12-10-2010

Distributed State Estimation With Phasor Measurement Units (Pmu) For Power Systems

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DISTRIBUTED STATE ESTIMATION WITH PHASOR MEASUREMENT

UNITS (PMU) FOR POWER SYSTEMS

By

Qinghua Huang

A Dissertation
Submitted to the Faculty of
Mississippi State University
in Partial Fulfillment of the Requirements
for the Degree of Doctor of Philosophy
in Electrical Engineering
in the Department of Electrical and Computer Engineering

Mississippi State, Mississippi

December 2010

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Pages in Study: 101

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Wide-area monitoring for the power system is a key tool for preventing the power system from system wide failure. State Estimation (SE) is an essential and practical monitoring tool that has been widely used to provide estimated values for each quantity within energy management systems (EMS) in the control center. However, monitoring larger power systems coordinated by regional transmission operators has placed an enormous operational burden on current SE techniques. A distributed state estimation (DSE) algorithm with a hierarchical structure designed for the power system industry is much more computationally efficient and robust especially for monitoring a wide-area power system. Moreover, considering the deregulation of the power system industry, this method does not require sensitive data exchange between smaller areas that may be competing entities. The use of phasor measurement units (PMUs) in the SE algorithm has proven to improve the performance in terms of accuracy and converging speed. Being able to synchronize the measurements between different areas, PMUs are perfectly suited for distributed state estimation. This dissertation investigates the benefits of the DSE

using PMU over a serial state estimator in wide area monitoring. A new method has been developed using available PMU data to calculate the reference angle differences between decomposed power systems in various situations, such as when the specific PMU data of the global slack bus cannot be obtained. The algorithms were tested on six bus, IEEE standard 30 bus and IEEE 118-bus test cases. The proposed distributed state estimator has also been implemented in a test bed to work with a power system real-time digital simulator (RTDS) that simulates the physical power system. PMUs made by SEL and GE are used to provide real-time inputs to the distributed state estimator. Simulation results demonstrated the benefits of the PMU and distributed SE techniques. Additionally a constructed test bed verified and validated the proposed algorithms and can be used for different smart grid tests.

DEDICATION

I would like to dedicate this research to my family: my parents, my husband and my son.

ACKNOWLEDGMENTS

I also want to thank my previous colleagues, Srinath Kamireddy, Minlan Lin and all the power group members for the emotional support and selflessly giving during my time here. There are quite probably too many to list who have contributed in ways large and small to complete this work.

ACKNOWLEDGMENTS

I would like to gratefully thank my dissertation director and Co-Advisor, Dr. Noel N. Schulz, for her support, guidance, and constant encouragement throughout the research work. I would like to thank my Co-Director, Dr. Anurag K. Srivastava, for his guidance and support throughout this research. Without their constant guidance it would not have been possible to complete this dissertation.

I would also like to express my appreciation to Dr. Sherif Abdelwahed, my major advisor, and Dr. Tomasz Haupt for their willingness to serve on my committee.

I also want to thank my previous colleagues, Srinath Kamireddy, Minlan Lin and all the power group members for the emotional support and selflessly giving during my time here. There are quite probably too many to list who have contributed in ways large and small to complete this work.

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LIST OF SYMBOLS, ABBREVIATIONS

Symbols

The symbols below summarize the quantities used in equations and figures for chapter III and IV.

i :	the index of the measurements
$\mathbf{Z}_i$:	the i_{th} measurement from SCADA system or other IED sensors
$\mathbf{x}$:	the state vector of the system under research
$\mathbf{f}_i(\mathbf{x})$:	The value of the nonlinear function corresponding to the i_{th} measurement calculated by using $\mathbf{x}$
$\mathbf{e}_i$:	the difference between $\mathbf{Z}_i$ and $\mathbf{f}_i(\mathbf{x})$
$\mathbf{J}(\mathbf{x})$:	Objective function used in weighted least square
$_i$:	the standard deviation of each measurement i
$\mathbf{R}_i$:	the variance of the i_{th} measurement
$\mathbf{g}(\mathbf{x})$:	the derivative of $\mathbf{J}(\mathbf{x})$ over $\mathbf{x}$
N:	the number of buses in the system under research
S:	the number of the states in the system
$\mathbf{H}$:	the N by S Jacobian matrix of $\mathbf{f}(\mathbf{x})$
$\mathbf{G}^{-1}(x)$:	the error covariance matrix of the estimated state vector
k :	the iteration index
$\mathbf{x}^k$:	the solution at k iteration
$\mathbf{E}_r$:	the real part of voltage phasor measurement
$\mathbf{E}_i$:	the imaginary part of the voltage phasor measurement
$\mathbf{I}_r$:	the real part of current phasor measurement
$\mathbf{I}_i$:	the imaginary part of the current phasor measurement
p:	the bus number that the current flows from
q:	the bus number that the current flows to
$g_{(pq)}$:	the conductance of line pq
$b_{(pq)}$:	the susceptance of line pq
$b_{(p0)}$:	the shunt admittance at bus p
$\mathbf{E}_{(p)r}$:	real part of the voltage magnitude for bus p
$\mathbf{E}_{(p)i}$:	imaginary part of the voltage magnitude for bus p
$\mathbf{I}_{(pq)r}$:	real part of the current magnitude flow in branch pq

$\mathbf{I}_{(pq)i}$: imaginary part of the current magnitude flow in branch pq

θ_v: the vector of the angles of voltage phasors

E_v: the magnitude of the voltage phasor

θ_i: the angle of the current phasor

I_i: the magnitude of the current phasor

m: the number of current phasor measurements

$\mathbf{E}_1$: the estimated results for the state vector from the traditional state estimator in rectangle coordinates

$\mathbf{Z}_2$: the phasor measurements vector in rectangle coordinates for adding PMU data in mixed-processing method

$\mathbf{W}_2$: the error covariance matrix of the measurements in polar coordinates for adding PMU data in mixed-processing method

$\mathbf{W}_2^{'}$: the error covariance matrix of the measurements in rectangle coordinates for adding PMU data in mixed-processing method

$\mathbf{W}_1^{'}$: the error covariance matrix of $\mathbf{E}_1$ in rectangle coordinates.

ϕ_{diff}: the reference angle difference

θ_{pmuAn}: the angle measurement of bus n from area A

θ_{pmuBm}: the angle measurement of bus m from area B

θ_{estAn}: the local estimated phase angle of bus n in area A

θ_{estBm}: the local estimated phase angle of bus m in area B.

$\theta_{pmuASlack}$: the angle measurement of slack bus from area A

$\theta_{pmuBSlack}$: the angle measurement of slack bus from area B

$\theta_{pmuA0\_vendor1}$: the phasor angle measurements of bus 0 in area A from vendor 1

$\theta_{pmuB0\_vendor2}$: the phasor angle measurements of bus 0 in area B from vendor 2

$\theta_{pmuAn\_vendor1}$: the phasor angle measurements of bus n in area A from vendor 1

$\theta_{pmuBm\_vendor2}$: the phasor angle measurements of bus m in area B from vendor 2

A_i: vector of exact values got from power flow

L_1 norm_states: L_1 norm of the entire state variable

L_1 norm_voltage: L_1 norm of the voltage magnitude

L_1 norm_angle: L_1 norm of the voltage angles

$state\_act$: Vector contains elements of actual states

$state\_estimated$: Vector contains elements of estimated states

V_{mag}_est: Vector contains elements of estimated bus voltage magnitude

V_{mag}_act: Vector contains elements of exact bus voltage magnitude

V_{angle}_est: Vector contains elements of estimated bus voltage angles

V_{angle}_act: Vector contains elements of exact bus voltage angles

Abbreviations

The following abbreviations are the ones used in this dissertation

FACTS:	Flexible Alternating Current Transmission Systems
EMS:	Energy Management System
SCADA:	Supervisory Control and Data Acquisition
WLS:	Weighted Least Squares
PMU:	Phasor Measurement Units
IED:	Intelligent Electronic Devices
CB:	Circuit breaker
ISO:	Independent System Operator
SE:	State Estimation
DSE:	Distributed State Estimation
GPS:	Global Positioning System

CHAPTER I

INTRODUCTION

This chapter introduces the restructuring of the power industry, concept of state estimation (SE), distributed state estimation (DSE) with phasor measurement unit and then presents the motivation of this dissertation.

1.1 The Electric Power Grid and the Power Industry

Today, electrical power plays an important role in everybody's daily life. Electricity has become a primary foundation for most modern technologies. The electricity system is made up of generation plants, transmission system, distribution systems and loads. Electric power travels from the power plant to the end user through the electric power grid. Power system engineers need to make sure the power will be constantly available to meet the needs of human society by planning, monitoring, analyzing and controlling this grid. The tools they use to reach this goal include load forecasting, state estimation, congestion management, security assessment and more. These tools are located in the control centers which are the nerve center of the power system.

The electric power industry is transitioning from a highly regulated industry to an increasingly deregulated one. The restructuring brings in competition among energy suppliers, allowing customers to choose their electricity supplier.

Deregulation, on the other hand, places challenges on the reliability and security of the power system. First, many facilities and strategies used in current power systems were developed for the previous vertically integrated and monopoly style operated power system. These strategies are centralized, independent, inflexible and closed. Second, power grids that are owned and operated by different competing power companies are physically connected with other parts of the power grid. Information on the status of the connected power grid is important as a must-have input when performing system wide analysis and monitoring, such as state estimation. This segmentation of the power grid has made it more complex and difficult to maintain since these companies will be reluctant to share the detailed information about their part of power system with their rivals. These two concerns have been considered during this research.

Based on the above concerns, between 1996 and 1999, several Independent System Operators (ISO's) were allowed by the Federal Energy Regulatory Commission (FERC) to be created as see in Figure 1.1. An ISO is a non-profit organization that combines the transmission facilities of several transmission owners into a single transmission system to move energy over long distances at a single lower price than the combined charges of each utility that may be located between the buyer and seller [1]. The ISO provides non-discriminatory service and must be independent of the transmission owners and the customers that use its system. In 1999, FERC required any transmission system owner to join a Regional Transmission Organization (RTO). RTOs also provide non-discriminatory access to the transmission network but need to meet specific FERC regulations. There are five ISOs and five RTOs operating in North America as shown in Figure 1.1 They manage the systems that serve two thirds of the customers in the U.S., and over half the population of Canada. Both ISO and RTO were created to increase operation efficiency and reliability for sections of the power system. They monitor and control the power systems and operate the power market in their regions. Over time, the distinction between ISOs and RTOs in the United States has become insignificant. An ISO/RTO is required to quickly detect and respond to contingencies, and direct the generation and transmission in any emergency. In other words, the ISO/RTO needs to have the capacity of monitoring its region of the power system continuously.

FERC has deemed wide area monitoring and control highly important mainly because the strong influence that wide area monitoring has on the security and reliability of the overall power system. This has been proven by the northeastern blackout that took place on August 14, 2003. This blackout resulted in the loss of 61,800 MW of electric load that served more than 50 million people [4]. The footprint of the blackout on both sides of the US-Canadian border included large urban centers that are heavily industrialized and important financial centers (e.g., New York City and Toronto). Service in the affected states and provinces was gradually restored with most areas fully restored within two days although parts of Ontario experienced rolling blackouts for more than a week before full power was restored [4]. ICF Consulting estimated the total economic cost of this blackout to be between $7 and $10 billion [4]. The U.S.-Canada Power System Outage Task Force showed, in their final report [5], that RTOs cannot manifest themselves especially at the boundary of the monitoring area. Lack of data sharing between system operators kept the system operators from visualizing the initial cause of the blackout and preventing cascading effects. A wide area blackout would probably have been avoided if prompt remedial actions had been taken. This suggests developing the ability among operators to share information in real time.

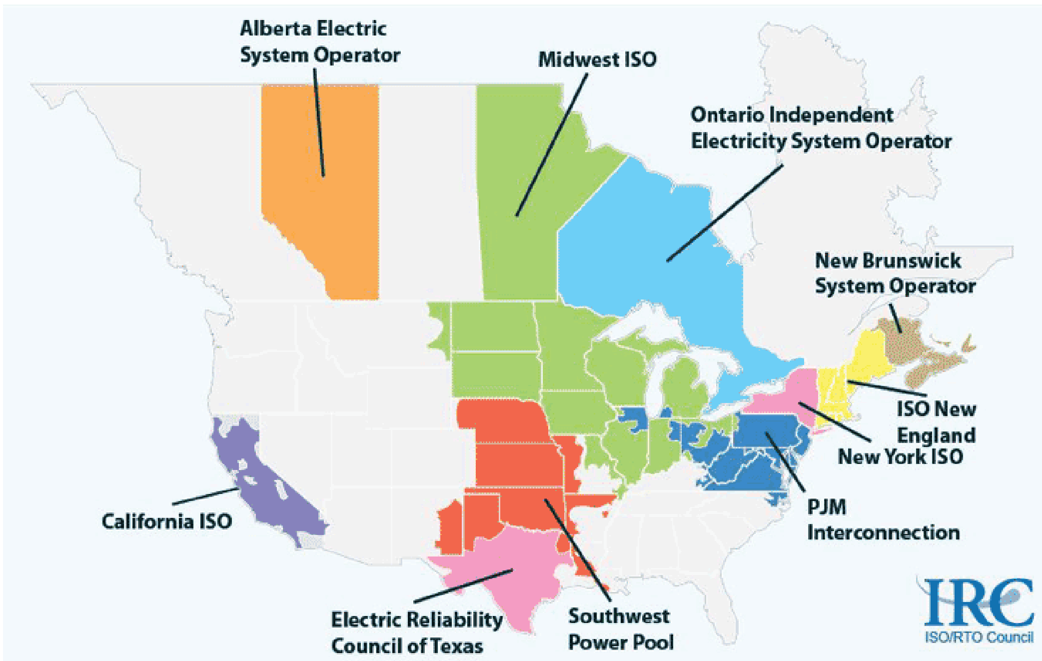


Figure 1.1 ISO/RTO Operating Regions [8]

Furthermore, as the key monitoring function in the control center, the centralized state estimation takes minutes to process a normal sized power system [2, 3]. This program's running time is much more than the data pooling cycle which is 2-10 seconds for the SCADA to scan the power system [3]. Urgent situations may need to be resolved in seconds to minutes. Furthermore, centralized state estimation on wide area power system needs much more time than that for a small area. Steps need to be taken to speed up the state estimation and thus help monitoring the grid closer to real-time. The phasor measurement unit (PMU), a newer intelligent electronic device, offers to provide accurate measurements of the states for the power system more frequently. However, due to its relative high costs, practically the PMUs are usually only installed on some selected buses of a power system.

1.2 State Estimation with PMU

State estimation is a traditional tool used by power engineers to get the profile of a power system with limited measurements from the system. Although the occurrence of a PMU makes it possible to directly measure the phase angles of the power system, two factors mean that state estimation cannot completely be replaced. First, due to the high cost of the PMUs, if a power system has thousands of buses and most of the buses are installed with a PMU, there would be a huge expense. So PMUs are placed on select buses. Second, if there is a communication problem, even if the PMU measurements are not available, the state estimation can still provide a snapshot for the whole system with other available information.

Therefore, a practical application is to integrate PMUs into the state estimation. With the help of PMUs, state estimation can produce a more accurate snapshot of the system. Two methods of including PMU measurements into the state estimation algorithm will be introduced in chapter two and the results of implementation of these two methods is described in chapter six.

1.3 Distributed State Estimation with PMU

Distributed state estimation (DSE) described in this dissertation has emerged to reduce the calculation time costs for the state estimation tremendously. This approach involves two stages. In the first stage, local state estimations will be done in each area. In the second stage, the solutions from all the local state estimation of the involved areas in the first stage will be gathered by a cooperator to generate a single coordinated solution for the entire power grid. This type of state estimation has been addressed in [6-7]. Using this type of distributed state estimation, the benefits are follows:

1. No need to change the SE algorithms in local control centers.

2. The local power system owners can keep their information safe by only sharing their system information with the ISO/RTO. There is no need for them to share the information with other competing companies.

3. Communication overhead between the control centers in local area and the control centers in ISO/RTO can be minimized.

4. DSE runs much faster than Centralized SE while providing acceptable accuracy at the same time.

5. DSE can provide parts of the state information in case of some parts of the area are lost. But centralized SE may not be able to provide acceptable accuracy if a large part is disconnected or lost based on my experiments..

PMUs will enhance the DSE when added in the coordinator of DSE by providing more accurate reference angle difference between different areas in the distributed state estimation because it can provide direct synchronized angle measurement among different areas. Chapter two includes detailed introduction on PMU.

1.4 Motivations and Contribution of this Dissertation

State estimation has become a 'must-run successfully' control center function as will be introduced in chapter 2. An ideal state estimator should be able to provide accurate estimation of the power system at a fast computation speed. It should also demonstrate a good numerical stability and less implementation complexity at the same time.

However, some recent challenges can cause the traditional state estimation algorithm's reliability to be degraded.

- The needs to monitor the power system in wide area which may include several different power system entities.
- The deregulation of the power system: the competing companies are reluctant to share information on the part of power system that they owned with each other.
- The size of power system keeps increasing and causes much more data needs to be dealt with and thus increases the time needed to run the state estimation.
- More and more power controlling devices, such as FACTS (Flexible alternating current Transmission Systems) and various compensators are connected to the power systems to improve the power quality. The connection of these devices may affect the convergence of the state estimation algorithm.

All these issues dictate a more advanced method for monitoring the power system and the method should also be tested and validated before used in real power system. This dissertation aims to provide an accurate profile of a wide area power system in a more robust way with the help of a PMU while considering the current situation in power system industry at the same time. Centralized state estimation with or without a PMU, and distributed state estimation with or without a PMU will be implemented on different size test cases. The results will be described and compared between these methods.

The contributions of this proposed dissertation include:

1. Improved the angle difference calculation in the coordination part of distributed state estimation algorithm by using PMU.

2. Considered the loss of PMU data in the coordinator of DSE.

3. Calibration of PMU data from different vendors. Offsets may exist in the measurements of PMUs from different vendors[4].

4. Built a real-time test bed to validate the algorithms of distributed state estimation with PMU before the algorithms and PMUs are installed in the real world.

5. Used the real-time test bed to demonstrate the online control schemes in the control center based on the security analysis of the power system.

1.5 Dissertation Organization

This dissertation is organized into seven chapters.

In chapter I, current status and challenges for wide area monitoring of the power system introduced. Current restructuring of the power industry is also discussed. Proposed solutions have been described. State estimation, as the important main function in EMS, is briefly introduced with the combination of PMU. Distributed state estimation with PMU is also briefly introduced.

Chapter II provides background information about the energy control center and its possible evolution, and the possibility of grid computing application in future power system.

Chapter III provides the literature review. Theory of state estimation has been illustrated. It introduces the state estimation algorithm in details, specifically including its importance in power system monitoring. Functions in state estimation and the algorithms used are described.. Both conventional and phasor measurements will be considered in this chapter. Two methods of including PMU measurements into the state estimations process have been investigated. Literature review of distributed state estimation and its combination with PMU measurements is also presented.

Chapter IV introduced the reference angle difference calculation in the coordinator level of distributed state estimation and the related research work. It also proposes the reference angle difference calculation using PMUs for distributed state estimation to make DSE more robust and accurate. Chapter V demonstrates the results using MATLAB in three test cases. The simple test case used in this research helped with the implementation, algorithm validation and problem solving in larger test cases. The larger test case, 118-bus IEEE standard power system, is commonly used by power system engineers. The effect of adding the PMU to SE or DSE has been tested. The proposed method of calculating the reference angle difference has also been implemented and compared with the method that uses direct measurement. Chapter VI demonstrates the RTDS real-time test-bed

Chapter VII summarizes this dissertation's research and discussion and describes the work to be in the future for this field

1.6 Summary

This chapter first introduces the current situation of the electric power grid. The power system is undergoing restructuring. More and more advanced computer and communication technologies are being applied to the power system. Horizontally integrating the power system makes monitoring the wide area of power system more complex yet more important at the same time. It shows the deficiency of current monitoring functions for wide area power system.

Then the key monitoring function in the control center, state estimation, is introduced including its role in energy management system (EMS) and challenges for the state estimation in general. The state estimation and its combination with PMUs are outlined. After that, distributed state estimation with PMUs is introduced. Motivations, contributions and the organization of this dissertation are also listed in this chapter.

CHAPTER II

BACKGROUND

2.1 Introduction

Modern power systems include not only the electric system but also the computer and communication networks. The evolution of the power system hardware and software will affect the design of monitoring tools for the wide area power system including the state estimation. The control center is the central information system in the power industry and is where state estimation and other power system monitoring, analysis and control functions are located. Grid service is the converging point of information and communication technologies. The smart grid is a conceptual goal model for future modernized power systems and advancements related to smart grid will likely to influence the future development direction of state estimation. This chapter will introduce the control centers in an electric utility, smart grid and grid service.

2.2 Evolution of Energy Control Centers

The control center is important due to its influence on the power system and its operations. It monitors the power system, analyzes and adjusts the system, coordinates its operation, and protects it from cascading failures or external attacks. Figure 2.1 shows one of the control centers.

Figure 2.1 China Light and Power's Control Center [11]

2.2.1 *The Past of the Energy Control Centers*

The reports from the northeast blackout of 1965 suggested that "utilities should intensify the pursuit of all opportunities to expand the effective use of computers in power system planning and operation. Control centers should be provided with a means for rapid checks on stable and safe capacity limits of system elements…through the use of digital computers." [9]. The control centers then became computer-based with Energy Management System (EMS) installed. This helped the control center and operational activities advance in intelligence and application software capabilities. The data acquisition device systems, the associated communications and the computational power within the power system paralleled the computer and communications technologies available at that time. As shown in Figure 2.1, today the control center collects the measurements from the substations and displays a system wide visualization of the status of the power system it manages. Figure 2.2 shows how the control center gathers data from substations.

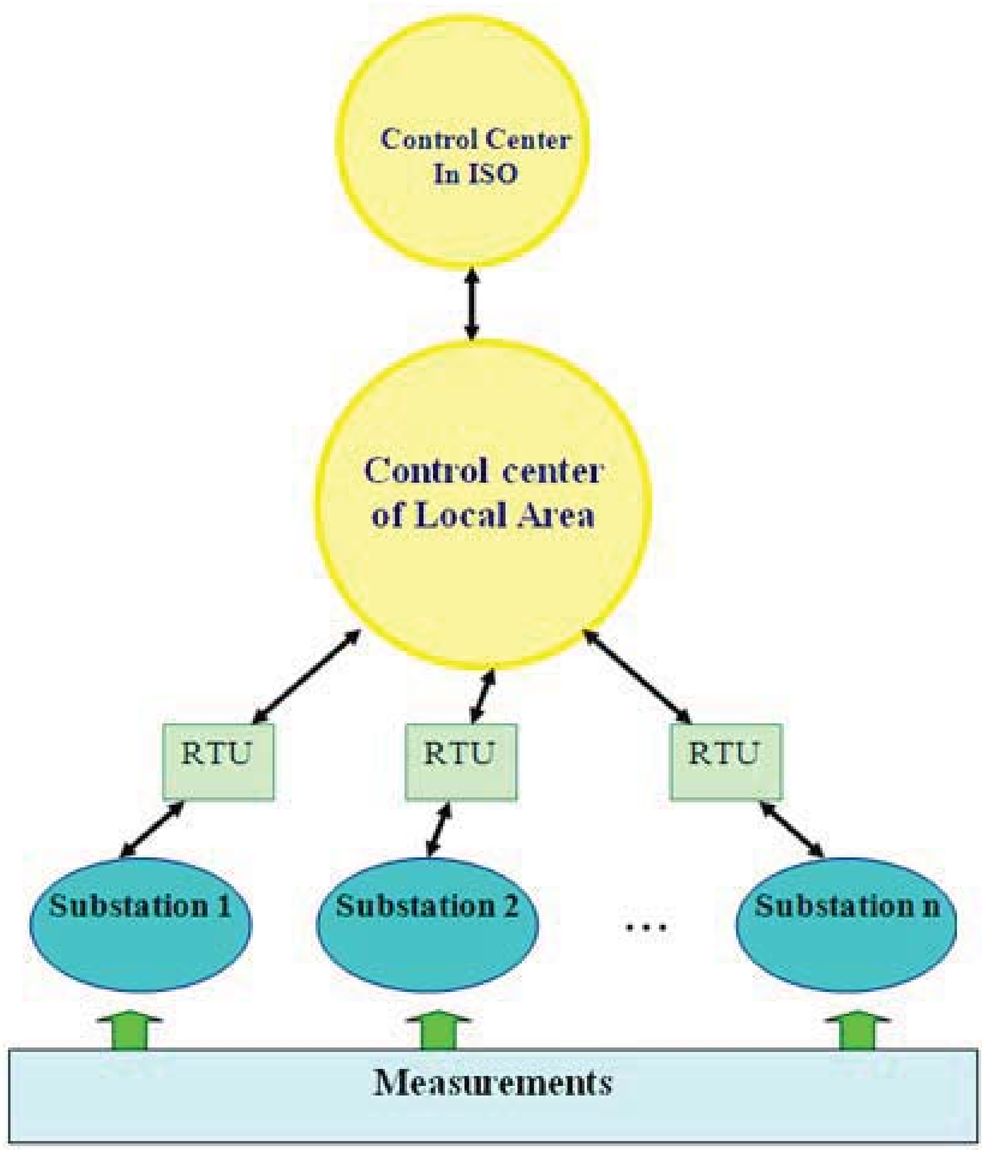


Figure 2.2 Control Center Gather Data from Substations

2.2.2 *Today's Control Centers*

Electric utilities integrated computer, communications and control techniques into their operations as time progressed. However, because of the size of the electrical grid, utilities have to balance the costs of available technologies with the benefits the additional data would provide. Additionally electric utilities continue to use older equipment and systems as long as they are operational. In recent decades, ISOs/RTOs were created to operate the power market and ensure the reliability of the power systems under its jurisdictions. The ISOs/RTOs need to collect data from the control centers in the area as shown in Figure 2.3 where CC means control center. The weakness in conventional utility control centers has been exposed their weakness in today's deregulation environment of the power industry. They are relatively too centralized, independent, inflexible and closed which prevented cooperation between neighboring utilities [10].

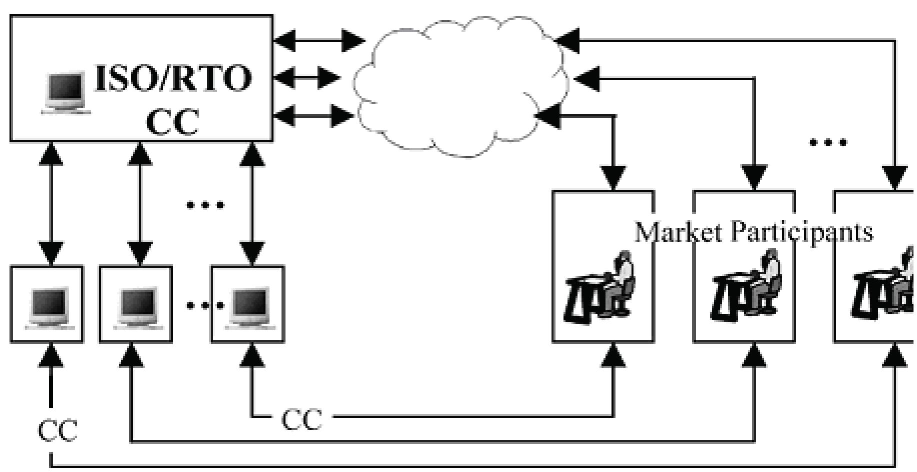


Figure 2.3 Control Centers in Market Environment [10]

Figures 2.2 and 2.3 imply that there are three level of information. The bottom level is within the substations. The middle level is between substations and the control centers of balancing authorities (BA), for example the control centers of the power companies. The upper level is between the BA and the reliability coordinator (RC), for example, ISOs/RTOs. The responsibilities of the control centers include [12]:

1. Monitoring the system by the operator with the visualization and alarms
2. Using EMS applications such as state estimation, contingency analysis and optimal power flow to analyze the vulnerability of the grid to the contingencies.
3. Applying automatic controls such as automatic generation control (AGC) if needed.

Today, newer hardware measurement devices, such as PMUs, have been installed in the substations with a star configuration where the PMU data are gathered to one phasor data concentrator (PDC), then from the PDC by a super PDC in the control center as shown in Figure 2.4.

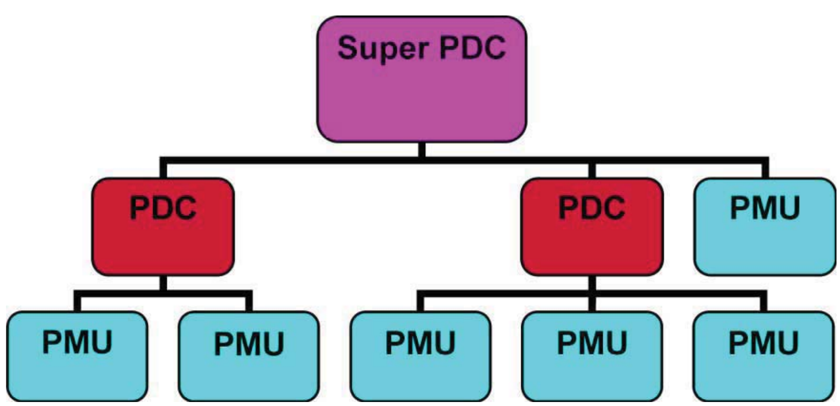


Figure 2.4 Today's architecture of PDC Gathering Data from PMUs [12]

2.2.3 Future Control Centers

Control centers have to be modified to fit in the changing environment of the power industry. First, the paradigm of the power market has shifted from centralized to decentralized decision making. The power market is separate from power system reliability but they affect each other. Thus data and application software in control centers are required to be decentralized and distributed too. Second, control centers should not be independent of other control parties for efficient operation. Their functions must be integrated in the enterprise architecture and the regional cooperation. Third, the control centers need to be flexible. For example, the design in the control centers has to be modular for better scalability and expandability. The software in the control center must be portable to be able to run on heterogeneous hardware and software modules and be interoperable within the system [10].

In the future, advanced computer and communication technologies need to be used to build the information infrastructure of the power system that can integrate future distributed control centers. Several candidates for the technologies are introduced in the following sections.

The transition of the control centers and the power system infrastructure need to be phased in over several years because the power system still needs to be fully operational at any time and the cost would be too high. The transition needs to be planned carefully and executed gradually with thorough testing.

2.3 Future Possible Technology Candidates

This section presents possible future technology candidates for building the information infrastructure of power system. These technologies include: service-oriented architecture, web service, and grid computing

2.3.1 Service-Oriented Architecture (SOA)

SOA is a flexible set of design principles used during the phases of system development and integration in computing. A system based on SOA architecture will provide a loosely-coupled set of services that can be used within multiple separate systems from several business domains[13]. SOA aims to support high performance, scalability, and availability in computing. A service is an application program that can be accessed through an interface. Three components are needed to build the SOA. They are the service provider, the service consumer and a service broker as shown in Figure 2.5. A service provider publishes the contract that describes its interface and then registers its available service with a service broker. A service consumer queries the service broker and finds a compatible service. The service broker then guides the service consumer where to find the service and its service contract. The service consumer uses the contract to bind the client to the server. [10]

Since the SOA allows the interaction between different enterprises, in the future it is possible that state estimation programs on a certain area are wrapped into a service, any authorized party will be able to access it and get the snapshot for a corresponding wide area.

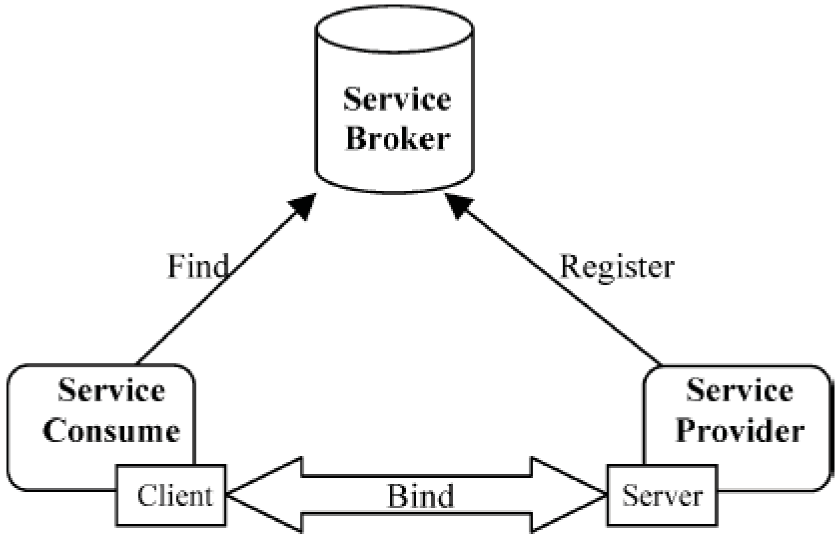


Figure 2.5 Service Oriented Architecture [10]

2.3.2 Web Services

Web services as shown in Figure 2.6 are typically application programming interfaces (API) or Web APIs that are accessed via Hypertext Transfer Protocol (HTTP) and executed on a remote system hosting the requested services[14]. Web services are a particular type of SOA (service-oriented architecture). It enables interoperability between users on various platforms.

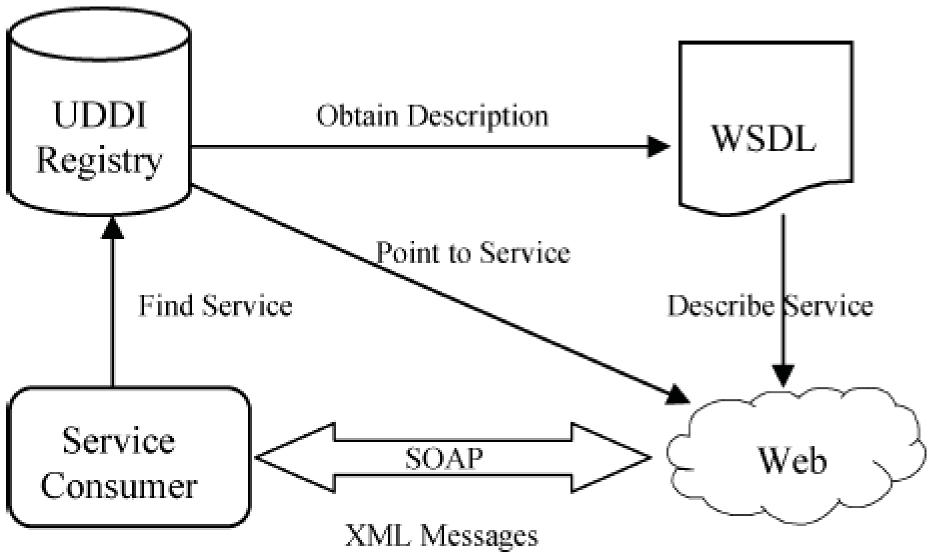


Figure 2.6 Web Service [10]

In this research, Web Service has not been chosen to implement the distributed state estimation because of two of its drawbacks. Web Service is not secure and is slow in the DSE application so grid computing middleware has been used.

2.3.3 Grid Computing and Grid Service

Grid computing is an advanced form of distributed computing. The definition of grid computing given in reference [15] is “Grid Computing enables virtual organizations to share geographically distributed resources as they pursue common goals, assuming the absence of central location, central control, omniscience, and an existing trust relationship”. It aims to make computation power accessible as easy as plugging into the outlet to use the electric power. Grid computing is a promising research area in computer science. It has attracted the attention of an increasing number of engineers. It promises to provide low cost computational resources by using only common computers [15]. Most types of grid computing middleware are developed in the Java language, which can make decoupled processing more flexible. Coordination and distribution are two fundamental concepts in grid computing [16]. According to [15], grid computing covers high performance, cluster, peer-to-peer and Internet computing. There are many separate and distinct grids. Segmented by organization, grid computing includes enterprise grids, partner grids and service grids. Enterprise grids are for private resources to be shared within a single enterprise. Partner grids provide extra-networking to enable resource sharing among selected enterprise partners. Service grids are internetworking to provide public resource sharing on a global scale. The later two are still developing. Segmented by function, there are enterprise compute grid, data grid, equipment grid and application grid. Enterprise Compute Grids are for computational intensive operations. Data Grids are for controlled sharing and management of large amount of distributed data. Equipment Grids are for controlling equipment remotely and analyzing the data produced. Application Grids provide shared access to applications. A grid computing application includes three layers – service layer, middleware and resource layer. Service layer is for computing, storage measurement and control. Middleware tends to provide security, information discovery, resource management, communication, and portability. Different middlewares for grid computing have been developed for different uses, such as Globus, GRIDBUS, and Narada Brokering, to name a few. Grid computing middleware that is suitable to be used in the monitoring of the power system is under development, for example in GRIDCC project.

The development of Grid computing and web service has converged to a common point. Grid service is based on web service and Grid computing. Grid computing can be used to build service oriented architecture. The topologies of the Grid computing include server to client, publish/subscribe and peer to peer.

2.4 Power System Real-Time Digital Simulator (RTDS)

RTDS, a real-time digital simulator is designed to simulate electric power systems. It employs graphical user interface which creates a working environment that is familiar to the power system engineers. It is designed to allow the user to prepare and run real-time simulations and analyze simulation results. RTDS allows a real time simulation with a time step up to 1 micro second. Thus, the RTDS is capable of enabling the user to simulate the scenarios that occur actually in the power system by generating the real-time signals. Its application in power system widely spreads. The RTDS at Mississippi State University Power and Energy Research Laboratory (MSU PERL) is shown in Figure 2.7. This RTDS hardware uses Digital Signal Processor (DSP), Reduced Instruction Set Computer (RISC), and advanced parallel processing techniques in order to achieve computational speeds required to maintain continuous real-time operation. There are two racks in the RTDS at PERL. Each rack can have three types of processor cards, which are 3PC, GPC and RPC. The Triple Processor Card (3PC) consists of three independent Analog Digital Signal Processors (ADSP21062). The ADSP21062 has clock speed of 40 MHz. The RISC Processor card (RPC) consists of two PowerPC 750Cxe RISC processors operating at a clock speed of 600 MHz. There is one Giga Processor Card (GPC). GPC contains two IBM PowerPC 750GX RISC processors each operating at 1 GHz. The RTDS simulator may consist of 3PC only or a combination of 3PC, GPC and RPC. RSCAD allows the user to build a test case by using the different power and control system components present in the RSCAD library [27].

Figure 2.7 RTDS at MSU

To build a desired power system for RTDS simulation, the user first need to connect the graphical power system component models after picking them up from the given component library. Then parameters in each model need to be set according to the desired power system. After compiling and confirming no grammar errors, the appropriate compiler automatically generates the low level code necessary to perform the simulation using RTDS hardware. The RSCAD determines the functions to be executed for each processor in the RTDS hardware. To further ensure the test case is built correctly, the load flow of the compiled power system can be done in the RSCAD. A six-bus test case has also been built in the RSCAD for this research work.

2.5 Summary

Future energy control centers need to be modified to be decentralized, distributed flexible and open to work under the deregulated power industry. Advanced computer and communication technologies will be used to build the information infrastructure to help the power grid to realize this transition. This chapter has described the likely evolution of the control center and introduced today's technologies in computer and communication technologies. The RTDS simulator has also been introduced in this chapter..

CHAPTER III

LITERATURE REVIEW

This chapter will provide literature review on state estimation and its distributed form, distributed state estimation.

3.1 Importance of State Estimation

Real-time operating conditions of the power system provided by the SCADA system are vital to the application functions, such as contingency analysis, and corrective real and reactive power dispatch for power system security analysis. However, the SCADA system may not always provide reliable information due to the errors in the measurements, telemetry failures, or communication noise [18]. Additionally at this time it is not economically feasible to include enough measurements to directly extract the corresponding AC operating state of the system, such as all the bus voltage phase angles measured by PMUs or to telemeter all possible measurements available from the transducers at the substations.

The introduction of the state estimation application enhanced the capability of SCADA system with respect to reliability and broadened its capability by addressing the above concerns. It was actually the reason to establish the Energy Management System (EMS) which is equipped with application functions including an on-line State Estimator (SE) [18].

Traditional measurements include line power flows, bus voltage and line current magnitudes, generator outputs, loads, circuit breaker and switch status information, transformer tap positions and switchable capacitor bank values. PMU phasor measurements include more accurate voltage and current magnitudes and their angles. These raw data and measurements are sent to the state estimator for an optimized snapshot of the system state based on a corresponding system model. The solution of the state estimator will then be passed on to all the other EMS application functions as shown in Figure 3.1. The solution will also be available via a LAN connection so that other planning and analysis functions can be executed off-line.

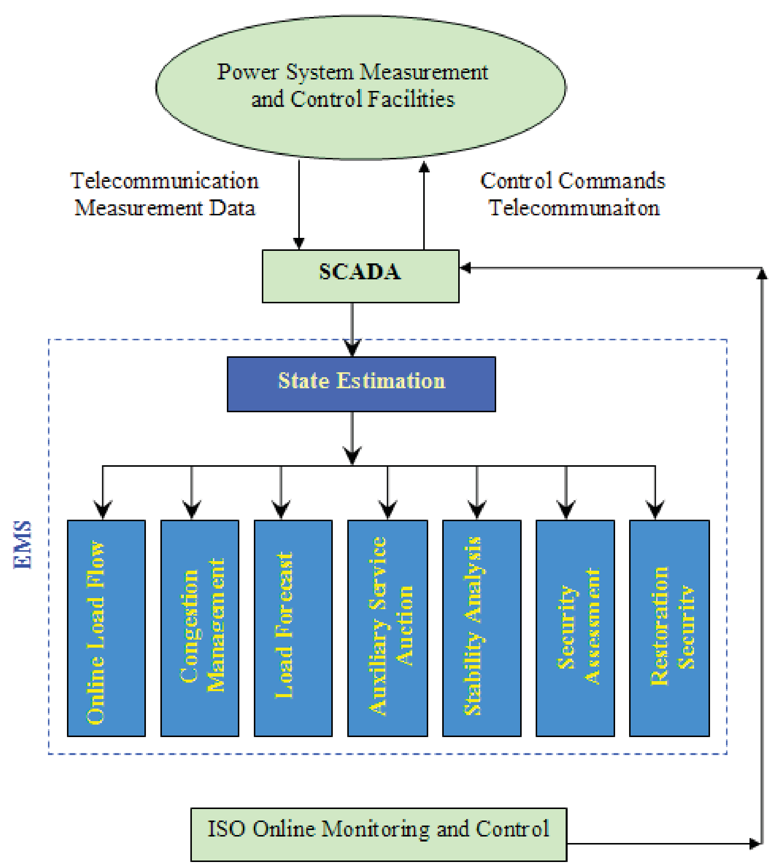


Figure 3.1 EMS Functions of ISO [19]

3.2 Functions in State Estimator

The state estimators provide a reliable real-time data base of the power system. They typically include the following functions [18]:

- A topology processor that gathers the status data about the circuit breakers and switches. It also configures the one-line diagram of the system.
- Observability analysis that determines if a state estimation solution is possible based on an available set of measurements.
- The state estimation solution that determines the optimal estimates for the power system state by using algorithms with numerical methods, such as the weighted least squares.
- Bad data processing that detects the existence of gross errors in the measurement set.
- Parameter and structure error processing that estimates the network parameters.

With all the functions above, the SE acts to filter errors in the system measurements by optimally computing the bus voltage phasors based on the available raw measurements. The measurements should also have redundancy for the power system to be observable. This dissertation will focus on improving the algorithms in the state estimation function. By using DSE in the control center, the results for the snapshot of the system estimation can be accomplished quicker.

3.3 Measurements in General

Conventional measurements include bus voltage magnitude, active power injections to the bus, reactive power injections to the bus, active power line flow and reactive power flow. In recent years, PMUs have begun to be used in monitoring the power system. The phasor measurements include more accurate, time synchronized bus voltage magnitude, bus voltage angle, line current magnitude and line current angle. Details about the PMU will be introduced later in this chapter

3.4 Weighted Least Squares State Estimation

This section will provide an overview of the Weighted Least Squares (WLS) State Estimation algorithm. For additional details see references [6] and [18].

3.4.1 Algorithm Detail for Weighted Least Square Method

A typical algorithm for state estimation uses the weighted least-squares algorithm that minimizes the sum of the squared weighted errors between the estimated and actual measurements. This method is popular among commercial state estimators.

For a N_s -bus power system with N measurements, assume an error vector to be standard Gaussian that has a zero mean and covariance. Let i be the index of the measurements, $\mathbf{x}$ be the states of the power system, namely bus voltage magnitudes and angles, $\mathbf{J}(\mathbf{x})$ be the objective function, N be the total number of the measurements, $\mathbf{Z}$ is the vector of the measurements, $\mathbf{f}(\mathbf{x})$ is the vector of the estimated value for the measurements, $_i$ is the standard deviation of each measurement i . It is calculated to reflect the expected accuracy of the corresponding meter used.

Suppose

1. The i^{th} measurement from SCADA system or other IED sensors is represented as $\mathbf{Z}_i$;

2. The nonlinear function of the system state vector $\underline{\mathbf{x}}$ to calculate the value of the i_{th} measurement is $\mathbf{f}_i(\mathbf{x})$;

3. The difference between steps 1 and 2 for the i^{th} measurement is called $\mathbf{e}_i$, namely measurement error.

Based on the above definitions, for the measurement, there is:

$$\mathbf{Z}_i = \mathbf{f}_i(x) + \mathbf{e}_i \tag{3.1}$$

$\mathbf{R}_i = {}_i^2$ is the variance of the i_{th} measurement,

$$\begin{bmatrix} {}_1^2 & & & \\ & {}_2^2 & & \\ & & \ddots & \\ & & & {}_N^2 \end{bmatrix} = \mathbf{R} = \mathbf{E}(e.e^T) = Cov(e) \tag{3.2}$$

The WLS formulation can be determined as a minimization function as follows:

$$\mathbf{J}(\mathbf{x}) = \sum_{i=1}^{N} \frac{[\mathbf{Z}_i - \mathbf{f}_i(\mathbf{x})]^2}{{}_i^2} = [\mathbf{Z} - \mathbf{f}(\mathbf{x})]^T \mathbf{R}^{-1} [\mathbf{Z} - \mathbf{f}(\mathbf{x})] \tag{3.3}$$

In the state estimation algorithm, WLS works to find the solution for state x that minimizes $\mathbf{J}(x)$ [6, 18]

The minimum requirement leads to the following equation:

$$\mathbf{g}(\mathbf{x}) = \frac{\partial \mathbf{J}(\mathbf{x})}{\partial \mathbf{x}} = -\mathbf{H}^T(\mathbf{x})\mathbf{R}^{-1}(\mathbf{Z} - \mathbf{f}(\mathbf{x})) = 0 \tag{3.4}$$

where H(x) is the N_s by S Jacobian matrix of $\mathbf{f}(\mathbf{x})$, N_s is the total amount of number of the buses in the system, and S is the number of the states in the system.

Expanding the above non-linear function into Taylor Series yields the derivative of $\mathbf{J}(\mathbf{x})$:

$$\mathbf{g}(\mathbf{x}) = \mathbf{g}(\mathbf{x}^k) + \mathbf{G}(\mathbf{x}^k)\ (\mathbf{x} - \mathbf{x}^k) + \ldots = 0 \qquad (3.5)$$

Neglecting the higher order terms leads to Gauss-Newton method which is an iterative solution scheme as shown below:

$$\mathbf{x}^{k+1} = \mathbf{x}^k - [\mathbf{G}(\mathbf{x}^k)]^{-1} * \mathbf{g}(\mathbf{x}^k) \qquad (3.6)$$

where

k is the iteration index

$\mathbf{x}^k$ is the state variable solution at k iteration,

$$\mathbf{G}(\mathbf{x}^k) = \frac{\partial \mathbf{g}(\mathbf{x}^k)}{\partial \mathbf{x}} = \mathbf{H}^T(\mathbf{x}^k)\mathbf{R}^{-1}\mathbf{H}^T(\mathbf{x}^k) \qquad (3.7)$$

$$\mathbf{g}(\mathbf{x}^k) = -\mathbf{H}^T(\mathbf{x}^k)\mathbf{R}^{-1}(\mathbf{Z} - \mathbf{f}(\mathbf{x}^k)) \qquad (3.8)$$

In the algorithm

$$\Delta\mathbf{x}^{k+1} = \mathbf{x}^{k+1} - \mathbf{x}^k = [\mathbf{G}(\mathbf{x}^k)]^{-1}\mathbf{H}^T(\mathbf{x}^k)\mathbf{R}^{-1}(\mathbf{Z} - \mathbf{f}(\mathbf{x}^k)) \qquad (3.9)$$

3.4.2 Running Time of WLS algorithm

As shown in reference [6], the running time of such an algorithm is about N_s^3, the cube of N_s, where N_s is the number of buses inside in the power system. This indicates that the size of the power system affects the time for the WLS solution.

3.5 Traditional State Estimation and Its Further Development

As introduced in section 3.1, state estimation is the foundation in power system security analysis. Other application functions must use the solution from the state estimation within their analysis. This requires that the state estimator produce the most accurate results in a faster way. State estimation has become a 'must-run successfully' control center function [20]. The shorter time that these EMS applications need to run, the more frequently and closely the power system can be monitored and analyzed. Therefore, it places a high requirement on the reliability and speed of the state estimation algorithm. An ideal state estimator should provide an accurate estimation of the power system at a fast computational speed. It should also demonstrate good numerical stability and less implementation complexity at the same time.

However, some recent factors listed as follows can cause traditional state estimation algorithm to not converge and thus degrade the reliability of the state estimation.

- The size of power system keeps increasing and
- More and more power controlling devices such as FACTs devices and various compensators are connected to the power systems to improve the power quality.

The above issues increased the need for a more advanced state estimator. The further development of the state estimator shows two directions. One is integrating Synchronized PMU into state estimation. The other is distributed state estimation. These two issues are also seeing some integration opportunities.

3.5.1 Integrating Synchronized PMU into State Estimation

The PMU is a power system IED that can provide time synchronized, accurate measurements. It can also provide the voltage phase angle, the key solution variable in SE, which was not available as a measurement before. PMUs are quickly becoming the ultimate tool for wide-area monitoring [21]. Many power utilities have already placed several PMU's in their systems. It is envisioned that more PMUs will be used for power system applications.

3.5.1.1 Block Diagram of PMU

The block diagram of the PMU shows a classical structure for digital signal processing. As shown in Figure 3.2, the inputs of the PMU are voltage and current analog signals. For the application in power system, the analog inputs are mainly from the outputs of the transducers. PMUs output digital signals representing the calculated phasor and frequency information of the inputs. The digital outputs are then transmitted to the control center through some communication method.

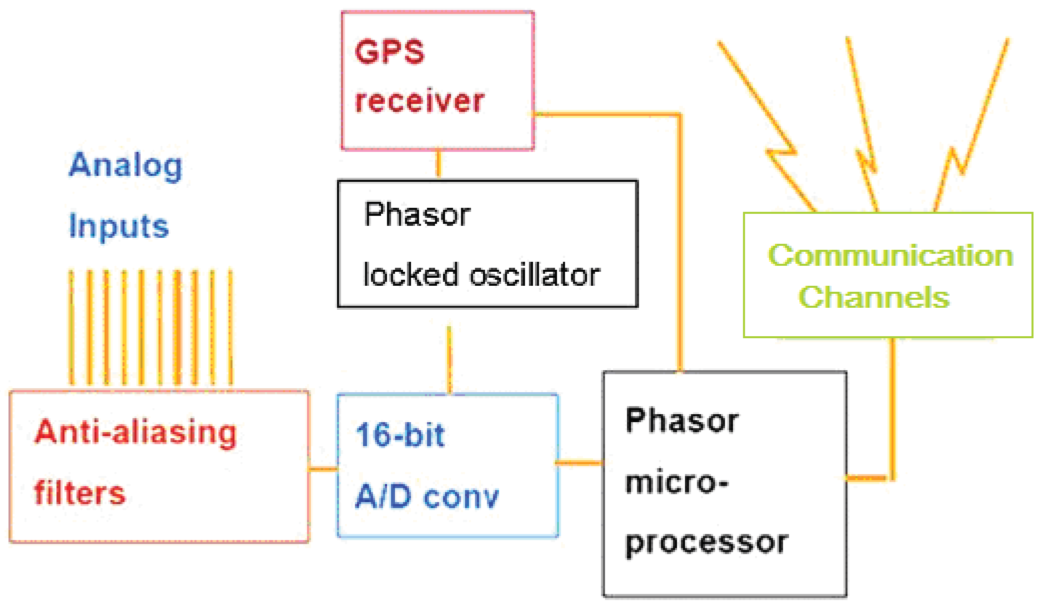


Figure 3.2 Block Diagram of a PMU [6]

The GPS receiver can get GPS signals that work the same as a usual digital clock for a microprocessor. A PMU with a GPS signal can provide two additional functions.

1. GPS can make one PMU processing be synchronized with another PMU that is geographically separated

2. GPS can also provide a global reference for the angle measurements based on the UTC second rollover [1pulse per second (PPS) time signal].

3.5.1.2 PMU Impact on State Estimation

Depending on the PMU measurement accuracy and calibration, the number of PMUs, PMU locations and related SCADA data accuracy, PMU data can benefit the state estimation analysis [22].

1. PMU data can improve the estimation of inaccurate measurements close to the PMU substation.

2. PMU provides phase angle measurement that could not be measured before.

3. PMU data trend analysis can detect CB/switch status changes in the network, which may improve the topology estimation and error detection.

4. Utilities are willing to share the boundary PMU data. In many instances, poor SE performance has been due to lack of reasonably accurate external area measurements [22].

According to reference [35], PMUs can also be synchronized by other broadcasting signals other than GPS.

3.5.1.3 Concerns When Integrating PMU data into the Integrated State Estimation

As implemented in reference [6, 7], the phasor measurements have been added to the measurement vector Z and are treated the same as the conventional measurements in the integrated state estimation. Because they are more accurate, the standard deviations for the phasor measurements are set much smaller than the conventional ones.

To integrate the PMU data into the state estimation, it should be considered that the phasor measurements and state estimator do not have the same reference. One solution can be to put a PMU at the reference bus of the state estimator and use this PMU as the reference for other PMUs. This uses the angle difference between any other PMU and the reference PMU in the state estimation algorithm. However, such an arrangement will result in a vulnerable system that always depends on the signals from the reference PMU. Please note that there may be undesired events, such as an outage at a measurement location, communication failure, or a failure in the reference PMU. Therefore, reference [23] also lists other methods to reconcile the phasor measurement and state estimator frames.

3.5.1.4 Algorithm of State Estimation with PMU

There are typically two methods when involving PMU phasor measurements to the state estimation [24]. One builds an estimator with phasor measurements mixed with traditional measurements and the other adds phasor measurements though a post processing step. Reference [24] proves that these two strategies produce the same results. The second method can keep the traditional state estimation algorithm and append a linear estimator.

3.5.1.5 Estimator with Phasor Measurements Mixed With Traditional Measurements

In this method, the traditional measurements are in polar coordinates and the phasor measurements are in the rectangle coordinates. The measurements vector should be:

$$[\mathbf{Z}] = \begin{bmatrix} \mathbf{Z}_1 \\ \mathbf{Z}_2 \end{bmatrix} = \begin{bmatrix} \mathbf{Z}_1 \\ \mathbf{E}_r \\ \mathbf{E}_i \\ \mathbf{I}_r \\ \mathbf{I}_i \end{bmatrix} \tag{3.10}$$

where

$\mathbf{Z}_1$ is the traditional measurement vector which is written as $\mathbf{Z}$ in section 3.4.1 of this chapter, and

$\mathbf{E}_r$, $\mathbf{E}_i$, $\mathbf{I}_r$ and $\mathbf{I}_i$ are the phasor measurements from PMU in the rectangle coordinates.

Let p indicate the bus number that the current flows from; q indicate the bus number that the current flows to; $g_{(pq)}$+j$b_{(pq)}$ indicate the series admittance of the line pq; and j$b_{(p0)}$ indicates the shunt admittance at bus p.

Other parts of the algorithm are similar to the traditional and the functions linking phasor measurements with the state vector is as follows [24]:

$$\begin{bmatrix} \mathbf{E}_{(p)r} \\ \mathbf{E}_{(p)i} \\ \mathbf{I}_{(pq)r} \\ \mathbf{I}_{(pq)i} \end{bmatrix} = \begin{bmatrix} |\mathbf{E}_{(p)}|\cos(\theta_p) \\ |\mathbf{E}_{(p)}|\sin(\theta_p) \\ (|\mathbf{E}_{(p)}|\cos(\theta_p) - |\mathbf{E}_{(q)}|\sin(\theta_q))g_{(pq)} - (|\mathbf{E}_{(p)}|\sin(\theta_p) - |\mathbf{E}_{(q)}|\sin(\theta_q))b_{(pq)} - b_{(p0)}|\mathbf{E}_{(p)}|\sin\theta_p \\ (|\mathbf{E}_{(p)}|\cos(\theta_p) - |\mathbf{E}_{(q)}|\sin(\theta_q))b_{(pq)} + (|\mathbf{E}_{(p)}|\sin(\theta_p) - |\mathbf{E}_{(q)}|\sin(\theta_q))g_{(pq)} + b_{(p0)}|\mathbf{E}_{(p)}|\cos\theta_p \end{bmatrix} \tag{3.11}$$

The error covariance matrix for the phasor measurements needs to transform from polar coordinates to rectangle coordinates by using the following equation:

$$[\mathbf{W}_2^{'}] = [\mathbf{R}][\mathbf{W}_2][\mathbf{R}^T] \tag{3.12}$$

Where:

$$\mathbf{R} = \begin{bmatrix} \mathbf{R}_v & 0 \\ 0 & \mathbf{R}_i \end{bmatrix} \tag{3.13}$$

$$\mathbf{R}_v = \begin{bmatrix} \cos\theta_{1v} & 0 & 0 & -E_{(1v)}\sin\theta_{1v} & 0 & 0 \\ 0 & \cos\theta_{2v} & 0 & 0 & -E_{(2v)}\sin\theta_{2v} & 0 \\ 0 & 0 & \vdots & 0 & 0 & \vdots \\ \sin\theta_{1v} & 0 & 0 & E_{(1v)}\cos\theta_{1v} & 0 & 0 \\ 0 & \sin\theta_{2v} & 0 & 0 & E_{(2v)}\cos\theta_{(2v)} & 0 \\ 0 & 0 & \vdots & 0 & 0 & \vdots \end{bmatrix} \tag{3.14}$$

$[\theta_v]_{polar} = [\theta_{1v}\ \theta_{2v}\ \cdots\theta_{lv}]$ indicates the angle of the voltage phasor

$[E_v]_{polar} = [E_{1v}\ E_{2v}\ \cdots E_{lv}]$ indicates the magnitude of the voltage phasor

l is the number of voltage phasor measurements.

$$\mathbf{R}_i = \begin{bmatrix} \cos\theta_{1i} & 0 & 0 & -I_{(1i)}\sin\theta_{1i} & 0 & 0 \\ 0 & \cos\theta_{2i} & 0 & 0 & -I_{(2i)}\sin\theta_{2i} & 0 \\ 0 & 0 & \vdots & 0 & 0 & \vdots \\ \sin\theta_{1i} & 0 & 0 & I_{(1i)}\cos\theta_{1i} & 0 & 0 \\ 0 & \sin\theta_{2i} & 0 & 0 & I_{(2i)}\cos\theta_{(2i)} & 0 \\ 0 & 0 & \vdots & 0 & 0 & \vdots \end{bmatrix} \tag{3.15}$$

$[\theta_i]_{polar} = [\theta_{1i}\ \theta_{2i}\ \cdots\theta_{mi}]$ indicates the angle of the current phasor

$[I_i]_{polar} = [I_{1i}\ I_{2i}\ \cdots I_{mi}]$ indicates the magnitude of the current phasor

m is the number of current phasor measurements.

3.5.1.6 Adding Phasor Measurements through A Post processing Step

For this method, both traditional measurements and the phasor measurements should be in rectangle coordinates. The new measurement set is defined as follows:

$$[\mathbf{Z}'] = \begin{bmatrix} \mathbf{E}_1 \\ \mathbf{Z}_2 \end{bmatrix} = \begin{bmatrix} \mathbf{E}_1 \\ \mathbf{E}_r \\ \mathbf{E}_i \\ \mathbf{I}_r \\ \mathbf{I}_i \end{bmatrix} = \begin{bmatrix} \mathbf{E}_{1r} \\ \mathbf{E}_{1i} \\ \mathbf{E}_r \\ \mathbf{E}_i \\ \mathbf{I}_r \\ \mathbf{I}_i \end{bmatrix} \tag{3.16}$$

where

$\mathbf{E}_1$ is the estimated results for the state vector from the traditional state estimator in rectangle coordinates.

$\mathbf{Z}_2$ is the phasor measurements vector in rectangle coordinates.

$\mathbf{E}_r$, $\mathbf{E}_i$, $\mathbf{I}_r$ and $\mathbf{I}_i$ are the phasor measurements from PMU in the rectangle coordinates.

The flow chart of this method is as Figure 3.3:

In Figure 3.3, $\mathbf{A}$ is described as following:

$$[\mathbf{Z}'] = \begin{bmatrix} \mathbf{E}_{1r} \\ \mathbf{E}_{1i} \\ \mathbf{E}_r \\ \mathbf{E}_i \\ \mathbf{I}_r \\ \mathbf{I}_i \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ 0 & 1 \\ 1' & 0 \\ 0 & 1' \\ \mathbf{C}_1 & \mathbf{C}_2 \\ \mathbf{C}_3 & \mathbf{C}_4 \end{bmatrix} * \begin{bmatrix} \mathbf{x}_r \\ \mathbf{x}_i \end{bmatrix} = [\mathbf{A}] * \begin{bmatrix} \mathbf{x}_r \\ \mathbf{x}_i \end{bmatrix} \tag{3.17}$$

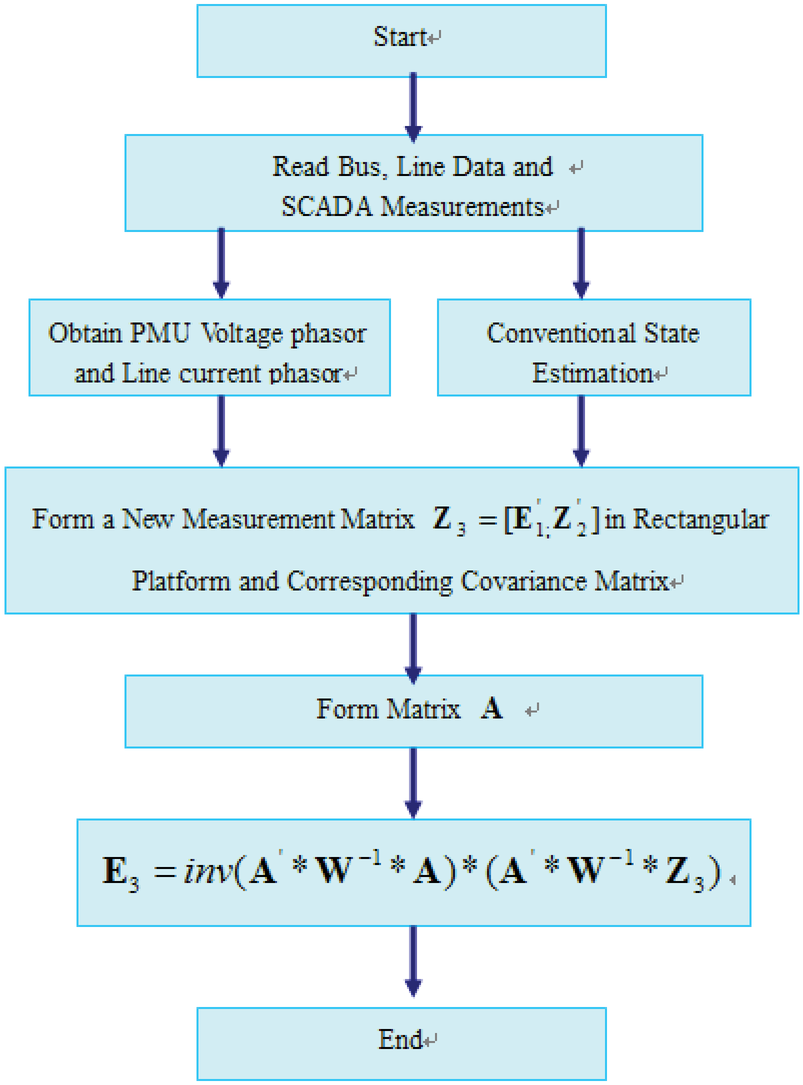


Figure 3.3 Flow Chart of Post Processing PMU Data

where

$\mathbf{x}_r$ and $\mathbf{x}_i$ are the state vector in rectangle coordinates.

$\mathbf{E}_r$, $\mathbf{E}_i$, $\mathbf{I}_r$ and $\mathbf{I}_i$ are the phasor measurements from PMU in the rectangle coordinates.

$$[\mathbf{A}] = \begin{bmatrix} 1 & 0 \\ 0 & 1 \\ 1^{'} & 0 \\ 0 & 1^{'} \\ \mathbf{C}_1 & \mathbf{C}_2 \\ \mathbf{C}_3 & \mathbf{C}_4 \end{bmatrix} \tag{3.18}$$

' 1' represents a unit matrix

' $1^{'}$ ' represents a unit matrix with zeros on the diagonals where no voltage phasors have been measured.

Suppose the current that PMU measure flows from bus p to bus q, then the series admittance of the line connecting buses 'p' and 'q' is

$$\vec{y}_{(pq)} = g_{(pq)} + jb_{(pq)} \tag{3.19}$$

and the shunt admittance at bus 'p' is

$$\vec{y}_{(p0)} = jb_{(p0)} \tag{3.20}$$

$\vec{y}_{(pq)}$ and $\vec{y}_{(p0)}$ are complex number.

thus

$$\mathbf{C}_1 = [\, g_{(pq)} \qquad -g_{(pq)} \,] \tag{3.21}$$

$$\mathbf{C}_2 = [\, -(b_{(pq)} + b_{(p0)}) \qquad b_{(pq)} \,] \tag{3.22}$$

$$\mathbf{C}_3 = [\, (b_{(pq)} + b_{(p0)}) \qquad -b_{(pq)} \,] \tag{3.23}$$

$$\mathbf{C}_4 = [\, g_{(pq)} \qquad -g_{(pq)} \,] \tag{3.24}$$

Second, $$\mathbf{W}^{-1} = \begin{bmatrix} \mathbf{W}_1^{'} & 0 \\ 0 & \mathbf{W}_2^{'} \end{bmatrix} \tag{3.25}$$

$\mathbf{W}_1^{'}$ is the error covariance matrix of $\mathbf{E}_1$ in rectangle coordinates.

To get $\mathbf{W}_1^{'}$, we need to convert the error covariance matrix of $\mathbf{E}_1$, namely $Cov([\mathbf{E}])]_{polar}$, in polar coordinates which is also the inverse of gain matrix $\mathbf{G}(x)$ used in the traditional state estimation into rectangle one, which means:

$$Cov([\mathbf{E}])_{rect} = [\mathbf{R}'][Cov([\mathbf{E}])]_{polar}[\mathbf{R}']^T = [\mathbf{R}'][\mathbf{W}_1][\mathbf{R}']^T \equiv [\mathbf{W}_1^{'}] \quad (3.26)$$

where

$$[\mathbf{W}_1] = \mathbf{G}^{-1}(x) \;=\; [\mathbf{H}^T(x^k)\mathbf{R}^{-1}\mathbf{H}(x^k)]^{-1} \quad (3.27)$$

$$\mathbf{R}' = \begin{matrix} \cos\theta_1 & 0 & 0 & -V_{1p}\sin\theta_1 & 0 & 0 \\ 0 & \cos\theta_2 & 0 & 0 & -V_{2p}\sin\theta_2 & 0 \\ 0 & 0 & \vdots & 0 & 0 & \vdots \\ \sin\theta_1 & 0 & 0 & V_{1p}\cos\theta_1 & 0 & 0 \\ 0 & \sin\theta_2 & 0 & 0 & V_{2p}\cos\theta_2 & 0 \\ 0 & 0 & \vdots & 0 & 0 & \vdots \end{matrix}\Bigg] \quad (3.28)$$

$\mathbf{E}_{1p} = [V_1 \quad V_2 \; ... \; V_n \quad \theta_1 \;\; \theta_2 \; ... \; \theta_n]$ is the state vector in polar coordinates.

n is the size of the power system under study

V_n is the estimated voltage magnitude for bus n by traditional state estimation

θ_n is the estimated voltage angle for bus n by traditional state estimation

3.6 Distributed State Estimation

The rapid development of new technologies in the areas of electrical engineering, computer hardware and computer communication have provided the solid foundation and necessary conditions for distributed power system state estimation. As the size of the electric power system continues to grow, a state estimator has to be more computationally efficient and robust. This cannot be achieved only by improving the state estimation algorithm itself. Distributed state estimation occurred as a new advance that decomposes the power system into smaller subsystems. This provides a way to simultaneously pool the measurements and execute the state estimation for a smaller size power system. The results calculated by the local state estimation will be sent to the reliability coordinator for further processing.

Since the PMUs can synchronize the measurements among different areas by using GPS, they are perfectly suited for distributed state estimation for a wide area power system and can improve the reference angle calculation in DSE. References [6, 7, 24, and 26] have presented the related research work and have shown that PMU can improve the performance of the distributed state estimation.

3.6.1 What is Distributed State Estimation

For most distributed state estimation, the power system is decoupled in such a way that each sub-area has a sub area control center (SACC). The SACC will take its own real-time measurements and processes those to perform a local state estimation. Then a coordinator is required to collect the information from sub-areas [19], calculate the reference angle difference of each area and re-estimate the boundary states.

The distributed state estimation implemented in this proposed research work has a hierarchical architecture with the following features:

1. Different sub-areas share limited information with each other.
2. Control centers in the sub-areas can use their own state estimator and only provide the SE results, boundary measurements and PMU data to the reliability coordinator as shown in Figure 3.4.
3. The coordinator only exchanges data with the sub-areas after the sub-areas finish estimating.

Recall that this dissertation proposed a new method to calculate the angle difference of the slack bus in each sub-area and compare this method with the existing methods by implementing the DSE in the MATLAB and RTDS test bed that I have built in the power lab. SE has also been implemented to compare with DSE. The addition of PMUs in SE/DSE has also been tested.

3.6.2 General Steps of Performing Distributed State Estimation

- Step 1 Obtain measurements.

  Power flow needs to run for the entire power system to get real values for the variables without considering any error that can be introduced by the measurement devices. Then variance should be added to the real values of the variables of the power system as introduced in Section 3.4.1 to get the measurements. This way, it simulates the perturbed measurements in reality based on the standard variance provided. Then generated measurements will be recorded for local state estimation algorithm to use.

- Step 2 Split the Power System

  In this step, the power system under research is divided into several sub-areas. The boundary of the sub systems need to be clarified.

- Step 3 Local State Estimations

  In step 3, local state estimations are performed on each sub-area using WLS based state estimation algorithm as introduced in previous section.

- Step 4 Coordinator Level

  The coordinator assembles estimates and boundary values from all the sub-areas. It then calculates the reference angle difference for each area to resolve the difference in voltage angle reference between the sub-areas as will be introduced in detail in the following chapter. After that boundary states recalculation: re-estimate the boundary states if needed.

3.6.3 Previous Work on Distributed State Estimation

The DSE approach has been studied by many researchers in different ways. The concept of DSE was introduced in 1970 [28] as two-step distributed SE. In earlier years, the research works were more concentrated on how to divide the measurements [30], and how to eliminate the mismatches of the boundary buses [28, 31, and 32]. After the PMUs were developed for the power system in recent years, the research areas include:

1. General methods of applying PMUs to DSE [6 and 7]
2. Study of which buses to place PMUs for DSE [29]
3. Study of applying PMUs to calculate the reference angle difference between sub-areas and the global slack bus [6]

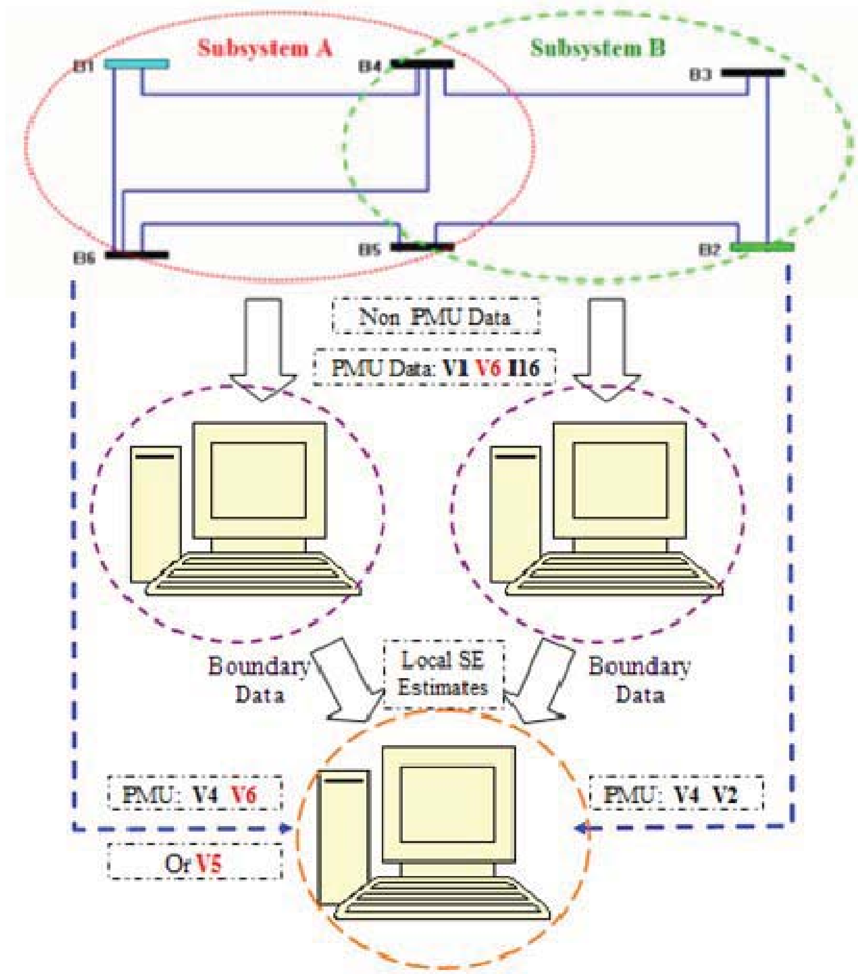


Figure 3.4 Proposed Distributed State Estimation Diagram

Most of the studies are based on the facts that state estimation only run in the control center of sub-area or ISO. Meliopoulos et al. performed DSE where the local SE runs on substations and the coordinator runs in the sub-area control center [26]. The SE in substations can make full use of all the raw data transmitted in a LAN including the raw data that usually are not sent to the control center. With the aid of enough PMUs and all the raw measurements, the SE in the substation produces good and fast results and the coordinator assembles the estimates from substations by calculating the reference angle difference and got fast and accurate results for the entire power system. This distributed estimator has been implemented in physical power systems and produces improved results. The function layout of this distributed estimator is shown in Figure 3.5.

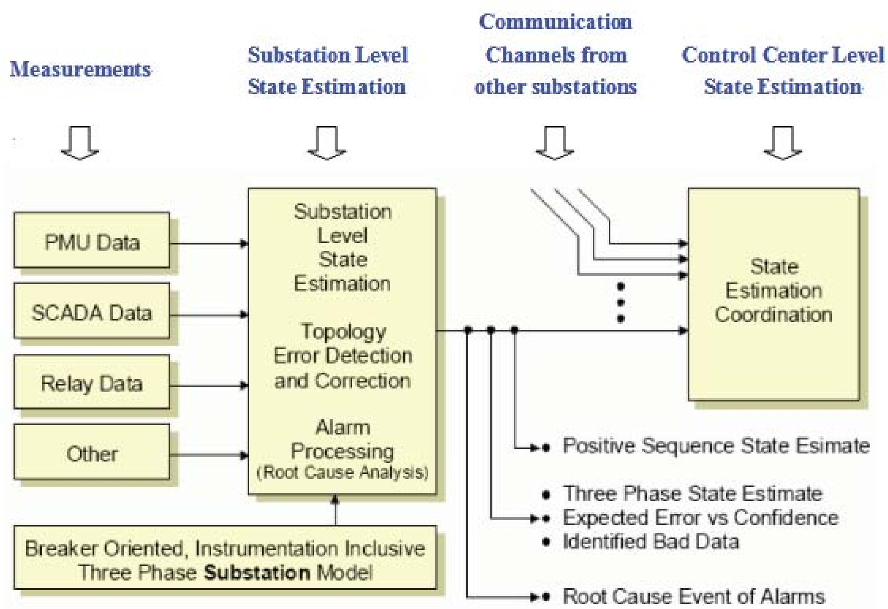


Figure 3.5 DSE between Substation and Control Center Level [26]

This above method can produce satisfactory results on the sub-area level, and therefore the difference of angle reference calculation becomes more important for the final estimates of the entire system. A new method using PMUs to calculate the reference angle difference between areas has been developed as part of this research effort and will be introduced in the next chapter.

3.7 Summary

This chapter has described the state estimation in detail including its strategic position in power system monitoring and control, the functions of state estimation in general, and the weight least squares algorithm for the conventional state estimation. It has also addressed the further development of the state estimation by involving phasor measurement units and the two algorithms of adding PMU measurements in the state estimation. Distributed state estimation (DSE) used the same algorithms in the local state estimation. This chapter presented how to perform a distributed state estimation and discussed previous research on DSE.

CHAPTER IV

REFERENCE ANGLE DIFFERENCE CALCULATION

As indicated in Chapter 3, the estimated results from local areas will be sent to the coordinator to produce a system wide view of the power system. The coordinator needs to assemble the inputs from different areas using the reference angle difference. This chapter introduces what is the reference angle difference and the new method developed for this research to calculate it using PMUs.

4.1 Definition of reference angle difference

In distributed state estimation, the power system under study needs to be decomposed into several sub-areas initially. The phase angles estimated in each sub-area are usually based on different reference buses. Assume the reference bus in one of the sub-areas is chosen as the global reference bus for the whole power system. The angle difference between the reference bus in sub-area B and the global reference bus in A is defined as the reference phase angle difference for B as shown in Figure 4.1.

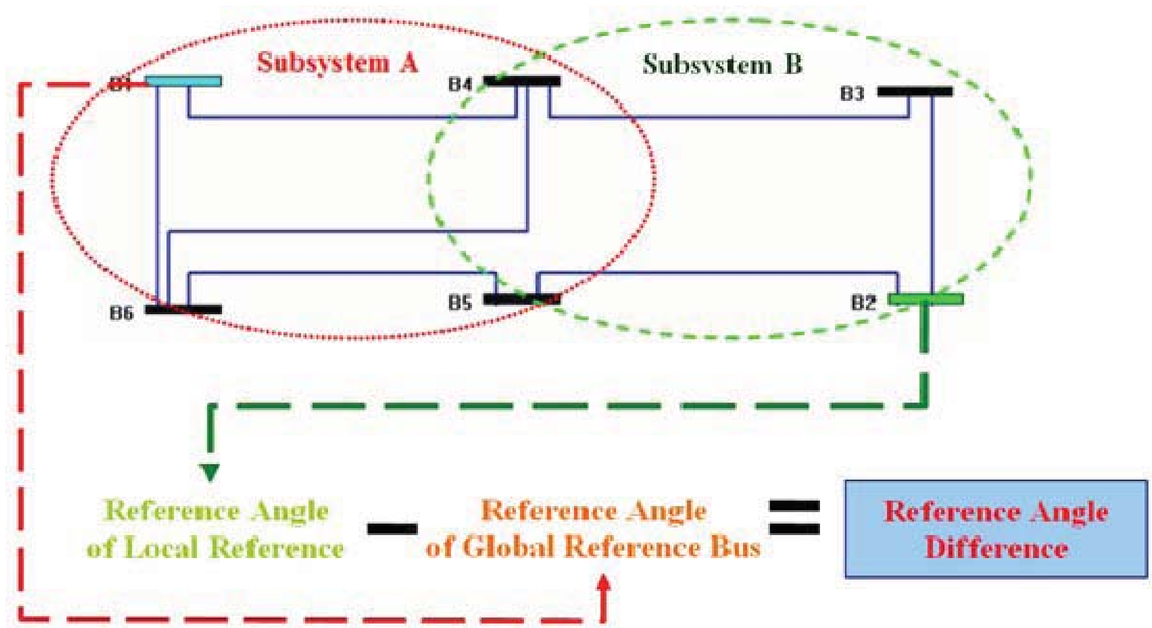


Figure 4.1 Definition of Reference Angle Difference

4.2 Motivation for reference phase angle calculation in Distributed State Estimation

The phase angle information is important in the AC power system, since power is flowing from a higher phase angle to a lower phase angle. The larger the phase angle difference between the source and the sink, the greater power flow between these points which means the larger static stress being exerted across those inferences and thus the closer the proximity to instability. Figure 4.2 shows the growing phase angle difference between two areas affected during the August 14, 2003 blackout in the Eastern Interconnection [25].

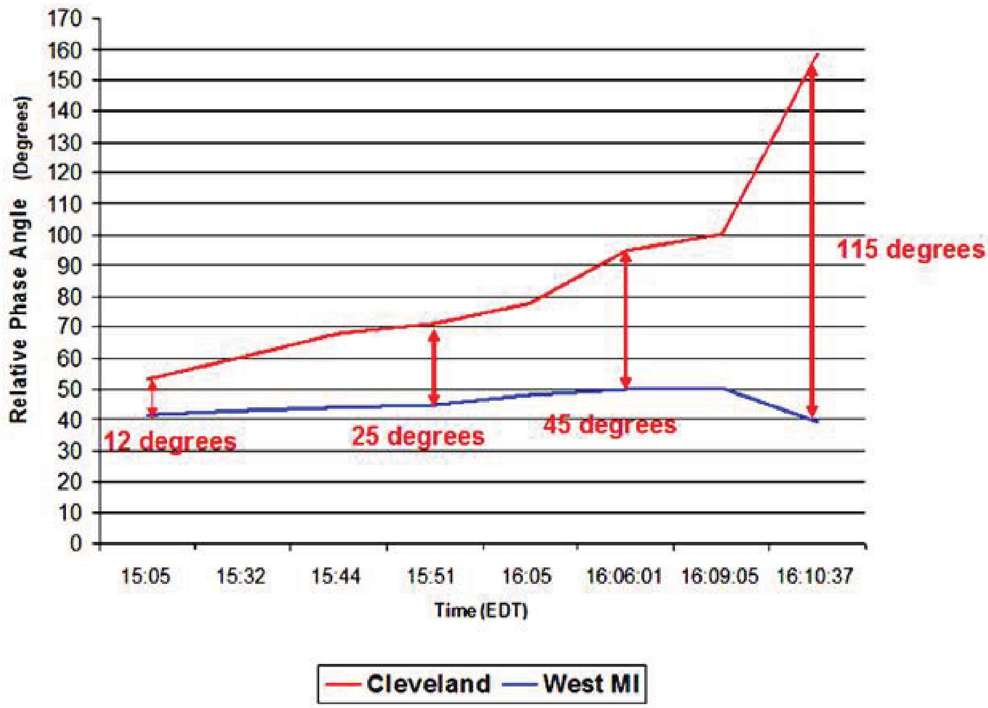


Figure 4.2 Growing Phase Angle Difference [25]

Figure 4.2 shows that as the cascading blackout took place, the phase angle difference between the above two areas becomes larger and larger. This provides an example that the angle difference is an important quantity for a power system. The distributed state estimation is assumed to use the method that sub-areas use their own state estimation and send the output to the reliability coordinator for the snapshot of the whole power system. In the stage that sub-areas execute their own state estimation, they may not use the same reference for their angle estimation. For example, they may all use the slack bus in their area as the reference bus. However, the angle output of the distributed state estimation for the whole power system needs to be in the same reference frame. Therefore, having received the local state estimation results from the sub-areas, the reliability coordinator needs to first resolve the angle difference between different areas so that in the coordinator stage of the distributed state estimation, all the angles will use the same reference.

4.3 Existing methods of calculating the reference phase angle difference with PMU data

Reference [6] has listed four optimization methods for calculating the reference angle difference. The basic idea in this reference is to take the phase angle measurement of any PMU in each sub-area (θ_{pmuAn} and θ_{pmuBm}) and the corresponding estimated angles to compute the angle difference ϕ_{diff} as shown in equation (4.1).

$$\phi_{diff} = \theta_{pmuAn} - \theta_{pmuBm} - \theta_{estBm} - \theta_{estAn} \tag{4.1}$$

where:

θ_{pmuAn} is the angle measurement of bus n from area A

θ_{pmuBm} is the angle measurement of bus m from area B

θ_{estAn} is the local estimated phase angle of bus n in area A

θ_{estBm} is the local estimated phase angle of bus m in area B.

Equation (4.1) will be used as an additional data point together with other items from non-synchronized measurements in the existing algorithm. The only difference is the different standard deviation. References [25] and [6] used only the PMUs from the reference bus in each sub-area which is the slack bus in this case and chose one of the slack buses as the global reference for the PMUs. Therefore the reference angle difference is calculated by equation (4.2).

$$\phi_{diff} = \theta_{pmuBSlack} - \theta_{pmuASlack} \tag{4.2}$$

where

$\theta_{pmuASlack}$ is the angle measurement of slack bus from area A

$\theta_{pmuBSlack}$ is the angle measurement of slack bus from area B

The slack bus in area A is set as the global reference and should also be the reference bus in the state estimation algorithm.

There are two concerns about the above two methods. First, these two methods do not consider or discuss the condition of PMU data loss, for example, in the situation of a PMU device breaks down or there is communication failure. For the second method, the reference angle difference calculation only depends on the measurements from the slack bus. Again, considering the possibility of communication failure, PMU failure or blackout at the substation where the PMU reference bus is located, it makes the system vulnerable by using a fixed reference PMU. Secondly, these two methods do not consider the PMU measurement offset issue caused by different vendors including integrated PMU (such as relays have PMU functions). There are some PMUs installed currently in the power system. Vendor issues should be considered if these PMUs are to be used for the reference angle difference calculation of the distributed state estimation since the measurements of PMU from different vendors may produce constant offset at each frequency point as shown in Figure 4.3[21, 34].

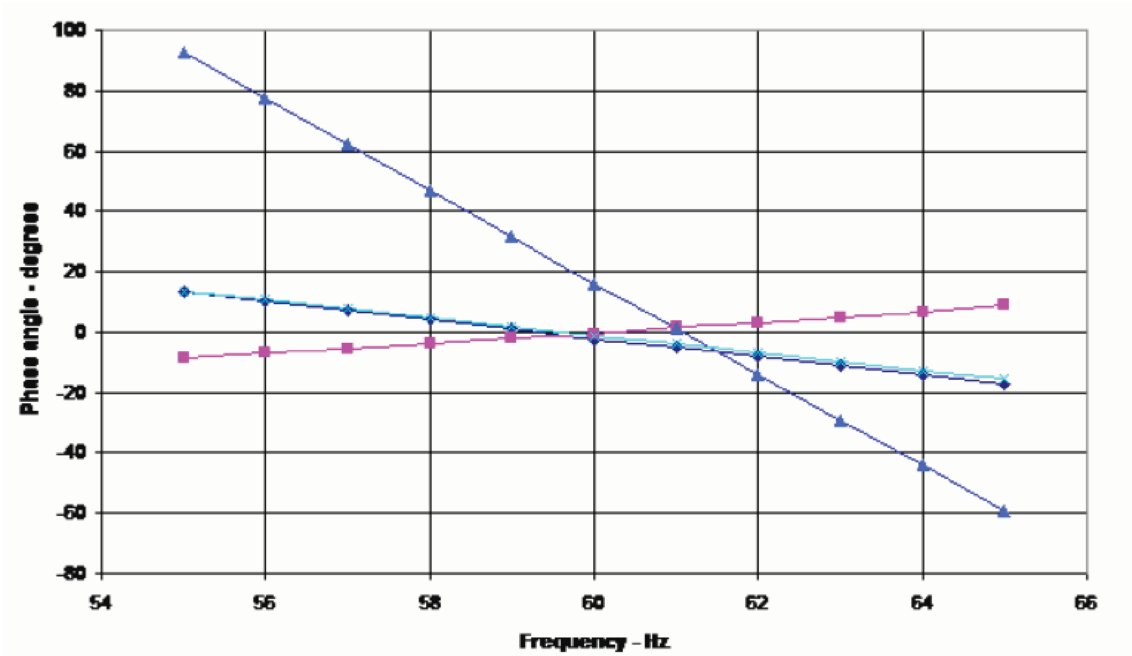


Figure 4.3 PMU Phase Angle Measurement Error for Different Vendor PMU [25]

4.4 The proposed method for calculating the reference angle difference

Based on the concerns presented in section 4.3 and considering there are multiple PMUs that have been installed in the power system, the following equation is proposed for the calculation of the reference angle difference.

$$\phi_{diff} = (\theta_{pmuA0\_vendor1} - \theta_{pmuAn\_vendor1} + \theta_{estAn}) - (\theta_{pmuB0\_vendor2} - \theta_{pmuBm\_vendor2} + \theta_{estBm}) \qquad (4.3)$$

where

$\theta_{pmuA0\_vendor1}$ and $\theta_{pmuB0\_vendor2}$ are the phasor angle measurements from area A and area B for the same variable, either current flow in the tie line or voltage angle on the shared bus.

$\theta_{pmuAn\_vendor1}$ and $\theta_{pmuBm\_vendor2}$ are the phasor angle measurements from area A and area B for one of the state of the local state estimation

θ_{estAn} and θ_{estBm} are the local estimated phase angle of bus n in area A and bus m in area B.

m and n can be the number of any bus in the sub-areas that has a PMU. This dissertation proposes these buses with PMU should also have good angle estimates by the local state estimation.

There are several issues to discussion with Equation 4.3.

1. This is a more generalized equation. When m and n equal to the reference bus number in each sub-area, equation (4.3) becomes equation (4.2). Please note that equation (4.2) can only be used when the correct PMU data from the reference bus can be successfully sent to the reliability coordinator.

2. When there is any fault in the reference PMU, the PMU will indicate that fault in the output signal. For example, the fault could be a failure in the D/A converter [35]. In this case, n and m have to be set to the other bus numbers with an available PMU.

3. This method allows using the best estimation based on certain placement of non-synchronized measurements and from the preliminary results, and it can provide good accuracy.

4. PMUs in different areas do not need to be in the same reference frame. This is considered, since all satellite broadcast systems are not placed for the purpose of time dissemination. During crises, such as a national emergency, their primary purpose takes priority and timing functionality has occasionally lost access [35]. At this time, a local broadcasting synchronized signal may be used.

5. Multiple PMUs can be used in local area. Hence if even one PMU data is missed, the reference angle difference can still be calculated. If all the PMU data is lost, the methods mentioned in reference [21] can be used.

6. Even if the fault signal of the PMU is not received by the coordinator, the calculation in [21] without considering PMU data should also be calculated to provide a certain level of validation.

7. Since there are usually many tie lines connecting two different areas, several of the tie line can be installed with PMUs.

The performance of this algorithm will be demonstrated in Chapter 5.

CHAPTER V

DEMONSTRATIONS USING MATLAB

The traditional SE and DSE with the proposed reference angle difference calculation method have been implemented in MATLAB and a real-time test bed for demonstration. This chapter discusses the implementation in MATLAB to demonstrate the performance of integrated state estimation (ISE) with and without PMU and distributed state estimation with and without PMU. Two methods of adding PMUs to integrated state estimation have been implemented. Three test cases have been used here and include the Ward Hale 6 bus test case, the IEEE 30 bus test case and the IEEE 118-bus test case. The flow chart for performing the SE and DSE, the way of forming the measurements and these test cases will be introduced as well as the results for each test case.

5.1 Flow Chart for Running SE and DSE in MATLAB

Figures 5.1 and 5.2 show the flow charts of running SE and DSE respectively. It can be seen that SE and DSE use the same sets of input data, in this case those are measurements, bus data and branch data. The difference is, in DSE, the input data will be divided into several parts according to which sub-area it belongs. Then SE will be done separately for each sub-area before the coordinator collects them, assemble them together to produce the estimates for the entire power system

5.2 Measurements for SE

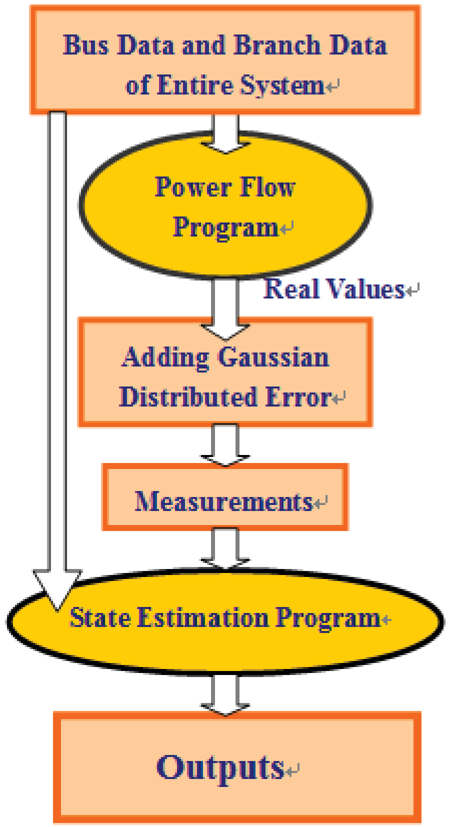


Figure 5.1 Flow Chart of Running SE in MATLAB

During operation of the power system, the state estimation algorithm collects a fixed amount of measurements at any time point to calculate all the variables for the corresponding system based on the topology of that system at that time point. Due to errors caused by the measurement instruments and signal transmission interference, the measurements may lose some accuracy. In our implementation of the state estimation, this factor has been considered as shown in the flow chart of Figures 5.1 and 5.2.

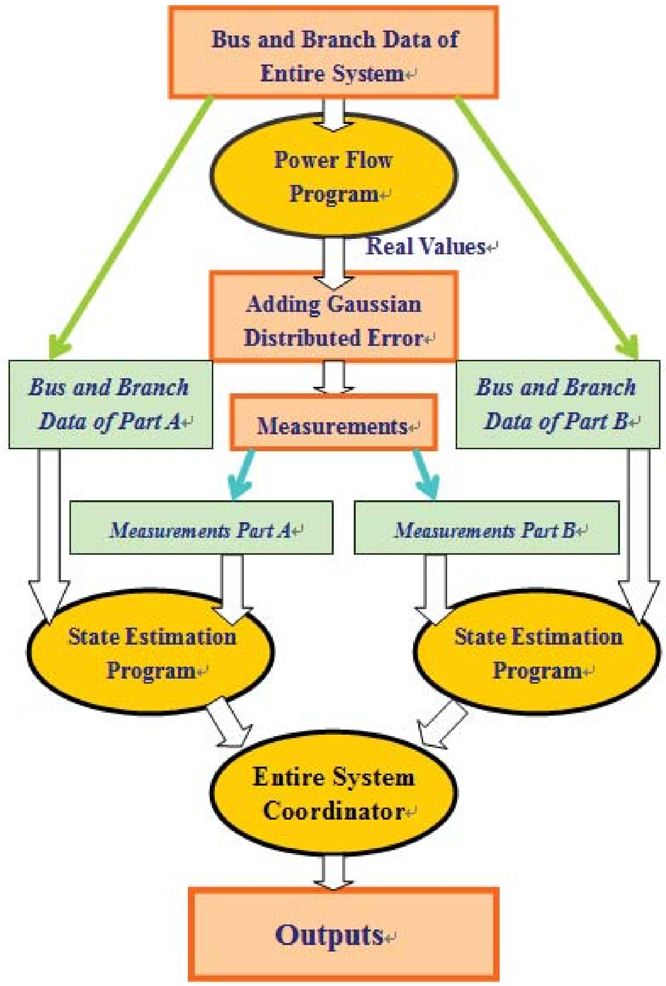


Figure 5.2 Flow Chart of Running DSE in MATLAB

A power flow program was developed in MATLAB to generate the exact value A_i for measurement Z_i corresponding to the measurements for each test case. Noise E_i will then be added to the exact values A_i calculated from the power flow program to generate the measurements for state estimation to use as shown in equation 5.1

$$E_i = randn_i * \delta_i * A_i \tag{5.1}$$

$$Z_i = A_i + E_i \tag{5.2}$$

where

i is the index of the measurements.

δ_i is the deviation.

$randn_i$ is the i_{th} element of the Gaussian distributed random generated array in MATLAB with standard deviation 1.0 and zero cross correlation. This length of the array is size (Z). The help file on function *randn* in MATLAB discusses how to calculate E_i with variance δ_i^2. The standard deviation δ used for each measurement in this research work is listed in table 5.1.

Table 5.1 Measurement Standard Deviation

Measurement Type	***Standard Deviation(*** δ ***)***
Conventional Bus Voltage	0.01
Conventional Power Injection	0.03
Conventional Power Flow	0.03
PMU Current Magnitude	0.0001
PMU Current Angle (radian)	0.000147
PMU Voltage Magnitude (radian)	0.0001
PMU Voltage Angle (radian)	0.000147

5.3 Criteria for a Robust State Estimation and Error Indices

The proposed criteria for a robust state estimation include:

1. The operation is as fast as possible so that SE can be done closer to real-time.

2. The method gives an optimally accurate solution for the state of the power system with given measurements.

3. The method can provide more information in case of data loss.

The L_1 norm [37] is the sum of the absolute value of all the residual of a vector. The residual of the vector is the absolute difference between estimated and actual vector. Since for a DSE, the state variables, the bus voltage magnitudes and angles estimated from the local SE will be used for the Coordinator in the DSE, their residual should be checked. In the demonstration, L_1 norm form of total states residual (equation 5.1), bus voltage residual (equation 5.2) and bus angle residual (equation 5.3) are presented.

$$L_1 \text{ norm\_states} = \sum \left| state\_est - state\_act \right| \tag{5.3}$$

$$L_1 \text{ norm\_voltage} = \sum \left| V_{mag}\_est - V_{mag}\_act \right| \tag{5.4}$$

$$L_1 \text{ norm\_angle} = \sum \left| V_{angle}\_est - V_{angle}\_act \right| \tag{5.5}$$

$state\_act$: Vector contains elements of actual states

$state\_estimated$: Vector contains elements of estimated states

V_{mag}_est : Vector contains elements of estimated bus voltage magnitude

V_{mag}_act : Vector contains elements of exact bus voltage magnitude

V_{angle}_est : Vector contains elements of estimated bus voltage angles

V_{angle}_act : Vector contains elements of exact bus voltage angles

The smaller the L_1 norm shown above, the more accurate the results are.

An alternative method would be to use the L_2 norm for calculating the differences between calculated and expected values. While not calculated in this particular work, it is also a viable method for error calculations.

5.4 Demonstrations on Six Bus Power System

5.4.1 Description on the Six Bus Test Case

The Ward-Hale 6 bus system is a simple power system test case shown in Figure 5.3. This test case contains the following components: two generators, seven lines and five loads.

Bus 1 is a swing bus or slack bus. Bus 2 is a PV bus. Buses 3, 4, 5 and 6 are PQ buses. The topology data for this test case is shown in Tables 5.2 and 5.3. Table 5.2 shows the bus data and Table 5.3 shows the branch data.

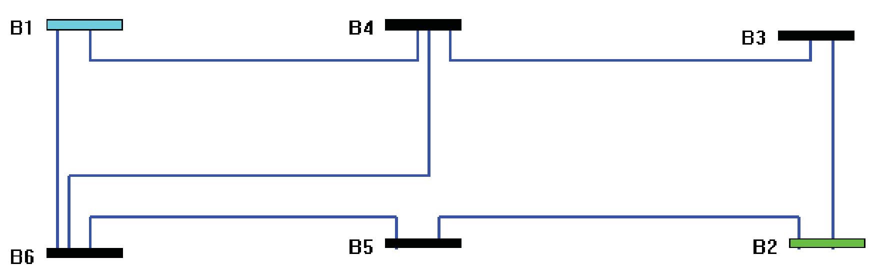


Figure 5.3 Ward-Hale Six Bus Power System [36]

Table 5.2 Bus Data for Entire Six Bus Power System

Bus No.	Type	Bus Voltage Magnitude |V| (pu)	Bus Voltage Angle (radian)	P_{gen} (pu)	Q_{gen} (pu)	P_{load} (pu)	Q_{load} (pu)
1	0	1.05	0	0	0	0.25	0.1
2	1	1.05	0	0.5	0	0.15	0.05
3	2	1.00	0	0	0	0.275	0.11
4	2	1.00	0	0	0	0	0
5	2	1.00	0	0	0	0.15	0.09
6	2	1.00	0	0	0	0.25	0.15

In Table 5.2, bus with type 0 indicates slack bus, bus with type 1 indicates PV bus and bus with type 2 indicates PQ bus. The bus voltage magnitudes and angles are the starting values for the WLS algorithm to converge to another set of estimated results. P_{gen} and Q_{gen} are the active power and reactive power generated by the generator on each bus. P_{load} and Q_{load} are the active power and reactive power consumed by the load on each bus. The unit for the angle is radian and the units for other quantities are pu. The base for the power is chosen as 100MVA and the base for the voltage is chosen as 1kV.

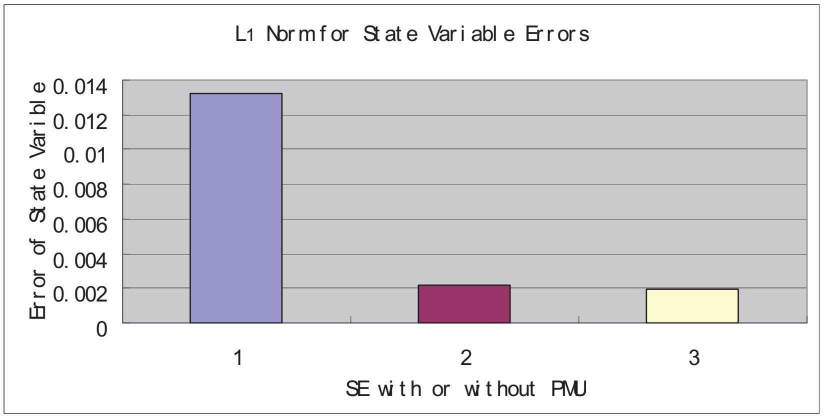
Table 5.3 Branch Data for Six Bus Power System

No.	To Bus No.	From Bus No.	R (pu)	X (pu)	B (pu)
1	1	4	0.020	0.185	0.009
2	1	6	0.031	0.259	0.010
3	2	3	0.006	0.025	0.000
4	2	5	0.071	0.320	0.015
5	4	6	0.024	0.204	0.010
6	3	4	0.075	0.067	0.000
7	5	6	0.025	0.150	0.017

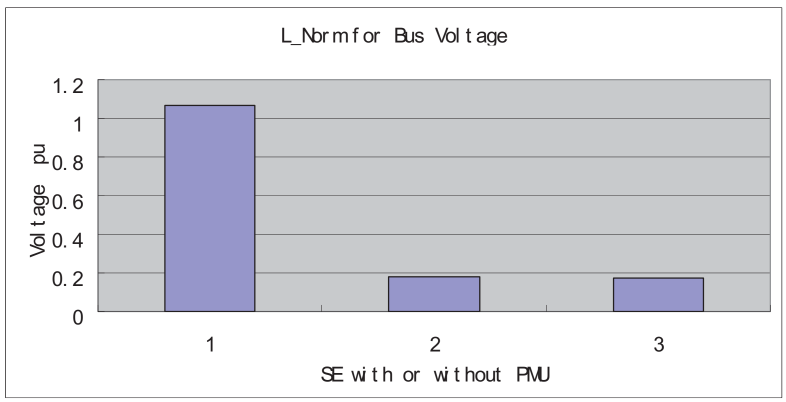
As shown in Table 5.3, seven rows in this table means there are seven lines in this power system. To Bus No. indicates the bus number that the line power flow flows from. From Bus No. indicates the bus number that the line power flow flows to. The order of the ‘To’ and ‘from’ bus number is the same as that of the power line flows generated in the power flow program and SE program. The explanation for the topology data is the same for all the three test cases.

5.4.2 Results Comparison for Test Case 1

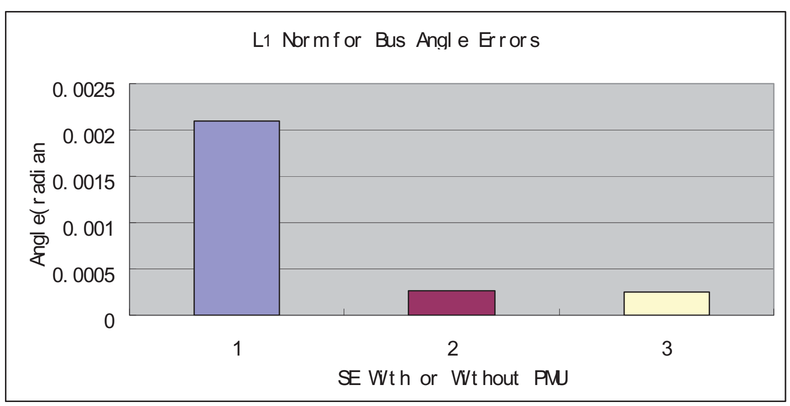
The SE cases with or without PMU have been implemented in MATLAB. L_1 norm Errors of the SE are shown in Figure 5.4, to demonstrate the benefit of adding PMU measurements in the SE algorithm. Two methods of adding PMU data are used. In (a), (b), and (c) of Figure 5.4, the numbers under the bars indicate the test cases. ‘1’ indicates SE without using PMU, ‘2’ indicates SE including PMU in the iterations and ‘3’ indicates SE algorithm with PMU data in the post processing part of the SE as introduced in Chapter 3. Figure 5.4 shows that adding PMUs to the SE algorithm improved the accuracy of the SE. It also showed that the two methods of adding PMU data produce similar accuracy for this system.



(a) L_1 Norm of Total State Variable Errors for SE



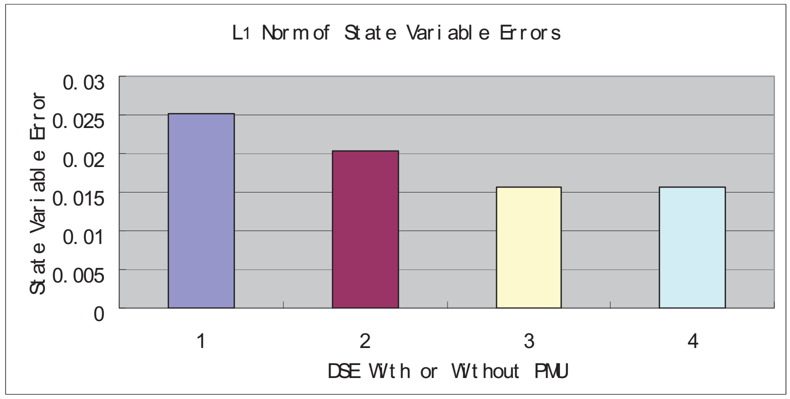
(b) L_1 Norm for Bus Voltage Errors for SE



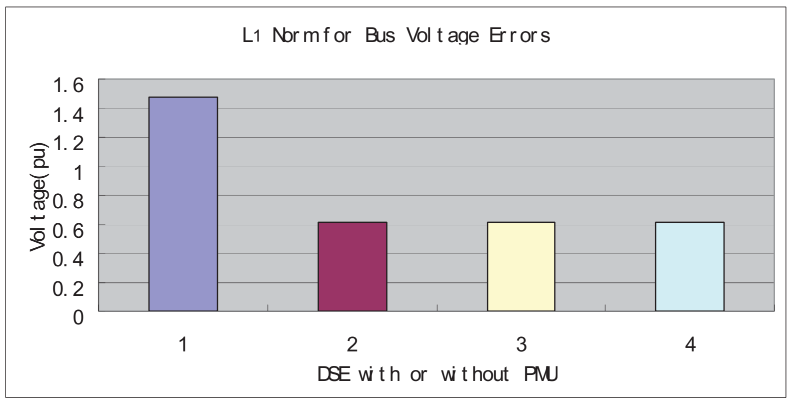
(c) L_1 Norm for Bus Angle Errors for SE

Figure 5.4 Comparison between SE for Test Case I: without PMU (Bar 1), with PMU pre-processing (Bar 2) and with PMU post-processing (Bar 3)

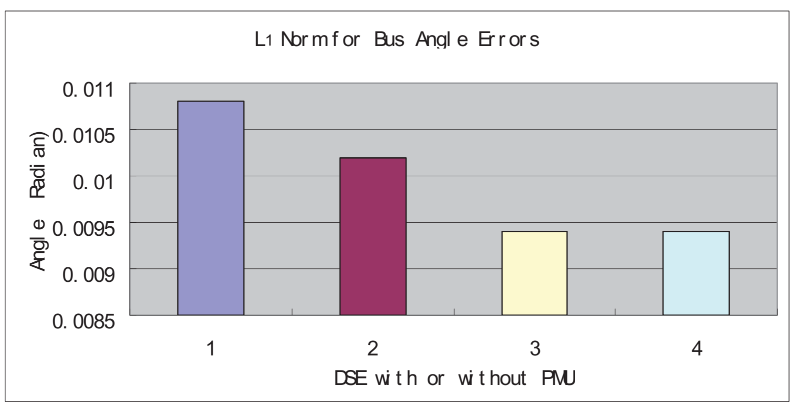
The PMU data has also been applied to DSE algorithm. Figure 5.5 shows the L_1 Norm Errors for DSE with or without PMUs in 6 bus power system. ‘1’ indicates the DSE without PMUs, ’2’ indicates the DSE with PMU in local state estimation, but without PMU in coordinator level, reference angle difference between areas is calculated using the estimated angles from the local state estimation. ‘3’ and ‘4’ indicate DSE using PMUs both in local state estimation and the coordinator level. PMUs are used to calculate the reference angle difference among areas. In particular, ‘3’ is the most accurate one, but it must use the PMUs from slack buses of the area. In case the PMU data from that specific slack bus is not available due to equipment failure or communication failure, alternative methods are needed to calculate the reference angle difference. This research work has proposed a novel way of using one PMU in any bus of each local area and one PMU from boundary bus. This method is represented as ‘4’ in the following figures.



(a) L_1 Norm of Total State Variable Errors for DSE



(b) L_1 Norm of Bus Voltage Errors for DSE



(c) L_1 Norm of Bus Angle Errors for DSE

Figure 5.5 Comparisons between DSE for Test Case I: without PMU (Bar 1), with PMU in Local State Estimations (Bar 2), with PMU both in Local and Coordinator where Direct Measurement Method are Used (Bar 3); with PMU both in Local and Coordinator where the Proposed Method are Used (Bar 4)

As shown in Figure 5.5, for six bus test case, by applying PMUs in the local state estimation, the accuracy of the algorithm is improved. To use '3' and '4' to calculate the reference angle difference, the final results will be even better. '4' produces compatible final results as '3'.

5.5 Demonstrations on Standard IEEE 30 Bus Power System

5.5.1 Test Case II

The IEEE 30 bus test case [37] represents a portion of the American Electric Power System (AEP). The test case was taken from University of Washington power system test case archive. The IEEE 30 bus system is shown by Figure 5.4.

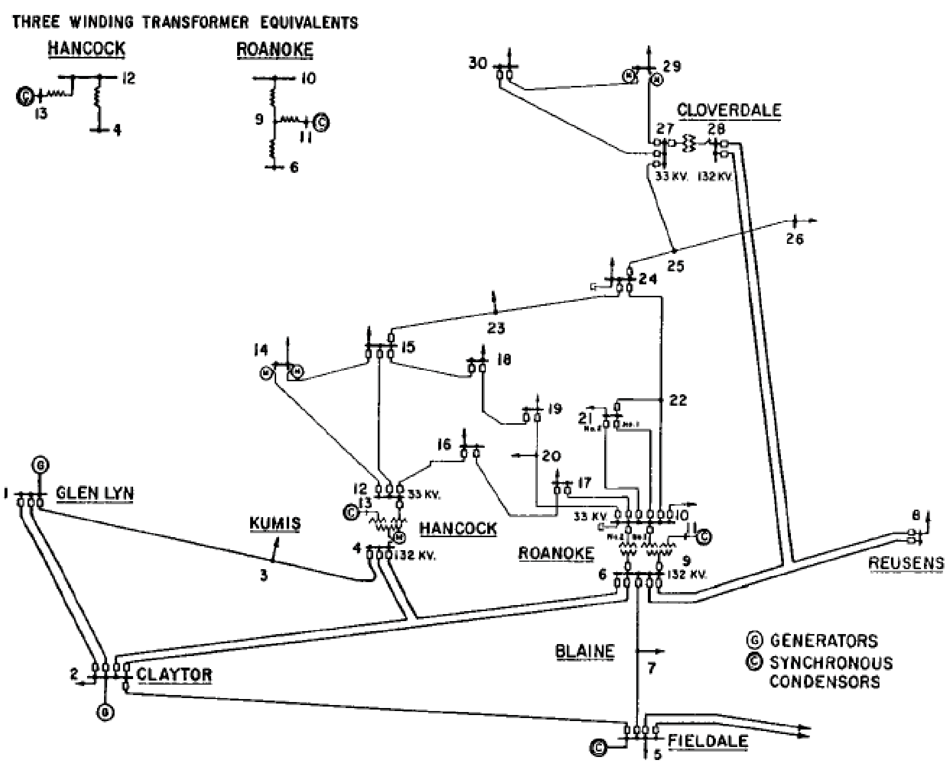


Figure 5.6 Test Case II

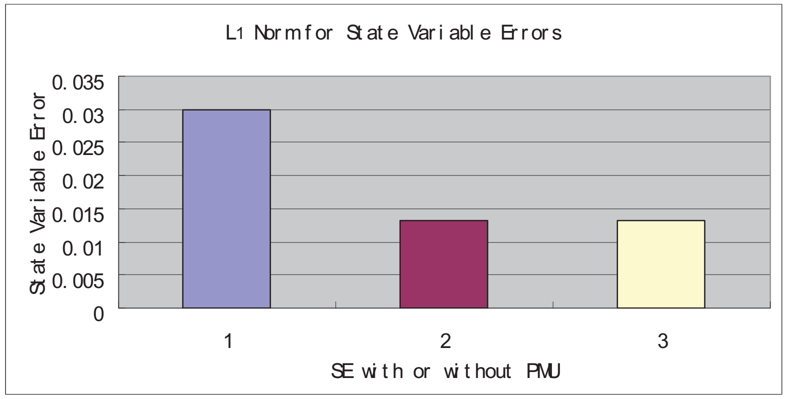
This test case contains:

1. Six generators
2. Four Transformers
3. Forty one transmission lines.
4. Twenty one loads.
5. Three synchronous condensers

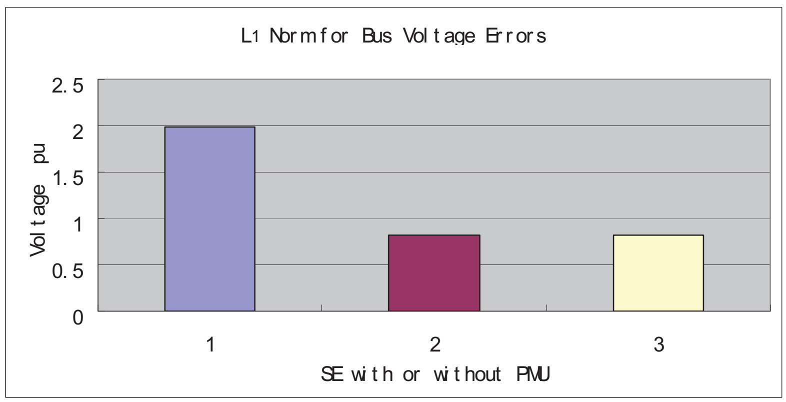
Bus 1 is a swing bus or slack bus.

5.5.2 Results Comparison for Test Case II

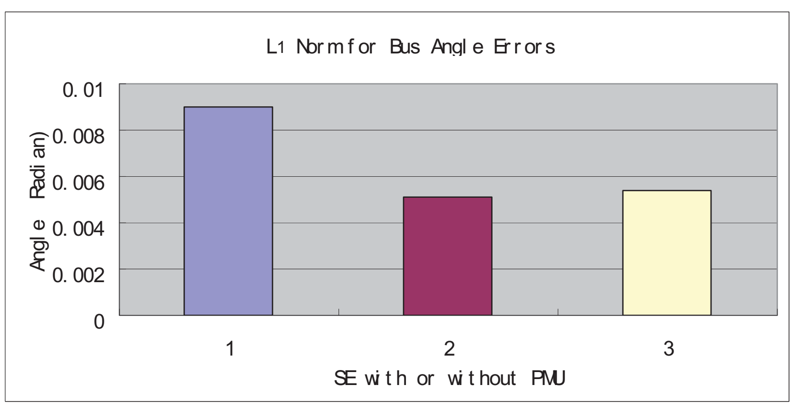
This section provides the results and the comparisons between SE and DSE with or without PMU for Test Case II. L_1 Norm Errors are shown in Figures 5.7 and 5.8 for test case II to show the benefit of adding PMU measurements in the SE and DSE algorithms. In (a), (b), and (c) in Figure 5.7, '1' indicates SE without using PMU, '2' indicates SE including PMU in the iterations and '3' indicates SE algorithm with PMU data in the post processing part of the SE. This shows that adding PMUs to the SE algorithm improved the accuracy of the SE. It also showed that the two methods of adding PMU data produce the same accuracy for the 30 bus test case.



(a) L_1 Norm of Total State Variable Errors for SE



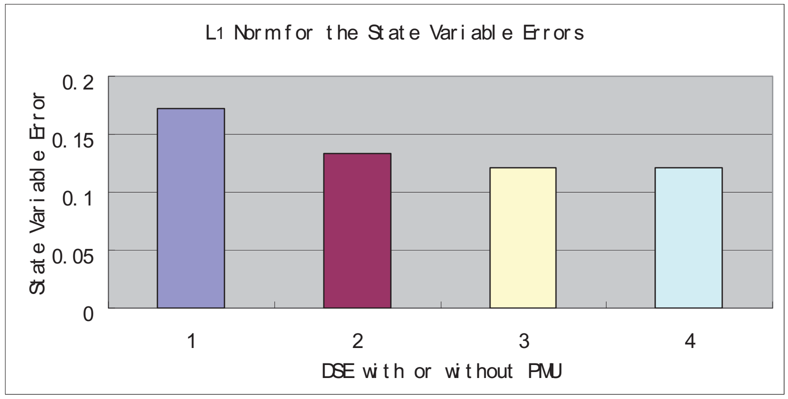
(b) L_1 Norm for Bus Voltage Errors for SE



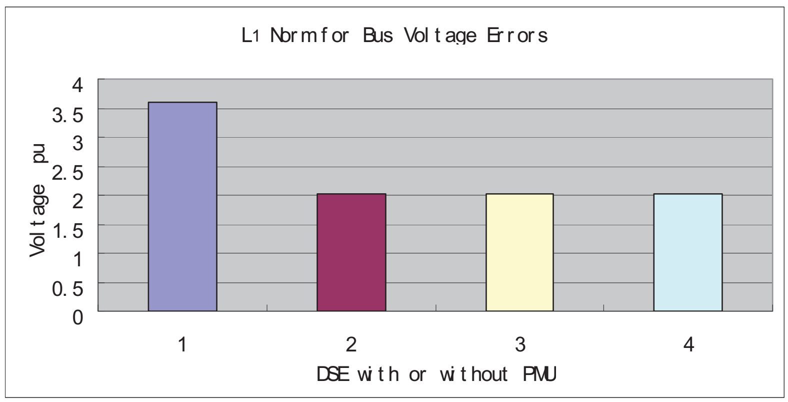
(c) L_1 Norm for Bus Angle Errors for SE

Figure 5.7 SE for Test Case II: without PMU (Bar 1), with PMU pre-processing (Bar 2) and with PMU post-processing (Bar 3)

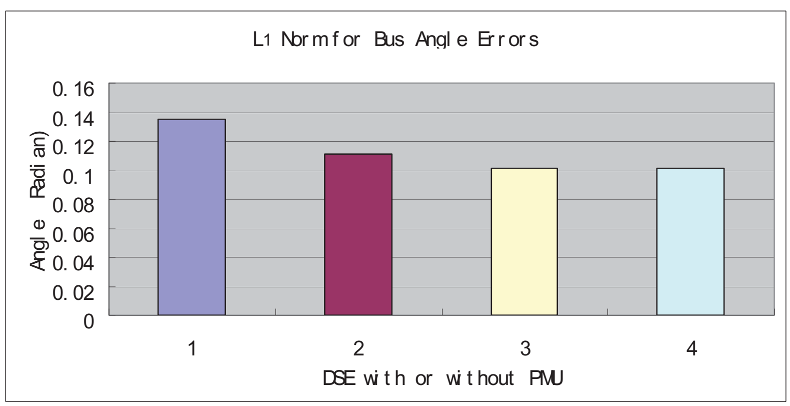
Figure 5.8 shows the L_1 norm errors for DSE with or without PMUs in 30 bus power system. The notation of this Figure is the same as the DSE in test case I, where '1' indicates the DSE without PMUs, '2' indicates the DSE with PMU only in local state estimation, reference angle difference between areas is calculated using the estimated angles from the local state estimation. '3' and '4' indicate DSE using PMUs both in local state estimation and the coordinator level.



(a) L_1 Norm of Total State Variable Errors for DSE



(b) L_1 Norm for Bus Voltage Errors for DSE



(c) L_1 Norm for Bus Angle Errors for DSE

Figure 5.8 Comparisons between DSE for Test Case II: without PMU (Bar 1), with PMU in Local State Estimations (Bar 2), with PMU both in Local and Coordinator where Direct Measurement Method are Used (Bar 3); with PMU both in Local and Coordinator where the Proposed Method are Used (Bar 4)

As shown in Figure 5.8, for 30 bus test case, by applying PMUs in the local state estimation, the accuracy of the algorithm is improved. Using ‘3’ and ‘4’ to calculate the reference angle difference, the final results will be even better. ‘4’ produces compatible final results as ‘3’.

5.6 Demonstrations on Standard IEEE 118-bus Power System

5.6.1 Test Case III

The IEEE 118-bus Test Case represents a portion of the American Electric Power System (in the Midwestern US) [38]. It is commonly used in demonstration by the power system engineers.

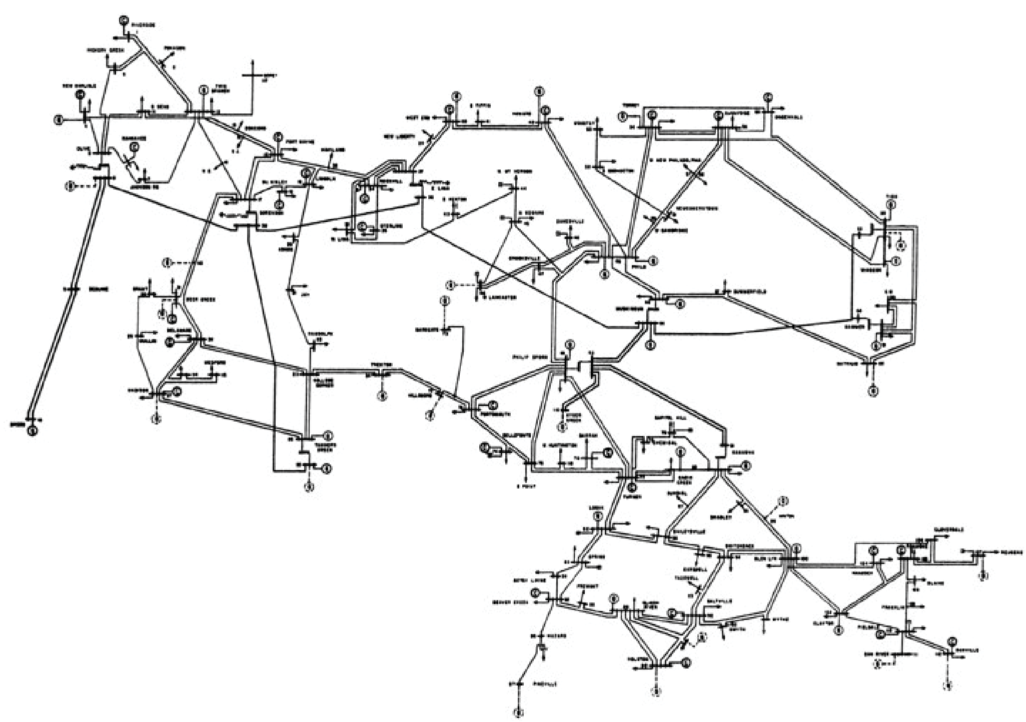
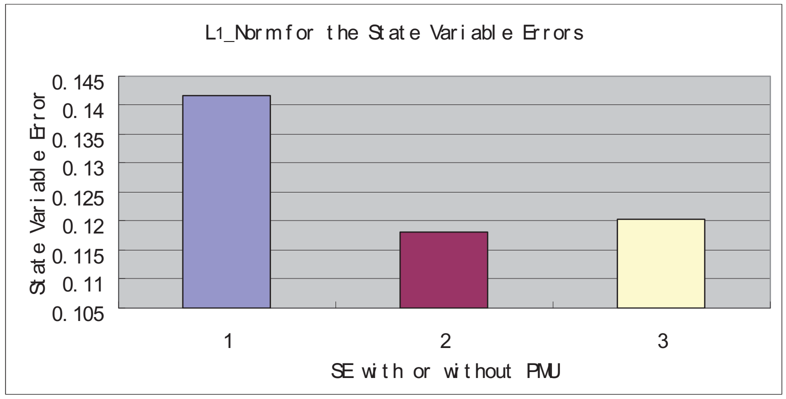


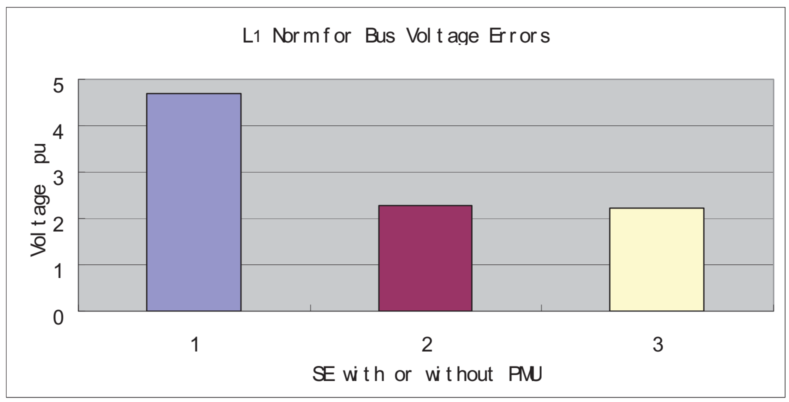
Figure 5.9 Test Case III [38]

5.6.2 *Results Comparison for Test Case III*

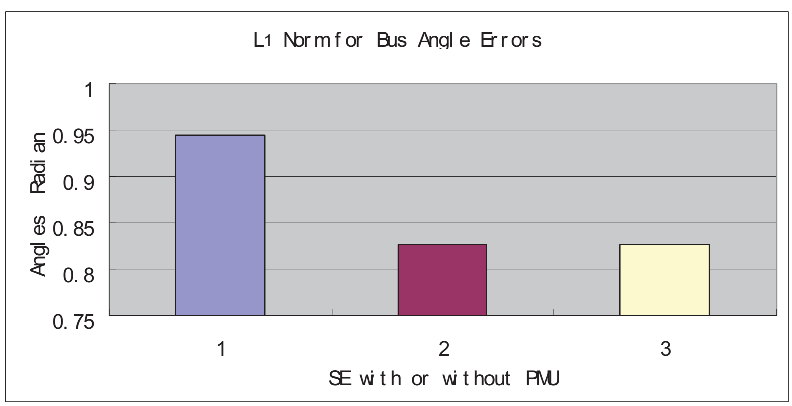
The section shows the results comparison for test case III between SE and DSE with or without PMU. Figure 5.10 and Figure 5.11 shows the L_1 norm values SE and DSE runs for test case III. In (a), (b), and (c) in Figure 5.10, ‘1’ indicates SE without using PMU, ‘2’ indicates SE including PMU in the iterations and ‘3’ indicates SE algorithm with PMU data in the post processing part of the SE. This figure also shows that adding PMUs to the SE algorithm improved the accuracy of the SE. It shows that the two methods of adding PMU data produce the same accuracy.



(a) L_1 Norm of Total State Variable Errors for SE



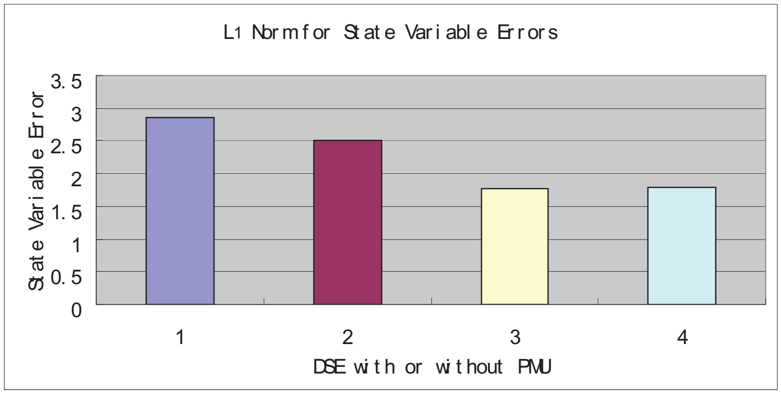
(b) L_1 Norm for Bus Voltage Errors for SE



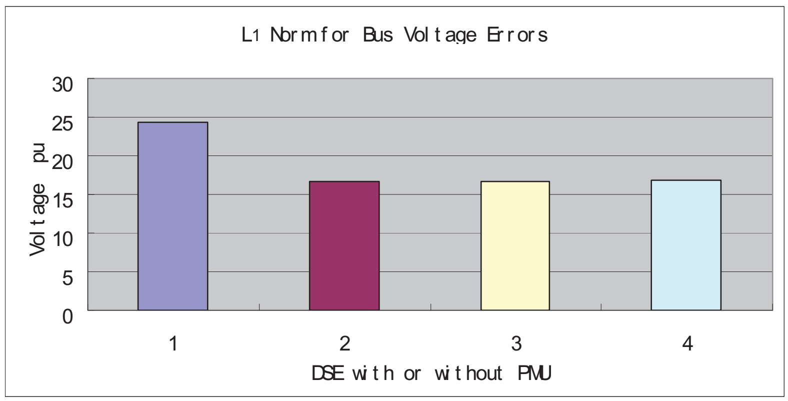
(c) L_1 Norm for Bus Angle Errors for SE

Figure 5.10 SE for Test Case III: without PMU (Bar 1), with PMU pre-processing (Bar 2) and with PMU post-processing (Bar 3)

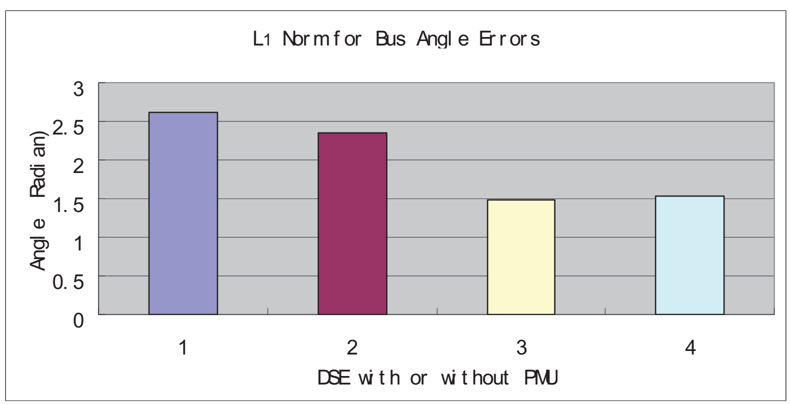
Figure 5.11 shows the L_1 norm Errors for DSE with or without PMUs in 118-bus power system. The notation of this figure is the same as the DSE in previous test cases, where ‘1’ indicates the DSE without PMUs, ’2’ indicates the DSE with PMU only in local state estimation, reference angle difference between areas is calculated using the estimated angles from the local state estimation. ‘3’ and ‘4’ indicate DSE using PMUs both in local state estimation and the coordinator level.



(a) L_1 Norm of Total State Variable Errors for DSE



(b) L_1 Norm for Bus Voltage Errors for DSE



(c) L_1 Norm for Bus Angle Errors for DSE

Figure 5.11 Comparisons between DSE for Test Case III: without PMU (Bar 1), with PMU in Local State Estimations (Bar 2), with PMU both in Local and Coordinator where Direct Measurement Method are Used (Bar 3); with PMU both in Local and Coordinator where the Proposed Method are Used (Bar 4)

As shown in Figure 5.11, for 118-bus test case, by applying PMUs in the local state estimation, the accuracy of the algorithms is improved. ‘4’ produces compatible final results as ‘3’.

5.7 Algorithm Running Speed Comparison

Figures 5.12 to 5.14 show the time for each algorithm to estimate the entire test case. Figure 5.12 is for test case I. Figure 5.13 is for test case II. Figure 5.14 is for test case III. For the figures, ‘1’ indicate SE without PMU; ‘2’ and ‘3’ indicate SE with PMU mixed-processing and post-processing; ‘4’ indicates DSE using no PMU; ‘5’ indicates DSE using the PMU only in local area and ‘6’ indicates DSE using PMUs both in local area and the coordinator.

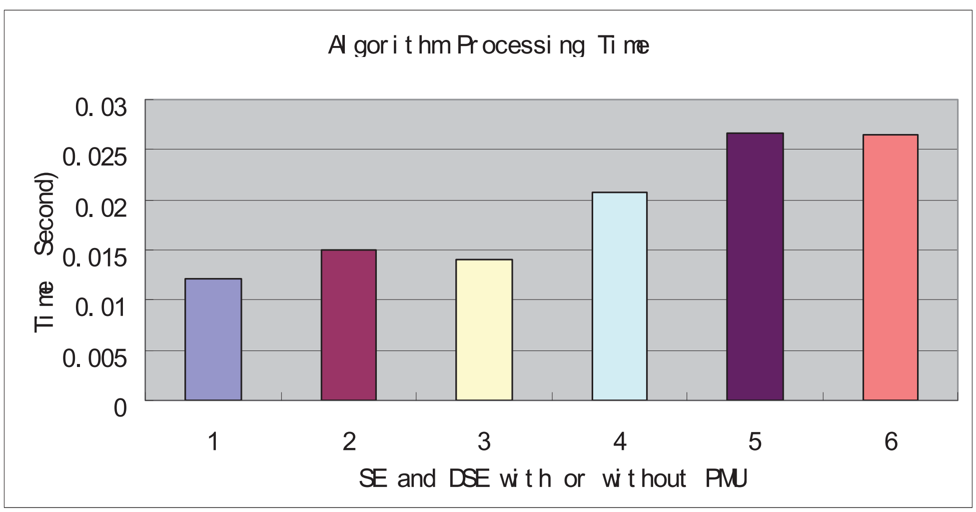


Figure 5.12 Comparisons in Six Bus Power System

Where ‘1’ indicate SE without PMU; ‘2’ and ‘3’ indicate SE with PMU mixed-processing and post-processing respectively; ‘4’ indicates DSE using no PMU; ‘5’ indicate DSE using PMU only in local area and ‘6’ indicates DSE using PMUs both in local area and the coordinator

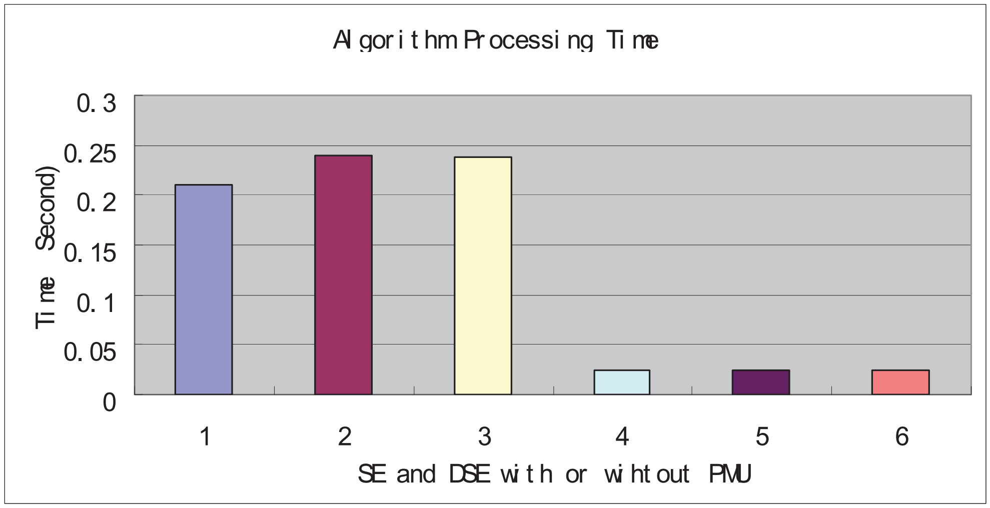


Figure 5.13 Comparisons in 30-bus Power System

Where '1' indicate SE without PMU; '2' and '3' indicate SE with PMU mixed-processing and post-processing respectively; '4' indicates DSE using no PMU; '5' indicate DSE using PMU only in local area and '6' indicates DSE using PMUs both in local area and the coordinator

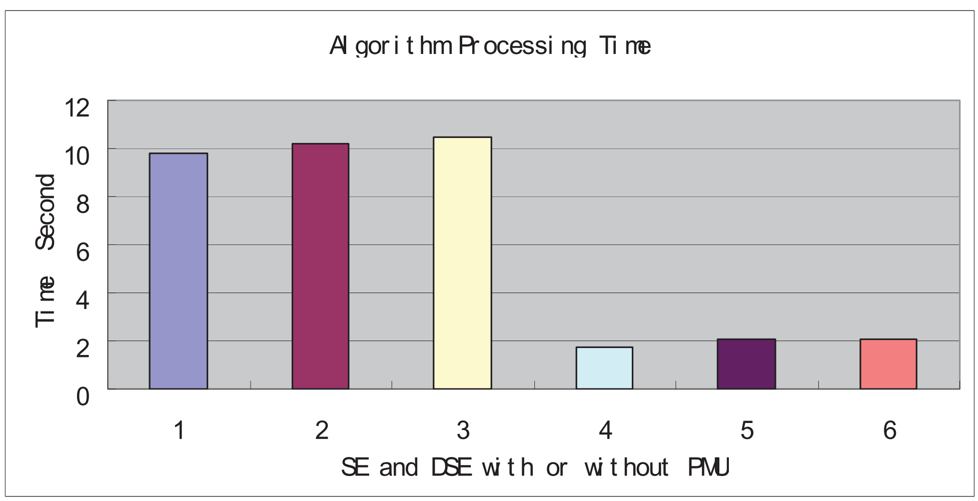


Figure 5.14 Comparisons in 118-bus Power System

Where '1' indicate SE without PMU; '2' and '3' indicate SE with PMU mixed-processing and post-processing respectively; '4' indicates DSE using no PMU; '5' indicate DSE using PMU only in local area and '6' indicates DSE using PMUs both in local area and the coordinator

The above figures show that for a larger system, the benefit is that DSE can save time of processing the algorithm is most obvious. This is because SE takes a lot more time for larger systems than for smaller systems. As shown in above figures, for 118 bus system, the time savings are several seconds. For small test case like the 6-bus one, the time benefit is overwhelmed by other factors. But in reality, normal power systems have thousands of buses. The time savings can be significant for those cases. Also, time cost for communication between local area and the coordinator should be considered. In the DSE implemented in this research work, each time of estimating the entire power system, data should be transmitted from the local area to the coordinator once. Moreover, the data scanning for different areas can take place in the same time in the case of DSE. Currently, the common scanning time of for a substation level is 2-10 seconds and for control center level, it will take several minutes [3].

5.8 Algorithm Accuracy Comparison between SE and DSE

Figures 15 to 17 compare the L_1 norm of state variable errors between SE and DSE. For these figures, '1' indicate SE without PMU; '2' indicates SE with PMU; '3' indicates DSE using no PMU; '4' indicates DSE using PMUs both in local area and the coordinator for each of the test cases.

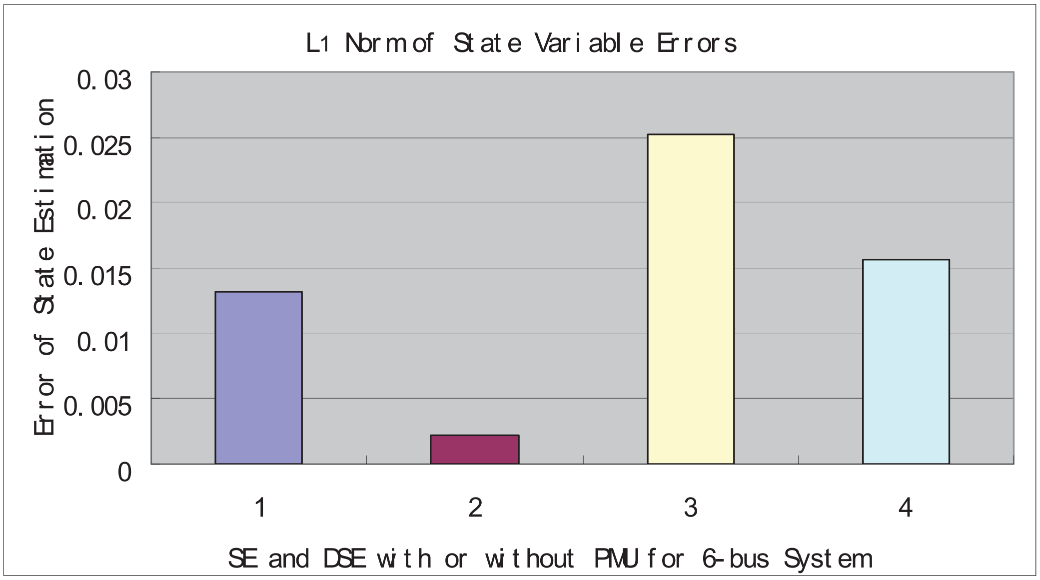


Figure 5.15 Accuracy Comparisons between SE and DSE for 6-Bus System

Where ‘1’ indicate SE without PMU; ‘2’ indicates SE with PMU; ‘3’ indicates DSE using no PMU; ‘4’ indicates DSE using PMUs both in local area and the coordinator

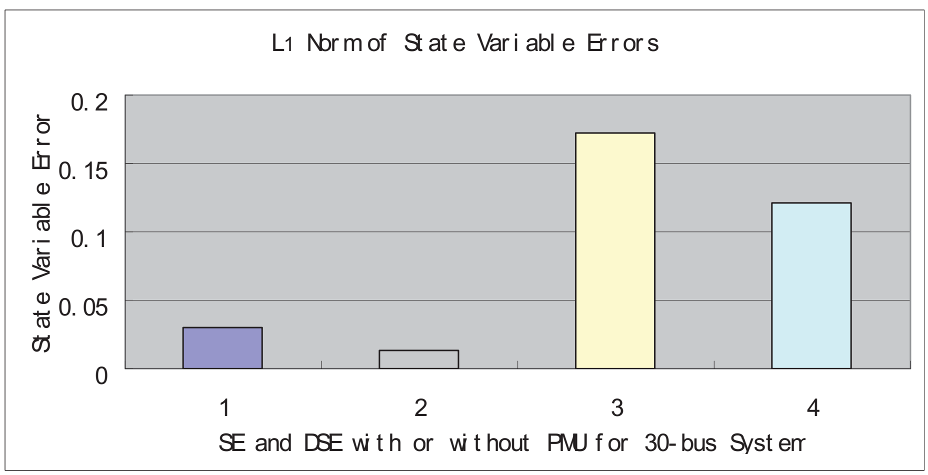


Figure 5.16 Accuracy Comparisons between SE and DSE for 30-Bus System

Where ‘1’ indicate SE without PMU; ‘2’ indicates SE with PMU; ‘3’ indicates DSE using no PMU; ‘4’ indicates DSE using PMUs both in local area and the coordinator

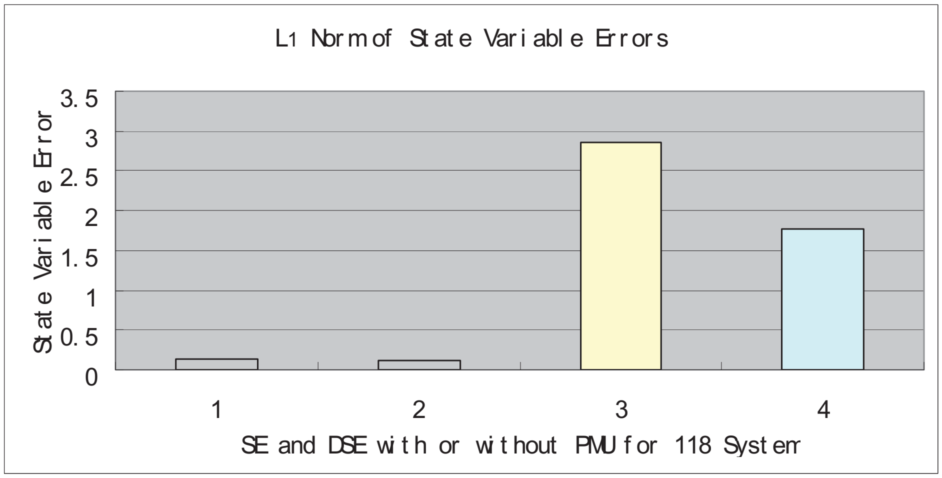


Figure 5.17 Accuracy Comparisons between SE and DSE for 118-Bus System

Where '1' indicate SE without PMU; '2' indicates SE with PMU; '3' indicates DSE using no PMU; '4' indicates DSE using PMUs both in local area and the coordinator

The DSE shows a larger error than the SE in each test case. There are two reasons. One is because in this research work, both SE and DSE are using the same number of measurements including traditional measurements and PMU measurements. Because the WLS algorithm in the local area of DSE is local optimal, local SE will produce results with bigger errors [6]. Second, in reality, the area state estimation should have better equivalent equations to represent their neighboring power system, and the DSE results will be better in that case [6]. However, as shown in section 5.7, DSE can provide more robust and faster results than SE, so DSE should be used to prevent the system failure from cascading to a wider area. By adding more PMUs in DSE, the accuracy of DSE will be improved.

5.9 Summary

In this chapter, results of the implementation of the SE and DSE with or without PMU have been presented for a 6-bus test case, 30-bus test case and 118-bus test case. For all the systems, adding PMUs to the SE can make the output more accurate. DSE needs much less processing time than SE for the two larger (>=30 bus) systems in this dissertation. One emphasis is to compare the performance of methods of calculating the reference angle difference in coordinator level of DSE. The method that was proposed in this thesis has competitive accuracy as the direct measured one. This method does not require the measurements from the slack bus to produce the reference angle difference among areas. The accuracy of the DSE also depends on the accuracy of the equivalent model for the connected power system, how the system been decomposed, and how many PMUs have been applied. Since the WLS is a local optimal algorithm, the DSE will not produce the same accuracy as SE in case of same amount of certain measurements. In this research work, for a same test case the measurements used in SE and DSE are the same. However, if the local area can get better estimates by fully using raw measurements at the substation level which has been introduced in chapter 3, the local state estimation can produce much better results. At this time, with an accurate reference angle difference, the accuracy of DSE can be significantly improved. SE on the ISO level, by the definition, is not supposed to make use of the raw data in the substation. Furthermore, the DSE can provide results much more frequently than the SE does and it is more robust than SE for a large sized power system which has been discussed in previous chapters.

CHAPTER VI

DEMONSTRATIONS ON THE ONLINE RTDS TEST BED

State Estimation is utilized for real time power system monitoring. The importance of State Estimation has been discussed in Chapters 1 and 2. This monitoring process needs to be robust and accurate. However, in the real world, it is normal that unexpected things may happen dynamically. For example, more and more new technologies are being applied in the power system. Will they be compatible with the proposed distributed state estimation algorithm? In order to avoid costly damage of the power system, the new technologies need to be thoroughly evaluated before integrating them into the system. For this research work a test bed has been built that allows the user to investigate the effects of disturbances on the monitoring system to ensure the monitoring system produces a quick and accurate profile of the power system. A real time test bed has been developed to simulate and validate the proposed monitoring system using Distributed State Estimation.

6.1 Block Diagram of the Real-time Test Bed

In this work, a real-time test bed was developed for testing and validating the proposed distributed state estimation with hardware PMUs. The architecture of this test bed is shown in Figure 6.1.

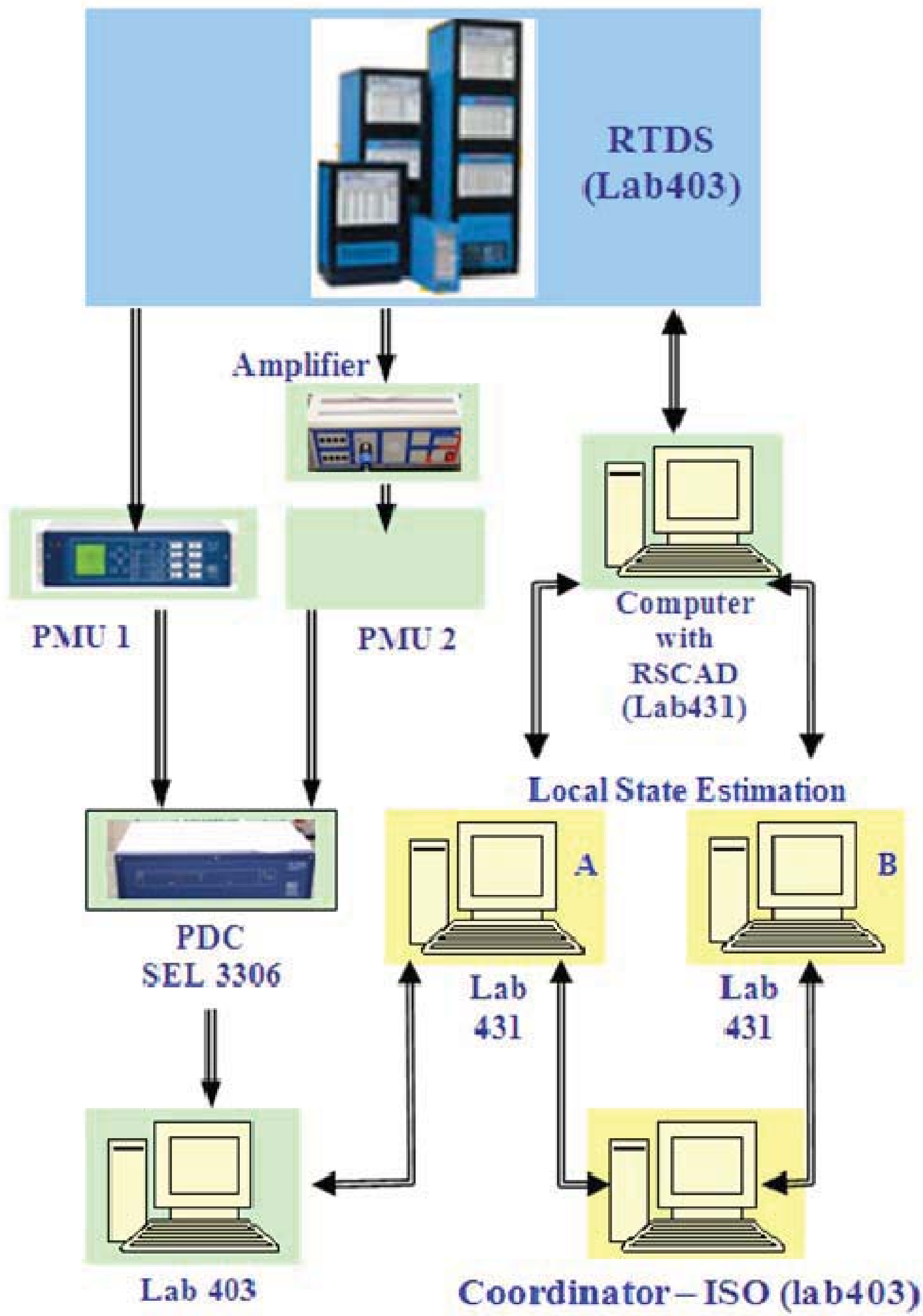


Figure 6.1 Block Diagram of the Test Bed

There are three layers in this real-time test bed shown in Figure 6.1. The first layer is the test case layer with blue background on the top in Figure 6.1. The 6-bus power system used in Chapter 5 has been implemented here in the real time digital simulator (RTDS). The components with green background make the second layer, measurement layer. The measurements collected from this layer will be sent to the DSE layer for calculation. One computer, located in SIMRAL Lab 431, with the green background in Figure 6.1 collects all the virtual measurements including conventional measurements and virtual PMU measurements from the RTDS. The other computer, located in a different location, SIMRAL Lab 403 with green background collects the measurements from the real measurement device PMUs. The third layer is the distributed state estimation layer with yellow background. In this layer, the distributed state estimation (DSE) is implemented in MATLAB script in the three computers, where two of the computers (A and B) work as local control centers to perform local state estimation and the other computer, the computer in lab 403 with yellow background in Figure 6.1, works as the Coordinator (namely ISO) to receive the estimated outputs from local control centers. All the computers in this test bed communicate with each other through the middleware embedded in MATLAB.

6.2 Building and Testing the Test Case using RSCAD in Test Case Layer

The 6-bus test case as introduced in Chapter 5 was first built in the RSCAD for the RTDS. To ensure the system has been built correctly, the results of the load flow of this system in RSCAD are compared with the load flow results in another software power education toolbox (P.E.T) as shown in Figure 6.2.

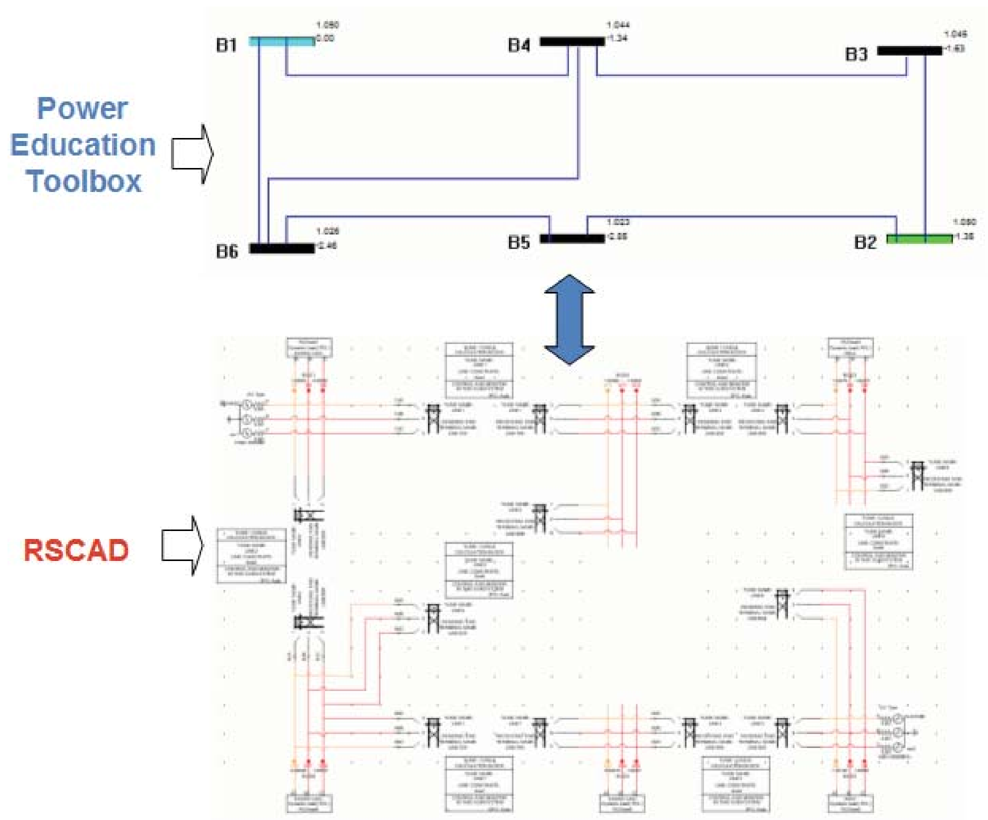


Figure 6.2 The Power System Simulated in RTDS

The power system in Figure 6.2 was simulated in both P.E.T and RSCAD. Figure 6.3 shows the comparison example for the PV bus – bus two. Figure 6.4 shows the comparison for the slack bus.

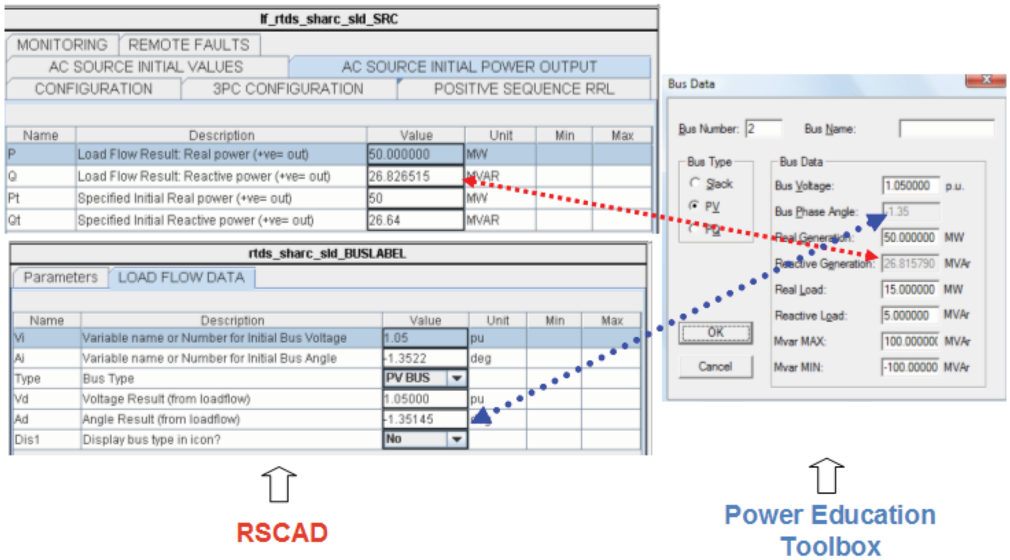


Figure 6.3 Load Flow Results Comparison for PV Bus

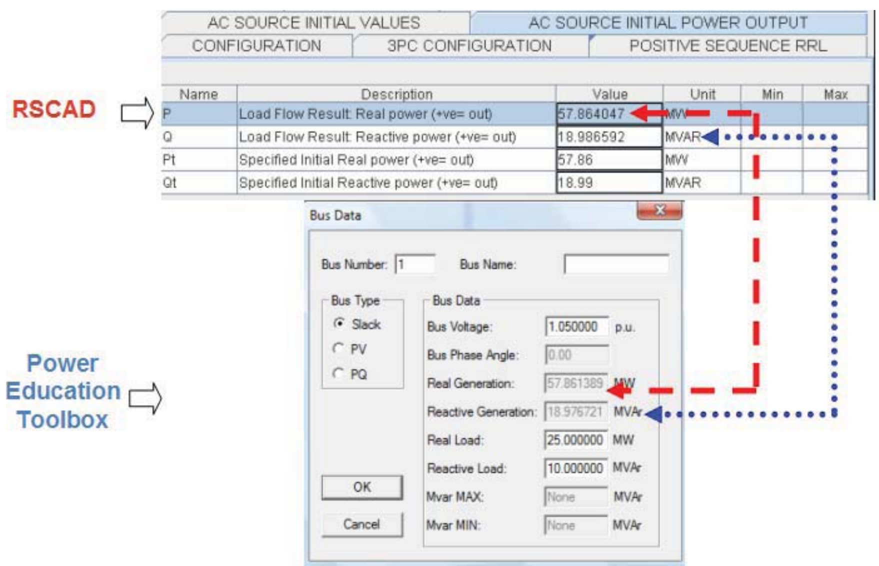


Figure 6.4 Load Flow Results Comparison for Slack Bus – Bus1

It can be seen from Figures 6.3 and 6.4 that the values on the two sides of the two-directional arrow are the same, which means the load flow of test case built in RSCAD produces correct results.

6.3 Measurements Generation

By following the method of the DSE for six-bus power system in MATLAB, there are 18 measurements generated. Most of the measurements are generated by adding a random measurement error to the results from the simulation of the RTDS. The hardware PMUs provide the phasor information for the reference buses in the two subsystems and have been involved in both local state estimation and cooperator.

The general introduction to PMU has been presented in previous chapter. Two integrated hardware PMUs have been in this stage of the test bed. These two integrated hardware PMUs are D60 from General Electric (GE) and SEL421 from Schweitzer Engineering Laboratories, Inc (SEL). These two integrated PMUs are also relays used in protection. The synchrophasor functions provided by these two integrated PMUs adhere to IEEE's C37.118 standard. The detailed connection diagram of these integrated PMUs in this test bed is shown in Figure 6.1.

6.4 Script Files

To generate the measurements for the state estimation or distributed state estimation to use, a script file is developed in the RTDS test bed. The script in RSCAD need to obtain the required quantities from the test case that is being simulated in the RTDS. Then add the errors to the measurements using the given standard deviation. Finally it records the measurements in the format that SE or DSE can read.

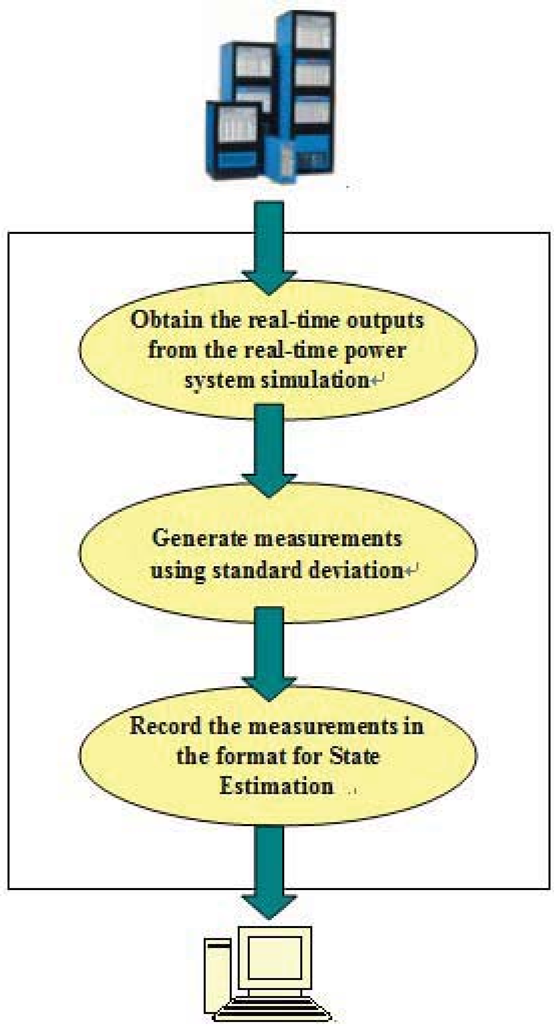


Figure 6.5 Flow Chart of the Script

It turns out the values of the quantities obtained by the script is the same as those got by RSCAD

6.5 Operation Steps and Results

The lab setup is shown in Figure 6.1 and the operation step should be as follows:

1. Run the real time simulation of the test case in RTDS. The virtual measurements from RTDS will be recorded during each loop of the RTDS script.

2. Record the hardware PMU measurements.

3. Run the state estimation or distributed state estimation.

By following the above steps, tests have been done for SE with PMU and DSE with PMU. The results agree with what was found in Chapter 5.

First, the PMUs from different vendors are integrated in the test bed as shown in Figure 6.1. The phasor measurements displayed by synchrophasor HMI (Human Machine Interface) provided by SEL, are shown in Figure 6.6.

In Figure 6.6, there are two small synchrophasor HMI windows. These two windows show the same set of phasor values from the PMUs in different time point. For a same bus voltage variable V1LPM, Blue broken line shows that the magnitude is almost constant. Red broken line and green broken line show that the measured angle is not constant to time since the angle refers to the GPS signal that change along with time. This verifies that when providing PMU angle measurements to the SE or DSE to use, at least two PMUs should be used. These two PMUs should also come from a same vendor according to the findings in chapter 4. To verify the constant measurement difference by different vendors, four PMUs, (two from one vendor, the other two from the other vendor), are needed.

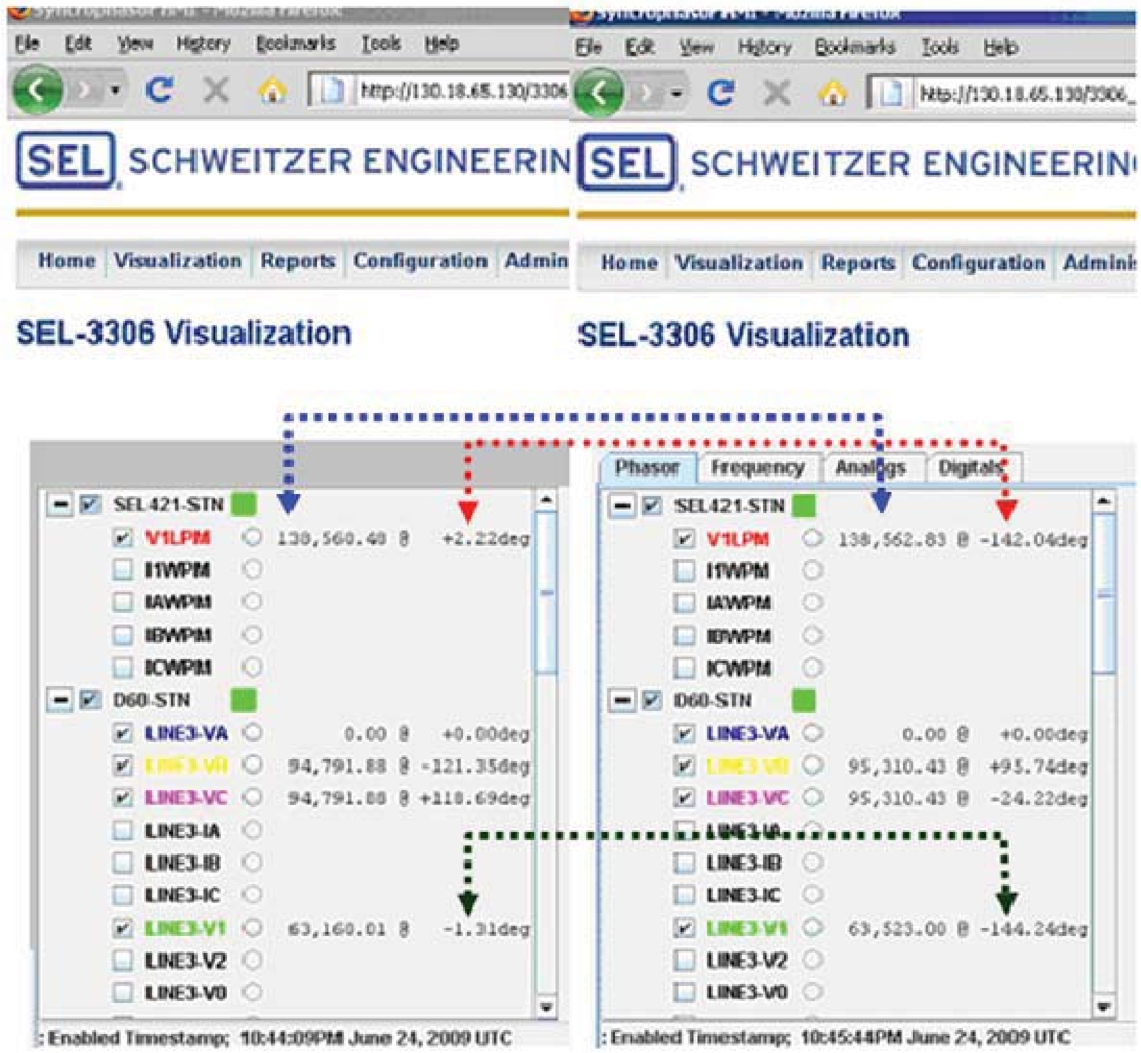


Figure 6.6 Phasor Measurements from the PMU

6.6 Discussion and Summary

The virtual measurements are randomly generated based on the results of the real time simulation from the RTDS. The measurements are the inputs of the distributed state estimation, so each time the estimated error is not the same. Each estimated errors found from this test bed introduced in this chapter are close to the estimated error from the distributed state estimation of the same six bus power system performed in MATLAB.

In this chapter, the real time test bed using the RTDS was built and an online distributed state estimation has been done on the test bed for a six bus power system with hardware PMU involved.

CHAPTER VII

CONCLUSIONS AND FUTURE WORK

7.1 Objective and Contributions

This dissertation examined several aspects of concern for wide area monitoring and control of power system. It was revealed from the 2003 North American blackout that the control area operators had little visibility of systems beyond their respective areas and reliability coordinators did not have real-time monitoring capability of their region of systems. A hierarchical structured distributed State Estimation with a modular feature could be the primary solution for a deregulated power system in terms of wide area monitoring. Furthermore, power system information infrastructure is progressing towards systems that are supporting a future smart grid with more decentralized, distributed, flexible and open control centers. This will provide a welcomed environment for applying DSE in the future. DSE has been progressing in recent decades. Especially in recent years, the application of PMUs to the power system greatly enhances the visibility and accuracy for the snapshot of the system. In the coordination level of the DSE, the relative angle difference between the slack buses in local areas needs to be used to tie the sub-systems together. The existing calculation of the angle difference relies on the PMU measurements of the slack bus. This dissertation has proposed a way to calculate this angle difference in a compatible accurate way. This method can be used in case equipment or communication failure causes the PMU data on specific buses to be unavailable. The design of this method also considered the realistic factors in the power industry, for example, different utilities may use the PMUs from different vendors on their own part of power system. The new method can resolve the constant angle measurement difference that may occur in the PMUs from different vendors. This method has been implemented in the SE with PMU and DSE with PMU and tested in MATLAB. A hardware based real-time test bed has also been built by the author to test the SE and DSE algorithms using PMUs from different vendors.

Within this dissertation research the following accomplishments and conclusions were obtained:

1. Using three IEEE test cases, the implementations of SE and DSE, both with and without PMUs as well as using various algorithm methods, were studied to examine the error and timing differences. From the tests, it was demonstrated that
    a. Both DSE and SE methods improved with PMU data.
    b. The DSE timing benefits became more apparent with the larger two systems where the distributed, parallel nature of the computational methods was used.
    c. The DSE methods were more robust when some data was missing as parts of the system could be solved instead of having a failure to converge for the overall system.
    d. The proposed method of computing the reference angle difference in DSE can provide as accurate solutions as the one using direct measurements.

2. A real-time Supervisory Control and Data Acquisition test bed with distributed measurements and computational resources was designed and implemented. This test bed implementation demonstrated the following outcomes:
    a. The test bed combined different PMU types with the real-time system to simulate the six bus test case that was analyzed as described in #1 above.
    b. By combining the test bed with the distributed computational resources, this project validated the proposed DSE algorithm using hardware-in-the-loop PMUs with a RTDS based test case.

These outcomes provide additional insights into how future smart grid applications will combine distributed information across multiple electric utilities into a comprehensive system snapshot that will allow power engineers to do local control as well as regional coordinators to manage interconnected systems.

7.2 Future study

This work has completed a real-time Supervisory Control and Data Acquisition (SCADA) test bed in the Power and Energy Research Lab (PERL), Mississippi State University. Algorithms of SE and DSE based on Weight Least Square (WLS) have been implemented in this test bed. Other methods such as Least Absolute Value (LAV) could be implemented in the SE and DSE algorithms and be tested on the test bed. Study of the DSE for unbalanced power systems, and the study of DSE time skew related to non-synchronized area SEs would be the next topic. It is also necessary to theoretically obtain the relation between computational time vs. number of parallel computer (processors) and verify with experimental results. Larger power system test cases could be implemented in the RTDS when the hardware is available.

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APPENDIX

In this appendix, the exact values of the results are given in the following tables. These results correspond to diagrams in chapter 5. Table A1 shows L_1 norms for SE in test case I which corresponds to Figure 5.4. Table A2 shows L_1 norms for DSE in test case I which corresponds to Figure 5.5. Table A3 shows L_1 norms for SE in test case II which corresponds to Figure 5.7. Table A4 shows L_1 norms for DSE in test case II which corresponds to Figure 5.8. Table A5 shows L_1 norms for SE in test case III which corresponds to Figure 5.10. Table A6 shows L_1 norms for DSE in test case III which corresponds to Figure 5.11. Table A7 shows the Run times of SE and DSE for all the test cases. Table A7 corresponds to Figure 5.14.

Table A.1 L_1 norms for SE in test case I

L_1 norms	SE without PMU	SE with Mixed-processing PMUs	SE with Post-processing PMUs
State Variable	0.0132	0.0022	0.0019
Bus Voltage(pu)	1.0680	0.1800	0.1740
Bus Angle(radian)	0.0021	0.0003	0.0003

Table A.2 L_1 norms for DSE in test case I

L_1 norms	DSE without PMU	DSE with PMU in Local SE only	DSE with PMU	DSE with PMU in proposed way
State Variable	0.0252	0.0204	0.0156	0.0156
Bus Voltage(pu)	1.4784	0.6125	0.6125	0.6125
Bus Angle(radian)	0.0108	0.0102	0.0094	0.0094

Table A.3 L_1 norms for SE in test case II

L_1 norms	SE without PMU	SE with Mixed-processing PMUs	SE with Post-processing PMUs
State Variable	0.0300	0.0132	0.0132
Bus Voltage(pu)	1.9800	0.8220	0.8190
Bus Angle(raidan)	0.0090	0.0051	0.0054

Table A.4 L_1 norms for DSE in test case II

L_1 norms	DSE without PMU	DSE with PMU in Local SE only	DSE with PMU	DSE with PMU in proposed way
State Variable	0.1722	0.1329	0.1212	0.1211
Bus Voltage (pu)	3.6090	2.0280	2.0268	2.0268
Bus Angle (radian)	0.1350	0.1110	0.1013	0.1013

Table A.5 L_1 norms for SE in test case III

L_1 norms	SE without PMU	SE with Mixed-processing PMUs	SE with Post-processing PMUs
State Variable	0.1416	0.1180	0.1204
Bus Voltage (pu)	4.7058	2.2762	2.2267
Bus Angle (radian)	0.9440	0.8260	0.8260

Table A.6 L_1 norms for DSE in test case III

L_1 norms	DSE without PMU	DSE with PMU in Local SE only	DSE with PMU	DSE with PMU in proposed way
State Variable	2.8650	2.5016	1.7700	1.7936
Bus Voltage (pu)	24.2726	16.6734	16.6734	16.8716
Bus Angle(radian)	2.6196	2.3482	1.4868	1.5304

Table A.7 Run time of SE/DSE for all the test cases

Run Time (s)	SE without PMU	SE with Mixed-processing PMUs	SE with Post-processing PMUs	DSE without PMU	DSE with PMU in Local SE only	DSE with PMU
Test Case I	0.0121	0.0150	0.0140	0.0207	0.0266	0.0265
Test Case II	0.2100	0.2400	0.2380	0.0240	0.0240	0.0250
Test Case III	9.7856	10.1795	10.4490	1.7307	2.0600	2.0500