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Phasor Measurement Unit (PMU) Implementation and Applications

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PRODUCT DESCRIPTION

The effective operation of power systems in the present and the future depends to a large extent on how well the emerging challenges are met today. Power systems continue to be stressed as they are operated in many instances at or near their full capacities. In order to keep power systems operating securely and economically, it is necessary to further improve power and control system protection. Synchronized phasor measurements—also known as phasor measurement units (PMUs)—are ideal for monitoring and controlling dynamic power system performance, especially during high-stress operating conditions. This report documents the challenges and opportunities the power industry faces in applying PMUs and identifying research, design, and development (RD&D) needs in this area.

Background

EPRI is taking the lead in developing a coordinated research program specifically aimed at improving industry understanding of transmission protection and control issues and developing innovative methods that result in more reliable and robust protection and control systems. EPRI's operational objective in this area is to improve the reliability of local and wide transmission grids by enhancing system protection and control schemes using PMU data.

Objectives

- To document RD&D needed in the area of transmission system protection and control in the next three years.
- To help build consensus for an RD&D plan involving PMU approaches.
- To stimulate interest in collaborative approaches to providing new and enhanced transmission protection methods and tools.

Approach

To ensure that the proposed research program is responsive to industry needs in terms of PMU implementation and applications, EPRI conducted the Power System Protection and Control Workshop, held March 1-2, 2007, in San Francisco, California. The workshop enabled EPRI to gather information from industry experts, including energy companies, regulators, consultants, and other stakeholders. The purpose of this workshop was to discuss industry trends, identify challenges and opportunities, exchange ideas, obtain suggestions for program directions, and prioritize R&D directions. EPRI summarized the recommended R&D projects, which address the challenges in PMU implementation and potential applications.

Results

EPRI and participants of the Power System Protection and Control Workshop identified the following two major research areas:

- PMU implementation—Research issues include PMU standards, communication, data management, testing and calibration, and placement.
- PMU applications—The five major applications include 1) improvement on state estimation, 2) oscillation detection and control, 3) voltage stability monitoring and control, 4) load modeling validation, and 5) system restoration and event analysis.

EPRI Perspective

The objective of the RD&D plan in transmission protection and control is to improve the reliability of local and wide area transmission grids. Achieving these objectives will require the coordinated efforts of a broad range of stakeholders, including regulatory agencies, industry associations, energy companies, regional transmission organizations, equipment and system vendors, and others to address both technological advancements and institutional changes. Collaborative approaches to addressing relevant issues will leverage industry knowledge and resources in the most cost-effective and time-efficient manner to meet RD&D objectives.

The success of the March 2007 workshop has stimulated interest in a broader forum on this topic in the near future, as well as establishment of a user group. In general, EPRI's role in this area includes the following:

- Establish a forum for the sharing of information and experiences
- Periodically assemble industry experts who can advise on current best practices and help shape RD&D needs
- Provide independent assessments of industry needs and equipment performance
- Manage and conduct collaborative RD&D projects that mutually benefit project participants and the industry as a whole

Keywords

Power System Protection
Power System Control
PMU Implementation
PMU Applications
Transmission Grids

ABSTRACT

The effective operation of power systems in the present and the future depends to a large extent on how well the emerging challenges are met today. Power systems continue to be stressed as they are operated in many instances at or near their full capacities. In order to keep power systems operating in secure and economic conditions, it is necessary to further improve power system protection and control system. Phasor measurement unit (PMUs), introduced into power system as a useful tool for monitoring the performance of power system, has been proved its value in the extensive applications of electric power system. In response, EPRI is forming a research program that is specifically aimed at using PMU to improve the power system protection and control. To ensure that the proposed research program is responsive to particular industry needs in this area, EPRI convened a workshop on March 1-2, 2007 in San Francisco, California to gather information from industry experts, including utilities, regulators, consultants, and other stakeholders. EPRI and participants of the workshop identified two major research areas in which technological and institutional solutions are needed: 1) PMU implementation, 2) PMU applications. EPRI recommends research, design, and development (RD&D) projects in this report. The objective of these projects is to improve the reliability of local and wide transmission grid by enabling and enhancing the system protection and control schemes by using PMU measurement data, reduce the economic burden of utilizes to implement PMUs.

ACKNOWLEDGMENTS

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- Bonneville Power Administration
- California Public Utilities Commission
- Chevron Energy Solutions
- Comision Federal de Electricidad
- Doble Engineering Co.
- Elequant, INC
- FirstEnergy Service Co.
- General Electric Co.
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- InfraSource
- IRD Corp
- Kalki Communication Technologies Private Limited
- KEMA, Inc
- Lawrence Berkeley National Laboratory
- Mississippi State University
- Modesto Irrigation District
- NERC
- Northeastern University
- NorthWestern Energy
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- Pacific Gas & Electric Co
- PacifiCorp (PC)
- PARC
- PNNL
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EPRI

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1 INTRODUCTION

The electrical grids are amongst the most complex systems worldwide. The power system planners and operators work hard to operate the system reliably, provide the safe and satisfied electric power to the customers. After the deregulation of the power system, the economic factors are added to the power system operation, leading to new uncertainties and challenges to large interconnected power system. Power systems continue to be stressed as they are operated in many instances at or near their full capacities.

Power system protection and control is an important safeguard of power system, and also is the key enabler to meet the challenges of the electrical grid in the 21st century. Traditionally, the power system protection and control is designed for protecting the power system from the large disturbances due the fault. The lessons from several recent major blackouts indicate that current protection systems were not always sufficient to slow or stop an uncontrolled cascading failure of the power system. The application of existing protection system should be revisited. The increasingly installations of synchronized phasor measurement units (PMUs) in power grids are made it possible by utilizing PMUs to improve power system protection and control.

Synchronized phasor measurements are ideal for monitoring and controlling the dynamic performance of a power system, especially during high-stress operating condition. Since PMUs were introduced into power system in 1980s, their values have been proved by their extensive applications in power system operation and planning. In recent years, varieties of PMU applications have been studied, proposed and implemented with their significant benefits. In our current power grids, a large number of PMUs also have been installed and more will be installed. The wide area measurement system (WAMS) that gathers real-time phasor measurements by PMUs across broad geographical areas has been gradually implemented across the United States.

In light of the challenges and needs outlined in the previous section, EPRI conducted a Power System Protection and Control Workshop on March 1-2, 2007. Hosted by the Pacific Gas & Electric Company (PG&E), participants included representatives from regulatory agencies, associations, utilities, regional transmission organizations (RTOs), equipment and system vendors and universities. Appendix A lists workshop participants, and Appendix B lists presentations given at the workshop.

Participants of the workshop presented the new technologies, research results and industrial experience regarding the implementation and applications of PMUs. Participants also identified the research needs. All these technologies, research results, experience and research needs are presented in this report and classified into the following two major areas:

- PMU implementation
- PMU application

In the first area, the implementation of PMUs covers the issues of standards, communication, data management, testing and calibration and PMU placement. The new "IEEE standard for Synchronphasors for power system" defines the synchronphasor measurement, provides a method of quantifying the measurements, quality test specifications, and data transmission formats for real-time data reporting. In response of the high scan rate of PMUs new communication architecture is needed to meet the requirement for wide area monitoring, protection and control scheme. New data and information management architecture and technology are also presented to enable and enhance the applications of PMUs in wide area protection and control. The issues in PMUs calibration and testing are also addressed in this section. When PMUs are involved in extensive applications, an optimal strategy for PMUs placement is needed to reduce the economic burden of the utilities and maximum the performance with limited number of PMUs. (See Chapter 2)

The second area addresses several PMU applications in power system protection and control. Five major applications will be discussed in the area:

- Improvement on State Estimation
- Oscillation Detection and Control
- Voltage Stability Monitoring and Control
- Load Modeling Validation
- System Restoration and Event Analysis

The application of Improvement on State Estimation includes bad data processing, state estimation accuracy, and dynamic state estimation. The application of Oscillation Detection and Control will address a research project tilted "adaptive out-of-step relaying", through which a PMU-based power system oscillation detection scheme is brought out. Then an example of PMU application in oscillation detection and control in Southern California Edison Cooperation will be presented. Finally, the opportunities for power industry to improve the oscillation detection and control will be discussed through two ongoing research projects. The application of Voltage Stability Monitoring and Control includes Voltage Instability Load Shedding (VILS) and Wide Area Voltage Stability Monitoring and Control. The application of Load Modeling Validation will illustrate the application of PMU in load modeling validation through a research study titled "measurement-based load modeling". The application of System Restoration and Event Analysis addresses the problem of fault location and the opportunity for PMU application in fault location. Then the Europe power system disturbance that happened on November 4, 2006 will be used as an example to illustrate how PMU improve the process of system restoration and event analysis. (See Chapter 3)

Recommended research, design, and development (RD&D) projects are summarized in Chapter 4.

2

PMU IMPLEMENTATION

2.1 Introduction

Synchronized phasor measurement unit (PMU) is essentially a digital recorder with synchronized capability. It can be a stand-alone physical unit or a functional unit within another protective device. By measuring the magnitude and phase angles of currents and voltages a single PMU can provide real-time information about power system events in its area, and multiple PMU can enable coordinated system-wide measurements. PMU also can time-stamp, record, and store the phasor measurements of power system events. This capability has made PMU become the foundation of various kinds of wide area protection and control schemes.

Figure 2-1 shows a typical synchronized phasor measurement system configuration. The analog input signals are obtained from the secondaries of the voltage and current transformers. The analog input signals are filtered by anti-aliasing filter to avoid aliasing errors. Then the signals will be sampled by the A/D converter. The sampling clock is phase-locked to the GPS time signal. The GPS receivers can provide uniform time stamps for PMUs at different locations. The phasor microprocessor calculates the values of phasor. The calculated phasors and other information are transmitted to appropriate remote locations over the modems.

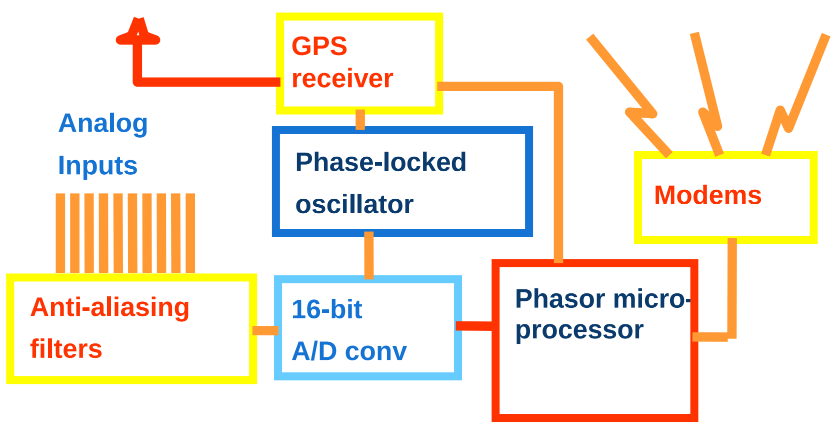


Figure 2-1
A typical block of PMU components [1]

A lot of PMU potential applications in power system monitoring, protection, and control have been studied since it was introduced in mid-1980s. Specially, in recent years, PMUs have been and extensively used or proposed to be used in many applications in the area of power system protection and control with the cost reduction of PMUs and improvement of communication technologies in power system

Technologies about PMU implementation, as the basis of all these implemented or proposed applications, have been widely studied in recent years.

This chapter will focus on the researches and technologies about PMU implementation in the following issues:

- Standard
- Communication
- Data Management
- Testing and Calibration
- PMU placement

Section 2.2 presents IEEE Standard for Synchrophasors for Power Systems, including the definition of synchrophasors and PMUs implementation and test standards in power system. Section 2.3 discusses the power system communication problems regarding PMU implementation, where the power system current communication architecture and existing problems are presented, and next generation communication system is proposed. Section 2.4 presents the current and future data management architecture with Eastern Interconnection Phasor Project (EIPP) experience and plan, meanwhile, the application of semantic web technology in data management is proposed. Section 2.5 discusses PMUs testing and calibration and provides the PMU test device from National Institute of Standards and Technology (NIST) as an example. Section 2.6 discusses the placement strategy of PMUs and presents available method and industrial practical experience.

2.2 Standard

The original standard of synchronphasors for power system, IEEE Standard 1344 -1995, was completed in 1995, and reaffirmed in 2001. The standard has been completely revised in 2005. The revised synchrophasor standard [2], IEEE Standard C37.118-2005, replaces the original one.

This new standard covers the issues about PMU's utilization in electric power system from various aspects. It defines the measurement, provides a method of quantifying the measurements, and quality test specifications. It also defines data transmission formats for real-time data reporting. This section will present the definition of a synchronized phasor, time synchronization, application of time tags, method to verify measurement compliance with the standard, and message formats for communication with PMU in the new standard.

Synchro**phasor definition -** The synchrophasor representation ***X*** of a signal $x(t)$ is the complex value given in Equation (2-1):

$$X = X_r + jX_i = (X_m/\sqrt{2})e^{j\phi} = X_m/\sqrt{2}(\cos\phi + j\sin\phi) \qquad \textbf{eq. 2-1}$$

where $X_m / \sqrt{2}$ is the rms value of the signal $x(t)$ and ϕ is its instantaneous phase angle relative to a cosine function at nominal system frequency synchronized to Universal Time Coordinated (UTC).

System time synchronization - Synchrophasor measurements should be synchronized to UTC time with accuracy sufficient to meet the accuracy requirements of this standard. The system must be capable of receiving time from a highly reliable source, such as the Global Positioning System (GPS), which can provide sufficient time accuracy to keep the Total Vector Error (TVE) within the required limits and provide indication of loss of synchronization.

Measurement timetag for synchrophasors - Synchrophasor measurements should be tagged with the UTC time corresponding to the time of measurement. This time stamp should consist of three numbers: a Second-of-Century (SOC) count, a fraction-of-second count, and a time status value.

Synchrophasor report format - As shown in Figure 2-2, the synchrophasor report message should consist of four parts:

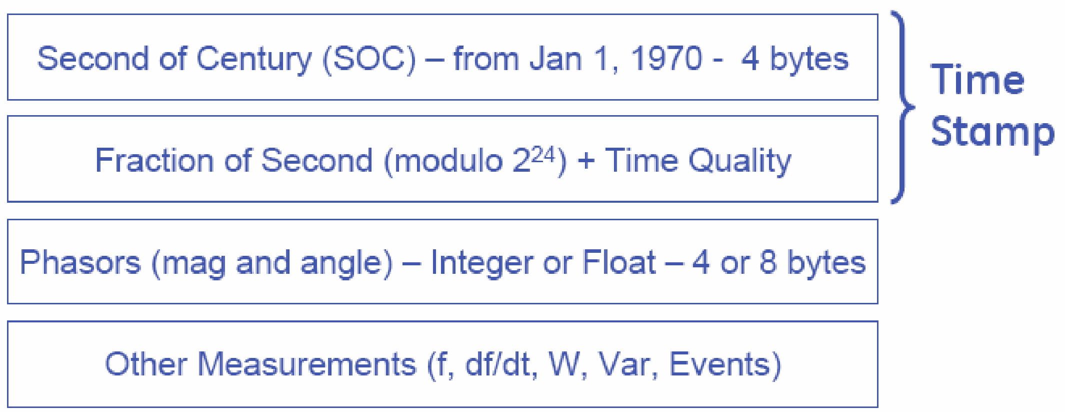


Figure 2-2
Construction of synchrophasor report message *[5]*

Reporting rates - The PMU should support data reporting (by recording or output) at submultiples of the nominal power-line (system) frequency. Required rates are different according different nominal frequency (50 Hz or 60 Hz). The reporting rates are listed in Table 2-1. The actual rate to be used should be user selectable. Inclusion of more rates, particularly up to system frequency is encouraged.

Table 2-1
Synchronous reporting rate

System Frequency	50 Hz		60 Hz				
Report rates (phasors/sec)	10	25	10	12	15	20	30

PMU response time - The PMU response time will be measured by applying a positive or negative 10% step in magnitude with the input signal at nominal magnitude and rated frequency. The response time is the interval of time between the instant when the step change is applied and the timetag of the first phasor measurement for which the TVE enters and stays in the specified accuracy zone corresponding to the compliance level (1%).

Accuracy limits - Under the conditions where X_m, ω, and ϕ are fixed, and for the influence conditions shown in Table 2-2, the TVE shall not exceed the TVE limit given in the table for the given compliance level. TVE is defined as shown in Equation (2-2)

$$TVE = \frac{\sqrt{(X_r(n) - X_r)^2 + (X_i(n) - X_i)^2}}{\sqrt{X_r^{\ 2} + X_i^{\ 2}}} \qquad \text{eq. 2-2}$$

where *X*r(n) and *X*i(n) are the measured values, given by the measuring device, and *X*r and *X*i are the theoretical values of the input signal at the same time of measurement, determined from Equation (2-1) and the known conditions of X_m, ω, and ϕ

Table 2-2
Influence quantities and allowable error limits for compliance levels 0–1

Influence quantity	Reference condition	Range of influence quantity change with respect to reference and maximum allowable TVE in percent (%) for each compliance level			
		Level 0		Level 1	
		Range	TVE (%)	Range	TVE (%)
Signal frequency	$F_{nominal}$	± 0.5 Hz	1	± 5 Hz	1
Signal magnitude	100% rated	80% to 120% rated	1	10% to 120% rated	1
Phase angle	0 radians	± π radians	1	± π radians	1
Harmonic distortion	<0.2% (THD)	1%, any harmonic up to 50th	1	10%, any harmonic up to 50th	1
Out-of-band interfering signal, at frequency f_i where $\lvert f_i - f_0 \rvert > F_s/2$, F_s = phasor reporting rate, $f_0 = F_{nominal}$	<0.2% of input signal magnitude	1.0% of input signal magnitude	1	10% of input signal magnitude	1

Compliance verification - Compliance tests shall be performed by comparing the phasor estimates obtained under steady-state conditions to the corresponding theoretical values of *X*r and *X*i and calculating TVE, as defined in Equation (2). Steady-state conditions are where X_m, ω, and ϕ of the test signal, and all other influence quantities are fixed for the period of the measurement. (Note that for off-nominal frequencies, the measured phase angle will change even though the test signal phases φ is constant.)

A calibration device used to verify performance shall be traceable to national standards and have a "test accuracy ratio" of at least four compared with these test requirements (for example, provide a TVE measurement within the test accuracy ratio less than 0.25% where TVE is 1%). In cases where there is no national standard available for establishing traceability, a detailed error analysis should be performed to demonstrate compliance with these requirements.

IEEE Standard C37.118-2005 address the needs of industrial to for easier integration, configuration, engineering, and maintenance of phasor measurements in power system environments, and to ensure that the measurement processes are producing comparable results. This standard will also benefit the industry by allowing data interchange among wide varieties of measurement systems for both real-time and off-line phasor measurements.

2.3 Communication

Reliable and robust communication systems are one of most important issues for power system monitoring, protection and control. The communications systems serve as the neutral system of entire power grids. With consideration of the high scan rates of PMU comparing to traditional tools and the communication requirements for new wide area protection and control scheme, a flexible, secure and integrated system-wide communication infrastructure will be the necessary basis for future power system protection and control system.

2.3.1 Current communication infrastructure

The traditional multi-layered communication infrastructure, which enables economic and reliable operation of current power system, has evolved over many decades. However, its evolution has been slow and incremental, partly due to the great capital expense of making changes to such a large system and also since the operation of power system in the vertically integrated utilities has changed very little until recently.

In power system, substations are usually connected to a control center in a hierarchical, centralized architecture. And the major function of the control center is an interface between the operators and the power system. Data acquisition allows the operators to monitor the condition of the system and implement supervisory (manual) control, such as, the opening and closing of circuit breaker, switching in and out capacitors, and son on. Therefore the traditional communication systems have the hierarchical architectures as shown in Figure 2-3, where a SCADA system gathers system-wide data from each substation and generator station with a scan rate in the range of 2-10 seconds.

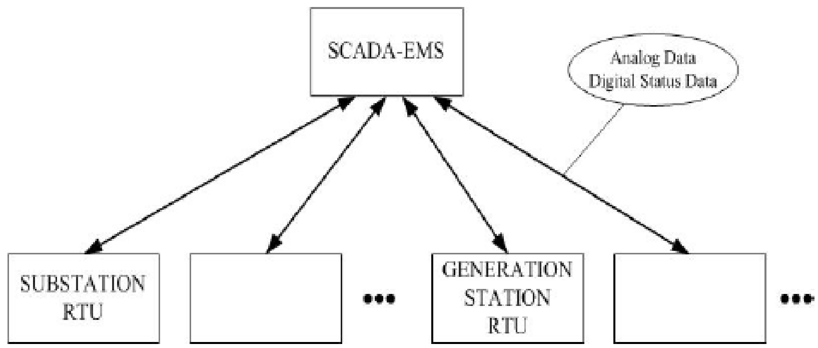


Figure 2-3
Existing SCADA infrastructure [6]

Recently, the use of Special Protection System (SPS), also known as Remedial Action Scheme (RAS), is increasing in the power system. Different from conventional local protection schemes, SPS/RAS covers a wide area and responds by tripping equipments which are remote to the fault or other event. Therefore, the communication network is essential for the successful operations of SPS/RAS. Current SPS/RAS communication networks usually consist of dedicated fast communication lines and a dedicated computer, as shown in Figure 2-4. Once installed, these are quite inflexible except for changing the settings link trip times. Also, with increasing installations of SPS/RAS, their coordination becomes very difficult, and the burden of off-line studies to coordinate the settings becomes onerous and error-prone.

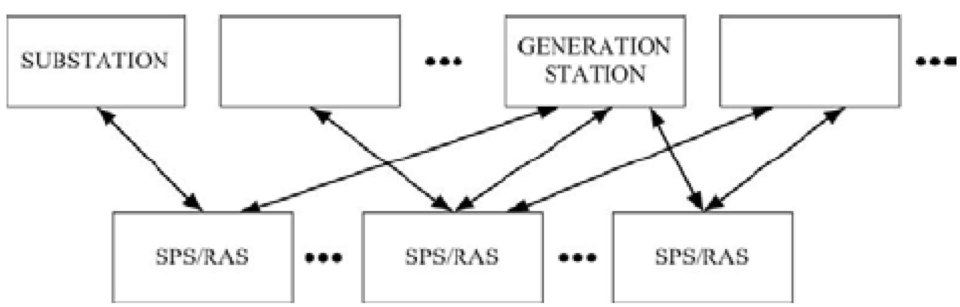


Figure 2-4
SPS/RAS communication links [6]

2.3.2 Communication infrastructure of PMUs

New measurement tools such as PMUs are increasingly implemented for power system monitoring, protection and control in order to improve the security of large power systems.

One practical successful use of this rich data source is the PMU-based wide-area measurement system (WAMS), which was deployed on the Western Grid some years ago [7]. Figure 2-5 illustrates the PMU communication infrastructure, where a hierarchical structure is used. PMUs first send the data to their respective data concentrators, where those data concentrators are connected to a centrally located data concentrator in a central control station. And the data concentrators are connected locally to their respective host computers via ethernet. The communication between a PMU and the data concentrator is carried over phone lines.

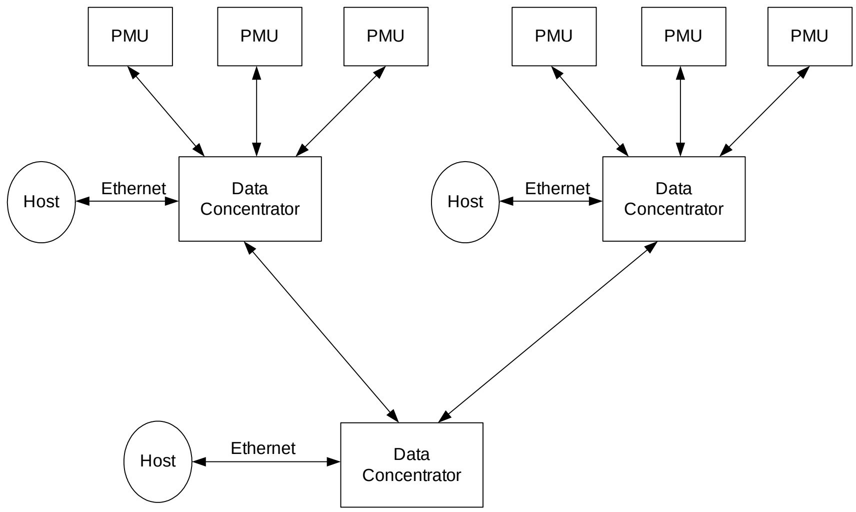


Figure 2-5
Communication infrastructure of PMUs in WSCC [7]

In the PMU communication infrastructure, an important concept is the Phasor Data Concentrator (PDC). The PDC serves as the hub of the measurement system, where data from a number of PMUs or other PDCs is brought together and then fed out to other applications. The PDC correlates phasor data by its timetag and sample number to create a system-wide measurement set precisely synchronized in time. It also performs quality checks on the data and inserts appropriate flags indicating data quality into the correlated data stream. Besides, the PDC also performs extensive functions in the measurement system as shown in Figure 2-6. It buffers the data stream internally and spools it out to other applications. It can send out a continuous stream of all data over ethernet or selected data based on application or flag status. The PDC also monitors the overall network and includes a network client program for user access. Therefore, the specific program on the PDC can indicate system disturbances and records a file of data once disturbance occurs.

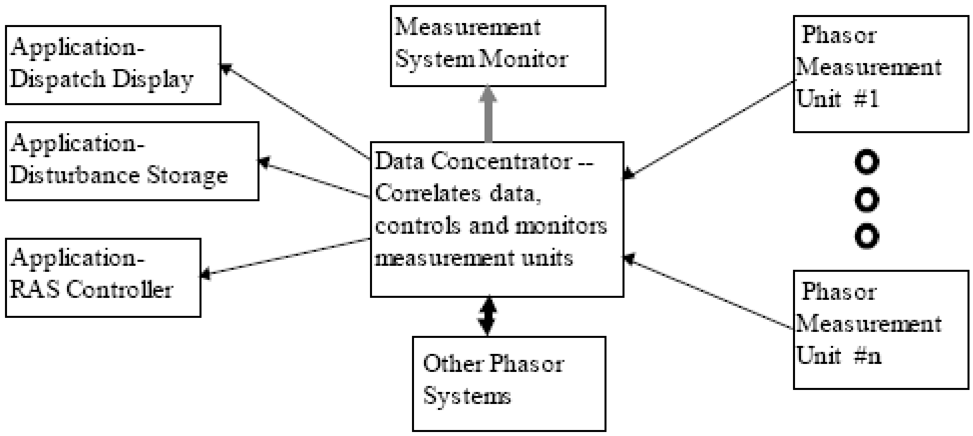


Figure 2-6
PDC in PMU measurement system [8]

In EPRI "Second Generation Phasor Data Concentrator" [8] project, EPRI collaborated with BPA in the development of the second-generation PDC. In this project, the developers tested, customized, and installed the latest version of the PDC Operating System (OS), including the improvement of the basic OS and network interface system. A new version of software was implemented in PDC, which was easier to configure and maintain. To further simplify configuration, the developers also created a Windows-based program that allows users to set up the basic configuration file via a Graphical User Interface (GUI).

The Eastern Interconnection Phasor Project (EIPP) is a Department of Energy (DOE) and Consortium for Electric Reliability Technology Solutions (CERTS) initiative. The purpose of this project is to sever as catalyst to deliver immediate value of phasor technology to the Eastern Interconnection (EI) participants. In EIPP, PMUs are currently being and will be deployed in a large number. Their dedicated communication infrastructure is also hierarchically deployed, as shown in Figure 2-7.

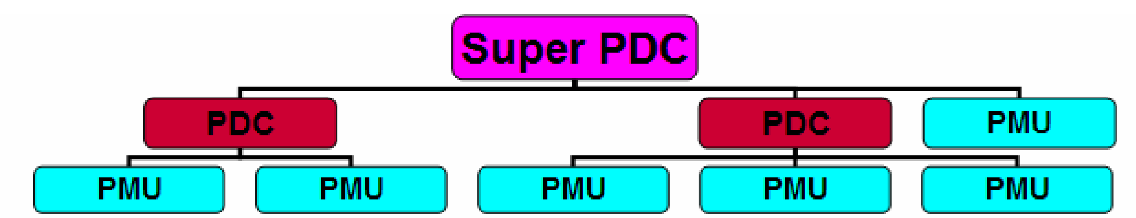


Figure 2-7
Communication infrastructure of PMUs in EIPP

2.3.3 Existing Problems in current communication system: "Inadequate, Inflexible, Expensive" [3]

The existing communication infrastructure is inadequate. The existing communication infrastructure limits the types of controls and protections that can be deployed in the power system. This limitation makes it difficult to use data collected to improve stability, reliability and efficiency of our system. The inadequacy exists in the following aspects:

- The slow response of grid operators to contingencies is partly due to inadequate situational awareness across the company and regional boundaries
- SPS/RAS deployment is expensive due to the cost of dedicate point-to-point communication links between substations
- New and potentially beneficial approaches for protection and control are limited by current communication infrastructure

The inflexibility is also a principle deficiency in current communication system. An obvious example is current SPS/RAS communication network. In such a communication infrastructure, engineering the communication component for a new participant – for example, a new control scheme – is costly in design, hardware, and programming. It is a barrier to deploy new technologies and practices which may be quite beneficial. Furthermore, power engineers are often quite hesitant to experiment and implement new control schemes which require new costly communication infrastructure.

Continued piecemeal creation of the grid's communication infrastructure will be excessively expensive and will unnecessarily limit the opportunities for improving the grid's control and protection schemes. To enable the beneficial schemes those are envisioned today, as well as those not yet invented, the evolvable and adaptable communication architectures is required for the future power system.

2.3.4 Next Generation Communication Network Architecture

In order to overcome the current limitations in current power system communication system, next generation communication network architecture should meet the following requirements:

- Status information should easily be made available to any legitimate participant at any location.
- Information delivery to each participant should be timely and reliable: for many envisioned control applications (such as SPS/RAS) faster is better, but, regardless of the absolute speed requirement, the latency should be predictable in case of any foreseeable communication failure or overload.
- Status information should be protected against illegitimate use, and participants can trust the status information they receive. Participants can reason about the trustworthiness of other parties to limit the risk of using inaccurate data or of disclosing information to unauthorized sites.

A possible evolution of next generation communication system is the high speed network that will connect all the fast scan rate measurement tools from all substations, as the architecture shown in Figure 2-8. The data can be made available to the control center to do the traditional control center functions. It also makes feasible distributed controls such as SPS/RAS or regional controls like wide area voltage control. Moreover, these controls can be reconfigured through software rather than the installation or reconfiguration of hardware. Finally, such architecture lends itself to levels of software management (middleware) that can be used to handle contingencies, quality of service and security.

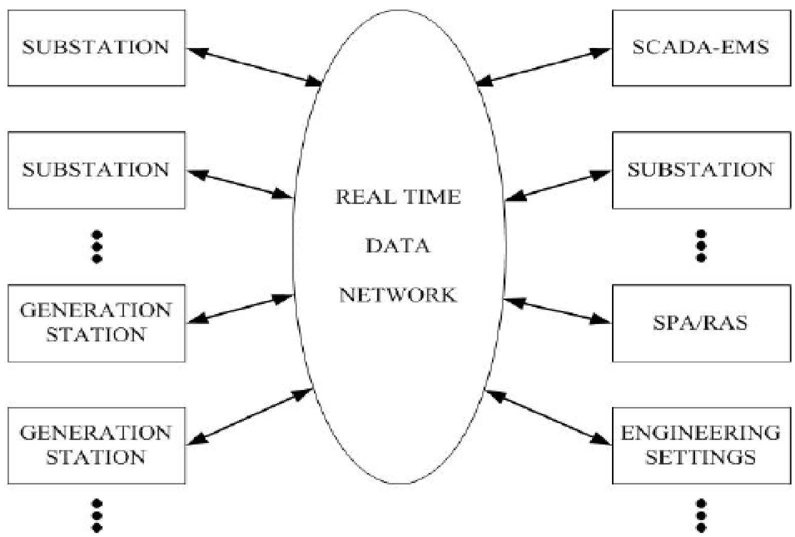


Figure 2-8
A conceptual network for communication of all power grid data [6]

The specific management software, Middleware is proposed in the report of “Next Generation Communication Network Architecture” [3]. Middleware is a new kind of software that emerged in recent years. Different from programs that use network protocols such as TCP/IP and ATM, middleware frameworks sit between the socket interface and applications – “in the middle”. It is built on underlying network technologies, wchich can specifically address the requirements of next generation communication system.

A prototype of a new communication framework called GridStat has been designed and built for delivering status information, data representing dynamic operational phenomena, (such as voltage and current), and command decisions.

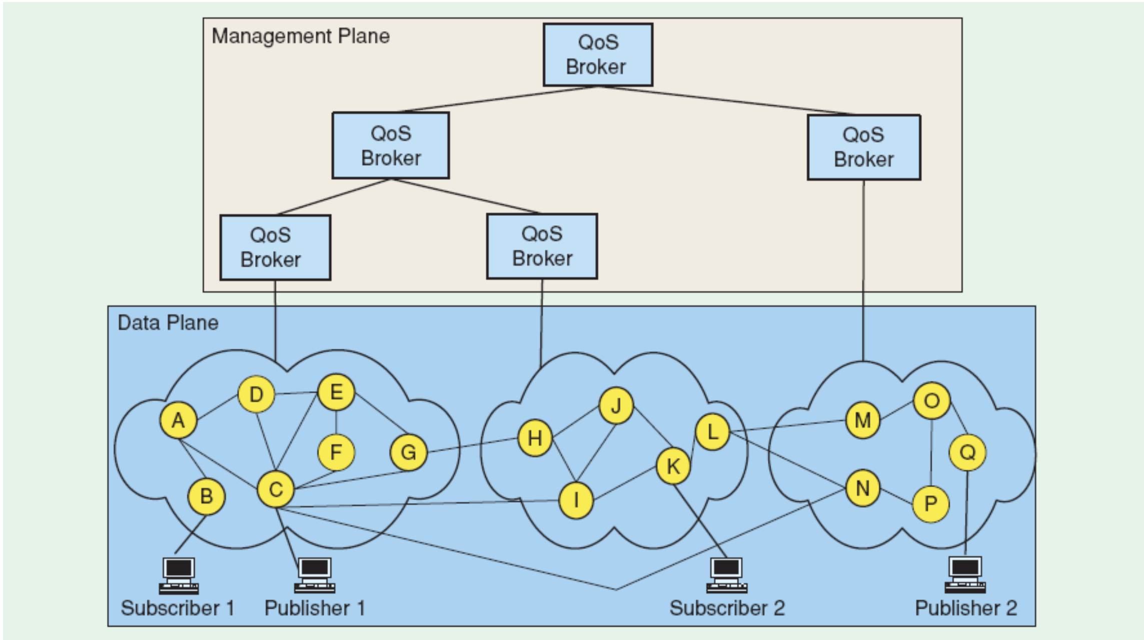


Figure 2-9
The GridStat architecture [3]

Figure 2-9 illustrates the architecture of a GridStat network. A status source, called a publisher, informs the middleware infrastructure of a status variable’s identity, type, and availability frequency. A directory service assists subscribers in identifying and locating particular status variables of interest.

Figure 2-10 illustrates the proposed next-generation power-grid infrastructure with GridStat. With such an infrastructure, GridStat has the following advantages:

- GridStat can easily accommodate changes in communication topology, whether it is to meet the large information requirements of a new generation company joining the grid or to quickly support an investigator drilling down through data to investigate a potential instance of sabotage.
- With GridStat’s flexible communication infrastructure, several kinds of control and monitoring applications become much easier to implement.
- Improved and lower cost special protection schemes are also possible. A natural extension of monitoring based on PMU measurements is to move toward more automatic control based on the wide-area measurements.

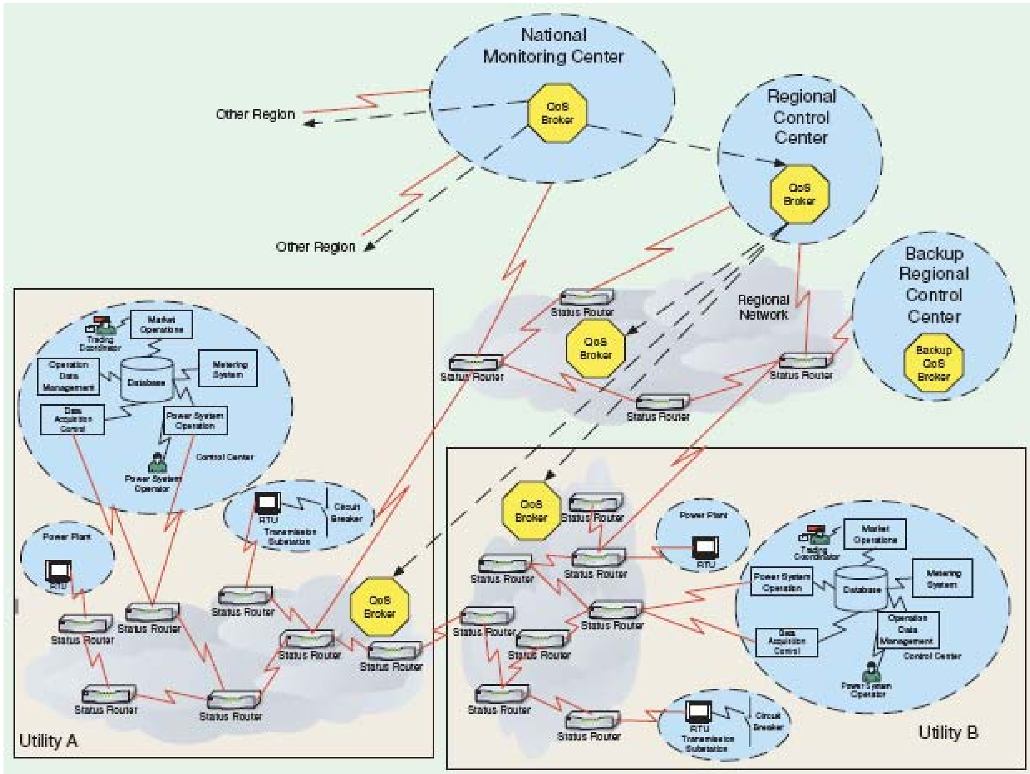


Figure 2-10
The next-generation power-grid infrastructure with GridStat [3]

2.4 Date management

With increasing PMUs as well as other measurement and recoding devices in power system, how to efficiently manage and utilize the vast amount of data becomes a major challenge. An efficient data management system should be able to integrate and exchange the multi-source data, extract and distribute the useful information, and assure general reliability and security of the overall information system.

In this section, the current and future data management model in EIPP is presented. Then the proposed application of semantic web technology in power system data management is introduced.

2.4.1 Existing Data Management Architecture

In the report of "Data Management Task Team" [4], the data management model in the EIPP is presented. The presented data management models are designed for the following types of applications:

- Near Real Time Applications (10's of milliseconds)
  - Real Time Dynamics Monitoring System (RTDMS)

- Wide Area Angle Separation
- Path / Flow gate - Monitoring / Control
- Inter-area Oscillations

- Historical Applications (about a second or much more)
  - State Estimation Enhancement
  - Event Analysis

Within the EIPP, each participating organization sets its own requirements for data management and handling, as shown in Figure 2-11. Therefore, in order to concentrate the collected measurement data from different organization in different protocols, it is necessary to have a comprehensive database support all phasor data transmission protocols. For this purpose, Tennessee Valley Authority (TVA) has made a substantial investment in developing a centralized EIPP Phasor Data Concentrator, called "Super PDC". A system is created with an open and completely scalable architecture that specifically supports the most popular phasor data transmission protocols, in particular: PC37.118, IEEE1344, the BPA PDCstream and OLE for Process Control (or OPC).

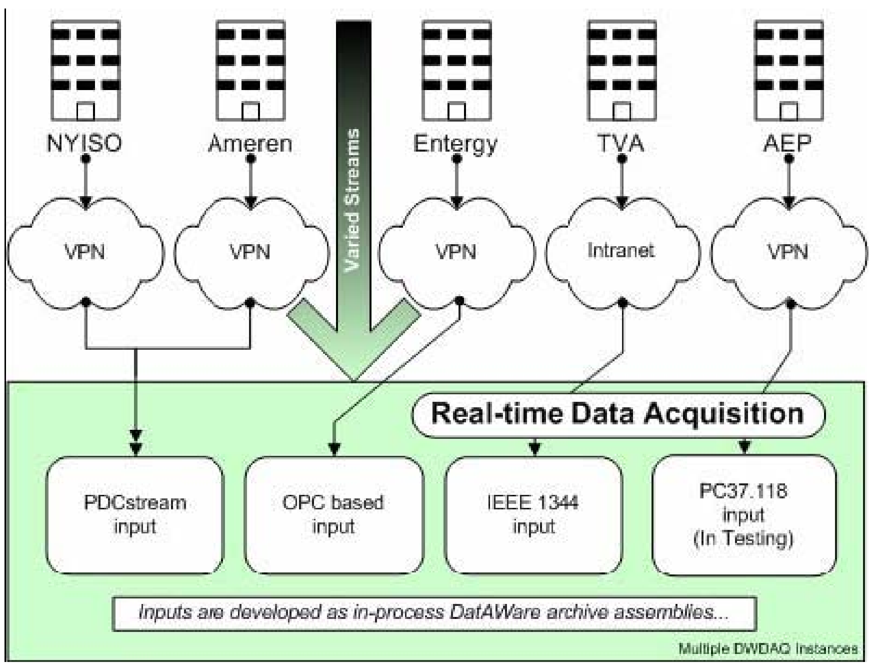


Figure 2-11
Existing Architecture [4]

In the current working implementation of the Super PDC, all of these transmission protocols have been developed. As shown in Figure 2-11, the project team has tested and deployed IEEE1344, PDC stream and OPC. Additionally, the C37.118 protocol is currently being tested with several different PMU vendors.

2.4.2 Future Data Management Architecture

Recently, the data management task team has been working to develop better data management architecture. The objective is to provide EIPP paticipants a robust, fault tolerant, and scaleable information system, which data management architecture should meet the following requirements: [9]

- System Reliability and Fault tolerance – System should be designed to preclude single point-of-failure in the communication or computer systems.
- Scalable – As newer PMU/PDCs are added by the utilities, the integration of additional data streams should be easily configured and recognized.
- Timeliness of data delivery by repositories – Application requests for data must be accommodated.
- System administration and security – The system should allow for efficient administration especially adding new sources, clients, system users, and providing security at all levels of communication and data access. Data should be secured in an industry standard manner that prevents corruption and tampering.

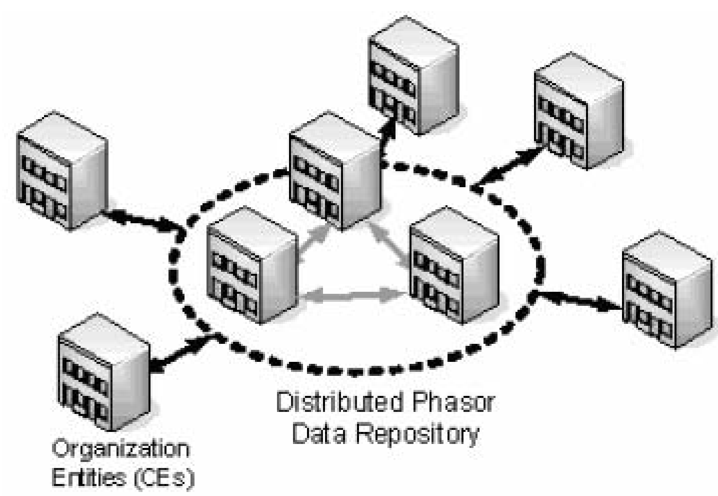


Figure 2-12
Proposed Architecture [9]

Figure 2-12 illustrates the overall proposed architecture. The labeled Distributed Phasor Data Repository (DPDR) is actually a distributed computing/communications environment that is geographically dispersed. It usually consists of several Organization Entities (OEs), and serves as the hub in this architecture. The OE represents the end users and producers of phasor measurement data.

Each OE has the same architecture and interfaces whether they are part of the DPDR or are at the end of a spoke as a client. Figure 2-13 illustrates the OE architecture and interfaces. Each OE maintains data from one or more PMUs and PDCs, a local data historian, and one or more applications. There are four interfaces:

- Aggregated real-time phasor data stream (Input)
- Un Aggregated real-time phasor data stream (Input)
- Aggregated real-time phasor data stream (Output)
- Historical database query/response, publish/subscribe interface

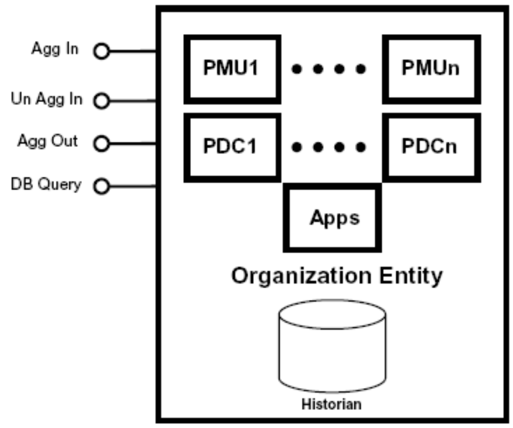


Figure 2-13
Organization Entity Architecture [9]

These interfaces allow the OE to act as either a simple client and supplier of PMU data to the DPDR, or one of the constituent OEs of the DPDR.

2.4.3 Application of Semantic Web Technology in Data Management

The Semantic Web is a mesh of information linked up in such a way as to be easily processed by machines, on a global scale. It is an efficient way of representing data on the World Wide Web, or as a globally linked database. The Semantic Web provides a common framework that allows data to be shared and reused across application, enterprise, and community boundaries. It is based on the Resource Description Framework (RDF), which integrates a variety of applications using XML for syntax and Uniform Resource Identifiers (URIs) for naming.

The Semantic Web makes the meaning of information accessible not only to humans, but also to machines. This property assures its advantages in information searching, navigating, visualizing and maintaining.

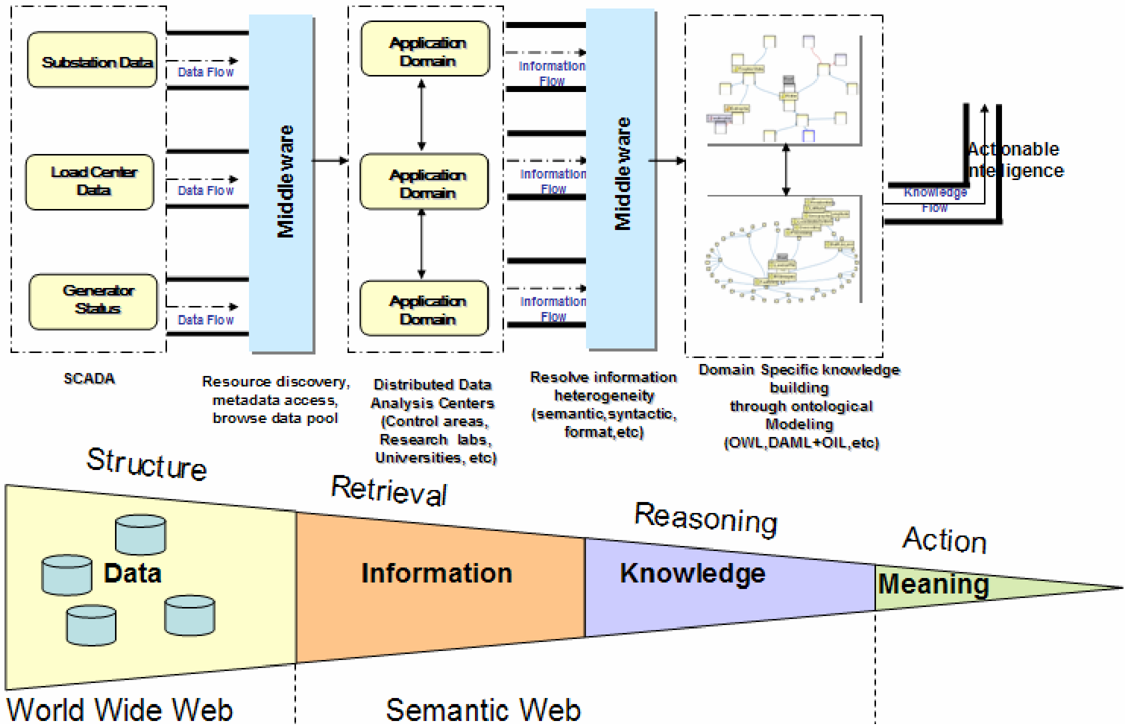


Figure 2-14
Information Process model for electric power grid using semantic web [10]

In the report of “Utilizing the Semantic Web for Electric Power Grid Monitoring and Advanced Real-time Control” [10], semantic web technology is introduced into the area of the data management of power system. The overall data management architecture with semantic web technology is proposed in Figure 2-14.

As illustrated in Figure 2-15, a Sensor Web Enablement (SWE) will perform as an extensive monitoring and sensing system in the overall power grid. It can provide timely, comprehensive, continuous, and multi-mode observations for the power systems.

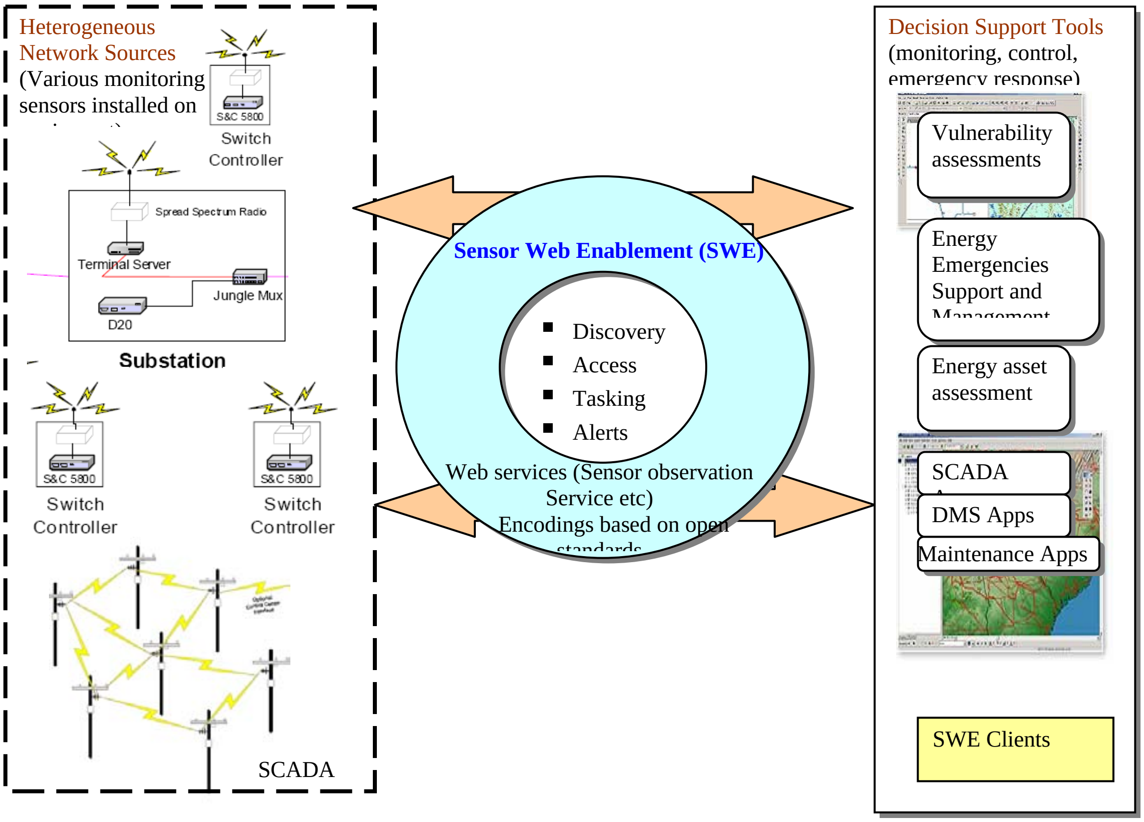


Figure 2-15
Sensor Web Enablement (SWE) for electric power grid [10]

2.5 PMU Testing and Calibration

The reliable power sources, samplers and associated standards for PMU testing and calibration have become a major hurdle to the further development and implementation of PMU applications in power system. Utilities need the guarantee of reliability and accuracy of PMUs and also the seamless interchangeability among the PMUs from different vendors before they will invest heavily in them.

In the IEEE Standard for Synchrophasors for Power Systems described in Section 2.2, associated standards for PMU testing and calibration has been developed and provided.

First, testing of PMUs requires providing an input signal synchronized to UTC (Universal Time Coordinated). The signal is generated with parameters matching a phasor definition. The parameters consist of a certain magnitude, phase angle, frequency, and the signal generator should be synchronized to a GPS reference. Then the phasor estimates output from the PMU are recorded and compared with the phasor representation of the input signal using the TVE criteria.

One of the difficult areas of testing is using a signal that is off the nominal power system frequency. The signal must be in synchronization with a 1 PPS (Pulse per Second) UTC signal. With off-nominal frequencies, it may be difficult to determine the exact phase at a given instant.

Testing can be done at whole or fractional integer frequency offsets to simplify testing. A test frequency of $f_0 + n$ where f_0 is the nominal frequency and *n* is an integer will be directly synchronizable every second (at 1 PPS). Therefore, for example, frequencies of 61 Hz, 62 Hz, and 63 Hz can be synchronized at every 1s rollover. Smaller fractional frequencies can be synchronized at longer integer intervals. For example, a test of 60.1 Hz will be synchronizable every 10s. Testing of these parameters can be tedious, but can be done accurately with carefully planned and executed procedures.

In the report of "Advance Technologies to Improve Power System Reliability" [11], National Institute of Standards and Technology (NIST) presented their development in the PMU calibration system.

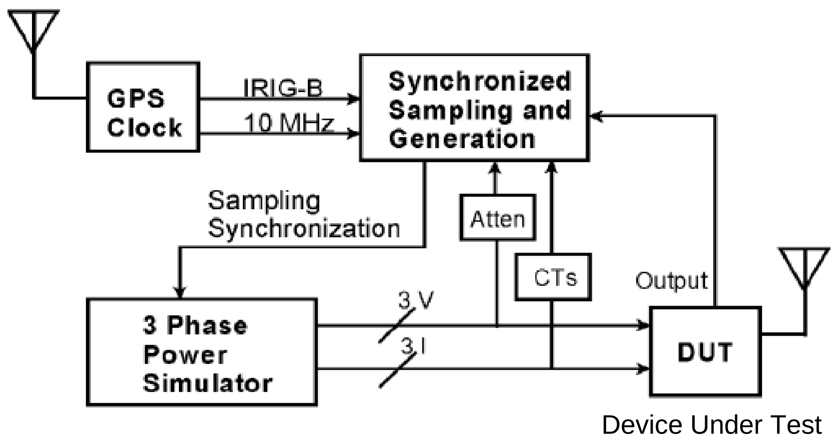


Figure 2-16
NIST Phase Measurement Unit Calibration System

As shown in Figure 2-16, the calibration system used at NIST consists of a GPS clock, a three-phase power calibrator, three voltage dividers, three trans-impedance devices and a six-channel sampler to measure the voltage and current waveforms supplied to the PMU under test.

The following numbers are initial estimates of the expected uncertainties of this system. [36] The voltage dividers are calibrated inductive voltage dividers (IVD) with errors generally less than 10 parts in 10^6 in ratio and phase. The trans-impedance devices are current transformers with a resistive load on their output. The total uncertainty of the combination of the two devices is expected to be less than 20 parts in 10^6 in ratio and phase. The uncertainties of the six-channel digital sampling system are less than 10 parts in 10^6 in amplitude and 100 ns in timing. The sampler is synchronized with the 10 MHz and 1 PPS output of the GPS clock in IRIG-B time format code.

2.6 PMU placement

Another key issue regarding PMU implementation is the placement of PMUs. For a wider-area interconnected power system, it is neither economical nor necessary to install PMU at every node. Meanwhile, considering the cost of equipments and operational constraints, PMUs implementation in a complex power system is a long-term process. It is more practical to install PMUs on the nodes with relative high priority in the early stages. Therefore, it is important for industry to develop a useful and convenient PMU placement strategy with a limited number of PMUs available.

The strategy of PMU placement is directly determined by the intended applications of PMU. Researchers and industrial engineers also have developed topological or numerical methods to determine the optimal placement of PMUs according to the specific PMU applications. In the previous and current projects, some methods and criterias also have already been developed and used to determine the PMU placement.

In this section, the specific method to determine the placement of PMUs regarding its application in state estimation will be first presented. Then, the successful practical experience of industry - the strategies of PMU placement used in the EIPP and Brazilian power system will be presented.

2.6.1 Placement of PMU for improving state estimation

State estimators provide optimal estimates of bus voltage phasors based on the available measurements and knowledge about the network topology. Measurements that are telemetered from the substations are processed at the control centers by the state estimator. State estimator provides the optimal estimate of the system state based on the received measurements and the knowledge of the network model. Conventional measurements include the following types:

- Power injections (real/reactive),
- Power flows (real/reactive),
- Bus voltage magnitude,
- Line current magnitude,
- Current injection magnitude.

As the PMU become more and more affordable, it is also proposed to be introduced in state estimation. PMUs can directly provide two other types of measurements, namely bus voltage phasors and branch current phasors. Depending on the type of PMUs used, the number of channels used for measuring voltage and current phasors will vary.

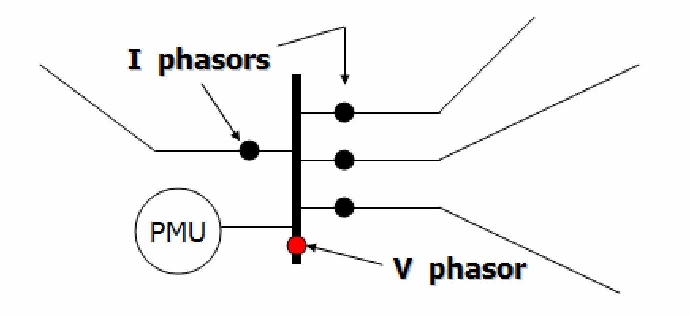


Figure 2-17
Phasor measurement provided by PMU

In the report of “Utilization of Synchronized Phasor Measurements for State Estimation: Benefits and Challenges” [12], two PMU placement strategies are presented to achieve two different objectives for PMU application in state estimation:

- Make all the system buses observable with only PMU measurements
- Improve the bad data detection and identification capability by placing PMUs

Since the PMUs can directly measure the phasor (both the magnitude and angle) of bus voltage and branch current, a linear state estimation can provide accurate system state, which also benifit from the high sampling speed and accuracy of PMU measurements. Therefore, the first strategy of PMU placement is to solve the problem of how to cover the entire system with minimal number of PMUs.

Using IEEE 14-bus system as an example, the report presents a procedure by which new PMU locations can be systematically determined in order to render an observable system. The procedure also can be extended to account for cases that a single PMU is lost. Buses with zero and nonzero injections and branches with power flow measurements also can be taken into consideration in this generalized procedure.

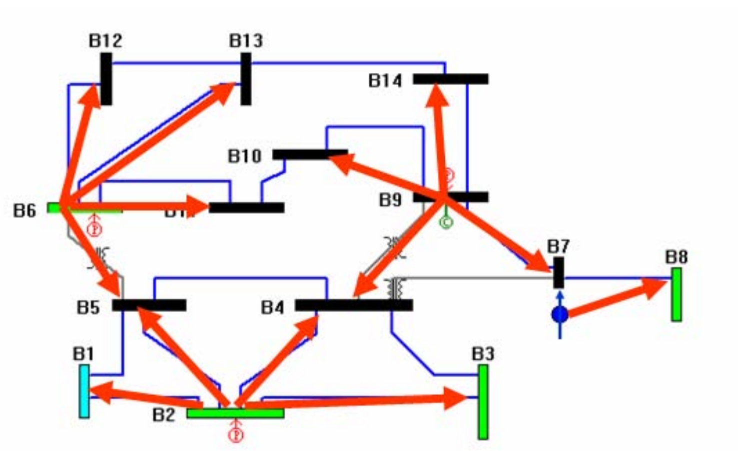
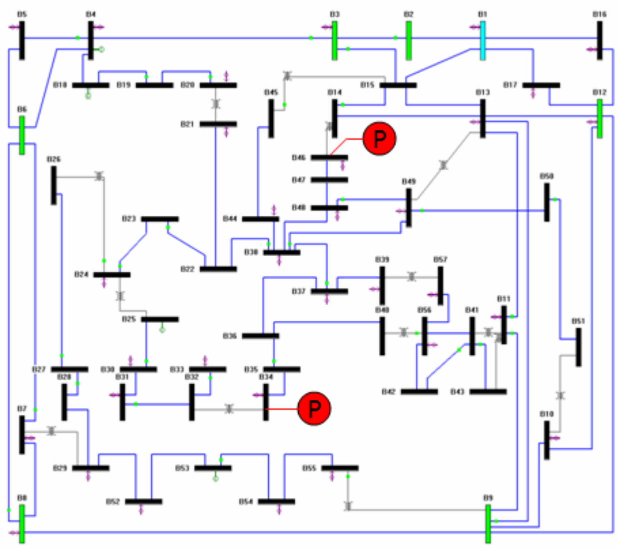


Figure 2-18
IEEE 14-bus system with PMUs [12]

Another strategy of PMU placement is to improve the measurement redundancy by placing PMUs so that the measurement bad data can be detected and identified by the state estimator. Due to the low measurement redundancy, there may be critical measurement in the power system. The bad data appearing in critical measurements can not be detected, which inevitable will cause state estimator obtain wrong system state. Strategically placement of new PMU measurements in some location of power system can transfer critical measurements into redundant measurements.

As showed in the Figure 2-19, adding 2 PMUs at specific locations can transfer 13 critical measurements into redundant ones, This result in great improvement of system measurement redundancy.



Critical Meas.	Type
1	F41-43
2	F36-35
3	F42-41
4	F40-56
5	I-11
6	I-24
7	I-39
8	I-37
9	I-46
10	I-48
11	I-56
12	I-57
13	I-34

Figure 2-19
Eliminating Critical Measurements via PMUs in 57-bus System [12]

2.6.2 PMU placement strategy in current projects

PMU placement in EIPP

In EIPP project, the PMU placement is determined for the objective of monitoring the system performance. Therefore, PMUs to be installed should provide good indication of whether the system is performing well or not at any given time. Also, for forensic analysis, these locations should provide good understanding of what happened to the system during a disturbance. And these locations were not necessarily chosen for the state estimation purpose.

Therefore, the strategy of PMUs placement in EIPP is designed to attempt to cover all the following locations: [13],

- Flowgates – Transmission Load Relief (TLR) 5s over last 2 years
- Generating Stations ≥ 1,500 MW
- Major Transmission Interfaces
- Regional/interregional studies
- Angular separation observability
- Covers inter-area oscillations
- Correlation to regional Disturbance Measurement Equipment (DME) locations
- Major load centers

PMU placement in Brazilian National Power System [14]

The Brazilian Interconnected Power System Operator (ONS) was created in 1998. Its responsibility is to operate the Brazilian National Interconnected Power System (NIPS), with transparency, fairness and neutrality, in order to guarantee continuous, economic and safe electric energy supply.

There are two projects related with implementation of PMU applications in the ONS' current action plan (2007-2009):

Off-line application - Implementation of a Phasor Recording System: The main goal is to install a PMU system to record NIPS dynamic performance during wide area disturbances.

Real-time application - Use of Phasor Measurement Technology on Real Time Decision Support: The main goal is to extend the application of the initial PMU System for real-time applications, mainly for state estimation enhancement.

According to these two applications, ONS develop a strategy for PMU placement: the PMU placement is determined to cover the following locations:

- Where voltage profile and dynamic performance are critical
- That are crucial for main load areas supply
- Neighboring the DC link associated to Itaipu Power Plant Transmission System

2.6.3 Assessment on Optimal Placement of PMUs

Although some practical strategies have been used in current projects, it should be noticed that the main objective of PMUs implementations in these projects are still on the level of monitoring and recording the performance of power system. A comprehensive PMU placement strategy becomes necessary when the extensive PMU applications are proposed in power system protection and control.

EPRI believes that the optimal placement of PMUs should be determined based on two major factors: system characteristic and intended applications.

Regarding to the system characteristic, topology configuration (system size, node location, weak nodes and power flow pattern etc.) and communication ability (available channels, bandwidth limits and time delay etc.) will influence the optimal placement of PMU. Topology configuration and communication ability are very important to PMU placement because they determine the potential PMU sites and communication pattern, which is the foundation of PMU placement. Furthermore, each system's topology configuration and communication ability are so unique that they need comprehensive study before the application of the technology of PMU.

Regarding to the intended application, study and research results have proven that different PMUs applications could have totally different PMU placement schemes. For example, the application of state estimation requires that PMUs should be placed by considering observability for overall system and the reliability of the estimated state. While the application of out-of-step protection requires that the placement of PMU should be performed considering observability of generator rotor angle in real time. The situation becomes more complicated when multi-applications are required, different optimal PMU placement schemes are developed first, then those schemes are evaluated together and a final optimal scheme is determined using optimal methodology.

EPRI is launching a new project named "Assessment on Optimal Placement of Synchronized Phasor Measurement Units (PMUs)" to help utilities members to determine the optimal placement of PMU. The major objective of this project is to provide the strategy of optimal PMU placement to the participating utilities members based on their system characteristics and intended PMU applications.

2.7 Summary

In this chapter a variety of issues about PMU implementation have been presented and discussed. The PMU implementation is a complicated issues that is related to industrial standard, communication system, data and information management, PMU calibration and testing and optimal placement.

After a long-term research and technology improvement, extensive applications of PMU have already been presented and proposed. In the near future, PMUs will be utilized not only for monitoring and recording the operation state of power system, but also for other functions in the area of power system planning and operation, including wide area protection and control, system modeling, etc.

Past industrial experience shows that the implementation of PMUs in power system is a long-term and multi-stage process. The process involves not only high investment but also collaborative work between utilities, research institutes and venders. Therefore, it is necessary and important for the industry to develop a future road map for PMUs implementation.

A PMU implementation roadmap is presented in the report of “Advance Technologies to Improve Power System Reliability” [11]. In this report, all current concerned applications with utilization of PMU are evaluated from three different aspects:

- Industry needs
- Roles of PMUs in the application
- Deployment challenge of the application

Figure 2-20 shows the evaluation results. The applications are classified into different groups based on the three key factors. Based on the evaluation result, a road map is proposed in Figure 2-21. In this roadmap, the deployments of these applications are planned in three stages: 1-3 years, 3-5 years, and more than 5 years.

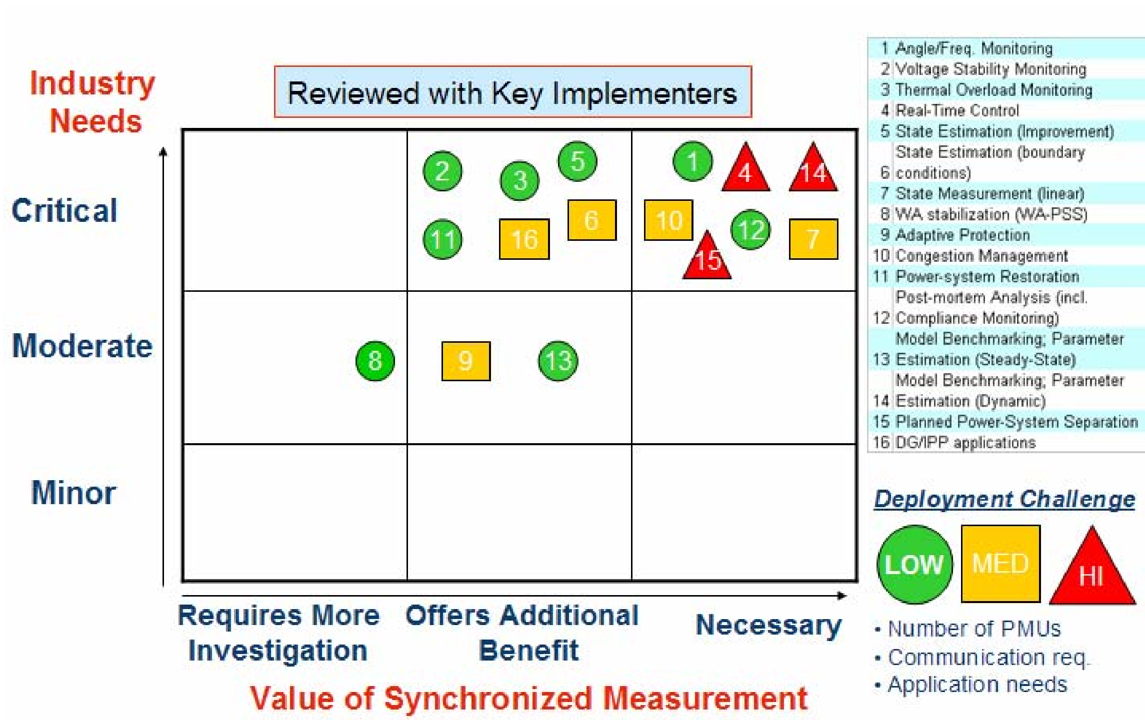


Figure 2-20
Industry Needs and Value of synchronized Measurements [11]

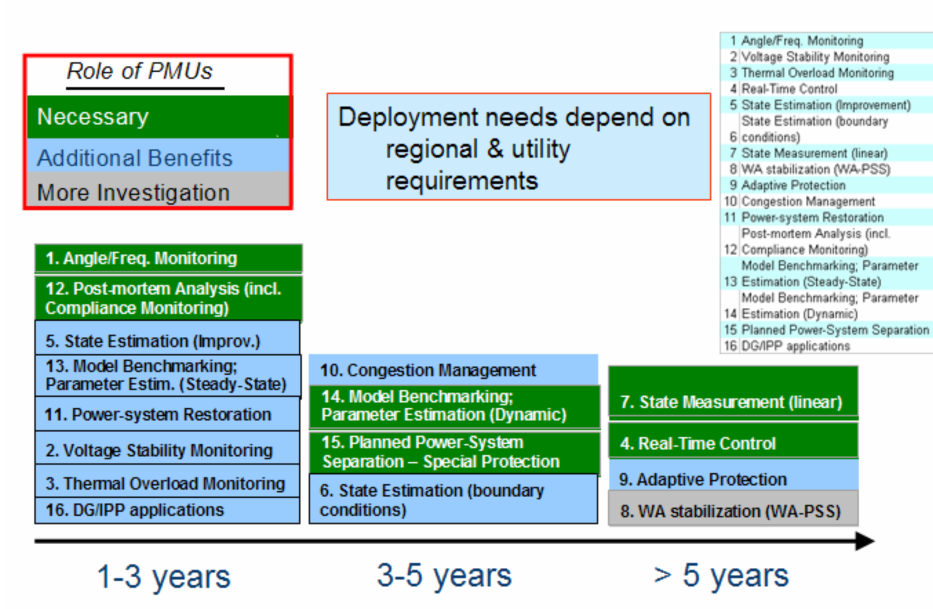


Figure 2-21
Deployment Roadmap [11]

Facing the both challenges and opportunities brought by increasing deployments and extensive applications of PMUs, EPRI will provide service to assist utility members in PMU implementation.

3
PMU APPLICATION

3.1 Introduction

The introduction of synchronized phasor measuring units (PMUs) in power systems improves the performance of monitoring, controlling and analyzing power system. Important system information about different AC quantities, such as currents, voltages, frequency, active and reactive power with same Global Position System (GPS) time reference, can be obtained using several PMUs installed at different locations of a power system. Synchronized measurements units make it possible to measure phase angles in different locations within the power system directly. System operators have the ability to utilize the existing power system more efficiently through improved monitoring and remedial action capabilities. Improved information allows faster and more reliable emergency actions. Synchronized phasor measurement units open a wide range of new applications:

- Improvement on state estimation
- Oscillation detection and control
- Voltage stability monitoring and control
- Load modeling validation
- System restoration and event analysis

This chapter is organized in six sections: Section 2 describes the use of PMUs to improve state estimation. This includes bad data processing, state estimation accuracy, dynamic state estimation and research requirement in state estimation. Section 3 deals with the applications of PMUs in oscillation detection and control. This section first addresses a research project tilted “adaptive out-of-step relaying”, through which a PMU-based power system oscillation detection scheme is brought out. Then an example of PMU application in oscillation detection and control in Southern California Edison Cooperation will be presented. Finally, the opportunities for power industry to improve the oscillation detection and control will be discussed through two ongoing research projects. Section 4 will illustrate the use of PMUs in voltage stability monitoring and control. This includes Voltage Instability Load Shedding (VILS) and Wide Area Voltage Stability Monitoring and Control. Section 5 will illustrate the application of PMUs in load modeling validation through a research study titled “measurement-based load modeling”. Section 6 will describe the uses of PMUs in system restoration and event analysis. This section first addresses the problem of fault location and the opportunity for PMU application in fault location. Then the Europe power system disturbance that happened on November 4, 2006 will be used as an example to illustrate how PMUs improve the process of system restoration and event analysis.

3.2 Improvement on State Estimation

State estimation has been introduced to power systems and implemented in the 1960s, and it plays a very important role in the real-time monitoring and control of the power system. State estimation processes redundant measurements and provides steady-state operating state for advanced Energy Management System (EMS) application programs (e.g. security analysis, economic dispatch, etc). Once receiving field measurement data, network parameter, network topology, and other information, state estimation filters incorrect data to ensure that the estimated state is correct. Through state estimation, the system operator has the ability to observe the operation conditions of power system. Furthermore, the consistent solution provided by the state estimation provides a starting point for studying the effects due to the loss of transmission lines or generation units.

Traditional state estimation only uses measured voltage, current, real power and reactive power to determine the operating condition of the electric network. Certain limitations persist in the traditional state estimation, and many of these limitations stem from the fact that it is technically more difficult and computationally more expensive to estimate the most likely state of the system based on measured voltage, current, real power and reactive power. Meanwhile, traditional state estimation is typically solved at intervals of minutes, which means that the results provided by state estimation may be old. Synchronized phasor measurement units (PMUs) which provide globally time synchronized phasor measurements with accuracy of one microsecond for bus voltages and line currents, together with the improvement of computer computation ability, can overcome those technical difficulties. This section will focus on the uses of PMUs to improve state estimation in the following areas: bad data processing, state estimation accuracy, dynamic state estimation, and research requirement in state estimation.

3.2.1 More Effective Bad Data Processing

Bad data processing is commonly integrated into the state estimation, and it is closely related to the measurement redundancy and configuration. For a given system, measurements are classified as either critical or redundant. Removing the redundant measurement from the measurement system will not cause the system unobservable and the errors can be detected by statistical tests, while removing the critical measurement will cause the system unobservable and the errors can not be detected. Critical measurement, however, can be transformed into redundant measurement by adding PMUs at strategic locations [15].

In order to convert all critical measurements into redundant ones, the procedure for the placement of PMUs can be described as three steps:

- Identification of critical measurements.
- Finding candidate PMU locations where each critical measurement can be transformed into a redundant one.
- Choosing the optimal set of PMU locations among those candidates.

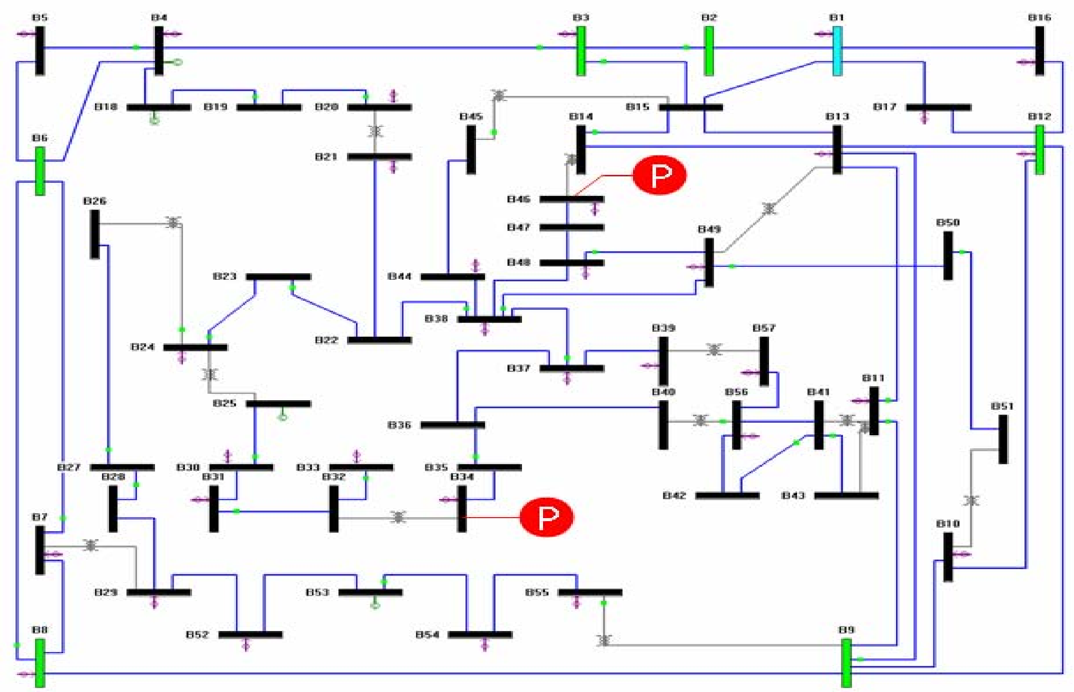


Figure 3-1
IEEE 57- Bus System [16]

Table 3-1
Critical Measurements for the IEEE 57-Bus System [16]

Critical Measurement	1	2	3	4	5	6	7
Measurement Type	F41-43	F36-35	F42-41	F40-56	I-11	I-24	I-39
Critical Measurement	8	9	10	11	12	13	
Measurement Type	I-37	I-46	I-48	I-56	I-57	I-34	

F means power flow, for example F41-43 represents power flow of line 41-43.
I means injection current, for example I-11 represents the injection current of bus 11.

In reference [16], IEEE 57-bus system has been used as a simulated system to demonstrate the performance of PMU in bad data processing. The simulated system has a total of 33 real power flow measurements and 32 injection measurements, as shown in Figure 3-1. This measurement configuration contains 13 critical measurements, which are listed in Table 3-1. By placing two PMUs at bus 34 and 46, no critical measurements exist in this system.

3.2.2 Improvement on State Estimation Accuracy

Compared with conventional measurements, synchronized phasor measurement units (PMUs) are able to improve state estimation accuracy. PMUs have the ability to measure voltage angles directly, which are the state variables to be estimated. Therefore, adding voltage phase angle measurements to a conventional state estimator could greatly increase the accuracy of state estimation. In addition, since the measurements from PMUs are real-time and no time skew exists between PMU measurements, this also improves the state estimation accuracy.

In Reference [16], the IEEE-30 Bus system has been used to demonstrate the improvement of state estimation accuracy with use of PMUs. Figure 3-2 compares the state estimation accuracy expressed as standard deviation of voltage magnitude, and Figure 3-3 shows the average value of standard deviation of voltage magnitude. Figure 3-3 shows that the average value of standard deviation of voltage magnitude is 0.0046 without any PMUs, while this value deceases dramatically to 0.001 when 10% of the buses are deployed with PMUs. Furthermore, this value decreases to 0.0005 when 20% of the buses are deployed with PMUs. However, no significant accuracy improvement can be observed if more PMUs are deployed into the system. The result of accuracy expressed as standard deviation of voltage angle is similar, which is displayed in Figure 3-4 and 3-5.

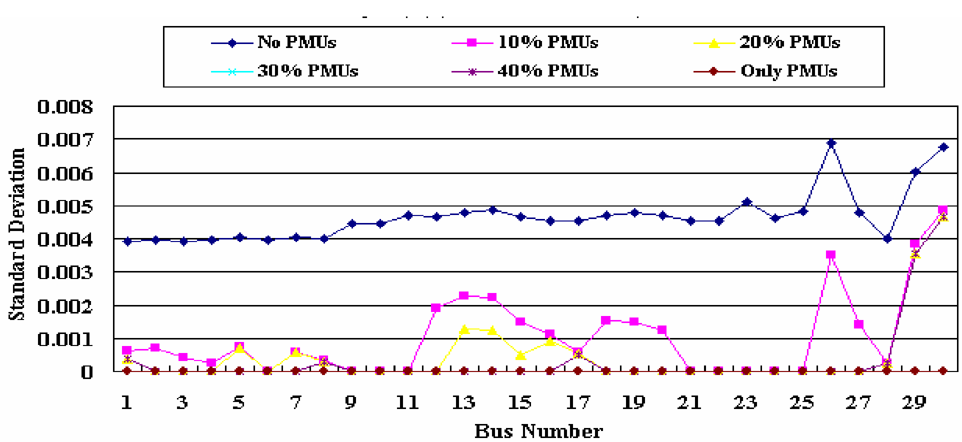


Figure 3-2
IEEE 30-Bus Accuracy of |V| (Std) [16]

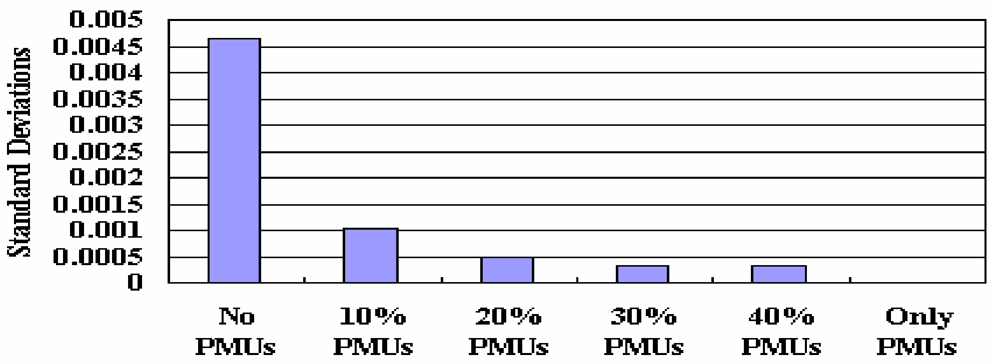


Figure 3-3
IEEE 30-Bus Average Std of |V| [16]

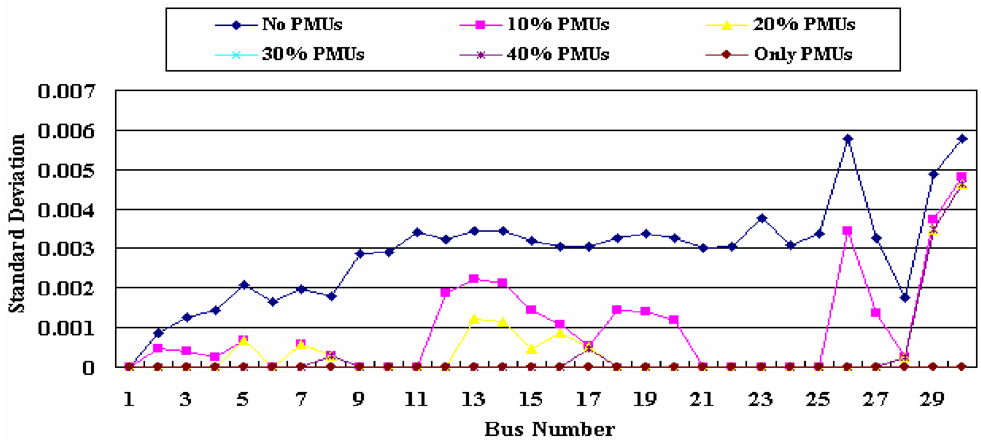


Figure 3-4
IEEE 30-Bus Accuracy of Angle of V (Std) [16]

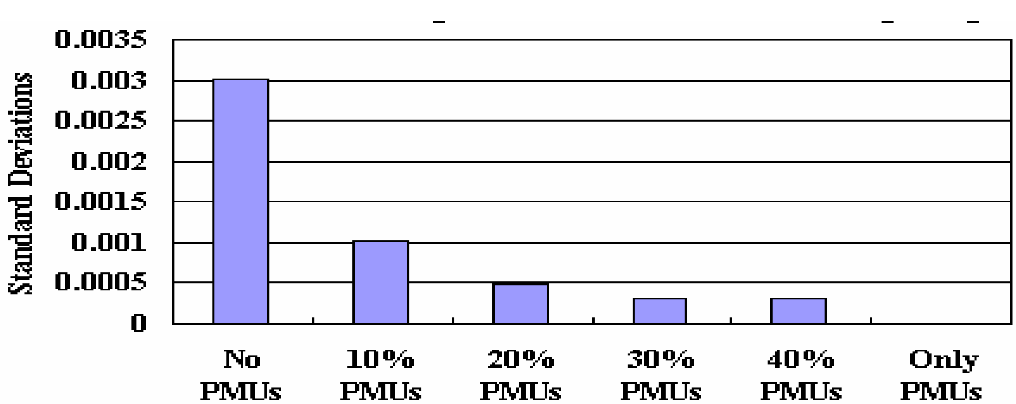


Figure 3-5
IEEE 30-Bus Average Std of Angle of V [16]

3.2.3 Dynamic State Estimation

The technology of synchronized phasor measuring units (PMUs) also makes dynamic state estimation possible. Conventional state estimation formulation assumes that the system is in quasi steady state and measurements are collected in a time window. It is assumed that changes in states in this time window are negligible and therefore they are used as if taken at the same time instant. While this assumption is valid during normal operating conditions, it can become problematic during system emergencies and system restoration. Because PMUs enable synchronized measurements to be collected, this assumption may no longer be necessary. Furthermore, since synchronized measurements from PMUs can be obtained much more frequently than conventional measurements, they can be used to capture fast dynamics associated with the states.

3.2.4 Research Requirement in State Estimation

In order to process the received data and information to obtain an accurate state, state estimation is required to have the ability to detect and identify the bad data and information. Such bad data and information include bad measurement data, network parameter error and network topology error. Among them, network parameter errors are the most challenging one to be detected. The network parameter errors may not be identified for a long time, which will lead to permanent errors in the results of state estimation. In recent years, more and more PMUs have been implemented in power systems; these phasor measurements offer an opportunity of improving the performance of state estimation.

EPRI is launching a supplemental project to improve the state estimation. Chapter 4 provides the detail description of the supplemental project.

3.3 Oscillation Detection and Control

Because of the competition between utilities and deregulation of the electric power markets, it is common to transfer large amount of electrical power from distant generators to load through long transmission lines. Therefore, the substantially increased amount of electric power transmitted through the existing networks might result in transmission bottlenecks and oscillations of power transmission systems.

The system oscillation origins from those interconnected generators in the system. The interconnected synchronized generators have the ability to remain synchronism because of the self-regulating properties of their interconnections. If one generator deviates from the synchronous speed, the rest generators in the system will provide power in order to reduce the speed deviation. Due to the effect of inertia of the generators, the whole system or part of it starts to swing. Normally, if the initial disturbance is not significant such as small change in load, the oscillations will decay and finally the system will maintain stable. If the initial disturbance is significant such as a few MWs load lost, however, the oscillations might cause the system lost of synchronism, and finally the system will collapse in worst case.

In order to keep system stable, system oscillation can be controlled either by operators or by automatic control through adjusting the output of generators. However, if a new system operating condition occurs which causes the oscillatory lightly damped, the operators might overlook this new condition, thus make the system potentially dangerous. Advanced monitoring of the power system can help the system operators to assess power system states accurately, control the system appropriately and finally avoid a total blackout. The synchronized phasor measurement units (PMUs), which can provide the measurements with both magnitudes and angles, and are time-synchronized with accuracy of one microsecond, offer a new opportunity in power system oscillation detection and control. Fed with the voltage and current phasors, the PMU-based power oscillation monitoring processes the input phasors and detects different power swing (oscillation) modes. The PMU-based power oscillation monitoring has the ability to quickly identify the amplitude, frequency and the damping of swing rate, which might incur angular instability.

This section first addresses a research project tilted "adaptive out-of-step relaying" conducted by EPRI and other members, through which a PMU-based power system oscillation detection scheme is brought out. Then a practical PMU application about oscillation detection and control in Southern California Edison Cooperation will be presented. Finally, with more and more PMUs are implemented in the power system, together with recent advancements in communications and computer technology, the opportunities for power industry to improve the oscillation detection and control will be discussed through two ongoing research projects.

3.3.1 Adaptive Out-of-Step Relaying[1]

This research project was jointly sponsored by EPRI, Florida Power and Light Company, Georgia Power Company, and the National Science Foundation. A prototype out-of-step relay at the interface between the Florida Power & Light and Georgia Power Company systems has been installed. The theory of adaptive out-of-step relaying was developed during a period of three years and field trial was conducted during a period of one-year. This research project has proven that adaptive out-of-step relaying can be applied to a power system interface to separate the system where unstable oscillations are detected.

3.3.1.1 Overview of Out-of-Step Relaying

The goals of out-of-step relay in power system are to detect transient swings, assess the swings, and classify the swings as stable or unstable. Conventional out-of-step relays use distance relays and timers to detect the system swings. The settings of the out-of-step relays are determined based on numerous of contingency cases studies. Through plotting the resulting apparent impedance trajectories on the R-X plane, the contingency cases can be classified into stable and unstable. However, if the prevailing condition of the power system changes, the response of the system to various transients may be totally different and the results of contingency cases studies are not valid any more. For example, the trajectory and depth of the swing will be different at

[1] Material from this subsection was excerpted from two EPRI report [17], [19], authored by several people, universities and companies.

different load level. Out-of-step relays have been known to mis-operate when the prevailing conditions have not been foreseen during the design phase [17].

Adaptive protection is a protection philosophy that permits and seeks to make adjustments automatically to various protection functions to make them more attuned to prevailing power system conditions [19]. The characteristic of out-of-step relay make it suitable for the application of adaptive techniques. Adaptive out-of-step relays have the ability to recognize the changes in the power system and adapt the setting to the prevailing conditions accordingly. As the system state changes, instead of trying to change the zone and timer setting of the adaptive out-of-step relaying, it is advantages to invokes entirely new approaches to the issue of out-of-step relaying. Since the function of the out-of-step relaying is to predict the outcome of a transient stability analysis, it is reasonable to consider the technique normally used for stability analysis. The transient analysis method of equal area criterion can be used for a system that behaves like a two-machine system.

3.3.1.2 System Description

There are two major initiating disturbances in the Florida system, one is the outage of high voltage lines and the other is loss of generation. If any lines are tripped due to some reasons and the consequence is so significant that will sufficiently affect the power angle characteristic, the change of status in these lines must be communicated to the out-of-step relay to determine the post-clearing system. If the system condition before disturbance is known, the equal area criterion can be used for stability analysis directly and the outcome of the resulting stability swing can be predicted accurately.

There are two 500-kV transmission lines that run from Georgia to the Duval substation in northern Floridian which are the major connections between Florida peninsula and the rest of the country. Several 230 kV lines also connect Florida to the rest of the country. Approximately 93% of the transfer power flows on the two 500-kV tie lines with the other 7% flowing on the smaller voltage lines. The 500-kV transmission system plays an important role in delivering the imported power. Due to the geography characteristic, the Florida system can be modeled as a two machine system, especially for faults on the tie lines. All the Florida generators can be grouped into one equivalent generator, while the generators in the rest of East Coast can be grouped into the second generator. Figure 3-6 shows the representation of the Florida-Georgia interconnection as a two-machine system. The original machine equivalent consisted of an equivalent inertia constant and an equivalent transient reactance, which is obtained by paralleling all the major generation in Florida and in the southeastern United States [18].

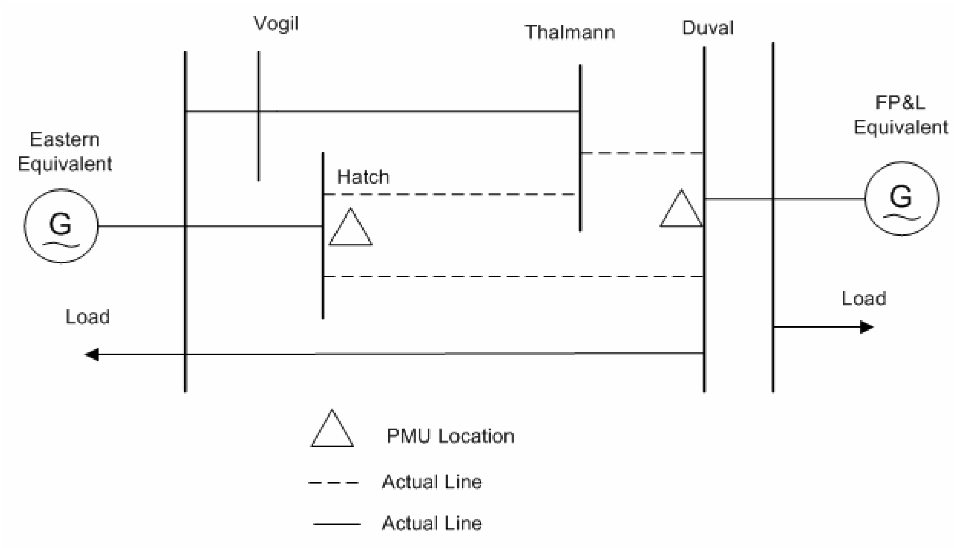


Figure 3-6
Two Machine System Model [19]

There are some discrepancies between the measured angle swings and those predicted by the original models by field testing. Therefore, in order to account for the errors in the angle prediction, the inertia constant of the Florida equivalent has to be adjusted. At first, the relay initialize the inertia constant of the Florida equivalent to a computed value, then the relay updates this value every time a swing is detected using the previous inertia constant and the angle difference measured for the first twenty cycles.

The network between the two equivalents was reduced to the interconnecting lines between the two measurement sites. Two Phasor measurements installed at the bus of Duval and Hatch respectively are used to compute the voltage phasors of the equivalents using the impendence matrix of the reduced network at the time of measurement. The voltage angles of the two equivalents are then used for equal area calculation to determine the degree of stability for the detected angle swing [20].

3.3.1.3 PMU-Based Adaptive Relaying

There are two PMUs, two relays and supporting communication hardware in the adaptive out-of-step relay system. As shown in Figure 3-6, the adaptive relay was installed at the Duval substation and Hatch substation. The PMUs measure positive sequence voltage and currents of various lines in the substation, as well as the status of important circuit breaker in the substation. Each PMU has a GPS receiver to generate the sampling pulses that drive the A/D converter of every input channel. The sampled data is digitally filtered and a combination of DFT and positive sequence algorithm is performed in three phase input to get the positive sequence phasor of the fundamental frequency components of the voltage and current. Every two cycles the data measured by PMU is sent to the local relay. The software in the digital relay has the ability to detect system swings and system changes. At the same time, the software can perform the equal area algorithm and angle prediction at a rate of 30 times per second, and keep the angle computational accuracy to 0.02˚ at the same time [17].

3.3.1.4 Experience and Lessons

Since its first operation in 1993, the adaptive relay system captured several significant swings and three lines faults. Based on those experiences, it is necessary to change relay's original algorithms. A fixed value of inertia constant for the Florida equivalent is used in the original algorithm at first. During the process of swing, the Florida inertia constant in the original model is smaller than the actual one. Therefore, an improved algorithm was adopted to use the first 20 cycles of the angle swing to determine a new value for Florida inertia constant based on the angle trajectory, power flow and previous value of inertia constant. The use of this improved algorithm enhances the adaptability of the out-of-step relay system to seasonal changes in the Florida system [21] [22].

The concepts and technology used for this research project demonstrate a sound base to apply adaptive out-of-step relaying into power system which behaves primarily as two-machine system. If the synchronized phasor measurement is used as input to the relay, estimation of stability or instability of an evolving swing can be made in sufficient time to produce blocking or tripping signals. Current information about the state of power system, if possible, should be communicated to the relay from control center. This information can be used to set up a current system model, which improves the relay performance. The relay can be programmed to learn and refine the system model from all observed transients. Especially, much can be learned about the system damping, a characteristic which is crucial for making accurate prediction of system swing.

3.3.2 Oscillation Detection and Control in Southern California Edison Cooperation (SCE) [23]

3.3.2.1 Project Overview

EPRI started the synchronized phasor measurement project in WSCC around 1993-1994, Southern California Edison joined this EPRI project in 1995. As part of the EPRI project, SCE installed four PMUs on the system and a Phasor Data Concentrator (PDC). With more additional PMUs were procured, SCE now have a total of 16 PMUs installed in its system. The PDC in SCE has the ability to receive multiple PMU inputs. The PDC triggers if any PMU detect a disturbance. It stores data from all the PMUs which is time synchronized. The recorded files are three minutes long, with one minute of pre-trigger and two minutes of post-trigger. The trigger takes place based on trigger settings for deviation of voltage, phasor angle, frequency and rate of change of frequency. All the phasors are stored in the file and the data can be viewed using software. Figure 3-7 shows the SCE network connectivity and PMUs' installation locations.

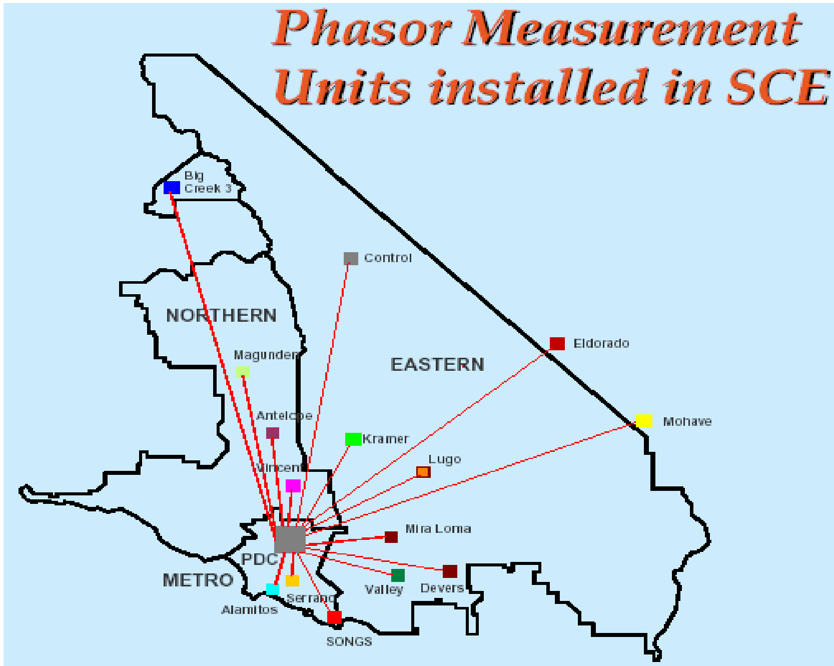


Figure 3-7
PMUs locations at SCE substation [24]

3.3.2.2 Oscillation Detection and Control in SCE

The Western System Coordinating Council (WSCC) system is one of the largest power grids in the United States and covers a wide geographical area. Because of the large inter-connected power system with the long transmission lines, some areas can suffer from power system oscillations with respect to other areas. Some of the inter-area oscillations occur at very low frequencies range from 0.2 to 1 Hz. The low oscillation frequencies are normally large generation/load areas connected by a weak transmission system and thus limit the power transfers on the inter-connected transmission lines. These oscillations occur when two large areas in an interconnected power system swing with respect to each other. Normally such power flow oscillations could be damped by system damping, but if the interconnected system is relatively weak, the oscillation can grow. This is exactly what happened in the major disturbance in the WSCC on August 10, 1996.

The implementation of PMU enables SCE monitor and controls the system oscillation. Figure 3-8 shows one event of system oscillation detected by PMUs in SCE on August 4, 2000. Based on the oscillation observed, immediate action taken by system operators prevented this oscillation to spread into whole system.

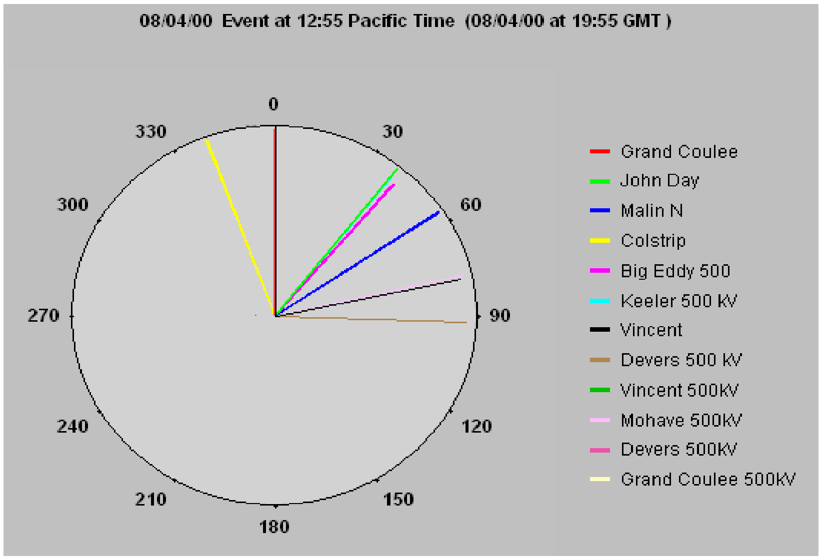


Figure 3-8
System Oscillations under Stressed Conditions [23]

3.3.3 New PMU Applications in Oscillation Detection and Control[2]

With more and more phasor measurement units are implemented in the power system, together with recent advancements in communication technology, there is a great opportunity for power industry to improve the oscillation detection and control. EPRI is launching two supplemental projects titled “PMU-Based Out-of-Step Protection Scheme” and “Pinpointing the Initiating Location of a Disturbance”, which use the state-of-art technology to improve the oscillation detection and control.

3.3.3.1 PMU-Based Out-of-Step Protection Scheme

Certain disturbances may cause the interconnected power systems to lose synchronism, which may lead to cascading blackouts and equipment damage. In order to avoid these severe results, controlled separation using out-of-step protection is an effective way to preserve stability in several smaller islands. The disadvantage of the traditional out-of-step protection scheme is that it only uses local measurements to estimate the condition of entire power system network, which inevitably affects its ability to detect the out-of-step conditions in certain circumstances.

PMU can provide real-time measurements of power system quantities such as phasor of voltage and current, frequency, rate of frequency deviation, and angle difference between different buses. Therefore, instead of the indirect measurement or estimation used in traditional out-of-step protection, the voltage frequency and angle measurement from different buses can provide the

[2] Material from this subsection was excerpted from two EPRI supplemental projects, authored by P. Zhang and G. Zhang respectively.

ability to directly monitor system transient stability conditions. At the same time, PMU is able to monitor power-flow change on some specific key buses and transmission lines. This information is important for developing the strategy of system separation, which can help keep the generation-load balance during the separation to minimize generation and load shedding.

This project will develop an out-of-step protection scheme using phasor measurements in order to prevent the loss of synchronism in the interconnected transmission network. The proposed protection scheme will be designed to realize the following key functions:

- Monitor the system and detect the out-of-step condition.
- Identify the out-of-step areas in the power system.
- Control separation of the interconnected system to prevent cascading failures.

Please refer Chapter 4 for more information about this supplemental project.

3.3.3.2 Pinpointing the Initiating Location of a Disturbance

The location of a disturbance on the electric power grid can be accurately pinpointed using multiple devices that accurately measure frequency of the grid. The frequency of the electrical grid will change whenever a line trips or generator trips. Because this change in frequency propagates like a wave over the system from the point or origin of the disturbance to the entire interconnected system, it is possible to detect the change in frequency with highly accurate monitors and back propagate to determine the location of the disturbance.

From the replay snapshots, it has been observed that the dots spread out gradually at a speed much less than the speed of light or in the form of electromechanical wave propagation in the system as the time progresses. If there are enough measurement units in the system, it would be able to view this propagation in greater detail as traveling “waves.” Fast communication may even allow real-time display as the travel time is measured in seconds. The time delays seen at different observation points in the system provide the opportunity for a number of applications, namely, to study the speed of propagation and to use the time difference for triangulation of event location.

Many utilities have placed Phasor Measurement Units (PMUs) on the high voltage transmission grid, and more and more PMU devices will be put into place in and around the utility electrical grid. With those measurement units in the system, disturbances can be located accurately by viewing the frequency propagation as traveling waves. Algorithms such as either time and distance or Fast Fourier Transform methods will be developed to back propagate from the measurements to the location of the disturbance.

The simulation results as well as data from PMUs show the frequency wave propagation speed varies from region to region and it is not the same between two points in opposite directions. In the same region, the speed of frequency wave propagation is almost proportional to the amount of real power generation tripped. The reactive power plays a much smaller role. Figure 3-9 shows the snapshots of frequency wave propagation after a trip of 501 MW and 22.6 MVAR from a generator in Tennessee.

In particular, the simulation results suggest that the frequency wave propagates faster in the west region than in the east region. The east region has denser generation than the western region so the wave would experience more "resistance." The simulation results also show that the wave would propagate slightly faster from the central part of the system than from the rim of the system, and the wave propagates at lower speed from north to south than from south to north.

Please refer Chapter 4 for more information about this supplemental project.

Figure 3-9
Snapshots of Frequency Wave Propagation

In conclusion, remote information such as active and reactive power flow, frequency and phasor provided by synchronized phasor measuring units (PMUs), together with advanced communication system technology, have made it feasible to enhance the performance of oscillation detection and control. Synchronized measurement information provides system-wide data in time frames appropriate for damping purposes, and system-wide communication makes it possible to decide where to measure and where to control.

3.4 Voltage Stability Monitoring and Control

Voltage stability is closely related to the loadability of a transmission network. In power systems, this may take place as a precursor to the traditional frequency instability problem. As power systems are pushed to transfer more and more power, environmental constraints restrict the expansion of transmission network and the need for long distance power transfers has been increased, voltage stability problem has become a major concern in planning and operating electrical power systems.

New measurement devices and high-speed communication systems have become available in transmission system operation. Based on these technologies, measurement-based on-line voltage stability monitoring and control become feasible, which has the ability to raise the transfer limits and increase security of system operation. This section describes recent research conducted by

EPRI based on the use of synchronized phasor measurements units (PMUs) to improve voltage stability monitoring and control through the following two applications:

- Voltage Instability Load Shedding (VILS) with focus on local protection control.
- Wide Area Voltage Stability Monitoring and Control with focus on system wide voltage stability and control.

3.4.1 Voltage Instability Load Shedding[3]

3.4.1.1 Overview of Conventional Under Voltage Load Shedding

Voltage stability now becomes a major concern in planning and operating electric power systems. Load increases and/or generation rescheduling stress the system by increasing power transfer over long distances and/or by drawing on reactive power reserves. It is critical to track how close the transmission system is to its loadability limit. If the loading is high enough, actions (such as load shedding) have to be taken to relieve the transmission system. A problem associated with tracking the loadability limit of the transmission system is that such limit is not a fixed quantity, but rather depends on the network topology, generation and load patterns, and the availability of VAR resources. All of these factors can vary with time due to scheduled maintenance, unexpected disturbances, etc.

Under Voltage Load Shedding (UVLS) scheme has been used as an economic means to avoid voltage collapse. This scheme is only used when all other means of avoiding voltage collapse are exhausted. Since load shedding results in high costs to electricity suppliers and consumers, UVLS schemes have been deployed as a ‘Safety Net’ to prevent voltage collapse following an extreme event. UVLS sheds load in pre-defined blocks that are triggered in stages when local voltage drops to various pre-defined levels.

In conventional UVLS schemes, voltage magnitude is the only triggering criteria. However, past research has demonstrated that voltage magnitude alone is not a satisfactory indicator of the proximity to voltage instability under all circumstances. In fact, voltage stability is determined by the power systems’ ability to supply and deliver reactive power. In actual systems, the computation of actual system PV curves may be very complicated due to the large number of generators, the widespread applications of capacitor banks, the uncertainty about the dynamic characteristics of system loads, and the variability of power flow pattern. In addition, operation of under load tap changers, the actual dynamic reactive capability of generators and accurate reactive reserve monitoring all affect the ability of the system to supply and deliver the reactive power.

Currently, settings of UVLS are determined by system engineers through extensive network analyses using computer simulation packages. However, simulated system behaviors do not usually coincide with actual measured system responses due to data and modeling issues.

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[3] Material from this subsection was excerpted from EPRI report “Voltage Instability Load Shedding”, authored by P. Zhang.

Developing appropriate settings for the under voltage levels and time delays are challenging problems faced by system engineers. Inappropriate settings can result in unnecessary shedding or failure to detect the needs for load shedding.

3.4.1.2 Voltage Instability Predictor (VIP)

Vu and Begovic et al. [25] have proposed Voltage Instability Predictor (VIP) method to estimate the proximity of a power system to voltage collapse. The VIP only uses the local measurements (voltage and current) at the bus terminal to estimate the Thevenin impedance and calculate the apparent impedance of local load, then detects the proximity to voltage collapse by monitoring the relationship between those two impedances. VIP method indicates that, at the point of maximum loading, the absolute value of the apparent load impedance and the equivalent Thevenin impedance are equal. Based on the closeness between those two impedances, VIP method will determine whether need to shed load. However, VIP method does not provide any information about how much load should be shed in order to bring the system back to voltage stable. Moreover, VIP method uses the Least Square technique to determine the Thevenin equivalent impedance. The Least Square technique makes use of measurements taken at different time instant to estimate the equivalent source impedance. Protective relay impedance comparators have been able to estimate the source impedance with some accuracy during faults, but this is primarily due to the fact that there is a significant difference in measurements between pre- and post-fault conditions. During power swings, this is not necessarily the case, and unless the measurements have changed sufficiently from one measurement to the next, the accuracy of the Least Square technique may be questionable.

3.4.1.3 Voltage Instability Load Shedding (VILS)

EPRI proposed an innovative control scheme named “Voltage Instability Load Shedding” to enhance traditional UVLS scheme. The VILS uses Kalman Filter technique to track Thevenin equivalent impedance which is a recursive method that has fast convergence property. VILS method computes Voltage Stability Margin Index (VSMI), which express voltage stability margin in terms of active, reactive, and apparent power, in order to continuously track the voltage stability margin at local bus level. Compared with the VIP method, VILS method can determine how much loads need to be shed at local bus level in order to prevent voltage instability or collapse.

The VILS method provides the load shedding information in the injection plane instead of the impedance plane. Displaying the voltage stability margin in the power injection space provides voltage stability margin in terms of MW, MVar and MVA. As a result, it not only judges whether load shedding action should be taken place but also provides the information about how much loads need to be shed.

IEEE 118-Bus system has been used in this research as an illustrative example. IEEE 118-Bus system is the equivalent system of a portion of the American Electric Power transmission network in Midwestern of US. Figure 3-10 shows the one-line diagram. Table 3-2 shows the partition of this system. Lists case is a transaction between area 2 and area 1.

- The load at Bus 22 in base case is 10+j5 MVA.
- The total load in area 1 increase 5 MW per step.
- The reactive power of load in area 1 increases correspondingly according to the power factor defined in the base case.
- Governor power flow is used to calculated generators' output in order to balance the increasing load.
- Generator reactive power output limits are also considered.
- The simulation ends when the power flow calculation failed to converge.

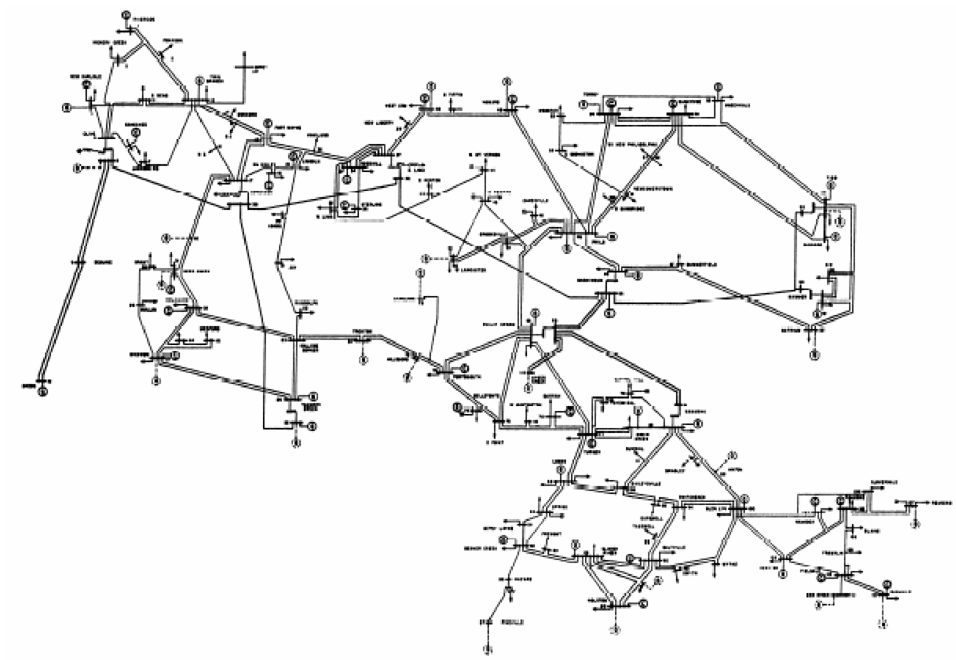

Figure 3-10
One Line Diagram of IEEE 118-Bus System [26]

Table 3-2
Transaction between Area 2 and Area 1 [26]

Area/Lines			Area/Buses		
Area 1	Area 2	Area 3	Area 1	Area 2	Area 3
1~29 31~43 178~182 184	46~53 55~107 183	109~115 117~118 120~125 127~177 185~186	1~23 25~32 113~115 117	33~69 116	24 70~112 118

Figure 3-11 shows the voltage stability margin as a function of local load at bus 22. It clearly indicates that as the load at bus 22 increases, the voltage stability margin will decrease.

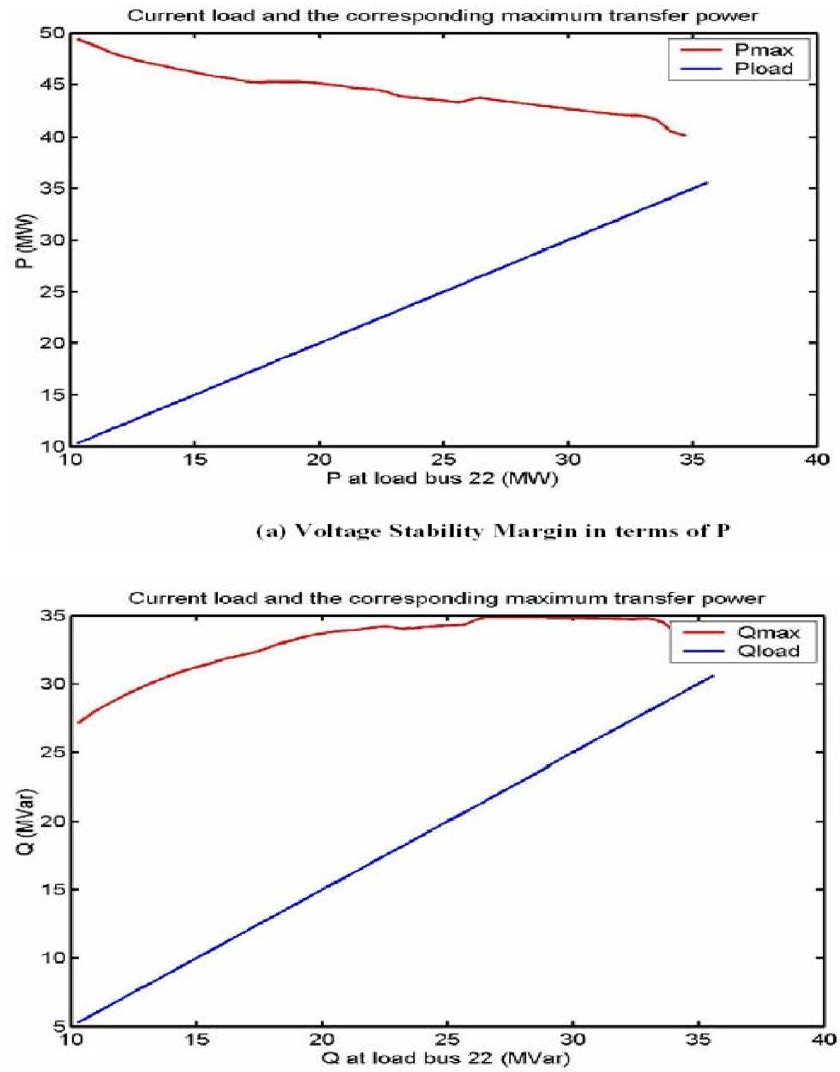

Figure 3-11
Voltage Stability Margin as a Function of Local Load at Bus 22[26]

Therefore, the new control scheme referred as "Voltage Instability Load Shedding" (VILS) has the ability to enhance the conventional UVLS at designated location. The VILS control scheme uses local measurements to continuously compute Voltage Stability Margin Index (VSMI) to track voltage stability margin at local bus level. The VSMI is expressed in terms of active, reactive and apparent power, which indicates how much load to be shed to bring the system back to voltage stable region. When this smart device detects that the voltage stability conditions cross a warning threshold, it will send an alarm signal to inform system operators. When it detects that the voltage stability conditions cross an emergency level, it will perform local load shedding function.

3.4.2 Wide Area Voltage Stability Monitoring and Control

3.4.2.1 Overview of Wide Area Voltage Stability Problem

Voltage stability is a major concern in power system operation and a leading factor to limit power transfers in the prevailing open access environment. Voltage stability assessment (VSA) program is a computer simulation tool to help operators monitor and control system voltage stability. The accuracy of VSA results fully depends on the accuracy of modeling the generation, load, and transmission facilities. Uncertainties of these factors pose challenges of obtaining accurate voltage stability analysis results using VSA program. Inaccurate VSA results may lead operators to make incorrect decisions, therefore increase the risk of voltage collapse. Moreover, VSA program also relies on the state estimator to provide steady-state solution for further analysis. In extreme operating conditions when state estimator fails to converge, VSA program also fails to help operators monitor and control system voltage stability.

The limitations of VSA program can be overcome by using measured data at substation level to calculate voltage stability margin in real-time and send the margin information to the control center for operators to monitor system voltage stability

3.4.2.2 Implementation of Wide Area Voltage Stability Monitoring and Control

EPRI invented a new algorithm titled “measurement-based voltage stability monitoring” that is able to calculate the critical voltage and voltage stability margin continuously at a local bus using measured voltage and current waveforms. The critical voltage is the voltage when the load at this local bus reaches the maximum value due to voltage stability limit. The calculated voltage stability margin can be expressed as active, reactive, and apparent power. This will provide system operators not only the power transfer limit to this local bus in terms of active power but also the reactive power support needed at this local bus.

Implementation of wide area voltage stability monitoring and control includes following major tasks:

<u>Task 1: Implementation of Measurement-based Voltage Stability Monitoring at Substation Level</u>

The critical substations need to be determined and monitored for voltage stability concerns. Once the critical substations are determined, the measurement-based voltage stability monitoring algorithm is implemented to calculate the voltage stability margin in real-time. The critical voltage and voltage stability margin in terms of active power and reactive power information will be sent to the control center for operators to monitor the voltage stability for those critical substations. Figure 3-12 shows the voltage stability margin in term of active power.

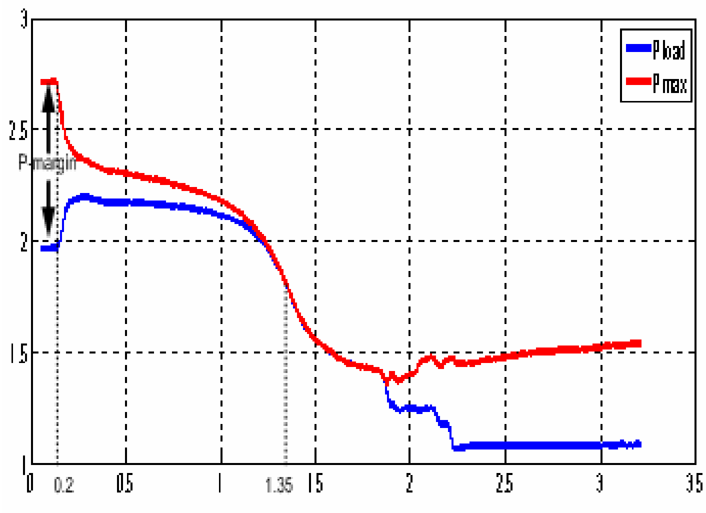

Figure 3-12
Stability Margin in terms of Active Power

<u>Task 2: Investigation of Voltage Stability Margin of Load Centers</u>

Most of load centers are supplied by more than one power source to ensure the security and reliability of power transfer. As a number of power sources are connected to the load center area at the distributed substations, the location of implementing the measurement-based voltage stability monitoring algorithm need to be determined. To monitor the voltage stability condition of a load center supplied by multiple sources, a new method is needed to calculate the voltage stability margin using the voltage stability margin calculated at individual substations. Figure 3-13 shows an example of a load center supplied by multiple power sources.

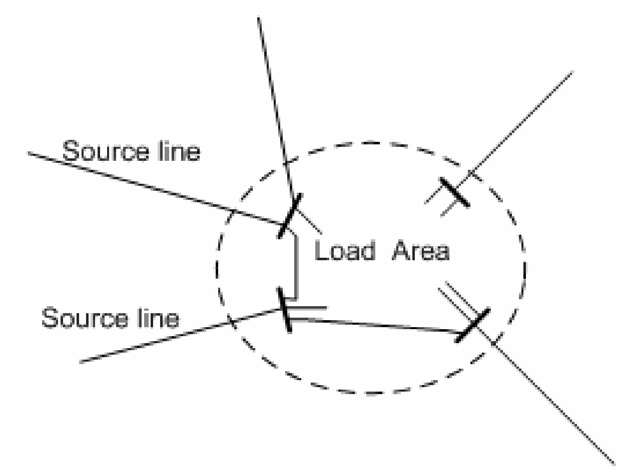

Figure 3-13
An Example of A Load Center Supplied by Multiple Power Sources

<u>Task 3: Development of Visualization Tools for Operators to Monitor Voltage Stability of Entire System</u>

Engage the operators of the participating utilities and experts in human factors to design effective human-machine interface to convey the critical voltage stability information calculated at the local substations and load centers. Based on the design, a visualization tool will be developed to help system operators to monitor voltage stability profile of the entire transmission network. This will broaden the visualization methods to help system operators to increase situation awareness.

In conclusion, the wide area voltage stability monitoring has the ability to modify the operation strategy in direction of higher used capacity while simultaneously reducing the risk of evolving collapse. EPRI is launching a supplemental project titled “measurement-based wide area voltage stability monitoring” to enhance the real-time voltage stability monitoring capability. Please refer to Chapter 4 for more information about this project.

3.5 Load Model Validation[4]

Power system planners and operators rely on the computer simulation programs to assess system dynamic performance. Loads have significant impact on system voltage and dynamic stability. Unfortunately, load is the most uncertain factor in the system studies and it is becoming more evident that the largest single source of simulation inaccuracy for planning and operations is the uncertainty of load model. Modeling load has always been a challenging task for power system engineers. Figure 3-14 illustrate a concept relating to the state of load modeling and identification [17]. The circle labeled Power System Load Model represents the performance of the load based on mathematical description of load dynamics. The circle labeled Actual Load represents the real load performance. The overlapping areas of these two represent the parts of the model that closely represents the behavior of the actual system. Ideally the two circles should completely overlap, indicating that the load model exactly represents the actual load.

[4] Material from this subsection was excerpted from EPRI report “Measurement-Based Load Modeling”, authored by P. Zhang

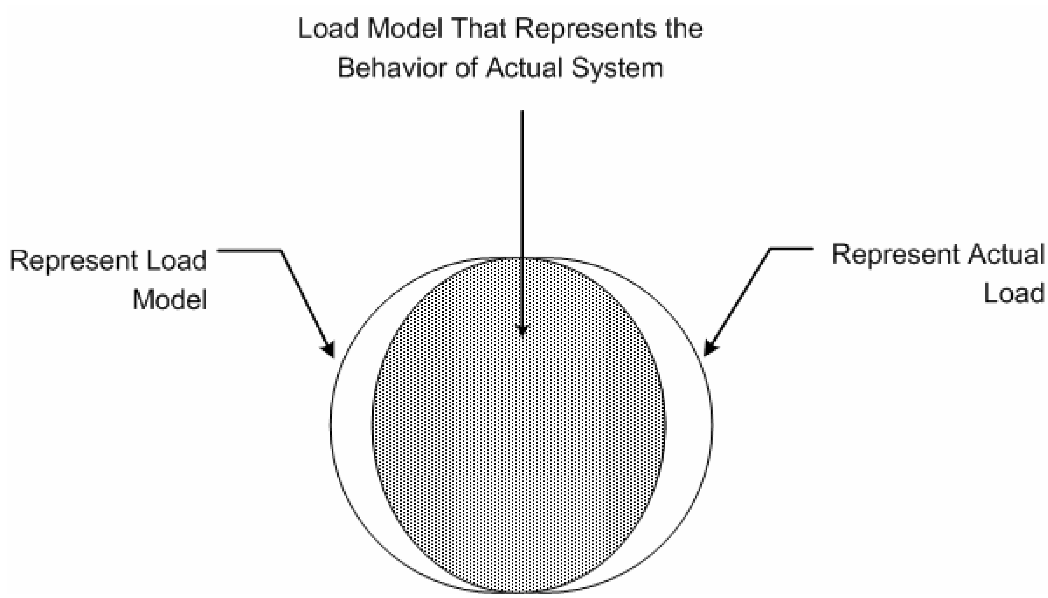

Figure 3-14
Illustration of the Concept of Comparing Load Model to Actual Load Response [17]

Traditionally, the component-based load modeling methodology, which was invented by EPRI in 1970s, has been used as a tool for power system engineers to model loads. The component-based approach requires performing an extensive survey to collect load composition information. After deregulation, however, transmission system planners may not be able to get access to such information. An alternative is to use measurement data from disturbance monitoring devices such as synchronized phasor measurement units (PMUs) to develop load models [27]. The measurement-based approach has certain advantages over component-based approach in that it reflects the actual load behavior during disturbances. This section will deal with the application of PMUs in load modeling validation through a recent research study titled “measurement-based load modeling” conducted by EPRI.

3.5.1 Overview of Load Modeling Problem

It is recognized that at high voltage levels, the power system loads have to be aggregated in order to obtain manageable models suitable for analysis and simulations. The usefulness of a load model is directly related to the correctness of the parameters of the model. High complexity models with a large number of parameters are not flexible for general applications because they may represent the load accurately for some specific situations, but may not be appropriate for others. A more simplified model defined by less parameters, provides a general description of the problem and high flexibility in the usage.

At the same time, depending on the load type (e.g. lighting, motor load, heating, etc.), the parameters of the aggregate load model may vary in a wide range. When the parameters of all load components are well known, the parameters of the aggregated load models can be readily determined. If the parameters of individual loads are not known or the load structure is known, but the proportion of various load components is not, deriving an aggregate load becomes more difficult.

Normally, modeling power system loads is more complicate than modeling a particular power system component because of following reasons [27]:

- Loads are time variant and stochastic
- At high voltage levels the loads must be aggregated
  - The large number of diverse load components
  - New load components penetration into the system
  - The lack of precise information on the composition and mix for certain loads
  - Level of details used to represent various load components
- Load models must be verified with actual measurements of the dynamic response

The last two reasons are due to the large number and types of loads that are connected at the transmission system level, which makes the consideration of each individual load numerically impractical and provides no insight into the bulk power system analysis. The time variance of loads can be taken into consideration by explicitly modeling their dynamic behavior using differential equations.

3.5.2 Measurement-Based Load Modeling

Measurement-based load modeling gives a closer look at the real-time power system loads and their dynamic characteristics. System steady state and dynamic response is currently available from a number of data sources, and PMU is one of them being deployed by numerous utilities around the world. PMU measure power system quantities such as phasor of voltage and current, frequency, rate of frequency deviation, and angle difference in real-time. Therefore, during disturbances in a power system, the response of load to voltage and frequency deviation, which is one of the key factors that influence the overall power system response, can be captured and recorded by PMU.

As load characteristics change from traditional incandescent light bulbs to power electronics-based loads, and as the characteristics of motors change with the emergence of high-efficiency, low-inertia motor loads, PMU has the ability to help system planner and operators to understand and model load response to ensure stable operation of the power system during different contingencies.

In [27], a systematic methodology has been developed to obtain load models at a bulk load delivery point in a power system using system disturbance data recorded by two PMUs. The key accomplishments include:

- A determination of the desirable characteristics and specifications of the synchronized phasor measurement units (PMUs) to be used for load modeling purposes.
- An improved non-linear optimization technique to derive composition percentages and individual parameters for static and dynamic load models.

- A survey of most existing disturbance monitoring devices including PMU that can be used for load modeling purpose.

In [27], the authors also suggest that the future research interest about load modeling should focus on:

- Sensitivity analyses of load model parameters because the impact of varying the values of specific load model parameters on the dynamic response of the load has not been fully investigated.
- Assessment of temporal and spatial variability of aggregate load models because the seasonal and geographical variations of parameters estimated from measured disturbances have not been evaluated.
- Study of the feasibility of utilizing single-phase and two-phase disturbance field measurements for load model parameter estimation.

In conclusion, EPRI provided a unique collaborative opportunity to use disturbance monitoring devices including PMU to address the important issue of power system load modeling in light of the growing importance of real time system security assessment and changing characteristics of end-use load.

3.6 System Restoration and Event Analysis

System restoration and event analysis are two major challenges that power system operators have to face during any major disturbance. System operators want to restore the system as quick as possible in order to limit the impact. System operators also want to conduct a complete event analysis to determine the root cause so that lessons can be learned and similar event can be avoid next time. However, because of the computational burden and absence of synchronized data, the process of system restoration and event analysis is always time consuming and technically difficult to implement. Synchronized phasor measurement units (PMUs) open up a new opportunity for system restoration and event analysis. This section first addresses the problem of fault location and the opportunity for PMU application in fault location. Then, the Europe power system disturbance that happened on November 4, 2006 will be used to present how PMU can improve the process of system restoration and event analysis.

3.6.1 Fault Location [17]

3.6.1.1 Overview of Fault Location Problem

Once a disturbance happens in a power system, the protection system should identify it correctly and take appropriate action immediately in order to isolate and minimize the disturbance area. After the area is isolated, the location and source of the disturbance should be identified and repaired to restore the power service as quick as possible. The fault location problem has been studied for a long time [29] [30].

For overhead transmission lines, it is time consuming to identify the fault location manually. However, the process can be expedited using the recording data from several equipments such as protective relay, digital fault recorder etc., which are located in substation and control center. One method named impedance-based fault location, which has been used in power industry for a long time, uses the fault impedance to calculate the fault location. The fault impedance can be calculated by post-fault voltages and currents. In [31], the fault location is determined using the knowing transmission line impedance per miles.

There are basically two main approaches in the impedance-based fault location method: single-ended and double-ended. In the single-ended approach, the data is only sampled at one point in the transmission line. Therefore, this approach could be affected by several factors such as line switching, load condition, fault current and fault resistance [32]. In double-ended approach, the data is sampled at two ends of the transmission line. Therefore, the result of this approach could be affected by factors such as ground resistance and communication failure. Both approached are used in power industry and have the ability to reduce the amount of time required by maintenance crews to find the fault location and reason.

PMU can provide the synchronized phasor information of voltage and current with accuracy of one microsecond. The new approach of fault location using PMU technology has advantages over previous methods because the computation burden and the assumptions techniques can be reduced.

3.6.1.2 Opportunities for PMU Application in Fault Location

The application of synchronized phasor measurements for the fault location is in the developing stage. There are several papers published describing the techniques [32, 33, 34]. Phasor measurement can be used for both single-ended approach and double-ended approach. It is not necessary to apply synchronized phasor measurements in single-ended approach, although it can complement the analysis. The double-ended approach can use the synchronized phasor measurements to synchronize the data sampling. In [32], a typical PMU-based double-ended fault location system is presented. With PMUs installed at both ends of the transmission line, the fault location system collects data samples through the CT and CCVTs at each substation. The data samples at the both ends of the transmission line with time-stamped are transmitted to one location and are processed by either DFR or separate computer.

Reference [32] suggests that the PMU-based double-ended fault location approach has the following advantages over single-ended approach:

- Approach is simple and only need transmission model and synchronized measurements at both ends of the lines.
- Not necessary to know the model characteristic and operating conditions.
- The operating conditions on the line can be highly unbalanced.
- The fault may have an inductance component.
- The fault resistance may be variable in time.

- Fault waveforms may be arbitrary, containing any number of harmonics.
- Line transposition does not significantly impact the results.

In conclusion, the time of restoring power system to its normal operating state after a fault can be improved by providing maintenance crews more exact information about the location and reason of the fault. Research has indicated that, for PMU-based fault location systems, the accuracy of pinpointing a fault increases from ±2 ~ ±3% for a system without phasor measurement to as accurate as ±0.6% in most instances [17].

3.6.2 The Europe Power System Disturbance that Happened on November 4, 2006 [5][35]

The Europe power system disturbance that happened on November 4, 2006 is a good example of PMU application in system restoration and event analysis. It should be noted that the event of November 4, 2006 is one of the most severe and largest disturbances in Europe. However, the impact of this event is limited compared with other similar scale blackouts:

- Full resynchronization of the UCTE system was completed 38 minutes after the splitting.
- The Transmission System Operators (TSO) were able to re-establish a normal situation in all Europe countries in less than 2 hours.
- The final report about the facts and analyses on the root causes of the disturbances as well as finial conclusion and recommendations came out in 87 days.

Much of these improvements are due to the PMU-based Wide Area Measurement System (WAMS) in UCTE system. With the help of Wide Area Measurement System in UCTE system, transmission system operators perform resynchronization actions immediately after having awareness about the system splitting. The actions which finally allowed the resynchronization can be grouped into the following phases:

- Resynchronization trials which did not result in real interconnection.
- Resynchronization attempts which resulted in real interconnection but failed after a few seconds.
- Successful resynchronization process.

The UCTE classification of actions to the above grouping is based on the WAMS measurements of frequencies in split areas (each measurement point with exact GPS time stamp, 100 msec resolutions). Figure 3-15 shows the frequencies in those three areas during the process of system resynchronization.

[5] Material from this subsection was excerpted from UCTE Final Report “System Disturbance on 4 November 2006”

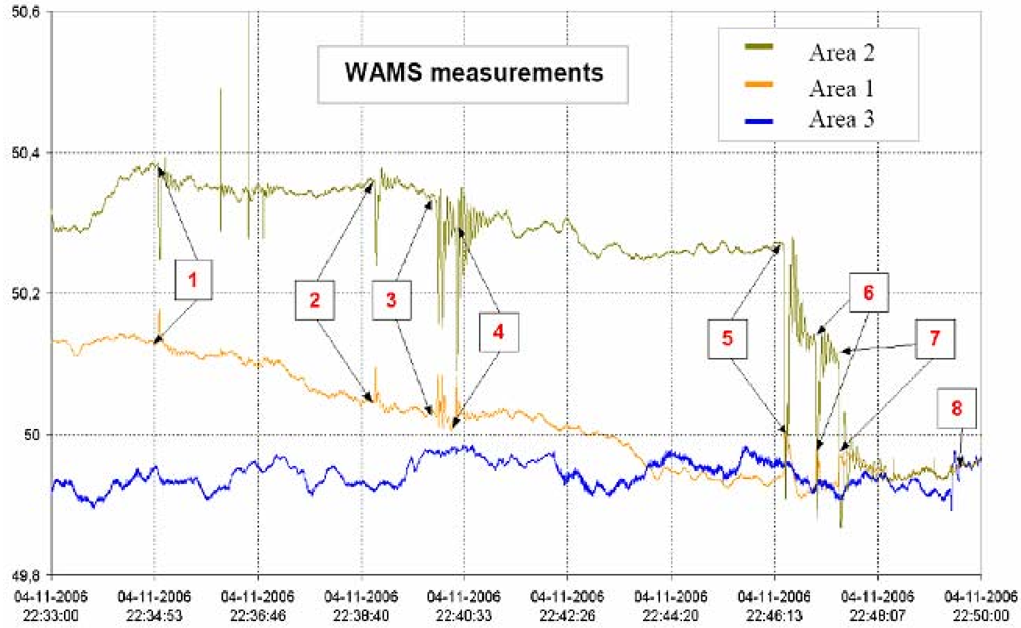

Figure 3-15
Frequencies Variation during UCTE Reconnection [29]

The UCTE investigation team also successfully replays the disturbance accurately through retrieving the disturbance data recorded by WAMS in UCTE system:

- The UCTE system was split at 22:10:28, and finally at 22:10:32 the system split into three areas, which is shown in Figure 3-16.
- The frequency recordings in the three areas from 22:10:06 to 22:10:30 are shown in Figure 3-17.
- The frequency recordings in the three areas from 22:09:30 to 22:20:00 are shown in Figure 3-18.

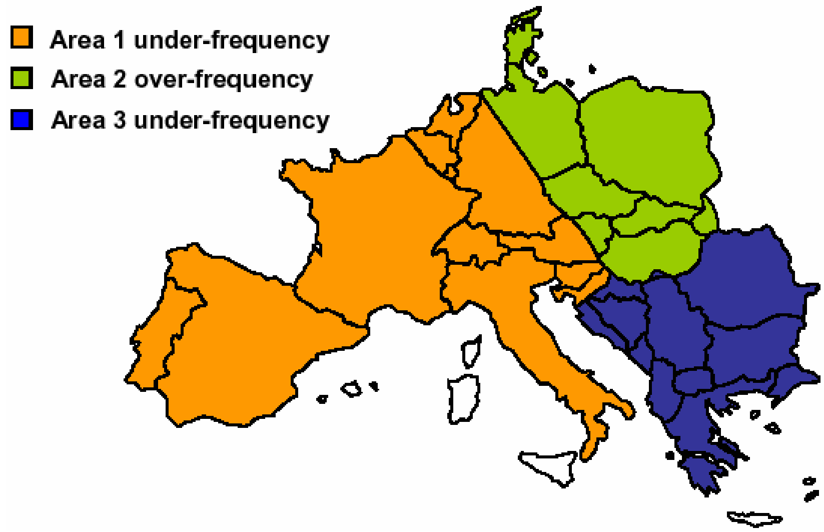

Figure 3-16
Schematic Map of UCTE Area Split into Three Areas [29]

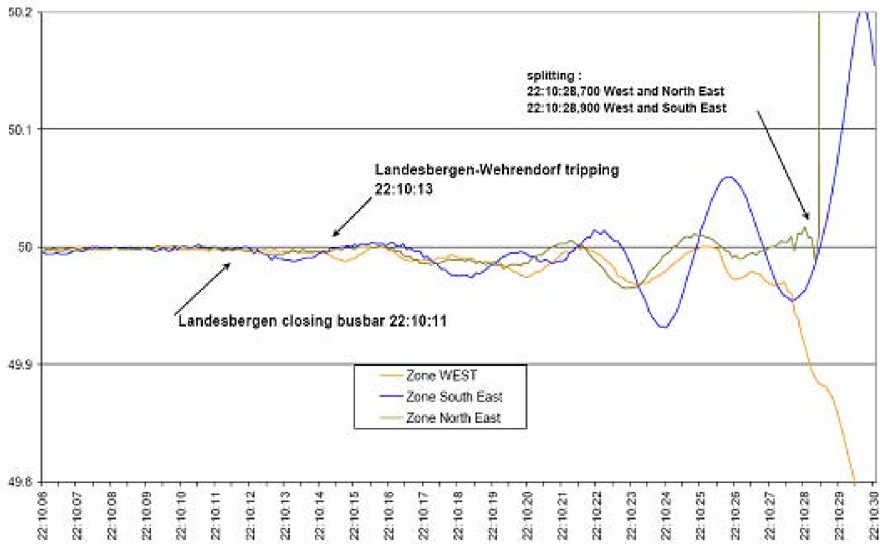

Figure 3-17
System Frequencies before Separation [29]

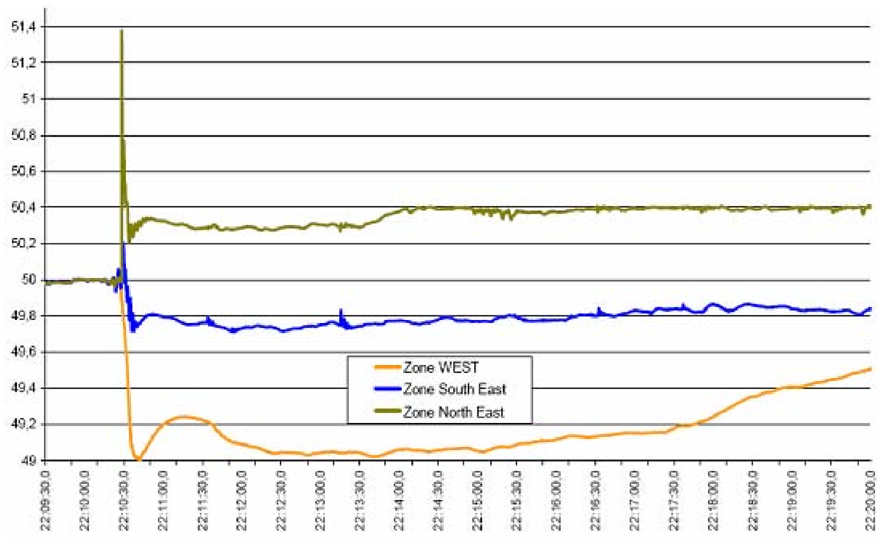

Figure 3-18
System Frequencies after Separation [29]

In conclusion, practical experience has proven that the application of PMU in power system significantly speeds up the system restoration process and technically simplifies the event analysis process. EPRI spent significant effort in the research about system restoration and event analysis. In March 2007, EPRI successfully organized the System Restoration Workshop with a number of experts in this area. To receive more information about this workshop, please contact Pei Zhang at pzhang@epri.com or 650-855-2244.

4
EPRI R&D PLAN FOR PMU IMPLEMENTATION & APPLICATION

The objective of the research, design, and development (RD&D) plan in the area of PMU implementation and application is to improve the reliability of the local and wide area transmission grid by preventing outages, and when outages occur, preventing the spread or cascade of the outage. Achieving these objectives will require the coordinated efforts of a broad range of stakeholders, including regulatory agencies, associations, utilities, regional transmission organizations (RTOs), equipment and system vendors, and others. Such efforts will include both technology advancements and institutional changes. In either case, collaborative approaches to addressing the relevant issues will leverage industry knowledge and resources in the most cost-effective and time-efficient manner to meet the objectives.

EPRI's role includes the following:

- Establish a forum for the sharing of information and experiences
- Periodically assemble industry experts who can advice on current best practices and help shape RD&D needs
- Provide independent assessments of industry needs and equipment performance
- Manage and conduct collaborative RD&D projects that mutually benefit project participants and the industry in general.

EPRI now proposes the following collaborative R&D projects to address the increasing industrial needs in the area of PMU implementation and application:

- Predicting Cascading Outages with Human Factor Research for Visualization of Massive Data
- Measurement Based Wide Area Voltage Stability Monitoring
- Network Parameter Error Identification
- PMU-Based Out-of-Step Protection Scheme
- Assessment on Optimal Placement of Synchronized Phasor Measurement Units (PMU)
- Pinpointing the Initiating Location of a Disturbance
- Transforming WAMS into WACS for Western Region

4.1 Predicting Cascading Outages with Human Factor Research for Visualization of Massive Data

4.1.1 Background

In its April 4, 2007 Final Rule on Mandatory Reliability Standards, FERC recognized the importance for a reliability coordinator to have a wide-area view of its own and adjacent areas to maintain situational awareness. Many utilities have spent money and time installing Phasor Measurement Units (PMU) and collecting massive amount of real-time data at high data rates. Apart from a few obvious uses, e.g., post-disturbance analysis, input to state estimators, visualization of phase angle differences between major load or generation centers to measure stresses due to power transfer, real-time frequency and voltage visualization, etc., the data have not been transformed in a way that human operators can spot the critical information for situational awareness and know how to respond to it and prevent cascading outages. This project will determine the predictive vulnerability index that measures and tracks a probabilistic risk of cascading outages. When that risk level takes a sharp turn upward and crosses beyond an acceptable level, operators will be alerted and advised what actions to take. EPRI believes that its recent research activities in cascading outages can provide new directions which will deliver the break-through.

EPRI believes that two major factors need to be considered: power system infrastructure degradation and system stresses. EPRI research in critical cut-sets (both for long distance power transfer and for load or generation clusters) show promise for incorporating probabilistic forced outage analysis into a loss of cut-set probability, similar to the LOLP (loss of load probability) method in generation adequacy analysis. Initial results indicated that under increasing power flows across the cut-set, especially with scheduled and forced transmission outages degrading the grid infrastructure, at some point, the probability of losing the entire cut-set (ultimately an N-N event) can have a value similar to an N-1 or N-2 random event. In other words, a cascading outage may then happen with a probability that existing Electric Reliability Organization (ERO) reliability standards may consider a violation.

4.1.2 Project Summary

This project will establish a forum for operators and researchers to turn operators' input on their visualization requirements into visualization tools which can be tested by users for their usability and effectiveness. Work includes the following activities:

- Monthly webcasts. Technical progress by EPRI and participants will be presented and discussed.
- Codes will be developed or contributed by EPRI and participants for visualization, vulnerability indices, diagnosis, operator-interface designs, and related applications. These will be maintained as open source by EPRI. Commercial vendors will also be encouraged to share information on their visualization tools.
- Research into human intelligence and application for wide-area situational awareness and control. PMU and other data sources can be processed locally and passed upward through

multiple layers, as in the human brain. Along the way, anomalies through comparison with short term prediction are detected and associated with other adjacent information, and further aggregated hierarchically into awareness of critical situations. Information flowing downward, after awareness at the top level, will provide the control signals for operators or automatic control systems to respond effectively and rapidly.

4.1.3 Benefit

Grid operators, ISO, RTO, reliability coordinators, operating engineers, transmission planners and organizations with investment into the installation of PMU, would benefit from this project. There will be significant and tangible benefits from the practical uses from such PMU investments. Grid reliability will be increased. Grid operators will have greater situational awareness on the potential risk of cascading outages, and have useful diagnosis and advices on how to respond to the risk. The man-machine interface for operators and for operating engineers will make them perform more effectively due to the advances in human factors research. Research will lead to the application of human intelligence into this project, which will pave the way for a humanly-intelligent grid of the future. Participants will share open-source code and their experiment results through task force meetings. This project will be conducted in support and in coordination with the North American Synchro-Phasor Initiative (NASPI).

4.1.4 Contact Information

For more information, contact the EPRI Customer Assistance Center at 800.313.3774 (askepri@epri.com).

Technical Contact

Stephen Lee at 650.855.2486 (slee@epri.com).

4.2 Measurement Based Wide Area Voltage Stability Monitoring

4.2.1 Background

Voltage stability is a major concern in power system operation and a leading factor to limit power transfers in the prevailing open access environment. Voltage stability assessment (VSA) program is a computer simulation tool to help operators monitor and control system voltage stability. The accuracy of VSA results fully depends on the accuracy of modeling the generation, load, and transmission facilities. Uncertainties of these factors pose challenges of obtaining accurate voltage stability analysis results using VSA program. Inaccurate VSA results may lead operators to make incorrect decisions, therefore increase the risk of voltage collapse. Moreover, VSA program also relies on the state estimator to provide steady-state solution for further analysis. In extreme operating conditions when state estimator fails to converge, VSA program also fails to help operators monitor and control system voltage stability.

Having recognized the limitations of VSA program, can we use measurement-data at substation level to calculate voltage stability margin in real-time and send the margin information to the control center for operators to monitor system voltage stability?

EPRI invented a new algorithm that is able to calculate the critical voltage and voltage stability margin continuously at a local bus using measured voltage and current waveforms. The critical voltage is the voltage when the load at this local bus reaches the maximum value due to voltage stability limit. The calculated voltage stability margin can be expressed as active, reactive, and apparent power. This will provide system operators not only the power transfer limit to this local bus in terms of active power but also the reactive power support needed at this local bus. EPRI name this approach as “Measurement-based Voltage Stability Monitoring”

4.2.2 Project Summary

This new supplemental project aims at enhancing the real time voltage stability monitoring capability using measurement-based approach.

Task 1 Implementation of Measurement-based Voltage Stability Monitoring at Substation Level

EPRI project team will work with the participating utilities to determine the critical substations to be monitored for voltage stability concerns. Once the critical substations are determined, EPRI project team will implement the measurement-based voltage stability monitoring algorithm to calculate the voltage stability margin in real-time. The critical voltage and voltage stability margin in terms of active power and reactive power information will be sent to the control center for operators to monitor the voltage stability for those critical substations.

Task 2 Investigation of Voltage Stability Margin of Load Centers

Most of load centers are supplied by more than one power source to ensure the security and reliability of power transfer. As a number of power sources are connected to the load center area at the distributed substations, the location of implementing the measurement-based voltage stability monitoring algorithm need to be determined. To monitor the voltage stability condition of a load center supplied by multiple sources, a new method is needed to calculate the voltage stability margin using the voltage stability margin calculated at individual substations.

Task 3 Development of Visualization Tools for Operators to Monitor Voltage Stability of Entire System

EPRI project team will engage the operators of the participating utilities and experts in human factors to design effective human-machine interface to convey the critical voltage stability information calculated at the local substations and load centers. Based on the design, EPRI project team will develop a visualization tool to help system operators to monitor voltage stability profile of the entire transmission network. This will broaden the visualization methods to help system operators to increase situation awareness.

4.2.3 Benefit

- EPRI measurement-based voltage stability monitoring method can calculate the voltage stability limit and margin in real-time, therefore help system operators to monitor voltage stability of the entire transmission system.
- EPRI measurement-based voltage stability monitoring method can avoid the potential problems of using simulation-based online Voltage Stability Assessment method.

4.2.4 Contact Information

For more information, contact the EPRI Customer Assistance Center at 800.313.3774 (askepri@epri.com).

Technical Contact

Pei Zhang at 650.855.2244 (pzhang@epri.com).

4.3 Network Parameter Error Identification

4.3.1 Background

State Estimation (SE) is an important function of Energy Management System (EMS). It processes redundant measurements and provides steady-state operating state for advanced EMS application programs (e.g. security analysis, economic dispatch, etc). Once receiving field measurement data, network parameter, network topology, and other information, state estimation filters incorrect data to ensure that the estimated state is correct. Weighted Least Squares (WLS) approach is usually used to solve state estimation problem due to its statistical prosperities.

In order to process the received data and information to obtain an accurate state, state estimation is required to have the ability to detect and identify the bad data and information, including bad measurement data, network parameter error and network topology error. Among them, network parameter errors are the most challenging one to be detected. Incorrect network parameters may be caused by inaccurate manufacturing data, miscalibration, tap changer being locally modified without knowledge of the control center, etc. The network parameter errors may not be identified for a long time, which will lead to permanent errors in the results of state estimation.

Existing parameter estimation techniques can be classified into two categories. The first category is based on residual sensitivity analysis, where the sensitivities of the measurement residuals to the assumed parameter errors are used for identification. The main advantage of this method is that it is performed on the solved state estimation case, and therefore, the core state estimation code will remain untouched. The second category uses a state vector augmented by additional variables, which are the suspected parameters. This method can be implemented in two different ways: one using the static normal equations, and the other using the Kalman filter.

In recent years, more and more GPS synchronized phasor measurement units (PMU) have been implemented in transmission systems. Incorporated into state estimation together with conventional measurements, these phasor measurements offer an opportunity of improving the performance of state estimation in terms of bad data detection and identification.

4.3.2 Project Summary

This project aims at developing a parameter error identification scheme in order to improve the performance of state estimation. The scheme will be designed to:

1) detect and identify the parameter error based on the solved result from state estimation and phasor measurements; 2) estimate the correct network parameter once the parameter error is detected. In order to achieve the objective, this project includes the following major tasks:

<u>Task 1 –Development of Parameter Error Identification Scheme</u>

EPRI project team will develop the parameter error identification scheme that will use the conventional measurements, phasor measurement data, and the initial state estimation result to detect and identify the network parameter errors. Once the parameter errors are determined, the scheme can also estimate the correct value of the parameters.

<u>Task 2 –Validation of Parameter Error Identification Scheme</u>

EPRI project team will produce parameter error scenarios to validate the correctness of the designed parameter error identification scheme. In this task, the parameter errors will be introduced into transmission lines, transformer taps, and shunt capacitors to create parameter error scenarios. Different parameter error scenarios will be simulated to evaluate the performance of the scheme.

<u>Task 3 – Implementation of Parameter Error Identification Scheme</u>

EPRI project team will investigate integrating the designed scheme into the existing EMS state estimation function. In this task, the designed parameter error identification scheme will be implemented as an added feature into a utilities member's existing state estimation without affecting the original functions of EMS. This task will include two steps: In the first step, the scheme will receive the measurement data and estimated results from state estimation in order to detect the errors of network parameters. In the second step, the scheme will fix the incorrect network parameters detected by the first step, so that state estimation can use the correct network parameters to produce a steady-state solution.

4.3.3 Benefit

EPRI's network parameter error identification algorithm can correct the network parameter errors; therefore, improve the performance of state estimator.

4.3.4 Contact Information

For more information, contact the EPRI Customer Assistance Center at 800.313.3774 (askepri@epri.com).

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4.4 PMU-Based Out-of-Step Protection Scheme

4.4.1 Background

Power systems are required to remain stable after experiencing any size of disturbance, which may be caused by a fault, loss of a generator, or loss of a transmission line.

Certain disturbances may cause the interconnected power systems to lose synchronism, which may lead to cascading blackouts and equipment damage. In order to avoid these severe results, controlled separation of the system using out-of-step protection is an effective way to preserve stability in several smaller islands.

Traditional out-of-step protection uses distance relays and timers to detect the out-of-step condition by deducting that the voltage and current during a power swing is gradual instead of a step change. Both faults and out-of-steps lead to a change of measured apparent impedance, but the change is much slower during out-of-step conditions. After the out-of-step condition is detected, out-of-step protection must block other fault relays prone to malfunction during out-of-step conditions. Meanwhile, the controlled separation at the pre-selected points provides load-generation balance in each separated area with the help of a load-shedding program. However, the disadvantage of the traditional out-of- step protection scheme is that it only uses local measurements to estimate the condition of the entire power system network, which inevitably affects its ability to detect the out-of-step conditions in certain circumstances.

The implementation of phasor measurement units (PMU) in the power system, together with recent advancements in communications technology provides the power industry a great opportunity to improve the out-of-step protection scheme.

PMU can provide real-time measurements of power system quantities such as frequency, rate of frequency deviation, current phasor, voltage phasor, and angle difference between different buses. Therefore, instead of the indirect measurement or estimation used in traditional out-of-step protection, the voltage frequency and angle measurement from different buses can provide the ability to directly monitor system transient stability conditions. Meanwhile, PMU is able to monitor power-flow change on some specific key buses and transmission lines. This information is important for developing the strategy for system separation, which can help keep the generation-load balance during the separation to minimize generation and load shedding.

EPRI is launching a project to develop a new out-of-step protection scheme using phasor measurement units. Using the voltage angle difference between different buses, the out-of-step conditions in the power system can be detected. This project will also investigate the use of wide-area measurement information to perform controlled separation in order to improve the reliability and security of the entire interconnected transmission system.

4.4.2 Project Summary

This project will develop an out-of-step protection scheme using phasor measurements in order to prevent the loss of synchronism in the interconnected transmission network. The proposed protection scheme will be designed to realize the following key functions: 1) monitor the system and detect the out-of-step condition, 2) identify the out-of-step areas in the power system, and 3) controlled separation of the interconnected system to prevent cascading failures.

The EPRI project team will design a PMU-based out-of-step protection scheme. The project team will also investigate the wide-area protection scheme to ensure its ability to identify the out-of-step areas and decide the optimal separation strategy. The device and associated algorithm will be examined using simulation and available field data.

This project includes three major tasks.

<u>Task 1 – Development of Out-of-Step Protection Using PMU</u>

The project team will develop the out-of-step protection scheme using PMU. This PMU-based out-of-step relay can process the measured data from phasor measurement devices and detect the out-of-step conditions from faults and swings.

<u>Task 2 – Validation of Out-of-Step Protection</u>

The team will simulate the out-of-step scenarios of a large interconnected network and use the simulated data to validate the correctness of the PMU-based out-of-step protection scheme. Moreover, if the recorded data during an out-of-step incident can be obtained, it will also be used to examine the performance of the PMU-based out-of-step relay.

<u>Task 3 – Investigation of Wide-Area Out-of-Step Protection</u>

The project team will further investigate the placement strategy of PMUs to monitor the transient stability condition of a large interconnected system. The project team will develop a central control algorithm using the measurement data from those PMUs to identify the out-of-step areas during faults and oscillation conditions. The central algorithm will use PMU and EMS data to determine the optimal separation point so that the unbalance of generation and load shall be minimized after the separation.

4.4.3 Benefit

Utilities, transmission owners, and independent system operators (ISOs), or regional transmission organizations (RTOs) that participate in this project will be able to enhance the effectiveness of out-of-step protection in both ensuring its safety net function and taking advantage of wide-area coordination.

4.4.4 Contact Information

For more information, contact the EPRI Customer Assistance Center at 800.313.3774 (askepri@epri.com).

Technical Contact

Pei Zhang at 650.855.2244 (pzhang@epri.com).

4.5 Assessment on Optimal Placement of Synchronized Phasor Measurement Units (PMU)

4.5.1 Background

Synchronized phasor measurement units (PMU) are power system devices that provide synchronized measurements of real-time phasors of voltage and current. The abilities to calculate synchronized phasors make PMU one of the most promising technologies in power system. Since its first appearance, PMU have evolved into a practical tool which can improve many applications of power system such as state estimators, stability controls, remedial action schemes, and disturbance monitors etc.

One challenge that utilities have to face when implementing the technology of PMU into their system is how to deploy the PMU. It is neither economical nor necessary to install PMU at each node of a wide-area interconnected system. Therefore, determination of optimal placement of PMU becomes one of the most important issues that need to be addressed in the emerging technology of PMU, and this issue becomes emergent as the devices are increasingly accepted in the utilities.

EPRI believe that system characteristic and intended application are two major factors that determine the optimal placement of PMU.

Regarding to the system characteristic, topology configuration (system size, node location, weak nodes and power flow pattern etc.) and communication ability (available channels, bandwidth limits and time delay etc.) will influence the optimal placement of PMU. Topology configuration and communication ability are very important to PMU placement because they determine the potential PMU sites and communication pattern, which is the foundation of PMU placement.

Furthermore, each system's topology configuration and communication ability are so unique that they need comprehensive study before the application of the technology of PMU.

Regarding to the intended application, study and research results have proven that different PMU applications could have totally different PMU placement schemes. For example, the application of state estimation requires that the placement of PMU should be performed considering the accuracy and reliability of the estimated state. While the application of out-of-step protection requires that the placement of PMU should be performed considering observability of generator rotor angle in real time. The situation becomes more complicated when multi-applications is required, different optimal PMU placement schemes are developed first, then those schemes are evaluated together and finally a final optimal scheme is concluded using optimal methodology.

Because of the above mentioned challenges and difficulties, it is very difficult and time consuming to determine the optimal PMU placement for most system, especially for those large inter-connected systems.

EPRI is launching a new project to help utilities members to determine the optimal placement of PMU. Through system characteristic study, PMU placement schemes design and PMU placement schemes evaluation, the final optimal PMU placement can be determined.

4.5.2 Project Summary

This project team will first perform a comprehensive system study in order to recognize the topology configuration and communication ability, which is the foundation of the PMU placement. According to various intended application required by utility members, the project team will then perform extensive system performance study to design the corresponding PMU placement schemes. Finally an optimization methodology will be used to evaluate and determine the optimal placement of PMU.

This project includes the following major tasks:

<u>Task 1 System Characteristic Study:</u>

The project team will perform a comprehensive system characteristic study aimed at identifying the topology configuration and communication ability. This study will justify the potential sites for PMU placement which could maximize the utilization of present system resource and avoid unnecessary cost.

<u>Task 2 PMU Placement Schemes Development:</u>

The project team will perform extensive system performance study to develop the PMU placement schemes. Those system performance studies could be electromechanical, small-signal, and voltage stability studies etc., depending on the intended application requirements. Based on the result of system characteristic study from task 1, each system performance study will come up with a resultant PMU placement schemes.

Task 3 PMU Optimal Placement Determination:

The project team will use an optimization methodology to evaluate and determine the optimal placement of PMU from those schemes which are developed in task 2. In the process of optimization, the team will also consider the technology migration path that the utilities will take in the near future.

4.5.3 Benefit

The knowledge gained from this project will help utility members determine the optimal PMU placement, and help utility members to apply the technology of PMU in cost-effective way.

4.5.4 Contact Information

For more information, contact the EPRI Customer Assistance Center at 800.313.3774 (askepri@epri.com).

Technical Contact

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4.6 Pinpointing the Initiating Location of a Disturbance

4.6.1 Background

It has been recently been determined that one can accurately pinpoint the location of a disturbance on the electric power grid by using multiple devices that accurately measure frequency of the grid.

When a line trips or generator trips, the frequency changes in the electrical grid. Because this change in frequency propagates like a wave over the system from the point or origin to the entire interconnection, it is now possible to detect the change in frequency with highly accurate monitors and back propagate to determine the location of the disturbance.

From the replay snapshots, we can observe that as the time progresses, the dots spread out gradually at a speed much less then the speed of light, or in the form of electromechanical wave propagation in the system. If there are enough measurement units in the system, we would be able to view this propagation in greater detail as traveling “waves”. Fast communication may even allow real-time display as the travel time is measured in seconds. The time delays seen at different observation points in the system provide the opportunity for a number of applications, namely, to study the speed of propagation and to use the time difference for triangulation of event location.

This is useful as a supplement to a Topology Estimator or State Estimator and may be faster than a Topology or State Estimator.

In addition, if a change occurs outside the footprint of the state estimator it is difficult to determine the cause or location of the disturbance just using a state or topology estimator.

4.6.2 Project Summary

Virginia Tech University has distributed some low cost frequency detector devices, FNET, in the United States on the distribution network that detects and accurately time stamp the measurements using GPS time stamps. In addition, many utilities have placed Phasor Measurement Units (PMUs) on the high voltage transmission grid. More of these FNET and PMU devices would have to be put into place in and around the utility electrical grid to support this project.

Algorithms would be developed to back propagate from the measurements to the location of the disturbance using either time and distance or Fast Fourier Transform methods.

The simulation results as well as FNET data show the frequency wave propagation speed varies from region to region and it is not the same between two points in opposite directions. In the same region, the speed of frequency wave propagation is almost proportional to the amount of real power generation tripped. The reactive power plays a much smaller role.

In particular, the East US simulation results suggest that the frequency wave propagates faster in the west region. The east part has denser generation than the western part so the wave would experience more “resistance.” The simulation result also shows that the wave would propagate slightly faster from the central part of the system than from the rim of the system, and the wave propagates at lower speed from north to south than from south to north.

Simulations also show the 127 bus WECC system has faster “speed” than the East US grid.

Using the derived electromechanical wave propagation speed of the uniform continuum model of a ring system example, some observations of how the speed would vary as a function of the system parameters can be further explained.

We will also investigate the scalability issue when the number of sensors is in the hundreds or a thousand. The study will be under the assumption that the current broadband Internet or private utility network will be used for data transmission will be used. The possibility of automating the trip location algorithm will be investigated. It may not be a very simple process based on the algorithm. However, the location identification difficulty is actually inversely proportional to the number of sensors in the field. As more data points are available, the location estimation will inevitably be more accurate.

4.6.3 Benefit

- Benefit from the development of algorithms to back propagate from the measurements to the location of the disturbance using either time and distance or Fast Fourier Transform methods.
- Accurately pinpoint the location of a disturbance on the electric power grid

4.6.4 Contact Information

For more information, contact the EPRI Customer Assistance Center at 800.313.3774 (askepri@epri.com).

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4.7 Transforming WAMS into WACS for Western Region

4.7.1 Background

The wide area measurement system (WAMS) consists of Phasor Measurement Units (PMUs) distributed throughout the Western region. These units accurately measure the voltage, current and phase angle at various points on the transmission grid at very high frequency (30-60 measurements per second) and are precisely time-stamped using Global Positioning System (GPS) satellite data. These phasor data can be used to calculate the relative phase angle of buses relative to one another on the transmission grid. It is well known that small relative phase angle differences happen when the grid is stable and not prone to oscillations whereas large relative phase angle differences across an interconnection (especially if increasing with time) tend to lead to oscillations and make the system unstable, particularly if a contingency or fault occurs.

This project plans to develop techniques so that the WAMS data can be used to monitor, diagnose and control the grid through two types of control schemes: one-shot remedial action scheme (RAS) and a feedback control scheme to prevent system oscillations. It is seen that this is a 5 phase process that will take several years to complete. The process will take time so that developers, operators and planners:

- Feel comfortable that the data and the modeling are accurate,
- Believe the results of the analysis of the data are reliable and
- Understand that control actions planned will actually improve the system stability.

4.7.2 Project Summary

Expert Panel and Workshop to Formulate Research Scope

As the very first step of this project, a workshop will be held and a panel of experts from the research community will be invited to interact with a panel of utility experts in a two-day meeting. The purpose of this workshop is to take a snapshot of the latest research efforts in the technical area of Wide Area Measurements and Wide Area Control, so that a comprehensive survey of expert opinions can be collected from the direct interaction between utility engineers and these researchers. This interaction will ensure that the technical work scope in this project is cast with a sufficiently wide technical net to increase its prospect of success and relevance. This workshop will be patterned after the successful EPRI/NSF workshop on cascading failures held in 2005. The research panelists will be asked to make presentations on their research efforts related to WAMS and WACS. The utility panelists will be asked to present their needs and requirement for practical implementations of WAMS and WACS. Exchanges between these two panels will be used to create research ideas, which will be categorized and prioritized in the workshop to provide input to the work scope of this project.

It is anticipated that out of this workshop, a request for proposal will be developed and sent out by EPRI. Two parallel efforts will be initiated:

- One to perform theoretical research for promising and innovative WACS approaches.
- One to develop operating tools which can be delivered to members of this research program.

A number of tasks are tentatively defined for this project, as follows:

<u>Task 1, Pattern Recognition using WAMS and Other Data</u>

Task 1 will be focused on developing a pattern recognition process so that a program can easily determine from a set of measurement data if the pattern of measurements can be classified so that one can infer the stability of the grid and how close the grid is to instability.

The pattern recognition process will take two parallel approaches. The first one, using Genetic Algorithms, is as follows:

The space of all generation and load patterns along with transmission line and generator configurations is a very large space to explore all situations. It is therefore necessary to use some high power techniques such as genetic algorithms to search the space for the likely locations for stable and unstable situations. The genetic algorithms provide a way to probe areas that are similar, but not identical, to their parent situation to come up with areas in the multidimensional space that have stable and unstable cases. The search technique needs to be paired up with a fast stability program simulating the Western region.

The results of step (a) can be put into a pattern classification learning program or neural network program to initialize the classification program.

Further classification can be done using real and actual conditions which are collected at a regular interval (e.g., hourly) by WAMS and ideally a state-estimated power flow case from some source. These data are then combined into a "real-time" Western grid model and run through a Dynamic Stability Assessment program using a selected number of potentially critical contingencies. If these ideal state-estimated cases are not available, a computerized process will be used to combine the WAMS and other real-time data with a Western planning power flow case to construct a close-to real-time model for the dynamic stability simulations.

The second approach, using Cluster Identification, is designed as a fail-safe alarm system. Developed by NASA in the aftermath of the Columbia shuttle disaster, this method continuously classifies streaming data into clusters. When the data suddenly departs significantly from previous cluster patterns, and the divergence continues to increase, an alarm will be tripped to warn the operator of some impending disaster. Coupled with geographical visualization of where these abnormal data come from, the operator will be able to quickly apply human intelligence to direct his attention to other sources of data which together would diagnose the causes of the unusual operating conditions.

Both methods will use a color scheme of Blue, Yellow and Red for indicating normal conditions, requiring corrective action, and requiring emergency action.

<u>Task 2, Operator Notification and Control</u>

The pattern recognition program would be run periodically (for example every 5 minutes) using the present system conditions (generation, load and network configuration). If a pattern of wide area measurements is detected in a real system that indicated a Yellow alert, operator(s) in the affected areas would be notified and they would take necessary redispatch actions to improve the system reliability. The Cluster Identification algorithm will be running continuously. When diverging anomalies appear and indicating a Red alert, a geographical visualization of the locations of the abnormal data will help the operator diagnose the problem and take emergency action, if appropriate.

<u>Task 3, Optimized Steady State Control</u>

The pattern recognition program would be run periodically (for example every 5 minutes). If a pattern of wide area measurements is detected in the real system that indicates a Yellow alert, then an application needs to be written to suggest control actions that will mitigate the problem. This application would be a combination of an optimal power flow program that would reset generation levels to optimize the angles and a stability program (considering voltage stability, angle stability, and small signal stability aspects) to verify the results. CIM data would be needed for the region affected to run the application programs.

The operator would be informed of the problem and the proposed optimized solution to the problem. The actual and proposed solution would be maintained in a data base for further evaluation by engineers.

<u>Task 4, SPS (Special Protection Schemes) Control Actions</u>

The pattern recognition program would be run periodically (for example every 5 minutes). If a pattern of wide area measurements is detected in the transmission system that indicates a Red alert, the supervisory control program would recommend that certain of the previously designed special protection schemes be set to trip load or generation if another contingency occurs that would further reduce the transmission system stability. These schemes may include automatic system separation, or wide-area under-voltage or voltage-instability load shedding.

Task 5, Wide Area Feedback Control System

If a pattern of wide area measurements is detected in the transmission system that indicates a Yellow alert and further diagnosed to be of an oscillatory nature, requiring a feedback control system, the supervisory control program will decide whether a feedback control scheme would be used, e.g., by exercising control devices on the grid such as power system stabilizers, generation levels, FACTS devices, dynamic brakes etc, in order to bring the system back to a stable state. In some scenarios it may be necessary to use both SPS schemes and feedback control schemes to make the system stable.

The developed concepts will be applied to a reduced order WECC test system in particular to damp the low frequency modes of oscillations (0.3 Hz and 0.7 Hz modes) that are observed in the WECC system.

4.7.3 Benefits

This effort is focused on the Western region in North America. Participation by a Western organization will bring the power of collaboration to modernize the Western power grid and deliver the promise of wide area control when the WAMS (wide area measurement system) concept was turned into reality about eight years ago, pioneered by BPA, EPRI and others. Participants will help direct the research in using WAMS data for Wide Area Control of the Western power grid and will have access to the results of this research and development effort. They will also work together as a group to ensure that the control system thus developed will be thoroughly tested over a sufficient period of time before a prudent decision would be made by the Western grid operators to deploy it for operation evaluation. The WAMS-WACS implementation is envisioned to be the platform for evolving into the future hierarchical energy control infrastructure as the Western region-wide supervisory control system of the future. This collaboration will draw on works done by other research programs at EPRI, other research entities and members of this collaborative.

4.7.4 Contact Information

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A
WORKSHOP ATTENDEES

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John	Finney	ABB Corporate Research
Michael	Kirschner	ABB, Inc.
Shane	Haveron	AMETEK Power Instruments
David	Reed	Arizona Public Service Co.
Randy	Spacek	Avista Utilities
James	Burns	Bonneville Power Administration (BPA)
John	Kerr	Bonneville Power Administration (BPA)
George	Carter	California Public Utilities Commission
Eduardo	Alegria	Chevron Energy Solutions
Karen	Kyain	Chevron Energy Solutions
Enrique	Martinez	Comision Federal de Electricidad (CFE)
Quintin, Jr.	Verzosa	Doble Engineering Co.
Jeremy	Bloom	Electric Power Research Institute (EPRI)
Jian	Chen	Electric Power Research Institute (EPRI)
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Robert	McFeaters	FirstEnergy Service Co.
Pui	Lau	GE Industrial Systems
Mark	Adamiak	General Electric Co.

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Damir	Novosel	InfraSource
Bartosz	Wojszczyk	InfraSource
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Abdul Salim	Fahid	Kalki Communication Technologies Private Limited
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Eric	Udren	KEMA Consulting
Yi	Hu	KEMA, Inc.
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Roger	King	Mississippi State University
Steven	Hill	Modesto Irrigation District
Bob	Cummings	NERC
Ali	Abur	Northeastern University
Daniel	Barry	NorthWestern Energy
Rikin	Shah	NorthWestern Energy
Renan	Giovanini	Operador Nacional do Sistema Eletrico
Rui	Moraes	Operador Nacional do Sistema Eletrico
Hector	Volskis	Operador Nacional do Sistema Eletrico
Farshid	Brojeni	Pacific Gas & Electric Co.
Christopher	Dux	Pacific Gas & Electric Co.
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Kristin	Tolentino.	Pacific Gas & Electric Co.
Mark	Wilhelm	Pacific Gas & Electric Co.
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Solveig	Ward	RFL Electronics Inc.
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Sarah	Majok	Sacramento Municipal Util. Dist.
Jonathan	Sykes	Salt River Project
Tariq	Rahman	San Diego Gas & Electric Co.
Armando	Guzman	Schweitzer Engineering Laboratories, Inc.
Greg	Rauch	Schweitzer Engineering Laboratories, Inc.
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Tadaaki	Yasuda	Tokyo Electric Co.
Paul	Myrda	TRC Companies, Inc.
Philip	Overholt	U.S. Department of Energy
Jim	Cole	UC/CIEE
Alfredo	Vaccaro	Universitâ”œÃ¢â”¬ del Sannio
Domenico	Villacci	University of Sannio, Italy
James	Thorp	Virginia Tech
Anjan	Bose	Washington State University
Alex	Apostolov	

B
WORKSHOP AGENDA

Thursday, March 1, 2007

Time	Item	Presenter
7:30 am	Registration	Refreshments
8:00 am	Introductions	Vahid Madani, PG&E / Pei Zhang, EPRI
	Welcome Host	PG&E -Officers and Sr. Management EPRI - Technical Executive Power System Assets, Planning and Operation Mark Wilhelm, PG&E - Director Electric System Engineering
8:15 am	Synchronized Phasor Standards Primer	Mark Adamiak – GE
9:00 am	Next Generation Communication and Network Architecture	Anjan Bose – Washington State Univ.
9:45 am	Application of integrated satellite technologies in large scale power systems monitoring and control	Alfredo Vaccaro & Domenico Villacci Power System Research Group, University of Sannio, Italy
10:30 am	**Break**	
10:45 am	Advance Technologies to Improve Power System Reliability	Damir Novosel – InfraSource Inc.
11:20 am	Utilizing the Semantic web for electric power grid monitoring and advanced real-time control	Roger King - Mississippi State Univ.
12:00	**Lunch – Group Discussions**	**Alex Apostolov & Vahid Madani**
12:45 pm	Event Analysis and Protection – System Considerations	Bob Cummings – NERC
1:30 pm	NERC / DOE Data Management Task team	Paul Myrda – Trans-Elect
2:15 pm	Application of the Supercalibrator for Real Time Protection Monitoring and Assessment	Sakis Meliopoulos - Georgia Tech. Univ.
3:00 pm	**Break**	
3:15	TEPCO's experiences with SIPS for islanding, utilizing phase angle measurements	Shinichi Imai & Tadaaki Yasuda Tokyo Electric Co.
3:45 pm	Next Generation SIPS and RAS System Integrity Protection Scheme	Vahid Madani – PG&E
4:20 pm	**Discussion of Research and Development**	**Group Discussion**
5:15 pm	Adjourn	

Friday, March 2, 2007

Time	Item	Presenter
7:30	• Registration	• Refreshments
8:00 am	System Integrity Protection Scheme using Synchrophasor Technology	Armando Guzman – SEL
8:45 am	PMU Applications for Real time identification of oscillatory modes and in use of flywheel energy storage to oppose inter-area oscillations	Yuri Makarov – PNNL
9:15 am	Synchronized Phasor Applications in Adaptive Protection	• James Thorp – Virginia Tech. Univ.
10:00 am	**Break**	
10:15 am	Experiences and Directions in Wide-Area Monitoring and Control	John D. Finney – ABB
11:00 am	Deployment of Large Phasor Systems	Rui Moraes & Hector Volskis – ONS (Brazilian ISO)
11:45 a.m	Grid modernization and priorities for real time grid reliability management	Philip Overholt - DOE
12:05 pm	**Lunch – Group Discussion**	**Alex Apostolov & Pei Zhang**
1:00 pm	Contingency Analysis with PMUs	Enrique Martinez, CFE
1:45 pm	a) Synchronized Measurement and Analysis in Real Time - SMART b) Piloting a Centralized Remedial Action System	Bharat Bhargava - SCE Patricia Arons – SCE
2:15	**Break**	
2:30 pm	Condition-Based Protection System Maintenance	Eric Udren – KEMA T&D Consulting
3:15 pm	Controlled Separation of Power Systems - Using Out-of-Step Blocking and Transfer Tripping Scheme	Mike Adibi
4:00 pm	**Discussion of Research and Development**	Group Discussion
5:00 pm	Adjourn	

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