POWER SYSTEM MONITORING USING INTELLIGENT TECHNIQUES AND SYNCHRONIZED SAMPLING

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Abstract– This paper discusses new approaches to real-time power system monitoring. The new approaches are based on the use of intelligent techniques and synchronized sampling. The intelligent techniques include utilization of neural nets and expert systems for automated analysis of the substation equipment operation. The synchronized sampling at two ends of a transmission line provides for accurate fault location and phase angle difference detection. The two approaches enable an accurate real-time detection, classification and location of faults which leads to improved monitoring of the related equipment. The paper discusses implementation details using the SCADA subsystem of an Energy Management Systems (EMS).

Keywords: Fault Detection, Fault Location, Fault Diagnosis, Neural Networks, Expert Systems, Synchronization, Supervisory Control

1. INTRODUCTION

Application of intelligent techniques to power system control, protection and monitoring has been an area of growing interest in the past several years. As a result, a number of papers were presented on this topic (ESAP, 1988; ESAP 1989; ESAP 1991; ESAP 1993; ISAP 1995). However, closer analysis of the applications indicates that very few papers were related to the real-time applications of intelligent systems. This is understandable since it is well known that the intelligent techniques, including expert systems, neural nets and fuzzy logic, do require extensive processing time. Therefore, it was difficult to take advantage of the intelligent techniques in the real-time applications.

Another area of growing interest is the application of synchronized sampling. Some recent studies indicate that there is a great potential for using the Global Positioning System (GPS) of satellites to provide synchronization of data sampling in control, protection and monitoring applications (Phadke, et al., 1994). Most of the applications of synchronized sampling were related to the phasor measurements. However, the phasors are only defined during the steady state conditions. Therefore, the transient conditions require some new approaches to the utilization of synchronized sampling for real-time detection of system disturbances.

This paper offers a new approach to real-time monitoring of power systems. This approach allows for significant improvements over the existing techniques. The improvements are related to the processing speed, accuracy and selectivity. The improvements are achieved using the intelligent techniques and synchronized sampling.

The first part of the paper describes the framework for implementation of the new monitoring techniques. The second part discusses the use of the expert system and neural net technologies for real-time analysis of the substation equipment operation initiated by protective relays. Next, the use of synchronized sampling in enhancing the fault location accuracy and phase angle difference detection is described. The substation equipment requirements and implementation approaches for the new techniques are also outlined. Various directions of including the new techniques in the overall Supervisory Control and Data Acquisition (SCADA) solution are presented at the end.

2. IMPLEMENTATION FRAMEWORK

2.1. Substation Equipment

The existing substation equipment varies from one utility to another. It differs, both in the technology used (electromechanical, solid state, computers) and the type of the devices selected (different relaying schemes, variety of the monitoring equipment practices). As an illustration, a summary of the substation equipment that may be found in the U.S.A. utilities is given in Figure 1. It is important to recognize that there may be no substation that will have all of the equipment shown in Figure 1 installed, but there is almost no substation in a developed country that will not have installed at least some of the equipment shown in Figure 1.

Regarding the new approaches proposed in this paper, it is obvious that the computer based equipment is a pre-requisite to pursue the new approaches. This requires either the existing monitoring equipment in a substation to be computer based or to have the add-on computer installed only for this purpose.

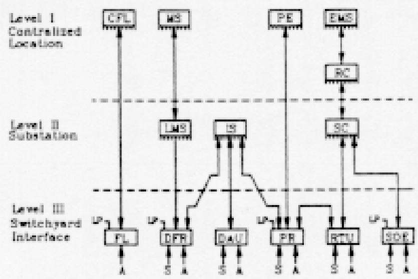

Fig. 1. Substation Equipment

CFL	–	Centralized Fault Location
MS	–	DFR Master Station
PE	–	Protection Engineer's Console
EMS	–	Energy Management System
RC	–	Regional Control Center
SC	–	Substation Computer
IS	–	Integrated Substation System
LMS	–	Local DFR Master Station
FL	–	Fault Locator
DFR	–	Digital Fault Recorder
DAU	–	Data Acquisition Unit
PR	–	Protective Relays
RTU	–	Remote Terminal Unit
SOE	–	Sequence of Events Recorder

Another important requirement is to have access to all of the analog signals and contact points in a substation. The monitoring approaches proposed in this paper are extremely powerful in making comprehensive conclusions about the fault conditions, but this is only possible if the overall substation data is available. Furthermore, the data has to be sampled in a consistent manner. Synchronization of data sampling across the entire substation is a preferable approach.

Once the mentioned requirements are analyzed, it turns out that a very small portion of the equipment shown in Figure 1 is indeed suitable for the implementation of the new approaches. As the only appropriate example one can consider the digital fault recorder (DFR). This equipment meets most of the requirements, and yet may not represent a major investment.

2.2. Power System Level Equipment

The implementation of the new approaches requires extensive communication between the substations and a control center. The existing Supervisory Control and Data Acquisition (SCADA) systems utilize an elaborate communication system, and hence, the new approaches would benefit from having an interface to such a system. However, separate dedicated communication links can also be used from each substation to the control center as presently used for the DFR and digital protective relay communications between substations and the protection engineer's office.

Yet another level of communications may be required if full advantage of the new approaches is to be explored. This is a high speed communication between adjacent substations. Most of the utilities provide this type of communication through the power line carrier or microwave. In some instances, fiber optic cables are available. In any case, the existing communication facilities between substations are utilized primarily for protective relaying. The future implementation of the new approaches would benefit from having access to wide band communication channels between substations.

Some of the new techniques require synchronized data sampling at two ends of a transmission line. Synchronization of data sampling across the entire power system is also desirable. The recent trend in the use of low cost receivers for the time reference from the Global Positioning System (GPS) of satellites has provided an opportunity to meet this requirement.

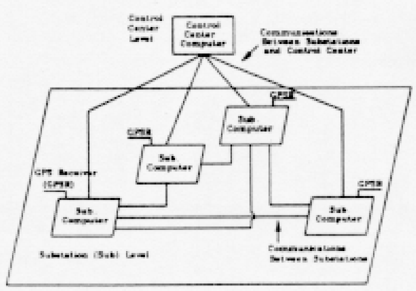

Fig. 2. Power System Implementation Framework

The final issue of the equipment at the power system level is the capability to process data that pertains to the overall system conclusions. The most logical location for this equipment is the control center. However, most of the processing can also be done at the substations. An interface between the substation computer equipment and the control center computer equipment has to be provided to allow for this hierarchical system architecture.

The overall implementation framework discussed is shown in Figure 2.

3. USE OF INTELLIGENT TECHNIQUES

3.1 Automated Fault Analysis Using Expert Systems

Such an expert system has already been developed for substation based automated analysis of faults and operation of the related equipment (Kezunović, et al., 1994a). This system uses a PC as an add-on to the digital fault recorder (DFR). The data acquisition is performed by the DFR and data is passed on to the PC using a GPIB parallel interface. The basic design of the system is shown in Figure 3.

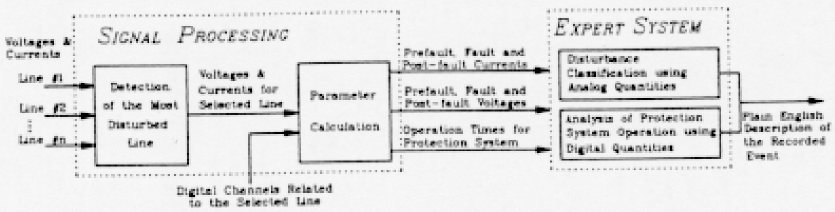

Fig. 3. Data Flow Diagram of the Expert System

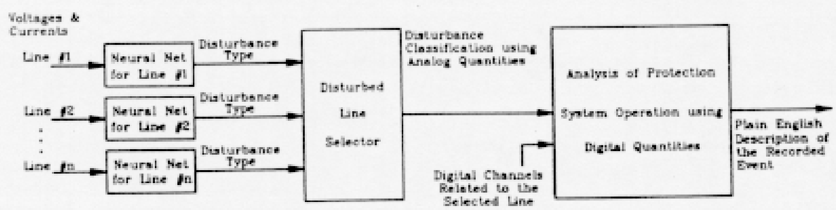

Fig. 4. Combined Neural Net and Expert System Solution

The expert system software consists of several modules (see Figure 3). The signal processing part does the following:

- detects the most disturbed line by analyzing the magnitudes of the current transients for each transmission line,
- calculates RMS and peak voltages and currents for prefault, fault and post-fault intervals,
- calculates the fault location if disturbance is a fault,
- extracts the operating times for protective relays, communication contacts and breakers for the selected transmission line, if they have operated for a given event.

The results of the substation processing depicted in Figure 3 can be communicated to the control center for further processing. The options for this interface are discussed later in this paper.

3.2. Automated Fault Analysis Using Neural Nets

An expert system solution discussed in the previous section can be enhanced by substituting the signal processing and a part of the expert system logic with the neural net approach (Kezunović, et al., 1994b).

Figure 4 shows a hybrid system that contains neural nets for disturbance detection and classification, as well as the expert system for evaluation of the protection system performance. A separate neural net is trained for every transmission line in the substation. The trained net is then used for fast disturbance detection and classification. The results of this classification are used, together with the digital contacts data (e.g., relays, communication channels, breakers, etc.), in the expert system part to assess the performance of the substation protection system.

This system can be used in two different modes of operation:

- event processing based on a "snapshot",
- event processing based on a "continuous" data flow.

The first mode of operation is a conventional approach, where digital fault recorder, based on its internal triggers, records the event. The event is then transferred to the neural net/expert system for automatic processing.

The second mode of operation requires continuous data flow from the digital fault recorder (or any other data acquisition device). In this case, the neural network "triggers" the analysis based on its detection capabilities.

As can be observed, the second approach represents a real-time solution that can detect, and classify, fault events in real-time. The expert system then can give the results of the substation analysis extremely fast. If this data is immediately communicated to the control center, an analysis of the overall switching conditions in the system can be performed within a few minutes.

4. USE OF SYNCHRONIZED SAMPLING

4.1 Fault Location

To simplify introduction of the new fault location concept, a two-terminal transmission line is considered using a lumped parameter model where the line conductance and capacitance are neglected. The one-line representation of the three-phase system is used. The fault location set-up is shown in Figure 5, where "S" and "R" are the sending and receiving ends, CT is the current transformer, CCVT is the capacitor coupling voltage transformer, CB is the circuit breaker, DFR is the digital fault recorder, F is the location of the fault, d is the transmission line length, and x is the distance to the fault.

For the transmission line given in Figure 5, the following two vectors can be defined, where $V_S(t)$ and $V_R(t)$ are the vectors of phase voltage samples; $I_S(t)$, $I_R(t)$, and $I_F(t)$ are the vectors of phase current samples; "S" and "R" are the transmission line ends; and R and L are the matrices of self and mutual line parameters:

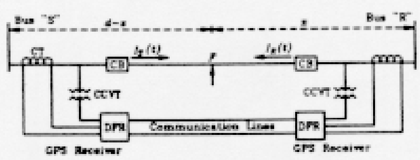

Fig. 5. Fault Location System

$$\Delta I(t) = I_S(t) + I_R(t) \tag{1}$$

$$\Delta V(t) = V_S(t) - V_R(t) + d\left[RI_R(t) + L\frac{dI_R(t)}{dt}\right] \tag{2}$$

In the normal operating conditions, the fault current $I_F(t)$ is zero. As a consequence of Kirchoff's current and voltage laws, the above vectors are equal to zero.

$$\Delta I(t) = 0$$
$$\Delta V(t) = 0 \tag{3}$$

If the line is faulted, the values of these vectors are:

$$\Delta I(t) = I_F(t) \tag{5}$$

$$\Delta V(t) = x\left[RI_F(t) + L\frac{dI_F(t)}{dt}\right] \tag{6}$$

where $I_F(t)$ is the phase vector of samples of fault current. The fault current does not have to be measured since it may be eliminated from equations (5) and (6) leading to:

$$\Delta V(t) - x\left[R\Delta I(t) + L\frac{d}{dt}\Delta I(t)\right] = 0 \tag{7}$$

Equation (7) can directly be used to find the fault location x.

It has been demonstrated that this algorithm has an extreme accuracy under some difficult system and operating conditions (Kezunović, 1994). The algorithm is quite simple and it is executed very fast. It has also been shown that the algorithm can be used for fault detection and classification as well as the fault location (Kezunović, et al., 1995).

4.2. Phase (Angle) Difference Measurement

An important measurement in most of the control approaches is the phase (angle) difference between two nodes (buses) in a power system. If data sampling at the two nodes is synchronized, a new technique for direct measurement of the difference can be developed (Kezunović, et al., 1993).

If the samples of the waveforms at the two ends of a line are defined as:

$$X_n = X\cos(\delta_n + \psi) \tag{8}$$

$$Y_n = Y\cos(\delta_n + \phi) \;\; ; \;\; \delta = 2\pi\frac{f_s}{f} \tag{9}$$

where the two signals are pure sinusoids of the same frequency f, then the phase angle difference can be calculated as (Kezunović, et. al., 1993):

$$\psi - \phi = \sin^{-1}\left\{\frac{BFH_1XY(n)}{\sqrt{QFH_2X(n)\cdot QFH_3Y(n)}}\right\} \tag{10}$$

where values $BFHXY$ and $QFHX$ are defined as:

$$BFHXY = \propto(\delta)\frac{X}{2}\cos(\psi - \phi)$$

$$+ \beta(\delta)\frac{XY}{2}\sin(\psi - \phi) \qquad (11)$$

$$QFHX = \propto(\delta) \cdot \frac{X^2}{2} \qquad (12)$$

and values $\propto(\delta)$ and $\beta(\delta)$ as:

$$\propto(\delta) = \sum_{s=0}^{N-1}\sum_{m=0}^{N-1} h_{km}\cos(m-k)\delta \qquad (13)$$

$$\beta(\delta) = \sum_{s=0}^{N_1}\sum_{m=0}^{N-1} h_{km}\sin(m-k)\delta \qquad (14)$$

Weights h_{km} belong to weight matrices H_1, H_2 and H_3 that have the sums of their anti–diagonals equal to zero. They also satisfy two additional conditions:

$$\propto_1(\delta) = 0 \quad \beta_1^2 = \propto(\delta) \cdot \propto_3(\delta) \qquad (15)$$

Any three matrices satisfying the above conditions may be used for the calculation of the phase shift.

One requirement to observe is that the samples X_n and Y_n, taken at the two ends of the line, have to be taken simultaneously, and then transmitted to a common point where the calculation of the phase difference is performed.

5. UTILIZATION OF NEW APPROACHES

5.1. Substation Level

The utilization of the new approaches is dependent on the equipment available and the goals defined. The use of the intelligent techniques does require synchronized data sampling across the substation, but does not require synchronization between adjacent substations. If the GPS receivers are available at adjacent substations, and the communication link exists to transmit data between the substations, then the new fault location and phase difference measurements can also be implemented.

As a summary, the proposed techniques can be utilized for the following applications:

- fault detection
- fault classification
- fault location
- phase difference between adjacent substations
- automated analysis of operation of the relaying equipment and associated communication and switching equipment

The above applications are an essential part of the analysis of the power system switching status during system faults. This information is critical in determining the system restoration strategy. Therefore, the mentioned improvements are contributing to the reliability and speed of the restoration once a fault is detected and isolated in a power system.

5.2. Power System Level

The applications described for the substation level are only providing information about the system conditions as these are seen looking at a given substation and some of the adjacent substations. In order to provide a comprehensive analysis for the entire system, an additional logic has to be executed at the centralized location. A detailed description of this logic is beyond the scope of this paper. However, it is obvious that this logic will use the results obtained at the individual substation and combine them to make the final decisions. Therefore, a hierarchical processing for system analysis can be envisioned. In order to make this approach feasible, various architectures for hierarchical processing can be considered.

The following sections are concentrating on some possible approaches of incorporating the mentioned solutions in the Supervisory Control and Data Acquisition (SCADA) system.

6. INTEGRATION OF NEW SOLUTIONS INTO THE SCADA SYSTEMS

6.1. Substation Solutions

At the substation level, there are at least three different implementation approaches:

- redesign of the Remote Terminal Unit (RTU)
- common front–end data acquisition
- use of high performance DFRs

If the new techniques are to be used directly in the SCADA system, the RTUs will have to be redesigned to add the following features: synchronized sampling across all inputs; additional computing power for local processing; addition of GPS receivers. Even though this approach may be the most comprehensive, it may also be prohibitively expensive, at least initially.

Another approach is to use an advanced data acquisition front end as it is found in the DFRs, but use a separate PC for implementation of the new techniques. Since the RTU packaging, termination blocks, input relays and other interfacing hardware are already there, the cost of providing the data acquisition part may not be as high as if a separate DFR was installed.

Yet another approach would be to use a separate DFR for implementation of the new techniques. As it is well known, at least one manufacturer offers a high performance DFR with a GPS receiver (Macrodyne, Inc., 1993). In this case, the algorithms can be put on the DFR to avoid the cost of an additional PC for the processing.

6.2. Overall Power System Solutions

Depending on the implementation approach taken at the substation, the following are the possible system solutions:

- two independent systems

- separate communication systems and common user interface
- common user interface and communication system
- totally integrated solution

The two independent systems is an obvious solution since all of the new techniques, and their implementation requirements, can be viewed as being independent from the SCADA system. In that case, the substation processing, the communication links and the centralized processing are customized to the specific technique or their combination.

The first step in integrating the two solutions could be through the user interface at the control center level. Even though the substation data is collected and processed independently, the final results are communicated to the same central point, processed at that point and finally displayed to the operators.

The next level of integration is to interface the separate hardware at the substation to a common communication link of the SCADA system. This solution is shown in Figure 6. In this case, data acquisition and processing at the substation may be done separately, but the results are combined in a common data base and transmitted using the common communication link.

The total integration may be achieved by using a new RTU design that accommodates all of the requirements for the new technique implementation. An intermediate solution is the common data acquisition front end, while the processing is still separated between the RTU and DFR as shown in Figure 6.

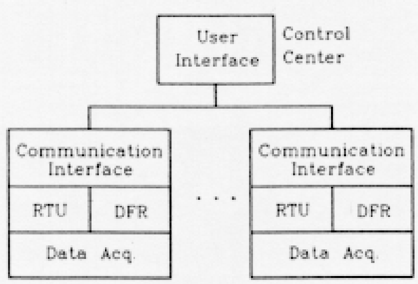

Fig. 6. New SCADA Architecture

7. CONCLUSIONS

Based on the discussions given, the following can be concluded:

- Some new techniques using intelligent systems and synchronized sampling are available for real-time power system monitoring.
- There are a number of different approaches that can be taken when implementing the new techniques.
- The SCADA system can be used as a basis for adding the new techniques.
- The new techniques are aimed at improved determination of the power system switching state immediately after faults are detected, which leads to improved system restoration after fault disturbances.

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