CONTINGENCY ANALYSIS MODEL FOR POWER SYSTEMS BASED ON AGENTS

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วัตถุประสงค์หลักของการวิจัยนี้จะขึ้นอยู่กับการเพิ่มประสิทธิภาพการคำนวณเวลาในการวิเคราะห์ระบบไฟฟ้าฉุกเฉิน การวิเคราะห์ระบบไฟฟ้าฉุกเฉินเป็นงานสำคัญในการดำเนินงานระบบไฟฟ้า

งานวิจัยนี้เป็นการศึกษาการรวมของเทคโนโลยีตัวแทนในการทำงานฉุกเฉินเพื่อให้เวลาในการคำนวณและเวลาตัดสินใจที่เหมาะสม แบบจำลองทางสถิติที่ใช้ในการทำงานใช้เวลาการวิเคราะห์ฉุกเฉิน เช่นการประเมินสภาพ

เพื่อลดปัญหาการสื่อสารเพื่อการควบคุมกำกับดูแลและจัดหาข้อมูล (SCADA) เป็นเวลาบริโภคในหน้าที่ควบคุมเครือข่ายระบบไฟฟ้าประกอบด้วยในหลายพื้นที่แล้วอิทธิพลของแต่ระดับและการดำเนินการแก้ไขได้เป็นที่ ในเขตที่เกี่ยวข้อง

แบบจำลองนี้ได้ทำการสอนรวมไปถึงทำการพยากรณ์เพื่อประมาณการค่าพิกัดหลังเกิดความผิดพร่องที่สาย และ แรงดันไฟฟ้าที่บัสที่จะรักษาระบบการป้องกัน

การทดสอบแบบจำลองจะใช้การจำลองการทำงาน และนำผลลัพธ์ที่ได้มาทำการวิเคราะห์เพื่อแสดงให้เห็นผลการทำงานของแบบจำลองโดยทั่วไปแบบจำลองนี้จำมีการการปรับปรุงประสิทธิภาพการแจ้งเตือนฉุกเฉินในเงื่อนไขของเวลาการใช้คอมพิวเตอร์ที่ดีที่สุด

KENEDY ALIILA GREYSON: CONTINGENCY ANALYSIS MODEL FOR POWER SYSTEMS BASED ON AGENTS. THESIS ADVISOR: ASST. PROF. ANANT OONSIVILAI, Ph.D.

AGENTS/CONTINGENCY ANALYSIS/POWER SYSTEM/MODEL

The main objective of this research is based on the contingency analysis in a power system using agents. Power system contingency analysis is a vital operation in power system operations. This research work explores the integration of agent technology in contingency analysis functions so that the computation time and decision time is optimized. The distributed systems and statistical model approaches are proposed in the time-consuming functions of the contingency analysis. In order to minimize the communication problem for supervisory control and data acquisition (SCADA), as well as the time consumed in control function, the power system network is composed in several areas, and then the influence of each outage and its remedial action is taken in the respective zone. A model is trained to forecast the post-fault values of limits such as critical line flows and bus voltages to maintain system preventive action. Agents are trained so as to optimize the load and energy to be curtailed during contingency event. The model has been tested based on the simulation; and results are analyzed to show the model performance.

School of Electrical Engineering Student Signature ________________________

Academic Year 2010 Advisor's Signature________________________

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INTRODUCTION

1.1 Background

Electricity industry throughout the world is undergoing enormous changes. Restructuring has necessitated the decomposition of the three components of electric power industry: generation, transmission, and the distribution (Shahidehpour, et. al., 2002). Therefore, each component is devoted to its function while maximizing the profit. The system control remains the most important element in restructured power system operations.

Security of the power system operations is the main aspect in this research. The electric power market entities involved in this research are classified into two categories: market operators such as independent system operators (ISO), and market participants such as generating companies (GENCOs), transmission system companies (TRANSCOs), electric power distributers (DISTCOs) etc.

Several functions are considered and explained in this research work. This chapter explains the objectives of the research, the method used to accomplish the objectives, and the underlying assumptions. The report presents techniques used to perform power system contingency analysis using agent technology. Each agent in the agent community is assigned a specific task or several tasks. The communication between agents in a community enables the collaboration towards the main objectives.

The contingency analysis is referred to the interim measures to recover power system services following an emergency or system disruption. Contingency analysis can also be considered as a method of treating uncertainty that explores the effect on the alternatives of change in the power system operations, based on a 'what-if' type of analysis. Scheduled services, transmission line outages and generators outages are among the contingency events addressed in the contingencies analysis in the power system.

The generating units and transmission line outages mentioned above are either probabilistic or scheduled events. Moreover, contingency event may result from the breakdown of related equipments such as transformers, fire, service and maintenance schedules, sabotages, terrorist attack, etc. Other causes of contingency events are weather catastrophe, such as hurricane, tornado, flood, etc. Most serious power system contingencies are probabilistic events. This research presents the method that addresses the details of the possible risks related to the respective contingency.

Generally, it is the intention of this research, that the reliability of the power system is maximized while minimizing the operation costs. The research utilizes the notion of agent technology to address the power system contingencies problems. There are two main issues to be considered: optimization of the computing time and the accuracy in decision making when the contingency event occurs. Among the theory used in contingency analysis is based on the fact that the effect of an event is more in the neighboring areas (Shahidehpour and Wang, 2003). Therefore, the computation can be based on the respective region (area) and results communicated for coordination in the control center. However, in this research, most iteration processes in contingency analysis functions are based on regression models, hence the computation time is minimized.

1.2 Statement of the Problem

Power system contingency events affect the reliability of power services. If not well managed, the entire system may be driven into a disastrous state. The system security may be jeopardized and their consequences may become severe and harsh to the system operations. With exception of the scheduled outages, most components outages in power systems are probabilistic events.

The contingency analysis depends mainly on the state estimators which estimate the power system state variables, i.e. the bus magnitude voltages and the respective angles of the power network state at a time. Similarly, the frequencies of the contingency events contribute in estimating the reliability of the respective power system. Both estimation process and contingency analysis are computation-time consuming; therefore an approach should be able to minimize this computation time when addressing the large system networks which is composed by many buses. The approach considered in this research is based on agent technology. Agents are assigned to perform individual tasks and then coordinated so that the contingency of the entire system is analyzed at a levelheaded time hence the computational burden is reduced.

Challenges intended to be addressed in this research include: computation time in both the state estimators and the contingency analysis and appropriate decision making during contingency analysis. The function of state estimation is a key factor of accuracy in contingency analysis, therefore it is considered separately to accomplish the objective related to the computing time and its accuracy. Upon the achievement of the goals mentioned, at a certain level, the risk related to the contingencies will be managed and the reliability of the power system will be improved. The contingency planning ensures that unit schedules and corresponding power flows through the transmission system are able to deliver required power to meet load demand under various contingency scenarios (Mazer, 2007).

1.3 Research Motivation

During the deregulation process, power utilities have been reformed into competitive markets. The need is to improve and enhance market efficiency, to minimize the production cost and to reduce the electricity price, remain the main components. Knowledge about the system stability contributes in market analysis in the power system. Therefore, in competitive market each participant aims to maximize the profit. The power system security in that scenario is the main component towards its efficient performance.

Power system contingency events are among the major components that affect the operations in both technical sides as well as market point of view. Therefore, knowledge about these contingency events, such as their probability to occur and effects related to them contributes towards the better management in the power system operations, and hence contingency planning takes place. The knowledge search must be in the appropriate time so as to aid the related operations before the system is driven into inappropriate state or inappropriate decision. The agent technology has proven success in many operational power system applications. Therefore, this research intends to utilize multiagent technology in the power system to perform contingency risk assessment, analyze, and manage the contingency risks.

1.4 Research Objectives

The main objective of this research is to improve performance of the electric power system operations by adopting agent technology to aid in contingency analysis based on optimization on computation time and appropriate decision making.

In order to achieve the main objective, this research is composed of the following sub-objectives:

a) To explore uncertainties and effects on alternative internal and external changes in the power systems.
b) To treat and minimize the effects of the risks related to the possible power system contingencies.
c) To identify limitations that can affect the power reliability and security operations.
d) To improve computation time in contingency analyses using agents.

1.5 Methodology

This thesis presents the series of relationships and influences within the power system operations and contingency events. Through available literatures and synopsis presented in the form of a case study, contingency analysis of a power system is studied. Data related to the contingency events are collected and used as the input of the proposed model of the contingency analysis. The probabilities in the form of the prior- and conditional probabilities are computed and used as the information of the model. The contingency event and the related effects are the output of the model. The power system operating state is estimated together with probable outcomes due to the contingency events at a particular time of operation. Thus the relationships between the outputs and inputs is presented and discussed.

The series of empirical relationships are mainly causal statements. Generally, the influences over the relations are viewed as the probabilistic. Despite of the fact that, this research does not utilize all variables that may be available in all power system, yet it presents the way forward on the theory behind the technique for a generalized model. More variables can be added in the similar manner and a sophisticated model is likely to be used in a particular system.

1.6 Research Assumptions

This research is guided by several assumptions. Each assumption is interpreted according to the effect on the power system operations. In this section, these interpretations are presented.

a) Contingency analysis and risk assessment are important tasks for the safe operation of electrical energy networks.

The knowledge about the possible contingency events in a system can be utilized in the forecast estimation of the system state. This assumption is supported by authors in (Semitekos and Avouris, 2002). It is stated by the authors that, during the steady state study of an electrical network, any one of the possible contingencies can have either no effect, or serious effect, or even fatal results for the network safety, depending on a given network operating state.

b) Contingency risk assessment performed through load-flow analysis is a tedious and time consuming operation.

The load-flow analysis is a time consuming approach when a large power system is considered. However, in this research, the performance of power-flow results is appreciated and used as a base measure in the model performance and design.

c) Agent based technology may results a significant optimization in computation time for contingency analysis.

For the agents to enhance the contingency analysis, they are to be coordinated so as to achieve the main task. Each agent takes a portion of task and hence a minimized time towards the completion of its assigned task.

1.7 Scope and Limitations of the Study

The computing time for the conventional contingency analyses are based on the formulation of the network equations. In power systems power flow equations are solved by iterative techniques such as Gauss-Seidel, Newton-Raphson, or fast decouple method. In this research, a statistical approach is introduced in some of the contingency functions, as an alternative method and agents are assigned task to perform individual tasks so as to optimize the entire computing time.

1.8 Expected Benefits

Results from this research can be used as a design guideline of the real-time system for contingency analysis process in large power systems. The statistical approach is applied in time consuming functions of contingency analysis which eventually minimize the computing time of the entire process of contingency analysis.

1.9 Organization of the Thesis

The thesis is divided into eight chapters. In chapter I the introduction of the research, motivation, approach and goals are presented.

Chapter II gives the information of the literature review and related techniques proposed for the power system contingency analysis as obtained from text books, technical research reports and academic publications.

Chapter III gives the theory behind the computing distribution and details about the agent technology in the contingency analysis of power system.

In chapter IV the power system state estimation is discussed. The background of the state estimation and the proposed method used in the model are expressed in details.

Chapter V provides theory background of contingency analysis techniques. The details of main functions related to contingency analysis in the power system and computational algorithms in those functions are discussed.

Chapter VI gives the model design and its implementation is presented.

Finally, chapter VII presents the conclusion and related remarks.

CHAPTER II

LITERATURE REVIEW

2.1 Introduction

The continuity of service in a power system is certainly the main concern of system operators. Free access to the interconnected system, bilateral contracts settled between generating companies and consumers make conditions of operation more complex. The effort made by all participants in electric power market is to get the maximum profit. This may leads to the use of interconnection capacities far beyond their capabilities. For this reason and related security issues, it is thus necessary to know more precisely these limits and to better understand what happens when the limits are violated.

The state of the power system defined by the voltage and its phase angle at every bus are calculated from solving the power flow problem, a state estimator or a linearized network solved by applying Kirchhoff's Laws (Kusic, 2009). The operator or dispatcher of a power system need contingency analysis in order to be acquainted with the possibility of the system being driven to a vulnerable condition on a real-time basis as the load and generator change. Extremely accurate results are not necessary since it is only a possible situation, so linear approximations are adequate (Kusic, 2009).

In this chapter, some of the proposed techniques for the contingency analysis and some techniques used in applications of agent technology in power systems are presented and briefly discussed.

2.2 Contingency Analysis Techniques

There are several methods proposed for contingency analysis, in this section, some of the commonly used techniques are mentioned. The theory about contingency analysis is spared in the next chapter.

The contingency analysis which use the system Z_{bus} and also Y_{bus} become attractive from computational point of view with linearized loads replaced by current injections into the various buses of the system (Kusic, 2009; Grainger and Stevenson, 1994). More details about this method are presented in chapter III. Most accurate methods are based on AC load flow computations. This computation poses a challenging task even for fast computers and efficient (Maghrabi, et al., 1998).

Authors in (García-Lagos, et. al., 2001) present an analysis of the applicability of different neural paradigms to contingency analysis in power systems. The performance of this method is based on the neural network training where the output and input are related by the neural network parameters.

Shahidehpour and Wang (2003) propose the bounding method used for contingency analysis. The bounding method is based on the fact that the outage has a limited geographical effect on its surrounding. Therefore, the outage analysis is carried out in a limited area instead of the entire system. This method is more efficient in terms of computation time for the contingency analysis in a large scale power system.

Patidar and Sharma, (2008) presents a model tree (MT) based approach for fast voltage contingency ranking, of most severe contingencies for online applications in energy management systems. The proposed method in this publication is mainly in three steps. In the first step the database is generated for a power system under study. The database is generated by computer simulation, using an AC power flow. The second step is based on training patterns from the database generated. Finally, in the last step an MT model is tested for the contingency ranking of the power systems.

2.2.1 Artificial Intelligence Techniques

Artificial intelligence and machine learning techniques provide qualitative as well as quantitative assessment of the power system security state (Warwick, et. al., 1997). Machine learning techniques which develop a global description of the power system of the power system state and operating space using statistical data such as pattern recognition and artificial neural networks (ANNs) are among ongoing research in power system applications. Some successful implementations of an expert systems use statistical case analysis as an essential tool in order to collect case-independent qualitative knowledge of the power system (Warwick, et. al., 1997). In the following subsections brief theory of ANN and pattern recognition is presented.

2.2.1.1 Artificial Neural Networks

Human brain is composed of many millions of interconnected units known as *neurons*. Each neuron consist of cell to which is attached several *dendrites* and single axon. Artificial Neural Networks (ANNs), on the other hand, is a computer processing system that attempts to emulate their biological counterparts. ANNs have the following advantages for intelligence systems (Burns, 2001):

- They learn from experience rather than by programming
- They have the ability to generalize from given training data to unseen data
- They are fast, and can be implemented in real-time

Their structure are classified based on their connections namely, feed-forward networks and feedback (or recurrent) networks. The basic model of ANN of N-layer feed-forward consisting of N-hidden layers is shown in Figure 2.1.

The basic model of a single artificial neuron in the j^{th}-layer consists of a weight summer and an activation (or transfer) function as shown in Figure 2.2, where $x_1, x_2, \ldots, x_i$ are inputs, $w_{j1}, w_{j2}, \ldots, w_{ji}$ are weights, b_j is a bias, f_j is the activation function, and y_j is the output.

The weighted sum s_j is therefore given as

$$s_j(t) = \sum_{i=1}^{N} w_{ji} x_i(t) + b_j \qquad (2.1)$$

A single-layer fully-connected recurrent network containing delay feedback paths is as shown in Figure 2.3. The inputs occur at time (kT) and the outputs are predicted at time $(k+1)T$, then the network can be represented in matrix form by

$$y(k+1)T = W_1 y(kT) + W_2 x(kT) \qquad (2.2)$$

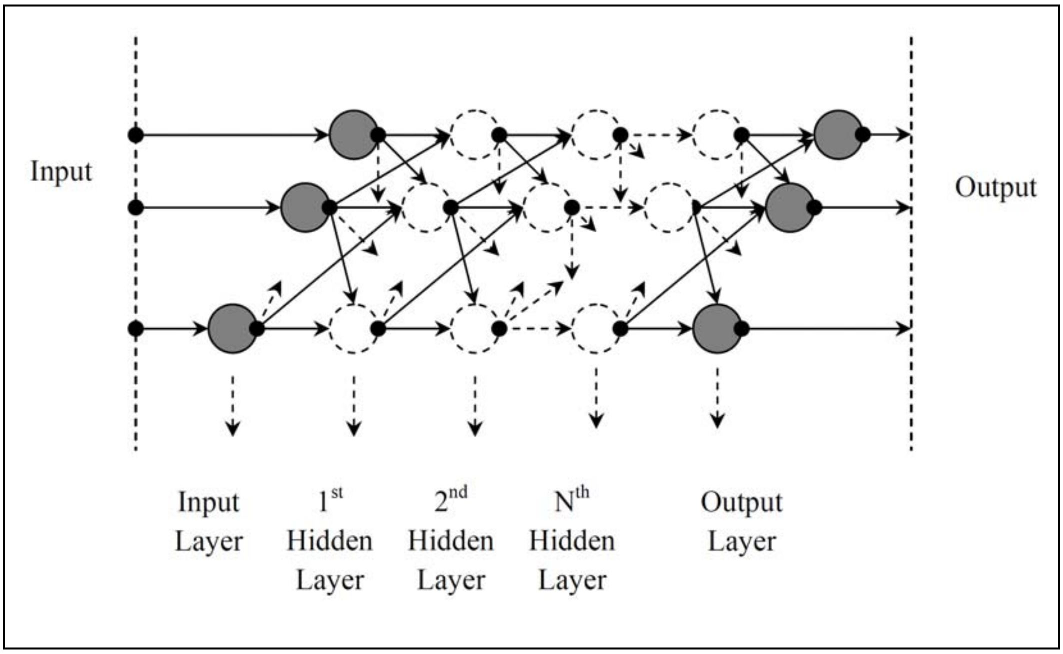


Figure 2.1 N-layer feed-forward neural network.

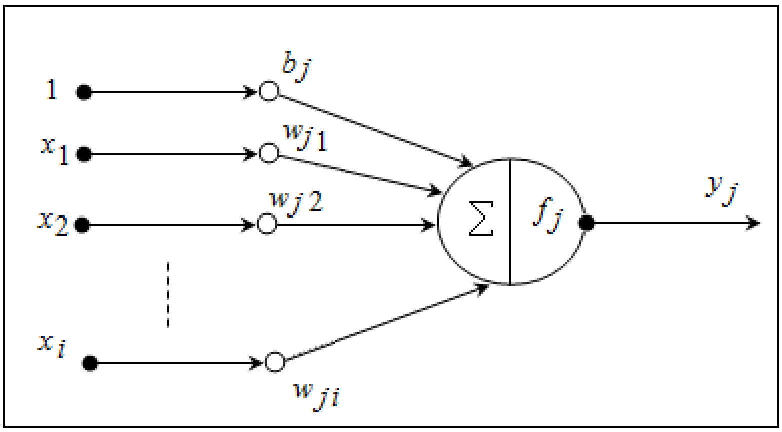


Figure 2.2 Basic Model of a single artificial neuron.

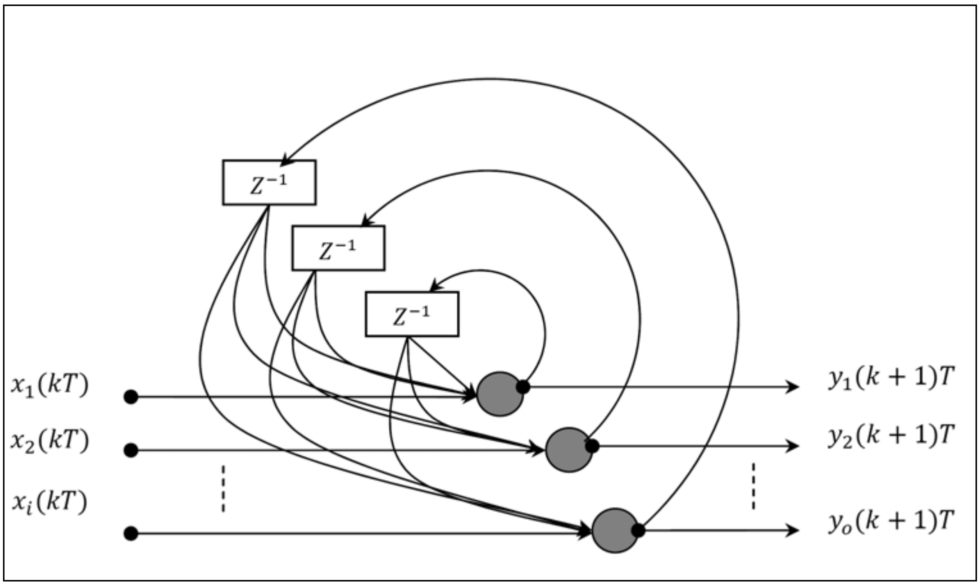


Figure 2.3: Recurrent neural network.

2.2.1.2 Pattern Classification

Heijden, et. al., (2004) define a pattern classification as the acct of assigning a class label to an object, a physical process or an event. The assignment is always based on measurements that are obtained from that object (or process, or event). The sensory system presents the measurement vector needed to classify all objects correctly.

2.3 Agent Based Technology in Power System Applications

Recently, several publications demonstrated the ability of agent technology in power system functions. In this section, selected publications based in agent technology in power systems are presented.

About, et. al., (2008) present the publication that introduces the multiagent technology in power system control function. In this paper, the capability for monitoring and controlling the electrical network by adopting the properties of multi-agent technology to enhance power system transient stability is presented. The theory behind the proposed technique is based on collaborating two agents. The first agent is a prediction agent that predicts power system instability by a transient stability program, while the second strategy agent is a control agent which uses the methodology of increasing power transfer through the healthy portion of network during disturbances by a load flow program using fast decoupled method.

Another proposed multiagent system application in a power system is presented by Ono and Williams (2009) in their technical report. In their report, market-based distributed planning algorithm for multi-agent systems under uncertainty, called MIRA Market based Iterative Risk Allocation (MIRA) is presented. Multiple agents act collectively in order to optimize the performance of the system, while satisfying mission constraints. These optimal plans are particularly susceptible to risk when uncertainty is introduced. The objective is that a distributed planning algorithm minimizes the system cost while ensuring that the probability of violating mission constraints is below a user-specified level.

Zhao, et. al., (2005) present a solution to the reactive power dispatch problem with a novel particle swarm optimization approach based on multiagent systems (MAPSO). In this paper integrates the multiagent system (MAS) and the particle swarm optimization (PSO) algorithm. In order to obtain optimal solution quickly, each agent competes and cooperates with its neighbors, and it can also learn by using its knowledge.

2.4 Conclusion

The mentioned proposed techniques and methods are only some of the work related to the contingency and agent technology. More and more researches are going on and still to be published in future. Also there are many ongoing aspects incorporating domain knowledge as it has been shown in the referred publications earlier in this chapter. In power system, the input: power flow measurements, injected bus currents, injected active power, injected reactive power, etc, can be used to obtain the system output be it state variables, or any other variable while the network topology remains constant. More information on the linearization of input-output variables are presented in chapter IV.

CHAPTER III

AGENT TECHNOLOGY AND DISTRIBUTED SYSTEMS

3.1 Introduction

In order to optimize the computation process in terms of time consumption and probably the accuracy, the distribution process presented by Shahidehpour and Wang (2003), is proposed. In this chapter, several techniques related to the contingency events are presented. More likely, several researches relates agents technology and the distribution systems. Power systems are composed of transmission lines, generating units, and many other components in dispersed geographical locations. The requirement for a secured power system is based on being maintained in a secured state as the operating conditions vary or from a list of critical contingencies. As it is for contingency analysis to be discussed in the next chapter, computing processes play great role on flexibility, reliability, combination of cost-effective processors, etc. For instance, consider the problem in which the system is required to do the following: executes a set of tasks on N number of nodes; collects results; coordinates the output accordingly so as to obtain the main objective.

Kshemkalyani and Singhal (2008) define distributed system as a collection of independent entities that cooperate to solve a problem that cannot be individually solved, and it is characterized as a collection of mostly autonomous processors communicating over a communication network and has no common physical clock, no shared memory, and geographically separated. Ghosh (2007) includes set of criteria that defines the logical distributions of the functional capabilities as multiple processes; inter-process communication; disjoint address space; and collective goal.

There are several research reports that present the utilization of distribution systems in power systems. Nagata and Sasaki (2002), proposes a multi-agent approach to power system restoration. Refer to other reports presented in chapter II. The distribution system can be expressed in detail by decomposing each task from N task into n subtasks. Each subtask n is carried out by individual agent. Therefore, one or more agents can reside in one computer. The communication between agents residing in the same computer is expressed as internal-communication, and communication between agents hosted in different computers is expressed as external-communication. To be more specific, the term processor and computer are used interchangeably while, agents refers the autonomous process capable of reacting and initiating changes in its environment, possibly in collaboration with other agents in their community which expresses the so called multi-agent systems. Theory behind agent technology is discussed briefly in the next section.

3.2 Agent Technology

This section extends the explorations of agent technology applied to the power system contingency analysis. Agents are active objects that are used to model parts of the real world system. They may be employed to represent separate processes which operate independently and interact with each other by exchanging the pertinent information. The systems that contain a group of agents that may interact with one another are called multiagent systems. The goal is to create collaborated agents to perform power system contingency. In this research, JADE (Java Agent Development framework), agent-oriented middleware (Bellifemine et al., 2007), and MATLAB® (MathWorks Inc.) were the main tools used to accomplish the task set forth for each agent. As it was mentioned earlier, reliable and continuous supply of electric supply are essential for the functioning of a power system. Due to the increase of energy consumption, power systems are operated in or close to their limits (Warwick, 1997). Therefore, the need of monitoring the system components is important and each item is dealt by the individual entities, here referred to an agent.

3.2.1 Multiagent Model

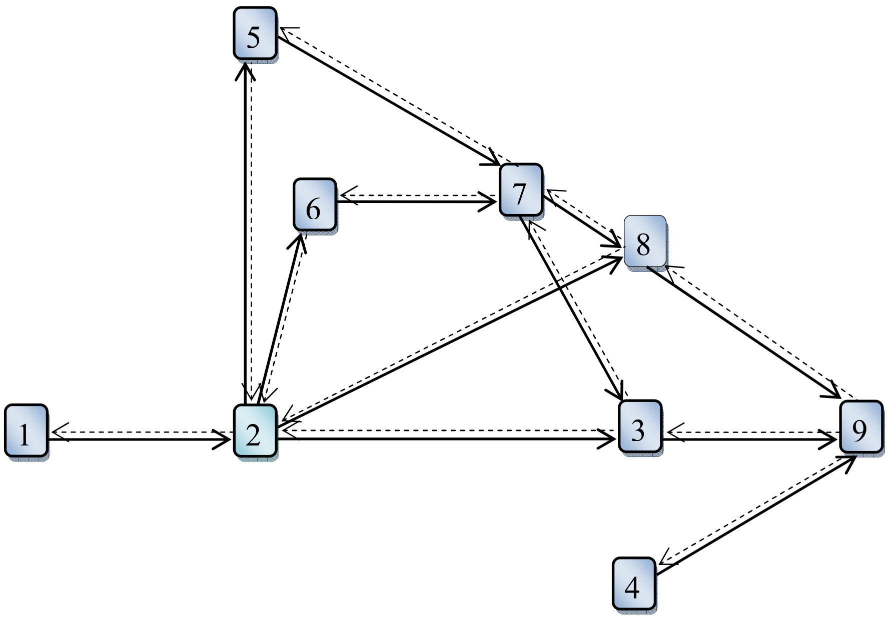
The role of multiagent model is to allow its members to coexist in a shared environment and pursue their respective roles in the presence of or in cooperation with others (Plekhanova, 2003). Therefore, modeling multiagent systems requires the consideration of the means of communicating between agents, in order to coordinate tasks. In this section, the main aspect of the multiagent, i.e. purpose, structure, rules, and norms are explained.

3.2.2 Multiagent Structure

As it has been mentioned earlier, in this research, the objective of the agents in a power system is set in order to perform contingency analysis. Firstly, the state of the system to be explained in chapter four is obtained through the state estimators and hence the contingency analysis is performed. Finally, the probability of contingency event is obtained. The posterior probabilities for the selected components, in this case, weather, exclusive equipments, and other ambiguous components, collectively known as ‘others’, are computed. In this stage, the updates are taken into consideration in each moment of contingency analysis process. Decision technique used that depends on the outcomes and the system condition is based on the causal belief, which will be introduced later in this chapter. In contingency analysis, the limits of power system components such as transmission line capacity and bus voltage, minimization of load shedding, etc., are expected to be cooperated in more sophisticated systems. Structure of multiagent is determined by the roles, interaction rules, and communication language. Roles can be defined by four attributes: responsibilities, permissions, actions, protocols as demonstrated in Gaia (Wooldridge et al., 2000). Each agent is assigned a specific responsibility and respective permission to support these responsibilities. Similarly, the action is performed through computations. In case of association with other agents, protocols that govern external interactions are set.

3.2.3 Inter-process Communication

In a distributed system, computers are connected to one another through a network. Much of the communication in a distributed system is carried out by one computer sending messages to each other. The message-passing can take place within the same computer or to a different computers connected through a network. In this research, the main focus is on the communication between agents, i.e. agent communication channel (ACC), regardless of the agent host. The message-passing model is among the key elements to be addressed. Furthermore, the research demonstrates the possibility of this theory. Figure 3.1 depicts the communication network of agents used in contingency analysis and management. The proposed model for agents collaboration in the power system contingency model is shown in Figure 3.2.



1 – SCADA; 2- SE; 3-TCA; 4-EPA; 5-VVA; 6-PLVA; 7-SCA; 8-GCA; 9-RA

Figure 3.1 Agent Communication Network

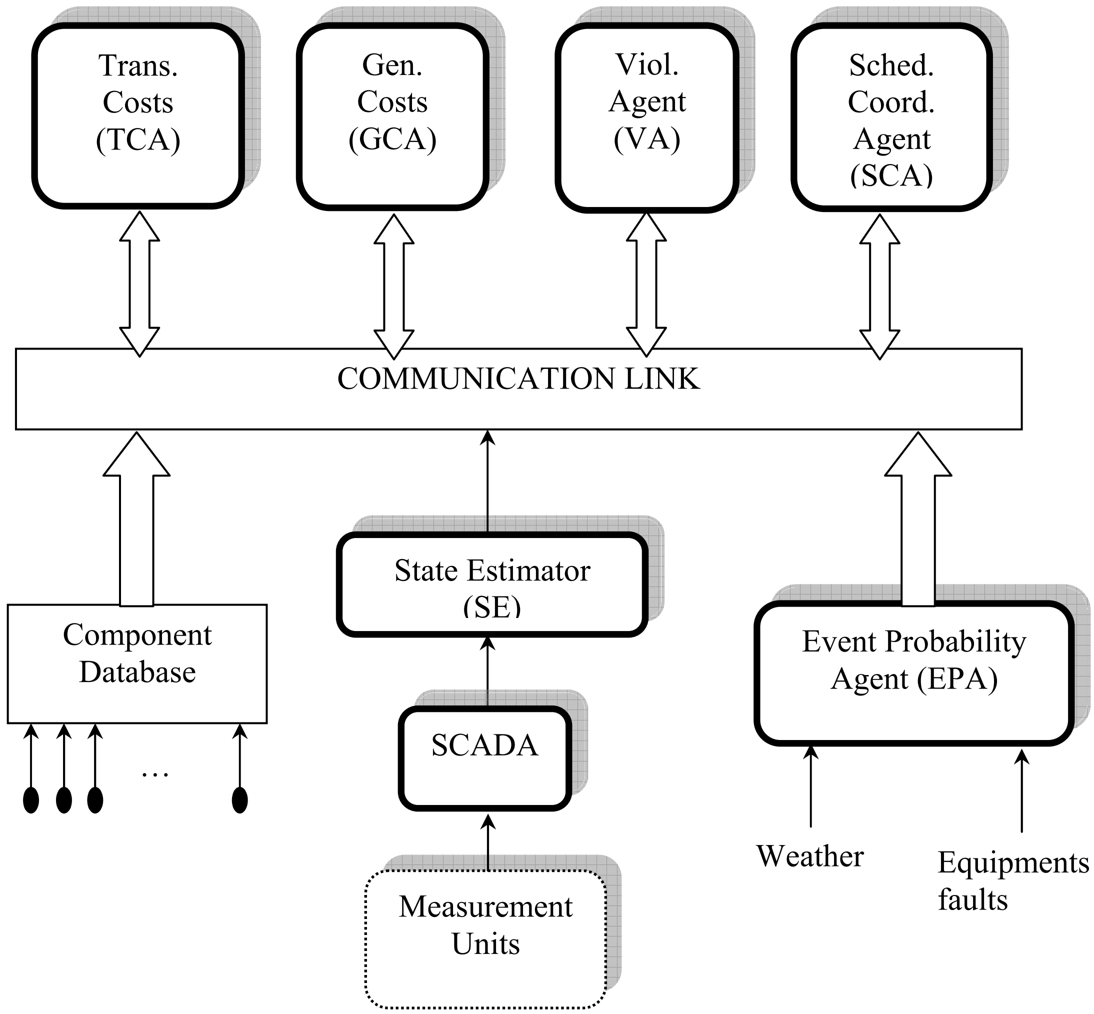


Figure 3.2 Agents collaboration diagram in the power system contingency model

3.3 Tasks Decompositions

The main task of the multi-agent system in this research, as it was mentioned earlier, is to perform contingency analysis process. Agents and their tasks are listed in Table 3.1. The hierarchy of agents is based on their dependency. The lower level agents should perform their tasks and pass their results in terms of messages to the higher level agents. The higher level agents use the lower level agent outputs as their inputs.

Event probability agents (e.g. EPA_1, EPA_2, etc.) compute the prior probabilities such as weather probability, equipments failure, etc. Data for EPAs are collected from the source, such as monitoring devices, and hence they fall in the top level agents, or primary level agents. EPA algorithms are based on probability computations meant for their tasks. Other agents such as violation agents (VA), scheduling coordinators agents (SCA), and transmission cost agents (TCA), and generation cost agents (GCA), depends also on the state estimators to perform their tasks. Hence they fall on the secondary level agents. Although the limits of system elements such as power line capacity, etc., are set by the manufacturer, yet the knowledge about the system state is required to decide if there is a violation on those limits. The relationship of agents, task-based, can be shown using Petri NET diagram in Figure 3.2 and Table 3.1. In this diagram the task based collaborations using Petri NET diagram for the contingency risk analysis is presented.

Table 3.1 Agents descriptions

Agent Code	Description	Method	Details
EPA	Event probability agent	Task	Updating contingency events probabilities.
		Data From	Monitoring devices
		devices	– fault recorders, – weather, etc.
		Method	Capacity outage probability, CEProb( )
VA	Violation agents (PLVA and BVVA)	Task	Check for violations (i.e. bus voltage and line limits).
		Data from	State estimator.
		method	Adapting the power flow algorithm and regression method, VViolation( ) and PLViolation( ).
TCA	Transmission costs agent	Task	Determine the incremental transmission cost upon the contingency event
		Data From	SCA
		Algorithm	Power flow and/or regression method, TransCost( )
GCA	Generation cost agent	Task	Determine the incremental generation cost upon the contingency event
		Data From	SCA
		Method	Power flow and/or regression method, GenCost( )
SCA	Scheduling Coordinator agent	Task	Enabling negotiation process
		Data From	All agents
		Algorithm and method	Negotiation based on each agent task, control( ).
RA	Risk analyzer	Task	Perform risk analysis
		Data From	EPAs, TCA, and GCA
		Method	Risk analysis computation, RiskAnalysis( ).

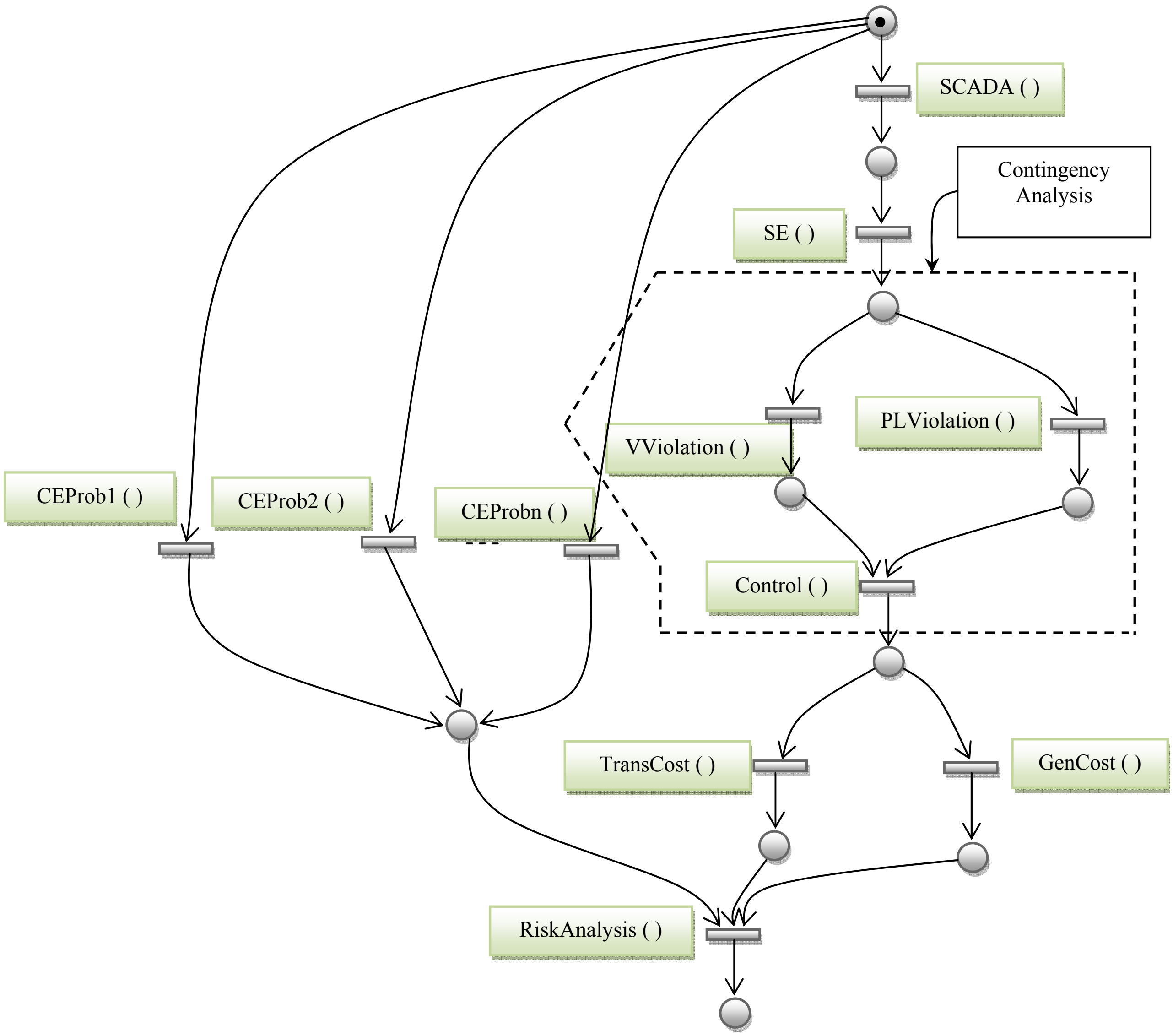


Figure 3.2 Petri NET diagram for the contingency process

Table 3.2 Data relationship within agents

Agent	Process	Input	Output
SCADA	SCADA( )	Measuring units records	Injected active and reactive power, voltages, etc.
EPA	CEProbn( )	Events recorders	Event probabilities
SE	SE( )	SCADA output	Bus voltage (magnitude and phase angle)
VVA	VViolation( )	SE output	Voltage violation and no voltage violation
PLVA	PLViolation( )	SE output	Power flow violation and no power flow violation.
SCA	Control( )	VVA and PLVA outputs	Regulated power flows and bus voltages
TCA	TransCost( )	SCA output	Transmission cost
GCA	GenCost( )	SCA output	Generation costs
RA	RiskAnalysis( )	GCA, TCA, and EPA outputs	Risk evaluation

3.4 Distributed Systems

For clarification, in this research the IEEE 57 bus system is divided in three regions as shown in Table 3.3, Table 3.4, Figure 3.3, and Figure 3.4. Each region has individual state estimator. More details about this process are made available by authors of (Oonsivilai and Greyson, 2009b). Figure 3.4 shows the part of the system defined by its internal and external connections.

The ongoing restructured East African Community (EAC) electric network is a practical approach applied in this research. More details about EAC network is presented in chapter four.

3.5 Assessing Risk Probability

As it is stated by Ward and Chapman, (2001), effective risk management requires assessment of inherently uncertain events and circumstances. In this research, risks involved are merely events or circumstances that might occur and if they did, how would they affect the operating conditions of the power system. This is quantified by evaluating the maximum load to be curtained, operating costs, etc. Once they can be identified, the scales for measuring the probability and impact of risks can be quantified. Therefore, it is perfectly possible to weight risk in terms of high, medium or low or numerically. Generally, the probability presents the answer to the main question of “how likely the uncertainty is to occur (probability). The effect (impact) of the contingency event is another component towards the evaluation of the risk in which the system is involved with during the contingency events such as transmission line outages, generation unit outages, etc. It is therefore important to assess probability with some degree of confidence.

Table3.3 Distributed regions for IEEE 51 bus system

<table>
<tr><th>Area</th><th>No. of bus</th><th>Main buses</th><th colspan="2">External Buses</th></tr>
<tr><td rowspan="2">Region-I</td><td rowspan="2">22</td><td rowspan="2">1, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, and 51</td><td>Region-II</td><td>2, 3, 6, 7, and 55</td></tr>
<tr><td>Region-III</td><td>38 and 56</td></tr>
<tr><td rowspan="2">Region-II</td><td rowspan="2">12</td><td rowspan="2">2, 3, 4, 5, 6, 7, 18, 29, 52, 53, 54, 55</td><td>Region-I</td><td>1, 8, 9, and 15</td></tr>
<tr><td>Region-III</td><td>19 and 28</td></tr>
<tr><td rowspan="2">Region-III</td><td rowspan="2">23</td><td rowspan="2">19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 56, and 57</td><td>Region-I</td><td>41, 42, 44, 48 and 49</td></tr>
<tr><td>Region-II</td><td>18 and 29</td></tr>
</table>

Table 3.4 Distributed regions for IEEE 57 bus system and regional-tier lines

<table>
<tr><th>Area</th><th>Internal Line Indices</th><th colspan="2">Tied Lines</th></tr>
<tr><td rowspan="2">Region-I</td><td rowspan="2">7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 23, 24, 25, 26, 27, 28, 54, 55, 56, 58, 59, 60, 61, 62, 63, 64, 65, 66, 71, and 72, and 78,</td><td>Region-II</td><td>1, 2, 18, 22, and 80</td></tr>
<tr><td>Region-III</td><td>57, 74, 75, 78, and 79</td></tr>
<tr><td rowspan="2">Region-II</td><td rowspan="2">2, 3, 4, 5, 6, 19, 20, 21, 41, 67, 68, and 69, and 70</td><td>Region-I</td><td>1, 7, 18, 22, and 80</td></tr>
<tr><td>Region-III</td><td>29 and 40,</td></tr>
<tr><td rowspan="2">Region-III</td><td rowspan="2">29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 57, 73, 74, 75, 76, 77, 78 and 79</td><td>Region-I</td><td>57, 74, 75, 78, and 79</td></tr>
<tr><td>Region-II</td><td>29 and 40,</td></tr>
</table>

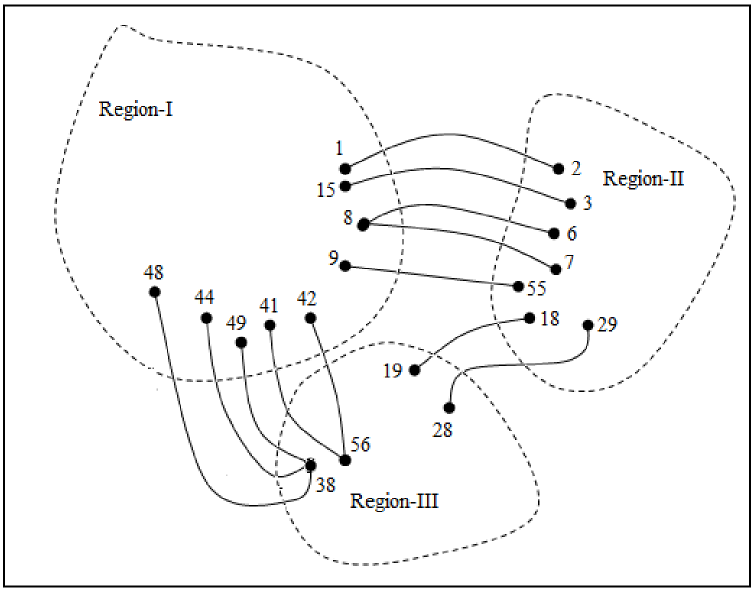


Figure 3.3 Distribution regions representation and tie lined for IEEE 57 bus system

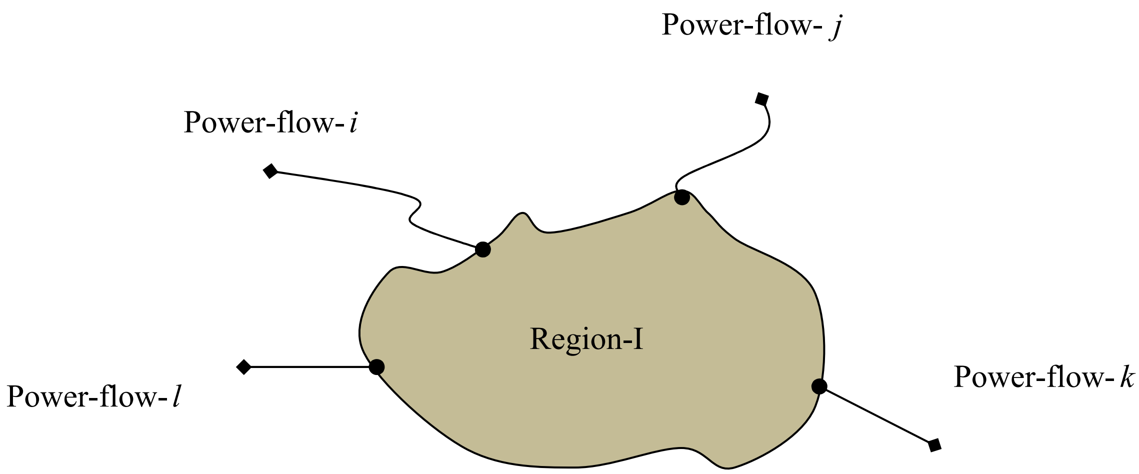


Figure 3.4 The sub network system

3.6 Agent Based Contingency Analysis Overview

Figure 3.5, shows the concept of the system model structure used in this research. In this model, agents are collaborated in such a way that the probability of line outages is determined. As expressed in the previous chapters, there are number of reasons in each interruption in a power system such as catastrophic weather, equipments failure, etc. In tropical countries, the probability of line outage during rainy season is higher compared to other seasons. This is due to heavy rain, extreme wind, flood, tornados, hurricanes, lightning storms, etc. Similarly, each piece of equipment on a power system has probability of failure. Among the reasons of equipments failure are poor manufacturing, damage during shipping, aging, improper installation, overloaded, i.e. working beyond its limits, etc (Brown, 2009). For example, variables related to the weather, are recorded so as to compute the probability of the line outage events.

For simplicity, In this section, components under consideration for line outages includes weather, exclusive equipments failure, and line outages results from the violations of operating limits causing protective devices to isolate the line from the system. The concept of cooperation of agents is presented in Figure 3.6. There are several agents, each assigned a specific tasks such as weather data collection, i.e., expected data and previous data, equipments performances, measurements records, and others components records. The contingency analysis inputs are probability of event to occur, and the system state variables.

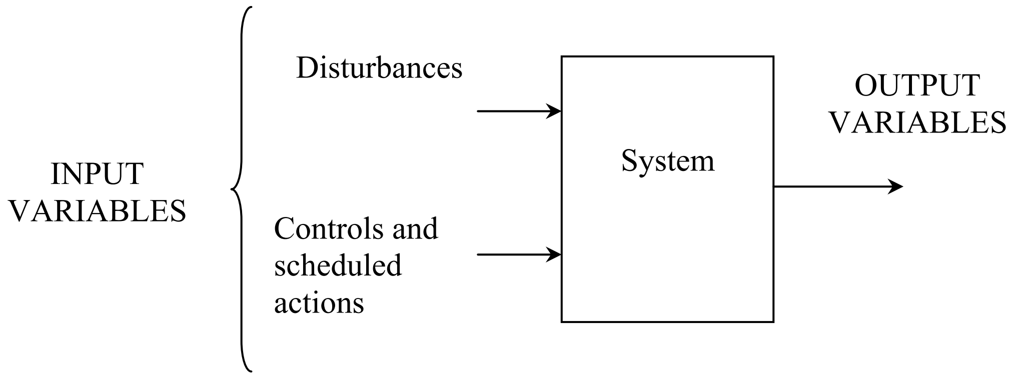


Figure 3.5 Concept of a system model

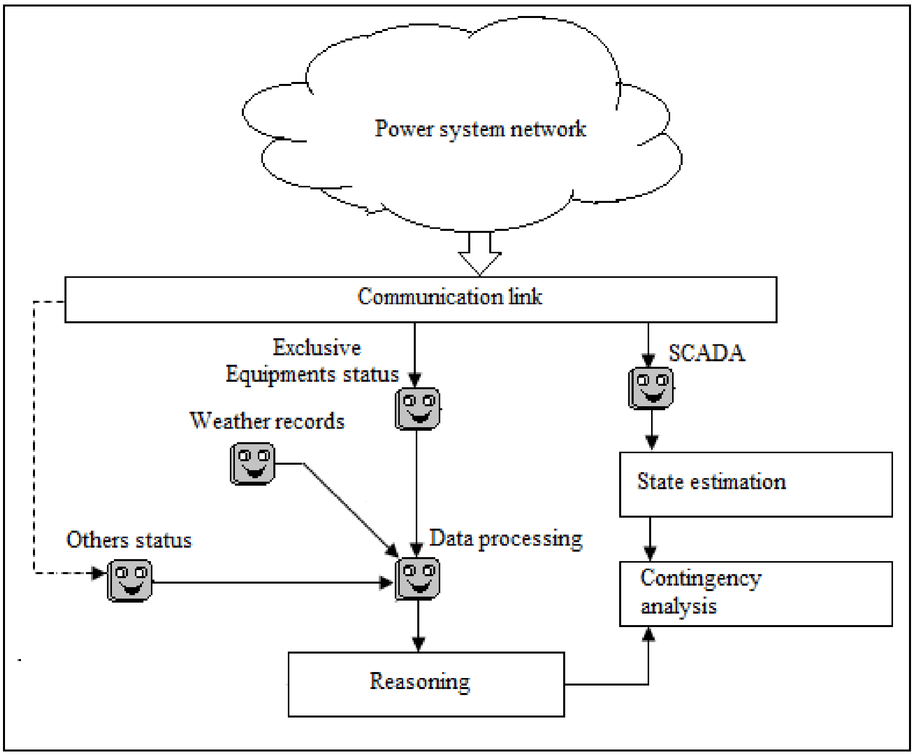


Figure 3.6 The structure of agent based for contingency analysis in a power system

3.7 Acquiring Information

The acquisition of probabilities involves eliciting conditional probabilities along causal information. As shown in Figure 3.6, records for equipments and other related components related to the cause of line outages, weather condition, and line outages, are collected. Agents are assigned the task of data collection are responsible for local processing to determine the conditional probabilities by sharing the information within themselves. The SCADA is responsible for measurements reading collection and send the measurement vector to the state estimator. Reasoning and decision making is a key element required by the contingency analysis. The reasoning process require built-in intelligence which is used to make proper decision and conclusion. Figure 3.7 presents the functional components of the model. Each agent perform its task and update the status periodically. In order to describe the function of weather agent as an example, the records obtained from weather stations is posted, or sent to the station so as to update the weather status. This may also include the weather forcast as well. The agent use its current weather probability and update the weather records sub-system. The weather forcast is considered as an evidence of the weather status. Similarly, equipments other record agents updates their status accordingly in the same manner. In combining all possible input parameters, the probability of contingency event is computed. The effect of the event is estimated through contingency analysis. The effect of the contingency depends on the operating condition which can be obtained by the state estimator. In other words, if the line outage will result overloads in several lines the control action presents the output effects of the event.

3.7.1 SCADA Information

The contingency analysis is based on the base-system condition. The base-system is an operating condition without contingency event. Therefore, the first requirement is the measurement vector, Z to be used in computing power system state (bus voltage magnitude and respective phase angle). For example, as expressed in chapter four, three types of measurements are going to be used, injected active power injected reactive power, and voltage measurements in each bus. Agents as shown in Table 3.2 are assigned tasks and the agent community is formed. Thus, an agent SCADA is assigned a task of gathering these measurements as they are telemetered to the control center and post them on the SCADA-soft-board, a data file ready to be used by the SE as shown in Figure 3.7. The SE provides the state variables for its respective area. The accuracy of the state estimator depends on the accuracy, and the number of telemetered measurements. Therefore the state estimation is accomplished by agents responsible for network observability, bad data detection and identification, and topology error processing. The SE agent posts its output (bus voltage magnitude and phase angle) on the state-variable-soft-board as shown in the structure of SE and SCADA in the Figure 3.8. The intelligence in an agent may be based on the decision making explained in the next section.

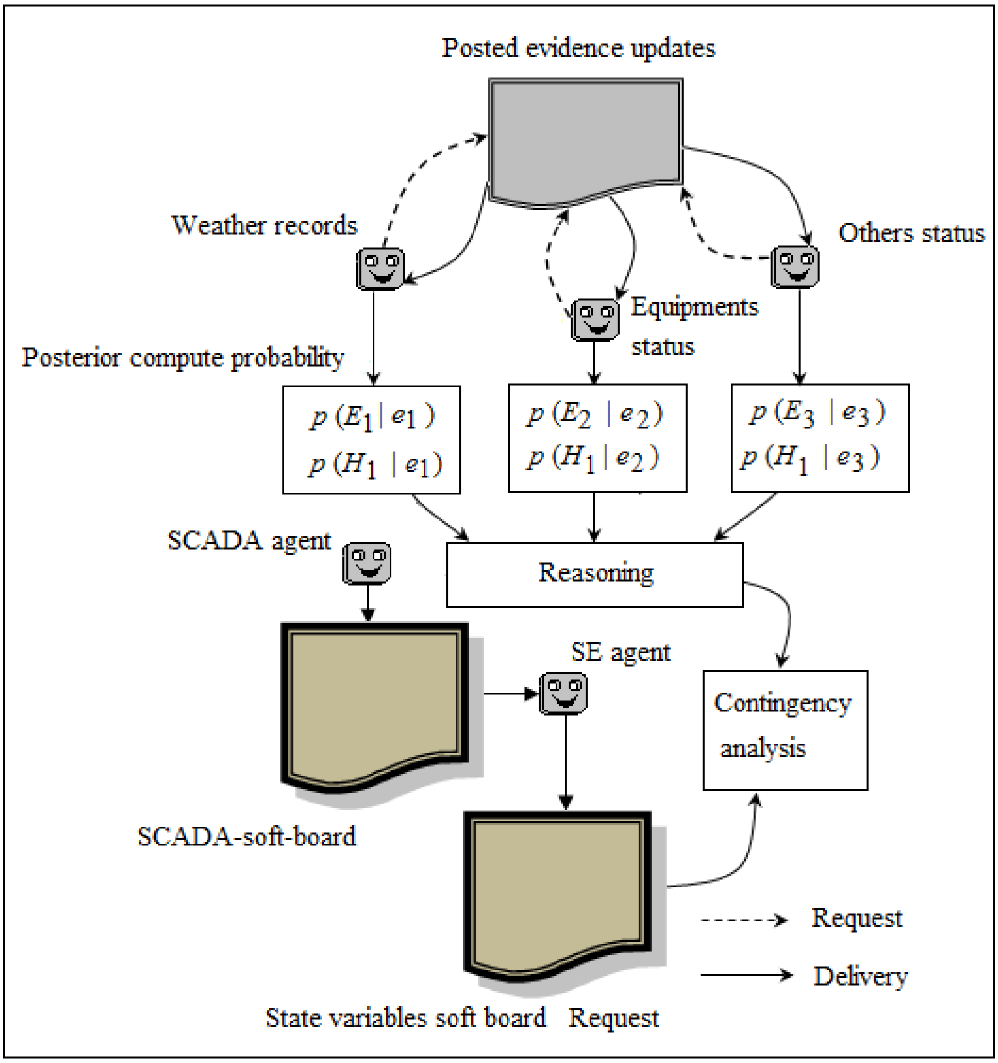


Figure 3.7 Functional components of the model

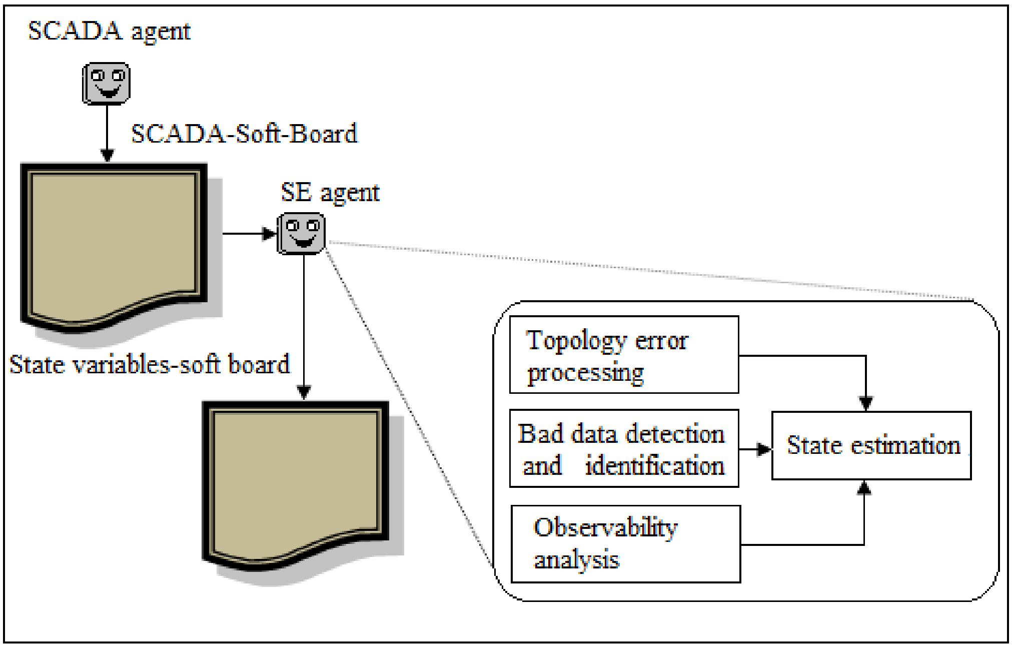


Figure 3.8 Structure of SE and SCADA components

3.8 Decision Making

Decision to act is a key of an ability of an agent to achieve its objective. The decision making problem is present at least in every sector. Industry, business, medicine, are among the examples. In power systems, power reliability relates to equipment outages and customer interruptions (Brown, 2009). Scheduled and unscheduled events lead to the line- or generator outages. Among the causes of power interruption includes equipments failures, weather, etc.

The causal network (also known as Bayesian networks) approach to statistical modeling uses probabilities as a way of quantifying the beliefs of an observer about the parameters of a model, given the data that have been observed (Das, 2009), (Korb and Nicholson, 2004), and (Morgan, 2009). It is to choose a *prior* distribution, which reflects the observer's beliefs on the basis of data observed, resulting in the *posterior* distribution (Morgan, 2009). In (Yongli, et al., 2006), the authors present the three element-oriented models based on simplified Bayesian networks with Noisy-Or and Noisy-And nodes proposed to estimate the faulty section of a transmission power system. Authors also present results to show that the approach is feasible, efficient and promising to be used in a large transmission power system for online fault diagnosis. In (Zhou, et al., 2007) authors present the use of causal network to make the fault-section model of line. In this paper, the causal relationships among protected sections, relays and breakers are analyzed by using the operation information of relays and breakers.

In this research, the causal network is used to build intelligent and practical decision aiding agents. Logic and probability reasoning with epistemic state and beliefs are analyzed and represented by probability measure defined some state space.

3.8.1 Epistemic Model Based on Agent

The effect of the power system is based on the state of the power system at the particular time. For example, if the power demands at bus X is very high, and line $i-j$ that carries the power towards the bus X, then the line outage effect is higher compared to the time when the demand is very low. Similarly, if the outage in a particular line drives the system into the emergency or insecure state, then the effect is higher than the outage with no violation in operational limits. The relationship between the system state and other causes of outage, outages caused by external and internal components. Consider the arguments by an agent to determine the status of the line under investigation:

If the weather is rainy, i.e. rainy season,

- *there are higher chances of line outages.(premise)*

If equipments and other components are faulty,

- *the chance of the line outage becomes high, etc.(premise)*

This fashion of model is termed as prepositional epistemic model. The "*if*" is followed by the occurrence of an event, and then the hypothesis (D) takes place.

Another fashion of the model for epistemic state is a probabilistic. The knowledge that constitutes an epistemic state in this research is based on probabilistic epidemic model which is the case for the most uncertain environments. In this case, an agent receives information from uncertain environments. The knowledge of the agent is built on the beliefs formed based on the received uncertain information. Causal networks also known as Bayesian belief networks, can be used to quantify the information in the joint probability distribution for a domain. This can be expressed as *"The weather conditions, exclusive equipments status as well as other related* *components together determine the status of the line under investigation".* Variables in this statement are *weather*, *equipments*, and *other related components*. The embellishment of rules with degrees of uncertainty really combines the pure prepositional epistemic model with the probabilistic epistemic model (Das, 2008).

Bayesian inference requires an initial (prior) probability for each hypothesis in the problem space (Das, 2009), (Korb and Nicholson, 2004), and (Morgan, 2009). The inference scheme then updates probabilities using evidence. The Bayesian rule is defined as

$$p(A \mid B) = \frac{p(B \mid A)p(A)}{p(B)} \tag{3.1}$$

where A and B are events that are not necessarily mutually exclusive, $p(A \mid B)$ is the conditional probability of event A occurring given that event B has occurred, $p(B \mid A)$ is the conditional probability of event B occurring given that event A has occurred, $p(A)$ is a probability of event A occurring and $p(B)$ is the probability of event B occurring.

For the m mutually exclusive and exhaustive hypotheses, which is implied by the relationship $H_1,..., H_m$ i.e., $\sum_{i=1}^{m} p(H_i) = 1$ and n possible events $E_1,..., E_n$ that can occur, then the probability of a hypothesis given some evidence is computed as (Das, 2008)

$$p(H_i \mid E_j) = \frac{p(E_j \mid H_i)p(H_i)}{\sum_{k=1}^{m} p(E_j \mid H_k)p(H_k)} \tag{3.2}$$

In the power system analysis shown in Figure 3.7, the information about the weather (external cause), and internal causes (from the power system) of the line outages such as overload, that drives protective devices to isolate the line from the system, fault equipments, etc are recorded. From these information, reasoning process or simply data processing, used to aid the contingency analysis. In the following section, line outages causes are expressed.

3.8.2 Causal Network for Decision Making Agents

Causal Network also known as probabilistic network is reported being efficient (Das, 2008). As expressed in the previous section, for instance, consider the line outage events which may be caused by several reasons, such as catastrophic weather, power line aging, scheduled maintenance, etc. In consideration of each cause, referred to as domain of the contingency, for example, weather has mutual exclusive random variables in a year. Weather in variables in tropical countries may be either sunny or rainy. In other regions, other variables for weather include snow, etc. Then the probability that weather is rainy will assume the value x based on the records and information about the particular location. It should be noted that, reliability varies naturally from year to year. Therefore, in this research, the model presented is a highlight of how the causal network can be used using simple component model, leaving more details for a practical approach of a particular location.

The causal influence as shown in Figure 3.9 defines the case that: weather condition determines the condition of the line. For instance, rain season is likely to cause line outage. Similarly, condition of equipments and other components together determine the reliability of the line in inspection. Weather condition of a day of a year in most tropical countries such as Tanzania and Thailand are likely to be either sunny or rain. Prior probabilities of weather (sunny, rain), equipments (normal, faulty), and other components (normal, faulty) are given in Figure 3.9. The six conditional probabilities of the belief network (also known as Bayesian belief network) without parents are presented. In this example, the update of the probability referred to a node belief. In Figure 3.9, node line has three parents, weather node, equipments node, and others node. Similarly, line is a child to all weather, equipments and others. More details on this theory can be obtained from (Brown, 2009).

3.8.3 Conditional Independent in Belief Network

Two random variables Y and Z are said to be (marginally) *independent*, denoted by $Y \perp Z$, if $p(Y,Z) = p(Y)p(Z)$ for any combination of values for the variables Y and Z (Das, 2008). The variable Y is *conditionally independent* of Z given another variable X, denoted as $Y \perp Z \mid X$, if $p(Y,Z \mid X) = p(Y \mid X)p(Z \mid X)$. The following cases presents the causal network theory (Das, 2008) and (Korb and Nicholson, 2004).

Case I: Conditional independence in chain causal fragment: Z is conditionally independent of Y given X. That is, node X is between two other nodes Y and Z. Depicted in Figure 3.10 (Das, 2008), the joint probability distribution of the variables X, Y, and Z is factorized as

$$\begin{aligned} p(X,Y,Z) &= p(Z \mid X,Y)p(X,Y) \\ &= p(Z \mid X)p(X \mid Y)p(Y) \end{aligned} \tag{3.3}$$

Case II: Conditional independence in a tree network (common cause) fragment of a causal network where the node X is the parent of two other nodes Y and Z as shown in Figure 3.11. The joint probability distribution of the variables X, Y, and Z is factorized as

$$p(X,Y,Z) = p(Z \mid X,Y)p(X,Y) = p(Z \mid X)p(Y \mid X)p(X) \tag{3.4}$$

Case III: Conditional dependence in a polytree (or forest) network fragment between the nodes Y and Z, given that the knowledge about X is present as shown in Figure 3.12. The two variables are marginally independent if the knowledge about X is not present. The joint probability distribution of the variables X, Y and Z is factorized as

$$p(X,Y,Z) = p(X \mid Y,Z)p(Y,Z) = p(X \mid Y,Z)p(Y)p(Z) \tag{3.5}$$

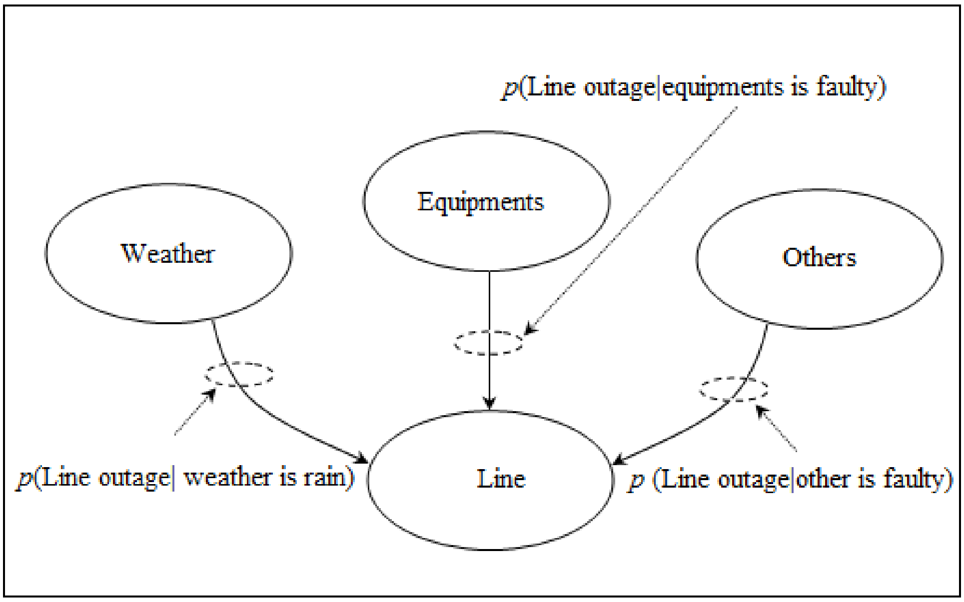


Figure 3.9 Initial probabilities

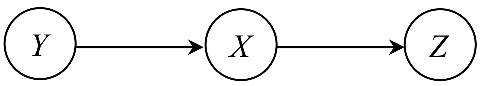


Figure 3.10 Conditional independence in chain fragment where Z is conditionally independent of *Y* given *X*.

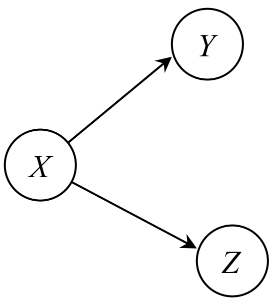


Figure 3.11 Conditional independence in common cause where Z is conditionally independent of *Y* given *X*.

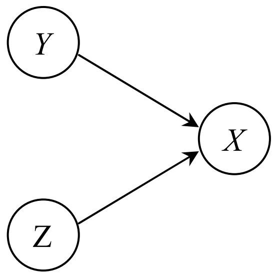


Figure 3.12 Conditional dependence in polytree where *Y* is conditionally dependent on *Z* given X.

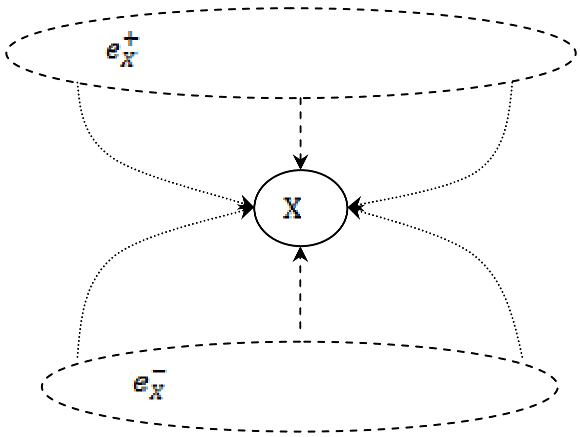


Figure 3.13 Network fragment containing node **X**

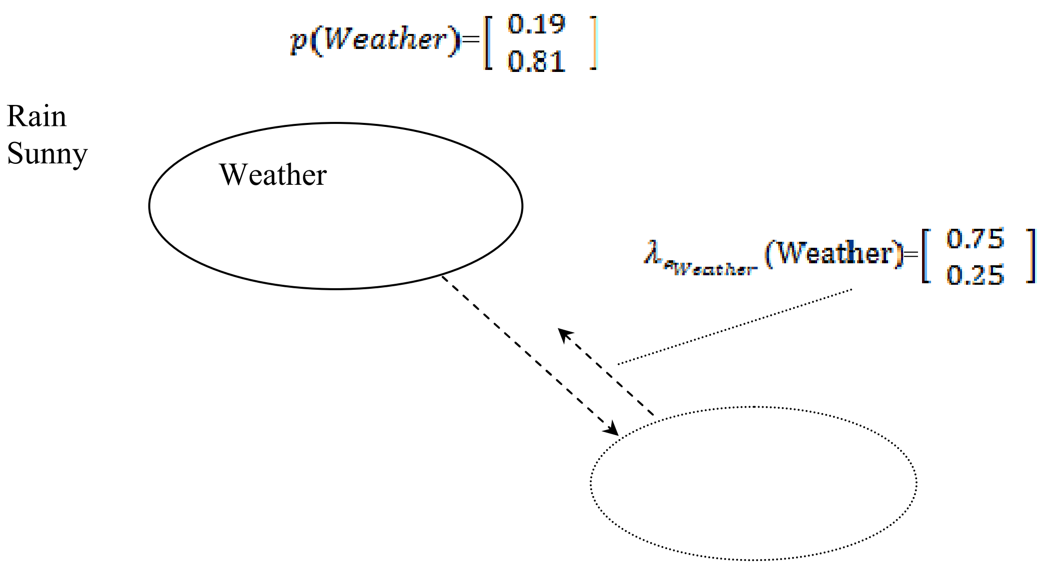


Figure 3.14 Posting evidence on a node

3.8.4 Inference in Causal Networks

Consider the network fragment as shown in Figure 3.13. Total evidence connected to X through its parents and children being e_X^+ and e_X^- respectively as expressed in (Das, 2008) and (Korb and Nicholson, 2004). The distributions of the total supports among the states of X through its parents and children are represented by vectors $\pi(\mathrm{X}) = p(\mathrm{X}|e_X^+)$ and $\lambda(\mathrm{X}) = p(e_X^-|\mathrm{X})$ respectively. Then the belief of the node X of the belief (causal) network, $Bel(\mathrm{X})$ contributed. For e being the evidence received so far connected to X, the updating equation is given as (Das, 2008) and (Korb and Nicholson, 2004).

$$Bel(\mathrm{X}) = p(\mathrm{X}|e) = \alpha\pi(\mathrm{X})\lambda(\mathrm{X}) \qquad (3.6)$$

where α is a normalizing constant

3.8.5 Prior Probabilities in Networks without Evidence

It should be noted that, belief updating at a node and evidence propagation starts with fresh network without any observed evidence (Das, 2008). The update of the belief followed when the evidence is propagated. If no evidence propagation, every variable X in a network, $\pi(\mathrm{X})$ is $p(\mathrm{X})$. If X has no parent (i.e. root nodes) then its conditional probability table (CPT) is $p(X)$ else if it has parents $U_1, U_2, \dots, U_n$ then

$$p(\mathrm{X}) = \sum_{U_1,\dots,U_n} p(\mathrm{X}|U_1,\dots,U_n)\, p(U_1,\dots,U_n) \qquad (3.7)$$

$$= \sum_{U_1,\dots,U_n} p(\mathrm{X}|U_1,\dots,U_n)\, p(U_1|U_2,\dots,U_n) \dots p(U_{n-1}|U_n) p(U_n)$$

Since $U_1, U_2, \dots, U_n$ are marginally independent,

$$p(\mathrm{X}) = \sum_{U_1,\dots,U_n} p(\mathrm{X}|U_1,\dots,U_n)\prod_{i=1}^{n} p(U_i) \tag{3.8}$$

3.8.6 Belief Update in Networks with Evidence

Causal networks, can be used to calculate new beliefs of a particular node X, upon the receiving new information. The information or evidence might be negative evidence about node X, in such that $p(\mathrm{X}) = -x$ being negative implying that the probability of node X is not in a state$x$. Upon the receiving evidence, e_X node revised its own belief. In other words, if the current probability vector is $p(\mathrm{X})$, then its posterior probability is defined as given in the literature (Das, 2008)

$$p(\mathrm{X}|e_X) = \frac{p(\mathrm{X})p(e_X|\mathrm{X})}{p(e_X)} = \alpha p(\mathrm{X})\lambda(\mathrm{X}) \tag{3.9}$$

given that,

$$\alpha = \frac{1}{p(e_X)} = \frac{1}{\sum_X p(\mathrm{X}, e_X)} = \frac{1}{\sum_X p(e_X|\mathrm{X})p(\mathrm{X})} \tag{3.10}$$

Consider the case of weather, exclusive equipments, and other components given earlier and through explanation on posting evidence (Das, 2008); Figure 3.14. presents the explanation on posting evidence on a node (weather). Assume the current probability of weather is the probability of weather in January.

The evidence of weather on a variable of weather is hypothetically considered. Hence, the posted evidence e_{Weather} on a variable weather in a network is hypothetically considered as a child of the node weather, and CPT $p(e_{\text{weather}}|\text{Weather}) = \lambda(\text{Weather})$. The normalizing constant, α is computed as

$$\alpha = \frac{1}{(0.19 \times 0.75) + (0.81 \times 0.25)} = 2.8986$$

Posterior probability of weather is computed as

$$p(\text{Weather}|e_{\text{Weather}}) = \begin{bmatrix} 2.8986 \times 0.19 \times 0.75 \\ 2.8986 \times 0.81 \times 0.25 \end{bmatrix} = \begin{bmatrix} 0.4131 \\ 0.5869 \end{bmatrix}$$

The revised λ and belief are computed as follows

$$\lambda_{new}(\text{Weather}) = \lambda(\text{Weather})\lambda_{e_{Weather}}(\text{Weather}) \tag{3.11}$$

$$Bel_{new}(\text{Weather}) = \alpha\pi(\text{Weather})\lambda_{new}(\text{Weather})$$

Hence, if we consider initial $\lambda(\text{Weather})$ to be

$\lambda(\text{Weather}) = \begin{vmatrix} 1 \\ 1 \end{vmatrix}$, then $\lambda_{new}(\text{Weather})$ becomes

$$\lambda_{new}(\text{Weather}) = \begin{bmatrix} 1 \\ 1 \end{bmatrix}\begin{bmatrix} 0.19 \\ 0.81 \end{bmatrix} = \begin{bmatrix} 0.19 \\ 0.81 \end{bmatrix}$$

Note that $\pi(\text{Weather})$ remains unchanged for root nodes and if e_{-}^{+} is unchanged.

$$Bel_{new}(\text{Weather}) = 2.8986 \times \begin{bmatrix} 0.19 \\ 0.81 \end{bmatrix}\begin{bmatrix} 0.75 \\ 0.25 \end{bmatrix} = \begin{bmatrix} 0.4131 \\ 0.5869 \end{bmatrix}$$

3.9 System Reliability

In this section, the theory behind power system reliability using probability method is presented. For clarification of the reliability, the transmission line and generation unit components are used. Both can be in operational (up) or in outage (down) state. These states have a direct influence upon the power system reliability.

3.9.1 Characteristic of Component Failure

The characteristic of component failure is based on its continuous working time, failure rate function $\lambda(t)$, and mean time between failures (MTBF) (Wang and McDonald, 1994). The mean time before failure is the mean of random variable *T*, which is another index to evaluate a component's reliability.

3.9.2 Repair and Availability Characteristic of Component

The repair process depends on the random factors such as, cause of the failure, failure location, repair facilities, degree of damage, etc. Therefore, the repair time T_D is also a random variable. The mean time to repair (MTTR) is the mean of the component's repair time. Therefore the relationship between the repair rate μ and mean time to repair is given as

$$MTTR = \frac{1}{\mu} \tag{3.12}$$

The steady state availability (*A*) is used given as (Wang and McDonald, 1994)

$$A = \frac{\mu}{\lambda + \mu} \tag{3.13}$$

3.10 Transmission Line Reliability Model

As mentioned earlier, the transmission line is the component and its reliability can be demonstrates. Other components such as generating units, transformers, etc. can also be used. The reliability data include the failure rate λ, repair rate μ, and forced outage rate (FOR) q. The outage capacity model for a single line with capacity z, is explained in (Billinton and Allan, 1996), and (Wang and McDonald, 1994) as shown in Table 5.9.

3.10.1 Example of Weather Probability Related to the System Model

It is pointed out that the transmission line failure rate is closely related to weather conditions; the failure rate in rainy or in severe weather is many times higher than that in sunny or normal weather conditions (Wang and McDonald, 1994). Similarly, the failure rates in rain seasons $\lambda^{''}$ are higher than the failure rates $\lambda^{'}$ in sunny seasons. Usually the given failure rate λ is the average of $\lambda^{'}$ and $\lambda^{''}$.

$$\lambda = \lambda^{'} \frac{T_S}{T_S + T_R} + \lambda^{''} \frac{T_R}{T_S + T_R} \qquad \text{outages/yr} \tag{3.14}$$

where T_S is the number of sunny days per year (statistical figure) and T_R is the number of rain days.

3.11 Simulation Results

In this section, the simulation results for estimating the probability of contingency event and system reliability are presented.

3.11.1 Probability and Belief of Contingency Event

Weather status and failure rate of exclusive devices, in this case, transformers, circuit breakers, etc., is among the known causing line outages. The protective devices can also be considered when operated to protect the system. The initial probabilities are as shown in Figure 3.7. Upon the receiving of the evidence e_X, and posted to the node X, the node belief is updated using normalizing constant given by equation (3.10) as

$$Bel(\mathrm{X}) = p(\mathrm{X}|e) = \alpha\pi(\mathrm{X})\lambda(\mathrm{X}) \tag{3.13}$$

where $\pi(\mathrm{X})$ and $\lambda(\mathrm{X})$ represents the distribution of the total supports among the states of X through its parents and children respectively. Two mutually exclusive and exhausted hypotheses for a line under investigation are:

$H_1 = \text{line outage}$

$H_2 = \neg\text{line outage}$

Independent events on which evidence cab ne gathered are:

$E_1 = \text{weather is rainy}$

$E_2 = \mathit{exclusive}\ \text{equipment is faulty}$

$E_3 = \text{related component, i.e. "others" is faulty}$

From the three rules of knowledge base, the conditional probabilities $p(H_i|\mathrm{E}_j)$ for hypotheses are inferred based on $(H_1|\mathrm{E}_j) + p(H_2|\mathrm{E}_j) = 1$.

Table 5.9 Conditional and prior probabilities

Prior probabilities	
Probability of weather = rain $P(E_1)$	0.19
Probability of excl. equipments = faulty, $P(E_2)$	0.0001
Probability of other related components = faulty, $P(E_3)$	0.005
Probability of line = outage, $P(H_1)$	0.00001
Probability of line = —outage, $P(H_2)$	0.99999
Conditional probabilities	
Probability line outage given weather = rainy , $p(H_1\|E_1)$	0.071
Probability line outage given excl. equip =faulty, $p(H_1\|E_2)$	0.81
Probability line outage given others = failure, $p(H_1\|E_3)$	0.93

The simulation is based on the information, given in Table 5.9, which can be replaced by the data obtained from the operational power system. Simulation is based on the data collected for a system as shown in Table 5.1 to obtain updated belief. The probability of rain (roughly) can be estimated in a particular season of the year (rainy season or sunny season). The average ratio of number of days which have rain and no rain is estimated to be 0.19:0.81. This can be considered in details such as 0.35: 0.55 during rainy seasons and 0.03:0.97 during sunny season. The degrees of uncertainty are represented as a probability value from [0, 1]. Each piece of evidence updates the probability of a set of the hypotheses calculated via Bayesian rule presented in Equation (3.2).

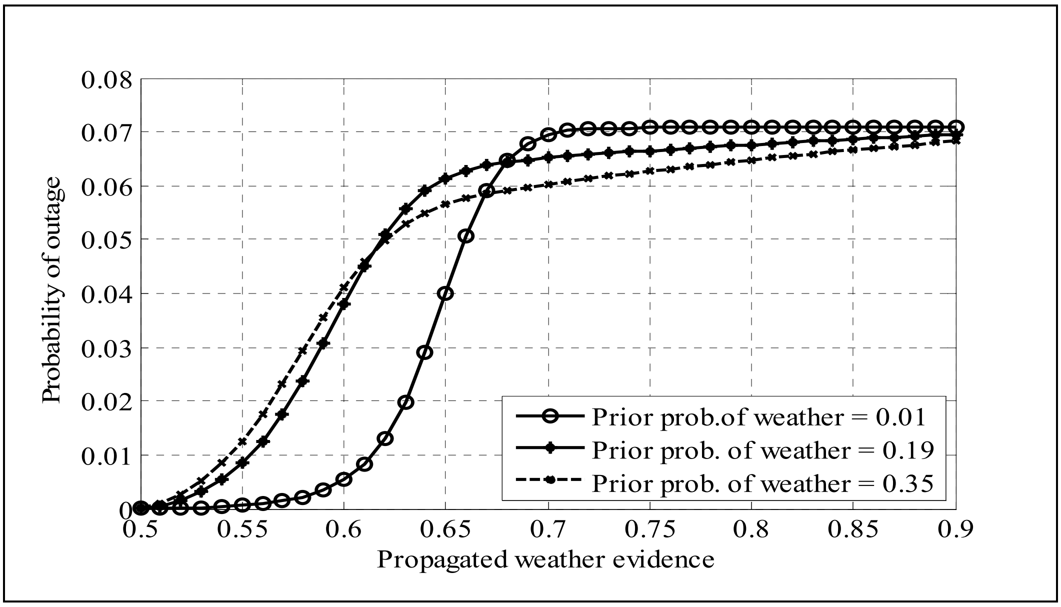


Figure 3.15 Weather knowledge-base describing the chances of a line-outage

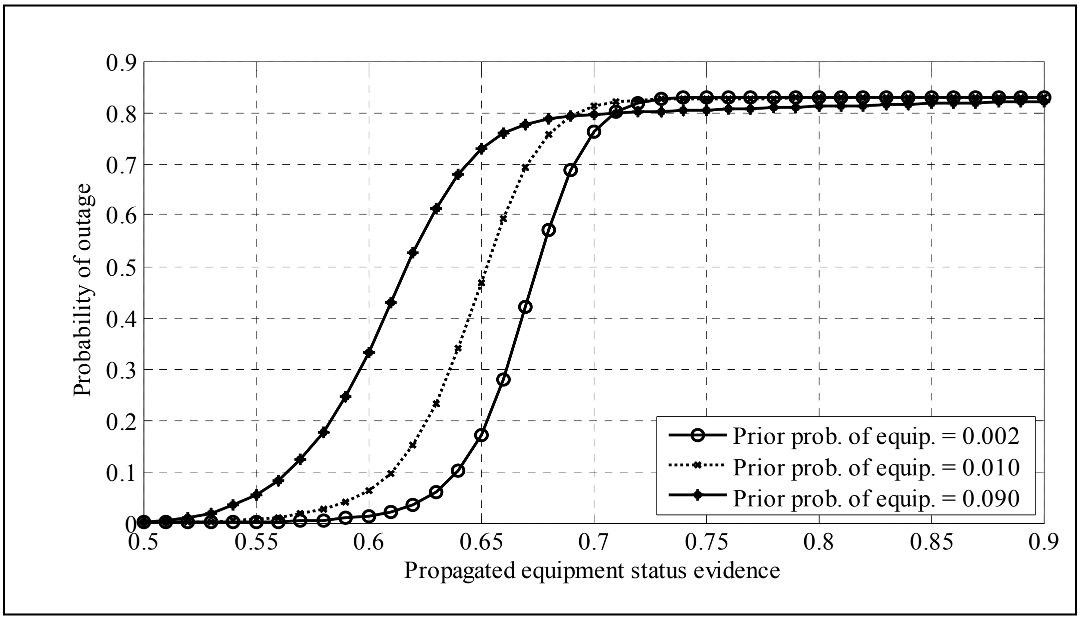


Figure 3.16 Equipments knowledge-base describing the chances of a line-outage

Figure 3.15 presents the updates of the line outage probabilities when confirming evidence e on E_1, (weather is rainy). Then the probability of line outage given that weather is rainy, $p(H_1|E_1)$ directly provides the posterior probability 0.071 for line being outage, which is significant increase from the prior probability of line outage 0.00001. The soft evidence e are encoded as probability of e given that weather is rainy, $p(e|E_1)$ are 0.55, 0.60, 0.65, and 0.75.

It should be noted that, the probability of line outage has increased significantly from the earlier prior value 0.00001, but not as much as 0.071 despite of the number of updates (updates), when evidence on E_1 was certain. Figure 3.16 presents the updates of the line outage probabilities when confirming evidence e on E_2, (exclusive equipments are faulty). Similar observation as it was for weather applies. That is, the probability of line outage has increased significantly from the earlier prior value 0.00001, but not as much as 0.81 despite of the number of updates (updates), when evidence on E_2 was certain.

Finally, Figure 3.17 presents the updates of the line outage probabilities when confirming evidence e on E_3, (other related components are faulty). As for the observation for weather and equipments, expressed above, the probability of line outage has increased significantly from the earlier prior value 0.00001, but not as much as 0.93 despite of the number of updates, when evidence on E_3 was certain.

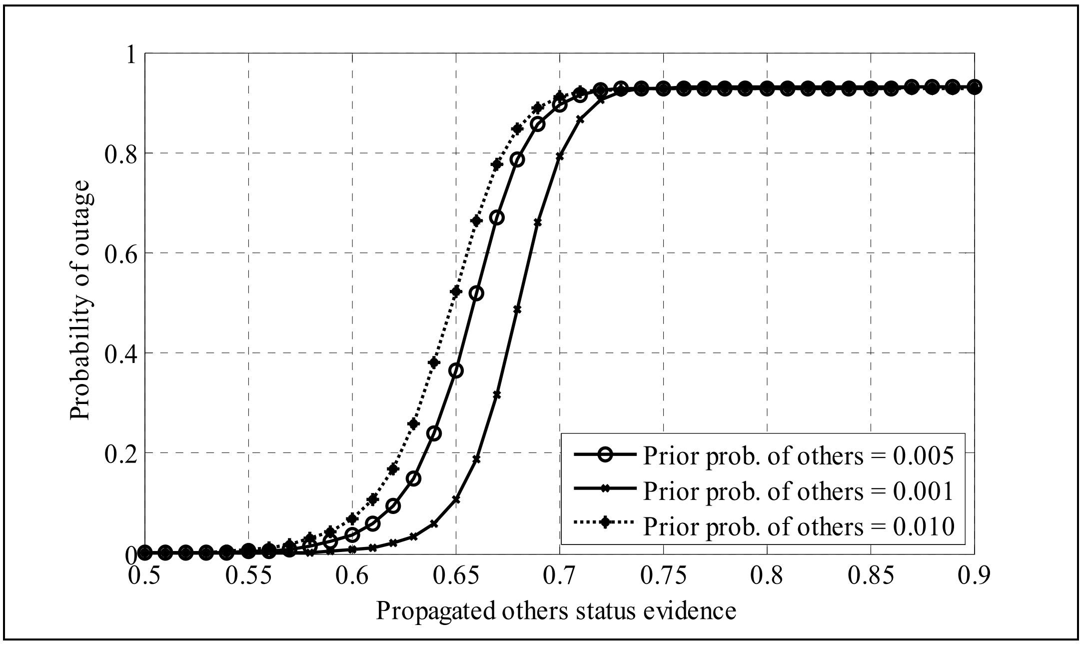


Figure 3.17 Other related components knowledge-base describing the chances of a line-outage

3.12 Conclusion

This chapter presents the techniques of estimating the probability of a contingency event, such as line outage due to the weather condition. The reliability of power system during rainy weather and normal weather are presented in chapter five. It is also observed in this chapter that, the closer the evidence e becomes nearer to the certain the less updates towards the higher probability of the event is achieved. It has been observed that, if evidence on a node (weather, equipments, and other components) variable is observed, then it is posted to line node and the joint distribution can be computed to find the belief of the line variables (outage or in). It should be noted that, the updates such as weather status from weather stations can change and the update must follow the changes. Similarly, multi-knowledge obtained from various sensors presents the similar results.

CHAPTER IV

STATE ESTIMATION

4.1 Introduction

State estimation is one of the main functions in a power system. In chapter five, the role state estimator is explained in a power system contingency analysis. In this chapter, this component of contingency analysis is discussed in details and several techniques and algorithms used in state estimators are presented.

The theory of system state estimation (SE) was initiated by Fred Schweppes in 1969 (Schweppes, 1970). In power systems, state estimation is the process carried out in the energy control centers in order to provide estimate of the system state based on the real-time system measurements model. The importance of state estimation is pragmatic since it is impractical to install each measuring unit at each location of the power system; therefore, several locations will remain unmetered. However, even if, in theoretical sense, all locations have measuring units, still due to unavoidable cases of communication problems or through any other logical reason, some of measurement records from measurement units may not be telemetered or received at the control center. In this case, the role of the state estimation is to obtain the best estimate of the system using the available measuring units in the state estimator (Young, et. al., 1988).

4.2 State Estimation Background

In principle, state estimators use measurement records from remote measurement units to estimate the states of a power system. These measurements are telemetered through communication systems from various locations to the control center. Measurements records can be bus injected active power, bus injected reactive power, line power flow, etc. As it will be explained later, the state estimator uses the received measurements to estimate the power system operating condition. The operating conditions of a power system at a given time can be determined if the network model and complex phasor voltages at every system buses are known as it is mentioned in Premrudeepreechacharn, et al., (2003); Ketabi and Hosseini, (2008); Abur and Expósito, (2004); Greyson and Oonsivilai, (2008); and Oonsivilai and Greyson (2009).

The operating condition of the power system may be in normal state, emergency or restorative, as the operating condition change (Abur and Expósito, 2004). Therefore, introduction of state estimation functions is to broaden the capability to the establishment of the energy management systems (EMS). The state estimation facilitates the EMS performance through identification of the operating state of the system using the telemetered measurements to the control center of the system. The state estimator's solution determines the optimal estimate for the system state based on the network model and the gathered measurements from the system. The number of measurement records and their accuracy contributes in the state estimator's performance in terms of the accuracy. In the end of this chapter, the algorithm used ensures that the state estimator is providing the close to accurate solution simply by increasing the number of measurements records in the state estimator is presented.

Critical elements affecting power system operations and control such as overloaded lines, credible contingencies, and unsatisfactory voltages can be determined through state estimation process. Under observability criterion, it is required to have number of measurements, m greater than or equal to the number of states, n. Thai is to say, for N bus system, considering a slack bus where phase angle of the bus is known, state variables becomes (2N-1), therefore at least (2N-1) measurements must be made available to the state estimator (Greyson and Oonsivilai, 2009; and Greyson and Oonsivilai, 2008).

Several methods have been proposed for powersystem state estimation. For example, many researchers including Premrudeepreechacharn, et al., (2003); and Ketabi and Hosseini, (2008) use iterative approach such as Newton-Raphson method to obtain the state estimation solution. Jacobian matrix and gain matrix is recalculated during iterations. In all cases, it is observed that, the accuracy of the estimated states is proportional to the number of measurement records, accuracy of the measurements, and the locations of the measurements in the power system network. The most common approach used in solving state estimation problem is based on weighted least squares (WLS). However in this chapter, other methods are introduced. The following section explains the details of WLS.

4.3 Weighted Least-Squares (WLS)

As mentioned in the previous section, the most common algorithm used in achievement of state estimation is weighted least-squares criterion where the objective is to minimize the sum of the squares of the weighted deviations of the estimated measurements from the actual measurements. More details regarding WLS state estimation process can be obtained from many available literatures including (Shahidehpour and Wang, 2003; Abur and Expósito, 2004; and Monticelli, 1999). Variable vector *x,* the output of the state estimators, include the magnitude voltages and the phase angle of the buses within the power system. The measurement model can be expressed as:

$$Z = H(x) + e \tag{4.1}$$

where, $Z \in \Re^m$ $z \in \Re^m$ is the measurements vector,

$x \in \Re^n$ is the state variables, and

$e \in \Re^m$ $e \in \Re^m$is the measurement error vector which is assumed to be made of independent random variable with Gaussian distribution.

Measurement model of the electric power system shown in Equation 4.1 can be represented by the measurement vector *Z*, the nonlinear function relating measurement $i \in 1,2,...,m$ $i \in 1,2,...,m$to the state vector *x*, and the vector of measurement error e as (Abur and Exposito, 2004)

$$Z = \begin{bmatrix} z_1 \\ z_2 \\ \vdots \\ z_m \end{bmatrix} = \begin{bmatrix} h_1(x_1, x_2, \ldots, x_n) \\ h_2(x_1, x_2, \ldots, x_n) \\ \vdots \\ h_m(x_1, x_2, \ldots, x_n) \end{bmatrix} + \begin{bmatrix} e_1 \\ e_2 \\ \vdots \\ e_m \end{bmatrix} \tag{4.2}$$

The standard deviation σ_i of each measurement i is calculated to reflect the expected accuracy of the corresponding meter used. The WLS is mainly introduced to emphasize the more accurate measurements more heavily than less accurate measurements, so that the estimation procedure can then force the results to coincide more closely with the measurements of greater accuracy (Crow, 2003). This leads to the weighted least squares estimation (Wood and Wollenberg, 1996):

$$\begin{aligned} \min J(x) &= \sum_{i=1}^{m} \frac{[z_i - h_i(x)]^2}{R_{ii}} \\ &= [z - h(x)]^T R^{-1} [z - h(x)] \end{aligned} \tag{4.3}$$

A weighting matrix reflects the level of conference in each measurement set as the inverse of the covariance matrix $W = R^{-1} \in \Re^{m \times m}$. Thus, measurements that come from instruments with good consistency (small variance) will carry greater weight than measurements that come from less accuracy in instruments (high variance) (Crow, 2003). The weighting matrix is given by

$$W = R^{-1} = \begin{bmatrix} \frac{1}{\sigma_1^2} & 0 & \cdots & 0 \\ 0 & \frac{1}{\sigma_2^2} & \cdots & 0 \\ \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & \cdots & \frac{1}{\sigma_m^2} \end{bmatrix} \tag{4.4}$$

The quantities being measured are themselves functions of other variables that have to be estimated. For a given measurements vector z, state variables designated as vector x can be estimated, where the number of state variables is n. Again, the state variables are those variables that, if known, completely specify the system.

One way to estimate x_i value is to minimize the sum of the squares of difference between the measurement values z_i and their estimates $\hat{z}_i$ that is, in turns, an objective function of the estimates of x_i given by Equation (4.3). In order to minimize $J(x)$, the derivative of $J(x)$ with respect to each $x_j (j = 1,2,...,n)$ is set to zero (Abur and Exposito, 2004).

$$\frac{\partial}{\partial x} J(x) = -H^T R^{-1}[z - h(x)] = 0 \tag{4.5}$$

where, $H(x) = \frac{\partial}{\partial x} h(x)$

4.4 State Estimation Using Statistical Approach

In this section, a statistical approach and the regression model (RM) utilized by the state estimator is presented. Regression models have been proposed for Least Absolute Value (LAV) estimators where a set of measurements $\{z_i, i = 1,2,...,m\}$ are assumed to be linearly related to a set of vector $\{A_i \in \Re^n i = 1,2,...,m\}$ and state variables represented by the unknown vector, $x : \{\xi_1, \xi_2,..., \xi_k\} \in \Re^k$ and observation i contains some random errors e_i (Wu and Hamada, 2000), (Abur and Exposito, 2004) and (Oonsivilai and Greyson, 2009). Although the technique has been utilized mostly in linear systems, as it is for neural network linerization approach, the regression surface model (RSM) can also be used in nonlinear systems. Note that, neural network is considered as an advanced regression surface model (Myers and Montgomery, 2002).

In this research, the regression surface model is applied to estimate the state variables of an electric power system. The daily load data are used for estimating the parameters of the regression function consists of observations on the predictor variables in this case, the recorded measurements $z \in \Re^m$ and the corresponding observations on the response variable, state variable $x \in \Re^k$. For each trial there are m measurement records and k state variables. More often for the better RSM performance, the number of trials (observations) n should be greater than the state variables k, that is $(n > k)$.

The logic behind this technique is based on the fact that, if power measurements of transmitting lines joining at bus i as shown in Figure 4.1 are known, then the bus voltage at the respective bus can be calculated. The regression function is simply based on the respective variables. For example,bus voltage for the bus i joining line 1, line 2, …, line l can be obtained when the power flow of the joining lines are known. Other parameters such as injected bus voltages, injected bus currents injected active or reactive powers at buses adjucent to bus i can also be used.

A sequential experimentation strategy is considered an efficient search of input factor space by using a first-order experiment. Response of the trials is a strategy to achieve a goal that involves experimentation, modeling, data analysis, and optimization (Islam and Lye, 2009). A first order experiment is analyzed by approximating the response relationship with a fitted first-order regression model. To obtain good estimator of the regression parameters, $\beta_0, \beta_1, ..., \beta_m$, the method of least square is employed.

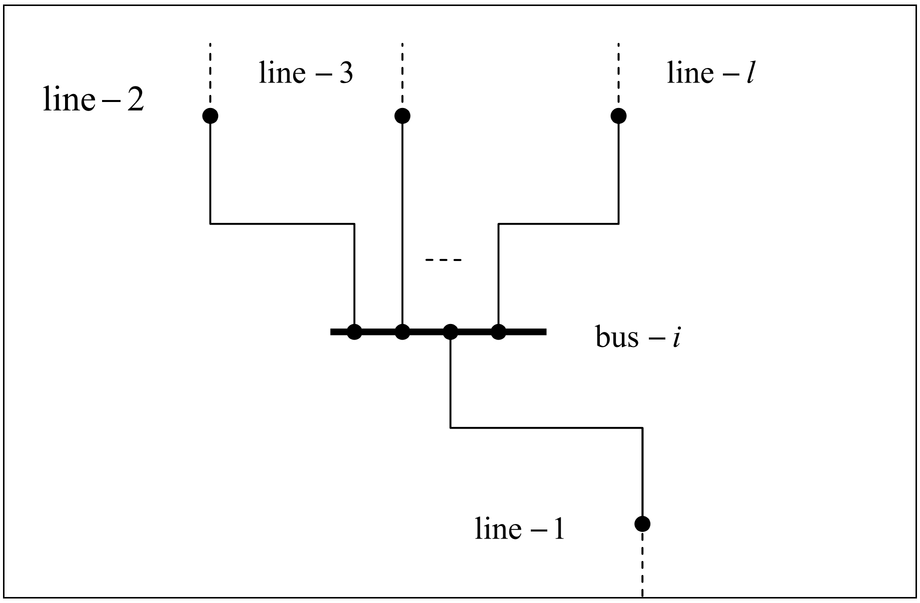


Figure 4.1 Transmission lines joining at bus i

4.4.1 Sequential Response Surface Model

The concept of sequential response surface model in a power system state estimation application is based on the statistical records obtained from the system. The load curve can be used as a tool in developing the model. Based on the limitation of this research, the stabilized system is assumed. In statistics, response surface methodology explores the relationships between several explanatory variables and one or more response variables. The main idea of RSM is to use a sequence of designed experiments to obtain an optimal response. The motive on RSM is based on the fact that the model is easy to estimate unknown. Although, most applications that use RSM are linear in their original form, the nonlinear system can also be linearized to take the form of RSM model.

Consider the observed measurements $z(t)$ of the power system that depends on the state variables, $(x_1(t), x_2(t),..., \xi_k(t)) \in \Re^k$ their relationship can be modeled by

Equation (3.48) given available m measurement readings and n state variables in each time of computation (Greyson and Oonsivilai, 2008) and (Greyson and Oonsivilai, 2009).

$$z = f(x_1, x_2, \ldots, x_k) + e \tag{4.6}$$

where $f(x_1, x_2, \ldots, x_k) \in \Re^{m \times k}$ is the true response function and $e \in \Re^{m}$ is the independent error term that represents the sources of variability not captured by $f(x_1, x_2, \ldots, x_k)$.

In this context, the p.u. (per unit) values are considered coded variables. In RSM, it is convenient to transform the natural variables to coded variables $x_1, x_2, \ldots, x_k)$ which are usually defined to be dimensionless with mean zero and the same spread or standard deviation (Myers and Montgomery, 2002). The reciprocal of Equation (4.6) can easily be used to obtain power state variables when the measurements are available. In this research, recorded measurements are used as the variable parameters to calculate the state variables. In this case, the state variables replace the system response given by z while measurements are considered to replace the values of x. The foundation of mathematical approach for this technique is presented in the following subsections.

4.4.1.1 Least Square Normal Equations

In this section, the mathematical approach is used to explain the concept of least square (LS). For more than two independent variables, multiple-regression model, the relationship between a set of independent variables and the response z is determined by Equation (4.7) (Myers and Montgomery, 2002).

$$z_i = \beta_0 + \beta_1 x_{i1} + \beta_2 x_{i2} + \ldots + \beta_k x_{ik} + e$$
$$= \beta_0 + \sum_{j=1}^{k} \beta_k x_{ik} + e \tag{4.7}$$

$i = 1,2,\ldots,n$ and $j = 1,2,\ldots,k$

where n is the number of observations, and k is the number of variables.

The method of least square chooses $\beta's$ in Equation (4.7) so that the sum of the squares of the errors, e_i are minimized.

$$LS = \sum_{i=1}^{n} e_i^2$$
$$= \sum_{i=1}^{n} \left(z_i - \beta_0 - \sum_{j}^{k} \beta_j x_{ij} \right) \tag{4.8}$$

Hence, the least square (LS) function is minimized with respect to $\beta_0, \beta_1, \ldots, \beta_k$ where the Least Square Estimator (LSE) $b_0, b_1, \ldots, b_k$ is given by

$$\left. \frac{\partial LS}{\partial \beta_0} \right|_{b_0, b_1, \ldots, b_k} = -2 \sum_{i=1}^{n} \left(z_i - b_0 - \sum_{j}^{k} b_j x_{ij} \right) = 0 \tag{4.9}$$

and also,

$$\left. \frac{\partial LS}{\partial \beta_j} \right|_{b_0, b_1, \ldots, b_k} = -2 \sum_{i=1}^{n} \left(z_i - b_0 - \sum_{j}^{k} b_j x_{ij} \right) x_{ij} = 0 \tag{4.10}$$

$j = 1,2,\ldots,k$

Equation (4.9) and (4.10) are simplified as

$$\begin{aligned}
&nb_0 + b_1 \sum_{i=1}^{n} x_{i1} + b_2 \sum_{i=1}^{n} x_{i2} + \ldots + b_k \sum_{i=1}^{n} x_{ik} = \sum_{i=1}^{n} z_i \\
&b_0 \sum_{i=1}^{n} x_{i1} + b_1 \sum_{i=1}^{n} (x_{i1})^2 + b_2 \sum_{i=1}^{n} x_{i1} x_{i2} + \ldots + b_k \sum_{i=1}^{n} x_{i1} x_{ik} = \sum_{i=1}^{n} x_{i1} z_i \\
&\quad \vdots \qquad\qquad\qquad \vdots \qquad\qquad\qquad \vdots \qquad\qquad \vdots \\
&b_0 \sum_{i=1}^{n} x_{ik} + b_1 \sum_{i=1}^{n} x_{ik} x_{i1} + b_2 \sum_{i=1}^{n} x_{i2} x_{i2} + \ldots + b_k \sum_{i=1}^{n} (x_{ik})^2 = \sum_{i=1}^{n} x_{ik} z_i
\end{aligned} \tag{4.11}$$

Equation (4.11) is the *least square normal equations* (LS-NE). These LN-NEs can be written in a matrix form, using the vector of regression coefficients, β observation vector, z and independent error vector, ϵ as shown by Equation (4.12)

$$z = x\beta + e \tag{4.12}$$

where

$$x = \begin{bmatrix} z_{l1} \\ z_{l2} \\ \vdots \\ z_{\ln} \end{bmatrix}; \quad l = 1,2,\ldots,m; \quad x = \begin{bmatrix} 1 & x_{11} & x_{12} & \cdots & x_{1k} \\ 1 & x_{21} & x_{22} & \cdots & x_{2k} \\ 1 & \vdots & \vdots & \ddots & \vdots \\ 1 & x_{n1} & x_{n2} & \cdots & x_{nk} \end{bmatrix}$$

$$\beta = \begin{bmatrix} \beta_0 \\ \beta_1 \\ \vdots \\ \beta_k \end{bmatrix}; \quad \text{and} \quad e = \begin{bmatrix} e_1 \\ e_2 \\ \vdots \\ e_n \end{bmatrix};$$

Thus to find the vector of Least Square Estimator (LSE), b that minimizes LS function

$$LS = \sum_{i=1}^{n} e_i^2 = e'e = (z - X\beta)'(z - x\beta) \tag{4.13}$$

Hence, it is expressed that,

$$\left.\frac{\partial LS}{\partial \beta}\right|_b = -2x'z + 2x'xb \tag{4.14}$$

Thus the LSE of β is computed as

$$b = (x'Xx)^{-1} x'z \tag{4.15}$$

The fitted regression model is

$$\hat{z} = xb \tag{4.16}$$

Equation (4.16) can be expressed in scalar notation as

$$\hat{z} = b_0 + \sum_{j=1}^{k} b_j x_{ij} \qquad i = 1,2,..., n \tag{4.17}$$

The difference between the observation z_i and the fitted value $\hat{z}_i$ is a residual.

4.4.1.2 Model Adequacy

Fitting a regression model requires that the errors are uncorrelated random variables with mean zero and constant variance (Wu and Hamada, 2002) and (Montgomery, et al., 2007). The residuals from the regression model are helpful in inspecting the assumptions of normality and constant variance, and in determining whether additional terms in the model would be useful. If the model is correct, the residuals should be structure-less, i.e. unrelated to any other variable including the predicted response (Montgomery, 2005).

4.5 Regression Surface Model Performance

The performance of Response Surface Model method, described in the previous section, is analyzed using two different power system networks, IEEE-14 bus system shown in Figure 4.3 and IEEE-57 bus system shown in Figure 4.5. Due to convergence issues in IEEE 57 bus system, only performance of RSM method results is presented. For IEEE-14 bus system, the comparison of WLS and RSM are presented. Measurement set is generated by adding random noise in accordance with the respective standard deviation. The injected bus power measurements are generated by adding Gaussian noise, $(\sigma = 0.001)$ to the exact values corresponding to the state given in example presented by Abur and Exp□sito (Abur and Exp□sito, 2004).

4.5.1 IEEE 14 Bus System

For IEEE 14-bus system presented in Figure 4.3, the theoretical daily load is used. Three operating points at 1700, 2300, and 0400 hours, are used in comparing the performance of the regression surface model, weighted least square and the power flow method. It is assumed that, the results obtained from the power flow computation are true values. Comparison based on the system state estimation solution results are presented in Table 4.1, Table 4.2, and Table 4.3. The set of load data used in the regression model in this research for IEEE-14 bus were generated randomly and respective true real and reactive power injection at buses are computed from the bus information of the particular power system. Bus data for IEEE-14 bus obtained from (Wang and MacDonald, 1994). The testing model is based on the measurements records collected from each bus of the system. The load flow curve for IEEE-14 system is as shown in Figure 4.2.

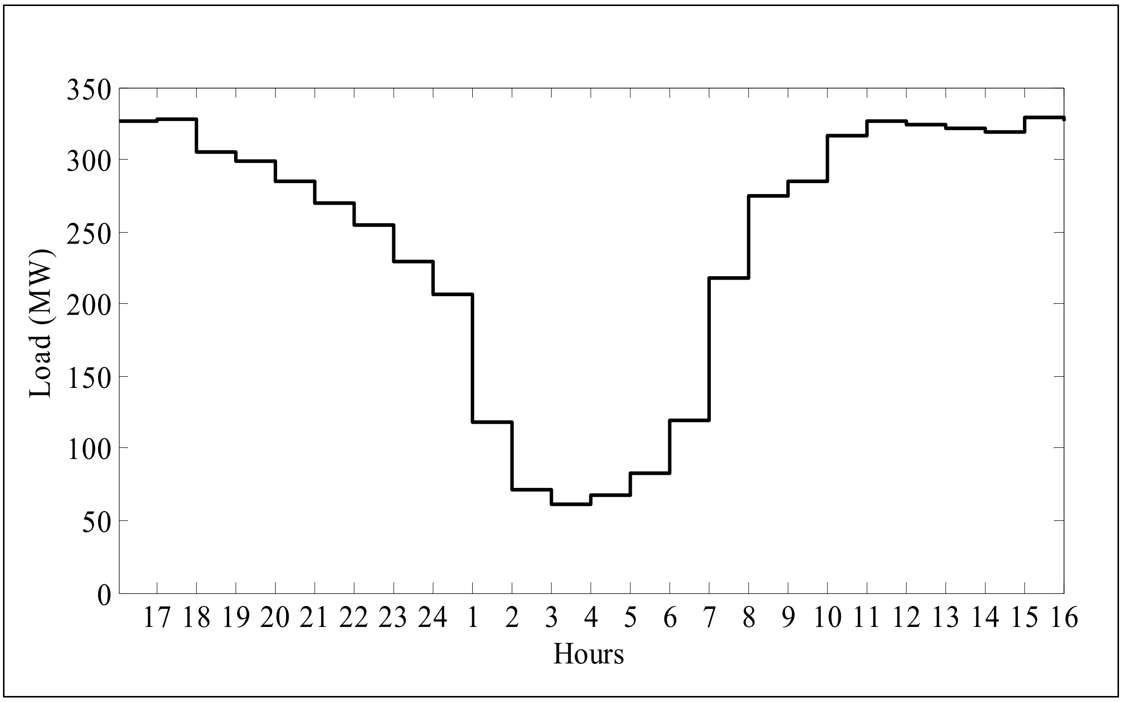


Figure 4.2 IEEE-14 bus system daily load flow curve

Table 4.1 The state estimation comparison for IEEE 14 bus system – case 1.

	True measurements		Recorded Measurements			
Bus	Injected Active Power, P	Injected Reactive Power, Q	Injected Active Power, P	Injected Reactive Power, Q	Mag. V (p.u.)	Phase angle (Deg.)
1	2.324	0.180	2.317	0.183	1.060	0.00
2	0.110	0.181	0.104	0.177	1.045	-7.06
3	-0.920	0.041	-0.930	0.046	1.010	-16.01
4	-0.330	0.039	-0.338	0.035	0.995	-14.21
5	-0.080	-0.016	-0.088	-0.013	0.997	-12.64
6	-0.150	0.063	-0.144	0.061	1.070	-24.25
7	0.000	0.000	0.000	-0.009	1.037	-20.22
8	0.000	0.174	0.000	0.164	1.090	-20.22
9	-0.440	-0.164	-0.444	-0.174	1.020	-23.36
10	-0.160	-0.058	-0.155	-0.053	1.015	-24.36
11	-0.180	-0.018	-0.181	-0.022	1.027	-25.18
12	-0.300	-0.016	-0.294	-0.017	1.019	-27.09
13	-0.190	-0.058	-0.186	-0.068	1.028	-25.98
14	-0.220	-0.050	-0.228	-0.051	0.999	-26.18

Table 4.1 The state estimation comparison for IEEE 14 bus system case-1 (continued)

WLS		Residual (WLS)		RSM		Residual (RSM)	
Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)
1.090	0.00	-0.030	0.00	1.060	0.00	0.000	0.00
1.061	-4.60	-0.016	-2.47	1.039	-5.92	0.006	-1.15
1.023	-11.71	-0.013	-4.30	1.020	-15.14	-0.010	-0.87
1.024	-9.63	-0.029	-4.58	0.996	-14.28	-0.001	0.07
1.027	-8.41	-0.030	-4.23	0.996	-12.78	0.001	0.13
1.061	-16.37	0.009	-7.88	1.068	-24.14	0.002	-0.11
1.049	-13.43	-0.012	-6.78	1.029	-20.28	0.008	0.06
1.079	-13.00	0.011	-7.21	1.086	-20.14	0.004	-0.08
1.034	-16.02	-0.014	-7.34	1.014	-24.18	0.005	0.82
1.030	-16.64	-0.015	-7.72	1.004	-24.34	0.011	-0.02
1.038	-17.13	-0.011	-8.05	1.017	-25.20	0.011	0.02
1.029	-18.67	-0.010	-8.42	1.001	-27.71	0.018	0.62
1.037	-17.73	-0.009	-8.26	1.021	-26.26	0.008	0.27
1.016	-17.99	-0.017	-8.19	0.985	-27.03	0.014	0.85

Table 4.2 The state estimation comparison for IEEE 14 bus system – case 2.

	True measurements		Recorded Measurements			
Bus	Injected Active Power, P	Injected Reactive Power, Q	Injected Active Power, P	Injected Reactive Power, Q	Mag. V (p.u.)	Phase angle (Deg.)
1	2.324	0.180	2.333	0.179	1.060	0.00
2	0.240	0.394	0.246	0.399	1.045	-5.08
3	-0.730	0.033	-0.725	0.040	1.010	-12.08
4	-0.260	0.039	-0.263	0.032	1.006	-10.86
5	-0.040	-0.016	-0.045	-0.010	1.007	-9.66
6	-0.110	0.046	-0.103	0.041	1.070	-19.30
7	0.000	0.000	0.009	-0.003	1.045	-15.67
8	0.000	0.174	0.004	0.175	1.090	-15.67
9	-0.330	-0.164	-0.328	-0.169	1.028	-18.20
10	-0.130	-0.058	-0.136	-0.053	1.023	-19.04
11	-0.140	-0.018	-0.140	-0.008	1.033	-19.83
12	-0.270	-0.016	-0.274	-0.020	1.023	-21.83
13	-0.180	-0.058	-0.179	-0.064	1.031	-20.82
14	-0.190	-0.050	-0.188	-0.057	1.008	-20.74

Table 4.2 The state estimation comparison for IEEE 14 bus system case-2 (continued)

WLS		Residual (WLS)		RSM		Residual (RSM)	
Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)
1.094	0.00	-0.034	0.00	1.060	0.00	0.000	0.00
1.069	-4.43	-0.024	-0.65	1.047	-5.50	-0.002	0.41
1.027	-10.88	-0.017	-1.20	1.006	-12.28	0.004	0.20
1.019	-9.59	-0.013	-1.26	1.009	-10.85	-0.003	-0.01
1.022	-8.44	-0.015	-1.22	1.010	-9.58	-0.003	-0.08
1.040	-17.60	0.030	-1.71	1.073	-19.31	-0.003	0.00
1.035	-14.42	0.009	-1.25	1.047	-15.74	-0.002	0.07
1.064	-14.45	0.027	-1.22	1.090	-15.77	0.000	0.10
1.017	-16.98	0.010	-1.22	1.031	-17.90	-0.003	-0.30
1.011	-17.76	0.013	-1.27	1.025	-19.11	-0.002	0.08
1.017	-18.39	0.017	-1.45	1.036	-19.79	-0.002	-0.04
1.002	-20.28	0.021	-1.55	1.031	-21.77	-0.008	-0.06
1.011	-19.27	0.020	-1.55	1.038	-20.60	-0.006	-0.22
0.992	-19.44	0.016	-1.30	1.015	-20.53	-0.007	-0.21

Table 4.3 The state estimation comparison for IEEE 14 bus system – case 3.

	True measurements		Recorded Measurements			
Bus	Injected Active Power, P	Injected Reactive Power, Q	Injected Active Power, P	Injected Reactive Power, Q	Mag. V (p.u.)	Phase angle (Deg.)
1	2.324	0.180	2.317	0.170	1.060	0.00
2	0.350	0.575	0.354	0.579	1.045	0.06
3	-0.090	0.004	-0.088	0.010	1.010	-0.66
4	-0.030	0.039	-0.028	0.032	1.032	-1.30
5	-0.030	-0.016	-0.021	-0.020	1.032	-1.22
6	-0.050	0.021	-0.044	0.026	1.070	-3.86
7	0.000	0.000	0.002	-0.009	1.061	-2.57
8	0.000	0.174	-0.009	0.180	1.090	-2.57
9	-0.080	-0.164	-0.081	-0.166	1.046	-3.24
10	-0.030	-0.058	-0.034	-0.053	1.045	-3.41
11	-0.030	-0.018	-0.031	-0.015	1.054	-3.73
12	-0.060	-0.016	-0.051	-0.016	1.056	-4.38
13	-0.060	-0.058	-0.056	-0.061	1.054	-4.15
14	-0.090	-0.050	-0.093	-0.048	1.036	-4.17

Table 4.3 The state estimation comparison for IEEE 14 bus system case-3 (continued)

WLS		Residual (WLS)		RSM		Residual (RSM)	
Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)
1.098	0.00	-0.038	0.00	1.060	0.00	0.000	0.00
1.078	-4.05	-0.033	4.11	1.068	-4.48	-0.023	4.54
1.043	-7.94	-0.033	7.28	0.983	-2.86	0.027	2.20
1.015	-9.21	0.017	7.91	1.062	-1.42	-0.030	0.12
1.017	-8.42	0.016	7.19	1.063	-0.53	-0.031	-0.69
1.022	-18.94	0.048	15.08	1.125	-4.07	-0.055	0.21
1.021	-16.31	0.040	13.75	1.145	-2.66	-0.084	0.09
1.049	-17.67	0.041	15.10	1.153	-2.52	-0.063	-0.04
1.002	-18.41	0.045	15.17	1.141	-0.99	-0.095	-2.25
0.992	-19.43	0.053	16.02	1.148	-4.14	-0.103	0.74
0.996	-20.09	0.058	16.37	1.159	-3.59	-0.104	-0.13
0.989	-21.29	0.067	16.91	1.195	-4.12	-0.139	-0.26
0.991	-20.72	0.063	16.57	1.155	-3.68	-0.101	-0.47
0.969	-21.34	0.067	17.17	1.173	-3.12	-0.137	-1.04

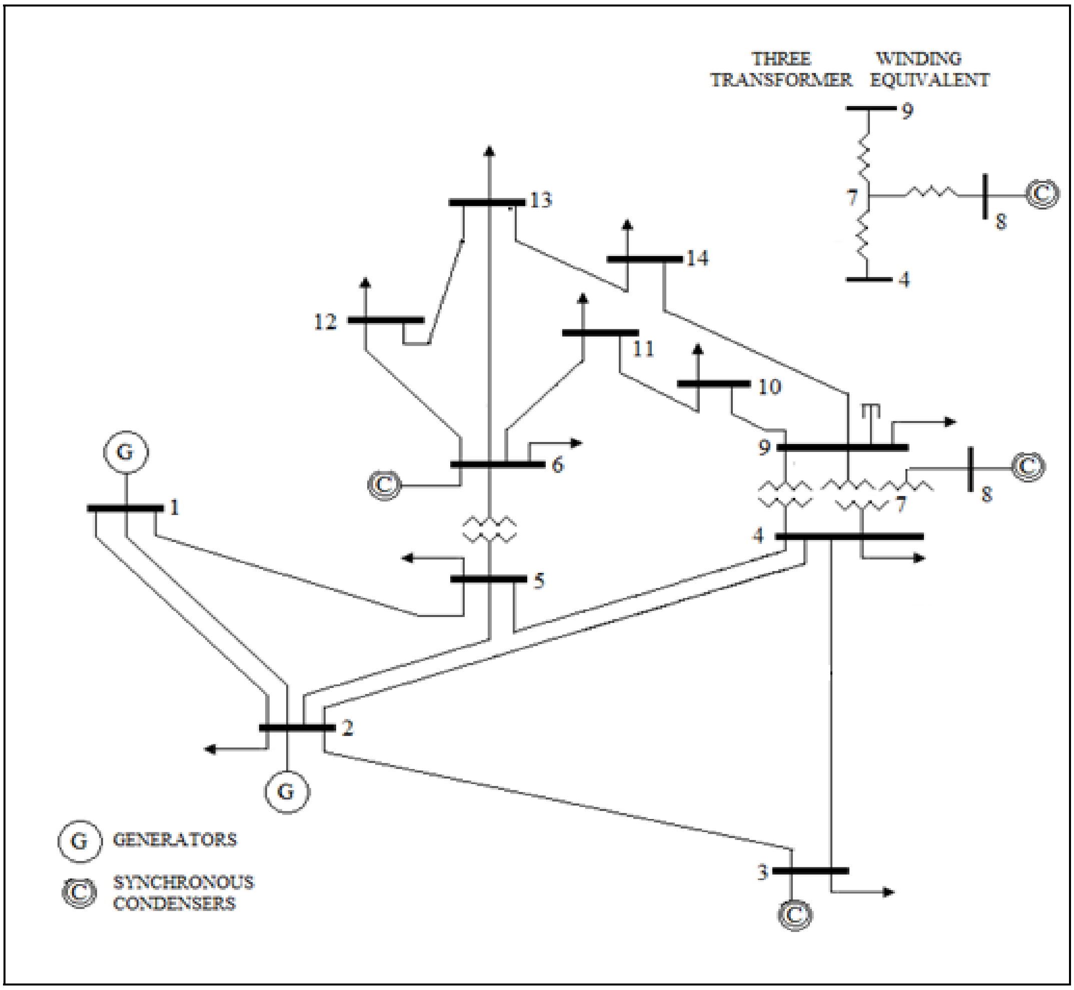


Figure 4.3 The IEEE 14-Bus System.

4.5.2 IEEE-57 Bus System

For IEEE-57 bus system the state estimation solution comparison is between the RSM and results obtained from the load flow. The measurements obtained from each case are presented. The load flow curve for IEEE-57 system is as shown in Figure 4.4. As for the IEEE-14 bus system, three operating points at 1700, 2300, and 0400 hours, are used in comparing the performance of the RSM with the power flow method. Results are presented in Table 4.4, Table 4.5 and Table 4.6 for case1, case 2, and case 3, respectively.

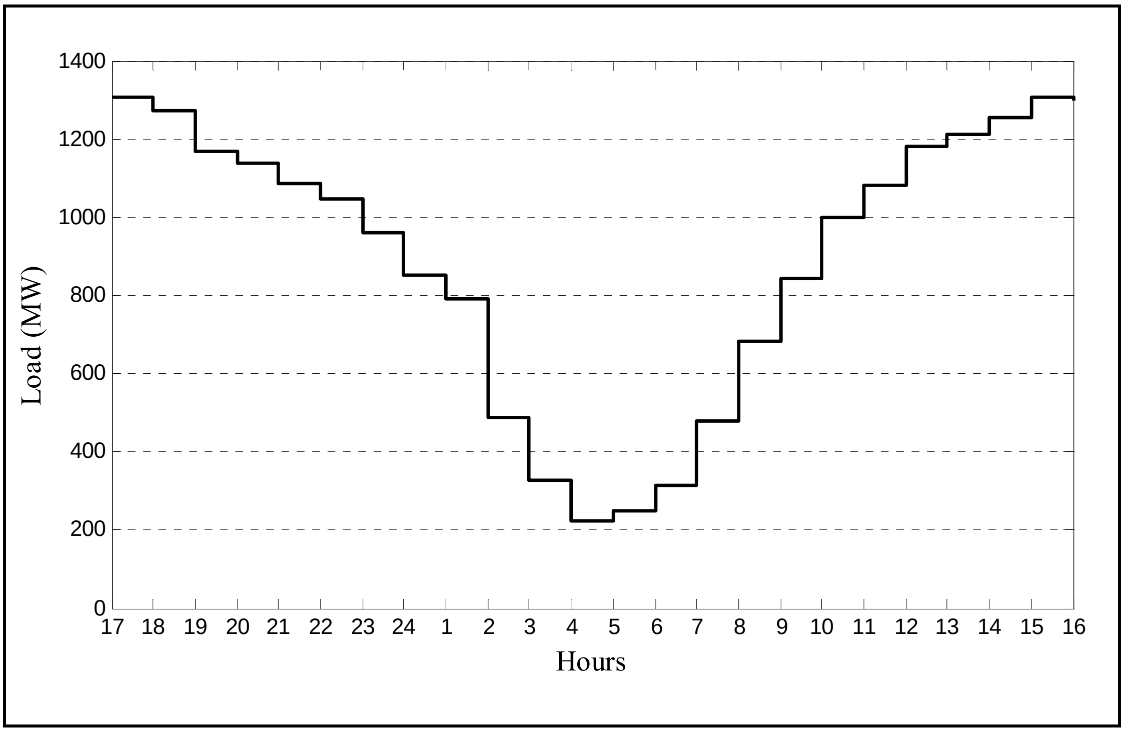


Figure 4.4 IEEE-57 bus system daily load flow curve

Table 4.4 State estimation comparison for IEEE 57 bus system – case 1.

	True measurements		Recorded Measurements			
Bus	Injected Active Power, P	Injected Reactive Power, Q	Injected Active Power, P	Injected Reactive Power, Q	Mag. V (p.u.)	Phase angle (Deg.)
1	3.991	2.033	3.999	2.035	1.040	0.00
2	0.900	26.612	0.908	26.608	1.010	0.10
3	1.340	29.485	1.337	29.483	0.985	-5.53
4	0.000	0.000	-0.004	-0.008	0.991	-8.90
5	-0.300	0.092	-0.296	0.088	0.982	-13.01
6	0.260	0.013	0.262	0.007	0.980	-13.64
7	0.000	0.000	-0.007	0.004	1.002	-17.44
8	-0.578	0.093	-0.587	0.095	1.005	-17.52
9	-0.020	0.004	-0.023	0.001	0.980	-16.59
10	-0.050	0.020	-0.058	0.013	1.015	-16.15
11	0.000	0.000	0.007	-0.009	0.999	-16.76
12	-0.054	0.084	-0.062	0.090	1.015	-12.94
13	-0.210	0.027	-0.206	0.031	1.002	-14.24
14	-0.210	0.106	-0.212	0.099	1.002	-13.54
15	-0.190	0.043	-0.186	0.038	1.009	-9.53
16	-0.380	0.026	-0.384	0.020	1.018	-10.53
17	-0.440	0.084	-0.440	0.082	1.029	-6.54
18	-0.300	0.107	-0.303	0.103	1.048	-15.05
19	-0.120	0.022	-0.123	0.020	1.017	-22.72
20	-0.120	0.052	-0.118	0.053	1.029	-24.42
21	0.000	0.000	0.010	0.003	1.077	-20.94
22	0.000	0.000	-0.007	-0.008	1.083	-20.49
23	-0.090	0.030	-0.095	0.035	1.082	-20.72
24	0.000	0.000	0.005	-0.003	1.070	-23.25
25	-0.040	0.020	-0.032	0.017	1.124	-30.27
26	0.000	0.000	-0.009	0.006	1.025	-23.03
27	-0.110	0.006	-0.104	-0.002	1.031	-21.62
28	-0.100	0.050	-0.110	0.059	1.040	-20.52
29	-0.080	0.012	-0.078	0.006	1.047	-19.43
30	-0.060	0.030	-0.062	0.037	1.117	-32.73
31	-0.120	0.060	-0.121	0.060	1.112	-37.00
32	-0.110	0.055	-0.109	0.053	1.122	-37.94
33	-0.140	0.070	-0.138	0.072	1.119	-38.30
34	0.000	0.000	-0.003	-0.002	1.029	-26.86
35	-0.140	0.070	-0.136	0.077	1.037	-25.71
36	0.000	0.000	-0.001	-0.007	1.047	-24.34
37	0.000	0.000	-0.009	0.004	1.057	-23.27
38	-0.170	0.085	-0.164	0.077	1.087	-19.92
39	0.000	0.000	0.001	-0.007	1.054	-23.48
40	0.000	0.000	0.000	0.004	1.043	-24.56

Table 4.4 State estimation comparison for IEEE 57 bus system – case 1 (continued)

41	-0.080	0.038	-0.073	0.041	1.100	-24.30
42	-0.130	0.081	-0.123	0.079	1.088	-28.74
43	-0.130	0.065	-0.138	0.055	1.063	-19.62
44	-0.130	0.020	-0.120	0.013	1.083	-18.00
45	0.000	0.000	0.007	-0.007	1.084	-13.03
46	0.000	0.000	-0.003	0.002	1.118	-16.02
47	-0.290	0.113	-0.280	0.113	1.110	-18.43
48	0.000	0.000	0.007	0.004	1.103	-18.91
49	-0.270	0.128	-0.264	0.120	1.114	-18.87
50	-0.160	0.080	-0.159	0.088	1.108	-19.05
51	-0.190	0.056	-0.196	0.048	1.102	-17.19
52	-0.160	0.072	-0.150	0.081	1.039	-22.18
53	-0.120	0.060	-0.119	0.065	1.040	-22.52
54	-0.080	0.027	-0.083	0.035	1.051	-21.27
55	-0.210	0.105	-0.213	0.101	1.069	-18.93
56	-0.260	0.075	-0.253	0.065	1.079	-30.22
57	-0.150	0.045	-0.142	0.053	1.081	-30.99

Table 4.4 State estimation comparison for IEEE 57 bus system – case 1 (continued)

			Residual			RSM		Residual (RSM)	
	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)		Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)
1	1.040	0.00	0.000	0.00	30	1.158	-31.10	-0.041	-1.63
2	1.010	0.22	0.000	-0.11	31	1.161	-35.00	-0.049	-2.00
3	0.993	-5.19	-0.008	-0.35	32	1.169	-35.83	-0.047	-2.11
4	1.003	-8.42	-0.011	-0.48	33	1.167	-36.16	-0.047	-2.14
5	0.999	-12.24	-0.017	-0.76	34	1.066	-25.89	-0.037	-0.97
6	0.998	-12.77	-0.018	-0.88	35	1.073	-24.80	-0.035	-0.91
7	1.029	-16.33	-0.027	-1.11	36	1.080	-23.46	-0.033	-0.88
8	1.037	-16.24	-0.032	-1.28	37	1.088	-22.40	-0.031	-0.86
9	1.003	-15.54	-0.023	-1.04	38	1.112	-19.09	-0.025	-0.83
10	1.033	-15.21	-0.018	-0.94	39	1.086	-22.62	-0.032	-0.86
11	1.020	-15.88	-0.021	-0.88	40	1.077	-23.68	-0.034	-0.88
12	1.028	-12.06	-0.013	-0.88	41	1.131	-23.11	-0.031	-1.20
13	1.019	-13.49	-0.017	-0.74	42	1.125	-27.43	-0.036	-1.31
14	1.018	-12.89	-0.016	-0.64	43	1.089	-18.66	-0.026	-0.96
15	1.021	-9.09	-0.012	-0.45	44	1.105	-17.24	-0.023	-0.76
16	1.028	-9.91	-0.011	-0.62	45	1.100	-12.41	-0.016	-0.63
17	1.035	-6.20	-0.006	-0.34	46	1.139	-15.28	-0.020	-0.74
18	1.066	-14.51	-0.017	-0.54	47	1.133	-17.62	-0.023	-0.81
19	1.040	-22.24	-0.023	-0.47	48	1.127	-18.09	-0.024	-0.82
20	1.058	-23.77	-0.028	-0.66	49	1.137	-17.99	-0.023	-0.88
21	1.103	-20.13	-0.026	-0.81	50	1.129	-18.15	-0.021	-0.91
22	1.109	-19.64	-0.026	-0.85	51	1.122	-16.27	-0.020	-0.93
23	1.108	-19.86	-0.026	-0.86	52	1.072	-21.11	-0.034	-1.07
24	1.100	-22.18	-0.030	-1.07	53	1.074	-21.44	-0.034	-1.08
25	1.161	-28.80	-0.037	-1.47	54	1.081	-20.14	-0.030	-1.13
26	1.053	-21.95	-0.028	-1.08	55	1.096	-17.74	-0.028	-1.19
27	1.059	-20.46	-0.028	-1.17	56	1.122	-28.93	-0.043	-1.29
28	1.069	-19.38	-0.029	-1.14	57	1.127	-29.57	-0.046	-1.42
29	1.076	-18.29	-0.029	-1.14					

Table 4.5 State estimation comparison for IEEE 57 bus system – case 2.

	True measurements		Recorded Measurements			
Bus	Injected Active Power, P	Injected Reactive Power, Q	Injected Active Power, P	Injected Reactive Power, Q	Mag. V (p.u.)	Phase angle (Deg.)
1	2.948	1.501	2.950	1.497	1.040	0.00
2	0.887	26.230	0.886	26.230	1.010	0.46
3	1.157	25.449	1.160	25.442	0.985	-3.96
4	0.000	0.000	0.001	0.007	0.992	-7.14
5	-0.190	0.058	-0.197	0.068	0.983	-11.20
6	-0.150	0.007	-0.152	0.013	0.980	-12.30
7	0.000	0.000	0.006	-0.006	1.004	-14.88
8	-0.967	0.155	-0.966	0.158	1.005	-15.54
9	-0.113	0.022	-0.117	0.022	0.980	-13.66
10	-0.010	0.004	-0.016	0.007	1.015	-12.50
11	0.000	0.000	0.002	0.004	1.004	-12.82
12	-0.032	0.050	-0.035	0.041	1.015	-9.78
13	-0.100	0.013	-0.095	0.013	1.008	-10.68
14	-0.120	0.061	-0.119	0.059	1.009	-9.98
15	-0.120	0.027	-0.113	0.030	1.015	-7.01
16	-0.240	0.017	-0.247	0.022	1.021	-7.80
17	-0.290	0.055	-0.287	0.057	1.032	-4.79
18	-0.250	0.089	-0.248	0.080	1.045	-11.65
19	-0.080	0.015	-0.074	0.013	1.033	-16.11
20	-0.060	0.026	-0.066	0.024	1.044	-16.85
21	0.000	0.000	-0.005	0.005	1.096	-14.83
22	0.000	0.000	-0.004	0.004	1.100	-14.59
23	-0.080	0.027	-0.088	0.026	1.099	-14.79
24	0.000	0.000	0.001	0.007	1.091	-16.98
25	-0.010	0.005	-0.018	-0.004	1.135	-21.77
26	0.000	0.000	0.000	-0.001	1.045	-16.90
27	0.000	0.000	-0.010	0.002	1.045	-16.30
28	-0.050	0.025	-0.043	0.035	1.045	-16.07
29	-0.030	0.005	-0.025	0.000	1.046	-15.71
30	-0.090	0.045	-0.093	0.045	1.131	-23.74
31	-0.110	0.055	-0.101	0.054	1.132	-25.90
32	-0.050	0.025	-0.059	0.017	1.146	-24.27
33	-0.060	0.030	-0.050	0.034	1.145	-24.41
34	0.000	0.000	0.008	0.000	1.075	-17.58
35	-0.050	0.025	-0.054	0.027	1.079	-16.87
36	0.000	0.000	0.003	0.007	1.084	-16.17
37	0.000	0.000	-0.007	-0.007	1.089	-15.67
38	-0.100	0.050	-0.091	0.053	1.103	-14.14
39	0.000	0.000	0.000	-0.003	1.088	-15.74
40	0.000	0.000	0.008	-0.002	1.082	-16.22

Table 4.5 State estimation comparison for IEEE 57 bus system – case 2 (Continued)

	True measurements		Recorded Measurements			
Bus	Injected Active Power, P	Injected Reactive Power, Q	Injected Active Power, P	Injected Reactive Power, Q	Mag. V (p.u.)	Phase angle (Deg.)
41	-0.100	0.048	-0.095	0.038	1.093	-16.39
42	-0.060	0.037	-0.067	0.031	1.097	-18.08
43	-0.080	0.040	-0.086	0.038	1.064	-14.27
44	-0.130	0.020	-0.136	0.025	1.096	-12.90
45	0.000	0.000	0.009	0.004	1.089	-9.36
46	0.000	0.000	0.002	-0.005	1.125	-11.70
47	-0.250	0.098	-0.253	0.089	1.118	-13.35
48	0.000	0.000	0.004	0.005	1.114	-13.61
49	-0.120	0.057	-0.119	0.053	1.120	-13.65
50	-0.160	0.080	-0.152	0.090	1.111	-14.28
51	-0.160	0.047	-0.166	0.042	1.100	-13.21
52	-0.060	0.027	-0.062	0.035	1.042	-17.60
53	-0.110	0.055	-0.115	0.049	1.042	-18.17
54	-0.100	0.034	-0.105	0.028	1.050	-17.67
55	-0.190	0.095	-0.180	0.092	1.067	-15.72
56	-0.080	0.023	-0.079	0.029	1.101	-18.38
57	-0.040	0.012	-0.047	0.017	1.105	-18.47

Table 4.5 State estimation comparison for IEEE 57 bus system – case 2 (continued)

			Residual			RSM		Residual (RSM)	
	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)		Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)
1	1.040	0.00	0.000	0.00	30	1.135	-23.24	-0.004	-0.50
2	1.011	0.23	-0.001	0.22	31	1.132	-25.22	0.000	-0.68
3	0.997	-3.98	-0.012	0.02	32	1.143	-23.70	0.003	-0.57
4	1.004	-7.04	-0.011	-0.10	33	1.141	-23.81	0.004	-0.60
5	0.996	-10.91	-0.013	-0.29	34	1.075	-17.22	0.000	-0.36
6	0.994	-11.89	-0.014	-0.41	35	1.079	-16.53	0.000	-0.34
7	1.020	-14.40	-0.016	-0.48	36	1.084	-15.85	0.000	-0.33
8	1.028	-14.92	-0.023	-0.62	37	1.090	-15.36	-0.001	-0.31
9	0.994	-13.17	-0.014	-0.49	38	1.106	-13.86	-0.003	-0.27
10	1.022	-12.18	-0.007	-0.31	39	1.088	-15.43	-0.001	-0.32
11	1.012	-12.46	-0.008	-0.36	40	1.082	-15.89	0.000	-0.33
12	1.019	-9.44	-0.004	-0.34	41	1.096	-16.11	-0.003	-0.28
13	1.014	-10.39	-0.006	-0.29	42	1.095	-17.83	0.002	-0.25
14	1.014	-9.74	-0.006	-0.23	43	1.071	-13.93	-0.007	-0.34
15	1.021	-6.88	-0.006	-0.13	44	1.099	-12.67	-0.003	-0.23
16	1.024	-7.59	-0.003	-0.21	45	1.093	-9.20	-0.005	-0.16
17	1.033	-4.66	-0.001	-0.13	46	1.130	-11.46	-0.005	-0.24
18	1.056	-11.36	-0.011	-0.29	47	1.123	-13.10	-0.004	-0.25
19	1.039	-15.63	-0.006	-0.48	48	1.118	-13.35	-0.004	-0.26
20	1.049	-16.49	-0.005	-0.36	49	1.124	-13.37	-0.004	-0.28
21	1.099	-14.56	-0.003	-0.28	50	1.115	-13.97	-0.004	-0.30
22	1.103	-14.32	-0.003	-0.27	51	1.107	-12.92	-0.007	-0.29
23	1.103	-14.52	-0.003	-0.27	52	1.054	-17.24	-0.012	-0.35
24	1.095	-16.61	-0.003	-0.37	53	1.056	-17.80	-0.014	-0.37
25	1.139	-21.33	-0.004	-0.45	54	1.065	-17.24	-0.015	-0.43
26	1.049	-16.52	-0.004	-0.38	55	1.081	-15.20	-0.014	-0.52
27	1.050	-15.91	-0.005	-0.39	56	1.095	-18.12	0.006	-0.27
28	1.054	-15.67	-0.009	-0.39	57	1.098	-18.31	0.007	-0.16
29	1.058	-15.33	-0.013	-0.38					

Table 4.6 State estimation comparison for IEEE 57 bus system – case 3.

	True measurements		Recorded Measurements			
Bus	Injected Active Power, P	Injected Reactive Power, Q	Injected Active Power, P	Injected Reactive Power, Q	Mag. V (p.u.)	Phase angle (Deg.)
1	1.353	0.689	1.350	0.690	1.040	0.00
2	0.073	2.172	0.065	2.170	1.010	0.14
3	0.394	8.671	0.400	8.671	0.985	-0.93
4	0.000	0.000	0.002	0.005	0.994	-2.10
5	-0.050	0.015	-0.042	0.014	0.986	-3.55
6	-0.040	0.002	-0.050	-0.004	0.980	-3.99
7	0.000	0.000	-0.003	-0.006	1.003	-5.37
8	-0.410	0.066	-0.406	0.073	1.005	-5.59
9	-0.172	0.034	-0.167	0.037	0.980	-4.62
10	-0.040	0.016	-0.041	0.007	1.015	-4.04
11	0.000	0.000	-0.008	0.009	1.005	-4.31
12	0.051	0.080	0.049	0.073	1.015	-3.05
13	-0.090	0.012	-0.098	0.011	1.011	-3.59
14	-0.070	0.035	-0.066	0.033	1.012	-3.37
15	-0.030	0.007	-0.034	0.004	1.018	-2.29
16	-0.030	0.002	-0.028	0.006	1.026	-2.33
17	-0.070	0.013	-0.076	0.016	1.035	-1.46
18	-0.070	0.025	-0.065	0.025	1.032	-3.50
19	-0.040	0.007	-0.038	0.013	1.033	-5.48
20	-0.010	0.004	-0.019	0.009	1.043	-5.67
21	0.000	0.000	0.009	0.009	1.100	-5.08
22	0.000	0.000	-0.006	0.001	1.103	-5.06
23	-0.010	0.003	-0.003	-0.003	1.102	-5.16
24	0.000	0.000	-0.007	-0.002	1.096	-6.68
25	-0.070	0.035	-0.065	0.039	1.128	-9.58
26	0.000	0.000	0.005	-0.001	1.049	-6.66
27	-0.020	0.001	-0.013	0.003	1.043	-6.37
28	-0.030	0.015	-0.027	0.022	1.042	-6.16
29	-0.060	0.009	-0.054	0.015	1.042	-5.89
30	-0.010	0.005	-0.004	0.005	1.129	-10.06
31	-0.030	0.015	-0.022	0.023	1.133	-10.93
32	-0.030	0.015	-0.034	0.012	1.141	-10.91
33	-0.060	0.030	-0.057	0.035	1.140	-11.06
34	0.000	0.000	-0.006	-0.003	1.086	-6.76
35	-0.040	0.020	-0.046	0.017	1.089	-6.31
36	0.000	0.000	0.006	0.002	1.091	-5.84
37	0.000	0.000	0.005	-0.008	1.095	-5.57
38	-0.030	0.015	-0.027	0.016	1.104	-4.85
39	0.000	0.000	-0.010	-0.008	1.094	-5.57
40	0.000	0.000	0.006	-0.003	1.089	-5.78

Table 4.6 State estimation comparison for IEEE 57 bus system – case 3 (continued)

41	-0.030	0.014	-0.030	0.006	1.075	-5.07
42	0.000	0.000	0.000	-0.002	1.083	-5.52
43	-0.030	0.015	-0.030	0.009	1.058	-4.69
44	-0.020	0.003	-0.025	0.001	1.097	-4.31
45	0.000	0.000	0.001	-0.008	1.084	-2.97
46	0.000	0.000	-0.004	0.005	1.122	-4.01
47	-0.060	0.023	-0.067	0.023	1.115	-4.57
48	0.000	0.000	-0.007	0.008	1.112	-4.65
49	-0.030	0.014	-0.033	0.005	1.115	-4.61
50	-0.020	0.010	-0.022	0.006	1.108	-4.50
51	0.000	0.000	0.006	-0.001	1.095	-4.05
52	-0.040	0.018	-0.034	0.010	1.042	-6.50
53	-0.020	0.010	-0.019	0.015	1.044	-6.54
54	-0.050	0.017	-0.046	0.009	1.048	-6.30
55	-0.040	0.020	-0.037	0.026	1.057	-5.32
56	-0.010	0.003	-0.012	0.001	1.092	-5.97
57	-0.010	0.003	-0.013	0.008	1.096	-6.14

Table 4.6 State estimation comparison for IEEE 57 bus system – case 3 (continued)

			Residual			RSM		Residual (RSM)	
	Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)		Mag. V (p.u.)	Phase angle (Deg.)	Mag. V (p.u.)	Phase angle (Deg.)
1	1.040	0.00	0.000	0.00	30	1.135	-23.24	-0.006	13.17
2	1.011	0.23	-0.001	-0.10	31	1.132	-25.22	0.000	14.29
3	0.997	-3.98	-0.012	3.05	32	1.143	-23.70	-0.002	12.78
4	1.004	-7.04	-0.010	4.94	33	1.141	-23.81	-0.001	12.75
5	0.996	-10.91	-0.010	7.36	34	1.075	-17.22	0.012	10.46
6	0.994	-11.89	-0.014	7.90	35	1.079	-16.53	0.010	10.22
7	1.020	-14.40	-0.017	9.04	36	1.084	-15.85	0.007	10.01
8	1.028	-14.92	-0.023	9.32	37	1.090	-15.36	0.005	9.78
9	0.994	-13.17	-0.014	8.55	38	1.106	-13.86	-0.002	9.01
10	1.022	-12.18	-0.007	8.15	39	1.088	-15.43	0.006	9.86
11	1.012	-12.46	-0.007	8.15	40	1.082	-15.89	0.008	10.10
12	1.019	-9.44	-0.004	6.38	41	1.096	-16.11	-0.021	11.04
13	1.014	-10.39	-0.003	6.81	42	1.095	-17.83	-0.012	12.31
14	1.014	-9.74	-0.002	6.37	43	1.071	-13.93	-0.013	9.24
15	1.021	-6.88	-0.003	4.59	44	1.099	-12.67	-0.002	8.36
16	1.024	-7.59	0.002	5.26	45	1.093	-9.20	-0.010	6.23
17	1.033	-4.66	0.002	3.20	46	1.130	-11.46	-0.008	7.44
18	1.056	-11.36	-0.025	7.86	47	1.123	-13.10	-0.007	8.54
19	1.039	-15.63	-0.006	10.15	48	1.118	-13.35	-0.006	8.70
20	1.049	-16.49	-0.006	10.82	49	1.124	-13.37	-0.009	8.77
21	1.099	-14.56	0.001	9.47	50	1.115	-13.97	-0.007	9.47
22	1.103	-14.32	-0.001	9.26	51	1.107	-12.92	-0.012	8.87
23	1.103	-14.52	0.000	9.36	52	1.054	-17.24	-0.012	10.75
24	1.095	-16.61	0.001	9.93	53	1.056	-17.80	-0.013	11.27
25	1.139	-21.33	-0.011	11.75	54	1.065	-17.24	-0.017	10.94
26	1.049	-16.52	0.000	9.86	55	1.081	-15.20	-0.024	9.88
27	1.050	-15.91	-0.007	9.53	56	1.095	-18.12	-0.003	12.15
28	1.054	-15.67	-0.012	9.52	57	1.098	-18.31	-0.002	12.17
29	1.058	-15.33	-0.016	9.44					

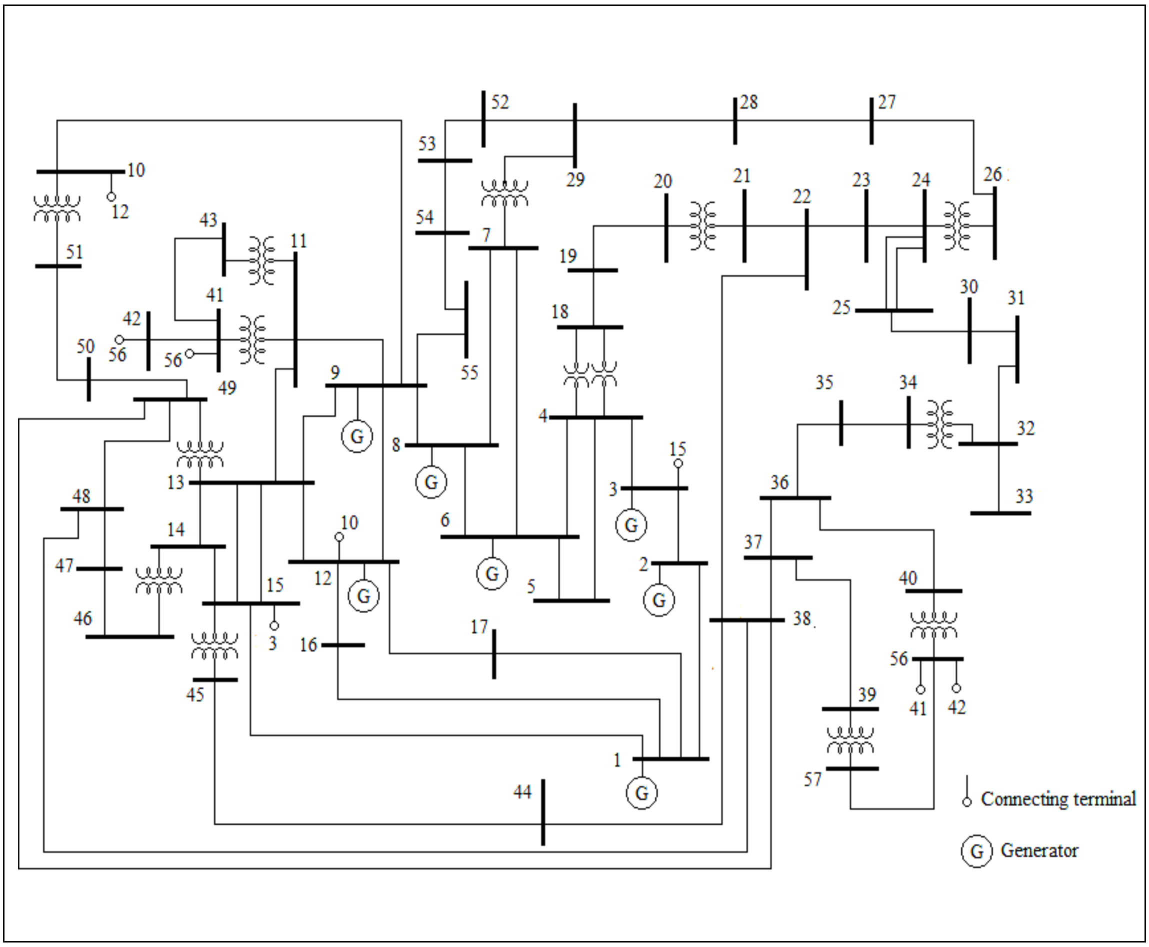


Figure 4.5 IEEE 57 bus system

4.5.3 Observations and Remarks

It has been observed that, the performance in case 1 and case 2 were better than case 3. This is due to the fact that, the records at the lower point in a load curve are less compared to other operating points. It is recommended that, in order to obtain better performance, the measurements must be divided according to the hour of operations. For example, records at the lower points and peak hours must be dealt separately.

4.6 Searching Unavailable Measurements: Regression Method

When regression method is used, it requires that all input are made available so as to be used to estimate the output. However, as mentioned earlier, availability of all measurements used in a regression function is not guaranteed. In this section, the proposed method for searching unavailable measurements is explained.

The sum of the squares of the deviation of any functional records, $f_i(.)$ from their mean $\overline{f_i(.)}$ can be expressed as shown in Equation (4.18). The background of this theory is explained in details by Chapra and Canale, (2006), and Palm III, (2001).

$$\varepsilon_z = \sum_{i=1}^{m} \left[f(x) - \overline{f(x)} \right]^2 \qquad (4.18)$$

where $f_i(.)$ represents the function that defines measurement record i.

Equation (4.18) can be used to compute the coefficient of determination, also known as r-squared (r^2) value, which is a measure of quality of the curve fit (Palm III, 2001).

$$r^2 = 1 - \frac{J'(x)}{\sum_{i=1}^{m} \left[f(x) - \overline{f(x)} \right]^2} \tag{4.19}$$

For perfect fit, $J'(x) = 0$ and thus $r_z^2 = 1$, or $1 - r_z^2 = 0$. The value ε indicates how much the data is spread around the mean and the value $J'(x)$ indicates how much data spread is unaccounted for by the model. Thus the ratio $J'(x)/\varepsilon$ indicates the fractional variation accounted for by the model.

If the coefficient of determinant is *negative*, the model indicates a very poor response that should not be used. Equation (4.18) and (4.19) can be applied to individual estimated variables *x*. note that *x* represents any variable under investigation.

$$J'(x) = \sum_{i=1}^{m} \left(x - \hat{x} \right)^2 \tag{4.20}$$

where $J'(x)$ is sum of the squares of the deviation of the x_i from their estimated values $\hat{x}_i$.

$$\varepsilon_x = \sum_{i=1}^{m} \left(\hat{x} - \bar{\hat{x}} \right)^2 \tag{4.21}$$

where ε_x is the sum of the squares of the deviation of the estimated variables $\hat{x}$ from their mean $\bar{\hat{x}}$.

Solution of state variable *x* in the iterative algorithm to Equation (4.1) is obtained by solving

$$\Delta x = G^{-1} H^T R^{-1} \Delta z \tag{4.22}$$

where the gain matrix G is formed using the measurement Jacobian H and the measurement error covariance matrix, R .

$$G = H^T R^{-1} H \tag{4.23}$$

During the process of estimating the missing measurement records, following quantities are to be set.

- *Variation resolution* (δ): this is the difference of readings variation used in curve fitness technique to estimate the $(k+1)^{th}$ measurement.

- *Measurements range* (D): this is the estimated range of the expected measurement. For example, if the estimated voltage measurement at bus i is between 0.70 and 0.90, then the range is 0.70-to-0.90. The range of measurements to be tested should be adequate to reach the best solution. Previous measurements can lead in the choice of measurement range.

In order to obtain the missing measurements the following steps are followed and its algorithm chart is presented in Figure 4.6.

Step 1: From the $(m+1)^{th}$ range of measurements, using the minimum as a $(m+1)^{th}$ measurement and other available m measurements, include i^{th} row with respect to the $(m+1)^{th}$ measurement location in the network to form a new Jacobian measurement matrix, H' .

Step 2: Estimate new state variables, x' which is computed as

$$G' = H'^T R^{-1} H' \tag{4.24}$$

$$x' = (G')^{-1} (H')^T z \tag{4.25}$$

Step 3: Using the obtained variables, x' calculate the new measurements, such as power active, power reactive, etc.

Step 4: Using regression analysis compute the coefficient of determination to measure the quality of curve fitness.

Step 5: While maximum value of the range of measurements is not reached add $(m+1)^{th}$ with variation resolution, else end.

Step 6: Select the values with the best coefficient of determinations, and compute their mean to select the best $(m+1)^{th}$. Mean of the values that have the best fitness ($r^2 \approx 1$) is selected as the $(m+1)^{th}$ measurement.

Step 7: For all measurements estimated, compute the final state variables.

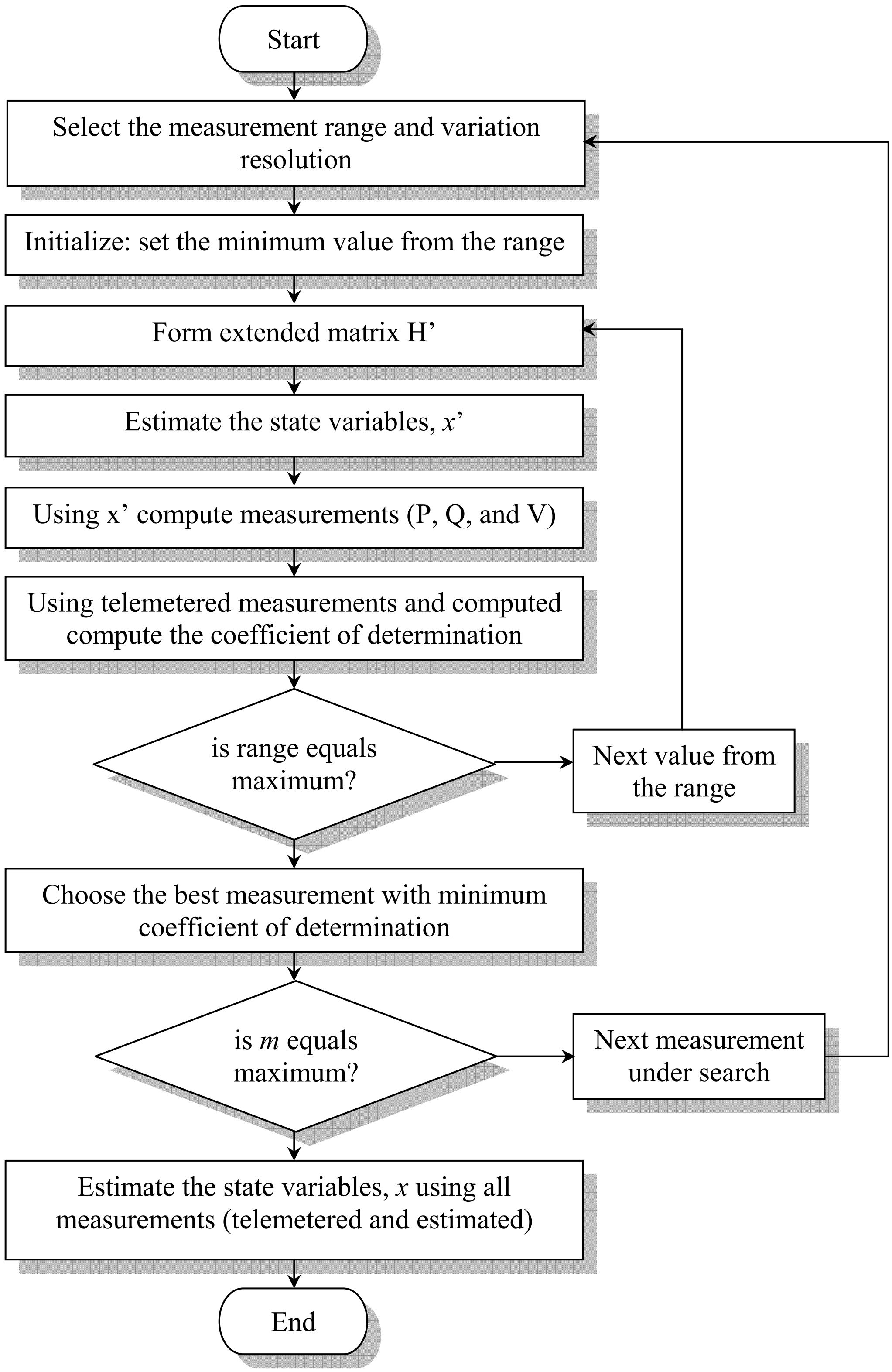


Figure 4.6 Measurements search algorithm flow chart of the algorithm

Table 4.7: Measurements records received at the control center and their location

Measurement type	Bus Location	Total number
Injected Active Power	1-3, 6-29, 31-53, and 55-57	53
Injected Reactive Power	6-8, 11-14, 23-31, 41-47, and 50-55	29
Bus Voltage	1-7, 11-24, and 30-43	35

Table 4.8: Measurement selection step-1

Meas. Type/ Bus No.	Meas	$(1-r^2)$					
		Iter-1	Iter-2	Iter-3	Iter-4	Iter-5	Iter-6
Injected Active Power: Bus -4	-4	1.36e-3	1.45e-3	1.52e-3	1.69e-3	1.48e-3	1.65e-3
	-3	3.32e-4	4.32e-4	3.84e-4	4.29e-4	3.98e-4	4.25e-4
	-2	1.41e-4	3.58e-5	3.72e-5	3.69e-5	3.70e-5	3.70e-5
	-1	5.97e-5	2.64e-5	2.27e-5	2.23e-5	2.22e-5	2.22e-5
	0	2.01e-5	2.25e-7	1.30e-7	1.30e-7	1.30e-7	1.30e-7
	1	4.56e-5	1.93e-5	2.02e-5	2.01e-5	2.01e-5	2.01e-5
	2	1.33e-4	5.94e-5	6.32e-5	6.31e-5	6.31e-5	6.31e-5
	3	3.14e-4	7.51e-5	8.36e-5	8.44e-5	8.44e-5	8.44e-5
	4	7.00e-4	5.41e-5	4.92e-5	7.21e-5	5.05e-5	5.20e-5
Meas. with minimum $(1-r^2)$		0	0	0	0	0	0

Table 4.9: Measurement selection step-2

Meas. Type and Bus No.	Meas.	$(1-r^2)$ Iter-1	Iter-2	Iter-3	Iter-4	Iter-5	Iter-6
		$\times10^{-4}$	$\times10^{-4}$	$\times10^{-4}$	$\times10^{-4}$	$\times10^{-4}$	$\times10^{-4}$
Injected Active Power: Bus -4	-1.0	5.97e-1	2.64e-1	2.27e-1	2.23e-1	2.22e-1	2.22e-1
	-0.9	5.31e-1	2.27e-1	1.99e-1	1.97e-1	1.96e-1	1.96e-1
	-0.8	4.69e-1	1.90e-1	1.69e-1	1.68e-1	1.67e-1	1.67e-1
	-0.7	4.13e-1	1.54e-1	1.38e-1	1.37e-1	1.37e-1	1.37e-1
	-0.6	3.63e-1	1.20e-1	1.08e-1	1.08e-1	1.08e-1	1.08e-1
	-0.5	3.20e-1	8.94e-2	8.05e-2	8.02e-2	8.02e-2	8.02e-2
	-0.4	2.83e-1	6.24e-2	5.59e-2	5.57e-2	5.57e-2	5.57e-2
	-0.3	2.52e-1	3.98e-2	3.52e-2	3.51e-2	3.51e-2	3.51e-2
	-0.2	2.28e-1	2.21e-2	1.90e-2	1.89e-2	1.89e-2	1.89e-2
	-0.1	2.12e-1	9.54e-3	7.58e-3	7.56e-3	7.56e-3	7.56e-3
	0	2.01e-1	2.25e-3	1.30e-3	1.30e-3	1.30e-3	1.30e-3
	0.1	1.98e-1	3.08e-4	2.29e-4	2.29e-4	2.29e-4	2.29e-4
	0.2	2.02e-1	3.67e-3	4.38e-3	4.38e-3	4.38e-3	4.38e-3
	0.3	2.12e-1	1.22e-2	1.37e-2	1.37e-2	1.37e-2	1.37e-2
	0.4	2.28e-1	2.57e-2	2.79e-2	2.79e-2	2.79e-2	2.79e-2
	0.5	2.51e-1	4.40e-2	4.69e-2	4.69e-2	4.69e-2	4.69e-2
	0.6	2.80e-1	6.66e-2	7.04e-2	7.04e-2	7.04e-2	7.04e-2
	0.7	3.15e-1	9.33e-2	9.80e-2	9.79e-2	9.79e-2	9.79e-2
	0.8	3.56e-1	1.24e-1	1.29e-1	1.29e-1	1.29e-1	1.29e-1
	0.9	4.03e-1	1.57e-1	1.64e-1	1.64e-1	1.64e-1	1.64e-1
	1.0	4.56e-1	1.93e-1	2.02e-1	2.01e-1	2.01e-1	2.01e-1
Meas. with minimum $(1-r^2)$		0.1	0.1	0.1	0.1	0.1	0.1

Table 4.10: Measurement selection step-3

meas. type and bus no.	Meas.	$(1-r^2)$					
		iter-1	iter-2	iter-3	iter-4	iter-5	iter-6
		$\times 10^{-4}$	$\times 10^{-6}$	$\times 10^{-6}$	$\times 10^{-6}$	$\times 10^{-6}$	$\times 10^{-6}$
injected active power: bus no. -4	0.00	2.01e-1	2.25e-1	1.30e-1	1.30e-1	1.30e-1	1.30e-1
	0.01	2.01e-1	1.82e-1	9.56e-2	9.53e-2	9.53e-2	9.53e-2
	0.02	2.00e-1	1.43e-1	6.66e-2	6.66e-2	6.66e-2	6.66e-2
	0.03	2.00e-1	1.11e-1	4.28e-2	4.28e-2	4.28e-2	4.28e-2
	0.04	1.99e-1	8.32e-2	2.43e-2	2.43e-2	2.43e-2	2.43e-2
	0.05	1.99e-1	6.11e-2	1.09e-2	1.09e-2	1.09e-2	1.09e-2
	0.06	1.99e-1	4.43e-2	2.85e-3	2.85e-3	2.85e-3	2.85e-3
	0.07	1.98e-1	3.30e-2	5.12e-6	5.12e-6	5.12e-6	5.12e-6
	0.08	1.98e-1	2.69e-2	2.40e-3	2.40e-3	2.40e-3	2.40e-3
	0.09	1.98e-1	2.62e-2	1.00e-2	1.00e-2	1.00e-2	1.00e-2
	0.10	1.98e-1	3.08e-2	2.29e-2	2.29e-2	2.29e-2	2.29e-2
	0.11	1.98e-1	4.07e-2	4.10e-2	4.10e-2	4.10e-2	4.10e-2
	0.12	1.98e-1	5.59e-2	6.43e-2	6.43e-2	6.43e-2	6.43e-2
	0.13	1.98e-1	7.64e-2	9.28e-2	9.28e-2	9.28e-2	9.28e-2
	0.14	1.99e-1	1.02e-1	1.27e-1	1.27e-1	1.27e-1	1.27e-1
	0.15	1.99e-1	1.33e-1	1.66e-1	1.66e-1	1.66e-1	1.66e-1
	0.16	1.99e-1	1.70e-1	2.10e-1	2.10e-1	2.10e-1	2.10e-1
	0.17	2.00e-1	2.11e-1	2.59e-1	2.59e-1	2.59e-1	2.59e-1
	0.18	2.00e-1	2.58e-1	3.13e-1	3.13e-1	3.13e-1	3.13e-1
	0.19	2.01e-1	3.10e-1	3.73e-1	3.73e-1	3.73e-1	3.73e-1
	0.20	2.02e-1	3.67e-1	4.38e-1	4.38e-1	4.38e-1	4.38e-1
meas. with minimum $(1-r^2)$		0.1	0.09	0.07	0.07	0.07	0.07

The maximum number of measurements estimated depends on the number of different measurement units used. In this research paper, three measuring units; active power, reactive power, and voltage measurements are used. In this case there are $3N$ possible measurement locations in total. If the available number of measurement records is only $(2N-1)$ then, there are $(N+1)$ measurements to be estimated.

4.7 Simulations and Results

In order to present results of the proposed method performance, three measurement units were considered: bus injected active power measurements, bus injected reactive measurements and bus magnitude voltage measurements with neglected standard deviations. Using MATLAB (MATLAB ®), IEEE 57-bus systems shown in Figure 4.5 is simulated and results are presented in this section.

Measurements were selected randomly and considered to be the records telemetered to the control center. The minimum number of required measurements is one hundred and thirteen (113), i.e. ($2N$-1). The total number of telemetered and received measurements in the control center was one hundred and seventeen (117) as shown in Table 4.7. Using Newton-Raphson method, with accuracy set to 0.0025, and maximum iteration set to 30, the convergence was obtained at the sixth iteration and results of state variables bus voltage per unit and their phase angles in degrees are shown in the third and fourth columns of Table 4.13 when only available measurement records were used.

Table 4.11: Measurement selection step-4

Meas. Type and Bus No.	Meas.	$(1-r^2)$					
		Iter-1	Iter-2	Iter-3	Iter-4	Iter-5	Iter-6
		$\times 10^{-4}$	$\times 10^{-7}$	$\times 10^{-8}$	$\times 10^{-8}$	$\times 10^{-8}$	$\times 10^{-8}$
Injected Active Power: Bus -4	0.060	1.9868e-1	4.43e-1	2.85e-1	2.85e-1	2.85e-1	2.85e-1
	0.061	1.9866e-1	4.30e-1	2.33e-1	2.33e-1	2.33e-1	2.33e-1
	0.062	1.9863e-1	4.16e-1	1.86e-1	1.86e-1	1.86e-1	1.86e-1
	0.063	1.9861e-1	4.04e-1	1.45e-1	1.45e-1	1.45e-1	1.45e-1
	0.064	1.9858e-1	3.91e-1	1.08e-1	1.08e-1	1.08e-1	1.08e-1
	0.065	1.9856e-1	3.80e-1	7.73e-2	7.73e-2	7.73e-2	7.73e-2
	0.066	1.9854e-1	3.69e-1	5.15e-2	5.15e-2	5.15e-2	5.15e-2
	0.067	1.9851e-1	3.58e-1	3.09e-2	3.09e-2	3.09e-2	3.09e-2
	0.068	1.9849e-1	3.48e-1	1.55e-2	1.55e-2	1.55e-2	1.55e-2
	0.069	1.9847e-1	3.39e-1	5.39e-3	5.39e-3	5.39e-3	5.39e-3
	0.070	1.9845e-1	3.30e-1	5.12e-4	5.12e-4	5.12e-4	5.12e-4
	0.071	1.9843e-1	3.21e-1	8.67e-4	8.67e-4	8.67e-4	8.67e-4
	0.072	1.9841e-1	3.13e-1	6.46e-3	6.46e-3	6.46e-3	6.46e-3
	0.073	1.9840e-1	3.06e-1	1.73e-2	1.73e-2	1.73e-2	1.73e-2
	0.074	1.9838e-1	2.99e-1	3.33e-2	3.33e-2	3.33e-2	3.33e-2
	0.075	1.9836e-1	2.93e-1	5.47e-2	5.47e-2	5.47e-2	5.47e-2
	0.076	1.9835e-1	2.87e-1	8.12e-2	8.12e-2	8.12e-2	8.12e-2
	0.077	1.9833e-1	2.82e-1	1.13e-1	1.13e-1	1.13e-1	1.13e-1
	0.078	1.9832e-1	2.77e-1	1.50e-1	1.50e-1	1.50e-1	1.50e-1
	0.079	1.9830e-1	2.73e-1	1.92e-1	1.92e-1	1.92e-1	1.92e-1
	0.080	1.9829e-1	2.69e-1	2.40e-1	2.40e-1	2.40e-1	2.40e-1
Meas. with minimum $(1-r^2)$		0.080	0.080	0.070	0.070	0.070	0.070

In selecting the range, it is suggested that wide measurement range is selected with a wider variation resolution. For example, in estimating the first measurement, say, injected active power measurement in bus 4; the initial range can be set from -10 to 10 with variation range of 1 (unit resolution). The coefficient of determination is computed. The minimum $(1-r^2)$ is calculated to obtain the best selection. The results obtained are presented for iterations used. It is also observed that the better choice in the first stage will lead to the better final estimation. As shown in Table 4.8, in all cases of iterations used, the selected measurement value was 0. For the better choice, in step-2, the range is narrowed to -1 to 1 with narrower variation resolution say, 0.1 (1-decimal point). In this case, 0.1 was obtained as the best selection. The process goes on in the range of 0 to 0.2 with the variation resolution of 0.01. Other steps results are shown in Table 4.9 to Table 4.11. The step-5, the range is 0.0690 to 0.0710 and 0.0001 (4-decimal point). In Table 4.12 the selected measurement is 0.0704 per unit. For any selected range, the number of tested values is given by:

$$\text{No. of tested values} = \left[(21 \times \alpha) + (2\beta + 1)\right] \tag{4.26}$$

where α is the decimal point of the variation resolution, e.g. for variation resolution 0.0001, α is 4. β is given by

$$\beta = \frac{(\text{Max range - Min. range})}{2} \tag{4.27}$$

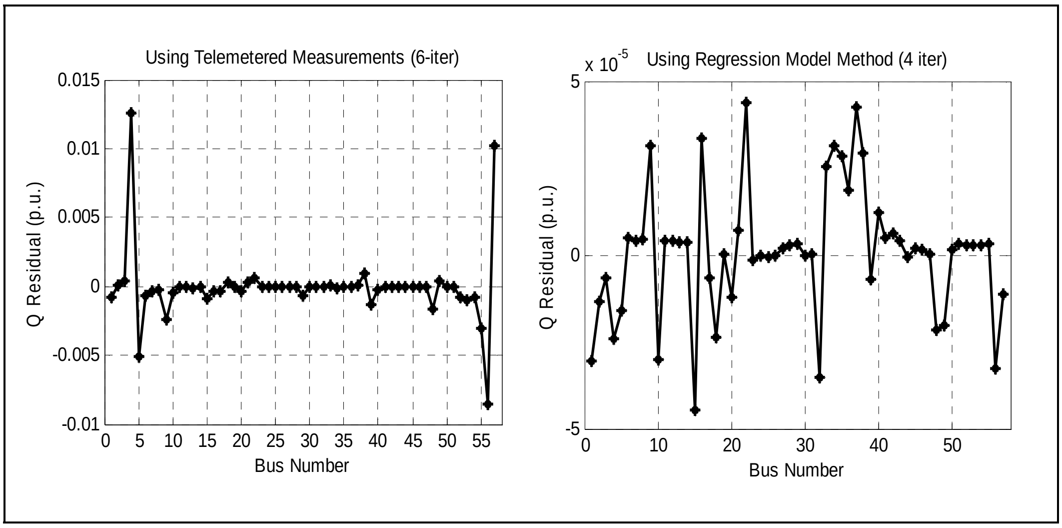


Figure 4.7 Residual for bus injected reactive power measurements obtained from estimation, using only telemetered measured and using regression model method

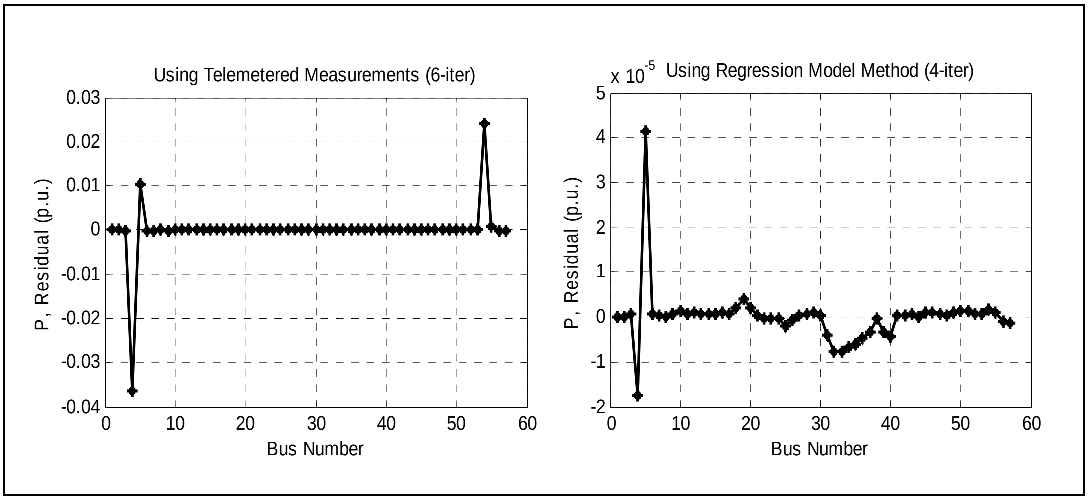


Figure 4.8 Residual for bus injected active power measurements obtained from estimation, using only telemetered measured and using regression model method

Practically, the measurement range is between -10 and 10 p.u. which require only 105 numbers to be tested when $\alpha = 4$ (i.e. resolution is 0.0001) although there are 200,001 numbers from -10.000-+10.000 for 0.0001 steps. The range of -100-to-100 would require 285 numbers to be tested instead of 2,000,001 numbers available in this range.

The higher resolutions, such as 10^{-10} and above is possible but due to space limitations in this paper only 0.0001 is used for demonstration in Table 8 to Table 11. For resolution of 10^{-10}, only 231 values are tested. Figure 4.7 and Figure 4.8 present the residual for bus injected reactive power measurements and residual for bus injected active power measurements obtained from estimation when only telemetered measurements were used and when the estimated measurements were included, respectively.

Table 4.12: Measurement selection step-5

Meas. Type and Bus No.	Meas.	$(1-r^2)$					
		1	2	3	4	5	6
		$\times 10^{-4}$	$\times 10^{-7}$	$\times 10^{-10}$	$\times 10^{-10}$	$\times 10^{-10}$	$\times 10^{-10}$
Inj. Active Power: Bus -4	0.0690	1.98472e-1	3.39e-1	5.39e-1	5.4e-1	5.39e-1	5.39e-1
	0.0691	1.98470e-1	3.38e-1	4.67e-1	4.7e-1	4.67e-1	4.67e-1
	0.0692	1.98468e-1	3.37e-1	4.00e-1	4.0e-1	4.00e-1	4.00e-1
	0.0693	1.98466e-1	3.36e-1	3.38e-1	3.4e-1	3.38e-1	3.38e-1
	0.0694	1.98464e-1	3.35e-1	2.81e-1	2.8e-1	2.81e-1	2.81e-1
	0.0695	1.98462e-1	3.34e-1	2.30e-1	2.3e-1	2.30e-1	2.30e-1
	0.0696	1.98460e-1	3.33e-1	1.84e-1	1.8e-1	1.84e-1	1.84e-1
	0.0697	1.98458e-1	3.32e-1	1.43e-1	1.4e-1	1.43e-1	1.43e-1
	0.0698	1.98456e-1	3.31e-1	1.07e-1	1.1e-1	1.07e-1	1.07e-1
	0.0699	1.98454e-1	3.30e-1	7.65e-2	7.7e-2	7.65e-2	7.65e-2
	0.0700	1.98453e-1	3.30e-1	5.12e-2	5.1e-2	5.12e-2	5.12e-2
	0.0701	1.98451e-1	3.29e-1	3.12e-2	3.1e-2	3.12e-2	3.12e-2
	0.0702	1.98449e-1	3.28e-1	1.64e-2	1.6e-2	1.64e-2	1.64e-2
	0.0703	1.98447e-1	3.27e-1	6.86e-3	6.9e-3	6.86e-3	6.86e-3
	0.0704	1.98445e-1	3.26e-1	2.55e-3	2.6e-3	2.55e-3	2.55e-3
	0.0705	1.98443e-1	3.25e-1	3.48e-3	3.5e-3	3.48e-3	3.48e-3
	0.0706	1.98441e-1	3.24e-1	9.64e-3	9.6e-3	9.64e-3	9.64e-3
	0.0707	1.98439e-1	3.24e-1	2.10e-2	2.1e-2	2.10e-2	2.10e-2
	0.0708	1.98437e-1	3.23e-1	3.77e-2	3.8e-2	3.77e-2	3.77e-2
	0.0709	1.98435e-1	3.22e-1	5.95e-2	6.0e-2	5.95e-2	5.95e-2
	0.0710	1.98433e-1	3.21e-1	8.67e-2	8.7e-2	8.67e-2	8.67e-2
Meas. with min. $(1-r^2)$		0.0710	0.0710	0.0704	0.0704	0.0704	0.0704

Table 4.13: Estimated State and the Residuals

Bus No.	True Values		Est. Base		State Residuals		Inj. Pow. Residual	
	Mag. Volt.	Phase (Deg.)	Mag. Volt.	Phase (Deg.)	Mag. Volt.	Phase (Deg.)	P	Q
1	1.040	0	1.040	0	-3.1e-9	0	-4.5e-6	-8.3e-4
2	1.010	-0.62	1.010	-0.61	7.5e-10	-7.8e-3	-1.1e-5	6.5e-5
3	0.985	-3.52	0.985	-3.48	2.6e-9	-3.3e-2	-6.9e-5	3.7e-4
4	0.987	-4.48	0.987	-4.41	-4.8e-7	-6.8e-2	-3.6e-2	1.3e-2
5	0.984	-4.85	0.984	-4.88	-1.1e-6	3.1e-2	1.0e-2	-5.1e-3
6	0.980	-4.96	0.980	-4.99	2.4e-6	3.0e-2	-1.9e-4	-6.4e-4
7	0.985	-4.13	0.985	-4.21	8.2e-6	7.3e-2	-7.0e-5	-3.5e-4
8	1.005	-0.82	1.005	-0.88	6.4e-6	6.9e-2	-1.7e-5	-2.0e-4
9	0.980	-6.42	0.980	-6.50	1.4e-5	7.7e-2	-1.5e-4	-2.5e-3
10	0.994	-8.91	0.994	-8.96	-2.0e-5	4.9e-2	-6.6e-6	-4.4e-4
11	0.979	-7.83	0.979	-7.89	-1.8e-7	5.3e-2	-1.5e-5	-5.9e-5
12	1.015	-8.44	1.015	-8.47	-1.2e-7	3.3e-2	-1.1e-5	-5.5e-5
13	0.984	-7.66	0.984	-7.69	5.6e-7	3.1e-2	-4.5e-5	-1.4e-4
14	0.974	-7.41	0.974	-7.43	8.8e-8	1.9e-2	-1.0e-5	-3.2e-5
15	0.994	-5.45	0.994	-5.46	-2.8e-7	2.7e-3	-4.6e-5	-8.7e-4
16	1.016	-7.56	1.016	-7.59	-2.5e-8	2.4e-2	-5.3e-6	-3.1e-4
17	1.021	-4.82	1.021	-4.83	-1.2e-8	1.3e-2	-3.6e-6	-3.1e-4
18	0.983	-9.54	0.983	-9.48	5.4e-9	-6.0e-2	-2.4e-6	2.7e-4
19	0.932	-13.58	0.932	-13.55	7.3e-10	-2.7e-2	-4.6e-6	-6.5e-5
20	0.933	-13.72	0.933	-13.72	-4.5e-9	-6.3e-3	-1.9e-6	-3.2e-4
21	0.987	-11.67	0.987	-11.69	4.0e-9	1.9e-2	2.0e-8	2.6e-4
22	0.992	-11.46	0.992	-11.48	9.7e-6	2.3e-2	-2.4e-7	5.8e-4
23	0.988	-11.56	0.988	-11.58	7.3e-6	2.5e-2	-7.5e-6	-6.0e-6
24	0.949	-12.15	0.949	-12.20	-3.8e-5	5.2e-2	-5.8e-6	-3.3e-6
25	0.880	-23.60	0.880	-23.66	-1.6e-6	5.3e-2	2.8e-6	-4.2e-6
26	0.913	-11.56	0.913	-11.61	-8.9e-5	5.6e-2	-4.8e-6	-3.7e-7
27	0.960	-9.03	0.960	-9.11	-1.0e-4	8.5e-2	-5.3e-6	-7.7e-6
28	0.984	-7.69	0.984	-7.78	-9.7e-5	9.6e-2	-9.0e-7	-3.5e-6
29	1.005	-6.68	1.005	-6.78	-8.3e-5	1.0e-1	7.8e-5	-7.1e-4
30	0.842	-26.17	0.842	-26.22	1.4e-5	5.3e-2	1.6e-4	-6.9e-6
31	0.800	-29.56	0.800	-29.61	1.6e-6	4.5e-2	-6.7e-7	-5.5e-6
32	0.828	-29.67	0.828	-29.70	-4.2e-6	3.4e-2	1.1e-6	-5.6e-5
33	0.822	-29.91	0.822	-29.94	8.1e-8	3.3e-2	1.5e-6	9.6e-5
34	0.893	-14.56	0.893	-14.58	-2.8e-7	2.4e-2	4.6e-7	-1.2e-4
35	0.914	-13.82	0.914	-13.84	-6.1e-8	2.3e-2	2.4e-7	-2.2e-5

Table 4.13: Estimated State and the Residuals (Continued)

Bus No.	True Values		Estimation Base		State Residuals		Injection Power Residual	
	Mag. Volt.	Phase (Deg.)	Mag. Volt.	Phase (Deg.)	Mag. Volt.	Phase (Deg.)	P	Q
36	0.937	-13.15	0.937	-13.17	4.6e-8	2.2e-2	-1.1e-7	-6.3e-5
37	0.954	-12.69	0.954	-12.71	1.5e-7	2.0e-2	-2.7e-7	9.3e-5
38	0.999	-11.21	0.999	-11.24	6.7e-8	2.2e-2	-1.1e-6	8.9e-4
39	0.952	-12.73	0.952	-12.75	1.3e-8	1.8e-2	-3.9e-5	-1.3e-3
40	0.935	-13.17	0.935	-13.20	4.2e-8	2.4e-2	2.2e-7	-2.4e-4
41	0.991	-12.96	0.991	-13.01	9.8e-7	5.2e-2	7.9e-9	-9.6e-8
42	0.953	-14.54	0.953	-14.59	-6.9e-7	5.2e-2	1.4e-7	8.1e-8
43	1.011	-9.75	1.011	-9.80	6.3e-9	5.2e-2	-3.3e-	-3.2e-8
44	1.008	-10.26	1.008	-10.28	-5.3e-6	1.8e-2	-1.0e-6	-4.3e-6
45	1.036	-7.67	1.036	-7.68	-2.7e-5	9.1e-3	-1.5e-6	-4.6e-6
46	1.061	-9.25	1.061	-9.27	-2.7e-5	2.1e-2	-6.4e-7	-5.6e-7
47	1.030	-10.67	1.030	-10.69	-4.7e-5	2.3e-2	-3.3e-7	-3.3e-7
48	1.021	-10.84	1.021	-10.87	-4.9e-5	2.4e-2	-1.6e-6	-1.7e-3
49	1.035	-11.00	1.035	-11.03	9.4e-6	2.8e-2	3.4e-6	3.9e-4
50	1.022	-11.55	1.022	-11.59	6.5e-6	3.5e-2	-9.1e-6	-2.2e-6
51	1.060	-10.10	1.060	-10.15	6.7e-6	4.6e-2	-6.8e-6	-8.6e-7
52	0.965	-8.52	0.965	-8.73	8.2e-4	2.2e-1	1.1e-4	-8.3e-4
53	0.954	-9.10	0.952	-9.37	1.3e-3	2.8e-1	1.9e-4	-9.9e-4
54	0.991	-8.59	0.989	-8.99	2.7e-3	4.0e-1	2.4e-2	-7.8e-4
55	1.037	-7.71	1.038	-7.91	-1.9e-4	2.0e-1	8.6e-4	-3.1e-3
56	0.952	-14.75	0.952	-14.80	-2.3e-6	5.2e-2	-2.9e-4	-8.6e-3
57	0.942	-15.62	0.940	-15.59	2.5e-3	-3.1e-2	-5.5e-5	1.0e-2

4.8 Conclusion

Although the system can depend on the RSM method discussed in this chapter, care is called forth so as to keep the degree of performance at the satisfactory level. Such as, the classification of data used in the regression should be closely related. For example, the data for low loads, mid loads, and peak loads should be classified separately. Data for 0400 hours (low load) may lower the performance of RSM during 1700 hours (peak load).

When using WLS method, the number of iterations for the convergence was observed to be higher when less number of measurement records was used in state estimator compared to the number of iterations when the number of measur records was increased.

In both methods, the search of missing measurements explained in the previous section is important. As for the RSM, the missing measurement must be made available, for WLS, enhance good state estimation solution in terms of accuracy.

CHAPTER V

CONTINGENCY ANALYSIS THEORY

5.1 Introduction

This chapter presents the theory behind the contingency analysis in electric power system. The details of main functions and techniques used in contingency analysis are discussed. As mentioned in chapter one, operators and dispatchers of a power system need contingency analysis in order to be acquainted with the possibility of the system being driven to a vulnerable condition as per predictable and unpredictable events occur. Therefore, contingency analysis is among the major components in the operations of the power system.

Generally, power systems are composed of transmission lines, generation units, and other components. The power system is said to operate in a *normal state* if all the demands in the system can be supplied power by the existing components without violation of operation constraints (Abur and Exp□sito, 2004). These constraints may be set by the capacity of the transmission lines power flow, limits on buses voltage magnitudes, or other limitations set by system components. However, due to the unexpected events, such as transmission line outages, generating unit outages, or other malfunction of the components, the power system may be driven into the *insecure operating state*.

Contingency events may result from the failure of equipments, scheduled services or natural causes such as storms, tornadoes, hurricane, flood, fires, sabotage, terrorist attack, etc. When the contingency event occurs and the transmission line is de-energized, new steady state bus voltages and line currents can be predicted through contingency analysis program (Grainger and Stevenson, 1994). The contingency analysis is a control element to optimize power system operations. Optimization problems in a power system functions include economic dispatch, production costs, transmission costs, etc. These functions aim to provide economical, reliable and secured services in the power system. Later in this chapter, load point indices are used to observe the system performance upon the single contingency event.

The power system security and the reliability are concerned with the degree to which the performance of the elements in bulk results in electrical energy being delivered to the customers within the framework of the specified standards and in amount required (Dhillon, 2007), and (Billinton and Allan, 1996). Therefore, the power system contingency analysis is a key element in many operations in the power system and power market analyses, such as load indices evaluation, security assessment and transaction arrangement (Sun and Overbye, 2003b). Figure 5.1 summarizes the emergency and restorative control actions which will be deployed under abnormal operating conditions (Abur and Exp□sito, 2004). Figure 5.1 also explores the stages associated with the contingency analysis of the power system. Possible consequences and remedial actions required by transmission line outages are discussed in this chapter. The presented contingency analysis will model possible system troubles before they arise. The security-constrained optimal power flow is the essence of the security system. Therefore, as mentions in the literatures (Billinton and Allan, 1996) and (Mello, et al., 1997) the probability of consumers being disconnected for any reason can be reduced by increased investment during the planning phase, operating phase, or both. In the next section the contingency event related to the power generation unit is discussed.

5.2 Generation Unit Outage

In engineering application systems, the probability of finding the unit on forced outage is known as the unit forced outage rate (FOR) defined as (Billinton and Allan, 1996)

$$Unavailability\ (FOR) = \frac{\sum down\ time}{\sum down\ time + \sum up\ time} \tag{5.1}$$

Consider the theoretical power system consisting of generating units data shown in Table 5.1, the cumulative probability of a particular capacity outage state of X MW after a unit capacity C MW and forced outage rate U is added is given as (Billinton and Allan, 1996)

$$P(X) = (1-U)\ P'(X) + (U)\ P'(X-C) \tag{5.2}$$

where $P'(X)$ denotes the cumulative probabilities of capacity outage state of X MW before the unit is added, $P(X)$ denotes the cumulative probabilities of capacity outage state of X MW after the unit is added, and the initial values of $P'(X)\ = 1.0$ for $X \le 0$ and $P'(X)\ = 0$ otherwise.

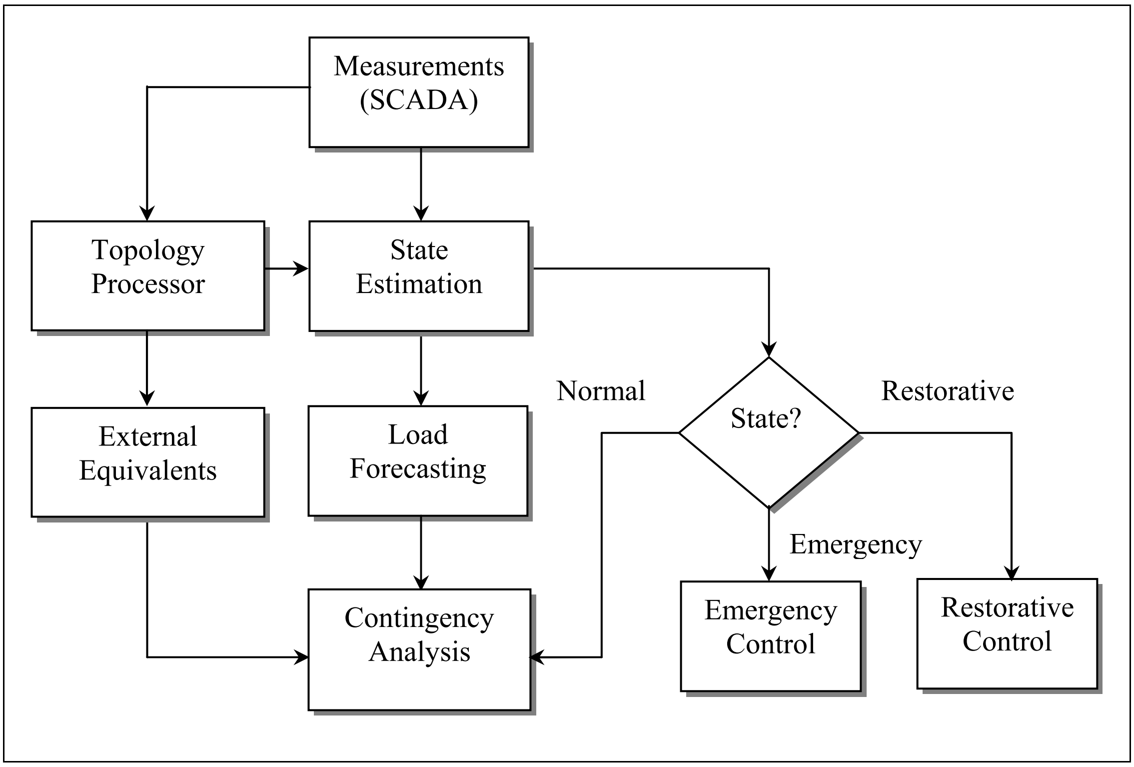


Figure 5.1 The security assessment functional diagram (Abur and Exp□sito, 2004)

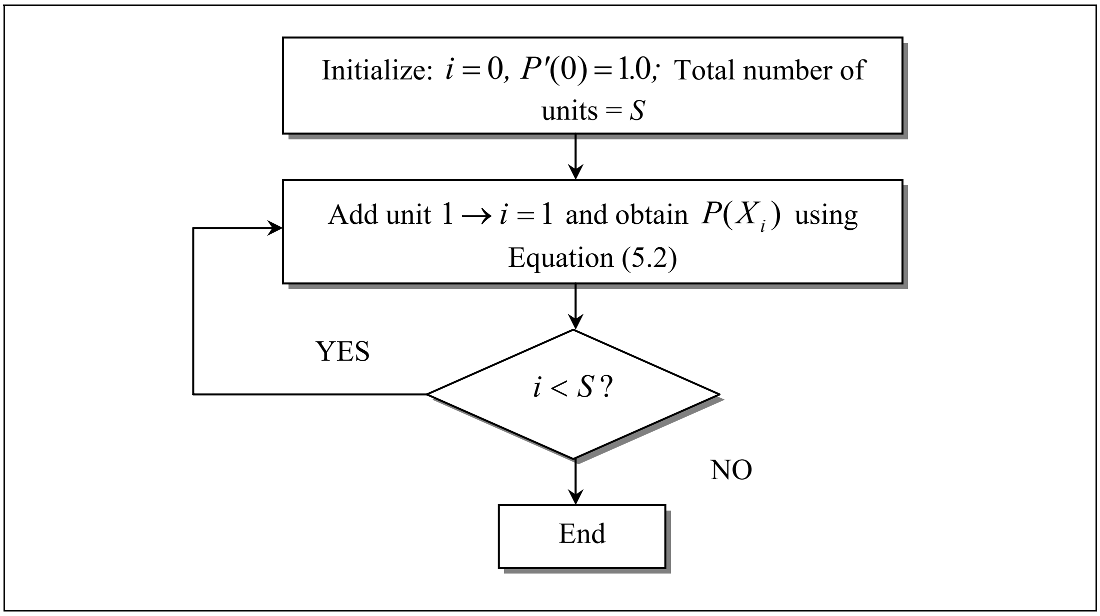


Figure 5.2 The non derated-capacity model building algorithm

Table 5.1 The theoretical system data

Unit	Capacity (MW)	Unavailability, U
1	10	0.012
2	10	0.012
3	10	0.012
4	10	0.012

Table 5.2 Capacity outage probability table for the system

System Capacity (MW)		Probability	
Out	In	Individual	Cumulative
0	40	0.95281400	1.00000000
10	30	0.04633300	0.04718564
20	20	0.00084500	0.00085220
30	10	0.00000682	0.00000684
40	0	0.00000002	0.00000002

From Equation (5.2), the recursive algorithm is formulated and presented as shown in Figure 3.2. For clarification of the algorithm, consider a system consisting of 4×10 MW units each having forced outage rate of 0.012 given in Table 5.1, the system capacity probability for initial step, i.e. when the first unit is added, is given as follows:

$$P(0) = (1 - 0.012)(1.0) + (0.012)(1.0) = 1.000$$

$$P(10) = (1 - 0.012)(0) + (0.012)(1.0) = 0.012$$

The system capacity probability for step -2, i.e. when the second unit is added, is computed as

$$P(0) = (1 - 0.012)(1.0) + (0.012)(1.0) = 1.000$$

$$P(10) = (1 - 0.012)(0.012) + (0.012)(1.0) = 0.02390$$

$$P(20) = (1 - 0.012)(0) + (0.012)(0.012) = 0.00014$$

The system capacity probability for step -3 (when the third unit is added) is computed as follows:

$$P(0) = (1 - 0.012)(1.0) + (0.012)(1.0) = 1.0$$

$$P(10) = (1 - 0.012)(0.0239) + (0.012)(1.0) = 0.035613$$

$$P(20) = (1 - 0.012)(0.00014) + (0.012)(0.0239) = 0.00043$$

$$P(30) = (1 - 0.012)(0) + (0.012)(0.00014) = 0.0000017$$

The system capacity probability for step -4 (when the fourth unit is added) is given as

$$P(0) = (1 - 0.012)(1.0) + (0.012)(1.0) = 1.000$$

$$P(10) = (1 - 0.012)(0.035613) + (0.012)(1.0) = 0.04718564$$

$$P(20) = (1 - 0.012)(0.00043) + (0.012)(0.035613) = 0.00085220$$

$$P(30) = (1 - 0.012)(0.0000017) + (0.012)(0.00043) = 0.00000684$$

$$P(40) = (1 - 0.012)(0) + (0.012)(0.0000017) = 0.00000002$$

The modification can be implemented when derated states is included. In order to demonstrate the process, consider a system in Table 5.1 replaced by 3×10 MW units each having forced rate of 0.012 and a 10 MW unit with three states as shown in Table 5.3.

In this case, the Equation (5.2) is modified to include multi-state unit representation (Billinton and Allan, 1996)

$$P(X) \quad = \sum_{i=1}^{n} p_i P'(X - C_i) \tag{5.3}$$

where n is the number of unit states, C_i is the capacity outage of state i for the unit being added, and p_i is the probability of existence of the unit state i. Hence the system outage probability can be created using the method proposed in (Billinton and Allan, 1996) and the last step (step -4) is computed as follows:

The system capacity probability for step -3 (when the third unit is added) is

$P(0)$ = (0.975)(1.0) + (0.020)(1.0) + (0.005)(1.0) = 1.0

$P(5)$ = (0.975)(0.0356) + (0.02)(1.0) + (0.005)(1.0) = 0.059722675

$P(10)$ = (0.975)(0.0356) + (0.02)(0.0356) + (0.005)(1.0) = 0.040434935

$P(15)$ = (0.975)(0.0004) + (0.02)(0.0356) + (0.005)(0.0356) = 0.0013096

$P(20)$ = (0.975)(0.0004) + (0.02)(0.0004) + (0.005)(0.03561) = 0.0006059

$P(25)$ = (0.975)(0.000002) + (0.02)(0.0004) + (0.005)(0.0004) = 0.000012

$P(30)$ = (0.975)(0.000002) + (0.02)(0.000002) + (0.005)(0.0004) = 0.0000038

$P(35)$ = (0.975)(0) + (0.020)(0.0000017) + (0.005)(0.0000017) = 0.00000004

$P(40)$ = (0.975)(0) + (0.020)(0) + (0.005)(0.0000017) = 0.000000009

Table 5.3 A 10 MW unit – three state representation

Unit	Capacity (MW)	State Probability (p_i)
1	0	0.975
2	5	0.020
3	10	0.005

Table 5.4 Capacity outage probability table for the system, derated state included

System Capacity MW)		Probability	
Out	In	Individual	Cumulative
0	40	0.940277325	1.000000000
5	35	0.019287740	0.059722675
10	30	0.039125360	0.040434935
15	25	0.000703660	0.001309575
20	20	0.000593508	0.000605915
25	15	0.000008566	0.000012408
30	10	0.000003799	0.000003842
35	5	0.000000034	0.000000043
40	0	0.000000009	0.000000009

Based on these computation processes, the new capacity outage probability table for the system is presented in Table 5.4. The probabilistic risk of the system can be found from individual probabilities in the capacity outage probability. For example, if the expected demand in system is 35 MW, then from Table 5.4 the probabilistic risk in this system is about 0.0404. Other probabilistic risks are obtained using the similar method.

5.3 Transmission Line Outages

In the previous section, the power generating unit outage was discussed. In this section, the contingency analysis event is discussed based on the transmission line outage. In this section, the influence of transmission outages on a system is analyzed by the static security assessment. There are several techniques used in contingency analysis based on line outages. In (Shahidehpour, and Wang, 2003) the bounding method is used to extend the interest subarea of the contingency, starting from a subset of the area around the contingency location. In the literature (Wang and McDonald, 1994), the combined network line outage analysis and contingency ranking technique is introduced. In order to optimize the computational time that results from iterations during power flow computation process, the following subsections presents an alternative for contingency analysis.

5.3.1 Network Problem

Large power networks are comprised with large number of transmission lines. In order to perform quick contingency analysis, several ways have been proposed. Both DC and AC power flow may be used in contingency analysis. The limitations attributes to the DC power flow is that, only branch MW flows are calculated and these are only 5 percent accuracy. Hence, the method does not present the MVAR flow or bus voltage magnitudes (Wood and Wollenberg, 1996). Therefore, DC flow calculation model is only suitable for preliminary analysis. In the next subsection, the voltage magnitudes role in computing bus power and limitations is presented, hence the proposed model utilizes a full AC power flow for contingency.

5.3.2 Linearization of Bus Power Equation

The injected bus power equations in the system are given as (Abur and Exp□sito, 2004), and (Wang and McDonald, 1994)

$$P_i = V_i \sum_{j \neq i} V_j \left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij} \right), \text{ and} \tag{5.5}$$

$$Q_i = V_i \sum_{j \in i} V_j \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij} \right) \tag{5.6}$$

$$i = 1,2,3,\ldots,N$$

where,

P_i and Q_i, are the net active and reactive power injected to bus i respectively,

N is the number of buses,

V_i and V_j are the voltage magnitudes at nodes i and j respectively,

θ_{ij} is the phase angle difference across the branch i and j, and

$j \in i$ denotes the nodes that are connected to the node i including $j = i$.

Both Equation (5.5) and (5.6) can be represented in the form of $Z = f(X,Y)$ where Z is the vector representing active and reactive power injected measurements, X is the power state variables vector (i.e. bus voltage magnitudes and voltage phase angles) and matrix Y is the network parameters representing admittance between the nodes.

In the initial state, under normal conditions, the relationship between the measurement vectors and state variables is given as

$$Z_0 = f(X_0, Y_0) \tag{5.7}$$

where the superscript '0'denotes under the normal condition.

Upon the disturbance ΔZ (through variation of injected bus active or bus reactive power, or generating unit outages), or ΔY (through line outages) will results a change of ΔX in the state variables. Hence Equation (5.8) is satisfied (Wang and McDonald, 1994) and (Shahidehpour and Wang, 2003).

.

$$Z_0 + \Delta Z = f(X_0 + \Delta X, Y_0 + \Delta Y) \tag{5.8}$$

Using Taylor series expansion to Equation (5.4) gives (5.9)

$$\begin{aligned} Z_0 + \Delta Z f(X_0, Y_0) &+ \Delta X\left[\frac{\partial f}{\partial x}(X_0, Y_0)\right] + \Delta Y\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right] \\ &+ \frac{1}{2}\left\{(\Delta X)^2 \frac{\partial}{\partial x}\left[\frac{\partial f}{\partial x}(X_0, Y_0)\right] + 2\Delta X \Delta Y \frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right]\right. \\ &\left. + (\Delta Y)^2 \frac{\partial}{\partial y}\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right]\right\} + \ldots \end{aligned} \tag{5.9}$$

When the disturbance is not very large, term $(\Delta X)^2$ and higher orders are ignored hence, Equation (5.9) is simplified to

$$\begin{aligned} Z_0 + \Delta Z = f(X_0, Y_0) &+ \Delta X\left[\frac{\partial f}{\partial x}(X_0, Y_0)\right] + \Delta Y\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right] \\ &+ 2\Delta X \Delta Y \frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right].. \end{aligned} \tag{5.10}$$

By substituting Equation (5.7) into (5.10) gives

$$\Delta Z = \Delta X\left[\frac{\partial f}{\partial x}(X_0, Y_0)\right] + \Delta Y\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right] + \Delta X \Delta Y \frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right] \tag{5.11}$$

By combining the terms containing ΔX gives

$$\varDelta Z = \varDelta X\left\{\left[\frac{\partial f}{\partial x}(X_0,Y_0)\right] + \varDelta Y\frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\right\} + \varDelta Y\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]$$

$$\varDelta X = \left\{\left[\frac{\partial f}{\partial x}(X_0,Y_0)\right] + \varDelta Y\frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\right\}^{-1}\left\{\varDelta Z - \varDelta Y\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\right\} \tag{5.12}$$

Note that, if the change in network parameters is ignored (generating unit outage consideration), $\varDelta Y = 0$ hence Equation (5.12) becomes

$$\Delta X = \mathrm{S}_0 \Delta Z \tag{5.13}$$

where

$$S_0 = \left[\frac{\partial f}{\partial x}(X_0,Y_0)\right]^{-1}$$

If the disturbance on nodal injection power is ignored, $\varDelta Z = 0$ and Equation (5.12) becomes

$$\varDelta X = \left\{\left[\frac{\partial f}{\partial x}(X_0,Y_0)\right] + \varDelta Y\frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\right\}^{-1}\left\{-\varDelta Y\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\right\}$$

$$\varDelta X = \left[\frac{\partial f}{\partial x}(X_0,Y_0)\right]^{-1}\left(1 + \varDelta Y\frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\left[\frac{\partial f}{\partial x}(X_0,Y_0)\right]^{-1}\right)^{-1}\left\{-\varDelta Y\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\right\}$$

(5.14)

$$\varDelta X = \left\{S_0\left(1 + \varDelta Y\frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]S_0\right)\right\}^{-1}\left\{-\varDelta Y\left[\frac{\partial f}{\partial y}(X_0,Y_0)\right]\right\} \tag{5.15}$$

$$\varDelta X = S_0 \varDelta Z_y$$

The $\varDelta Z_y$ may be regarded as the disturbance on the nodal injection power caused by contingency event such as line outages.

$$\Delta Z_y = \left\{1 + \Delta Y \frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right] S_0\right\}^{-1} \left\{-\Delta Y\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right]\right\} \tag{5.16}$$

The load flow in branch i to j is calculated as

$$P_{ij} = V_i V_j \left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}\right) - t_{ij} G_{ij} B_i V_i^2 \tag{5.17}$$

$$Q_{ij} = V_i V_j \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}\right) + \left(t_{ij} B_{ij} \text{-} b_{ij0}\right) V_i^2 \tag{5.18}$$

where,

t_{ij} is the transformer ratio per unit, and

b_{ij0} is the half of branch i to j susceptance.

5.3.3 Single-Line Outage Case

Equation (5.12) is simplified as (Wang and McDonald, 1994)

$$\Delta Z_y = \left[1 + L_0 S_0\right]^{-1} \Delta Z_i \tag{5.19}$$

where,

$$L_0 = \Delta Y \frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right], \text{ and}$$

$$\Delta Z_l = -\Delta Y \frac{\partial}{\partial x}\left[\frac{\partial f}{\partial y}(X_0, Y_0)\right]$$

The ΔZ_l is related to the flow through the outage branch under normal operation conditions. If the admittance of the branch i to j is Y_{ij}, then the impedance angle of the branch i and j is α_{ij}. Hence, it is summarized as follows:

$$G_{ij} = y_{ij} \cos\alpha_{ij} \qquad \frac{\partial G_{ij}}{\partial y_{ij}} = \cos\alpha_{ij} = \frac{G_{ij}}{y_{ij}}$$

$$B_{ij} = y_{ij} \sin\alpha_{ij} \qquad \frac{\partial B_{ij}}{\partial y_{ij}} = \sin\alpha_{ij} = \frac{B_{ij}}{y_{ij}}$$

From Equation (5.5)

$$\frac{\partial P_i}{\partial y_{ij}} = \frac{V_i V_j \left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}\right) - t_{ij} G_{ij} V_i^2}{y_{ij}}$$

$$\frac{\partial Q_i}{\partial y_{ij}} = \frac{V_i V_j \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}\right) + \left(t_{ij} B_{ij} \text{-} b_{ij0}\right) V_i^2}{y_{ij}}$$

Substituting Equation (2.17) and (2.18) into above equations

$$\frac{\partial P_i}{\partial y_{ij}} = \frac{P_{ij}}{y_{ij}} \tag{5.20}$$

$$\frac{\partial Q_i}{\partial y_{ij}} = \frac{Q_{ij}}{y_{ij}} \tag{5.21}$$

Similarly,

$$\frac{\partial P_j}{\partial y_{ij}} = \frac{P_{ji}}{y_{ij}} \tag{5.22}$$

$$\frac{\partial Q_j}{\partial y_{ij}} = \frac{Q_{ji}}{y_{ij}} \tag{5.23}$$

The elements in Equation (5.20), (5.21), (5.22), and (5.23) are the four non-zero elements in the column of $\frac{\partial f}{\partial y}\left(X_0, Y_0\right)$ corresponding to branch i to j and its other elements are:

$$\frac{\partial P_k}{\partial y_{ij}} = 0 \tag{5.24}$$

$$\frac{\partial Q_k}{\partial y_{ij}} = 0 \tag{5.25}$$

where $k \notin \{i,j\}$

From Equations (5.19) to (5.25), for a network with N nodes, and b branches, $\frac{\partial f}{\partial y}\left(X_0, Y_0\right)$ is a $2N \times b$ matrix,

$$\Delta Z_l = -\Delta Y\left[\frac{\partial f}{\partial y}\left(X_0, Y_0\right)\right] = \left[0, \ldots, 0, P_{ij}, Q_{ij}, 0, \ldots, P_{ji}, Q_{ji}, 0, \ldots, 0\right] \tag{5.26}$$

Also, the L_0 is a $2N \times 2N \times b$ matrix, which is equivalent to the partial derivatives of the Jacobian matrix with respect to branch admittance. Each branch corresponds to a $2N \times 2N$ matrix.

Since $k \notin \{i, j\} \wedge m \notin \{i, j\}$ hence,

$$\frac{\partial^2 P_k}{\partial y_{ij} \partial \theta_m} = 0 \tag{5.27}$$

$$\frac{\partial^2 Q_k}{\partial y_{ij} \partial \theta_m} = 0 \tag{5.28}$$

$$V_m \frac{\partial^2 P_k}{\partial y_{ij} \partial V_m} = 0 \tag{5.29}$$

$$V_m \frac{\partial^2 Q_k}{\partial y_{ij} \partial V_m} = 0 \tag{5.30}$$

For each branch, there are at most 16 non-zero elements in the $2N \times 2N$ matrix, which may be obtained from the Jacobian matrix Equations (5.20) to (5.23) as follows:

$$\frac{\partial^2 P_i}{\partial y_{ij} \partial \theta_i} = \frac{V_i V_j\left(-G_{ij} \sin\theta_{ij} + B_{ij} \cos\theta_{ij}\right)}{y_{ij}} = -\frac{H_{ij}}{y_{ij}} \tag{5.31}$$

$$\frac{\partial^2 Q_i}{\partial y_{ij} \partial \theta_i} = \frac{V_i V_j\left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}\right)}{y_{ij}} = -\frac{J_{ij}}{y_{ij}} \tag{5.32}$$

$$V_i \frac{\partial^2 P_i}{\partial y_{ij} \partial V_i} = \frac{V_i V_j\left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}\right) - 2V_i^2 G_{ij} t_{ij}}{y_{ij}} = \frac{2P_{ij} - N_{ij}}{y_{ij}} \tag{5.33}$$

$$V_i \frac{\partial^2 Q_i}{\partial y_{ij} \partial V_i} = \frac{V_i V_j \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}\right) + 2V_i^2 \left(t_{ij} B_{ij} - b_{ij0}\right)}{y_{ij}} = \frac{2Q_{ij} - L_{ij}}{y_{ij}} \tag{5.34}$$

$$\frac{\partial^2 P_i}{\partial y_{ij} \partial \theta_j} = -\frac{H_{ij}}{y_{ij}} \tag{5.35}$$

$$\frac{\partial^2 Q_i}{\partial y_{ij} \partial \theta_j} = -\frac{J_{ij}}{y_{ij}} \tag{5.36}$$

$$V_i \frac{\partial^2 P_i}{\partial y_{ij} \partial V_j} = \frac{N_{ij}}{y_{ij}} \tag{5.37}$$

$$V_i \frac{\partial^2 Q_i}{\partial y_{ij} \partial V_i} = \frac{L_{ij}}{y_{ij}} \tag{5.38}$$

Since $\Delta \mathrm{Y}$ has only one non-zero element $\Delta Y_{ij} = -y_{ij}$, the L_0 becomes

$$L_0 = \begin{bmatrix} -H_{ij} & 2P_{ij} - N_{ij} & H_{ij} & N_{ij} \\ -J_{ij} & 2Q_{ij} + L_{ij} & J_{ij} & L_{ij} \\ H_{ij} & N_{ij} & -H_{ij} & 2P_{ij} - N_{ij} \\ J_{ij} & L_{ij} & -J_{ij} & 2Q_{ij} - L_{ij} \end{bmatrix} \tag{5.39}$$

Therefore, Equation (5.19) can be as

$$\begin{bmatrix} \Delta P_i \\ \Delta Q_i \\ \Delta P_j \\ \Delta Q_j \end{bmatrix} = H^{-1} \begin{bmatrix} P_{ij} \\ Q_{ij} \\ P_{ji} \\ Q_{ji} \end{bmatrix} \tag{5.40}$$

where,

$$H = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 \\ 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix} = \begin{bmatrix} -H_{ij} & 2P_{ij} - N_{ij} & H_{ij} & N_{ij} \\ -J_{ij} & 2Q_{ij} + L_{ij} & J_{ij} & L_{ij} \\ H_{ij} & N_{ij} & -H_{ij} & 2P_{ij} - N_{ij} \\ J_{ij} & L_{ij} & -J_{ij} & 2Q_{ij} - L_{ij} \end{bmatrix} \times \begin{bmatrix} S_{ii}^{(1)} & S_{ii}^{(2)} & S_{ij}^{(1)} & S_{ij}^{(2)} \\ S_{ii}^{(3)} & S_{ii}^{(4)} & S_{ij}^{(3)} & S_{ij}^{(4)} \\ S_{ji}^{(1)} & S_{ji}^{(2)} & S_{jj}^{(1)} & S_{jj}^{(2)} \\ S_{ji}^{(3)} & S_{ji}^{(4)} & S_{jj}^{(3)} & S_{jj}^{(4)} \end{bmatrix}$$

(5.41)

where,

$S_{ij}^{(1)}, S_{ij}^{(2)}$ are elements of the sensitive matrix relevant to the terminal nodes of the outaged branch.

Figure 3.3 shows the summarized flowchart of fast outage analysis explained in this subsection as proposed by Wang and McDonald (1994).

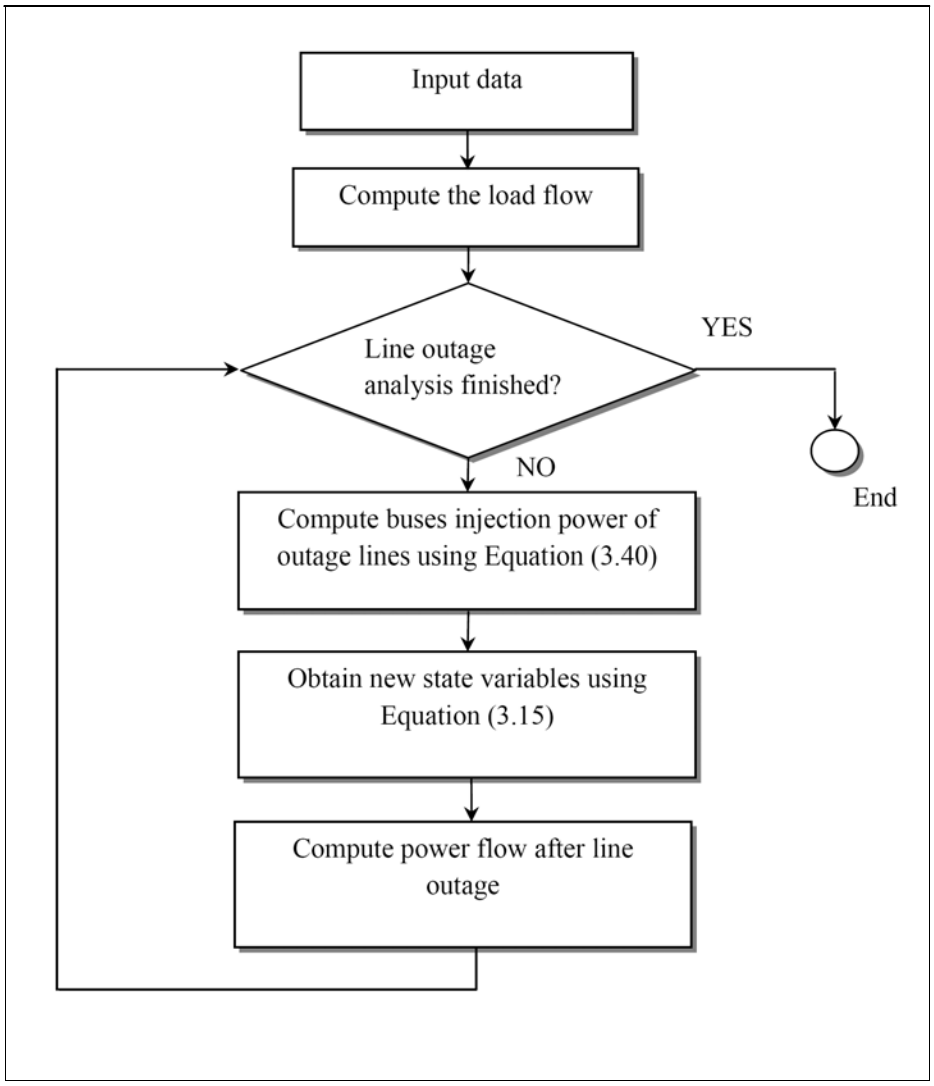


Figure 5.3 Flowchart of fast outage analysis [Source: (Wang & McDonald, 1994)]

5.3.4 Linear Method Based on Z_{bus}

The method discussed in the previous section can alternatively be performed when Z_{bus} of the system is considered. The voltage changes due to an additional current ΔI_m being injected into bus m of the system are given by (Grainger and Stevenson, 1994)

$$\begin{bmatrix} \Delta V_1 \\ \vdots \\ \Delta V_i \\ \Delta V_j \\ \vdots \\ \Delta V_N \end{bmatrix} = \begin{bmatrix} V_1' - V_1 \\ \vdots \\ V_i' - V_i \\ V_j' - V_j \\ \vdots \\ V_N' - V_N \end{bmatrix} = Z_{bus} \begin{bmatrix} 0 \\ \vdots \\ \Delta I_m \\ \vdots \\ 0 \end{bmatrix} = \begin{bmatrix} Column\ m\ of \\ Z_{bus} \end{bmatrix} \tag{5.42}$$

where the Z_{bus} is for the normal condition. The changes in the voltages of buses i and j is given as

$$\Delta V_i = Z_{im} \Delta I_m \qquad\qquad \Delta V_j = Z_{jm} \Delta I_m \tag{5.43}$$

The current change in the line p-q due to the outage of line m-n is given as

$$\Delta I_{pq} = -\frac{Z_a}{Z_b}\left[\frac{(Z_{pm} - Z_{pn}) - (Z_{qm} - Z_{qn})}{(Z_{mm} + Z_{nn} - 2Z_{mn}) - Z_a}\right]\Delta I_{mn} \tag{5.44}$$

where Z_a is the series impedance between bus m and n, Z_b is the series impedance between bus p and I_{mn} is the pre-outage current between bus m and n.

From (5.44), the line outage distribution factor is given as

$$L_{pq,mn} \cong \frac{\Delta I_{pq}}{I_{mn}} = -\frac{Z_a}{Z_b}\left[\frac{(Z_{pm} - Z_{pn}) - (Z_{qm} - Z_{qn})}{(Z_{mm} + Z_{nn} - 2Z_{mn}) - Z_a}\right] \tag{5.45}$$

It is observed that, the current injected into bus m changes by ΔI_m and it can be obtained as

$$\Delta I_m = \frac{Z_{pq} \Delta I_{pq}}{\left(Z_{pm} - Z_{qm}\right)} \tag{5.46}$$

The correspondence between per-unit power and per-unit current in the line then allow the line-outage distribution factors to be written as

$$\Delta I_{pq,mn} \cong \frac{\Delta P_{pq}}{P_{mn}} = -\frac{Z_a}{Z_b}\left[\frac{\left(Z_{pm} - Z_{pn}\right) - \left(Z_{qm} - Z_{qn}\right)}{\left(Z_{mm} + Z_{nn} - 2Z_{mn}\right) - Z_a}\right] \tag{5.47}$$

5.4 System Reliability Evaluation

5.4.1 Minimization of Load Curtailment

The line outage will result in a violation either bus voltage violation or power line violation. In this research, state estimator expressed in chapter four is used to compute the bus voltage and power flow in each line. If the power line is violated, that is, the power flow exceeds the line capacity, the load curtailment is taking place. In each operating point, the load curtailment levels is computed. This is the level that present the effect of load reduction at each bus in sytem and its effect to the respective line in overload state. The higher level represent the point where the less load could minimize the problem or resolve the problem. When the line j is under investigation, the power flow in each line is computed. The list of lines under violations are listed and extent of violation in each line is calculated. For example, if the power flow is 180 MW and the capacity of a line is 150 MW, then the extent of violation is 30 MW. Using common load, such as 10 MW for each bus, the load curtailment level is computed and ranked from the highest to the lowest. This is showing the location where the minimum load can be curtailed while solving the violation effect.

$$Line_{Level(i)} = C_{line(i)} - curtail_{load(j)} \tag{5.48}$$

Given that

$$Line_{Level(i)} = C_{line(i)} - curtail_{load(j)}$$

where,

$C_{line(i)}$ – Capacity of line i

$curtail_{load(j)}$ – Load curtailed in bus j

i – line under investigation;

j – bus in which load is curtailed.

5.4.2 IEEE 57 Bus System

In this section, reliability evaluation and results obtained during simulation are presented. The scenarios presented in this section are as follows. Load status in each bus for IEEE 57 bus system is shown in Table 5.5.

The concept of load point indices are given by Billinton and Allan, (1993) as follows: the probability of failure Q_k at bus k in a network is expressed as

$$Q_k = \sum_j P(B_j)P_{lj} \tag{5.49}$$

where B_j is an outage condition in the transmission network, and P_{lj} is the probability of load at bus k exceeding the maximum load that can be supplied at that bus without failure.

$$F_k = \sum_j F(B_j)P_{lj} \tag{5.50}$$

where $F(B_j)$ is the frequency of occurrence of B_j.

Expected number of load curtailments (NLC) is given as

$$NLC = \sum_{j \in x} F(B_j) \tag{5.51}$$

Where $j \in x$ includes all contingencies resulting in line overloads which are alleviated by load curtailment at bus k.

Expected load curtailed (ELC) in MW is given as

$$ELC = \sum_{j \in x} L_{kj} D_{kj} F(B_j) \tag{5.52}$$

where L_{kj} is the load curtailment at bus k to alleviate line overloads arising due to contingency j.

Expected energy not supplied (EENS) in MWh, is given as

$$EENS = \sum_{j \in x,y} L_{kj} D_{kj} F(B_j) \tag{5.53}$$

where D_{kj} is the duration in hours of the load curtailment arising due to the outage j.

Expected duration of load curtailment (EDLC) is given as

$$EDLC = \sum_{j \in x} D_{kj} F(B_j) \tag{5.54}$$

Table 5.5 IEEE 57 bus system load status

Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)
1	67	13	28	25	6.3	37	0	49	31
2	3	14	28	26	0	38	14	50	33
3	41	15	26	27	9.3	39	0	51	39
4	0	16	35.26	28	4.6	40	0	52	4.9
5	13	17	58	29	17	41	21	53	20
6	75	18	27.2	30	3.6	42	22	54	4.1
7	0	19	3.3	31	5.8	43	24	55	6.8
8	156	20	2.3	32	1.6	44	23	56	7.6
9	125	21	0	33	3.8	45	0	57	6.7
10	16	22	0	34	0	46	0		
11	0	23	6.3	35	6	47	39		
12	301	24	0	36	0	48	0		

Other data are as follows:

	Rainy	Normal
Total days	90	275
Availability	0.929	0.999
Unavailability	0.071	0.001
λ	3.5	0.5
r	13	7.5
μ	288	880

Consider the IEEE 57 bus system, and theory of components outages due to the weather status expressed in chapter three. From Figure 3.15 that describes the probability of line outage when weather status is known is used in the reliability analysis of the system during rainy season. Each bus state values and load point indices is computed. For example, Table 5.6 and Table 5.8 present state values and load point indices for bus 13 during rainy season, estimated to be three months respectively. Likewise, Table 5.7 and Table 5.9 present the state values and load point indices for bus

13 during normal weather, respectively. Only contingency events that have effects have been presented. Table 5.10 present the load point indices for the entire system.

Table 5.6 Bus 13 state values – rainy season (estimated - 90 days)

Line out	State probability	Frequency (occ. /3 month)	P_{kj}	Failure	
				Probability	Frequency (occ. /3 month)
13	0.00090383	0.29600411	1	0.0009	0.296
14	0.00090383	0.29600411	1	0.0009	0.296
16	0.00090383	0.29600411	1	0.0009	0.296
17	0.00090383	0.29600411	1	0.0009	0.296
25	0.00090383	0.29600411	1	0.0009	0.296
26	0.00090383	0.29600411	1	0.0009	0.296
27	0.00090383	0.29600411	1	0.0009	0.296
28	0.00090383	0.29600411	1	0.0009	0.296
50	0.00090383	0.29600411	1	0.0009	0.296
57	0.00090383	0.29600411	1	0.0009	0.296
58	0.00090383	0.29600411	1	0.0009	0.296
72	0.00090383	0.29600411	1	0.0009	0.296
				$Q_k = 0.0108$	$F_k = 3.55205$

Table 5.7 Bus 13 state values – normal weather (estimated - 275 days)

Line out	State probability	Frequency (occ. /3 month)	P_{kj}	Failure	
				Probability	Frequency (occ. /3 month)
13	0.00001273	0.01170523	1	0.000013	0.0117052
14	0.00001273	0.01170523	1	0.000013	0.0117052
16	0.00001273	0.01170523	1	0.000013	0.0117052
17	0.00001273	0.01170523	1	0.000013	0.0117052
25	0.00001273	0.01170523	1	0.000013	0.0117052
26	0.00001273	0.01170523	1	0.000013	0.0117052
27	0.00001273	0.01170523	1	0.000013	0.0117052
28	0.00001273	0.01170523	1	0.000013	0.0117052
50	0.00001273	0.01170523	1	0.000013	0.0117052
57	0.00001273	0.01170523	1	0.000013	0.0117052
58	0.00001273	0.01170523	1	0.000013	0.0117052
72	0.00001273	0.01170523	1	0.000013	0.0117052
				$Q_k = 0.000153$	$F_k = 0.1404627$

Table 5.8 Bus 13 load point indices – rainy season (estimated - 90 days)

Line out	State prob.	Freq. (occ./3 month)	P_{kj}	C	D_{kj}	L_{kj}	ELC	NLC	EENS	EDLC
13	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
14	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
16	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
17	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
25	0.0009	0.296	1	10	6.595	18	5.328	0.296	35.14	1.952
26	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
27	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
28	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
50	0.0009	0.296	1	24	6.595	4	1.184	0.296	7.809	1.952
57	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
58	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
72	0.0009	0.296	1	0	6.595	28	8.288	0.296	54.66	1.952
							89.39	3.552	589.59	23.43

Table 5.9 Bus 13 load point indices – normal weather (estimated - 275 days)

Line out	State prob.	Freq. (occ./3 mon.)	P_{kj}	C	D_{kj}	L_{kj}	ELC	NLC	EENS	EDLC
13	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
14	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
16	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
17	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
25	0.00001	0.0117	1	10	7.178	18	0.211	0.012	1.51	0.084
26	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
27	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
28	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
50	0.00001	0.0117	1	24	7.178	4	0.047	0.012	0.34	0.084
57	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
58	0.00001	0.0117	1	0	7.178	28	0.328	0.012	2.35	0.084
72	0.00001	0.0117	1	28	7.178	28	0.328	0.012	2.35	0.084

where C- Capacity available, and $D_{kj} = (P_j / F_j) * duration - (hours)$

Table 5.10 Overall load point indices

Bus	rainy season (estimated - 90 days)					
	Failure probability	Failure frequency	No. of curtailment	Load curtailed	Energy Curtailed	Curtailment duration
3	0.00090	0.28245	5.93138	0.28245	40.99770	1.95227
5	0.00181	0.80017	10.40217	0.80017	50.75906	3.90454
6	0.00181	1.02042	39.28630	1.02042	150.32490	3.90454
8	0.00181	0.80017	3.20067	0.80017	15.61817	3.90454
13	0.01085	3.55205	89.39324	3.55205	589.58596	23.42726
14	0.00904	4.00084	87.61829	4.00084	427.54743	19.52271
15	0.00452	2.00042	40.80852	2.00042	199.13168	9.76136
16	0.00090	0.40008	8.40175	0.40008	40.99770	1.95227
17	0.00090	0.40008	19.60409	0.40008	0.40008	0.40008
18	0.00181	0.80017	21.76454	0.80017	106.20356	3.90454
29	0.00090	0.40008	6.80142	0.40008	33.18861	1.95227
33	0.00090	0.40008	1.52032	0.40008	7.41863	1.95227
38	0.00090	0.40008	5.60117	0.40008	27.33180	1.95227
41	0.00090	0.40008	8.40175	0.40008	40.99770	1.95227
42	0.00452	2.00042	27.20568	2.00042	132.75445	9.76136
43	0.00904	4.00084	70.01462	4.00084	341.64749	19.52271
44	0.00090	0.40008	9.20192	0.40008	44.90224	1.95227
47	0.00452	2.00042	56.81186	2.00042	277.22254	9.76136
49	0.00271	1.20025	34.40718	1.20025	167.89534	5.85681
50	0.00271	1.20025	39.60827	1.20025	193.27487	5.85681
53	0.00090	0.40008	8.00167	0.40008	39.04543	1.95227
54	0.00090	0.40008	1.64034	0.40008	8.00431	1.95227
Total	0.06417	27.25960	595.62718	27.25960	2935.24965	137.05908

Table 5.10 Overall load point indices (continued)

normal weather (estimated - 275 days)					
Failure probability	Failure frequency	No. of curtailment	Load curtailed	Energy Curtailed	Curtailment duration
0.00001	0.01472	0.30917	0.01472	1.76438	0.08402
0.00003	0.02341	0.30434	0.02341	2.18447	0.16804
0.00003	0.01393	0.53636	0.01393	6.46938	0.16804
0.00003	0.02341	0.09364	0.02341	0.67214	0.16804
0.00015	0.14046	3.53498	0.14046	25.37342	1.00822
0.00013	0.11705	2.56344	0.11705	18.39993	0.84018
0.00006	0.05853	1.19393	0.05853	8.56983	0.42009
0.00001	0.01171	1.43974	0.01171	10.33421	0.08402
0.00001	0.01171	0.57356	0.01171	4.11688	0.08402
0.00003	0.02341	0.63676	0.02341	4.57058	0.16804
0.00001	0.01171	0.19899	0.01171	1.42830	0.08402
0.00001	0.01171	0.04448	0.01171	0.31927	0.08402
0.00001	0.01171	0.16387	0.01171	1.17625	0.08402
0.00001	0.01171	0.24581	0.01171	1.76438	0.08402
0.00006	0.05853	0.79596	0.05853	5.71322	0.42009
0.00013	0.11705	2.04841	0.11705	14.70314	0.84018
0.00001	0.01171	0.26922	0.01171	1.93241	0.08402
0.00006	0.05853	1.66214	0.05853	11.93055	0.42009
0.00004	0.03512	1.00665	0.03512	7.22554	0.25205
0.00004	0.03512	1.15882	0.03512	8.31778	0.25205
0.00001	0.01171	0.23410	0.01171	1.68036	0.08402
0.00001	0.01171	0.04799	0.01171	0.34447	0.08402
0.0009038	0.8246091	19.0623739	0.8246091	138.9908763	5.9652737

Table 5.10 Overall load point indices (continued)

Bus	Rainy season MLC (MW)	Rainy season Prob.	Normal weather MLC (MW)	Normal weather Prob.	Outage line
3	5.93	0.0009	0.31	0.000013	3
5	5.20	0.0018	0.15	0.000026	3, 18
6	38.27	0.0009	0.52	0.000013	3
8	2.40	0.0009	0.07	0.000013	3
13	8.29	0.009	0.33	0.00013	13,14,16,17, 26, 27, 28, 57, 58, 72
14	11.20	0.0054	0.33	0.000078	3, 5, 6, 14, 15, 28
15	10.40	0.0027	0.30	0.000039	2, 3, 15
16	8.40	0.0009	0.30	0.000013	21
17	19.60	0.0009	0.57	0.000013	17
18	10.88	0.0018	0.32	0.000026	3, 18
29	6.80	0.0009	0.20	0.000013	2
33	1.52	0.0009	0.04	0.000013	45
38	5.60	0.0009	0.16	0.000013	15
41	8.40	0.0009	0.25	0.000013	28
42	8.80	0.0018	0.26	0.000026	3, 28
43	9.60	0.0054	0.28	0.000078	3, 16, 17, 28, 28, 72
44	9.20	0.0009	0.27	0.000013	15
47	15.60	0.0018	0.46	0.000026	3, 15
49	12.40	0.0018	0.36	0.000026	3, 15
50	13.20	0.0027	0.39	0.000039	3, 15, 27
53	8.00	0.0009	0.23	0.000013	3
54	1.64	0.0009	0.05	0.000013	3

Table 5.10 Overall load point indices (continued)

Bus	Rainy season MEC (MWh)	Rainy season Prob.	Normal weather MEC (MWh)	Normal weather Prob.	Outage line
3	41.00	0.0009	1.76	0.000013	3
5	25.38	0.0018	1.09	0.000026	3, 18
6	146.42	0.0009	6.30	0.000013	3
8	11.71	0.0009	0.50	0.000013	3
13	54.66	0.009	2.35	0.00013	13,14,16,17, 26, 27, 28, 57, 58, 72
14	54.66	0.0054	2.35	0.000078	3, 5, 6, 14, 15, 28
15	50.76	0.0027	2.18	0.000039	2, 3, 15
16	41.00	0.0009	2.18	0.000013	21
17	95.66	0.0009	4.12	0.000013	17
18	53.10	0.0018	2.29	0.000026	3, 18
29	33.19	0.0009	1.43	0.000013	2
33	7.42	0.0009	0.32	0.000013	45
38	27.33	0.0009	1.18	0.000013	15
41	41.00	0.0009	1.76	0.000013	28
42	42.95	0.0018	1.85	0.000026	3, 28
43	46.85	0.0054	2.02	0.000078	3, 16, 17, 28, 28, 72
44	44.90	0.0009	1.93	0.000013	15
47	76.14	0.0018	3.28	0.000026	3, 15
49	60.52	0.0018	2.60	0.000026	3, 15
50	64.42	0.0027	2.77	0.000039	3, 15, 27
53	39.05	0.0009	1.68	0.000013	3
54	8.00	0.0009	0.34	0.000013	3

5.4.3 The East Africa Community Virtual Electric Network

In this section, contingency analysis is applied to a practical power system. The East Africa Community (EAC) Virtual Electric Network with the data given in the Appendix A, is an ongoing restructured system. In this system, three regions: Uganda, Tanzania and Kenya are served by thirty one (31) generators distributed in all regions. Data for EAC Virtual Electric Network is as shown in Table B2 to Table B4. Table B4 presents the EAC Virtual Electric Network Bus Data and estimated maximum load of the system. Using the system proposed, the operating point estimated to be a maximum operating point at 1700 hours (Table B4) is analyzed. Load status in each bus for EAC Virtual Electric Network Region I (Tanzania), Region II (Uganda) and Region III (Kenya) are shown in Table 5.11, Table 5.12, and Table 5.13 respectively.

Table 5.11: EAC Virtual Electric Network Region I (Tanzania) bus system load status

Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)
1	0	9	40	17	0	25	22	33	0
2	47	10	48	18	100	26	28	34	0
3	11	11	54	19	92	27	72	35	0
4	8	12	53	20	107	28	60	36	0
5	12	13	0	21	64	29	81	37	0
6	20	14	27	22	18	30	278	38	0
7	40	15	20	23	81	31	7	39	10
8	15	16	22	24	9	32	10.8	40	52

Table 5.12: EAC Virtual Electric Network Region II (Uganda) bus system load status

Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)
41	60	50	44	59	0	68	51	77	61
42	120	51	60	60	23	69	16	78	33
43	0	52	4	61	22	70	4	79	71
44	7	53	0	62	21	71	23	80	2
45	5	54	0	63	58	72	0	81	180
46	3	55	94	64	18	73	23	82	175
47	77	56	0	65	28	74	7	83	2
48	9	57	0	66	17	75	9		
49	0	58	61	67	44	76	32		

Table 5.13: EAC Virtual Electric Network Region III (Kenya) bus system load status

Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)	Bus	Load (MW)
84	95	93	18	102	12	111	0	120	0
85	98	94	21	103	0	112	33	121	55
86	29	95	4	104	0	113	19	122	29
87	0	96	102	105	33	114	41	123	55
88	212	97	32	106	29	115	22	124	0
89	4	98	44	107	17	116	31	125	70
90	0	99	67	108	43	117	108	126	12
91	0	100	0	109	9	118	8	127	19
92	6	101	50	110	8	119	3		

Other data are assumed to be as follows:

	Rainy	Normal
Total days	90	275
Availability	0.929	0.999
Unavailability	0.071	0.001
λ	3.5	0.5
r	13	7.5
μ	288	880

Analysis for line for first ten (10) lines in region II is considered. Table 5.14 and Table 5.16 present state values and load point indices for bus 41 during rainy season, estimated to be three months respectively. Table 5.15 and Table 5.17 present the state values and load point indices for bus 2 during normal weather, respectively.

Table 5.14 EAC Virtual Electric Network Region II (Uganda) Bus 41 state values – rainy season (Estimated - 90 days)

Line out	State probability	Frequency (occ. /3 month)	P_{kj}	Failure	
				Probability	Frequency (occ. /3 month)
2	0.002311576	1.304884843	1	0.00231	1.30488
4	0.002311576	1.304884843	1	0.00231	1.30488
5	0.002311576	1.304884843	1	0.00231	1.30488
6	0.002311576	1.304884843	1	0.00231	1.30488
7	0.002311576	1.304884843	1	0.00231	1.30488
8	0.002311576	1.304884843	1	0.00231	1.30488
10	0.002311576	1.304884843	1	0.00231	1.30488
15	0.002311576	1.304884843	1	0.00231	1.30488
				$Q_k = 0.01849$	$F_k = 10.43908$

Table 5.15 EAC Virtual Electric Network Region II (Uganda) Bus 41 state values – normal weather (estimated - 275 days)

Line out	State probability	Frequency (occ. /3 month)	P_{kj}	Failure	
				Probability	Frequency (occ. /3 month)
2	0.00003256	0.00006511	1	0.000033	0.000065
4	0.00003256	0.00006511	1	0.000033	0.000065
5	0.00003256	0.00006511	1	0.000033	0.000065
6	0.00003256	0.00006511	1	0.000033	0.000065
7	0.00003256	0.00006511	1	0.000033	0.000065
8	0.00003256	0.00006511	1	0.000033	0.000065
10	0.00003256	0.00006511	1	0.000033	0.000065
15	0.00003256	0.00006511	1	0.000033	0.000065
				$Q_k = 0.000261$	$F_k = 0.00026$

Table 5.16 EAC Virtual Electric Network Region II (Uganda) Bus 41 load point indices – rainy season (estimated - 90 days)

Line out	State prob.	Freq. (occ./3 month)	P_{kj}	C	D_{kj}	L_{kj}	ELC	NLC	EENS	EDLC
2	0.0023	1.3049	1	168.6	3.83	11.36	14.82	1.305	56.7	4.993
4	0.0023	1.3049	1	172.0	3.83	7.988	10.42	1.305	39.88	4.993
5	0.0023	1.3049	1	96.8	3.83	83.18	108.5	1.305	415.3	4.993
6	0.0023	1.3049	1	40.70	3.83	139.3	181.8	1.305	695.5	4.993
7	0.0023	1.3049	1	164.1	3.83	15.91	20.75	1.305	79.41	4.993
8	0.0023	1.3049	1	65.7	3.83	114.3	149.1	1.305	570.5	4.993
10	0.0023	1.3049	1	166.7	3.83	13.33	17.4	1.305	66.58	4.993
15	0.0023	1.3049	1	176.8	3.83	3.24	4.228	1.305	16.18	4.993
							507	10.44	1940	39.944

Table 5.17 EAC Virtual Electric Network Region II (Uganda) Bus 41 load point indices – normal weather (estimated - 275 days)

Line out	State prob.	Freq. (occ./3 month)	P_{kj}	C	D_{kj}	L_{kj}	ELC	NLC	EENS	EDLC
2	0.00003	0.00007	1	168.6	7.2	11.36	0.34	0.03	2.44	0.215
4	0.00003	0.00007	1	172.0	7.2	7.988	0.239	0.03	1.716	0.215
5	0.00003	0.00007	1	96.9	7.2	83.18	2.49	0.03	17.87	0.215
6	0.00003	0.00007	1	40.7	7.2	139.3	4.17	0.03	29.93	0.215
7	0.00003	0.00007	1	164.1	7.2	15.91	0.476	0.03	3.418	0.215
8	0.00003	0.00007	1	65.7	7.2	114.3	3.421	0.03	24.55	0.215
10	0.00003	0.00007	1	168.6	7.2	11.36	0.34	0.03	2.44	0.215
15	0.00003	0.00007	1	172.0	7.2	7.988	0.239	0.03	1.716	0.215
							11.14	0.18	79.93	1.2893

where C- Capacity available, and $D_{kj} = (P_j / F_j) * duration - (hours)$

5.5 Conclusion

The system reliability evaluation presented in this chapter shows how the system would perform under single line outage condition. Both rainy season and normal weather are considered in this chapter. Table 5.10 depicts the general overview of the load point indices during rainy season and normal weather. In order to be acquainted with the computing process within each agent explained in chapter three, the implementation of agents in a model proposed is presented in the next chapter.

CHAPTER VI

MODEL DESIGN AND IMPLEMENTATION

6.1 Introduction

In this chapter, the model theory, design, and implementation are presented. Numerical experiments and results using standard IEEE 57 bus systems are presented. The choice of the IEEE 57 bus system is based on its reasonable bus number that may reflect numerous power systems in many regions, particularly in developing countries. Most computation processes are accomplished by the use of MATLAB software. Control function is based on the negotiation technique and the best decision is considered as a model decision. The negotiation process used in decision making is also briefly expressed in this chapter.

6.2 Model Design

Power systems are extremely complex and highly interactive. In order to monitor, assess and control large-scale electric power system, operators depend on an array of measured quantities obtained from the SCADA system. Therefore, SCADA is used to send recorded measurements from their locations to the control where state estimation is computed by the system state estimator. The contingency analysis functions take place and contingency management is applied based on the decision set forth by the system. The chapter presents functions related to the proposed model and performance obtained based on the model simulations.

6.3 Task Assignment and Coordination for Agents

In this model, agents are based on the electric power market players and the scheduled coordination. The main agent players in this model are power producers (GENCOs), transmission providers (TRANSCOs), power consumers (DISTCOs), and agents responsible for maintaining the reliability through scheduled coordinators (SCs). As explained in the previous chapters, task assignment and agent coordination are the key elements to obtain the better performance of the multiagent systems. In this section, task assignment and agent coordination are presented. The objective is to perform contingency analysis in an optimized computing time.

6.3.1 Task Assignment

Agents and their tasks are as listed in Table 3.1. The hierarchy of agents is based on their dependency. Event probability agents (e.g. EPA_1, EPA_2, etc.) compute the prior probabilities such as weather probability, equipments failure, etc. Data for EPAs are collected from the source, such as monitoring devices, and hence they fall in the top level agents, or primary level agents. The algorithm used for EPA dedicated for generating units outage has explained in details in chapter five. Other EPA algorithms are based on probability computations meant for their tasks. Other agents such as violation agents (VA), scheduling coordinators agents (SCA), and transmission cost agents (TCA), and generation cost agents (GCA), depends also on the state estimators to perform their tasks. Hence they fall on the secondary level agents. Although the limits of system elements such as power line capacity, etc., are set by the manufacturer, yet the knowledge about the system state is required to decide if there is a violation on those limits. The agents' collaboration in the power system contingency model is as shown in Figure 3.2.

6.3.2 Events Probability Updates

An agent needs to know the actual state of a problem domain or parts of the domain in order to perform its task. Records collected are used to compute the probabilities are collected by task agents designed for that purpose. The task agents include: weather status records, equipment fault records, line outage records and miscellaneous, referred to as others, faults records.

During records collection, the time composed of hour, day, and year are the main attributes to be used by most agents. Being located in remote areas, agents communicate with their coordinated agent in the control center so compute the probabilities and to append the records. Agents in a control center are designed by the use of MATLAB to organize the data collected and perform their tasks. Practically, records regarding time are useful when more details are required for analysis, however in some agents such as weather records this attribute is considered redundant. This is due to the fact that, the weather records are mainly based on a day records and not seconds. Figure 6.1 shows the piece of MATLAB command used to organize the related data. In this format the data is recorded when the events occur. The data is saved in a format that can be shared by other agents. Equipment agents and other task agents present data in a similar manner, with the related task attribute, such as equipment failure, line outage event, etc.

Figure 6.2 presents the priori and posterior probabilities in a causal network. Data related to weather, equipments related to the line under investigation and other causes are collected and the conditional probability of line outage is computed. In order to demonstrate this category of data records, the equipment outages, in particular generating units is demonstrated. The data used for generators in IEEE 57 bus as presented by Kalyani, and Swarup, (2009) is presented in Table 6.1. In this system, seven (7) generators placed in buses 1, 2, 3, 6, 8, 9, and 12 are used.

```
% MATLAB command for data organization

if event == 1
rainfall  =  get(rainfall)          %  get  the  rainfall records
muda = now;                         % specify the event time
% organize data
halihewa = [day(muda) month(muda) year(muda) ...
      hour(muda) minute(muda) second(muda) rainfall]
save halihewa.dat halihewa –ascii – append
```

Figure 6.1 MATLAB code for rain records data organization.

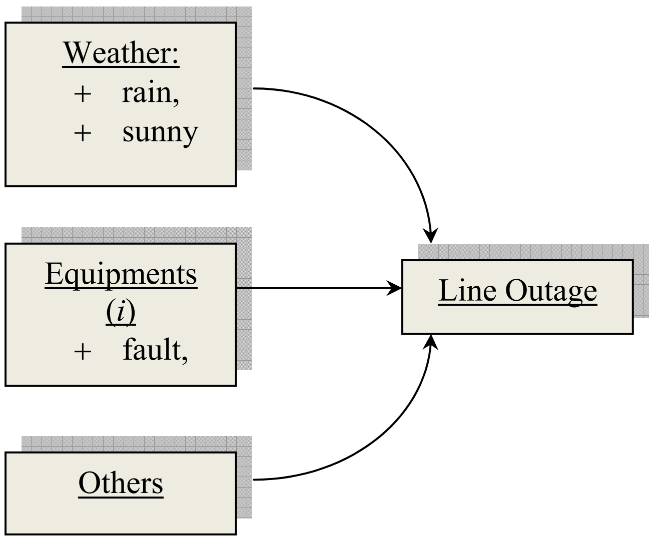


Figure 6.2 Priori and posterior probabilities in a causal network.

Table 6.1 IEEE 57 Bus System generators data

Generator.	Bus No.	P_{min} (MW)	P_{max} (MW)
1	1	0	575
2	2	0	100
3	3	0	140
4	6	0	100
5	8	0	550
6	9	0	100
7	12	0	410

Table 6.2 Power generating units availability data

State	Capacity out per unit							Probability
	1	2	3	4	5	6	7	
1	0	0	0	0	0	0	0	0.98
2	20	20	20	20	20	20	20	0.02

Table 6.2 Power generating units availability data (continued)

State	Capacity out per unit								Probability
	8	9	10	11	12	13	14	15	
1	0	0	0	0	0	0	0	0	0.970
2	20	20	20	20	20	20	20	20	0.022
3	50	50	50	50	50	50	50	50	0.008

Table 6.3 Capacity outage probability table for the fifteen-unit system

Cap. out	Individual probabilities	Cumulative Probabilities	Cap. out	Individual probabilities	Cumulative Probabilities
0	0.6803876218	1.0000000000	120	0.0001228660	0.0005265912
20	0.1234517747	0.3196123782	125	0.0003154151	0.0004037252
25	0.0971982317	0.1961606035	130	0.0000003205	0.0000883101
40	0.0097997801	0.0989623718	135	0.0000032798	0.0000879896
45	0.0176359678	0.0891625917	140	0.0000095958	0.0000847098
50	0.0508742184	0.0715266239	145	0.0000314040	0.0000751140
60	0.0004127742	0.0206524055	150	0.0000330017	0.0000437100
65	0.0013999686	0.0202396312	155	0.0000001077	0.0000107083
70	0.0019174675	0.0188396627	160	0.0000003564	0.0000106007
75	0.0129110114	0.0169221952	165	0.0000016046	0.0000102443
80	0.0000095419	0.0040111838	170	0.0000032575	0.0000086397
85	0.0000753991	0.0040016419	175	0.0000042010	0.0000053822
90	0.0002350356	0.0039262428	180	0.0000000062	0.0000011812
95	0.0013760739	0.0036912071	185	0.0000000000	0.0000011750
100	0.0016938343	0.0023151332	190	0.0000002343	0.0000011750
105	0.0000031493	0.0006212989	195	0.0000004106	0.0000009407
110	0.0000136472	0.0006181496	200	0.0000004154	0.0000005301
115	0.0000779112	0.0006045024	-	-	-

Table 6.4 IEEE 57- Bus System line limits

Line	From	To	Limits MVA	Line	From	To	Limits MVA
1	1	2	250	28	14	15	150
2	2	3	200	37	24	26	150
3	3	4	150	58	15	45	150
8	8	9	300	59	14	46	250
15	1	15	250	60	46	47	150
16	1	16	150	65	10	51	200
17	1	17	175				
22	7	8	150	All others			100
25	12	13	150				
27	12	17	150				

Table 6.2 presents data regarding the generating unit system in bus 1 composed of fifteen (15) units. The capacity of the generator is 575 MW as shown in Table 6.1. The units 1 to 7 can hold two states each with capacity of 25 MW, while units 8 to 15 can hold three states each with capacity of 50 MW. With the theory presented in section 3.2, the system is simulated and the capacity outage probability table for fifteen-unit system is as shown in Table 6.3. The same approach is applied for other generating units

6.1.1 Limits Violation

Violation agent checks if preset limits of the system are violated when the contingency events occur. In this research, buses limit and lines capacities are the preset limits used by the model. Table 6.4 shows the IEEE 57 bus system line limits as presented by Kalyani, and Swarup, (2009). The change of current in any other line is defined in a line outage distribution factor. This is demonstrated in Table 6.5 and Table 6.6. From these data it is observed that, line outage in one region can provide a significant change in the other regions. For example, line index 25 experiences the significant distribution factor of 0.2588 during line 65 outage.

6.2 Negotiating Agents

As mentioned in the previous section, scheduling coordinators agents, transmission cost agents, and generation cost agent, are used in contingency analysis in this research. These agents support the main agents, GENCOs, TRANSCOs, and DITSCOs in contingency management process.

In order to achieve the main objective, each agent must develop an effective communication within the platform and globally and build working relationship as they negotiate towards the main objective which is the laid criterion. Therefore the design starts by setting plans and goals for each agent in the system where an agent is armed with coded negotiation model for the conflict resolution via inter exchange of messages.

In power system contingency assessment technique proposed here, each agent is assigned individual goal. However, in the point of decision, each goal (analogous to an issue) is prioritized. In the systems, agents may share the main goal (objective). Negotiations between the agents are provoked based on observed changes in the system. The effective way of resolving the conflict (if any) caused by the change depends on how they understand the underlying dynamics of the conflicts. The next subsections give the method used for conflict management and negotiation contention used by agents.

All sub objectives maintained by agents should be an integral part of optimal power flow function. Therefore, the agents will negotiate and compromise based on the security of the power system while optimizing cost of power production represented as O={O_1, O_2, …, O_k}, $O = \{O_1, O_2, \dots, O_k\}$, where O is the main objective, and O_1, O_2, …, O_k $O_1, O_2, \dots, O_k$ are sub objectives.

Agent1:O_1 based on the power-flow

$$f_1(x,u) - 0 \; f_1\,(x,u) \; - \; 0 \qquad (6.1)$$

where, f_1 is the power-flow function, and

x is the state variable (bus magnitude voltage and angle), and u is the control variable.

Agent2:O_1 based on the power flow

$$f_1(x,u) = 0 \; f_2\,(x,u) \; = \; 0 \qquad (6.2)$$

where, f_2 is the operating constraints and limits on control variable.

Agent3: O_3 based on the cost of power production

$$f_1(x,u) = 0 \; f_3 \; (x,u) \; = \; 0 \tag{6.3}$$

where, f_3 is the voltage limit and power capacity of the bus and transmission line respectively.

6.2.1 Conflict Management

As mentioned in the previous chapters, for consistent service, power system must remain intact and be able to endure a wide variety of disturbances and it should operate in normal and secured condition. Figure 6.3 shows the algorithm of the conflict analysis and management. Violation to this will create conflict. Note that, conflict is not interest of any agent; however in solving the conflict, each agent is biased by its interest. Due to the fact that, the situation of difficult conflict based on the agents' objective models, the structure of agents should ranked to deal with the unions. These agents, which act as a group manager, intervene only when the conflict is difficult to be resolved because they are costly.

The conflict analysis is the process in which the system performance is analyzed and the output determines if there is any conflict or not. This process is shown in Figure 6.4. Limits analysis framework presents the results of the contingency analysis for both line outage and generators outage based on the limits.

Bus voltage limit is among the results of the power system contingencies. If the limit is reached, the further analysis is considered. The level of the limit can be rectified by adjusting the generator units' outputs, power system topology adjustments, limiting load at certain buses, etc so as to accept the level of conflict as shown in Figure 6.5. However, for the higher level of the conflict, that cannot rectify the problem. In this case, agents are involved to solve the problem by negotiation towards the optimum solution as shown by the negotiation framework presented in Figure 6.6.

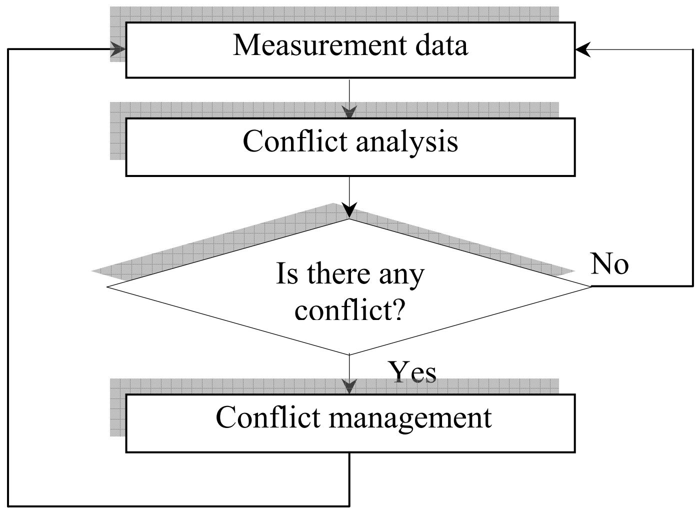


Figure 6.3 Conflict analysis and management algorithm

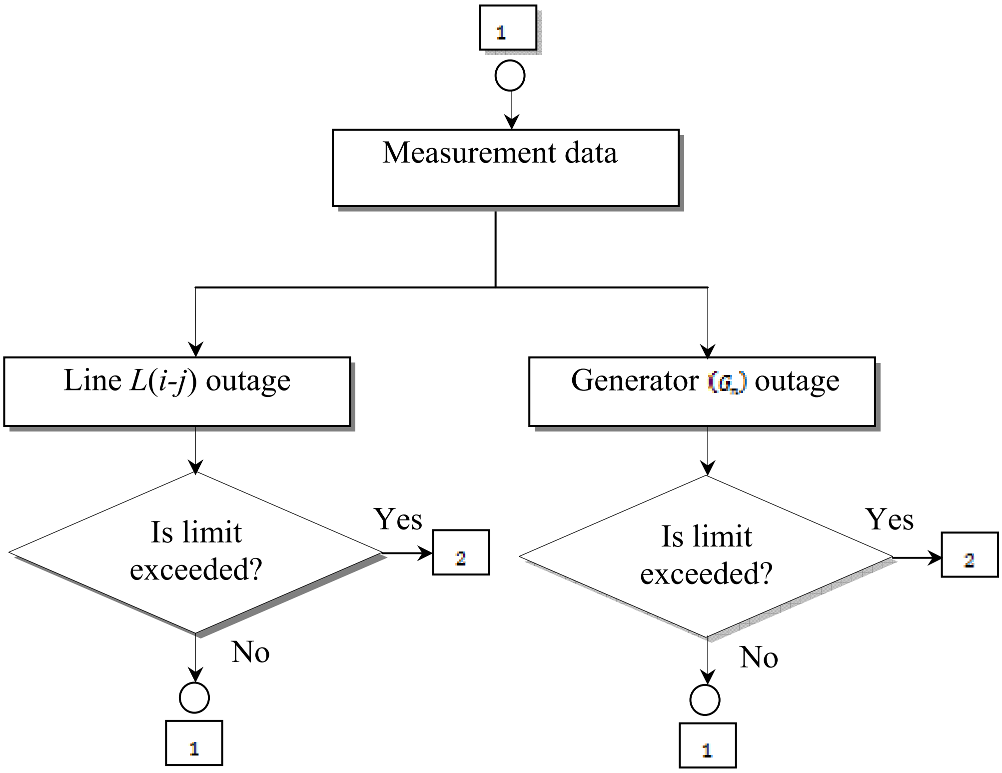


Figure 6.4 Limits analysis framework

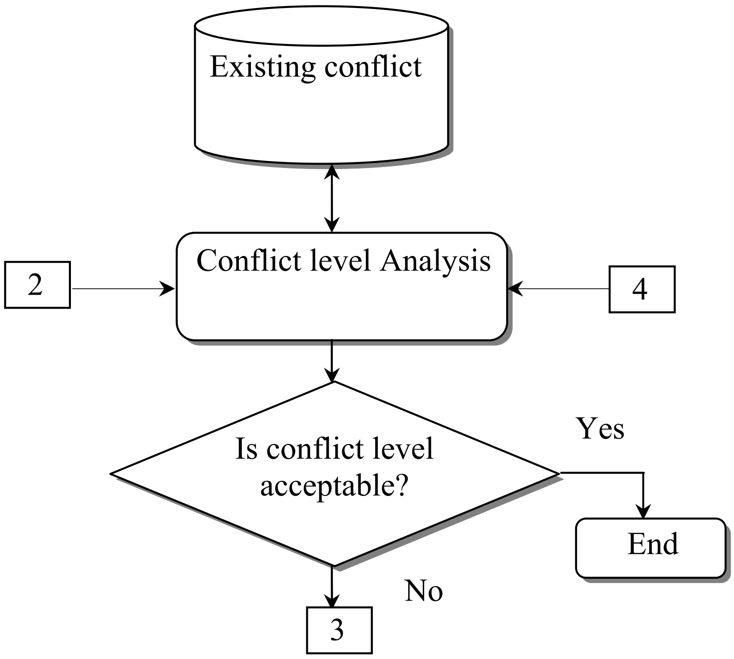


Figure 6.5 Conflict level analysis

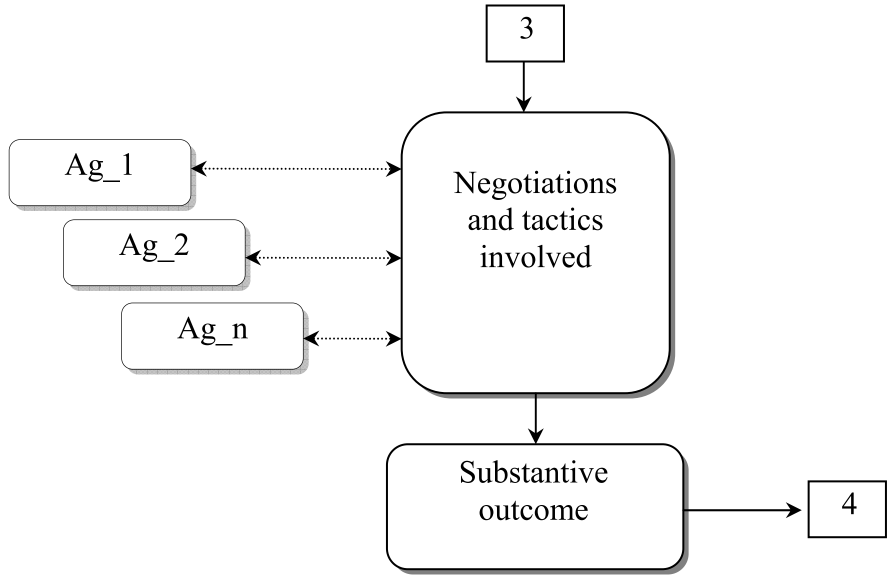


Figure 6.6 Negotiation framework

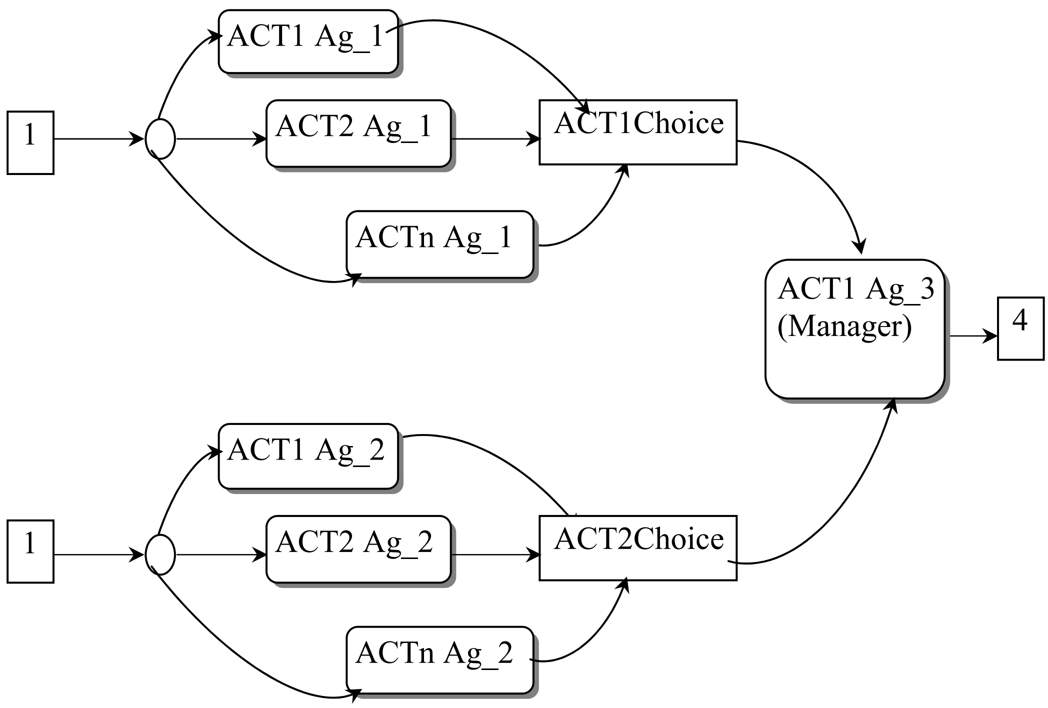


Figure 6.7 Petri nets and scope boundaries.

6.3 Contention Agents

All agents are given equal right to contend towards the conflict resolution. The winner in the contention will depend on the level of ranking set by the particular agent. The rank of agents defined based on the cost involved and criteria set forth. Based on the interest set by all contenders, the rules and criteria are used to decide the winner which focuses on maximizing substantive outcomes in negotiations.

In order to exchange information between agents, there must be a communication channel between the agents. In this research, both communications via message and procedure call are considered. Negotiations and tactics involved are based on individual objectives and decision is taken back to the conflict level analysis. In the negotiation process as shown in Petri net Figure 6.7, each agent is presenting its solution and choice is based on the best solution among the rest. The manager will issue a winning agent decision. The best choice is biased in the issues set as criteria for the decision.

6.4 Negotiation Process

In the human environmental field of negotiation, the skilled negotiators should learn the negotiation base, i.e. individual interests, objectives, and options available on table. The key point is to achieve the best of the possibilities. Similarly, agents in a system operate in the same manner, whereby agents (negotiators) are trained to know the system so that each will optimize its objective towards the success of the main objective. Unlike the human environment, in machine based negotiations both negotiators have individual objectives both all are aiming towards the same objective. In that case, there is no walk-away at the final court.

Depending on the scenario of the particular system, an agent can stand to achieve the objective or a team of agents can work together towards the same objective. In Figure 6.8, several agents work as a team to obtain a sub objective. The predefined sub objectives are designed in such a way that the main objective is achieved when sub objectives are achieved. This is referred to hierarchical designed agents.

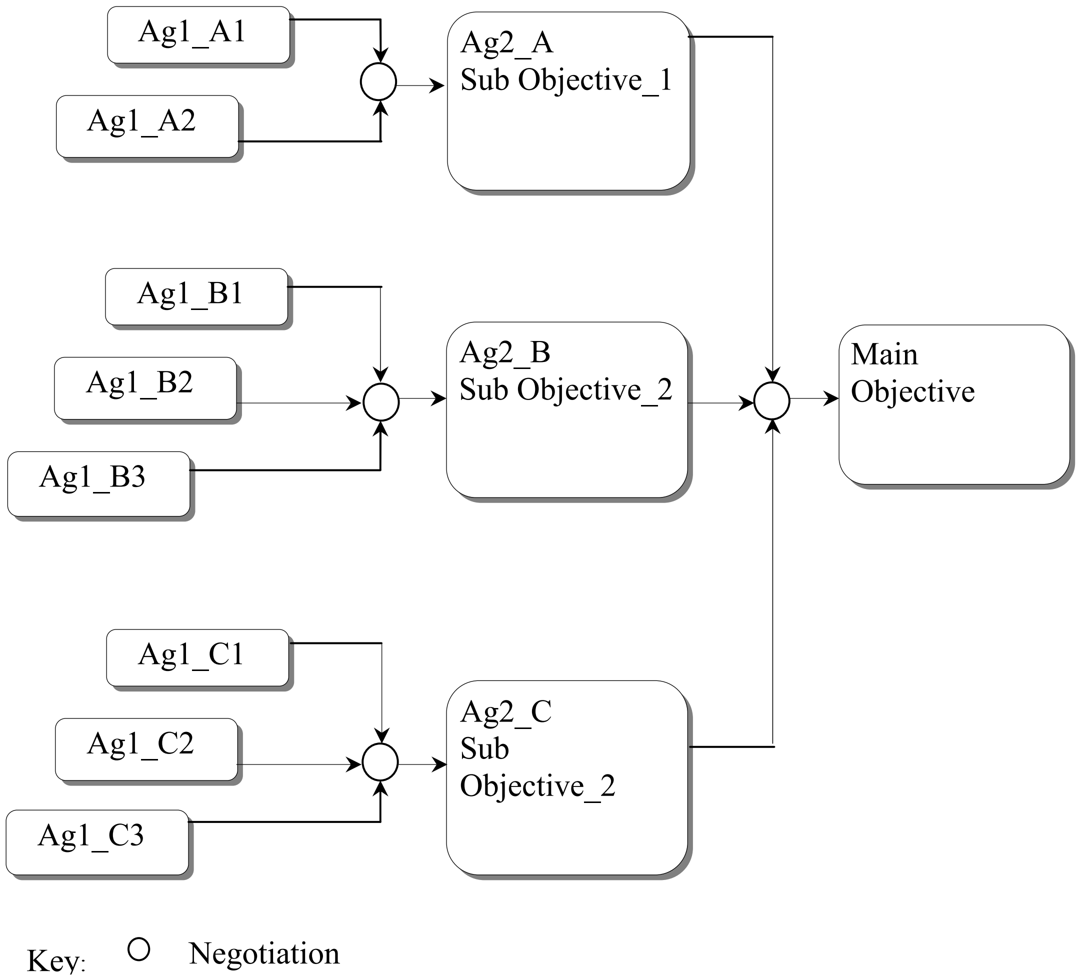


Figure 6.8 Agents in a team structure

6.4.1 Generation Costs

Since the cost of power industry services is charged to the consumers on the basis of their energy consumption (Kirschen and Strbac, 2004), then the minimization of generation costs is directly proportional to the minimization of consumer charges. Therefore, the GENCOs pass most of the generation costs to their customers in the form of higher prices for electrical energy. Using generation cost parameters presented in Table 6.7 for generators in IEEE 57 bus system, Figure 6.9 and Table 6.8 show the increase of generation cost during the contingency event (line-outage).

$$C_i = \alpha_i + \beta_i P_i + \gamma_i P_i^2 \qquad (6.5)$$

The steady-state ampacity of transmission lines system is obtained from the condition assumptions as presented in Table 6.4. The fuel cost of generator i is represented as a quadratic function of real power generation (Saadat, 2004), (Wood and Wollenberg, 1996), and (Grainger and Stevenson, 1994). If the probability of the line outage is known, the risk of the system can be calculated simply by multiplying the increase in generation and the probability of the line outage.

$$\text{Risk}_i = Prob_i \times \text{Generation Increase}_i \qquad (6.6)$$

where the Risk_i is the risk caused by the line i outage, and $Prob_i$ is the probability of line i outage.

Table 6.5 Generation cost parameters

Generator	Bus	Cost Parameters		
		A	B	C
1	1	200	5.0	0.004
2	2	570	6.0	0.0094
3	3	450	5.5	0.008
4	6	550	7.0	0.007
5	8	300	7.0	0.0092
6	9	250	6.0	0.009
7	12	350	5.5	0.0055

6.4.2 Control in Power Line Violation

There are several alternatives that can be used to control the violations back to normal. However, the agents assigned the task must communicate so as to obtain the main objective. In this researach, the minimum load curtailment is given a priority. For example, in order to resolve the power line problem during the line outage, the consideration is either to increase or decrease generation power, or load curtailment in several buses. An example of algorithm for the similar case is proposed by Shahidepour and Wang (2003) where GENCOs agents communicate to resolve the limitation is used. When congestion occurs, the ISO agent publishes the information about the congestion to all agents. Agents negotiate and solution is obtained. For this case, ISO divides GENCOs into two groups, RED agents and GREEN agents according to their contibution to the congestion line. The RED agents represents agents whose decremental adjustment could mitigate the congestion and GREEN agents represents agents whose incremental adjustments could mitigate the congestion.

The agent theory used in this model is based on competition on their own benefits to mitigate the problem. The TRANSCOs agents are meant for minimizing the possibility of line and bus violations while DITSCOs agents are minimizing the costs reflected to the customers. In this method ISO devides GENCOs into RED and GREEN GENCOs. GREEN GENCOs reprsent GENCOs whose decremental adjustment could resolve the line congestion and RED GENCOs represent GENCOs whose increment could resolve the line congestion

6.5 Model Implementation

In this section, method used in transforming the model into the software is explained. In this research the top-down design technique is used. This is a process of starting with a large task and breaking it into smaller, more easily understandable pieces (subtasks) which perform a portion of the desired task (Chapman, 2000).

The concept of top-down design is illustrated in Figure 6.9. Hence, the software implementation is based in a systematically structured approach into the workflow of a model structure shown in Figure 6.10. Functional blocks shown in Figure 6.10 are explained in details in this chapter. Setting of the system based on the branch parameters is an initial task..

6.5.1 SCADA

The first step of security analysis is to monitor the state of the system (Abur and Exposito, 2004). This involves acquisition of measurements from all parts of the system and then processing them in order to determine the system state. In this research, the key function of the SCADA function block is to collect the measured remote measurements transmit them to the control room for further processing so as to accomplish the entire function of the SCADA. Therefore two main methods are getMeas ( ) and transmitMeas ( ).

6.5.1.1 The getMeas ( )

The method getMeas() is responsible for the acquisitions of measurements from various parts of the power system. The state estimation process based on regression model demand the required input measurements to be available, therefore incase some of measurements are not available, the search process expressed in chapter IV, section 4.4 is used to replace unavailable measurements.

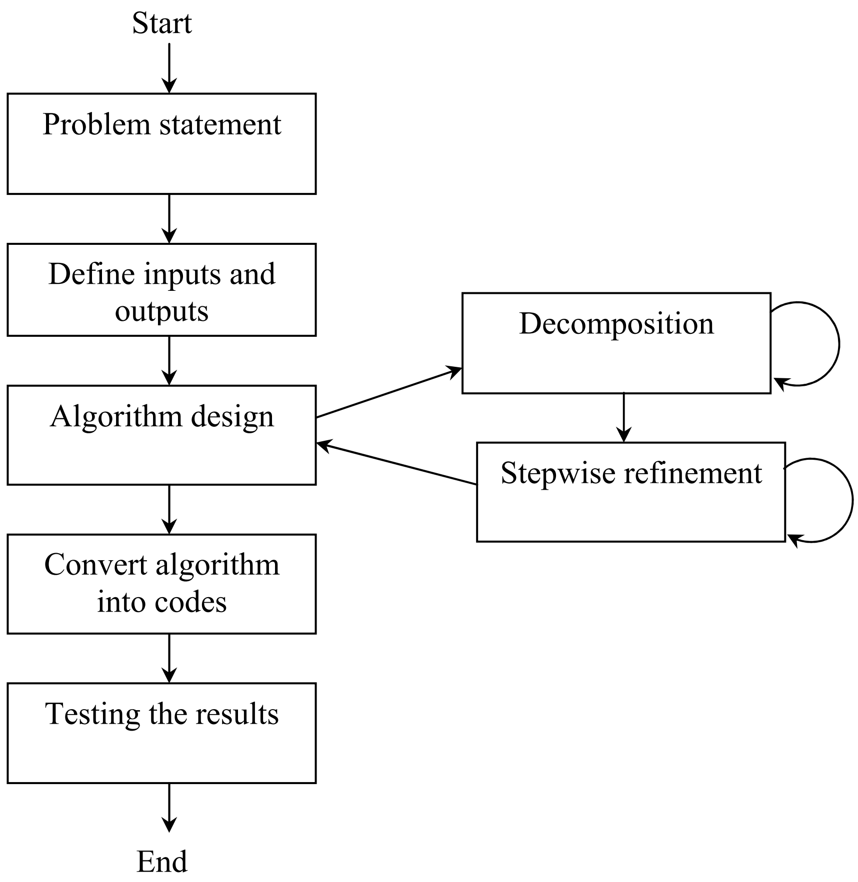


Figure 6.9 The software design process (Chapman, 2000)

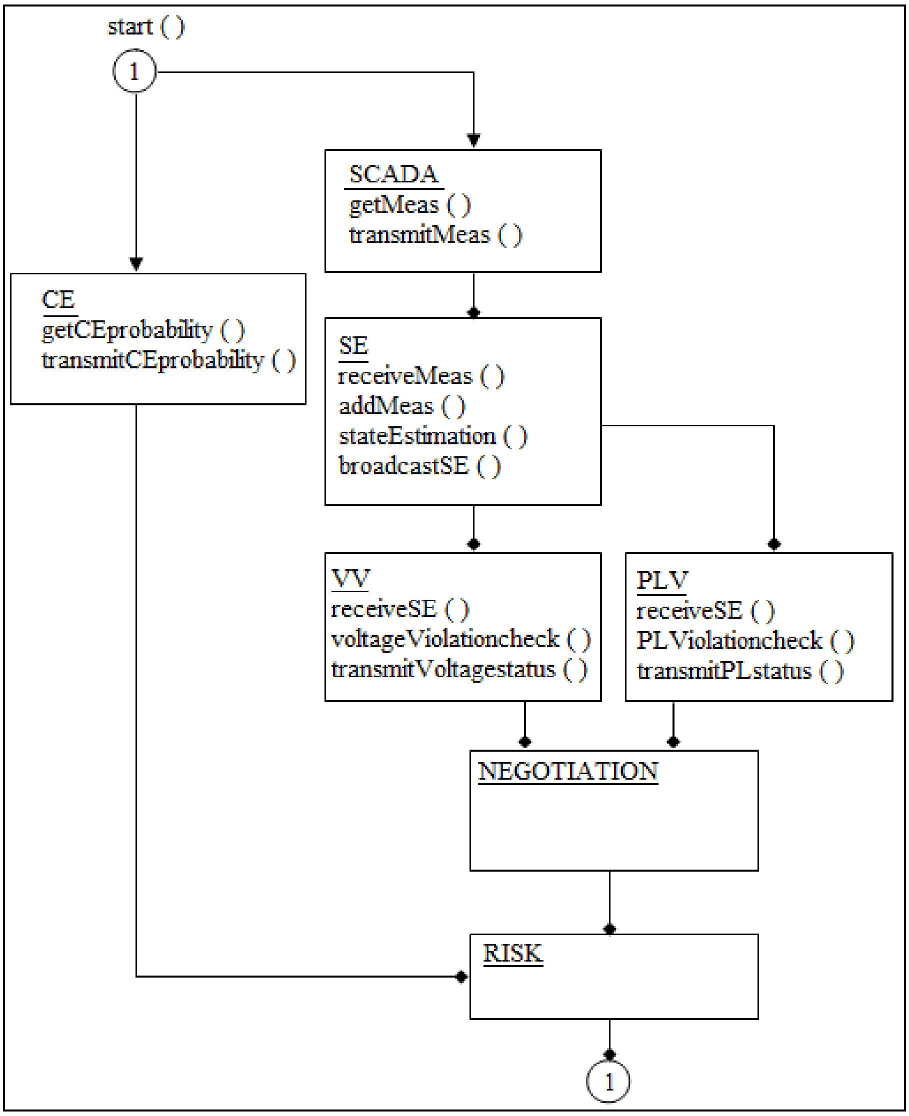


Figure 6.10 Data flow diagram of the proposed system

Power flow measurements of each branch in a region are collected. The checkbox allow the data to be telemetered.

6.5.1.2 The transmitMeas ( )

The recorder measurements are telemetered to the control center. The transmitMeas() method is carried out within '*behaviours*' of JADE. Behaviour represents a task that an agent can carry out and is implemented as an object that extends jade.core.behaviours.Behaviour (Bellifemine, et. al., 2007). As mentioned authors in (Bellifemine, et. al., 2007), the path of execution of agent thread is depicted in Figure 6.11.

6.5.2 Scheduling Operations

The design of the agent takes an advantage of JADE which is provided with the TickerBehaviour, a ready-made class which can be implemented to produce behaviors that execute at selected points in time. Apart from TickerBehaviour, JADE is also provided with WakerBehaviour which has action() and done() methods pre-implemented to execute the onWake()abstract method after a given timeout expires (Bellifemine, et. al., 2007).

A TickerBehaviour never completes unless it is explicitly removed or its stop() method is called. The method is implemented using JADE codes shown in Figure 6.12. This can be implemented using Netbean IDE or any other editor. When Netbean IDE is used, the JADE library files are added in the libraries folder of Netbean IDE.

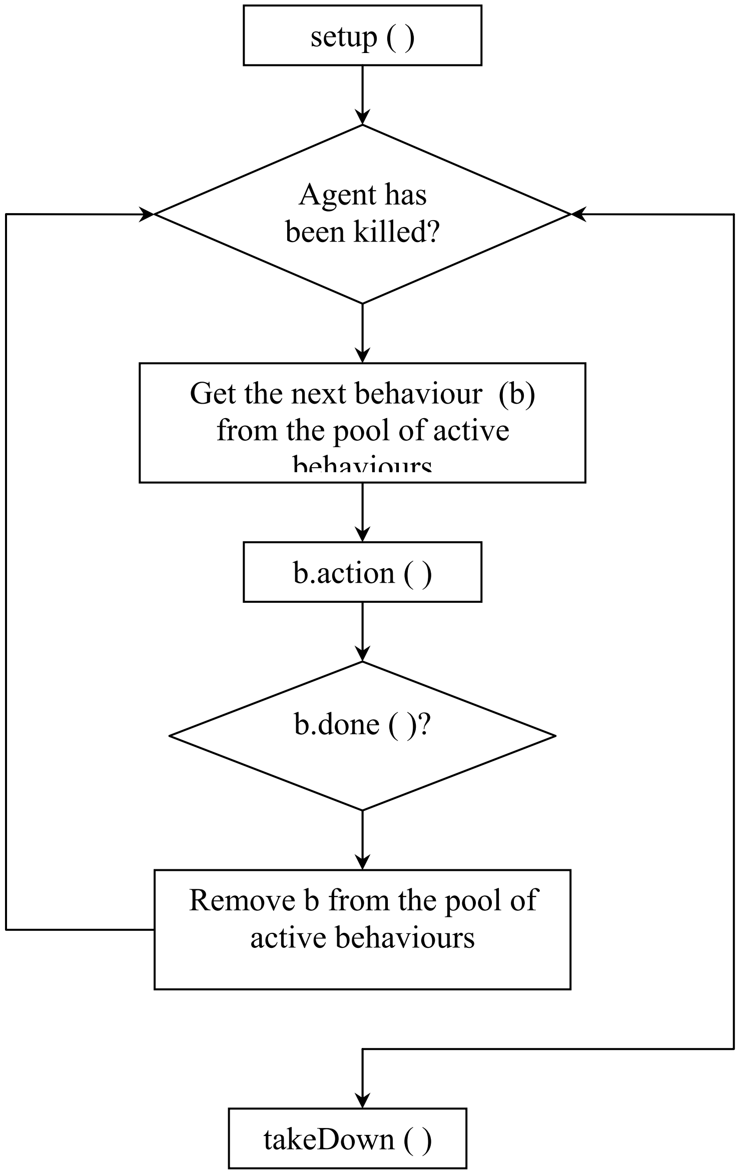


Figure 6.11 Agent thread path of execution [Source: (Bellifemine, et. al., 2007)]

```
import jade.core.Agent;
import jade.core.behaviours.*;
import jade.lang.acl.ACLMessage;
import java.lang.String;
import jade.core.AID;

public class transmitMeas extends Agent
{
    protected void setup()
     {

        addBehaviour(new TickerBehaviour(this, 10000)
          {
                protected void onTick()
               {

                    // perform operation transMeas()

           ACLMessage           msg           =           new
ACLMessage(ACLMessage.INFORM);
           msg.addReceiver(new AID("SE", AID.ISLOCALNAME));
                  ...
                  //Set message content

                  ...

                  send(msg);

               }
          });
     }
}
```

Figure 6.12 Implementation of transmitMeas() method using JADE platform

6.5.3 State Estimation (SE)

The state estimation process in the control center is carried out by the state estimator. As shown in Figure 6.10, four main sequential methods included in this stage are: `receiveMeas`, `addMeas()`, `stateEstimation()`, and `broadcastSE()`.

6.5.3.1 The ReceiveMeas()

The message sent by the SCADA is received in the control center. The method receiveMeas() is similar to the transmitMeas() except in the action(),where the following code is used in Figure 6.13.

```
public void action()
{
     ACLMessage msg = myAgent.receive();
          if(msg!=null)
          {
               // take an action
          }
          else
          {
               // take an alternative action
          }
}
```

6.5.3.2 The addMeas()

The model adequacy is based on the received measurements; therefore, if there is any missing measurement/s, the effort is made to obtain it/them. This is achieved by the method addMeas()which is employed using technique expressed in chapter four, section 4.6. If all measurements are available, this step is skipped. The process used to implement addMeas() using MATLAB codes is shown in Figure 6.13.

```
% Unavailable Measurements Search
% Identify measurement to be searched

% STAGE 1

% XX = [ Available Measurements ];

for insert = -10:10

Meas(searchMeas) = insert;

% Insert in the corresponding location
% Using Newton-Raphon Method compute state variables
% With the state estimated variables Compute the
measurements
% YY = [ Computed measurements ];

xp  = 1:length(XX);

     for k = 1
               yp = polyval(polyfit(XX,YY,k),xp);
           JEY(k) = sum((polyval(polyfit(XX,YY,k),XX)-
YY).^2);
          end

     mu = mean(YY);
     for k = 1
          S(k) = sum((polyval(polyfit(XX,YY,k),XX)-mu).^2);
          r2(k) = 1 - JEY(k)/S(k);
     end

     r3(in) = r2;
     r4(in) = 1-r3(in);

end

r5 = min(abs(r4));

% STAGE 2
% This follow the 0.1 interval;
% STAGE 3
% This follow the 0.01 interval, etc.
```

Figure 6.13   Implementation of addMeas() method using MATLAB codes

6.5.3.3 The stateEstimation()

The state estimation is a computational process. In this research, a statistical regression model expressed in the previous chapters is used.

6.5.3.4 The broadcastSE()

The state variables obtained by the stateEstimation() method is broadcasted to agents responsible to violations.

6.5.4 Voltage Violation (VV)

As explained in previous chapters, the contingency event may cause voltage violation. The voltage violation (VV) agent is responsible for the voltage violation inspection. This stage is composed of three main methods: receivesSE(), voltageViolationchech(), and transmitVoltagestatus(). With exemption of voltageViolationchech() the two methods, receives(),and transmitVoltagestatus()are similar to the receive and transmit methods explained in the previous sections. The difference is only the receiving agents and message contents.

The system buses voltage limitations are made available in the database where the computed bus voltage during contingency event is compared with the limit set in the database. If the computed bus voltage falls beyond the limit, then the control process is informed so as to take the corrective action.

6.5.5 Power Line Violation (PLV)

The methods for power line violation is quite similar the bus voltage violation methods. The difference is only the message contents and their respective algorithms. The PLV is composed of three main methods: receivesSE(), PLViolationchech(), and transmitPLstatus(). Similar to the system buses voltage limitations, power line capacities are made available in the database where the computed power flow for each line during each contingency event is compared with the capacity of the respective line. If the computed line power flow falls beyond the limit, then the control process is informed so as to take the remedial action.

6.5.6 Negotiation Process

The control process is based on negotiations process. In this research possible remedial actions are presented in the negotiation process. While each agent tries to maintain its objective the voluntary response is called forth. Method proposed by Shahidehpour and Wang (2003) is adopted during violation mitigation process. When violation is encountered, the scheduling control agent broadcasts the information to all participants able to make decisions and to offer voluntary adjustments for congestion management. GENCOs and DISTCOS are grouped according to their contributions to the violation management. The decremental or incremental adjustments could mitigate the problem. The agents whose decremental adjustment could mitigate the problem are referred to as ‘red agents’. These are subject to congestion charges if the congestion is not mitigated. In this research the assumption is made such that the bidding contract is in place. However, the key components in the whole process are: the effect of congestion management. The assumption of a single TRANSCO in the system is considered in this research.

6.5.7 Power Distribution Factor to Congestion Management

In (Shahidehpour, et. al., 2002), major transmission costs allocation methods are discussed. In this research, distribution factors mainly used in security and contingency analysis is applied in the proposed model. Therefore, in order to minimize the cost of congestion mitigation, the power distribution factor is considered. In this approach not only based on merit order of bidding prices, as used by linear programming method mostly used by ISO for congestion mitigation (Shahidehpour and Yang, 2003), but also the closer generating unit is closer to the congested line.

Distribution factors are calculated based on linear load flows. They have been used to approximately determine the impact of generation and load on transmission flows (Shahidehpour, et. al., 2002).

6.5.7.1 Generation Shift Distribution Factors (or A-Factors)

These factors provide line flow changes due to change in generation or change in network topology. They can be used in determining maximum transaction flows for bounded generation and load injections. An A-factor is defined as (Shahidehpour, et. al., 2002).

$$\Delta F_{l-k} = A_{l-k} \Delta G_i$$
$$\Delta G_r = -\Delta G_i \tag{6.7}$$

where

ΔF_{l-k} is the change in active power flow between bus l and k.

$A_{l-k,i}$ is the A-factor of line joining bus l and k corresponding to change in generator at bus i.

ΔG_i is the change in generation at bus i, with the reference bus excluded.

ΔG_r is the change in generation at reference bus (generator) r

6.5.7.2 Generalized Generation Distribution Factors

These factors determine the impact of each generator on active power flows based on dc model. They can only be used for active power flows. A D-factors are defined as

$$F_{l-k} = \sum_{i=1}^{N} D_{l-k,i}\, G_i \qquad (6.8)$$

where

$$D_{l-k,i} = D_{l-k,r} + A_{l-k,i}$$

$$D_{l-k,r} = \left\{ F_{l-k}^{0} - \sum_{\substack{i=1 \\ i \neq r}}^{N} A_{l-k,i}\, G_i \right\} / \sum_{i=1}^{N} G_i$$

and

F_{l-k} is the total active power flow between buses l and k

F_{l-k}^{0} is the power flow between buses l and k from the previous iteration

$D_{l-k,i}$ is the D-factor of the line between buses l and k corresponding to generator at bus i

$D_{l-k,r}$ is the D-factor of the line between buses l and k corresponding to generator at bus r

G_i is the total generation at bus i

D-factor measures the total use of the transmission network facilities produced by the generator injections.

6.5.7.3 Generalized Load Distribution Factors (or C-Factors)

These factors determine the contribution of each load to line flow. A C-factor are defined as

$$F_{l-k} = \sum_{j=1}^{N} C_{l-k,j}\, L_j \qquad (6.9)$$

where

$$C_{l-k,j} = C_{l-k,r} - A_{l-k,j}$$

$$C_{l-k,r} = \left\{F_{l-k}^{0} + \sum_{\substack{j=1 \\ j\neq r}}^{N} A_{l-k,j}\, L_j\right\} \Big/ \sum_{j=1}^{N} L_j$$

and

F_{l-k} is the total active power flow between buses l and k

F_{l-k}^{0} is the power flow between buses l and k from the previous iteration

$C_{l-k,j}$ is the C-factor of the line between buses l and k corresponding to demand at bus j

$C_{l-k,r}$ is the D-factor of the line between buses l and k due to the load at reference bus r

L_j is the total demand at bus j

C-factor measures the total use of the transmission network facilities by loads in which loads are seen as negative injections.

The entire negotiation process is based on the adjustment of GENCOs and DISTCOs are based on the comparison of the bid price and the power distribution factor.

6.6 Conclusion

The contingency analysis system presented in this chapter presents limited domain but crucial for adequacy evaluation. The individual load point indices and the system indices are both valuable. The fact that the system reliability and contingency analysis are complicated, the most valuable measures have been considered.

CHAPTER VIII

CONCLUSION AND RECOMMENDATIONS

7.1 Conclusion

This research is built up on four main components; exploration of the possible uncertainties and their effects in a power system performance, minimizing risks related to the contingency events, identification of the limitations that can affect the power reliability and, improving computation time.

Method expressed in chapter three expresses the details of proposed algorithm suitable for the system condition forecast. In this chapter, the weather condition is used to explain the performance of the method. The effect of weather in a system component, in this case, line outage, is presented. Simulation of system condition during rainy season and normal weather are presented in chapter five. This is an external effect of the system while the line outage is an internal effect. The relationship between the external effect, rain and the internal effect line outage has been presented.

The system state forecast presents the expected situation upon the contingency event. Agents are organized in a manner that, the load curtailment is maintained to the minimum in case of the contingency event, line outage. This process is expressed in chapter six.

In this research, the computation time can be minimized during state estimation when regression method is used because no iteration process takes place in this method, hence less time consumption. In a regional computation, number of tested lines is less and hence computation time in the entire process is minimized.

7.2 Recommendation

Although most functions of contingency analysis are discussed in this thesis, only preventive is considered. Therefore, the other side of corrective requires further research especially in decision making. This can be accompanied by the risk analysis and their mitigation

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