2. Use of different vendor specific programs increases personnel training costs due to distinctively different features as well as the look and feel of different packages.
3. Slow response (for example, manual analysis of IED data takes time) is an impediment if several records supplied by different IEDs for the same event must be uploaded and analyzed. Slow response can also be a result of the communication issues or the fact that different types of IEDs are used, or that the used devices are coming from different vendors.
4. Lack of ability to integrate data coming from different IED types and models is evident when one attempts to integrate the different IED systems and services. Sometimes different IED

subsystems require different communication channels and interfaces, different protocols, and almost on a regular bases use different data formats.

5. Highly-skilled people devote a lot of time to routine tasks because most of the records may just confirm the proper operation of the equipment being monitored.
6. Non-selectivity (for example, IED data records are not event prioritized) is an issue if the operator must sort out the records for the analysis purposes. This generally depends on the type of the IED and its functions, but when dealing with multiple devices it is a common problem.
7. Inefficient data archival and retrieval due to rather primitive means of time-stamping, storing and retrieving the captured data. Some of the devices are being installed for their main functions and these problems occur when one wants to use them as recording devices. For example, a process of replacing electromechanical relays with digital relays does not always include considerations regarding the possible use of digital relays as recording devices. It is common that providing communication resources to connect to these substations as well as to interconnect the IEDs inside the substations comes after the relays have been installed.

B. Multiple Uses of Substation Data

In answering the question how the substation data can be used one can categorize the possible uses into following main groups:

- Data archival and exchange purposes,
- Easy access and viewing,
- Different data analysis functions.

Data Archival and Exchange Purposes – a common goal for almost all end users is to provide a safe and secure data archival system and to be able to exchange the data with other users within the same group or company or with others. Having the substation data coming from a variety of IED types and vendors it is very important to utilize unified data formats and system configuration descriptions. The data archival system should provide for easy access, search through, and retrieval of the data whenever needed. The data formats and configuration descriptions should provide sufficient information related to each event recognized and recorded by the network of available IEDs in the system.

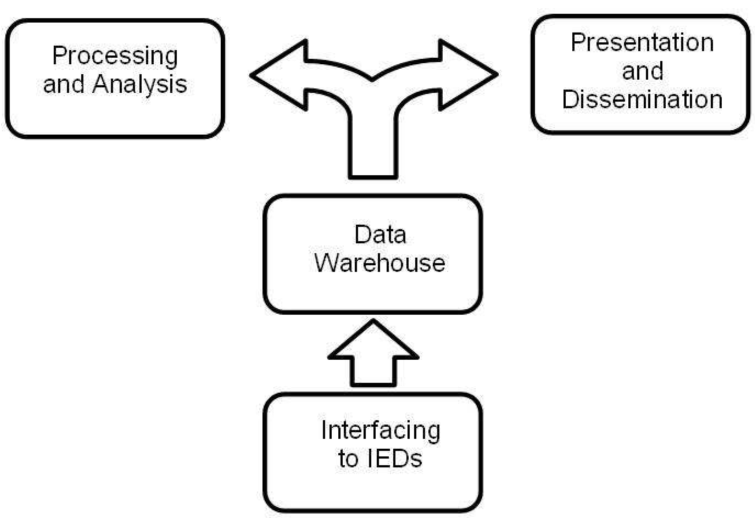
Easy Access and Viewing is commonly lacking in the existing IED systems and is a cause of lots of the problems discussed above. End users want to be able to access and view substation data. In some cases there is a need even to combine the data coming from different IEDs that pertain to same event or group of events. Typically, users want to be able to quickly locate and display event data in order to visually inspect and manually analyze the event information. Additional tools that support this process can be used here. Examples are: reading RMS values, Fourier analysis and viewing of harmonics, scaling, zooming, etc. An important issue for an end user here is to be able to use same viewing tools for all event data regardless of the source (IED type or vendor or configuration).

Different Data Analysis Functions – having substation IED data retrieved and integrated opens endless possibilities for utilization of all kinds of automated data analysis functions. Some examples are determining the fault type, verifying system protection operation, calculating fault location (single- or two-end), performing redundancy checks, etc. Most of these functions can be implemented automatically as the data become available. Automated analysis can provide user with a variety of additional information based on the partially or fully processed IED data hence significantly affecting the decision making process and system restoration. The main challenge is proper handling of system configuration information and data formats. Having event data available without being able to map the data to the actual power system components being monitored and without knowing the system component parameters makes the automated analysis impossible.

TLI has proposed an open system approach to perform automated analysis of integrated substation data. A concept of utilizing universal substation data warehouse as a connecting point for different analysis functions is presented in a form of a framework for application integration. The main focus is on the analysis agents that utilize intelligent electronic device (IED) data collected in power system substations. The framework is introduced through its application to a case study. Many different analysis agents from different vendors may be integrated utilizing the proposed framework.

2.2.1 *System description*

The proposed open system framework is shown below [12]. The concept discussed in this section is addressing another important angle – analysis agents and their interaction. Each analysis agent can be seen as an individual application that utilizes data from the warehouse as an input data and stores its output data back to the warehouse or to a user via user interface. To achieve an open system design, it is absolutely necessary to provide users with a transparent data warehouse solution that can be easily maintained and used by variety of analysis agents. As shown in the figure, the key for the integration is the data ware house. The main building blocks of the open system solution are discussed next.



Concept: Integrating Agents Through Data

A. Interfacing to IEDs

Software modules for data integration provide interfacing to IEDs to allow automated retrieval of newly recorded data. This interfacing is typically implemented by using vendor specific software for data retrieval and then dedicated routines for importing the IED data into the file repository. Sometimes, the interface is implemented by the use of direct communication to IEDs. The key here is automating data format conversion and file format unification. The solutions discussed in this paper provide modules that can interface to variety of IED products from different vendors.

B. Organizing data warehouse

Being identified as a central block in the solution it is critical that the data warehouse is implemented to be easily utilized by both the users and application agent developers. The database functions should be implemented using as standardized as possible database engines. A good approach is using standard SQL database engine with an instructions subset that is common across SQL database implementations. The files should be stored in manageable file repositories to allow an easy access and maintenance of the data files.

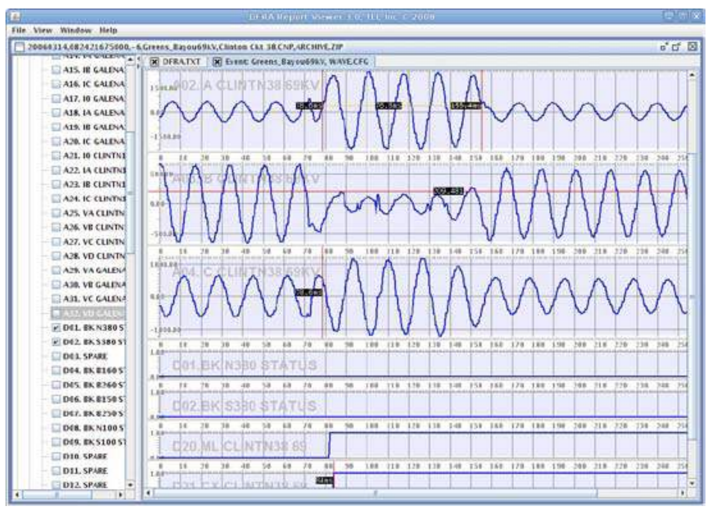
C. Processing and analyzing IED data

The simplest model of the processing and analysis functions (core functions) is that a module reads data from the repository, creates an output without corrupting the original data, and the output results are stored back into the repository into location predefined for the processing results. In some instances, processing and analysis functions may have their own data repositories and/or databases that may be decoupled from the integrated data. The processing and analysis functions are typically implemented as stand-alone programs and provide fully automated mode of operation. The key feature of the open system design is the ability to integrate software agents from different vendors.

D. Presenting and disseminating results/reports

When creating a solution by integrating different applications several user interfaces may be created. An example is shown next. While each core application may have its own user interface, a universal approach may also be feasible. Main functions of a universal user interface are

- Event browser: enabling navigation through event tables
- Event viewer: displaying event waveforms and reports
- Configuration editor: providing tools for editing and creating configuration setup
- Top level user interface (web portal): directing user to specific application
- Dissemination: accessing data via Graphical User Interface (GUI) and/or utilizing automated notifications (pager, email, printer, fax)

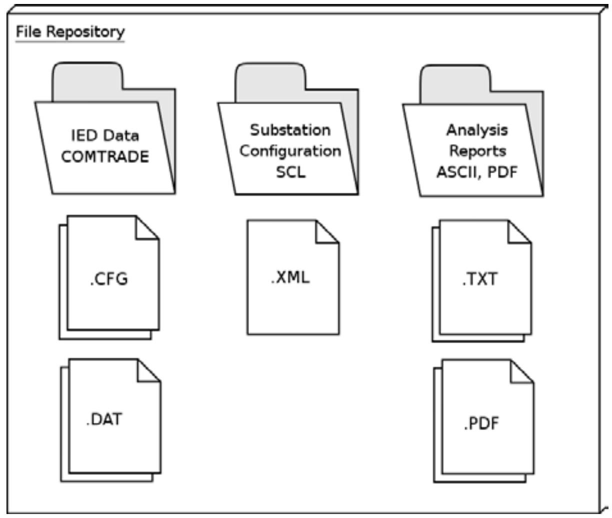


DFR Assistant™ Event Data and Report Viewer

2.2.2 *Integration and use of substation data*

The example of the substation data warehouse design combines the use of a file repository and a database engine in attempt to get the best from both worlds. The file repository is used to store the following:

- IED data
- Configuration data (IED, substation, agents)
- Analysis reports/results



Data Warehouse Example – File Repository

A. IED data

The example of the substation data warehouse design combines the use of a file repository and a database engine in attempt to get the best from both worlds. The file repository is used to store the following:

- Proper time synchronization, most commonly through GPS or NTP.
- Use of unified data format (COMTRADE, IEEE Std C37.111-1999).
- Utilization of file naming convention (modified IEEE recommendation C37.232-2007).

B. Configuration data (IED, substation, agents)

- Providing universal substation configuration in XML file format (SCL).
- Keeping the configuration history (to be able to retrieve configuration for the given time stamp).
- Enabling import/export of configuration data to core applications.

C. Analysis reports/results

- Analysis reports to be kept in ASCII, XML, PDF (preferably all). Use of widely accepted standard formats makes the system more open and easy to interface with third party programs, which provides more flexibility for the users.

- Utilization of proper file naming convention (same as used for IED data files with an optional field to identify report type)

D. Additional Considerations

- Automatic synchronization of all the new IED event data to appear in the repository in a timely matter.
- Use of "read only" format for the repository data when accessed by the applications. Applications using database should not modify original IED data created in the integration layer.
- Allowing addition of new data types in the file repositories. It is anticipated that additional data may be artificially created (by agents) "virtual IED data".

In this example the focus is on the triggered data captured by Digital Fault Recorders (DFRs) or Digital Protective Relays (DPRs) The solution may be expanded to provide for storage of periodic or log type data (such as generated by PMUs or PQ meters) or agent generated data (merging substation IED data into "virtual IED" or "virtual substation" data).

2.2.3 *Framework for application integration*

Data warehouse has been identified as a main connecting point for analysis agents and other applications. In order to enable functional integration of different applications, the framework for applications implementation has been developed as depicted in section 2.2.2.

The framework for application integration is focusing on implementing four interfacing components:

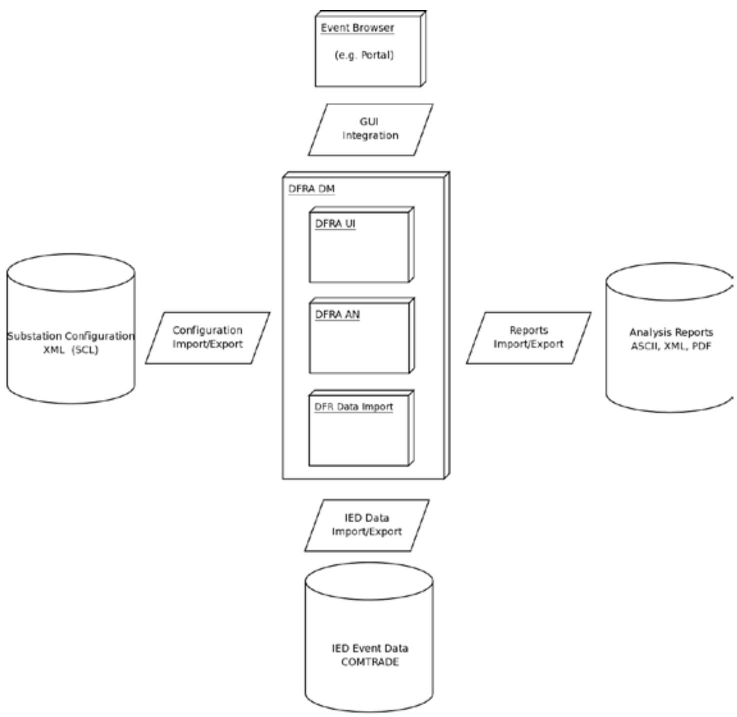
- IED data import/export.
- Configuration data import/export.

- Report import/export.
- GUI integration (optional).

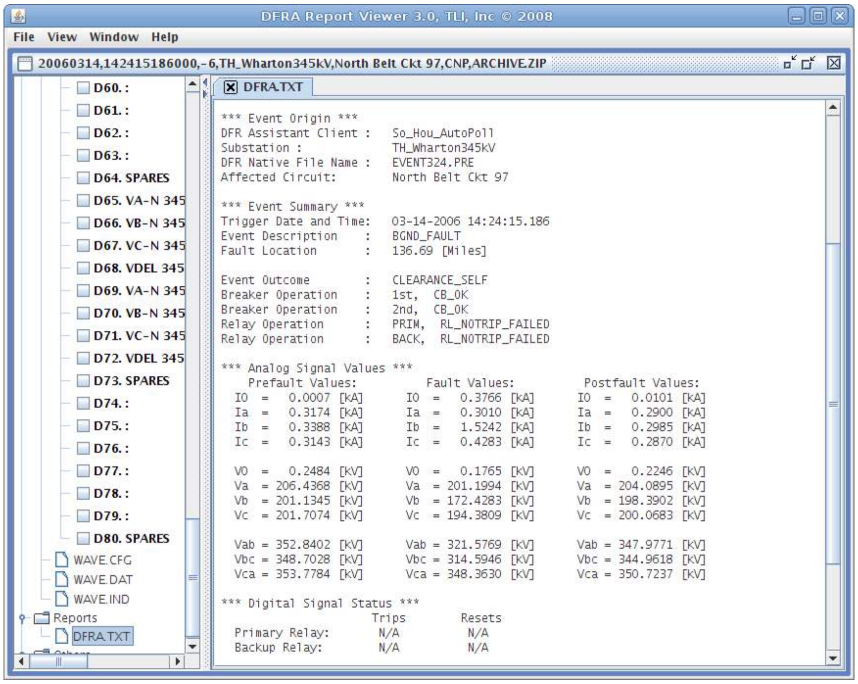
First three interfaces are a direct connection to the warehouse. These should be implemented universally and transparently for different application agents. The optional GUI integration is only to enable user to directly communicate with and configure the analysis agent.

DFR Assistant™ agent processes newly downloaded DFR records. The analysis uses both the converted DFR data (COMTRADE file) and system configuration data to create an analysis report.

The analysis reports are stored back to the data warehouse and available for both the users and other agents.



Typical Processing and Analysis Agent



DFR Assistant™ Agent – Analysis Report

2.2.4 *Example implementations*

This section provides examples of an open system design and its uses in building different solutions. The examples are related to on-going deployment projects at FirstEnergy, CenterPoint Energy, and New York Power Authority.

A. Data integration (Multiple IED types)

In the data integration deployment example the concept is being implemented in a two-substation setup. The setup requirements are:

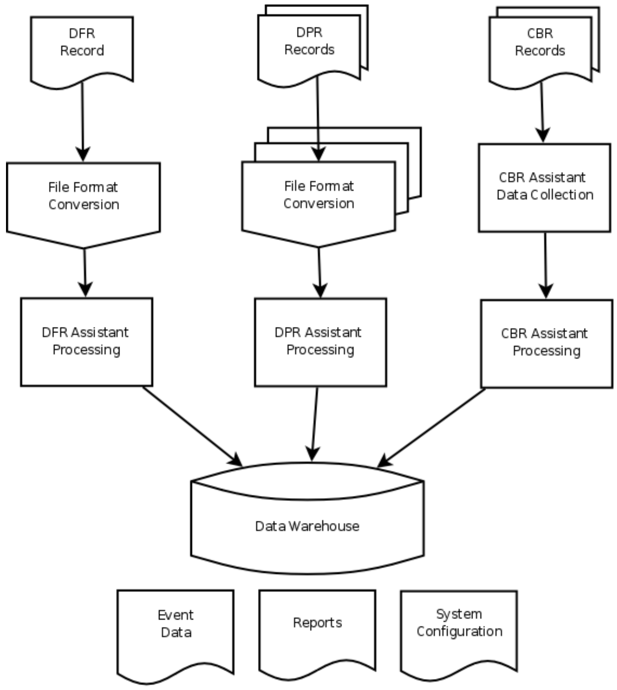
- One Digital Fault Recorder (DFR), five Digital Protective Relays (DPRs), and ten Circuit Breaker Recorders (CBRs) in the first substation.
- Radio modem communication from CBRs to the control house.
- One DFR and two DPRs in adjacent substation (for collecting two-end transmission line records).
- Data warehouse

- Processing agents for the three IED types.
- User interfaces (web based).

The data from three different types of IEDs is being integrated and automatically processed by individual IED-based processing agents. All the data coming from digital fault recorders (DFR), digital protective relays (DPR), and new device called circuit breaker recorder (CBR) is collected and stored in the data warehouse. The processing and analysis agents make sure that the data file formats are being unified (COMTRADE, proper file naming). DFR Assistant™ agent provides detailed analysis and fault location calculation based on DFR data. DPR Assistant creates the packages with event data (oscillography) and reports obtained from relays.

Circuit breaker recorder device monitors the signals inside the control circuit of circuit breakers. CBR Assistant™ agent creates reports based on extracted signal features and status changes relevant to the trip and close operations of circuit breakers.

All the IED data is integrated into universal data warehouse and accessible through web-based user interface, also implemented as an application agent.



Data Integration Solution

B. Adding Digital Relay Data to DFR System

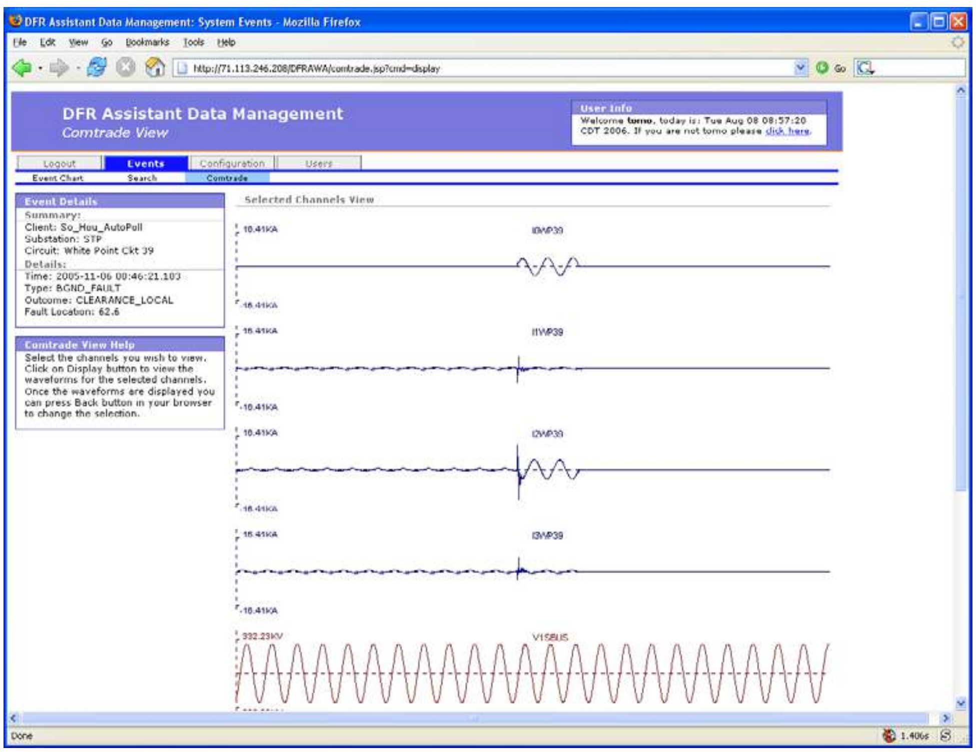
Existing system with DFR data integration and analysis solution based on the DFR Assistant™ Agent is being expanded with digital relay data. The setup requirements are:

- ~50 substations
- ~50 DFRs, one DFR vendor, different vintages (old and new models)
- Two master stations
- Data Warehouse
- DFR data processing agent
- User interfaces (web and desktop)

Primary focus in this example is to expand the DFR solution to include the relay data coming from digital protective relays in the transmission system. Initially, a small number of relays are being added into the picture with a goal of covering different vendors and models in the future. The main features are:

- Two major relay vendors
- Distance and current differential relays
- File format conversion, proper file naming
- Relay data processing agent

The primary issue in this example is utilizing universal presentation layer for all the data, as well as the results/reports. Both the web-based and desktop-based user interface versions utilize transparent access to the data in the warehouse for different purposes. The events are listed and accessed the same way regardless of the IED type, model, or vintage. An example of the solution is shown below.



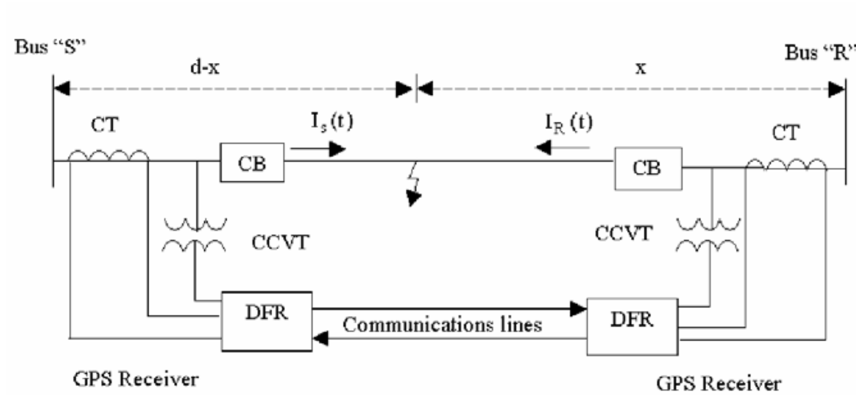
Data Integration Solution

C. Two-End Fault Location Calculation Agent

This example covers an implementation of a DFR data integration and analysis solution enhanced with two-ended fault location. The main setup requirements are:

- ~20 substations
- ~20 DFRs, two vendors, different vintages

- ~20 master station setups (in each substation)
- Data Warehouse
- DFR data processing agent
- User interfaces (web and desktop)
- Two-end fault location calculation agent



Two ended fault location setup

The two-end fault location agent in this example is being implemented to work off of the data from the data warehouse that combines records from two ends of a transmission line. The configuration of the two-end Fault location algorithm deployment is shown above. The agent interfaces into the repository and scans the newly stored event data looking for pairs of DFR records that correspond to two ends of the same transmission line and same fault event. The actual operation of the agent is triggered by occurrence of a DFR data record and report created by analysis agent from one end. The biggest challenge in this case is obtaining "good" test data as the DFR records have to be time synchronized and there is not much historical data available. For the purpose of initial setup and evaluation the two-end fault location algorithm is being tested with in-house simulated faults.

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2.3 PEDA-PROTECTION ENGINEERING DIAGNOSTIC AGENTS: AUTOMATED ANALYSIS SCADA AND DFR DATA FOR THE POST-FAULT DIAGNOSIS OF POWER SYSTEM DISTURBANCES AND THE ASSESSMENT OF PLANT CONDITION

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The proliferation of monitoring equipment on transmission and distribution networks has resulted in an ever-increasing amount of data being made available to utility engineers. Data provided by Supervisory, Control and Data Acquisition (SCADA) systems, Digital Fault Recorders (DFR), microprocessor-based protection relays with fault recording capabilities, travelling-wave fault locators, and condition monitoring systems for circuit breakers and transformers, can aid engineers in making more informed, and potentially more profitable, power system operations and asset management decisions. The belief that monitoring can provide information which can lead to improved management and operation of the power system is one of the commercial justifications for the investment in monitoring systems and meeting the cost of maintaining and running those systems. However, there are a number of barriers to the effective use of this data:

- The raw data is often uninformative: information relating to plant health or the performance of the power system is implicit rather than explicit. Expert interpretation of the data is required;
- As the number of monitoring devices deployed on the network increases, the volume of data they produce, especially under storm conditions, renders manual analysis time-consuming if not intractable; and

- Data from different monitoring systems is related however it tends to be stored in different databases and file systems. Relating and collating this data can be a time-consuming task.

While utilities wish to use monitoring data to inform both power systems operations and asset management decisions, without adequate support for the analysis and management of the data, it is difficult for utilities to fully realize the benefits of monitoring.

In order to automate the analysis of SCADA and digital fault recorder (DFR) data for a transmission network operator arm of SP Energy Networks' business, SP Energy Networks and the University of Strathclyde have developed a multi-agent system which integrates a number of legacy intelligent systems for analyzing power system data. The integration achieved through multi-agent systems technology enhances the diagnostic support offered to engineers by focusing the analysis on the most pertinent DFR data based on the results of the analysis of SCADA. In addition to providing basic data management and archiving functionality, PEDA provides automatic analysis of the disturbances on the power system, and evaluates the performance of the protection schemes. Trials with historical data were completed in 2003 [1]. In 2004 an initial subset of the PEDA system's agents were deployed at SP Energy Networks for online trials. Results of the online trials were reported in [2].

This appendix give a brief description of PEDA, provides screenshots of the web-based interface to its results database and, for the benefit of other analysis system developers, discusses the lessons learnt from the both the initial and ongoing development of implementation of PEDA deployed at SP Energy Networks.

2.3.1 *System monitoring at SP energy networks*

SP Energy Networks manage, operate and maintain the transmission network in central and southern Scotland. The transmission network comprises a total 272 circuits at 132kV, 275kv and

400kV with interconnection to the transmission network managed by National Grid in England and Wales to the south, the transmission network managed by Scottish and Southern Electricity in the highlands to the north, and to Northern Ireland by a DC link. In terms of monitoring, it is arguably the most the comprehensively monitored part of the UK grid: at the time of writing over 300 DFR units were installed on the network. These units are GPS synchronized and auto-polled at least once every 24 hours with any new records being downloaded to the utility's headquarters. Through a system called PS Alerts, SCADA data from the Energy Management System is made immediately available to staff outside the control room. In addition, a number of circuits are equipped with travelling-wave fault locators, to which engineers have dial-in access.

Engineers at the utility can use these data sets above to build a picture of the power system's response to a disturbance. SCADA data is immediately available and can be used to quickly identify the occurrence of an incident as well as be used as the basis of a basic assessment of a protection operating sequence. Fault recorder data can provide a more complete picture, allowing the performance of the protection scheme to be assessed based on voltage and currents seen by protection relays and measured operating times of relays, inter-trips and circuit breakers. The distance-to-fault derived from the calculated impedance seen by the fault recorder can be compared and corroborated with the distance-to-fault derived from travelling-wave fault locator data. For each protection operation sequence on the transmission network, engineers at SP create a report which gives details of their expert interpretation of the data and an assessment of the performance of the protection scheme.

While engineers at the utility are adept at analyzing the data, the volume of data coupled with time constraints on the few engineers with the requisite expertise make manual analysis difficult. For example, in 2003 the DFR network captured in excess of 20,000 records even though the network experienced only a handful of disturbances (under 70). Over the same period the SCADA system generated around 3,000,000 alarms. The last major storm experience by the utility in 2002 resulted in the transmission network being subject to 166 disturbances in 24 hours with most occurring in a four-hour period resulting in 1650 fault records and 15,000 SCADA alarms.

When the development of PEDA began, the authors' aim was to analyze data from a protection engineering perspective, i.e. automate the assessment of protection performance. However, over the course of its development, the way that engineers at the utility use DFR data has extended beyond protection performance assessment and the analysis of disturbances. A key result learnt through the deployment of PEDA is that relatively small percentage of the fault records captured outside storm conditions relate to protection operation sequences. Engineers at the utility discovered that amongst the large body of data unrelated to protection operations are records containing indicators of plant condition, e.g. records which indicate problems with voltage transformers (VTs). This is discussed in more detail on the further development section of this appendix.

2.3.2 *Integrated analysis of SCADA and DFR data*

PEDA is the result of a nearly two decades of research collaboration between the University of Strathclyde and SP Energy Networks. Since the early 1990's the research partnership has led to the development of a number of different SCADA and DFR data analysis tools. Alarm Processing Expert System [3] was developed both as a control room decision support tool and later as a support tool for protection engineers at SP (APEX was also developed in partnership with ASCADA as integrated product called APDEX for the ENMAC system). The University of Strathclyde also developed a model-based approach to protection analysis as well as tools for the automatic classification of DFR records [4][5]. As a result, by the end of the 1990s, lessons learnt from the development of those tools had led to the development of a number of legacy standalone intelligent systems suitable for the deployment at the utility:

- **The telemetry processor**: A descendant of APEX, the telemetry processor is a rule-based expert system that assesses the operation of protection based on SCADA data. From a live SCADA feed, the telemetry processor identifies what engineers at SP Energy Networks term ‘incidents’ and ‘events’. An ‘incident’ is a group of alarms that relate to a disturbance on a particular circuit or item of plant. ‘Events’ are alarms or groups of alarms that make up a part of an incident, e.g. alarms indicating protection operation, circuit breaker movement, the initialization of delayed auto re-close (DAR) sequences or communication signals sent between substations. For each incident, the telemetry processor assesses protection performance using knowledge elicited from protection engineers and highlights if further investigation is required. Details of the implementation of the telemetry processor can be found in [6].

- **A model-based reasoning engine for the validation of protection operation**: The model-based reasoning (MBR) engine, which is part of an MBR toolset [7], implements a model-based approach to the analysis of DFR data [8]. The MBR engine propagates DFR data through a model of the protection scheme thus predicting the expected behaviour of the components of the scheme. By comparing simulated protection behaviour with the actual behaviour observed by the fault recorder, the MBR engine can identify components of the scheme which may not have operated correctly, e.g. the failure of a trip relay to operate or a missing or late receipt of an inter-trip signal. The MBR engine supports the use of various types of protection relay model, including the detailed dynamic protection models described in [9].
- **A fault record interpretation expert system**: Also part of the MBR toolset [7], the fault record interpretation expert system is a rule-based system with two functions: it converts fault records from the COMTRADE format to the format required by the MBR engine and performs some additional interpretation by classifying the type of disturbance, e.g. red phase to earth, and determining the total fault clearance time.

Each of the tools above offers assistance to the protection engineer by removing the burden of manual analysis of individual types of data, however, as discussed earlier, diagnostic support can be enhanced by using the results of analysis of SCADA data to focus the analysis of DFR data. By comparing when a fault record was captured with the timing and location of power system disturbances identified from SCADA data by the telemetry processor, it is possible to perform a first-cut classification of the DFR data. Records can be classified as:

- Directly related to an incident: a fault record captured during an incident from the end of the circuit involved in that incident.
- Related to an incident: a fault record captured during an incident from a substation that contains one of the ends of the circuit involved in the incident, however the record does not contain data from that particular circuit.
- Indirectly related to an incident: a fault record captured during an incident by a fault recorder in a substation that was not directly involved in the incident. The fault recorder has triggered or been cross-triggered because of the voltage depression created by the disturbance.
- Miscellaneous fault record: a fault record that cannot be associated with an incident, i.e. no incidents occurred at the time the record was captured.

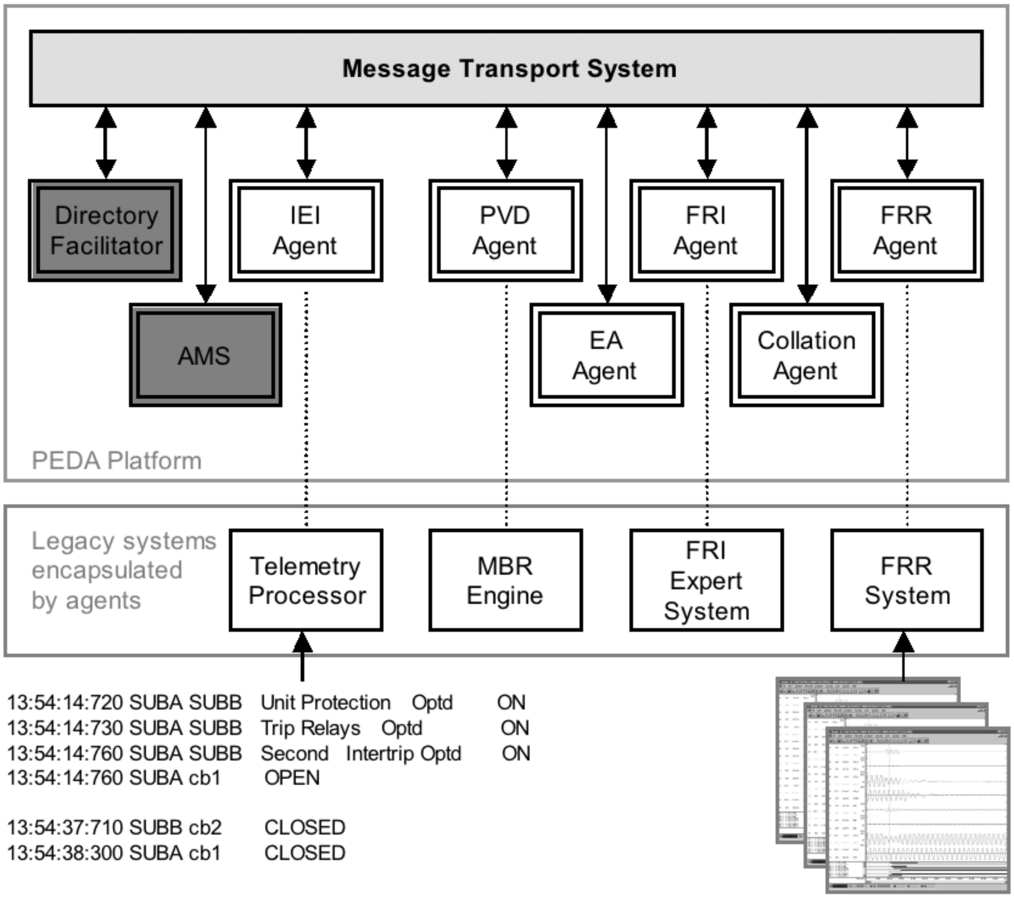
By performing the first-cut classification above, it is possible to quickly identify and highlight the fault records which are of immediate interest to protection engineers, i.e. records that are directly related to incidents, without having to analyze the content of the record. The analysis of these records using the fault record interpretation expert system and the MBR engine can then be prioritized based on the relevance of the record to protection engineers, resulting in more timely decision support.

Earlier research by McArthur et al [4] discovered that, not only were engineers using multiple data sets during post fault analysis, they were also using the results of the analysis of one data set to focus the analysis of another, i.e. the SCADA data to focus the analysis of DFR data. Because SCADA data was available immediately, engineers were using it to identify when and where on the network protection operations had occurred and if there was any evidence of a genuine power system fault. This knowledge was then used to focus the retrieval and analysis of the DFR data. McArthur et al [4] argued that an existing set of tools for SCADA and fault record analysis could be integrated to automate this process and provide enhanced diagnostic support. Based on the automated analysis of SCADA using alarm processing techniques, the retrieval and analysis of fault records from sites where incidents have occurred can be prioritized.

The problem then became one of how to integrate these legacy intelligent systems. While integration in the laboratory was straightforward, in the industrial context a number of practicalities arise: the software and hardware associated with monitoring equipment is liable to change as new monitoring technologies become available; any integration strategy has to allow the addition of new data sources, improved data analysis tools and version changes to manufacturers' software. In 2001, after failed attempts at maintaining a modular software architecture, the authors began investigating the use of multi-agent systems technology as a means of building a flexible and extensible post-fault analysis system. The interested reader can find a comprehensive description of MAS technology and its potential benefits from a power engineering perspective in [10].

2.3.3 *System Description*

MAS technology, through the use of standardized agent communication languages and standardized open architectures, can provide a means of building flexible, extensible, distributable software systems [10]. The de facto standards for MAS are the Foundation for Physical Intelligent Agents (FIPA) standards.



PEDA in relation to the FIPA Agent Management Reference Model

The architecture of the PEDA system is based on the FIPA Agent Management Reference (Figure 1) model which defines “the normative framework within which FIPA agents exist and operate. It establishes the logical reference model for the creation, registration, location, communication, migration and retirement of agents”. It includes two utility agents: the agent management service agent (AMS), which is compulsory, and the directory facilitator (DF) agent, which is optional. The AMS acts as white pages, maintaining a directory of agents registered with the MAS.

The DF acts as yellow pages, maintaining a directory of agents and the services they can offer other agents. An agent can use the DF to search for other agents that can provide services that will aid it in fulfilling its own particular goals.

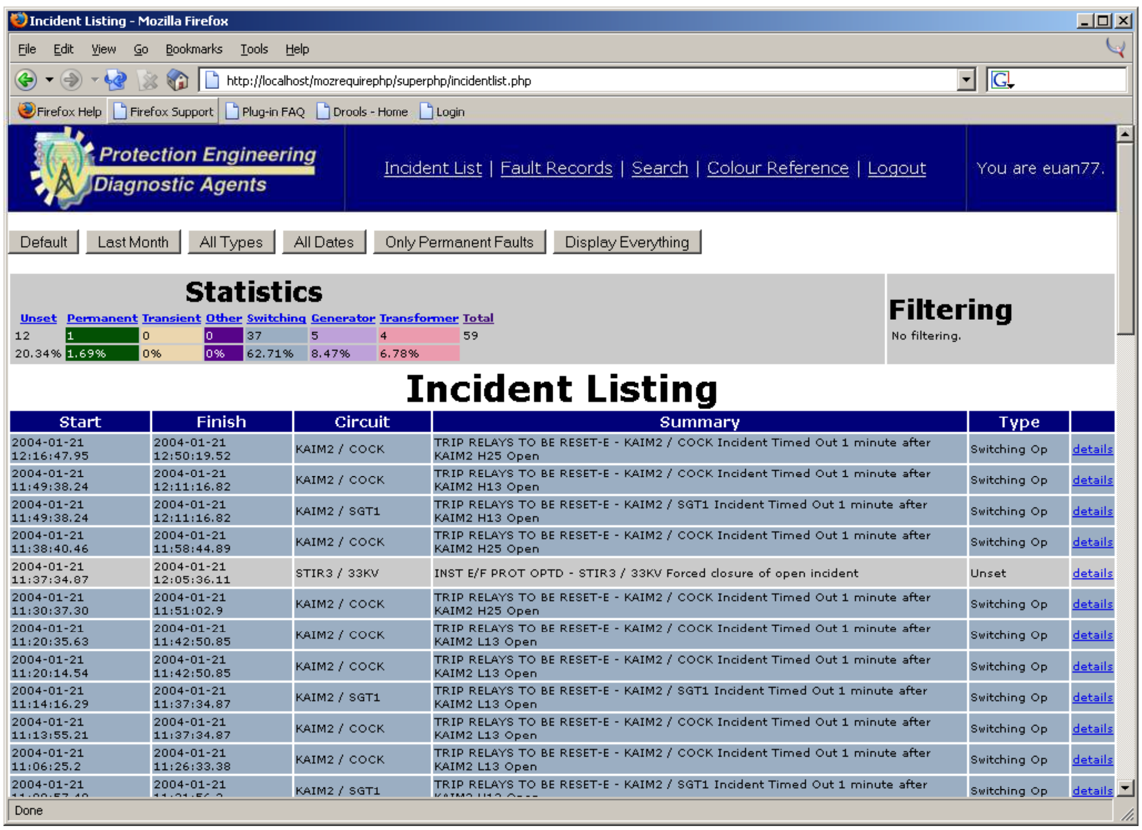
PEDA achieves its functionality by wrapping the legacy intelligent systems as autonomous intelligent agents which support the FIPA standards for interoperable multi-agent systems.

In addition to the information discovery agents required by FIPA, PEDA comprises the following data management and analysis agents:

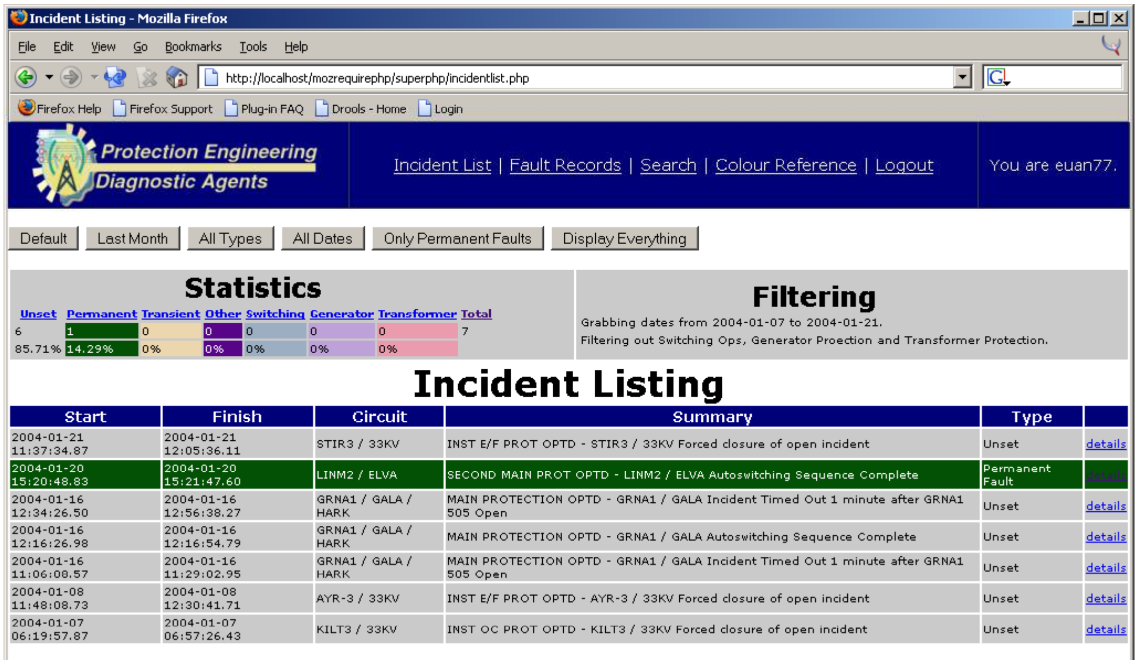
- An Incident and Event Identification (IEI) agent which encapsulates the telemetry processor;
- A number of Fault Record Retrieval (FRR) agents which interface with the fault record retrieval system used by SP PowerSystems;
- A Fault Record Interpretation (FRI) agent which encapsulates the fault record interpretation expert system of the MBR tool-set;
- A Protection Validation and Diagnosis (PVD) agent which encapsulates the MBR tool-set's diagnostic engine;
- A Collation Agent which gathers information from the agents above and stores it in a relational database; and
- A number of Engineering Assistant (EA) agents which engineers can configure to inform them of new diagnostic information as soon as it becomes available.

Full details of how the agents interact, the standards they employ and how they were designed can be found in [2]. However, for the sake of brevity, the process PEDA executes can be summarized as follows.

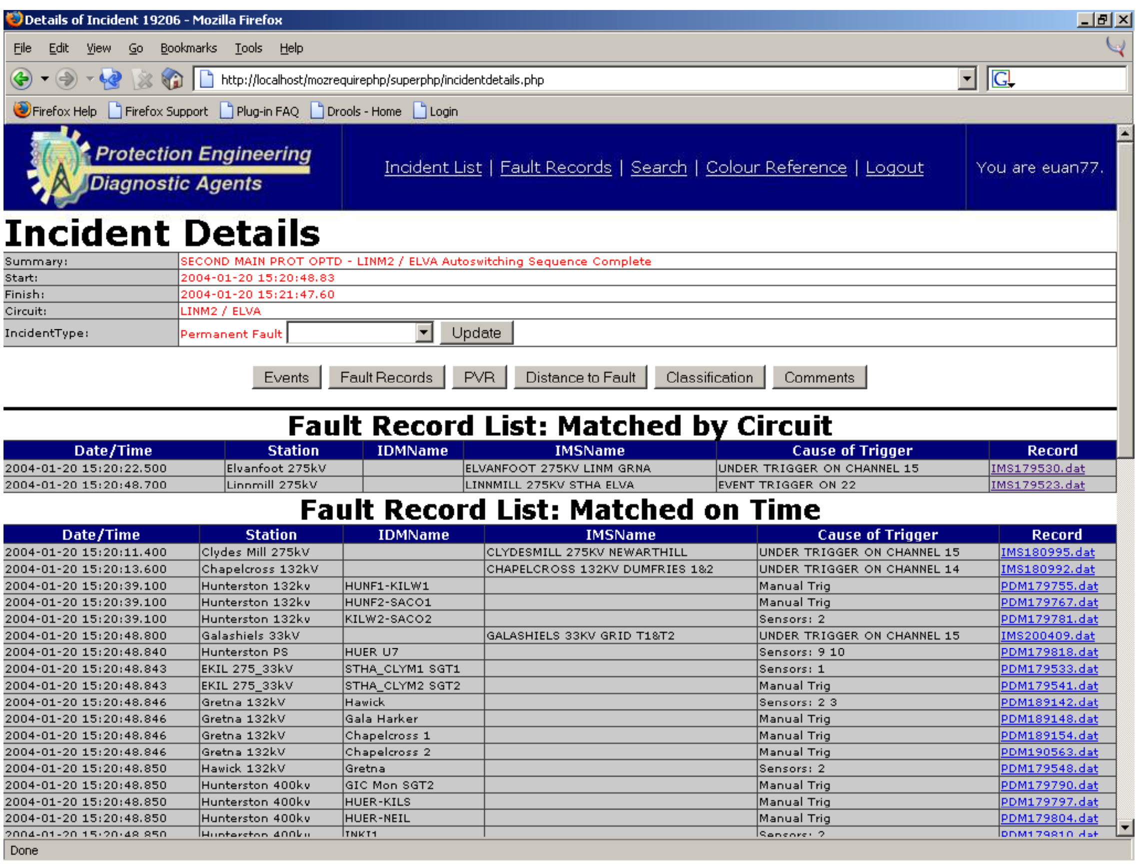
When a fault record has been retrieved, the FRR agent asks the IEI agent if there was an incident on the network at the time the record was generated. The IEI agent replies with the details of the any relevant incidents. The FRR agent can then perform the first cut classification of the DFR data before sending it to the FRI agent and PVD agent for analysis. The results of all analyses and the fault records are sent to the collation agent which stores them in a relational database. This database has a web-based front-end which allows engineers to access the information generated by PEDA via the corporate intranet. The web front end gives details of all the incidents that the telemetry processor has identified and all the records that are related, directly and indirectly to the incident. By clicking a hyperlink on the web browser the user can view the records. As a result, records are classified and made available over the utility's intranet within seconds of being downloaded from the substation.



Incident list accessed through PEDA's web front-end. Clicking on the "details" hyperlink displays results of the Telemetry Processor automatic analysis of the SCADA data.



Incident list filtering out incidents relating to transformer and generator protection operations



Fault records related to incident (highlight in green in previous figure), downloadable.

2.3.4 *Operational Experience*

After testing the full version of PEDA, described above, on historical SCADA and DFR data in the laboratory, a subset of the system's agents were deployed at SP Energy Networks in 2004. For initial testing the IEI agent, 9 FRR agents, the collation agent, and its database and associated web server were installed at the utility. The FRI agent and PVD agent were not deployed at that stage. The utility wished to test a commercially available, and thus commercially supported, fault record classification tool. Based on their experience with that tool a decision would be made whether or not to include that in PEDA rather than the tool developed at the University of Strathclyde. Research has now restarted concerning the rollout of the University's fault record classification tool.

Model-based validation of protection operation requires a database of protection settings and models of the protection schemes in service to be maintained. The utility wished to explore the possibility of using existing protection settings databases rather than having to maintain a dedicated database for the PVD agent. As a result, the PVD agent was not included in the initial rollout although its effectiveness has been demonstrated with historical data.

Results of the initial trails have already been reported in [2]. From the research perspective, in addition to demonstrating the efficiency of the integrated approach, the trials demonstrated that MAS technology had matured to the point where it could be used for data analysis applications in power engineering and could display the robustness utilities require. The trials also illustrated some of the ancillary benefits of MAS: the technology lends itself to incremental/staged roll out of functionality as well as the removal of redundant functionality. Initially 9 FRR agents were deployed, one for each type of fault recorder and version of the DFR unit manufacturer's software. As the firmware on a particular model of recorder was updated, the FRR agent associated with that model and previous software version was easily removed from the system without affecting the other agents.

During the deployment of PEDA additional knowledge elicitation meetings were held with the utility's chief expert in fault record analysis to investigate the kinds of additional information that can be gleamed from both the fault records relating to incidents and the miscellaneous fault records. These meetings also helped researchers at the University of Strathclyde to identify areas where the automated analysis of DFR data could be extended in the future.

2.3.5 *Further Development*

Active development of PEDA was restarted in 2007. Plans include the roll out of the existing PVD and FRI agents. Since the hiatus in the development of PEDA, researchers at the University and engineers at the utility have been investigating tools at techniques for the automatic analysis of the miscellaneous fault records. Through knowledge elicitation with the utility's engineers it was discovered that information relating to the health of plant could be found in those records. Reference [11] describes how DFR data can be used to identify VT problems and impending VT failures. SP Energy Networks also uses their DFR units for CB condition monitoring by capturing the trip coil current trace on one of the recorder's analogue channels. The authors are currently investigating the possibility of using automated analysis techniques developed for SP Energy Networks distribution circuit breaker condition monitoring programme [12, 13] for transmission breakers. It is in this respect that MAS technology comes into its own. As discussed earlier, MAS offer a standardized open architecture; data analysis agents can easily be added to or removed from the MAS. It is this property that makes MAS a prime candidate technology for automated data analysis given utilities ever changing data analysis requirements and advances in monitoring technologies.

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