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Managing Complexity Through Data Integration and Information Exchange

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Abstract- This paper addresses two important issues in the power system monitoring and control: a.) Accurate detection, classification and characterization of faults, and b.) Reliable determination of system topology at any given time. The discussion leads to the ability to better predict the system states and dynamic operating conditions, which in turn leads to better understanding of power system operating complexities. The underlining capability comes from better utilization of the field-recorded data, which is achieved through exploration of the concept of intra- and inter-substation data integration.

Introduction

Many authors studied the power system complexities over the last four decades. Some major breakthroughs in better understanding the power system behaviour came about through development of advanced Supervisory Control and Data Acquisition (SCADA) systems in the late sixties [1]. Associated implementation of the SCADA hardware and software led to the need to establish a basic paradigm of "splitting" the power system complexity into somewhat independent operating states. The concept of power system operating states (Normal, Alert, Emergency, Restorative), with a variety of interpretations of the state definitions, reduced the complexity and associated analysis of the power system monitoring and control [2, 3]. The follow up work provided further theoretical understanding of the various operating constraints and associated models used to develop the control strategies for each of the operating states [4]. Recently, the state-oriented concept has been extended to include monitoring and control of electricity markets [5].

The basic paradigm of the four operating states has been successfully used to implement many energy management systems (EMS) around the world, which have been utilized to successfully monitor and control the power system. Admittedly, the system operators performed most of the control, except for the Automatic Generation Control (AGC). They have relied on the SCADA infrastructure to provide adequate information about the system states so that the support functions such as State Estimation and Security Assessment can be properly executed and adequate information for operator actions can be provided.

In the past decade, the utility business has dramatically changed. Besides the deregulation, privatization, and liberalization that have affected the business model, the complexity of the infrastructure of the primary (power apparatus) and secondary (monitoring and control) equipment has also increased. As a result, a combined effect of introducing the new business models and operating the power system under different set of constraints has led to the need to revisit the definition of the system operating states [6]. A new paradigm that will be able to capture both the temporal and spatial characteristics of the power system behaviour in a more dynamic and timely manner needs to be developed. A recent EPRI study has addresses this issue and some important results are shared in this paper [7].

A major blackout in the Northeast USA has demonstrated that the existing monitoring and control infrastructure is inadequate to deal with complex dynamic behaviour of the power system. The unfolding cascading events are difficult to detect and predict, and require revisiting the traditional four-state paradigm to accommodate for this rare situation. As a result, the software tools deployed for system operators to guide them in making the decisions have not been very helpful in this case. This paper addresses the need to develop new tools capable of more attuned system monitoring and information processing for the operator needs.

The paper first explains, as the background, the various aspects of the time and spatial characteristics of the power system operating conditions. Next, the existing infrastructures used for power system monitoring, control, and protection are discussed to emphasize the differences in the characteristics of the recorded and extracted information associated with the major infrastructure types. The subsequent sections are aimed at illustrating the main benefits of introducing the new paradigm of data integration and information exchange. The new ways of implementing Fault Analysis (FA) and State Estimation (SE) are used as examples. The paper ends with conclusions and several suggestions for the follow up work. References are given at the end.

Background

The complexity of power system operation today is a result of many historical factors:

- A vertically integrated utility concept has been changed, which removed from a utility an authority to operate the generation to provide and maintain the security and reliability of the power grid operation.
- Industry deregulation has introduced the concept of the independent system operator (ISO), which has been charged with managing a competitive electricity market, while maintaining acceptable levels of system reliability.

- The aging infrastructure of the power grid in the U.S.A. is a widely acknowledged fact, which introduces additional reliability issues if and when the systems are overloaded or operated close to the operating limits.
- The Regional Transmission Organizations (RTOs) have been formed to improve the power grid reliability by assuring adequacy of resources at regional (inter-state) levels, as well as facilitating wide area grid monitoring for security, which introduces an additional monitoring complexity

The time considerations

In power system monitoring and control, the time considerations are very important. As well recognized, the system topology can change very fast as a result of the action of distributed automata such as protective relays. In addition, the sampled data of analogue waveforms, such as voltages and currents, can represent different time-scale changes, ranging from milliseconds to hundreds of milliseconds, seconds, minutes and hours. The following are some most important time considerations that do affect the ability to better understand the complexity of power system behaviour:

- Absolute time, which enables one to better understand both sequential and spatial correlation of the events resulting from the power system dynamic transitions from one operating point to another. The absolute time may be maintained through a time-stamp "appended" at a control canter, or a time-stamp assigned at the substation, as close as possible to the Intelligent Electronic Device (IED) responsible for data acquisition. Synchronizing the data stamp with the absolute time clock becomes a major challenge when a high-resolution time stamp is to be used.
- Relative time, which enables one to better understand both sequential and spatial correlation of the events caused by a major system disturbance, such as a fault on a transmission line. In this case, the occurrence of the fault inception needs to be determined as precisely as possible so that the other events and control operations can be aligned in time relative to the occurrence of the cause. Having the data sampling function synchronized to a precise clock reference, all the samples can be synchronously taken over all the signals.

Table I illustrates the time scales for different applications, the IEDs involved, and the techniques used for time synchronization.

Table I. Typical examples of the temporal consideration

Time Scale	Application	IED Used	Synchronization
Microseconds	Phasor Measurements	PMUs	GPS receiver
Milliseconds	Relaying	DPRs	Local clock
100s of ms	Fault location	FLs	Two line ends
Seconds	State Estimation	RTUs	Local/Central time stamp

PMUs-Phasor Measurement Units FLs- Fault locators
DPRs – Digital Relays; RTUs-Remote Terminal Units

The spatial consideration

Power system spatial complexity may be considered from a local or centralized standpoint. Understanding protective relay operations may entirely be related to the local conditions while the stability considerations may be viewed from the system viewpoint. Interestingly enough, one can reverse the analysis and look at the system-wide relaying and local stability control approaches as well. In order to perform the spatial analysis, one has to decide what kind of models and data are required, and what are the levels of detail involved. As a general categorization, the spatial consideration may be categorized as follows:

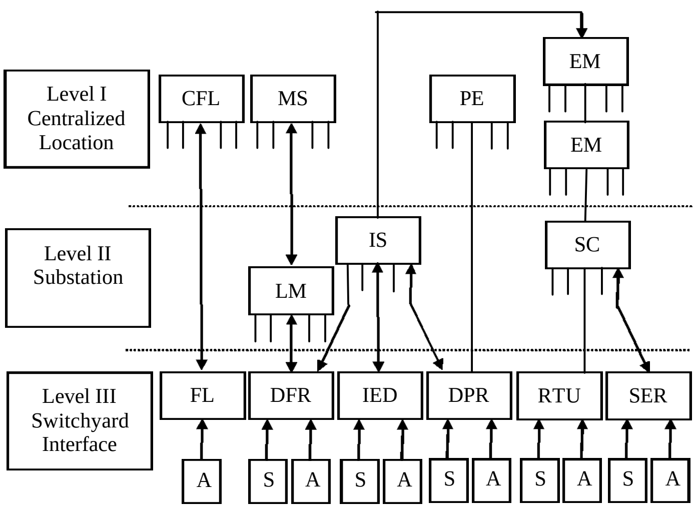
- Bay location (Transmission line, Bus, Transformer) , which assumes collection of analogue and status data related only to monitoring or controlling a given part of the substation, including a few instrument transformers and breakers related to the same power system element. This requires establishing a correlation among the phases in the three-phase system for determination of the fault type and fault location as well as monitoring the operation of the circuit breakers and/or their individual poles.
- Substation location, which assumes collection of detail information on the three phase lines connected to the buses and power transformers located in a given substation. The collection of data needs to correlate all analogue and contact data for the purpose of establishing various checks such as the first and second Kirchhoff's Laws and timing of the substation switching sequences.
- Regional location, which may vary in complexity from containing two adjacent substations, to covering a wider region of a power system. In this case, samples from two ends of a transmission line may be synchronized and brought together to perform a common function such as fault location or current differential relay protection. At a regional level, different interactions between relaying function acting in the first, second and third zone as well as the local stability criteria may be examined.
- Centralized, single utility location, which assumes the field-recorded data across the entire power system is made available. Due to the limited amount of data that can be handled by the communication solutions, the centralized data typically represents only a snapshot of the steady state measurements and as such does not provide time-dependent assessment of power system transients and operations of breakers.
- Centralized, which covers the multi-utility area, and hence should have data from the entire interconnection. Due to the desire of the utilities in the interconnection to keep some of the system data for the private use, only the boundary data for each of the participating utilities may be available. This requires selection of data to be integrated and further processed to extract the relevant information. Special models that can take such sparse data are also needed to better utilize the data.

Data Integration and Information Exchange Concept

The ability of a given monitoring and control infrastructure to provide a sufficient view of the power system behaviour is very important. The common infrastructure for centralized power system control is the Supervisory Control and Data Acquisition (SCADA) System. Besides SCADA, many other Intelligent Electronic Devices (IEDs), and their supporting communication and operator interfacing infrastructure, are available today providing access to the data with much higher resolution than what is available through SCADA. Further discussion points out how the data integration and information exchange concept can significantly enhance the ability to monitor the power system dynamic behaviour with high accuracy and adequate time-resolution.

Legacy Solutions: Limited View of Power System Dynamics

A typical equipment infrastructure outline for the legacy solutions is given in Figure 1.



A- Analogue inputs S- Status (contact) inputs
SC-substation computer MS-master station
CFL-centralized fault location EM-energy management
PE-protection engineer IS- integrated systems

Figure 1. Legacy infrastructure for monitoring and control

Substation recording equipment can be quite versatile [7]. This may depend on many factors including the history of the substation construction and upgrades, utility operating practices, strategic importance of the substation, etc. The different recording equipment types that are typically used in modern substations are:

- Digital protective relays (DPRs)
- Digital fault recorders (DFRs)
- Sequence of event recorders (SERs)
- Remote terminal units (RTUs) of a SCADA system
- Intelligent Electronic Devices (IEDs) used for variety of monitoring and control applications
- Fault locators (FLs) developed for stand-alone high accuracy fault locating

Observing the legacy infrastructure and learning more about the properties of the data acquisition parts of each of the infrastructures, one can quickly conclude that the RTUs give a very limited view of the system dynamics while the digital protective relays and digital fault recorders give much better time-resolution of the signal and status changes. The limited "view" of the power system dynamics captured by SCADA may be enhanced with a "view" available from other infrastructures, but the infrastructures not being open" prevents this from happening.

Future Solutions: Enhanced View of Power System Dynamics

The new data integration and information exchange paradigm proposed in the mentioned EPRI study and discussed in this paper is based on a different infrastructure concept as shown in Fig. 2.

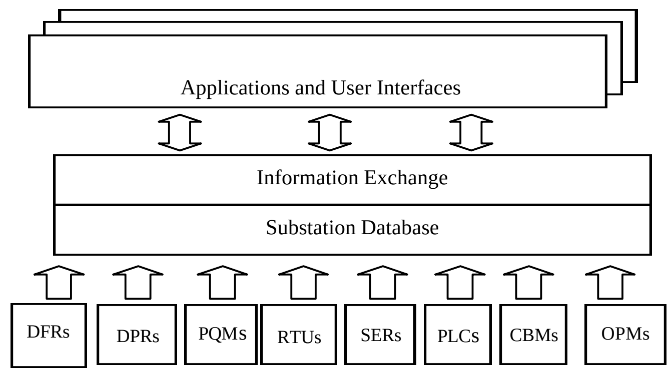


Figure 2. New infrastructure for monitoring and control

Once the data from different substation IEDs is collected in a substation data base, the high resolution samples are used to determine the power system behaviour in great detail. If the behaviour shows very little deviation from the previous state, the information extracted at the substation is minimal but sufficient for the operator at the centralized location to make the appropriate control decisions. The moment the system goes through a major local or system-wide disturbance, the substation data is processed to extract details of the dynamic changes, and the appropriate information, still in a compact form, is passed onto the operators. In the cases where the decisions can be made based on the local substation events, the local data is integrated, correlated and processed to extract the information pertinent to the decision-making. Such information is then passed on to the operators. In the cases when the decisions cannot be made based on the local substation data alone, pre-processed data is sent to the control location and/or to the neighbouring substation(s) for further processing and information extraction.

The options for monitoring and control can be reduced to the following three major cases:

- Decentralized (localized) data processing and decision making
- Centralized (EMS) data processing and decision making
- Distributed (Integrated substation system) data processing and decision making

Managing the Complexity of Dynamic Changes Caused by Faults: Fault Location and Fault Clearing

Related to the faults, the following complexities are very important to understand:

- Finding the location of the fault and hence verifying that the faults has indeed occurred
- Understanding the fault clearing sequence and making sure it has executed correctly
- Anticipating the follow up relaying actions that may occur as a consequence of the previous relay actions
- Assessing system-wide impacts of the fault clearing sequences, including both the correct and incorrect follow-up relaying operations

The mentioned complexities are difficult to assess, in particular in real time. As a consequence, the complexities are studied ahead of the time through the relay planning studies. This paper addresses how most of the analysis may be performed in real time allowing for a variety of remedial control actions to take place on a timely basis.

Real-Time assessment of Fault Location

A variety of traditional approaches to fault location have been studied over the last few years and a number of practical implementations have been deployed [8]. This paper addresses two important special cases:

a.) Locating faults using synchronized samples from both (all) ends of the line [9]
b.) Locating faults using the sparse, but system-wide, measurements [10]

Fault locating utilizing synchronized samples. Traditional phasor-based fault location techniques are rather accurate if the calculated phasors are correctly determined. In some special cases, such as very high speed tripping or time-varying fault resistance conditions, the phasor based techniques may experience large errors, while the synchronized sampling techniques are inherently transparent to such impacts. The proposed fault location method is based on discretization of Bergeron's traveling wave equations or lumped parameter line equations. In order to derive these equations we can consider the unfaulted long transmission line shown in Figure 3.

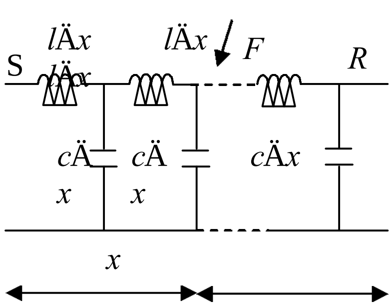


Figure 3. Unfaulted Long Transmission Line

A transmission line longer than 150 miles can be represented as an L-C circuit, since the contribution of the resistance and conductance to the series impedance and shunt admittance can be neglected. The length of the line is d. The l and c are the series inductance and shunt capacitance per unit length. The voltage and current at the point F, at distance x from the sending end S are given by

$$v_F(t) = \tfrac{z}{2}\left[i_S(t-t_x) - i_S(t+t_x)\right] + \tfrac{1}{2}\left[v_S(t-t_x) - v_S(t+t_x)\right] \qquad (1)$$

$$i_F(t) = -\tfrac{1}{2}\left[i_S(t-t_x) + i_S(t+t_x)\right] - \tfrac{1}{2z}\left[v_S(t-t_x) - v_S(t+t_x)\right] \qquad (2)$$

These equations follow directly from Bergeron's traveling wave equations. Here, z is the characteristic impedance of the line and t_x is the travel time to point F from S:

$$z = \sqrt{\frac{l}{c}} \quad , \qquad t_x = x\sqrt{lc} \qquad (3)$$

The voltage and current can also be written in terms of the R end voltages and currents by replacing the subscript S with R and changing the travel time t_x to t_{d-x}, which is the travel time from end R to F. f a fault occurs at F, then the voltage at point F due to the end S voltages and currents will be the same as the voltage at F due to the end R voltages and currents. Thus the fault location equation becomes:

$$\begin{aligned}&\frac{z}{2}\big[i_S(t-t_x) - i_S(t+t_x) \\ &\quad - i_R(t-t_{d-x}) + i_R(t+t_{d-x})\big] \\ &+ \frac{1}{2}\big[v_S(t-t_x) + v_S(t+t_x) \\ &\quad - v_R(t-t_{d-x}) - v_R(t+t_{d-x})\big] = 0\end{aligned} \qquad (4)$$

The distance to the fault does not appear explicitly in the equation. When the equation is discretized based on the sampling interval, the travel times to the point F from either end will not be exact any more. The right hand side of Equation 4 will have a finite non-zero value. Now, based on the sampling time step, the line can be divided into a number of discrete points, and Equation 4 can be used to compute the error voltage at each of those discrete points. The point that yields the minimum error value is the estimate of fault point.

This approach emphasizes the importance of both the time (synchronization to GPS) and spatial (data from all line ends) aspects of an accurate fault location calculation. The transient voltages and currents are processed in real time. A confirmation of the fault can be obtained very shortly after the fault occurrence allowing for subsequent switching sequences to be carried out either to mitigate the fault (disconnect the faulted line) or correct a wrong relaying operation (close the line back in service if the fault is not verified).

Locating faults using sparse measurements. This is yet another special case of locating faults when the measurements of voltages and currents may not be available at each (all) of the transmission line ends [10]. Figure 4 illustrates the sparse data case. The system represents a part of the 138 kV CenterPoint Energy transmission system. While the system part has a total of 19 buses, DFRs are installed at three buses only. Clearly, the system is sparsely monitored. When a fault occurs on the line between bus 11 and bus 12, the DFRs located at bus 1, 3, or 16 may be triggered to record the specified quantities during the fault. In certain cases some of the DFRs at bus 1, 3, 16 may not be triggered. Then even fewer measurements will become available for locating the fault. The data obtained in these cases may be designated as "sparse data". The fault may be several buses away from the DFR locations. None of the common algorithms, such as one-end, two-end, and three-end is applicable for locating the faults. To solve this problem a waveform matching approach is proposed as follows.

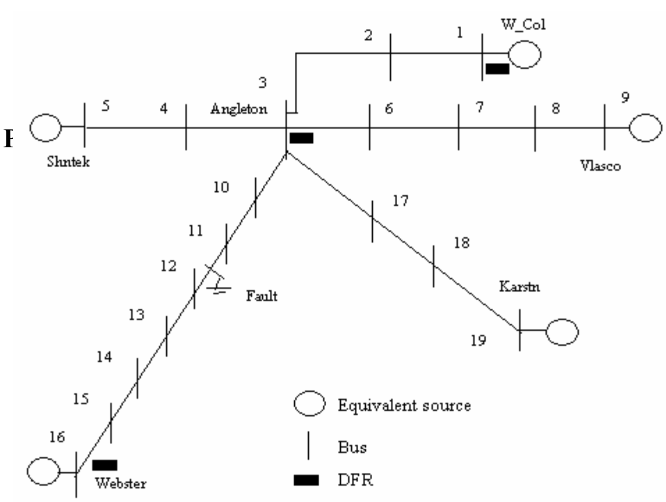


Figure 4. The sample system for illustrating data sparsity

The model of the power system is utilized to carry out simulation studies. The matching is made between the voltage and/or current waveforms captured by the recording devices and those generated in the corresponding simulation studies. The fault location is placed in the system model and simulations are carried out in an iterative way. First, an initial fault location is assumed and the simulation study is set up according to the specified fault location conditions. Next, the simulation study corresponding to the specified fault is carried out and simulated waveforms of the signals of interest are obtained. Then, the simulated waveforms are compared with the recorded ones, and the matching degree between the simulated and recorded waveforms is evaluated by using an appropriate criterion. The initial fault location is modified and the above steps are iterated until the best match between the simulated and recorded waveforms is produced. The fault location is then determined as the one specified in the simulation study generating the simulated waveforms that best match the recorded ones.

To evaluate the matching degree of the simulated and recorded waveforms, phasors are used for matching. For performing the phasor matching, short circuit model of the system is needed. Short circuit studies can usually directly generate simulation results in the phasor format. To extract phasors from the recorded fault transients, appropriate signal processing technique need to be applied. Fourier transform may be used for this purpose [11]. For this study, CenterPoint Energy provided the short circuit model in PSS/E [12].

In order to determine the matching degree between the simulated and recorded phasors and find out the best match, the criterion for determining the matching degree is necessary. First, the variables should be specified. When posing a fault in PSS/E, a fault location, and fault resistance should be specified. The matching degree can be formulated as follows:

$$f_c(x, R_f) = \sum_{k=1}^{Nv} \left\{ r_{kv} \left| \dot{V}_{ks} - \dot{V}_{kr} \right| \right\} + \sum_{k=1}^{N_i} \left\{ r_{ki} \left| \dot{I}_{ks} - \dot{I}_{kr} \right| \right\} \quad \textbf{(1)}$$

or

$$f_c(x, R_f) = \sum_{k=1}^{Nv} \left\{ r_{kv} \left\| \dot{V}_{ks} \right| - \left| \dot{V}_{kr} \right\| \right\} + \sum_{k=1}^{N_i} \left\{ r_{ki} \left\| \dot{I}_{ks} \right| - \left| \dot{I}_{kr} \right\| \right\} \quad \textbf{(2)}$$

where

$f_c(x, R_f)$: the defined cost function using either both phasor angle and magnitude or magnitude only for matching

x: the fault location

R_f: the fault resistance

r_{kv} and r_{ki}: the weights for the errors of the voltages and currents respectively

V_{ks} and V_{kr}: the during-fault voltage phasors obtained from the short circuit simulation studies and recorded waveforms respectively

I_{ks} and I_{kr}: the during-fault current phasors obtained from the short circuit studies and recorded waveforms respectively

k: the index of the voltage or current phasors match

N_v and N_i: the total number of voltage and current phasors to be matched respectively.

This approach deploys both the time and space concepts. The time is associated with lining up calculated phasors. properly. The spatial consideration is involved as well since the phasors are collected from a variety of measuring points scattered around the system.

Real-Time Assessment of Fault Clearing Sequences

The assessment of fault clearing sequences involves, as a minimum, the following:

a.) Analysis of analogue waveforms to determine if the fault has indeed occurred
b.) Analysis of contact information (from both the relay communication channels and breakers) to determine if the control actions have been executed correctly

Analysis of analogue waveforms. This requires an algorithm that can detect the fault, determine the fault type and associate the fault with a zone-of-protection section. Many techniques may be used for this purpose. The following discussion gives a brief summary of an application where neural networks and fuzzy logic are deployed to achieve the fault detection, classification and verification tasks [13].

The used neural network combines unsupervised and supervised learning techniques in an appropriate way to give the best performance. Neural network firstly uses unsupervised learning with unlabeled data to form internal clusters and labels are then assigned to the clusters during the supervised learning stage. The neural network training consists usually of few hundreds of iterations with consecutively alternating unsupervised and supervised learning phases, until prototypes of typical events (patterns) are established (Figure 5).

Classification of testing patterns is performed by using the cluster structure established during training and subsequently classifying a test pattern based on the class labels of selected number (usually very small, odd number) of nearest clusters. During classification, this classifier assigns to a test pattern the class label of the majority of class labels of nearest prototypes in neighborhood. Thus, output of this neural network is in the discrete form reflecting different types of faults common in protective relaying.

Input into the neural network is in the form of a moving data window containing samples of phase currents and voltages.

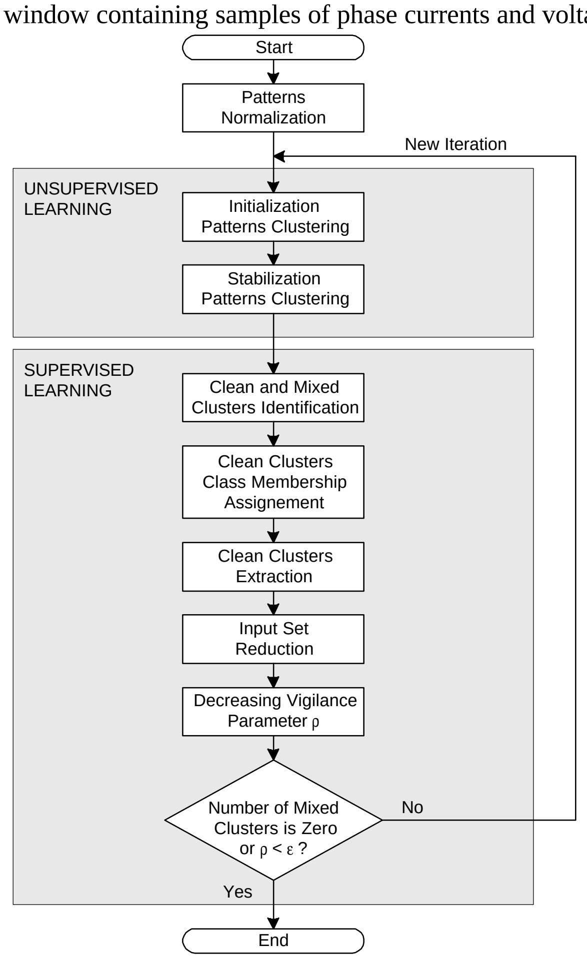


Figure. 5 Neural network training

The desired data window may include either three phase currents, or three phase voltages, or both the three phase currents and voltages. Phase current and voltage measurements are filtered by an analog filter and sampled with desired sampling frequency. Each pattern is extracted from the samples obtained in a desired length of moving data window, normalized, and arranged together to form a common input vector with feature components.

One illustrative example of a reference set of clusters related to the fault analysis requirements is shown in Figure 6. It relates to classification of the fault type and allocation of the fault location to the zone of relay protection. It is significantly simplified and given in only two dimensions.

In the training procedure used so far, incrementally established clusters tend to take positions where they mutually overlap, and therefore the classifying of test patterns located in overlapped regions may be erroneous. This may be prevented during training, and suitable training procedure without allowed overlapping among the clusters should be applied and classification results compared with existing case when clusters do overlap.

The test patterns might be very heterogeneous and quite different from the training patterns, since there are many operating states and possible events in the power network. Test patterns are classified according to their similarity to prototypes adopted during training. Classification is performed by applying the K-nearest neighbor classifier (K-NN) to the cluster structure established during neural network training procedure [14]. The main advantage of the K-NN classifier is its computational simplicity, but its substantial disadvantage is that each of the neighboring clusters is considered equally important in detecting the class membership of the pattern being classified, regardless of their size and distances to that pattern.

To solve the mentioned problem the theory of fuzzy sets is introduced into the K-NN technique to develop a fuzzy version of the classifier [13]. The first important extension of K-NN is based on is taking into account distances between pattern and selected number K of nearest clusters. The idea is that the closer neighbors should exert more influence on the class membership for the test pattern being labeled. The

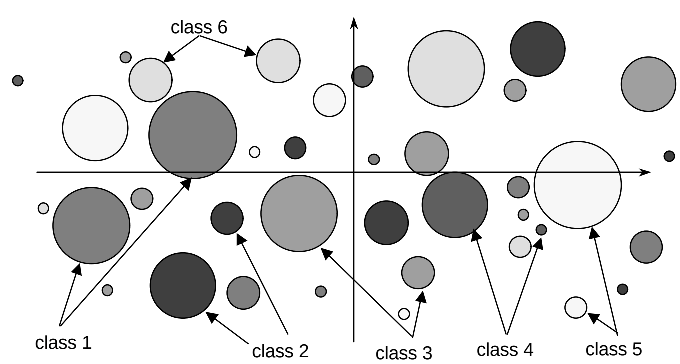


Figure 6. The structure of clean clusters

distance is generally selected to be a weighted Euclidean distance between a pattern and a prototype (cluster center). The fuzzy variable is introduced to determine how heavily the distance is weighted when calculating each neighbor's contribution to the class membership of a test pattern. The second extension is introduction of fuzzy membership value as a measure of cluster belonging to its own class. The idea has been interpreted on original way, considering special cluster structure generated by used neural network [13]. The measure of cluster membership to its own class is selected to be proportional to the cluster size. The outcome is that the larger clusters have more influences then the smaller ones.

Consequently, test patterns are classified based on the weighted distances to K nearest clusters, as well as on relative size and class labels of these clusters. Fuzzy K-nearest neighbor classifier calculates a vector of membership values of an input pattern to all classes present in K nearest prototypes. When membership values for all K neighbors have been calculated, pattern is classified to the class with the highest membership degree. Introduced fuzzyfication is a non-linear interpolation technique used to help classification of a test pattern dissimilar to all patterns presented during training process, and that pattern is classified based on level of similarity to the neighboring training patterns. This advanced approach offers more realistic classification of the test patterns, because it represents interpolation technique for interpreting the neural network outputs.

Analysis of contact changes. Event and protection system operation analysis includes the following checks:

- Relay and breaker contacts' state is checked for a change. A status change is an indication that the protection system has detected a fault.
- If the protection system operation is detected and the presence of a fault is not identified, it is an indication of a protection system misoperation.
- If a fault is detected and there is no protection system operation, it is an indication of a possible protection system failure.

The reasoning required to perform classification and analysis of the event is implemented by using a set of rules. The reasoning process is separated into two stages. In the first stage, the system reasons on the basis of the analog-signal parameters, and in the second step, it reasons by using the protection-system parameters. Signal and protection- system parameters are obtained by processing the recorded samples and extracting the relevant features of the signals recorded on the line that had experienced the largest disturbance.

A typical set of rules based on the analog parameters is shown in Figure 7 [15]. The circled numbers next to the rule definitions indicates a sequence of checks.

This set of rules represents the application's knowledge about the operation of a power system section in the form of "rules of thumb". The rule base is expandable and can be changed

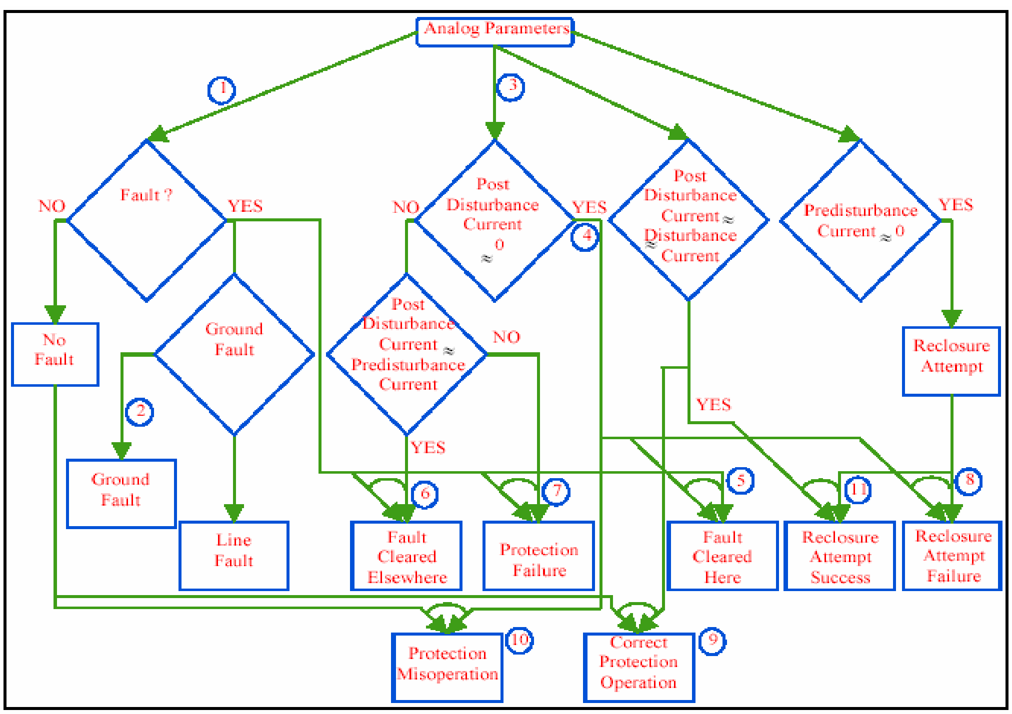


Figure 7. Rules for Fault Detection, Classification, and General Event Analysis Using Analog Parameters

over time, when a better understanding of particular operations of power system equipment becomes available.

To facilitate modularity and extensibility of the analysis logic, a "C Language Integrated Production System" (CLIPS) expert system tool was embedded in the application. This tool allows addition of new rules which specify a new set of actions to be performed for a given power system operating condition.
Figure 8 shows an example of a CLIPS rule to determine if particular conditions for a phase-to-ground fault are met. The exact thresholds (multiplication coefficients) will change from substation to substation, and may need to be determined by trial and error as well as modeling and simulation.

```
(defrule  AG_fault
(Ipre  ?Iap ?Ibp?Icp ?I0p)(Iflt ?Ia ?Ib ?Ic ?I0)
(vpre ?vap ?vbp ?vcp ?v0p)(vflt ?va ?vb ?vc ?v0)
(vlp ?vabp ?vbcp ?vcap)(vl ?vab& ?vbc ?vca)
(test (> ?I0 (* 0.20 ?Ia )))(test (> ?Ia (*1.40 ?Iap)))
(test (< ?Ib (* 0.33 ?Ia )))(test (< ?Ic (* 0.33 ?Ia )))
(test (> ?v0 (* 8.00 ?v0p)))(test (< ?va (* 0.90 Ivap)))
(test (> ?vb (* .96 ?vbp)))(test (> ?vc (* 0.96 ?vcp)))
(test (< (abs (-?vb ?vc))  (* .05 ?vbp)))
(test (< (abs (- ?vab ?vca))  (* .2 ?vabp)))
(test (< (abs (-?vbc ?vbcp)  (* .2 ?vbcp)))
=>
(format t "AG_Fault fired%n")
(assert (FaultType "phase A to ground fault")) )
```

Figure 8. Example of a CLIPS Rule

The expert system software is fully automated. Once configured, no operator interaction with the system is needed. The system reports is operating status on a daily basis by sending a fax message to the dispatcher's and protection engineer's office.

Managing Errors in System Topology Using State Estimation

The importance of knowing the correct network topology which is subsequently used for carrying out various energy management applications, is well recognized. Incorrect information about system topology will lead to biased state estimation results which often have adverse effects on quality of the security assessment runs. Residual based methods can detect such biases but identifying the cause of the bias is not easy. It is commonly assumed that the system topology is known accurately and any detected errors should be caused by incorrect analog measurements.

Detection and identification of topology errors have so far been carried out at the control centers based on the collected data and information from the system. As the system sizes increase and network models become more complex, topology error identification becomes a challenging issue. One way to manage this complexity is to tackle the problem locally at the substations. Each substation is equipped with intelligent electronic devices (IED) which measure voltages, power flows and bus injections and send them to the control center for further processing by the state estimator. There is usually a great deal of redundancy in the measurements available at the substation. This measurement set may include multiple measurements for the same quantity, such as a bus voltage or power flow due to the configuration of the meters inside the substation. Also, various logical checks can be carried out by applying Kirchhoff's laws and other consistency constraints related to the circuit breakers and switches, such as zero currents through open breakers or zero potential drops across closed breakers.

A small scale state estimator which considers all consistency relations among the available local data and measurements can be installed at the substation. This estimator does not have to use the simplified positive sequence model which is used by the system wide state estimator. It can explicitly model all phases of the mini-network inside the substation. The results of the substation estimator will be available at a much faster rate than the execution rate of the system wide state estimator. Therefore, the local results will not be communicated to the control center at the same rate as they are obtained. They will be kept in the local substation memory until the substation is polled for detailed data and measurements.

The central state estimator is executed based on the conventional measurements and the assumed system topology. If the estimator detects an anomaly in the calculated residuals of the measurements, then it will identify one or more suspect substations and will poll these substations for more detailed topology and measurement information. Local substation estimator can then provide its most recent output, which will then be used by the central estimator to incorporate the substation model and measurements into the overall system model.

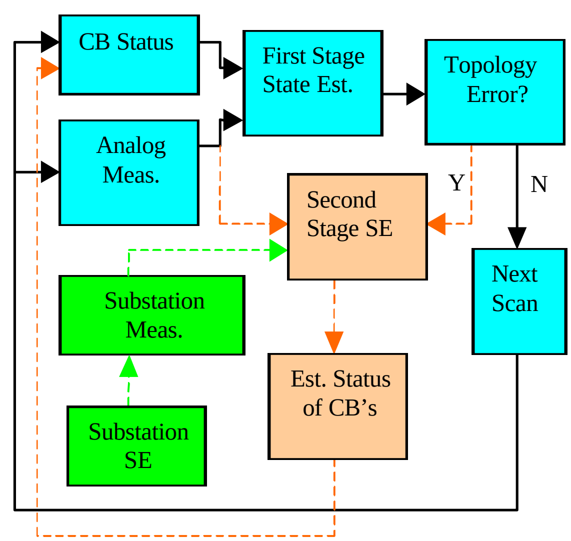


Figure 9 A two-stage state estimator

This approach calls for a two stage estimator as shown in Figure 9. The first stage is the conventional estimation and the second stage involves a detailed estimation of the suspect substation topology and states. The topology estimation will be accomplished by estimating the status of circuit breakers based on the estimated power flows through them. Breakers with statistically significant flows will be considered closed. This approach takes advantage of the computational power and built-in intelligence at the substations without drastically modifying the central state estimator function.

This is inherently a distributed approach and therefore its complexity is not expected to grow with the system size as long as the number of substations with simultaneous topology errors remains small.

Managing Parameter Errors via Dynamic State Estimation

If not reported, changes in network parameters, such as the transformer taps will lead to significant errors in the estimated system state. One way to detect network parameter changes is to use a dynamic state estimator like the one proposed by Debs in [16]. This algorithm estimates the network parameters assuming them as constants. If the parameters are changing over time, such as transformer taps or line resistances, then the algorithm can be extended as shown in [17] to account for time varying network parameters along with the state variables.

Consider that the states and parameters are modelled as Markov processes:

$$x(t_{i+1}) = x(t_i) + w(t_i)$$
$$p(t_{i+1}) = p(t_i) + v(t_i)$$

where subscript ***"i"*** represents the time step, $\boldsymbol{w(t_i)}$ and $\boldsymbol{v(t_i)}$ represent discrete time gaussian white noises, $\boldsymbol{x(t_i)}$ is (2*N-1) by 1 state vector and $\boldsymbol{p(t_i)}$ is $\boldsymbol{n_p}$ by 1 parameter vector. *(N is the number of buses, n_p is the number of the parameters*) .

The state vector $\boldsymbol{x}$ is augmented by adding the network parameters of interest, as given below:

$$y(t_i)=[x(t_i)^T, p(t_i)^T]$$

The state/parameter estimation problem is then formulated as the minimization of the following objective function:

$$f(y(t_i)) = \frac{1}{2}[z(t_i) - h(y(t_i))]^T R_z^{-1}[z(t_i) - h(y(t_i))] + \frac{1}{2}[y(t_i) - \bar{y}(t_i)]^T R_y^{-1}[y(t_i) - \bar{y}(t_i)]$$

where $\bar{y}(t_i)$ is the expected value of the state $\boldsymbol{y}$ at time step $\boldsymbol{i}$ obtained by using the values from the previous time step ***i-1***, $\boldsymbol{z}$ is the measurement vector, $\boldsymbol{h}$ is the nonlinear vector function of the measurements, $\boldsymbol{R_z}$ is the diagonal measurement covariance matrix and $\boldsymbol{R_y}$ is the block diagonal state covariance matrix given as:

$$R_y = \begin{bmatrix} R_x & 0 \\ 0 & R_p \end{bmatrix}$$

Simulation example

A dynamic estimator is implemented and used to estimate the system states as well as the three transformer taps for the IEEE 14 bus system whose meter configuration is shown in Figure 10. Assumed measurement set includes a total number of 45 measurements with 1 voltage measurement, 5 injections (P&Q) and 17 flows (P&Q).

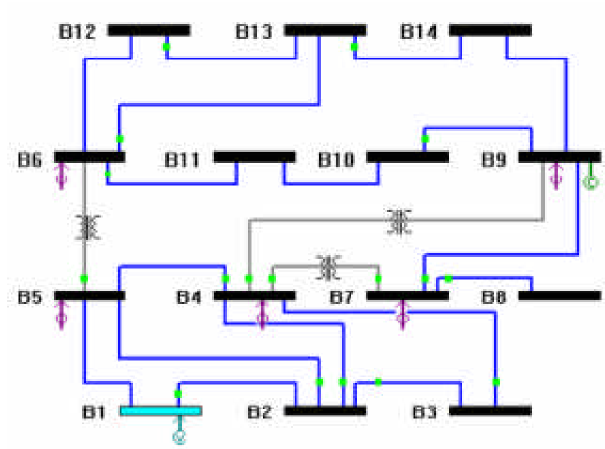


Figure 10. IEEE 14 bus system and the measurement configuration

Measurement data are generated for 100 time steps corresponding to an assumed daily load curve. The transformer tap of the branch 4-7 is increased from its default value (0.978) at the 50th time step until it reaches a value of 1.045. The dynamic estimator as shown in the Figure 11 successfully tracks transformers tap.

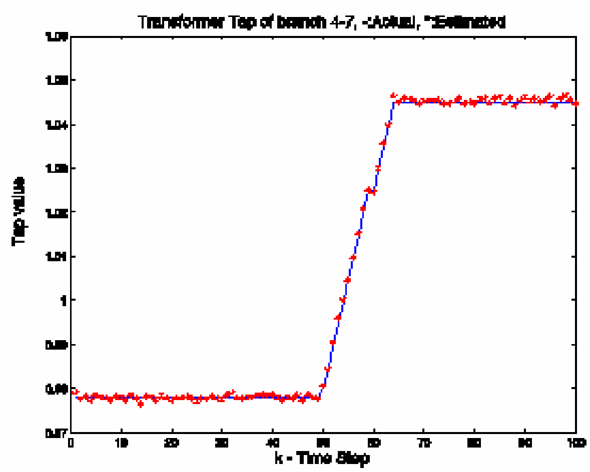


Figure 11. Tracking Transformer tap position

Conclusions

Based on the discussion, several conclusions may be reached:

- For managing complexities in power system operation one may have to resort to a more precise monitoring of the operating states

- Critical consideration for power system monitoring is the data integration and information exchange.
- Once the adequate data and information are extracted, one can develop both corrective and predictive controls for enhanced power system reliability, security and market adequacy.
- The interaction between the various operating states that are within the security limits and the market operating states needs to be better defined in the future
- The role of data integration and information exchange in the future generation of the control paradigm used by energy management systems, independent system operators and regional transmission organizations will have to be explored as the enabling information technology becomes readily available.

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