Reliability and Cost/Worth Evaluation of Generating Systems Utilizing Wind and Solar Energy

A Thesis Submitted to the College of
Graduate Studies and Research
in Partial Fulfillment of the Requirements
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Saskatoon

By

Bagen

TO MY MOTHER WHO GIVES ME ALL HER LOVE

TO MY WIFE *WUREN* WHO SHARES LOVE WITH ME

TO MY DAUGHTER *TEMULUN* WHO ADDS JOY, HAPPINESS AND LOVE

TO ALL OF US

AND

IN MEMORY OF MY GRANDMOTHER AND MY FATHER

-In Phonetic Mongolian-

EKHIIN SAIKHAN KHAIRAA KHUUDEE ZORIULSAN,

ACHLALT EEJDEE

ERKHEMSEG NANDIN KHAIRAA KHUVAALTSSAN,

AMRAG KHANI URANDAA

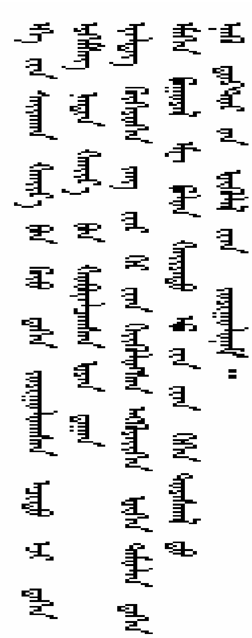
EILDEG KHOORKHON ZANGAARAA GEREE GIIGUULSEN,

ENKHRIIKHEN OHIN TEMUULENDEE

ENGEN BUURAL EMEE BOLON KHAIRT AAVIINKHAA GEGEEN DURSGALD

ENEKHUU DOCTORIIN OGUULELEE ZORIULNAM.

-In Traditional Mongolian-



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ABSTRACT

The utilization of renewable energy resources such as wind and solar energy for electric power supply has received considerable attention in recent years due to adverse environmental impacts and fuel cost escalation associated with conventional generation. At the present time, wind and/or solar energy sources are utilized to generate electric power in many applications. Wind and solar energy will become important sources for power generation in the future because of their environmental, social and economic benefits, together with public support and government incentives.

The wind and sunlight are, however, unstable and variable energy sources, and behave far differently than conventional sources. Energy storage systems are, therefore, often required to smooth the fluctuating nature of the energy conversion system especially in small isolated applications. The research work presented in this thesis is focused on the development and application of reliability and economic benefits assessment associated with incorporating wind energy, solar energy and energy storage in power generating systems. A probabilistic approach using sequential Monte Carlo simulation was employed in this research and a number of analyses were conducted with regards to the adequacy and economic assessment of generation systems containing wind energy, solar energy and energy storage. The evaluation models and techniques incorporate risk index distributions and different operating strategies associated with diesel generation in small isolated systems. Deterministic and probabilistic techniques are combined in this thesis using a system well-being approach to provide useful adequacy indices for small isolated systems that include renewable energy and energy storage. The concepts presented and examples illustrated in this thesis will help power system planners and utility managers to assess the reliability and economic benefits of utilizing wind energy conversion systems, solar energy conversion systems and energy storage in electric power systems and provide useful input to the managerial decision process.

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LIST OF ABBREVIATIONS

A	Availability
Ah	Ampere-hour
AL	Average Load
AR	Auto-regressive
ARMA	Auto-Regressive and Moving Average
CCDF	Composite Customer Damage Function
CD-With	Continuous Diesel Operation With Storage
CD-Without	Continuous Diesel Operation Without Storage
CIC	Customer Interruption Cost
CLU	Capacity of the Largest Unit
COPT	Capacity Outage Probability Table
CRM	Capacity Reserve Margin
CSU	Capacity of the Smallest Unit
D	Diesel
DC	Direct Current
DPLVC	Daily Peak Load Variation Curve
EAWE	Expected Available Wind Energy
EASE	Expected Available Solar Energy
EDFOSF	Expected Discharging Frequency of Storage Facility
EENS	Expected Energy Not Supplied
EESBES	Expected Energy Supplied by the Energy Storage
EESBPV	Expected Energy Supplied by PV
EESBSF	Expected Energy Supplied by the Energy Storage Facility
EESBWTG	Expected Energy Supplied by WTG
EESCC	Equal Energy Storage Capacity Curve

EGWE	Expected Generated Wind Energy
EGSE	Expected Generated Solar Energy
EIR	Energy Index of Reliability
ELOLD	Expected Loss of Load Duration
ELOLF	Expected Loss of Load Frequency
ENSSC	Expected Number of Start/Stop Cycle
ERC	Equal Risk Curve
ERECC	Equal Renewable Energy Capacity Curve
ERT	Expected Running Time
ESC	Energy Storage Capacity
ESG	Expected Surplus Generation
ESISS	Energy Stored in the Storage System
EUE	Expected Unsupplied Energy
FOR	Forced Outage Rate
h	Hour
HL	Hierarchical Levels
HL-I	Hierarchical Level-I
HL-II	Hierarchical Level-II
HL-III	Hierarchical Level-III
HSP	Healthy State Probability
IC	Installed Capacity
ID-with	Intermittent Diesel Operation With Storage
ID-without	Intermittent Diesel Operation Without Storage
IEAR	Interrupted Energy Assessment Rate
IEEE-RTS	IEEE Reliability Test System
IPLCC	Incremental Peak Load Carrying Capability
kW	Kilowatt
kWh	Kilowatt-hours
LDC	Load Duration Curve
LEM	Loss of Energy Method
LLM	Loss of Load Method

LLU	Loss of the Largest Unit
LMM	Load Modification Method
LOLD	Loss of Load Duration
LOEE	Loss of Energy Expectation
LOHE	Loss of Health Expectation
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MCS	Monte Carlo Simulation
MJ	Megajoules
MPP	Maximum Power Point
MSP	Marginal State Probability
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
MW	Megawatt
MWh	Megawatt- hours
NAH	Number of Autonomous Hour
NAD	Number of Autonomous Day
NID	Normally Independent Distributed
occ	occurrence
OUCM	Optimal Utility Cost Method
PL	Peak Load
PV	Photovoltaic
PVCS	Photovoltaic Conversion System
RBECR	Risk-Based Equivalent Capacity Ratio
RBTS	Roy Billinton Test System
RC	Reserve Capacity
RCWM	Reliability Cost/Worth Method
RG	Renewable Generation
S	Storage
SC	Solar Constant
SCDF	Sector Customer Damage Function

SD	Solar-Diesel
SG	Surplus Generation
SIC	Standard Industrial Classification
SIPS	Small Isolated Power Systems
SM	System Minutes
SSBC	Storage System Back-up Capacity
TC	Total Cost
U	Unavailability
UC	Utility Cost
UCF	Utility Cost Function
UPM	Unit Per Million
W	Wind
WD	Wind-Diesel
WECS	Wind Energy Conversion System
WSD	Wind-Solar-Diesel
Wh	Watt-hour
Wp	Peak Watt
WTG	Wind Turbine Generator
yr	Year

1. INTRODUCTION

1.1 Power System Reliability Evaluation

The basic function of an electrical power system is to supply its customers with electrical energy as economically as possible and with an acceptable level of reliability [1]. The provision of reliable electric power increases in significance with increasing dependence of modern society on electrical energy. Electric power utilities therefore must provide a reasonable assurance of quality and continuity of service to their customers. The level of assurance, however, depends on the needs of the customer and the associated cost of providing the service. In general, more reliable systems involve more financial investment. It is, however unrealistic to try to design a power system with a hundred percent reliability and therefore, power system planners and engineers have always attempted to achieve a reasonable level of reliability at an affordable cost. It is clear that reliability and related cost/worth evaluation are important aspects in power system planning and operation.

The reliability associated with a power system is a measure of the overall ability of the system to perform its basic function. System reliability can be subdivided into the two distinct categories of system adequacy and system security [1] as shown in Figure 1.1.

The concept of adequacy is generally considered to be the existence of sufficient facilities within the system to satisfy the consumer demand. These facilities include those necessary to generate sufficient energy and the associated transmission and distribution networks required to transport the energy to the actual consumer load points. Adequacy is therefore considered to be associated with static conditions which do not include system disturbances.

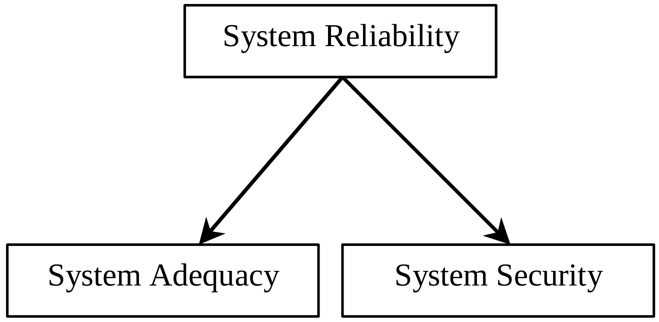


Figure 1.1: Subdivision of system reliability

Security, on the other hand, is considered to relate to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to whatever disturbances it is subjected. These are considered to include conditions causing local and widespread effects and the loss of major generation and transmission facilities [1].

Power system adequacy assessment can be conducted in all the three basic functional zones of generation, transmission and distribution. Three hierarchical levels (HL) can be structured by combining the functional zones. Figure 1.2 shows the three levels.

In an hierarchical level I (HL-I) study, the total system generation including interconnected assistance is examined to determine its adequacy to meet the total system load demand. Reliability assessment at HL-I is normally defined as generating capacity adequacy evaluation. The transmission network and the distribution facilities are not included in an assessment at the HL-I level. Adequacy evaluation at hierarchical level II (HL-II) includes both the generation and transmission in an assessment of the integrated ability of the composite system to deliver energy to the bulk supply points. This analysis is usually termed as composite system reliability evaluation (or bulk power system reliability evaluation). Adequacy assessment at hierarchical level III (HL-III) includes all of the three functional zones and is not easily conducted in a practical system due to the computational complexity and scale of the problem. These analyses are usually performed only in the distribution functional zone.

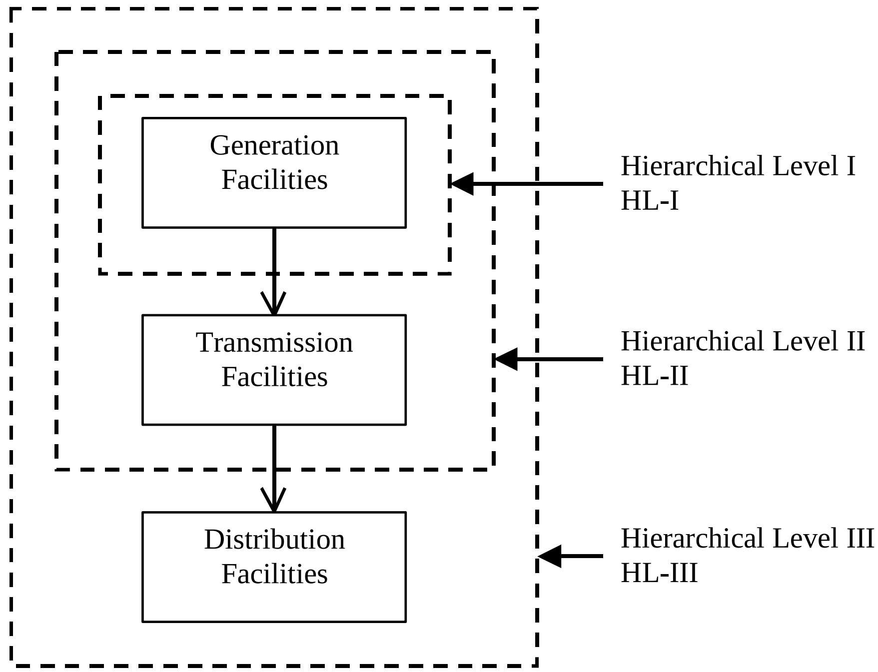


Figure 1.2: Hierarchical levels

The research described in this thesis is focused on HL-I adequacy and related cost/worth evaluation of power systems utilizing wind energy, solar energy and energy storage.

1.2 Utilization of Non-conventional Energy Sources and Energy Storage in Electric Power Systems

The growing demand for electrical energy and increasing fuel costs throughout the world have created an urgent need to explore new energy sources. These are usually termed as non-conventional energy sources for electricity supply. Among the non-conventional sources, wind and solar energy have been recognized as the most promising means of electrical power generation in the future. At the present time, small-scale applications of wind and/or solar energy are in operation and are steadily gaining new markets [2]. The growing awareness of the potential environmental impacts associated with conventional power production has resulted in increased emphasis on the large-scale utilization of these renewable sources [3]. There are also important social needs for developing renewable energy programs in small, widely scattered communities, especially in developing countries [4]. Wind and solar energy are the most suitable options for these remote areas.

There are five possible scenarios when utilizing wind and/or solar energy for electric power generation. These are: (1) Wind and/or solar energy based systems without energy storage, (2) Wind and/or solar energy based systems without energy storage combined with conventional generation such as a diesel engine, (3) Wind and/or solar energy based systems with energy storage, (4) Wind and/or solar energy based systems with energy storage combined with conventional generation, (5) Wind and/or solar energy based systems connected to a relatively large electric power grid. The first four applications are usually small in size, self-sufficient and not connected to any other assisting generation. These systems are generally designated as small isolated power systems (SIPS). SIPS are practical for applications in remote locations which are difficult and expensive to connect to an electric power grid. The fuel and maintenance costs are also usually quite high in these locations. Depending on the particular application and the site resources, a SIPS may or may not include energy storage facilities. Systems based entirely on the wind and/or solar energy, however, in many cases do not operate continuously because of factors such as fluctuations in wind speed, random cloud cover, diurnal effect etc. The output of wind turbine generators (WTG) and/or photovoltaics (PV) cannot be expected to match the energy demand schedule required to meet customer needs. Energy storage systems are, therefore, often required to smooth the fluctuating nature of the energy conversion systems and to match the customer energy demands. The integration of renewable and conventional generating sources such as diesel generators in isolated communities can assist these communities to attain a reasonable level of reliability at a reduced cost. It is also possible that WTG and/or PV facilities can be interconnected with a utility grid. These facilities can assist the utility grid to meet its power demands, to maintain its reliability and to reduce fuel costs and green house gas emissions.

Most electrical utilities around the world are vitally concerned with the reliability and the cost of their services especially in today's restructured environment. The utilization of unconventional energy sources can have considerable impact on overall power system reliability and costs. The main objective of this research project is to develop consistent reliability and related economic assessment models and evaluation techniques for power systems utilizing wind energy, solar energy and energy storage.

1.3 Reliability Considerations in Generating Systems Containing Non-conventional Energy Sources and Energy Storage

As noted previously, utilization of renewable energy resources such as wind and solar energy for electric power supply has received considerable attention in recent years due to global environmental concerns associated with conventional generation and potential worldwide energy shortages. At the present time, wind and/or solar energy sources are utilized to generate electric power both in main electric power grids or small isolated systems [2, 3]. Improvements in wind and solar generation technologies will increasingly encourage the use of these non-conventional systems. Wind and solar energy will, therefore, become important sources of power generation in the future.

In order to assess the actual benefits of using wind and solar energy to supply electricity and to provide utilities with useful methodologies and techniques for planning and operating power systems utilizing wind and solar energy, it is necessary to develop consistent adequacy and related cost/worth assessment models and evaluation techniques for such systems. Suitable models and techniques will also prove of benefit in the design of these systems and assist in promoting these technologies.

Considerable effort has been devoted to reliability assessment of power systems utilizing wind and solar energy. Most of the publications have been documented in four comprehensive bibliographies published since 1988 [5-8]. The contribution of wind energy to large grid-connected electric power systems is presented in [9-13]. These works are mainly concentrated on the reliability aspects of power systems operating in parallel with a single wind farm. A simple procedure to determine the impact of wind generation on system reliability is presented in [9]. Reference [10] presents an algorithm to derive a probabilistic wind turbine generator model and applied this model to determine the annual energy output of a grid connected wind farm. Chronological simulation methods for the reliability evaluation of electric power systems containing non-conventional energy sources are presented in [11-13]. There is, however, relatively little published material in the area of reliability and corresponding economic assessment of large scale utilization of wind and/or solar energy in electric power systems.

Reliability performance assessment of small stand-alone renewable energy based systems is presented in [14-20]. An approximate method for reliability evaluation of a stand-alone system consisting of one wind turbine feeding a load via a battery was presented in reference [14]. The same technique was later extended to a stand-alone solar energy based system [15]. This technique assumes a uniformly distributed customer load model in order to include the storage in the analyses. Reference [16] presents a method, which is similar to the one described in [14] and [15], for the computation of the loss of load probability (LOLP) and the expected energy not supplied (EENS) of a stand-alone system based on wind energy operating in parallel with a storage battery. The method modeled the generation, the load and the battery as Markov chains. A probabilistic method for the evaluation of the performance of a hybrid system consisting of a wind generator, a diesel engine and a battery was presented in [17]. References [18] and [19] present evaluation techniques for wind energy based and hybrid wind and solar systems with storage. These techniques assume that the wind speed and solar radiation follow a Weibull distribution and a β-distribution respectively. All of the above mentioned works are focused on the use of approximate analytical methods. The major disadvantage of these approaches is that the chronological random nature of wind speed and solar radiation, their effect on the power output of renewable energy based generating units and the system load pattern cannot be completely recognized and incorporated. Reference [20] considers the use of Monte Carlo Simulation (MCS) for the reliability and production cost evaluation of small isolated power systems consisting of both renewable sources and conventional diesel generation. Battery storage was, however, not considered in this research. Due to the highly variable nature of site resources such as wind and sunlight, the utilization of energy storage devices can significantly enhance the reliability of a SIPS. Conventional units are, however, often operated in stand-alone modes without the use of storage devices. The utilization of wind and solar resources requires storage capability or must be augmented by conventional units, such as diesel generators. Considerably less work has been done on reliability and corresponding economic evaluation of small electric power systems containing renewable energy and energy storage facilities operating in parallel with conventional sources such as diesel generators.

At the present time, power system reliability analyses are usually concerned only with the mean values of the reliability indices. The mean values are comparatively easy to obtain and provide valuable information, which can meet the system planning and operating requirements in most cases. There is, however, an increased awareness of the need to develop suitable techniques to obtain information regarding the distributions of the reliability indices around their mean values especially in distribution system reliability evaluation [21-27]. These newer approaches and the conventional techniques for the evaluation of mean values make it possible to generate detailed information on power system reliability performance. There is, however, relatively little published research on reliability index distributions at HL-I especially considering wind energy, solar energy and energy storage.

Most utilities prefer to use a deterministic technique rather than probabilistic methods to determine capacity reserves in small isolated system planning [28]. Deterministic criteria are easier to understand than a risk index determined using only probabilistic techniques. In order to alleviate the difficulty in interpreting the risk index and provide more applicable information for electric power utilities, accepted deterministic criteria can be incorporated in a probabilistic assessment [29-42]. These techniques overcome some of the difficulties in interpreting the risk index and provide more information in system planning compared to that available from a pure probabilistic method. The development of a well-being framework [29] that incorporates deterministic criteria in a probabilistic approach is an important concept. This framework is extended in this thesis to incorporate energy storage considerations.

Evaluation of the costs associated with different system configurations and the corresponding worth associated with the differences is generally termed as reliability cost/worth assessment [1]. This form of evaluation is also sometimes designated as value based reliability evaluation. The evaluation of costs associated with providing reliable service in large electric power systems is reasonably well established and accepted [1]. Considerable work has been done on developing techniques for reliability cost/worth assessment in large conventional electric power systems [43-63], especially in the last two decades. By comparison, the assessment of reliability cost/worth in electric power systems containing non-conventional energy sources and/or energy storage is not as well developed. A method for optimizing capital costs of stand-alone PV and battery systems using the loss of load probability as the reliability criterion is presented in [64]. Consideration has been given in recent years to evaluate the economic impacts of the utilization of wind and/or solar energy in electric power systems using the conventional techniques [65-66]. Considerable work is, however, needed in the development of general approaches to assess reliability cost/worth in planning electric power systems containing non-conventional energy sources and/or energy storage.

1.4 Research Objectives

As noted earlier, power systems can be divided into three functional zones. This research work is concentrated on the development of HL-I adequacy and related cost/worth evaluation models and techniques to incorporate wind energy, solar energy and energy storage facilities in generating system reliability assessment. The basic objective of the research described in this thesis is to investigate the reliability and economic benefits of utilizing wind energy, solar energy and energy storage in electric power supply. The objectives of this research have been accomplished by focusing on the following tasks.

1. Reliability modeling and assessment of generating systems utilizing wind energy, solar energy and energy storage incorporating risk index distributions.
2. Development and implementation of a wellbeing framework for power systems

containing energy storage

3. Evaluation of the different operating strategies associated with small isolated power systems
4. Development and application of reliability cost/worth evaluation models for power systems containing wind energy, solar energy and energy storage

There are significant reliability benefits associated with utilizing wind energy, solar energy and energy storage in electric power supply [20, 67]. The concepts and techniques presented in [20, 67] have been extended to include both conventional and non-conventional energy sources and energy storage capability. The extensions and modifications emphasize using both risk index mean values and distributions in power system reliability studies. The sequential Monte Carlo simulation method can be used to provide a wide range of indices in power system reliability analysis. In addition, the sequential simulation method can provide reliability index probability distributions. The distributions can widen the scope of practical reliability assessment and provide valuable information for power system reliability evaluation, planning and decision making. The ability to develop and utilize reliability index probability distributions in HL-I adequacy evaluation is examined in this research work.

As noted earlier, accepted deterministic criteria can be incorporated in a probabilistic assessment in order to overcome some of the difficulties in interpreting the risk index and provide more information in system planning. These concepts have been applied to electric power system without energy storage facilities [29-42]. The extension of the wellbeing concepts for reliability evaluation of generating systems operating in parallel with energy storage was an objective in this research. New models and techniques to incorporate the inclusion of wind energy, solar energy and energy storage capability in electric power system well-being analysis are proposed. The examination of small isolated power system well-being using the proposed method incorporating well-being index distributions is the basic focus of this research.

Most isolated and remote communities depend on conventional diesel fuel for their electricity supply [28]. Diesel generation in these locations is expensive mainly due to increasing fuel costs. The associated maintenance costs and transportation costs are also relatively high in many areas. Wind and solar energy based systems, however, involve no fuel cost and can, therefore, be integrated in conventional small isolated systems in order to replace costly diesel fuel by renewable energy. Considerable reliability and economic benefits can be obtained by selecting suitable operating strategies for a given system at a particular location. An important objective of the research described in this thesis is to develop appropriate evaluation models and techniques to assess possible operating strategies associated with the integration of wind and/or solar energy with conventional diesel generation in regard to reliability and fuel costs.

The development of appropriate methods to conduct reliability and corresponding economic evaluation of power systems using wind energy, solar energy and energy storage are the primary objectives of this research. The reliability of a given power system can be quantified by calculated reliability indices such as the loss of load expectation (LOLE) and loss of energy expectation (LOEE). These indices are valuable quantities that reflect the state of the system and assist in future planning. These indices can also be used to determine the utility cost and the worth of providing power service. LOLE can be used as a criterion for comparing different system costs based on a suitable cost model. The LOEE can be used in conjunction with customer cost functions to obtain a factor relating customer losses to the worth of electric service reliability. The conducted research examines some of the economic aspects of utilizing unconventional energy sources and storage facilities in power systems. This research is primarily focused on small isolated power system applications.

1.5 Overview of the Thesis

This thesis establishes a framework for reliability and the corresponding economic assessment of electric power systems containing wind energy, solar energy and energy storage. A wide range of case studies are presented to illustrate the possible application of the proposed models, indices and techniques in practical system developments. There are ten chapters in this thesis. The main topics of each chapter are as follows:

Chapter 1 introduces the basic concepts related to power system reliability evaluation. A brief introduction on power systems utilizing wind energy, solar energy and energy storage and a brief review of the available literature on reliability and economic assessment of such systems are presented in this chapter. It also outlines the scope and objectives of the thesis.

Chapter 2 reviews the basic evaluation concepts and techniques for generating capacity adequacy, system well-being analysis and reliability cost worth evaluation at HL-1. The direct analytical and Monte Carlo simulation methods widely used in power system reliability evaluation are introduced in this chapter.

Chapter 3 presents a general adequacy evaluation model using the sequential Monte Carlo simulation technique for power systems utilizing wind energy, solar energy and energy storage. The basic models necessary for the adequacy assessment of these systems namely, the site resource model, the generating source models, the energy storage model and the system load model are presented in this chapter.

Chapter 4 illustrates the application of the general evaluation models in small isolated power system reliability studies using the conventional mean values of reliability indices. This chapter also examines the effects of various parameters on the system adequacy. The effects of energy storage capacity, system annual peak load, system load variation, renewable energy installed capacity, generating unit forced outage rate and system geographic locations are illustrated using the developed models and techniques.

Chapter 5 presents a practical methodology for the construction and utilization of reliability index distributions in small isolated power system reliability performance assessment. A series of studies on reliability index distributions for small isolated power systems is presented. Reliability index distributions associated with generating capacity adequacy parameters such as the loss of load expectation (LOLE), loss of energy expectation (LOEE), expected loss of load duration (ELOLD), expected loss of load frequency (ELOLF), expected energy supplied by the storage facility (EESBSF) and expected discharging frequency of storage facility (EDFOSF) etc. are presented and examined.

Chapter 6 examines the reliability contribution of wind and/or solar energy in a large grid connected power system including a number of conventional generating units. The simulation models and techniques for the reliability evaluation of small isolated power systems have been extended, modified and applied to carry out a wide range of studies. The conventional generating unit ratings and reliability data from a small but representative test system [68] are utilized in conjunction with the developed models and techniques. The system reliability is analyzed in terms of various reliability indices such as the LOLE, LOEE, ELOLD and ELOLF. Probability distributions associated with some of these indices are also examined.

Chapter 7 presents a simulation technique which extends the conventional well-being approach to generating systems using energy storage. The proposed technique is illustrated and applied to several hypothetical small isolated power systems. The effects on the system well-being of some of the major system parameters and the deterministic criteria are illustrated. The distributions associated with the well-being indices are also presented and discussed.

Chapter 8 presents a sequential simulation technique to evaluate different operating strategies for SIPS using wind and/or solar energy as well as storage facilities. Four types of operating strategies for SIPS are discussed and evaluated. These are continuous diesel operation without storage, continuous diesel operation with storage, intermittent back-up diesel operation without storage and intermittent back-up diesel operation with storage. The advantage and disadvantage of these strategies are analyzed with reference to reliability, diesel fuel savings, back-up diesel average start-stop cycles and average running time etc. The probability distributions associated with these parameters are also constructed and analyzed.

Chapter 9 extends conventional reliability cost/worth evaluation techniques to assess the economic aspects of power systems containing conventional unit, WTG, PV and energy storage. Different types of costs related to electric power system planning are considered and modeled. Two different approaches for evaluating reliability costs and reliability worth are developed and discussed. These approaches are then applied to conduct a range of economic analysis using various example systems.

Chapter 10 summarizes the thesis and highlights the conclusions.

2. REVIEW OF GENERATING CAPACITY ADEQUACY EVALUATION

2.1 Introduction

As noted in Chapter 1, the primary concern in adequacy studies at HL-I is to assess the capability of the generating facilities to satisfy the total system load demand. The reliability of the transmission and its ability to deliver the generated energy to the customer load point is normally not included in an HL-I study. The system therefore can be simply represented by a single bus as shown in Figure 2.1, at which the total generation and total load are connected.

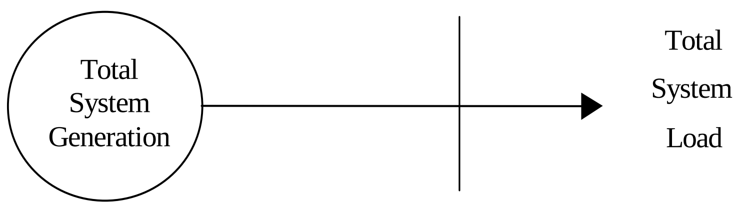


Figure 2.1: System representation at HL-I

The main objective in HL-I assessment is the evaluation of the system reserve required to satisfy the system demand and to accommodate the failure and maintenance of the generating facilities in addition to satisfying any load growth in excess of the forecast. This area of study can be categorized into two different aspects designated as static and operating capacity assessment. Static assessment deals with the planning of the capacity required to satisfy the total system load demand and maintain the required level of reliability. Operating capacity assessment, on the other hand, is mainly focused on the determination of the required capacity to satisfy the load demand in the short term (usually a few hours) while maintaining a specified level of reliability [1]. This thesis is focused on static capacity adequacy evaluation and corresponding cost/worth assessment of generating systems utilizing non-conventional wind and solar energy sources and energy storage.

There is a wide range of reliability techniques utilized in generating capacity planning and operation [1]. Basically, generating capacity adequacy evaluation involves the development of a generation model, the development of a load model and the combination of the two models to produce a risk model as shown in Figure 2.2.

The system risk is usually expressed by one or more quantitative risk indices. The calculated indices in HL-I evaluation simply indicate the overall ability of the generating facilities to satisfy the total system demand. Assessment can be performed using either a deterministic method or a probabilistic approach. Deterministic methods cannot recognize and reflect the actual risk associated with a given system and are gradually being replaced by probabilistic methods.

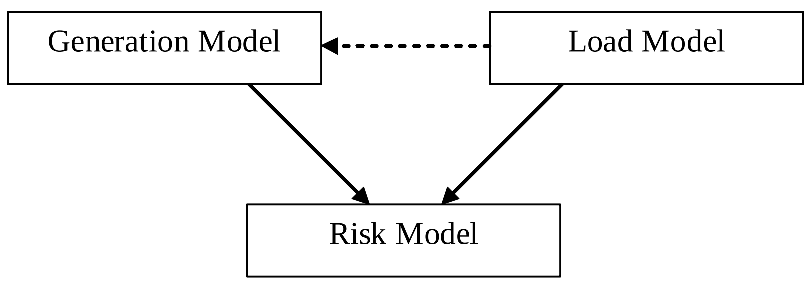


Figure 2.2: Conceptual tasks for HL- I evaluation

Generating unit unavailability is an important parameter in a probabilistic analysis. The most popular probabilistic risk indices are the loss of load expectation (LOLE) and loss of energy expectation (LOEE) [1]. The LOLE is defined as the expected time duration during which the load exceeds the available capacity. The LOEE is specified as the expected energy that will not be supplied by the generating system due to those occasions when the load demand exceeds the available capacity [1].

The fundamental approaches used to calculate the risk indices in a probabilistic evaluation can be generally described as being either direct analytical evaluation or Monte Carlo simulation. Analytical techniques represent the system by analytical models and evaluate the system risk indices from these models using mathematical solutions. Monte Carlo simulation, on the other hand, estimates the risk indices by simulating the actual process and the random behavior of the system. Both approaches have advantages and disadvantages, and each of them can be very powerful with proper application.

In the direct analytical method for generating capacity adequacy evaluation, the generation model is usually in the form of a generating capacity outage probability table, which can be created by the well-known recursive technique [1]. The load is usually represented by either a daily peak load or an hourly load duration model [1].

In the Monte Carlo method [1], the capacity model is represented by the system available generating capacity at points in time established chronologically or independently. The load model is usually represented by the chronological load pattern. The generation model is superimposed on the load model to produce the risk model.

This chapter briefly describes some of the various methodologies and techniques for generating capacity adequacy evaluation and their possible application to adequacy studies of power systems using wind energy, solar energy and energy storage. The concepts of well-being framework and reliability cost/worth evaluation are also briefly introduced.

2.2 Reliability Evaluation Methods

Reliability techniques can be divided into the two general categories of probabilistic and deterministic methods. Both methods are used by electric power utilities at the present time. Most large power utilities, however, use a probabilistic approach [69].

2.2.1 Deterministic Methods

Over the years, a range of deterministic methods have been developed by the power industry for generating capacity planning and operating. These methods evaluate the system adequacy on the basis of simple and subjective criteria generally termed as "rule of thumb methods" [1]. Different criteria have been utilized to determine the system reserve capacity. The following is a brief description of the most commonly used deterministic criteria without considering energy storage capability. The deterministic criteria associated with using energy storage in power system planning, especially in SIPS planning, is discussed in Chapter 7 of this thesis.

1. Capacity Reserve Margin (CRM)

In this approach, the reserve capacity (RC), which is normally the difference between the system total installed capacity ($IC = \sum G_i$, G_i is the capacity of Unit i in the system) and the system peak load (PL), is expressed as a fixed percentage of the total installed capacity as shown in Equation (2.1). This method is easy to apply and to understand, but it does not incorporate any individual generating unit reliability data or load shape information.

$$RC = \frac{IC - PL}{IC} \times 100\% \tag{2.1}$$

2. Loss of the Largest Unit (LLU)

In this approach, the required reserve capacity in a system is at least equal to the capacity of the largest unit (CLU) as expressed in Equation (2.2). This method is also easy to apply. Although it incorporates the size of the largest unit in the system, it does not recognize the system risk due to an outage of one or more generating units. The system reserve increases with the addition of larger units to the system.

$$RC \geq CLU \tag{2.2}$$

3. Loss of the Largest Unit and a Percent Margin

In this approach, the reserve capacity is equal to or greater than the capacity of the largest unit plus a fixed percentage of either the installed capacity or the peak load as shown in Equations (2.3) and (2.4). This method attempts to incorporate not only the size of the largest unit in the evaluation but also some measure of load forecast uncertainty. It does not reflect the system risk as the multiplication factor x (normally in the range of 0-15%) [28] is usually subjectively determined by the system planner.

$$RC = CLU + x \times IC \tag{2.3}$$

$$RC = CLU + x \times PL \tag{2.4}$$

The main disadvantage of deterministic techniques is that they do not recognize and reflect the inherent random nature of system component failures, of the customer load demand and of the system behavior. The system risk cannot be determined using deterministic criteria. Conventional deterministic criteria and techniques are severely limited in their application to modern complex power systems.

2.2.2 Probabilistic Methods

The benefits of utilizing probabilistic methods have been recognized since at least the 1930s and have been applied by utilities in power system reliability analyses since that time. As noted in Section 2.1, generating capacity adequacy evaluation normally involves the combination of a generation model and a load model to form a system risk model.

The unavailability (U) of a generating unit [1, 70] is the basic parameter in building a probabilistic generation model. This statistic is known as the generating unit forced outage rate (FOR). It is defined as the probability of finding the unit on forced outage at some distant time in the future. The unit FOR is obtained using Equation (2.5).

$$\text{FOR} = \frac{\sum[\text{down\_time}]}{\sum[\text{down\_time}] + \sum[\text{up\_time}]}. \tag{2.5}$$

The load model should provide an appropriate representation of the system load over a specified period of time, which is usually one calendar year in a planning study. The load representation is different for different evaluation techniques and study requirements as described later in this chapter.

2.3 Analytical Techniques

Analytical evaluation of generating capacity adequacy can provide utilities with information on the likelihood that the generation will be unable to serve the forecast load. The usual results obtained in this evaluation are the expected values of the various adequacy indices. Analytical techniques are relatively simple to apply and the results are easily reproduced. They may not, however, produce satisfactory results in some cases, particularly in situations involving non-conventional energy sources such as wind energy and solar energy, which are time dependent and correlated.

In most analytical techniques, the generation model is normally in the form of an array of capacity levels and their associated probabilities. This representation is known as a capacity outage probability table (COPT) [1]. Each generating unit in the system is represented by either a two-state or a multi-state model. The COPT can be constructed using a well-known recursive technique [1]. This technique is very powerful and can be used to add both two-state and multi-state units.

Case 1: No derated state

In this case, the generating unit is considered to be either fully available (Up) or totally out of service (Down) as shown in Figure 2.3.

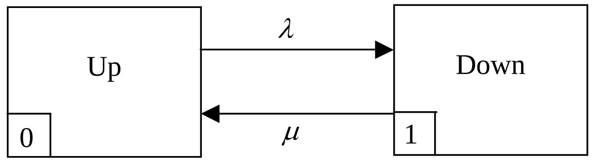


Figure 2.3: Two-state model for a generating unit

where λ = unit failure rate

μ = unit repair rate.

The availability (A) and the unavailability (U) of the generating unit are given by Equations (2.6) and (2.7) respectively.

$$A = \frac{\mu}{\lambda + \mu} \tag{2.6}$$

$$U = \frac{\lambda}{\lambda + \mu} \tag{2.7}$$

The probability of a capacity outage state of X MW can be calculated using Equation (2.8).

$$P(X) = (1 - U)P'(X) + (U)P'(X - C) \tag{2.8}$$

Where $P'(X)$ and $P(X)$ are the cumulative probabilities of a capacity outage level of X MW before and after the unit of capacity C is added respectively. Equation (2.8) is initialized by setting $P'(X) = 1.0$ for X < 0 and $P'(X) = 0$ otherwise.

Case 2: Inclusion of derated states

In addition to being in the full capacity and completely failed states, a generating unit can exist in a number of other states where it operates at a reduced capacity. Such states are called derated states. The simplest model that incorporates derating is shown in Figure 2.4. This three-state model includes a single derated state in addition to the full capacity and failed states. Recognition of generating unit derated states plays an important role in generating capacity adequacy evaluation especially for unconventional generating units such as WTG and PV units. These generating units usually have many capacity states, which are determined by the wind speeds or sunlight intensity at the system location.

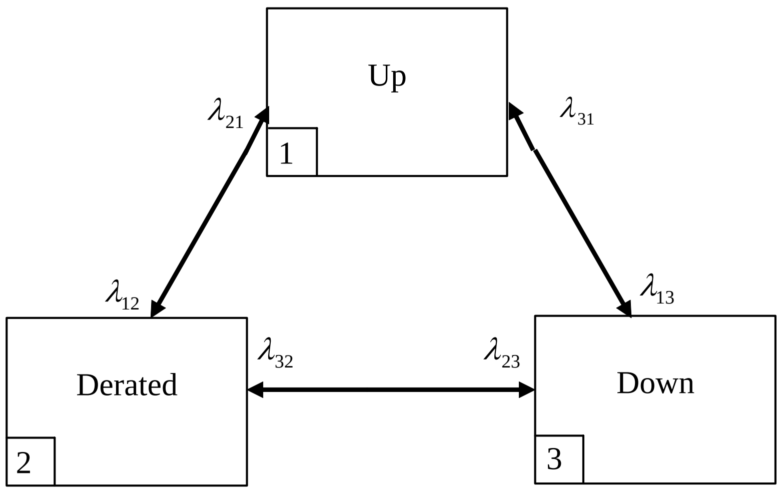


Figure 2.4: Three-state model for a generating unit

Equation (2.9) can be used to add multi-state units to a capacity outage probability table.

$$P(X) = \sum_{i=1}^{n} p_i P'(X - C_i), \tag{2.9}$$

where n - the number of unit states,

C_i - capacity outage state i for the unit being added,

p_i - probability of existence of the unit state i.

The load models used in the analytical techniques depend on the reliability indices adopted, the availability of load data and the evaluation methods used. Usually, the load model can be represented by either the daily peak load variation curve (DPLVC) or the load duration curve (LDC). The DPLVC is the cumulative load model formed by arranging the individual daily peak loads in descending order. The resultant model is known as the LDC when the individual hourly load values are used, and in this case the area under the curve represents the energy required by the system in a given period. This is not the case with the DPLVC. The DPLVC is an approximate representation of the actual system load demand. It is used extensively, however, due to its simplicity. The LDC is a more realistic representation of the system load.

The generation model obtained from the COPT and an appropriate load model are combined to evaluate the risk indices. The proposed analytical approaches at the present time fall into one of the following general categories [1]:

2.3.1 Loss of Load Method (LLM)

In this approach, the generation system represented by the COPT and the load characteristic represented by either the DPLVC or the LDC are convolved to calculate the LOLE index.

Figure 2.5 shows a typical load-capacity relationship where the load model is represented by the DPLVC. A capacity outage O_k, which exceeds the reserve, causes a load loss for a time t_k shown in Figure 2.5. Each such outage state contributes to the system LOLE by an amount equal to the product of the probability p_k and the corresponding time unit t_k. The summation of all such products gives the system LOLE in a specified period, as expressed mathematically in Equation (2.10). Any capacity outage less than the reserve does not contribute to the system LOLE.

$$LOLE = \sum_{k=1}^{n} p_k \times t_k \tag{2.10}$$

where n - the number of capacity outage state in excess of the reserve

p_k - probability of the capacity outage O_k

t_k - the time for which load loss will occur.

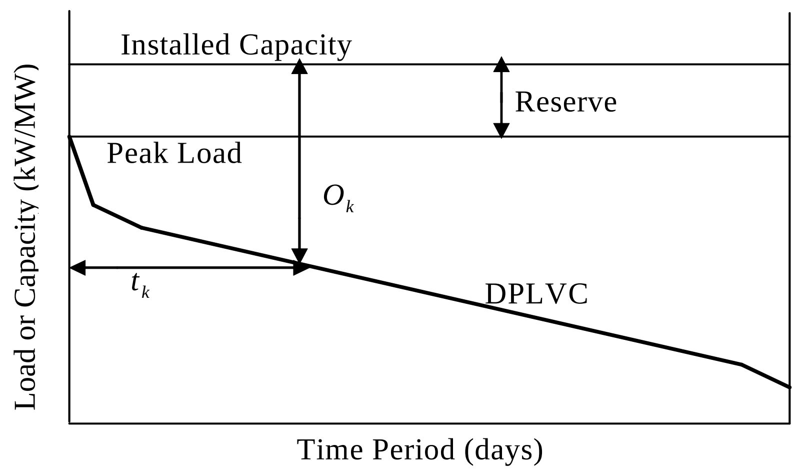


Figure 2.5: Evaluation of LOLE using DPLVC

The p_k values in Equation (2.10) are the individual probabilities associated with the COPT. The equation can be modified to use the cumulative probabilities as expressed in Equation (2.11).

$$LOLE = \sum_{k=1}^{n} P_k \times (t_k - t_{k-1}) \tag{2.11}$$

where P_k - the cumulative outage probability for capacity outage O_k.

The LOLE is expressed as the number of days during the study period if the DPLVC is used. The unit of LOLE is in hours per period if the LDC is used. If the time t_k is the per unit value of the total period considered, the index calculated by Equation (2.10) or (2.11) is called the loss of load probability (LOLP).

2.3.2 Loss of Energy Method (LEM)

In this approach, the generation system and the load are represented by the COPT and the LDC respectively. These two models are convolved to produce a range of energy-based risk indices such as the LOEE, units per million (UPM), system minutes (SM) and energy index of reliability (EIR) [1].

The convolution involved in this approach is similar to the LLM. The area under the LDC, in Figure 2.6, represents the total energy demand (E) of the system during the specific period considered. When an outage O_k with probability p_k occurs, it causes an energy curtailment of E_k, shown as the shaded area in Figure 2.6.

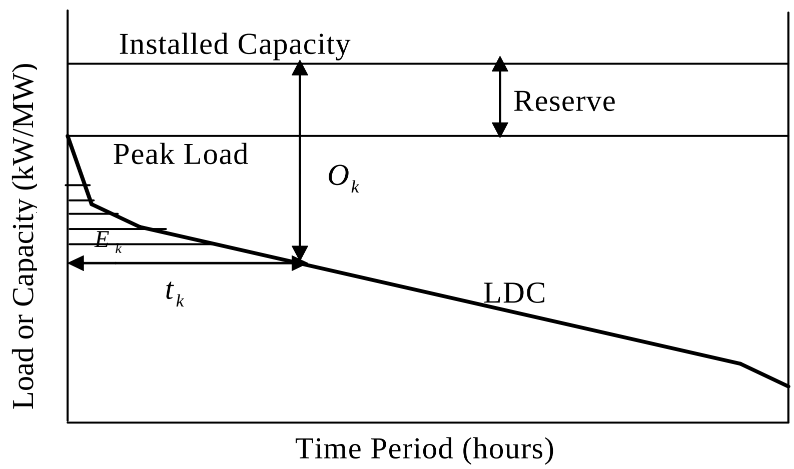


Figure 2.6: Evaluation of LOEE using LDC

The total expected energy curtailed or the LOEE is expressed mathematically in Equation (2.12). The other indices are expressed in Equations (2.13) to (2.15) respectively.

$$LOEE = \sum_{k=1}^{n} p_k \times E_k \tag{2.12}$$

$$UPM = \frac{LOEE}{E} \times 10^{6} \tag{2.13}$$

$$SM = \frac{LOEE}{PL} \times 60 \tag{2.14}$$

$$EIR = 1 - \sum_{k=1}^{n} \frac{p_k \times E_k}{E} \tag{2.15}$$

2.3.3 Load Modification Method (LMM)

A single COPT for all the generating units in the system is used in the LLM and LEM. The generation models used in the LMM are the capacity outage probability tables for each individual generating unit in the system rather than a single COPT. The load model in this approach is the LDC. The basic idea behind this technique lies in answering the question, "How does the load appear to the rest of the system when a generating unit is loaded to supply power to the system?" Conceptually, it is based on the idea of determining the equivalent load model that appears to the rest of the system as one or more generating units, each having a capacity probability model, are loaded to supply power to the system. The LMM is a sequential process to modify a given load model to produce an equivalent load model. If the generating system is energy-limited, the process includes modification of the equivalent load model by energy distributions of the generating unit. The basic concept and a practical way of applying this method to evaluate related reliability problems are presented in detail in reference [71].

2.3.4 Frequency and Duration Method

In this approach, Markov models are used to represent the generating units and the system load. The frequency and duration calculations require additional data such as the generating unit and load state transition rates. The indices obtained from this approach are expressed in terms of the frequency, duration and probability of encountering the various negative margin states [1].

2.4 Monte Carlo Simulation

The primary focus of this thesis is to develop generating capacity adequacy evaluation techniques and models for power systems containing wind energy, solar energy and energy storage. The installed capacity of these systems is not a fixed value as in the case of systems containing conventional units. The capacity of a non-conventional generating system is a function of fluctuating site resources at the system location. The existing deterministic techniques cannot be readily applied to such systems. The random behavior of wind and solar energy based generating systems can, however, be recognized and reflected using probabilistic techniques.

The analytical techniques described previously, work well for conventional generating systems and are used by many utilities throughout the world. These techniques cannot provide satisfactory solutions without excessive approximations in non-conventional system analyses due to the random, time-correlated chronological variation of the weather, its effect on the site resources, operating parameters of a non-conventional generating unit and the chronological variation of system load. The chronological nature of generation can be approximated in a COPT using valid historical data [9, 72]. The time sequential load variation is not recognized by either a DPLVC or a LDC. Additional variables, which cannot be easily reflected in the simple mathematical models used in the analytical techniques, are required when storage capability is included in the evaluation.

Stochastic simulation is the only practical technique for systems that include a large number of time dependent random variables that are related in various ways. In addition, the simulation technique may also be preferable in the following situations:

1. The time-distributions of the failure and repair processes in the system are non-exponential.
2. The density or distribution functions associated with the reliability indices are required.
3. The assessment of large systems where the analytical methods may not produce sufficiently accurate results.

The distributions associated with adequacy indices can provide additional information on system reliability performance. A method for the construction and utilization of this information in HL-I reliability studies is presented in Chapter 5 of this thesis.

The main disadvantage of the simulation technique is that the time involved in the simulation can be very extensive. This, however, is becoming less problematic with the technological improvements in modern computers.

Stochastic simulation methods are commonly known as Monte Carlo simulation (MCS). They can be broadly classified into one of the two categories, namely sequential or non-sequential methods [73, 74]. In the sequential method, the simulation process is advanced sequentially or chronologically, recognizing the fact that the system state at a given time point is correlated with that at previous time points. In the non-sequential method, however, the process does not move chronologically and the system behavior at each time point is considered to be independent of that at other points. The sequential Monte Carlo simulation method is utilized in the research described in this thesis.

2.4.1 Simulation Methodology

The capacity model in a time sequential Monte Carlo simulation is the generating capacity available at points in time established chronologically by random sampling. The generation model is then superimposed on the chronological load model to form the risk model. The main parameters used to create an operational history for each individual unit are usually in the form of generating unit mean times to failure (MTTF) and mean times to repair (MTTR) [1]. These parameters can be used in conjunction with random numbers between 0 and 1 to produce a state history consisting of a series of random up and down (or derated) times called state residence times for each generating unit in the system. The state residence time is sampled from its probability distribution. In this thesis, the relevant distributions are assumed to be exponential. The possible operating states of a generating unit are shown in Figure 2.7.

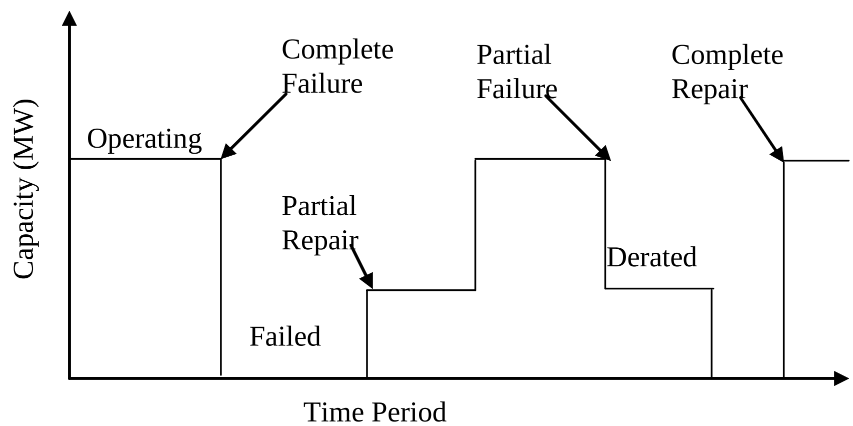


Figure 2.7: Operating history of a generating unit

If the state residence time is represented by an exponentially distributed random variable T, it has the following probability density function [74],

$$f(t) = xe^{-xt} \tag{2.16}$$

where x is the mean value of the distribution. The cumulative probability distribution function is given by

$$F(t) = 1 - e^{-xt} \tag{2.17}$$

Using the inverse transform method [74], the random variable T can be obtained as

$$T = -\frac{1}{x}\ln(1-u) \tag{2.18}$$

Where u is a uniformly distributed random number between 0 and 1 obtained from a suitable random number generator. Since 1-u is distributed uniformly in the same way as u in the interval [0,1], the random variable T can be expressed as

$$T = -\frac{1}{x}\ln(u) \tag{2.19}$$

Consider a two state generating unit as shown in Figure 2.3. If the unit is in the up state, then x in Equation (2.19) is the failure rate (λ) of the generating unit, which is the reciprocal of the MTTF. If the unit is in the down state, x is the repair rate (μ) of the generating unit, which is the reciprocal of the MTTR.

The basic overall simulation methodology can be briefly described as follows:

1. Generate operating histories for each generating unit. The operating history of each unit is then in the form of chronological up-down-up or up-derate-down-up operating cycles.
2. Obtain the system available capacity by combining the operating cycles of all the generating units in the system.
3. Superimpose the system available capacity obtained in step 2 on the chronological load model to construct the system available margin model.
4. Estimate the desired reliability indices by observing the margin model constructed in step 3 over a long time period.

The first two steps of this process are illustrated in Figure 2.8. An assumption made in Figure 2.8 is that all units are operational at the beginning of the simulation. Steps 3 and 4 are illustrated in Figure 2.9.

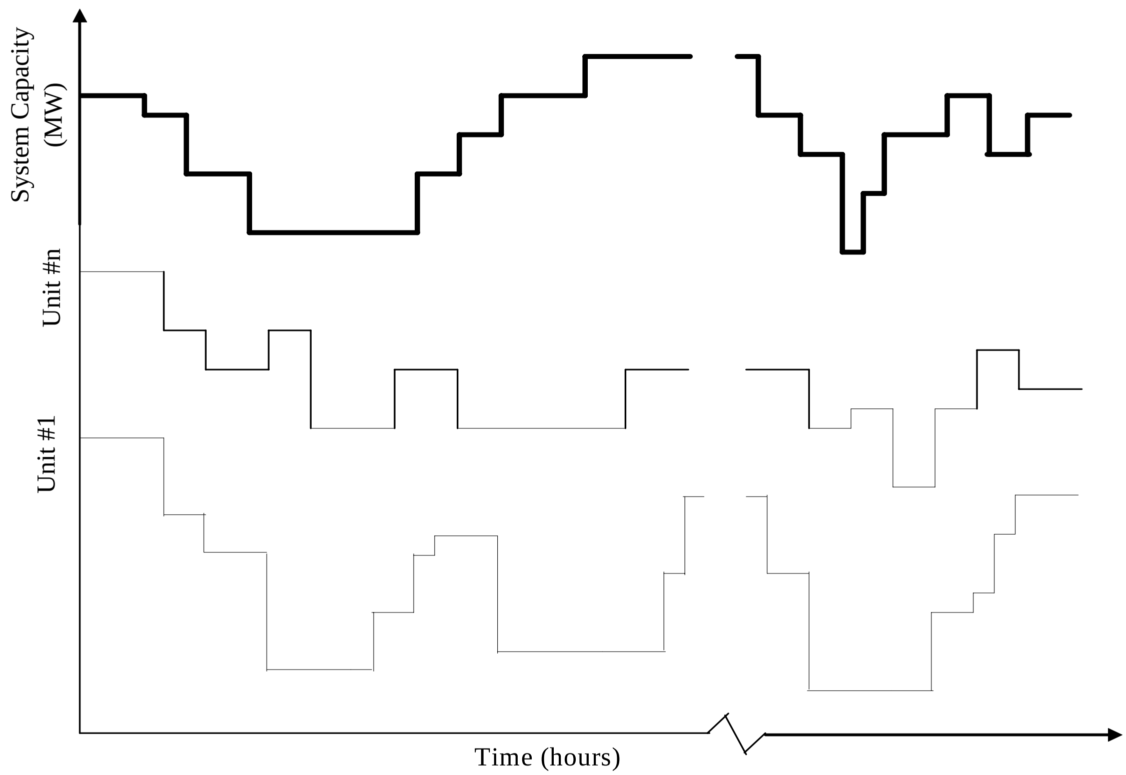


Figure 2.8: Operating history of individual generating units and the capacity states of an entire system

The load model in MCS is usually a chronological hourly load pattern. The desired adequacy indices can be determined from the margin model by superimposing the generation and the load models as shown in Figure 2.9. The load is usually modeled in one hour time steps, although smaller steps could be used. The available margin at a specific time point is the difference between the available capacity and the load at that point. A negative margin indicates that an outage has occurred. The simulation is repeated for a long period of time in order to obtain the desired level of accuracy.

Normally the time reference in a sequential Monte Carlo simulation is a year, and most indices are therefore year based. The LOLE and the LOEE are calculated by recording the loss of load duration t_i in hours for each load curtailment, the energy not supplied e_i in MWh or kWh at each curtailment and the total number of load curtailments ‘n’ as shown in Figure 2.9.

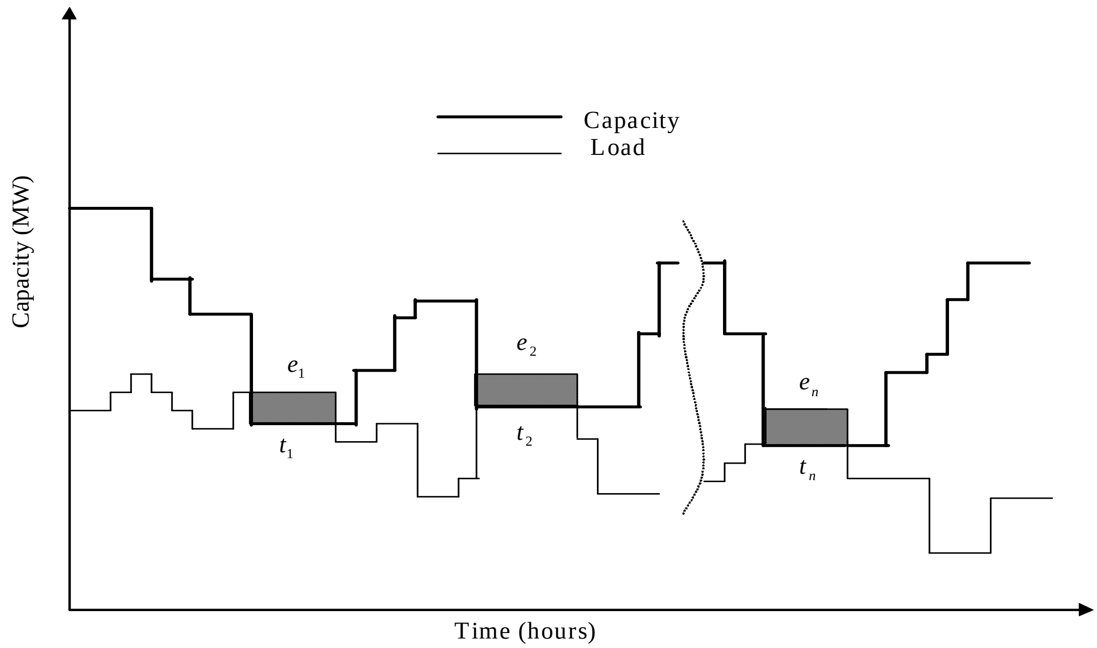


Figure 2.9: Superimposition of the capacity states and the chronological load pattern

Estimates of the reliability indices for a number of sample years (N) can be obtained using the following equations.

(1) Loss of load expectation (hours/year)

$$LOLE = \frac{1}{N}\sum_{i=1}^{n} t_i \qquad (2.20)$$

where t_i - loss of load duration in year i

N - total number of simulated years

n – number of load curtailments

(2) Loss of energy expectation (kWh or MWh/year)

$$LOEE = \frac{1}{N}\sum_{i=1}^{n} e_i \qquad (2.21)$$

where e_i - energy not supplied in year i

N - total number of simulated years

n – number of load curtailments

The LOLE and LOEE indices provide an overall indication of the ability of the generating system to satisfy the total system load. Other indices [74] such as the frequency of interruptions and the expected duration of interruptions can also be calculated if required.

2.4.2 Simulation Convergence and Stopping Criteria

Stochastic simulations require a large amount of computing time to simulate the actual operation of a system. The accuracy of the indices estimated by a simulation technique is improved by increasing the number of sample years. It is, however, not practical to run the simulation for a very large number of samples in order to achieve an extremely high level of accuracy. A stopping criterion (or rule) is often used to determine the most appropriate time to stop the simulation so that it not only reduces the simulation time but also provides an acceptable confidence in the results. There are different stopping criteria, which can be used to track the convergence of the simulation. In this thesis, the stopping criterion is selected as the ratio of the standard deviation of the expected value $E(X)$ and $E(X)$ where X is a reliability index such as LOLE or LOEE. The mathematical expression for each statistical value and the stopping criterion are as follows:

The basic reliability index is

$$E(X) = \frac{1}{N}\sum_{i=1}^{n} X_i \qquad (2.22)$$

where

X_i - the observed value of X in year i

N - the total number of simulated years.

The standard deviation of the mean is

$$\sigma[E(X)] = \frac{\sigma(X)}{\sqrt{N}} \text{ where } \sigma(X) = \left[\frac{1}{N-1}\sum_{i=1}^{n}\left(X_i^2 - E^2(X)\right)\right]^{\frac{1}{2}} \tag{2.23}$$

The stopping criterion is as follows:

When $\frac{\sigma(E(X))}{E(X)} < \varepsilon$, the simulation is terminated.

Where ε is the maximum error allowed.

Not all indices converge at the same rate. The LOEE index is slower to converge than the other indices [74] and is, therefore, taken as the base index to check for convergence.

2.5 Well-being Framework

Reliability modeling and assessment of power systems utilizing wind energy, solar energy and energy storage is a new emerging area in power system reliability evaluation. The reliability performance of an unconventional unit is quite different from that of a conventional generating unit. An unconventional unit largely depends on the site resources so that it may suffer unscheduled outage both from equipment failure and from site resource deficiencies. Valid and accurate site resource data are, therefore, essential inputs in a realistic evaluation of such systems. Most utilities use physical and observable reserve margins based on their past experiences obtained from conventional capacity planning, when considering unconventional generating sources. This is due to the relatively insignificant contribution of these sources in major power systems and consequently due to the lack of accurate data and appropriate evaluation techniques. Most Canadian utilities use a deterministic criterion in SIPS generating planning [28]. Despite the obvious disadvantages of deterministic approaches, there is considerable reluctance to apply probabilistic techniques. There are many reasons for this reluctance. Some of the most frequently cited are the difficulty in interpreting the numerical risk indices and more importantly the lack of system operating information contained in these risk indices, such as energy storage capability etc.

The conventional deterministic criteria can be included in the probabilistic evaluation of system well-being and risk. The system well-being as designated by the accepted deterministic criteria are identified as being healthy, marginal and at risk using the designations shown in Figure 2.10. A system operates in a healthy state when it has enough margin or storage capability to withstand the deterministic criterion. In the marginal state the system no longer has sufficient margin or storage capacity that it can withstand the specified deterministic criterion. The system is in the at risk state if the load exceeds the combined capability of the generation and storage. Reliability assessment based on these criteria should alleviate some of the difficulties encountered in interpreting the risk indices and should provide useful and comprehensive information for system planners.

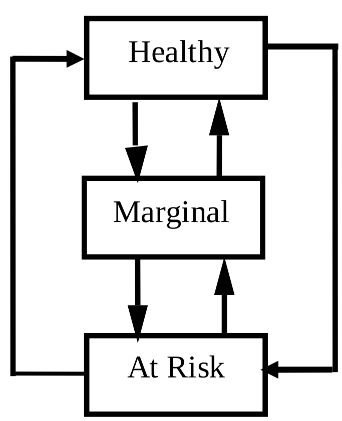


Figure 2.10: System well-being model

Conceptually, any of the deterministic technique described in Sub-section 2.2.1 can be used in system well-being analysis. The most commonly deterministic technique used in well-being analysis at the HL-I level is the LLU. Conventional deterministic techniques make use of the CLU to determine the amount of capacity reserve needed in order to meet the accepted adequacy criterion. In system well-being analysis, the required amount of capacity reserve is determined by the capacity of the largest operating unit at a particular point in time. This means that the capacity of the largest unit can be different for different generation system states. The system reserve is compared with the capacity of the largest operating unit throughout the total period of study to determine the health, margin and risk state in system well-being analysis at HL-I [20, 29, 32, 34, 41, 42].

The most commonly used analytical approaches in system well-being analysis at HL-I level are the contingency enumeration method [32] and the conditional probability COPT method [41]. Monte Carlo simulation can also be used to evaluate system well-being indices [42]. The Monte Carlo simulation technique can provide distributions and additional frequency and duration indices.

Well-being assessment of a power system utilizing wind energy, solar energy and energy storage depends on many factors such as the deterministic criterion used, storage capacity, system load, available site resources, system geographic location and generating unit forced outage rates etc. These aspects are considered and evaluated in Chapter 7 of this thesis.

2.6 Reliability Cost/Worth Evaluation at HL-I

Evaluation of the costs associated with different system configurations and the corresponding worth associated with the differences is generally termed as reliability cost/worth assessment [1]. Reliability cost refers to the additional costs needed to achieve a certain level of reliability. Reliability worth evaluation incorporates both cost analysis and quantitative reliability assessment into a common framework [1]. Direct evaluation of reliability worth or benefit is difficult due to the fact that the assessment of the societal worth of electric service reliability is an extremely complex task. Several general approaches have been used in the past with regard to the assessment of reliability worth [43-63]. Customer interruption costs are most often used to provide an indirect measure of reliability worth.

There are different costs associated with power system planning. Utility planners consider important factors such as, capital investment, operating and maintenance costs in reliability cost/worth analysis. They also incorporate customer interruption costs in the overall cost minimization process. The reliability of a system can be improved by installing additional components or better equipment. The customer interruption costs in these cases will decrease as the capital and operating cost increase. The main objective is to balance the benefits realized from providing higher reliability and the cost of providing it. A major objective of reliability cost/worth assessment is to determine the optimum level of service reliability. The basic concept is graphically illustrated in Figure 2.11.

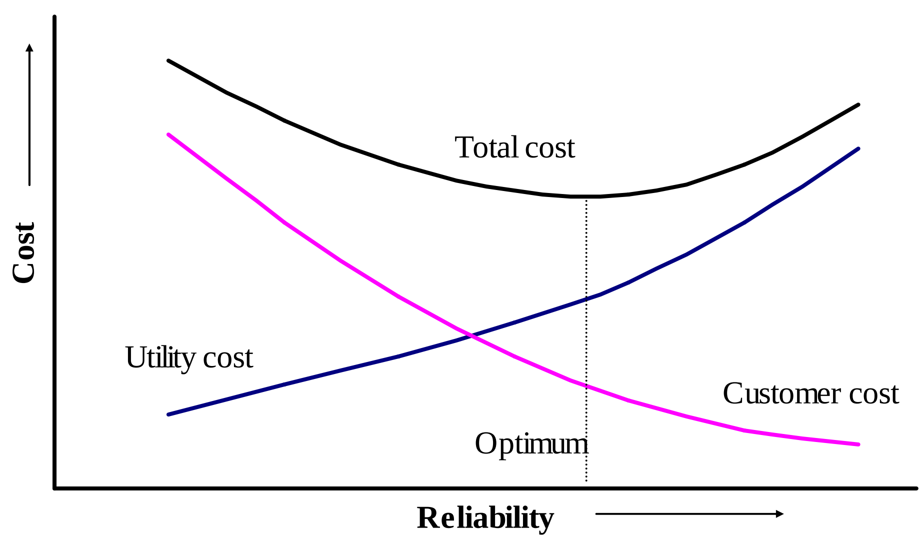


Figure 2.11: Reliability cost components

As shown in Figure 2.11, the utility cost including investment cost, maintenance cost and operating cost, increases while the customer interruption cost decreases with increase in the level of service reliability. The total cost is the sum of the two curves. The optimum level of reliability occurs at the point of lowest total cost. In a reliability cost/worth analysis, the annual expected customer interruption costs are added to the predicted annual capital and operating costs to obtain a total cost evaluation. Possible alternative configurations are examined to minimize the total cost and to identify the most appropriate configuration.

Both analytical and simulation techniques can be used to conduct reliability cost/worth assessment [43-63]. Three basic models are required in reliability cost worth evaluation at HL-I level. These are the generation model, the load model and the cost model. Composite customer damage functions (CCDF) [1] are the most commonly used cost models. The CCDF are usually used to obtain a cost factor in $/kWh known as the interrupted energy assessment rate (IEAR). The cost associated with generating capacity inadequacy can be determined using the IEAR and EENS. One of the major objectives of this research is to incorporate reliability cost/worth concepts in the evaluation of power systems utilizing different energy sources and energy storage. Conventional reliability cost/worth evaluation techniques at HL-I and the extensions of these techniques in such systems are presented in Chapter 9.

2.7 Summary

This chapter briefly describes the various techniques for generating capacity adequacy evaluation. The concepts of system well-being and reliability cost worth evaluation are also briefly introduced.

Generating capacity adequacy evaluation involves the combination of a generation model with an appropriate load model to obtain a risk model. The methods used by utilities for conducting adequacy evaluation broadly fall into the two categories of deterministic and probabilistic approaches. Deterministic methods cannot completely recognize and reflect the risk associated with a given system, and therefore electric power utilities are slowly changing from using deterministic criteria to probabilistic criteria.

Two different approaches exist in the probabilistic evaluation of generating capacity adequacy. They can be classified as being either analytical or Monte Carlo simulation approaches. Both techniques have advantages and disadvantages and can be very powerful for a particular application. The main disadvantage of the analytical approach is that it cannot produce satisfactory results when considering systems having chronological varying behavior or when modeling large complex systems. Monte Carlo simulation, on the other hand, is preferable in such situations.

The loss of load expectation (LOLE) and loss of energy expectation (LOEE) are the most widely used risk indices. They can be evaluated by suitably combining the generation model with the load model in both analytical and Monte Carlo simulation approaches.

System well-being analysis combines the deterministic and probabilistic methods and provides indices that can be useful in power system reliability assessment. The well-being indices can be evaluated using both analytical and simulation techniques.

Reliability cost/worth assessment involves the evaluation of the costs associated with different system configurations and the corresponding worth associated with the differences. A major objective of reliability cost/worth assessment is to determine the optimum level of service reliability.

The sequential Monte Carlo simulation technique is utilized in the research described in the following chapters in the generating capacity adequacy, system well-being and cost/worth analyses of power systems containing non-conventional energy sources and energy storage.

3. BASIC RELIABILITY EVALUATION MODELS FOR GENERATING SYSTEMS CONTAINING WIND ENERGY, SOLAR ENERGY AND ENERGY STORAGE

3.1 Introduction

Despite the increasing utilization of wind and solar energy for electric power generation around the world, power system planners and engineers have paid relatively little attention to the reliability issues associated with these non-conventional energy sources due to the absence of suitable modeling and evaluation techniques. As a result, the advantages of these promising energy options for electricity supply have not been completely recognized and the utilizations of wind and solar energy based systems are not as extensive as they could be.

Wind and solar energy based power systems convert the natural energy available due to the atmospheric conditions at the system location into electric energy. The usable energy that can be converted at any point in time depends on the amount of available energy contained in the weather related site resources at that time. Due to the dispersed nature of the site resources, wind and solar energy based systems inherently pose some special difficulties in modeling and related reliability analyses.

As noted earlier, most of the earlier reported work done on modeling wind and solar power generation and the use of such models in reliability assessment is in the analytical domain. The most obvious deficiency of analytical methods is that the chronological nature of the wind and the sunlight, their effect on the power output of a renewable energy based generating system and energy storage capability cannot be recognized and reflected. Sequential Monte Carlo simulation, on the other hand, can be used to incorporate such considerations in an adequacy assessment of a generating system containing wind energy, solar energy and energy storage.

This chapter presents the models required to perform generating capacity adequacy evaluation of power systems including wind energy, solar energy and energy storage using a sequential Monte Carlo simulation technique. The simulation technique is based on using hourly counted random events to mimic the operational history of a generating system, taking into account the chronological time correlated nature of the site resources and the failure and repair characteristics of the generating units in the system. The basic simulation process is described in Chapter 2. Time series models are utilized to simulate the hourly wind speeds and solar radiation. The power output of a generating unit can be simulated using the relationship between the power output and the site resources. Energy storage capability is an important component in the development of power systems containing wind and/or solar energy. A time series energy storage model can be developed from the chronological load pattern and the generation. A general model for the generating capacity adequacy evaluation of power systems using wind energy, solar energy and energy storage has been developed based on the generation, load and energy storage models described in the following sections.

3.2 Generation Models

It is noted in Chapter 2 that the generation and load models are combined to create a suitable risk model. It is relatively straightforward to develop an evaluation model for conventional generating systems. The number of time dependent variables associated with weather related site resources and the associated system components, however, increase the complexity when modeling wind and solar energy based systems.

The development of a generation model for a power system containing wind and solar energy requires the consideration of three major factors, which affect the generated power output. The first factor is the random nature of the site resources. This randomness must be included in an appropriate model to reflect the chronological and auto-correlation characteristics of the wind and sunlight at the particular site location. The second factor is the relationship between the power output and the site resources. This relationship can be determined by using the WTG and PV operational parameters and specifications. The third factor is the effect of the failure and repair characteristics of the WTG and the PV arrays. These characteristics are usually specified by the device FOR or the MTTF and MTTR as described in Chapter 2.

3.2.1 Modeling of Wind Energy Conversion Systems

Wind energy is an indirect form of solar energy. Winds result from unequal heating of different parts of the earth's surface, causing cooler, dense air to circulate and replace warmer, lighter air. This procedure is intermittent and varies randomly with time. Wind is therefore, highly variable, and it is both site specific and terrain specific. It has seasonal, diurnal and hourly variations.

Seasonal variations in the speed and direction of the wind result from the seasonal changes in the relative inclination of the earth towards the sun. Diurnal variations are caused by differential heating of local regions, such as adjacent land and oceans. This air movement is complicated by a number of other factors such as the earth's rotation, continents, oceans and mountain ranges. The wind speed also increases with the height above the ground. It is clear that any plans to harness the wind must take these variables into account.

3.2.1.1 Generation of Wind Speed

The time sequential simulation of a wind energy conversion system (WECS) involves the computation of hourly wind power generated by one or more WTG for a large number of sample years. The hourly power output of a WTG depends on the hourly wind speed at a specific site location. Wind speed, however, varies with time and site and at a specific hour is related to the wind speed of previous hours. Considerable work [75-77] has been conducted to model wind speed in order to perform planning and reliability analyses for WECS or mixed power systems containing wind energy. The wind speed was modeled as a random variable with a Weibull distribution and a simple auto-regressive (AR) model is presented in reference [75]. An AR (2) model was developed in reference [76] for simulating the main statistical characteristics of wind speed. Although these wind speed models are relatively simple and easy to use, the relatively high order auto-correlation of the wind speed is underestimated in such models. These models are therefore incomplete and may not adequately represent the site resources. A time series model was developed [77] to overcome the deficiencies and incorporate the chronological and auto-correlation nature of the actual wind speed. This time series model is used in the research described in this thesis to generate synthetic wind speeds based on the measured wind data at a specific site location.

In the time series model [77], the simulated wind speed SW_t can be obtained from the mean wind speed μ_t and its standard deviation σ_t at time t as follows:

$$SW_t = \mu_t + \sigma_t y_t \tag{3.1}$$

The original data series set y_t can be used to create a wind speed time series referred to as an ARMA (n, m) series model (Auto-Regressive and Moving Average Model). This is shown in Equation (3.2).

$$y_t = \sum_{i=1}^{n} \phi_i y_{t-i} + \alpha_t + \sum_{j=1}^{m} \theta_j \alpha_{t-j} \tag{3.2}$$

Where ϕ_i (i=1,2,…,n) and θ_j (j=1,2,…,m) are the auto-regressive and moving average parameters of the model respectively, $\{\alpha_t\}$ is a normal white noise process with zero mean and variance of σ_a^2, i.e., $\alpha_t \in NID(0, \sigma_a^2)$, where NID denotes Normally Independent Distributed. Equation (3.2) permits new values of y_t to be calculated from current random white noise α_t and previous values of y_{t-i}. The hourly wind speeds incorporating the wind speed time series can be generated using Equation (3.1).

The time series ARMA model described in Equations (3.1) and (3.2) is used in the wind speed simulation. The main steps can be briefly described as follows:

1. Generate white noise α_t.
2. Generate y_t from the present white noise α_t and previous values of y_t using Equation (3.2).
3. Calculate the simulated wind speeds using Equation (3.1).
4. Obtain hourly wind speed data through step 1 to step 3 for a calendar year.
5. Repeat step 1 to step 4 for a long period.

If $t \leq 0$, then y_t and α_t are assumed to be zero.

Different site locations usually experience different wind regimes. The ARMA time series models representing different locations, therefore, are not the same. The wind speed models and data from three different sites located in the province of Saskatchewan, Canada have been used in the studies described in this thesis. The mean wind speed and the standard deviation of the three different sites are given in Table 3.1. The ARMA models for the three sites given in Equations (3.3) to (3.5) were developed by the Power System Research Group at the University of Saskatchewan [77].

Table 3.1: Wind speed data at the three different sites

Sites	**North Battleford**	**Saskatoon**	**Regina**
Mean wind speed $\mu\,(km/h)$	14.63	16.78	19.52
Standard deviation $\delta\,(km/h)$	9.75	9.23	10.99

North Battleford: ARMA (3, 2):

$$\begin{aligned} y_t &= 1.7901 y_{t-1} - 0.9087 y_{t-2} + 0.0948 y_{t-3} \\ &\qquad + \alpha_t - 1.0929\alpha_{t-1} + 0.2892\alpha_{t-2} \\ \alpha_t &\in NID(0, 0.474762^2) \end{aligned} \tag{3.3}$$

Saskatoon: ARMA (3, 2):

$$\begin{aligned} y_t &= 1.5047 y_{t-1} - 0.6635 y_{t-2} + 0.1150 y_{t-3} \\ &\qquad + \alpha_t - 0.8263\alpha_{t-1} + 0.2250\alpha_{t-2} \\ \alpha_t &\in NID(0, 0.447423^2) \end{aligned} \tag{3.4}$$

Regina: ARMA (4, 3):

$$\begin{aligned} y_t &= 0.9336 y_{t-1} + 0.4506 y_{t-2} - 0.5545 y_{t-3} + 0.1110 y_{t-4} \\ &\qquad + \alpha_t - 0.2033\alpha_{t-1} - 0.4684\alpha_{t-2} + 0.2301\alpha_{t-3} \\ \alpha_t &\in NID(0, 0.409423^2) \end{aligned} \tag{3.5}$$

The simulated hourly wind speeds for a day, a month and a year using Equation (3.5) and the data for Regina are shown in Figures 3.1 to 3.3 respectively.

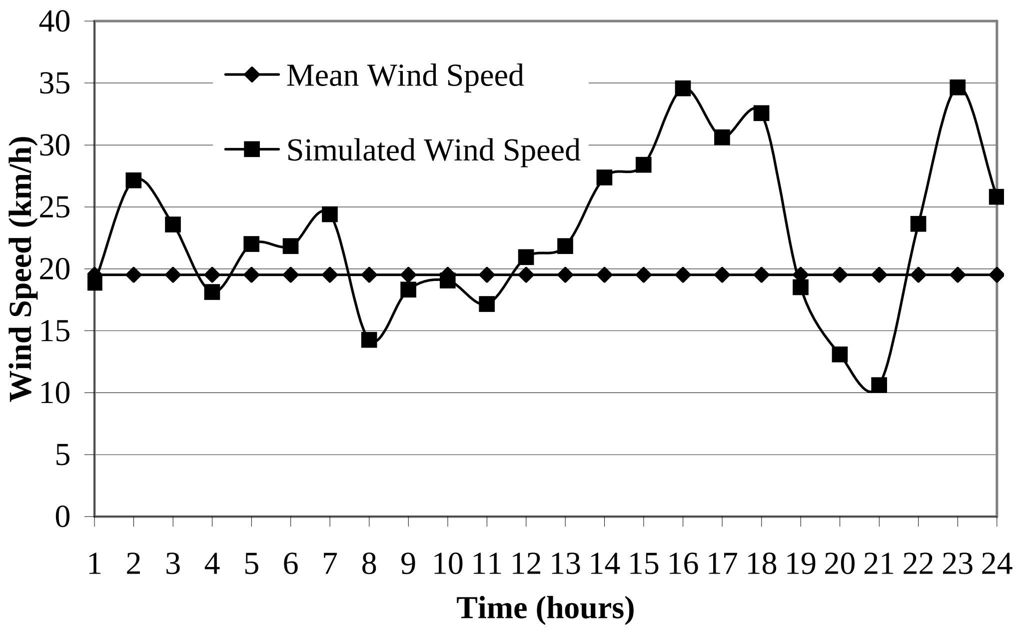


Figure 3.1: Simulated wind speeds for the first day of a sample year (Regina data)

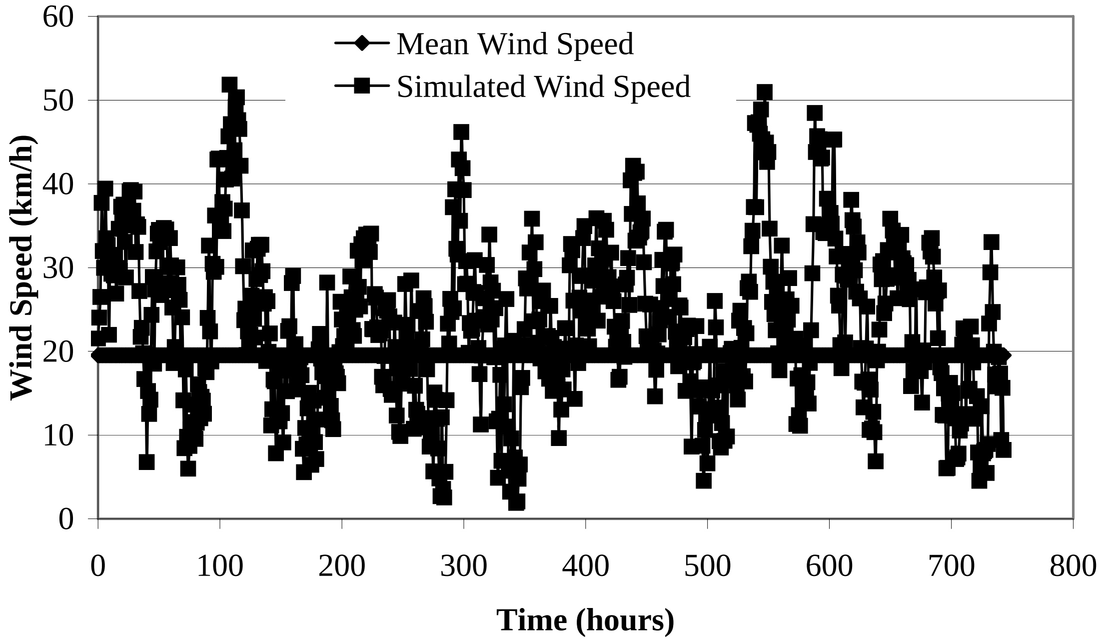


Figure 3.2: Simulated wind speeds for the month of
January in a sample year (Regina data)

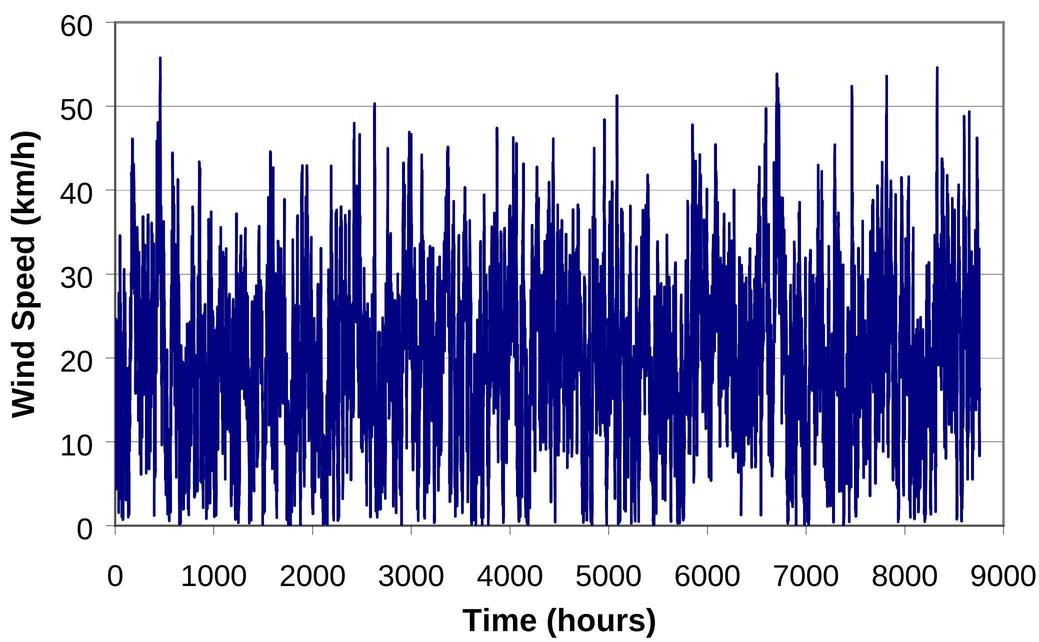


Figure 3.3: Simulated wind speeds for a sample year (Regina data)

Figures 3.1 to 3.3 show that the hourly wind speeds are distributed around the average value of 19.52 km/h. The time series ARMA models expressed in Equations (3.3) to (3.5) provide a valid representation of the wind regime, which includes the correlation between the average wind speeds of successive hours. These models can be used to predict future wind speeds based on the known data.

3.2.1.2 Available Wind Energy

A conventional generating unit is usually represented using a simple two-state model or multi-state model as discussed in Chapter 2. If the unit is operating in the up state it can produce its rated capacity. If the unit is in the down state, the power output is zero. If the unit is in the derated state, the power output is some value between the rated power and zero. The power output characteristics of WTG are, however, quite different from those of conventional generating units.

The electric power output of a WTG in the up state depends strongly on the wind regime as well as on the performance characteristics and the efficiency of the generator. Given the hourly wind speed variations, the next step is to determine the power output of the WTG as a function of the wind speed. This function is described by the operational parameters of the WTG. The parameters commonly used are the cut-in wind speed (at which the WTG starts to generate power), the rated wind speed (at which the WTG generates its rated power) and the cut-out wind speed (at which the WTG is shut down for safety reasons). The hourly output of a WTG can be obtained from the simulated hourly wind speed by applying Equation (3.6).

$$P(SW_t) = \begin{cases} 0 & 0 \le SW_t < V_{ci} \\ (A + B \times SW_t + C \times SW_t^{\,2}) \times P_r & V_{ci} \le SW_t < V_r \\ P_r & V_r \le SW_t < V_{co} \\ 0 & SW_t \ge V_{co} \end{cases} \tag{3.6}$$

Where P_r, V_{ci}, V_r and V_{co} are the rated power output, the cut-in wind speed, the rated wind speed and the cut-out wind speed of the WTG respectively [9]. The constants A, B, and C depend on V_{ci}, V_r and V_{co} as expressed in Equation (3.7) [9].

$$\begin{aligned}
A &= \frac{1}{(V_{ci}-V_r)^2}\left\{V_{ci}(V_{ci}+V_r) - 4V_{ci}V_r\left[\frac{V_{ci}+V_r}{2V_r}\right]^3\right\},\\
B &= \frac{1}{(V_{ci}-V_r)^2}\left\{4(V_{ci}+V_r)\left[\frac{V_{ci}+V_r}{2V_r}\right]^3 - (3V_{ci}+V_r)\right\},\\
C &= \frac{1}{(V_{ci}-V_r)^2}\left\{2-4\left[\frac{V_{ci}+V_r}{2V_r}\right]^3\right\}.
\end{aligned} \tag{3.7}$$

The relationship can also be illustrated graphically as shown in Figure 3.4 and is often referred to as the “Power Curve”. Actual power curve for a particular WTG is similar to the theoretical one shown in Figure 3.4 and can be obtained from the manufacturer. Major technical data for a VESTAS V29 225-50, 29 !O! turbine including the power curve are given in Appendix A.

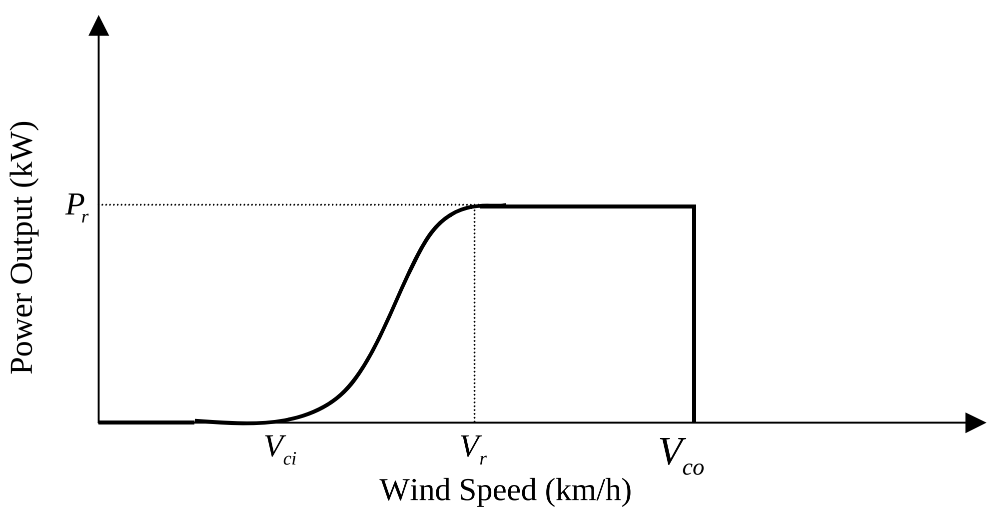


Figure 3.4: Wind turbine generator power curve

The hourly output power of a WTG can be easily obtained from the simulated hourly wind speeds using Equation (3.6). The simulated output power of a 30 kW wind generator with operating parameters of cut-in, rated and cut-out wind speeds of 12 km/h, 38 km/h and 80 km/h respectively over a one week period is shown in Figure 3.5. The output power of the WTG is between 0 and its power rating of 30 kW. The figure shows that the output power of the generator reaches its rated power only for a few hours in the middle of the week. This is due to the fact that the simulated wind speeds are seldom between the rated and cut-out wind speeds of the WTG during the sample week when the WTG is in the up state. Figure 3.6 shows that there is no power generated from the WTG for a few hours at the beginning, in the middle and by the end of the week. The reason for this could be that the simulated wind speeds are lower than the cut-in wind speed or are higher than the cut-out wind speeds of the WTG at these time points in the week. In either case the WTG produces no energy. Another possible reason is that the WTG may be on forced outage at these time points. A WTG FOR of 0.05 was used in the power calculations. Generating unit forced unavailability is discussed later in this chapter.

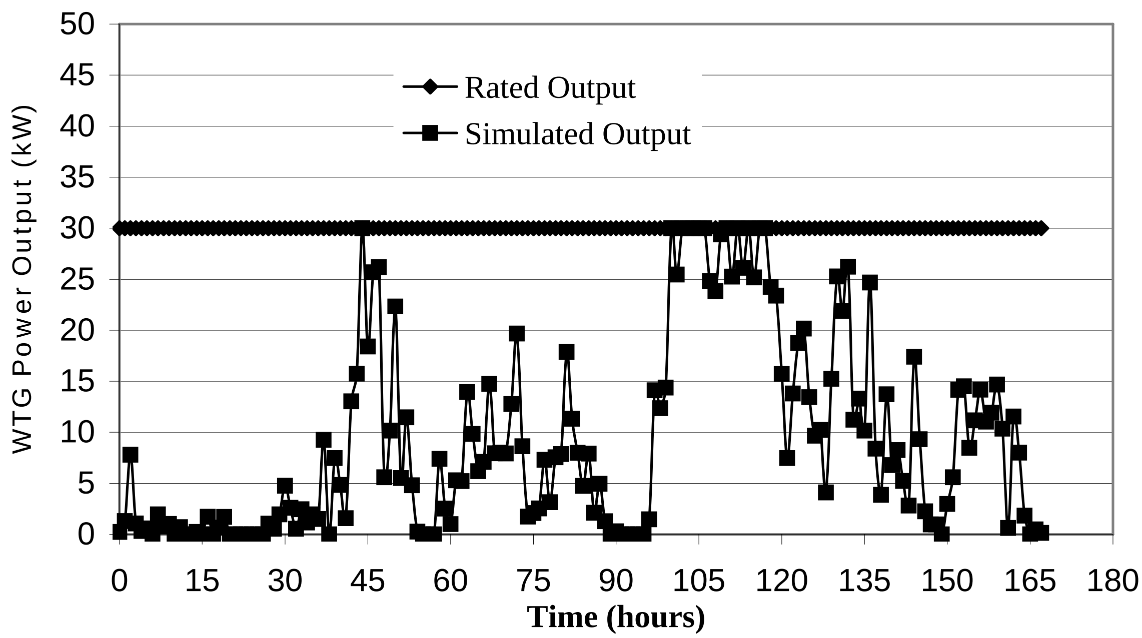


Figure 3.5: Simulated output power of a 30 kW WTG for a winter week in a sample year (Regina data)

3.2.2 Modeling of Photovoltaic Conversion Systems

The hourly output of a PV generating unit varies with time. This is an important factor in the reliability evaluation of these systems. Calculation of the available power from a PV conversion system (PVCS) involves modeling the solar radiation available on the earth at the site location in order to provide the necessary radiation data. The radiation data then can be converted into electric power.

The solar radiation at the surface of the earth is the available energy resource for the PV generating units. The basic component that converts solar energy into electrical power in a PV generating unit is called a solar cell. A generating unit is usually composed of arrays of individual cells to create a solar panel (or module). The amount of electric power generated by the unit depends on many factors, including (but not limited to) the operational constraints of the cells, the solar array arrangement and atmospheric conditions at the site location for example the solar radiation on the surface of the array, the ambient temperature around the array, the level of humidity and the wind speed. Each of these factors involves a number of random variables that affect the reliability performance of the system. All of these factors should be incorporated into the development of the overall generation model for a solar energy based power system.

3.2.1.1 Generation of Solar Radiation Data

The solar energy, which can be received on the surface of the earth, is only a minor portion of the amount of energy radiated from the sun. At the distance of the earth from the sun, this energy spreads out and reduces in its intensity when it reaches the top of the atmosphere. The solar radiation outside of the atmosphere is often referred to as extraterrestrial radiation. The amount of energy received on a unit area of a surface perpendicular to the direction of propagation of the radiation outside of the atmosphere at the earth's mean distance from the sun is essentially constant. This value is known as the solar constant (SC) and it is equal to 1353 W/m^2 [78]. Due to absorption and scattering, particularly by dust and water vapor, the atmosphere further attenuates the sun's radiation. The solar radiation received at the surface of the earth is usually known as global radiation (or terrestrial radiation).

The correct prediction of the power generated by PV arrays requires the determination of the intensity of the global solar radiation on the surface of the arrays at a specific site location. The total global radiation is normally composed of two components namely the direct and the diffuse radiation. The direct component is the radiation received from the sun without having been scattered by the atmosphere, while the diffused component is the radiation received from the sun after its direction has been changed due to scattering [78]. The contribution of the direct and diffuse components to the total radiation mainly depends on the cloud cover.

Valid and detailed data in the form of either total radiation or direct and diffuse radiation at the site location are required in PVCS simulation. In general, two basic methods are available to provide these data in the simulation of a solar process: 1. direct use of historical records and 2. generation of synthetic data. Although the first method may incorporate the random nature of the radiation process, detailed atmospheric records are usually not available in many locations around the world, especially in the remote isolated locations. The simulation of a solar energy based system, however, does not always require the use of measured historical data. Synthetic data can be generated on the basis of valid mathematical models for locations without atmospheric records or with very poor records.

A number of possible modeling approaches have been developed to simulate the solar radiation process for generating synthetic radiation data [79-82]. Reference [79] proposes a modeling approach for generating synthetic solar radiation data based on a stochastic time series methodology. A Markov transition matrix approach for generating hourly sequence of radiation data is presented in [80]. These methods, however, do not recognize and incorporate the optical characteristics of nighttime and therefore produce incomplete results. General methods for generating a synthetic radiation data series on the basis of daily and hourly events are described in references [81] and [82] respectively. These newer approaches reflect the characteristics of the solar radiation process more closely and overcome the shortcomings of previously developed methods.

A computer program known as WATGEN [83] has been developed at the University of Waterloo based on the mathematical models developed in [81, 82]. This program is widely used to conduct performance and design assessments on solar energy conversion systems. This program has been used in the research to generate hourly solar radiation data for the sequential Monte Carlo simulation studies described in this thesis.

The overall procedure for generating synthetic hourly solar radiation data in the program is a two-step process, as shown in Figure 3.6. The first step involves generating daily radiation data from the monthly mean values such as monthly average solar radiation, monthly average wind speed and monthly average ambient temperature at the particular site location. The second step is the generation of hourly solar radiation for a calendar year from the daily values generated in the first step.

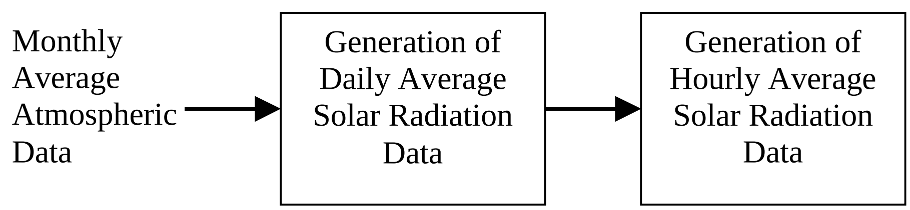


Figure 3.6: Basic steps involved in WATGEN

Each step involves the calculation of the clearness index, the ratio of the global radiation on a horizontal surface to the extraterrestrial radiation on a horizontal surface [78] as shown in Equation (3.8).

$$K_t = \frac{H_t}{H_0} \tag{3.8}$$

where H_t - global radiation on a horizontal surface

H_0 - extraterrestrial radiation on a horizontal surface

The program uses the clearness index instead of the radiation variable itself since the latter is location dependent. The major procedures in the program for generating synthetic hourly radiation are shown in Figure 3.7.

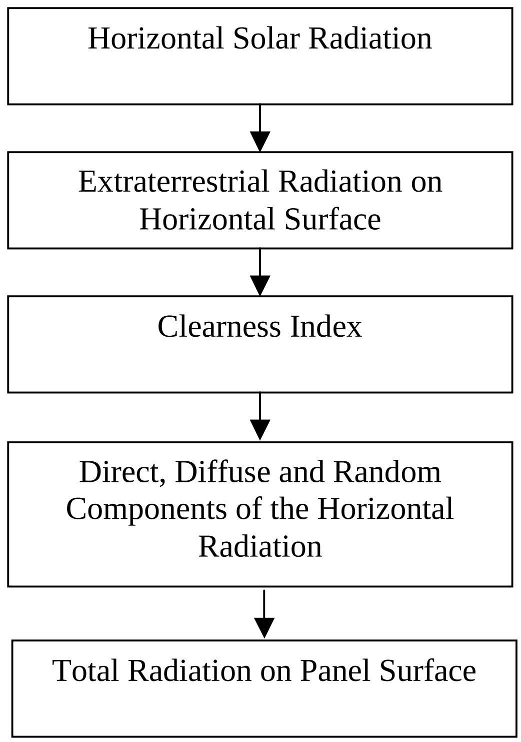


Figure 3.7: Diagram of the solar radiation calculation

The procedures in Figure 3.7 can be briefly described as follows:

1. Calculate the radiation at the horizontal surface based on the day of the year and the site latitude and then establish a clearness index.
2. The clearness index is then used to calculate the direct, diffuse and random components of the radiation on a horizontal surface.
3. The total radiation is then calculated from the direct, diffuse and random values.

4. Finally the radiation on the surface of the panel is determined.

WATGEN [83] requires monthly average meteorological data at a specific site location as its input for the simulation of the solar radiation process at that site. The necessary data is the monthly average values of solar radiation on the horizontal surface, the wind speed and the ambient temperature. The data for two different sites in Canada have been used in the studies described in this thesis. The monthly average data for the two sites are shown in Tables 3.2 and 3.3 respectively.

Table 3.2: Monthly average weather data at Swift Current (50.3 degree north)

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Wind Speed (km/h)	24	23	22	22	22	21	18	18	20	22	22	24
Temperature (^oC)	-13.	-9.6	-4.0	4.3	10.8	15.6	18.3	17.6	11.4	5.5	-4.0	-10.8
Radiation (MW/m^2)	4.95	8.58	13.6	18.0	21.3	23.4	24.2	20.2	14.0	9.3	5.2	3.8

Table 3.3: Monthly average weather data at Toronto (43.4 degree north)

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Wind Speed (km/h)	23.8	23.4	22.3	20.9	16.9	14.8	13.3	13.7	15.5	16.2	20.9	23.4
Temperature (^oC)	-3	-3	0	6	12	17	18	17	15	10	4	-1
Radiation (MW/m^2)	5.2	8.2	12	16.1	19.8	21.9	21.9	18.7	14	9.2	4.8	3.9

The simulated hourly total solar radiation on a horizontal surface for a mostly clear summer day, a partly cloudy summer day and a whole year using the data from the Swift Current site are shown in Figures 3.8 to 3.10 respectively. These figures show that the results obtained from the program are physically reasonable and can reflect the chronological and random characteristics of the solar radiation process.

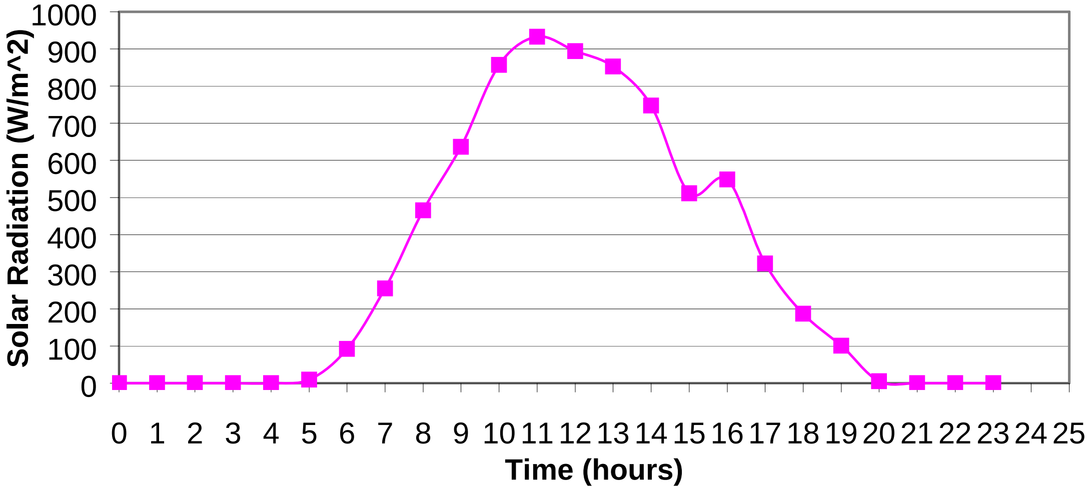


Figure 3.8: Simulated total solar radiation on a horizontal surface for a mostly sunny July day in a sample year (Swift Current data)

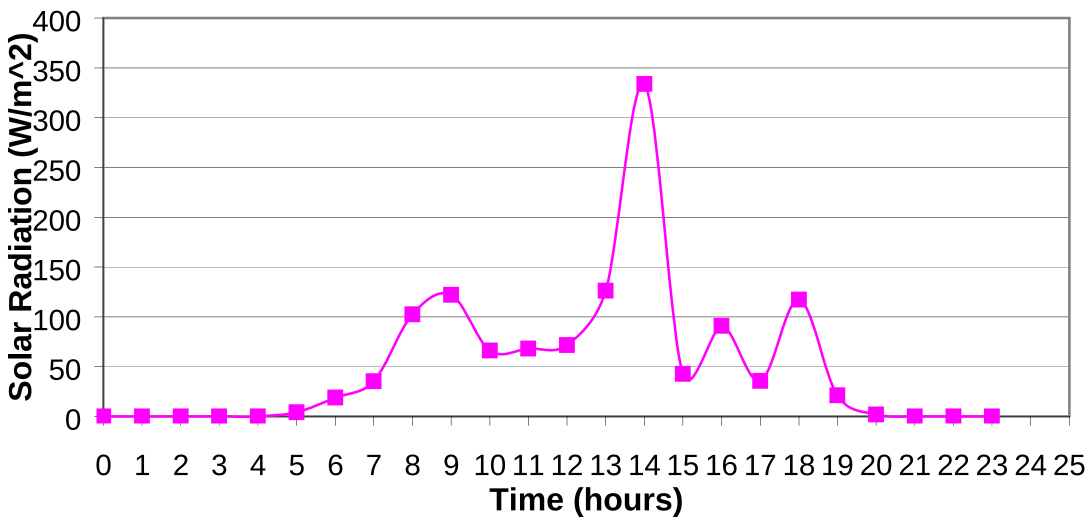


Figure 3.9: Simulated total solar radiation on a horizontal surface for a partly sunny and partly cloudy July day in a sample year (Swift Current data)

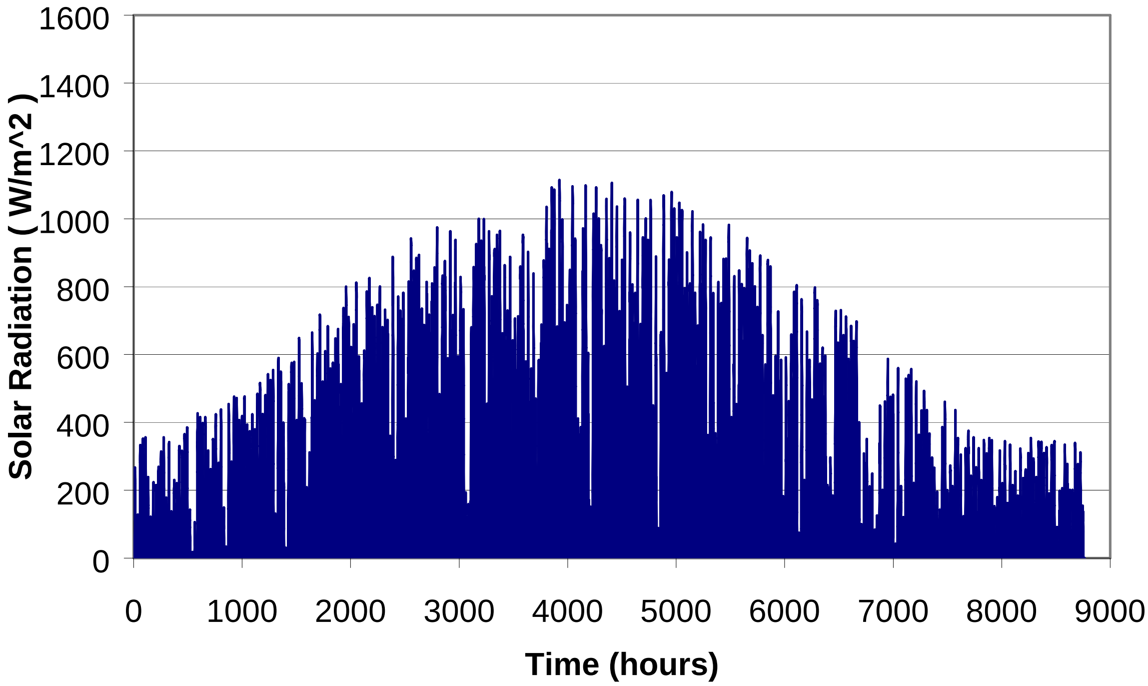


Figure 3.10: Simulated total solar radiation on a horizontal surface for a sample year (Swift Current data)

The radiation on a sunny day for a specific site located in the northern hemisphere is usually highest at noon and there is no radiation or very little radiation during the nighttime. This can be seen from Figure 3.8 for the Swift Current site, which is located at latitude 50.3 degrees north. Figure 3.9 shows that the radiation is variable if there is cloud during the daytime. Random cloud cover is an important factor, which affects the electric power output of a PV unit. WATGEN [83] can recognize and successfully incorporate this randomness and thus it mimics the actual process. Figure 3.10 shows the simulated annual variation pattern of the hourly radiation at the Swift Current site. The hourly solar radiation is highest during the summer months in the middle of the year, and it is lowest during the winter months at the beginning and end of the year. This is the most common weather pattern for locations north of the equator. Similar observations were found for the Toronto site.

3.2.2.2 Available Solar Energy

As noted earlier in this chapter, solar cells are the basic components used to produce electricity from sunlight. Solar cells are basically large area semiconductor junction devices. The light is converted to electricity within these junctions by the “photovoltaic effect”. The whole technology of converting light to electricity and using the generated power to supply various load demand is known as photovoltaics. In this thesis, the term PV, PVCS or solar energy based system is used to designate those systems that convert the energy from the sun to supply electricity through the ‘photovoltaic effect’ unless otherwise specified.

The hourly output of a PV panel can be calculated using the method adopted by the Watsun Simulation Laboratory [84]. It calculates the total irradiation incident on the solar panel and estimates the output power from the panel using an iterative method. An initial panel power P_0 can be estimated under reference values of voltage V_r, current I_r and insolation H_{Tr} level using Equation (3.9):

$$P_0 = \frac{V_r I_r}{H_{Tr} A} H_T \tag{3.9}$$

Where A is the panel area and H_T is the solar insolation at a particular hour.

The estimated initial power P_0 is used to obtain the individual solar cell temperature using a cell thermo-dynamic model [84]. The output power of a solar cell is usually evaluated from the cell’s current-voltage relationship. These characteristics are described by the voltage and current relationship of the cell and normally represented by a family of curves known as I-V curves. The I-V curve of a solar panel can be obtained from the I-V curves of the individual cells in the panel. A panel I-V curve can be constructed for the estimated insolation level and the panel temperature for the particular hour based on panel specifications. The largest rectangle that fits under the panel I-V curve will touch the curve at the maximum power point (MPP) as shown in Figure 3.11.

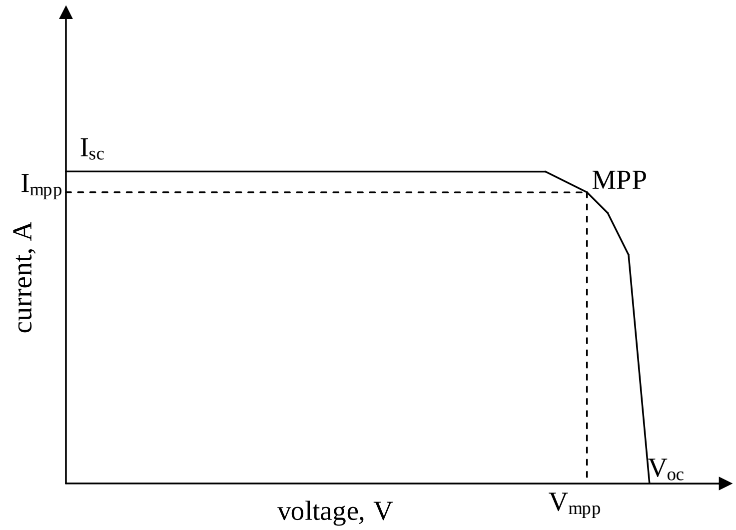


Figure 3.11: PV panel I-V curve

The maximum power can be calculated from the panel I-V curve using Equation (3.10):

$$P_{mpp} = P_r \frac{V_{oc} I_{sc}}{V_{ocr} I_{scr}}_T \tag{3.10}$$

Where P_{mpp} and P_r are the maximum and reference panel power and V_{ocr} and I_{scr} are the reference open circuit voltage and short circuit current of the panel. The necessary parameters defining the current-voltage relationship of a CANROM30 solar panel are provided in Appendix B. These data are used in all of the PV related analyses in this thesis.

The panel power calculated from Equation (3.10) further affects the panel temperature. The final solar panel steady output power can be obtained by iterative calculation of the panel power and the temperature. This model uses simulated hourly solar radiation and a necessary set of cell specifications from the manufacturers as its input to calculate the hourly power output of the panel. This panel output model has been utilized to calculate the power output of a PV generating unit in the relevant studies in this thesis. The hourly power output of a PV unit can be calculated from the I-V curves of the PV generating units using the simulated hourly solar radiation data. The simulated power output of a 30 kW_p PV array for a week in summer using data from Swift Current is shown in Figure 3.12.

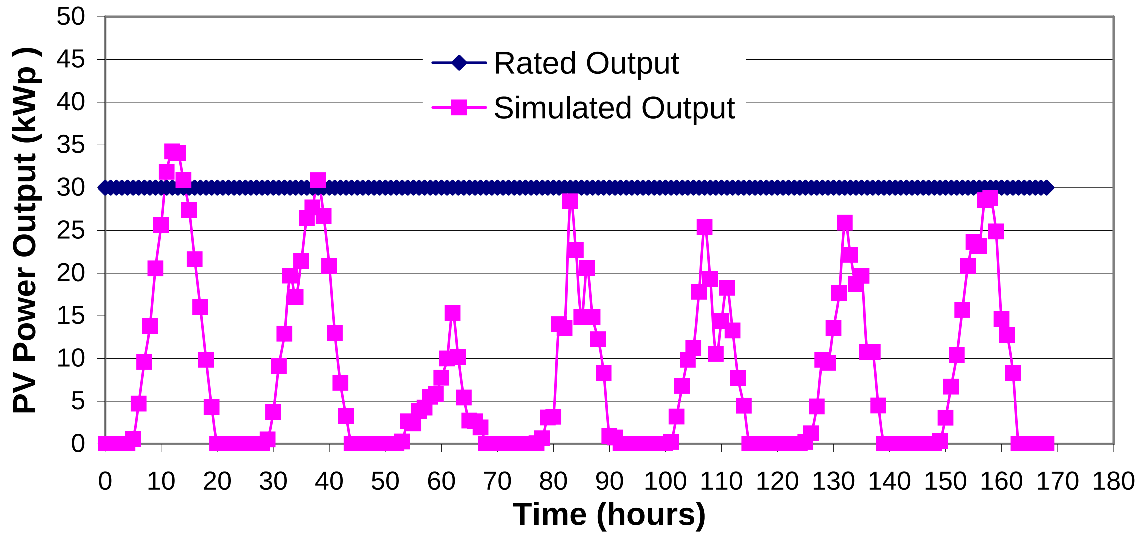


Figure 3.12: Simulated output power of a 30 kW_p PV array for a July week in a sample year (Swift Current data)

The power output of the PV array is mostly between 0 and 30 kW_p. A solar array can, however, generate more power than its rated value on some occasions [85]. Figure 3.12 shows that since the simulated week is mostly sunny, the power output of the generator exceeds or reaches its rated power at noon on the first, second, fourth and last days of the week. The electric power output of the PV unit is zero during nighttime. This is due to there being either no sunlight or the unit is on forced outage. A PV array FOR of 0.05 was used in the simulation.

A generating unit is assumed to be composed of a number of identical cells and panels in this thesis. A more complicated analysis, which is beyond the scope of this thesis, is required if the cells or panels are not identical. Wiring losses and inverter losses are not considered in this research.

3.3 Generating Unit Forced Unavailability

In generating systems based on wind and solar energy, the availabilities of site resources are important factors in capacity adequacy studies. Unlike conventional generating units, all units may not generate energy even when the units are in the up states due to limitations in the source energy. It has been shown in the previous discussions that it is possible to perform a detailed treatment of unit energy limitations utilizing time series analyses. In addition to energy limitations, generating units may fail to produce energy due to mechanical and electrical malfunction of the units. This can be included in the analyses using the concept of forced outage rate as described in Chapter 2.

Generally, the reliability of a generation system is strongly influenced by the forced outage rate of the generating units. Accurate data in the form of FOR, MTTF and MTTR values can be used to conduct valid evaluations of the system under consideration. These data are, however, not often available for WTG and PV generating units. In the studies described in this thesis, WTG or PV array failure and repair characteristics are simulated in a similar manner to those of conventional units. The sequential up-down-up or up-derated-down-up cycles of a generating unit are then combined with the hourly available power derived from the generators to obtain the final hourly available power output.

3.4 Load Models

The IEEE Reliability Test System (IEEE-RTS) [86] contains a very useful load model and procedure for generating hourly load levels. This procedure can be used to produce system hourly loads for a year on a per unit basis, expressed in a chronological fashion so that daily, weekly and seasonal patterns can be developed (reference to Appendix C). This process is described in the following steps.

1. Develop a 24-hour daily load curve as a percentage of the daily peak load.

2. Develop a 7-day weekly load curve as a percentage of the weekly peak load.
3. Develop a 52-week load curve as a percentage of the yearly peak load.
4. Determine the load $L(t)$ for hour t using equation (3.11).

$$L(t) = L_y \times P_w \times P_d \times P_h(t) \tag{3.11}$$

Where L_y is the annual peak load, P_w is the percentage of weekly load in terms of the annual peak, P_d is the percentage of daily load in terms of the weekly peak and $P_h(t)$ is the percentage of hourly load in terms of the daily peak. Once the annual peak load, weekly percentage, daily percentage and 24-hour load profile are determined, the annual hourly load curve can be developed from Equation (3.11). The IEEE-RTS model has been used in most of the simulation analyses in this research. Other load models such as constant load and time varying residential load models are also utilized as necessary in some comparative analyses.

3.5 Energy Storage Model

The output of a WTG or a PV array is intermittent, and wind and sunlight are not always available when there are power demands. Therefore energy storage facilities are useful additions in power systems using wind and solar energy, especially in small stand-alone applications. The present and future energy storage technologies that may be used in electric power systems includes, but are not limited to, flywheels, compressed air, superconducting coils and storage batteries. The most commonly used energy storage facilities in SIPS are deep cycle lead-acid batteries similar to car batteries.

The operating strategy of an energy storage element is that whenever the generation exceeds the load, the excess energy is stored and used whenever there is a generation shortage. The maximum charging and discharging rate of the energy storage determines the maximum energy stored and supplied from the energy storage at a specific time point. The energy storage state time series can be obtained from the load time series and the renewable energy generation time series taking into consideration the charging and discharging characteristics of the energy storage element. In the simulation, the energy storage state time series is calculated using the following steps:

1. Determine the surplus generation (it can be either a positive or a negative value) time series { $SG_t;\quad t=1,2,......,T$ } from the load time series { $L_t;\quad t=1,2,......,T$ } and the generation time series { $TG_t;\quad t=1,2,......,T$ } using Equation (3.12).

$$SG_t = TG_t - L_t \tag{3.12}$$

2. Compute the energy storage state time series { $ES_t\quad t=1,2,......,T$ } using Equation (3.13) [16].

$$ES_{t+1} = \begin{cases} ES_m & ES_t + SG_t \le ES_m \\ ES_t + SG_t & ES_m < ES_t + SG_t \le ES_M \\ ES_M & ES_M < ES_t + SG_t \end{cases} \tag{3.13}$$

Where ES_m and ES_M are the minimum and maximum allowable storage levels of the energy storage element.

3.6 Basic Reliability Evaluation Model for Generating Systems Containing Wind Energy, Solar Energy and Energy Storage

Generating capacity adequacy assessment of a power system using wind energy, solar energy and energy storage follows the general procedure shown in Figure 2.2. A typical system considered in this thesis is normally composed of conventional generating units such as diesel generators, non-conventional generating units such as WTG, PV arrays and energy storage. The overall generating system is categorized into the three sub-systems of conventional units, WTG and PV arrays. The modeling techniques described in the previous subsections of this chapter can be applied to individual generating subsystems to obtain the generation model for each generating subsystem. The generating model for an overall system can be constructed from those of the subsystems. An energy storage model can be incorporated in the evaluation based on the load and the total generation. A general adequacy evaluation model for a power system using wind energy, solar energy and energy storage is shown in Figure 3.13. The desired reliability indices can be computed using this model by combining the load with the generation and the state of energy storage. The basic reliability indices of LOLE and LOEE are used in this research to assess the system adequacy.

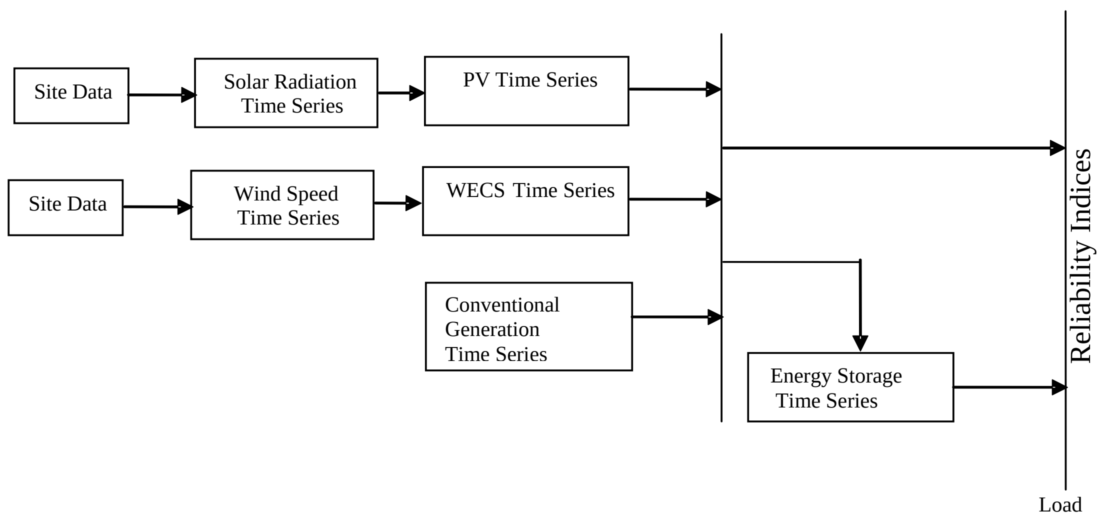


Figure 3.13: Overall system reliability evaluation model

In an analytical evaluation, each generating unit can be represented by a multi-state unit. The system generation can be represented by a COPT, which can be constructed from either historical site data or from a sequential simulation using a time series model. This form of capacity model does not retain any of the chronological characteristics of wind speed and solar radiation. The DPLVC or the LDC described in Chapter 2, although very useful in a wide range of studies, do not contain any chronological information. This deficiency can introduce significant errors in the reliability evaluation of power systems containing wind energy and solar energy. The inclusion of energy storage also complicates the problem considerably. These factors can be incorporated in the analysis using a time sequential Monte Carlo simulation approach as described in

Chapter 2. In a sequential Monte Carlo simulation, the system capacity model is the system available capacity at points in time established sequentially and the load model is represented by a chronological hourly load profile. The detailed simulation techniques and their application in reliability analyses for power system containing wind, solar energy and energy storage are discussed in the following chapters.

3.7 Indices Associated with Reliability and Cost/Worth Evaluation of Generating Systems Containing Wind Energy, Solar Energy and Energy Storage

Different types of system indices that reflect the specific aspects influencing the overall system reliability performance and economics have been utilized through the studies described in this thesis. These indices can be grouped into following categories.

1. Conventional risk indices

The conventional risk indices are the most widely used indices in power system reliability evaluation especially in the generating capacity adequacy evaluation of large conventional electrical utility systems. These indices are very useful in capacity adequacy planning and most common used indices are:

Loss of load expectation (LOLE) h/ year
Loss of energy expectation (LOEE) kWh or MWh/ year
Expected Loss of load duration (ELOLD) h/year
Expected Loss of load frequency (ELOLF) occ/ year

2. Well-being indices

As noted in Chapter 2, the system well-being analysis incorporates deterministic criterion into a probabilistic evaluation. The number of autonomous hours (NAH) or the number of autonomous days (NAD) [87-89] for energy storage is used as the accepted deterministic criterion in this research project. The basic indices are:

Loss of health Expectation (LOHE) h/ year

Healthy state probability (HSP)

Marginal state probability (MSP)

Loss of load probability (LOLP)

3. Indices associated with renewable energy generation and energy storage

The following indices are new indices related to reliability and economic evaluation of the renewable energy sources and the energy storage system:

Expected available wind energy (EAWE) kWh/yr: Expected amount of energy that would be generated by the WECS in a year, if there were no wind turbine generator outages.

Expected generated wind energy (EGWE) kWh/yr: Expected amount of energy that would be generated in a year by the existing wind turbine generators in the system considering their outages.

Expected available solar energy (EASE) kWh/yr: Expected amount of energy that would be generated by the PVCS in a year, if there were no solar generating units outages.

Expected generated solar energy (EGSE) kWh/yr: Expected amount of energy that would be generated in a year by the existing PVCS considering their outages.

Expected energy supply by the storage facility (EESBSF) kWh/ year: Expected amount of energy that would be supplied by the energy storage in a year.

Expected discharging frequency of the storage facility (EDFOSF) occ/ year: Expected number of discharging of the energy storage in a year.

4. Indices related to diesel unit operation

The following indices are new indices related to reliability and economic evaluation of the diesel unit operating strategies.

Expected number of start/stop cycle (ENSSC) occ/ year: Expected number of starts/stops of the diesel unit when the unit is operating intermittently.

Expected running time (ERT) h/ year: Expected hours of running time of the diesel unit when the unit is operating intermittently.

5. Economic Indices:

Customer interruption cost (CIC) $/ year
Utility cost (UC) $/ year
Total cost (TC) $/ year

3.8 Summary

The basic models for generating capacity adequacy evaluation of power systems using wind energy, solar energy and energy storage are presented in this chapter. The models are based on a sequential Monte Carlo simulation technique that can be used to generate an artificial history of a particular generating system.

The random weather-related site resources, the operating parameters of the generating unit and the equipment reliability are the major factors in reliability analyses of power systems using wind energy, solar energy and energy storage. A time series method can be used to simulate wind speeds incorporating any necessary chronological correlations. The power available from a wind turbine generator can be calculated from the simulated wind speed using a function describing the relationship between the wind speed and output power. A widely used computer program, called WATGEN was utilized to simulate solar radiation levels. The generated power of a photovoltaic generating unit was obtained based on the voltage-current characteristics of the generating unit using the simulated solar radiation data generated by the program. The characteristics of the wind and solar energy as well as some major aspects of the technology are briefly described in this chapter.

Wind and photovoltaics are intermittent sources of power and cannot meet the load demand all of the time. Energy storage, therefore, is a desired feature to complement these unconventional generating sources, particularly in small stand-alone applications. A time series energy storage model was developed based on the generation time series and the load time series models. A basic adequacy evaluation model is described in this chapter using the generation, load and energy storage models. The system reliability indices can be evaluated by suitably combining the three models. This procedure is illustrated in the following chapters.

4. UTILIZATION OF THE BASIC EVALUATION MODELS IN SMALL ISOLATED SYSTEM RELIABILITY STUDIES

4.1 Introduction

The basic models for generating capacity adequacy evaluation of power systems containing wind energy, solar energy and energy storage are discussed in Chapter 3. This chapter presents some applications of the developed models and methodologies in small isolated power system adequacy studies using sequential Monte Carlo simulation. These models are applied to hypothetical example systems to investigate the adequacy of SIPS using the mean values of reliability indices. The relative benefits obtained from various system configurations with different energy compositions and energy storage capabilities are examined using the estimated adequacy indices produced from the sequential simulation.

The performance of SIPS containing renewable energy sources and energy storage facilities is quite different from that of systems containing only conventional generating units [90-94]. This is due to the dispersed nature of the resource energy at the specific site location. In order to appreciate the impact of the major parameters that characterize SIPS adequacy, the simulation models and techniques described previously have been utilized to carry out a wide range of sensitivity analyses. These parameters include energy storage capacity, wind speed, solar radiation level, system peak load and load profile, generating unit FOR and total installed capacity. The effects on the system adequacy have been analyzed mainly in terms of their impact on the LOLE index. A wide range of indices could be used for comparison purposes if desired.

4.2 Basic Case Studies

The described simulation procedure has been used to perform a range of adequacy studies on hypothetical systems using data from different site locations in Canada. The generating unit ratings for different study system configurations are presented in Table 4.1. The reliability data associated with the systems shown in Table 4.1 are presented in Table 4.2. The hourly chronological load shape of the IEEE-RTS [86] has been used in the hypothetical systems with a peak load of 40 kW in most of the analyses described in this chapter. The system is assumed to be located at a geographic location with atmospheric conditions that can be represented by the Swift Current solar radiation data and the Regina wind speed data unless otherwise specifically stated. It is assumed that the WTG have operating parameters of cut-in, rated and cut-out wind speeds of 12 km/h, 38 km/h and 80 km/h respectively. An energy storage charging (discharging) rate of 60 kWh/h is applied in these studies.

Table 4.1: Generating unit rating and system configurations

Case	Type of generation and/or storage	Number of generators and/or storage	Rating of generators and/or storage
1	Diesel (D) Solar (PV)	2 2	20 kW 30 kW_p
2	Diesel (D) Wind (W) Solar (PV)	2 1 1	20 kW 30 kW 30 kW_p
3	Diesel (D) Wind (W)	2 2	20 kW 30 kW
4	Diesel (D) Solar (PV) Storage (S)	2 2 1	20 kW 30 kW_p 300 kWh
5	Diesel (D) Wind (W) Solar (PV) Storage (S)	2 1 1 1	20 kW 30 kW 30 kW_p 300 kWh
6	Diesel (D) Wind (W) Storage (S)	2 2 1	20 kW 30 kW 300 kWh

Table 4.2: Reliability data for the system configurations presented in Table 4.1

Case	Type of generation and/or storage	FOR (%)	Failure rate per year	MTTF (hour)	MTTR (hour)
1	Diesel (D) Solar (PV)	5 3	9.2 3	950 2910	50 90
2	Diesel (D) Wind (W) Solar (PV)	5 4 3	9.2 4.6 3	950 1920 2910	50 80 90
3	Diesel (D) Wind (W)	5 4	9.2 4.6	950 1920	50 80
4	Diesel (D) Solar (PV) Storage (S)	5 3 x	9.2 3 x	950 2910 x	50 90 x
5	Diesel (D) Wind (W) Solar (PV) Storage (S)	5 4 3 x	9.2 4.6 3 x	950 1920 2910 x	50 80 90 x
6	Diesel (D) Wind (W) Storage (S)	5 4 x	9.2 4.6 x	950 1920 x	50 80 x

A comparison of the system adequacy in terms of the LOLE for the cases in Table 4.1 is shown in Figure 4.1. It can be seen from this figure that the level of system reliability is different in each case. A comparison of the adequacy benefits of using unconventional energy sources such as wind and solar energy depends largely on the site resources where the system is installed. In these studies, WTG provide better system adequacy than PV arrays. This could be due to the reason that PV arrays generate no energy or little energy during the night. When both PV arrays and WTG are used, the adequacy benefit is generally between that of PV and WTG.

SIPS are usually designed to supply electricity demand in remote areas. Although system adequacy can be improved considerably by installing more conventional generation to SIPS, it is usually economically unjustifiable because of the relatively high fuel cost in these areas. It is therefore necessary to limit the use of conventional generation to some extent in small isolated applications. It can be observed from Figure 4.1 that even though the installed capacity is considerably in excess of the system peak load when unconventional sources are utilized in parallel with small amounts of conventional generation, the LOLE are unacceptably high with no energy storage, as in Cases 1, 2, and 3. These values are reduced considerably with the storage capabilities shown in Cases 4, 5, and 6. The generating system adequacy in Cases 4, 5, and 6 could be considered to be reasonable in a SIPS. Additional system indices for these cases are presented in Table 4.3. The results shown constitute a reference set of adequacy indices for the example systems considered in this chapter. The effects of varying a number of generating unit and system parameters are presented in the following sections using Cases 4, 5 and 6 as the basic example system configurations.

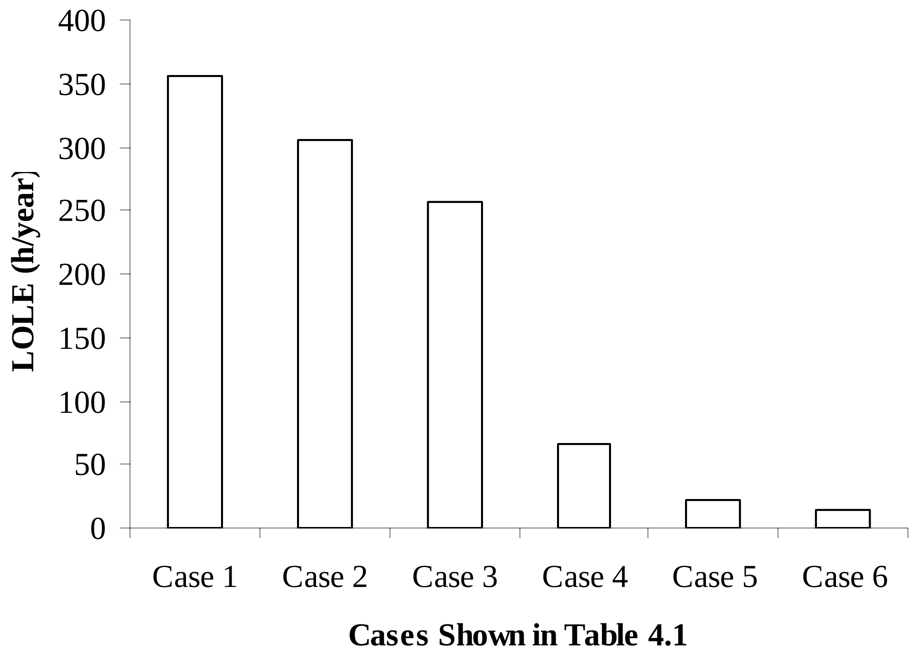


Figure 4.1: LOLE for the different system configurations shown in Table 4.1

Table 4.3: Additional reliability indices for Cases 4, 5 and 6.

Case	LOLE (h/yr)	LOEE (kWh/yr)	ELOLD (h/yr)	ELOLF (occ/yr)	EESBSF (kWh/yr)	EDFOSF (occ/yr)
4	65.85	639.62	15.97	4.12	1710.55	50.98
5	21.39	256.26	11.50	1.86	1363.43	51.49
6	14.33	175.63	8.98	1.60	1803.65	59.36

4.3 Effect of Selected Parameters on System Reliability

4.3.1 Effect of Energy Storage Capacity

As noted earlier, the available energy from wind and sunlight is intermittent and variable. In order to use these energy sources as viable power generation, energy storage is incorporated in many applications in order to match the power supply with the instantaneous power demand. Energy storage capability is a very significant component in power systems utilizing wind and/or solar energy especially in small isolated applications. It can be seen from the base case study that the presence of an energy storage device can significantly enhance the reliability of a SIPS.

The rated capacity of the energy storage is an important parameter and indicates the ability of the energy storage to deliver energy to the system. It can be expressed in the form of either ampere-hours (Ah) or watt-hours (Wh). The ampere-hour capacity is the product of the current in amperes (A) and the delivery time in hours (h). The product of the average discharge voltage and the ampere-hour capacity gives the watt-hour capacity of an energy storage system.

In order to appreciate the impact of energy storage capacity on the adequacy of SIPS, the three basic system configurations with different size storage facilities were investigated. The corresponding LOLE were determined as a function of the energy storage capacity. Figure 4.2 shows the LOLE as a function of energy storage capacity ranging from 0 to 600 kWh for the three basic system configurations. It can be clearly seen from this figure that the addition of energy storage capability significantly improves the reliability of a SIPS regardless of the type of energy sources installed in the system. The studies conducted show that minimal incremental benefit is obtained if the capacity of the energy storage exceeds a certain value (in this case it is approximately 400 kWh). It is, therefore impractical to try to improve the reliability of a SIPS by providing additional energy storage capacity to the system without considering the impact of the site resources. In order to further illustrate this effect, the expected energy supplied by the storage facility (EESBSF) is shown in Figure 4.3 as a function of the energy storage capacity for the three basic configurations. It can be seen from Figure 4.3 that the increment in EESBSF decreases when the energy storage capacity exceeds 400 kWh.

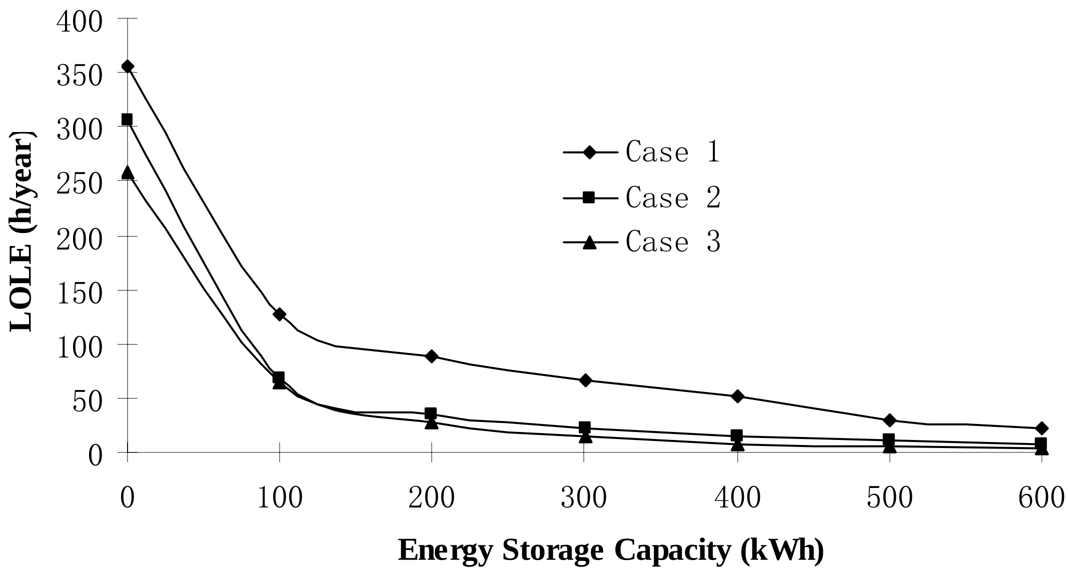


Figure 4.2: Effect of energy storage capacity on the LOLE

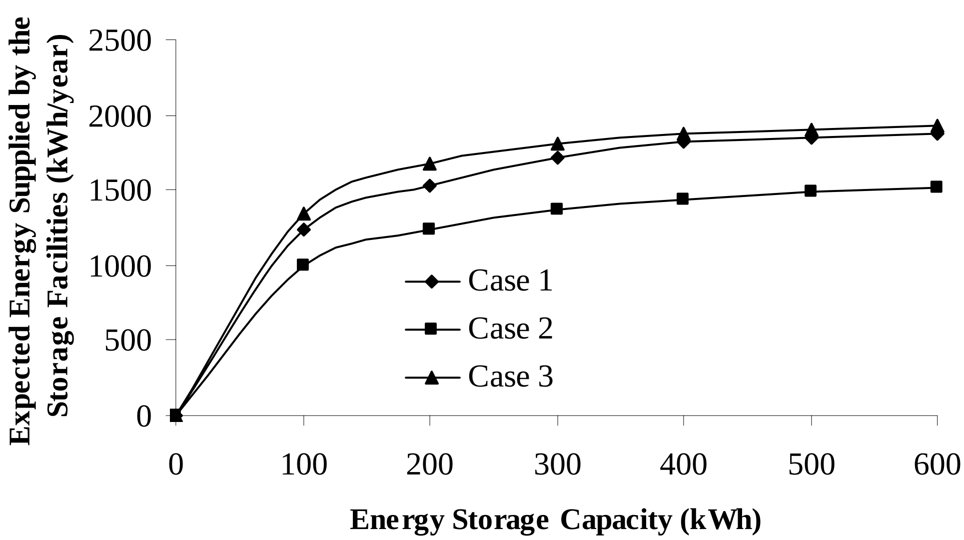


Figure 4.3: Effect of energy storage capacity on the EESBSF

4.3.2 System Load Considerations

The system load is an important factor in the reliability analysis of a generating system. Both the load profile and the annual peak impact the system reliability performance. These effects have been considered and the results are shown in Figures 4.4 to 4.6.

The risks for the three basic configurations for three different load profiles are illustrated in Figure 4.4. The LOLE of the system is lowest for the residential load model [55]. When the IEEE-RTS load model [86] is used, the LOLE is higher than the value obtained for the residential load profile. The IEEE-RTS load model is a composite load variation pattern incorporating different customer load characteristics. This load model is used in all of the other studies described in this thesis. A constant load at the peak value results in the highest risk, as expected.

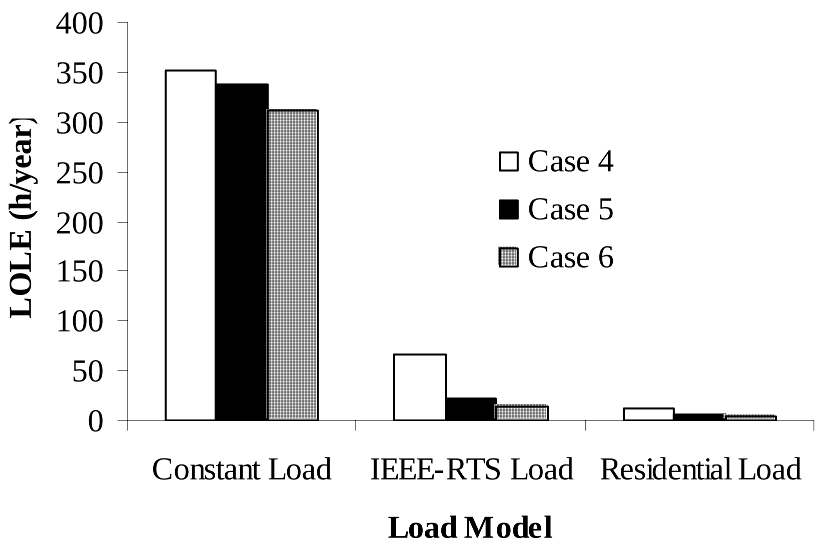


Figure 4.4: Effect of different load models on the LOLE

Figures 4.5 and 4.6 show the LOLE and ELOLF for the three basic system configurations as functions of the annual peak load respectively. The peak load is varied from 40 kW to 70 kW with equal steps of 5 kW while maintaining the basic shape of the load curve.

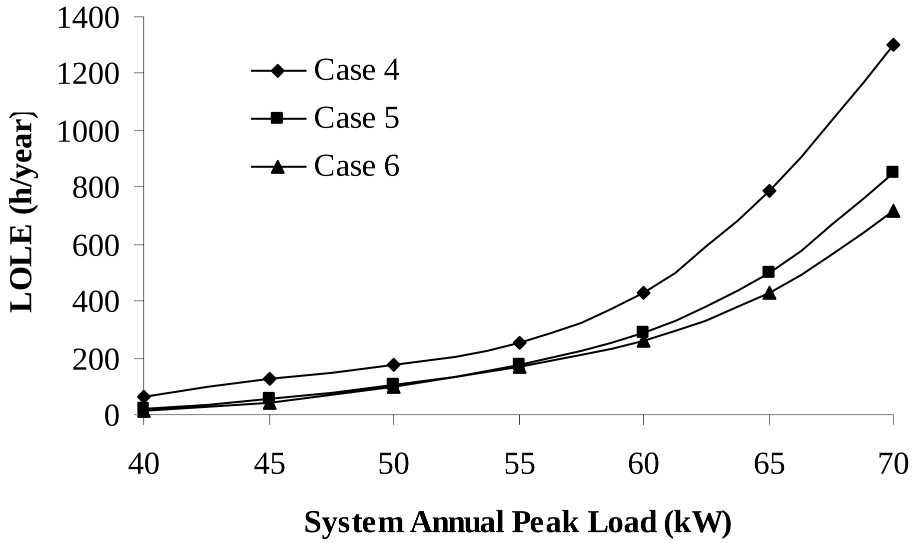


Figure 4.5: Effect of the annual peak load on the LOLE

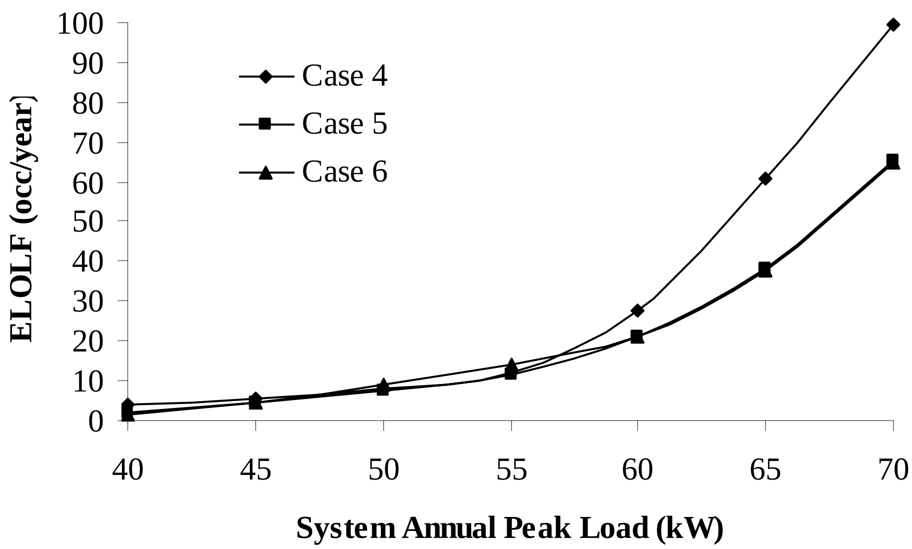


Figure 4.6: Effect of the annual peak load on the ELOLF

It can be seen from Figure 4.5 that the system risk increases with peak load in all the cases but not to the same degree. The LOLE increases almost linearly with the annual peak load when the annual peak load is under a certain value. When the peak load exceeds this value, the index increases sharply. Figure 4.6 shows that the system peak load has a significant impact on the number of interruptions per year. It can be seen from Figures 4.5 and 4.6 that system reliability performance is very sensitive to load growth. In such case, additional generating unit and/or energy storage are required to meet anticipated load growth.

4.3.3 Effect of Renewable Energy Penetration Level

Studies have been carried out to investigate the effects on the system adequacy of renewable energy penetration levels. The LOLE has been computed for situations in which the wind and the solar units are removed from Case 5 and the system is expanded using an equal step increase in wind and solar generation respectively with the other system parameters unchanged. The wind and solar capacity added in each step are 20 kW.

Figure 4.7 shows the LOLE as functions of the wind and solar capacity added to the system. The LOLE decreases with increase in the renewable energy penetration level. The reliability benefit, however, decreases with further penetration of wind and solar energy and reaches a point when no reliability improvement can be obtained by increasing the renewable energy penetration level.

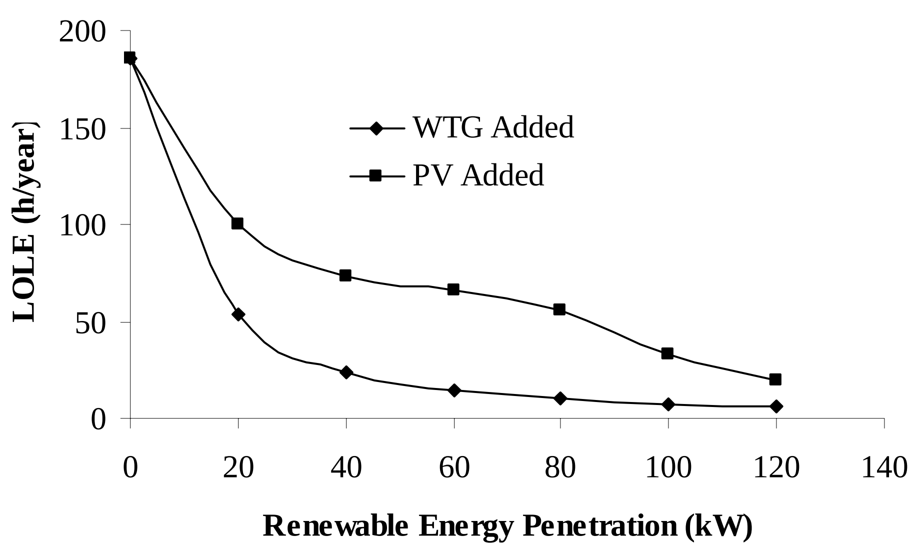


Figure 4.7: Effect of the renewable energy penetration level on the LOLE

It should be noted that the relative benefit from renewable energy sources depends on many variables. These include, but are not limited to, the weather characteristics at the site location, the chronological load pattern, the peak load and the energy storage capacity. It is, therefore, difficult to determine an optimum level of penetration for a given SIPS in a general sense.

The reliability benefit obtained from increased penetration of renewable energy sources is due to the increased available and generated energy that can be utilized by the system. Figure 4.8 illustrates the EAWE, EGWE, EASE and EGSE as functions of the wind and solar capacity added to the system. It can be seen that these expected values increase almost linearly with the penetration level. There is no significant difference between the available and generated energy in both the WTG and PV cases. This observation indicates that the generating unit FOR have very little impact on the system reliability performance. The effects of generating unit FOR of different energy sources are discussed in the following section.

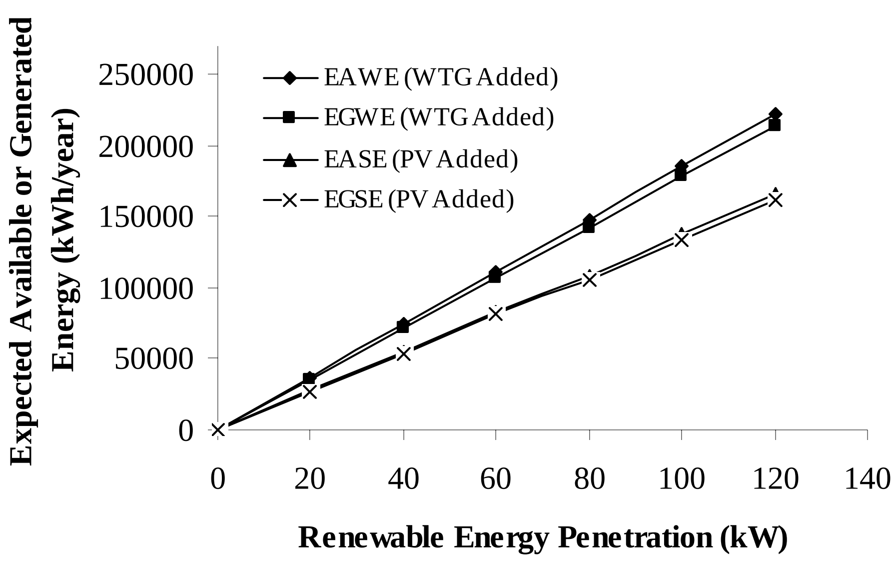


Figure 4.8: Effect of the renewable energy penetration level on the available and generated energy from the WTG and PV

4.3.4 Effect of Generating Unit FOR

Unscheduled outages of generating units normally have a strong impact on the reliability of a power system. Unscheduled outages of conventional units are normally associated with equipment failures. These random outages are incorporated in conventional power system reliability assessment using the FOR concept. The method and practice for obtaining data in the form of MTTF, MTTR, failure rate and repair rate are well established in conventional power systems and historical records are available for various conventional generating units and sizes. This is not the case for renewable energy sources. A WTG or a PV array can encounter unscheduled outages due to component failures, site resource deficiencies or both. Site resource deficiencies may be due to insulation levels at night, random cloud cover and wind speed variability. These effects can be incorporated in the overall evaluation model and the simulation methodology described previously. In order to illustrate the FOR effects of different types of energy generating units on SIPS adequacy, the FOR of WTG, PV array and diesel unit are varied from 2% to 10% with equal steps of 0.02 in Cases 4 and 6. The system LOLE is compared for the following scenarios.

1. Changing all the diesel units FOR from 2% to 10% keeping the PV units FOR unchanged for Case 4.
2. Changing all the PV units FOR from 2% to 10% keeping the diesel units FOR unchanged for Case 4.
3. Changing all the diesel units FOR from 2% to 10% keeping the WTG units FOR unchanged for Case 6.
4. Changing all the WTG units FOR from 2% to 10% keeping the diesel units FOR unchanged for Case 6.

Figure 4.9 shows the influence of the FOR on the LOLE for the cases listed above. It can be seen that the system LOLE increases significantly as the FOR of the diesel unit increases. On the contrary, the changes in FOR of the unconventional units have much less influence on the system LOLE. The reason is that the inherent energy limited nature of the unconventional unit will offset the effect of the FOR on the system reliability performance. The energy availability of a renewable source is largely dictated by the available site resources. The fluctuating site resources mask the effect of expected failures and repairs of the unconventional units and hence minimize the effect of unit FOR.

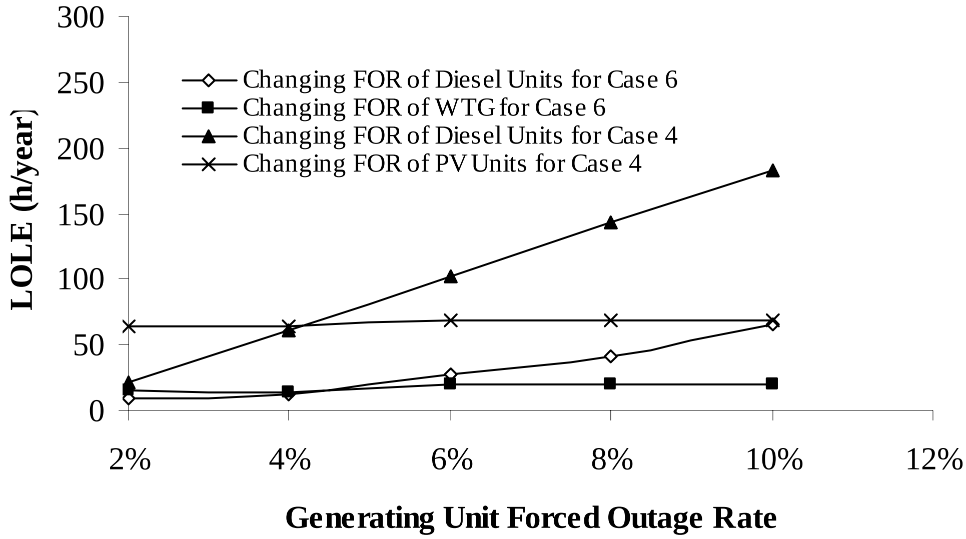


Figure 4.9: Effect of the generating unit FOR on the LOLE

4.3.5 Effect of Geographic Location

The power and energy outputs of a SIPS depend strongly on the site resources such as wind and sunlight. Generally, the weather characteristics associated with site resources very with different geographic locations. Any type of reliability or economic analysis in SIPS planning requires the necessary resource data at the selected location. A major deficiency in analyzing the full potential of renewable energy for small remote communities is the lack of detailed databases accurately defining the long-term variations in site resource availability. In such cases, approximate time series analyses and stochastic simulation methods can be used to estimate the system performance. The impact of the weather patterns on SIPS reliability have been studied by comparing the same system at different geographic locations.

The described simulation method has been used to perform adequacy studies on an integrated wind-diesel system using wind data from three different sites located in Saskatchewan, Canada. The average wind speed and the standard deviation for each site are shown in Table 3.1. Figure 4.10 shows the system risk for Case 6 with the wind characteristics represented by these three locations. The Regina site has the highest average wind speed and as expected, the adequacy at this location is better than that of systems located at the other two sites. The wind data from the Regina site is, therefore used in all of the other studies related to wind energy conversion systems described in this chapter.

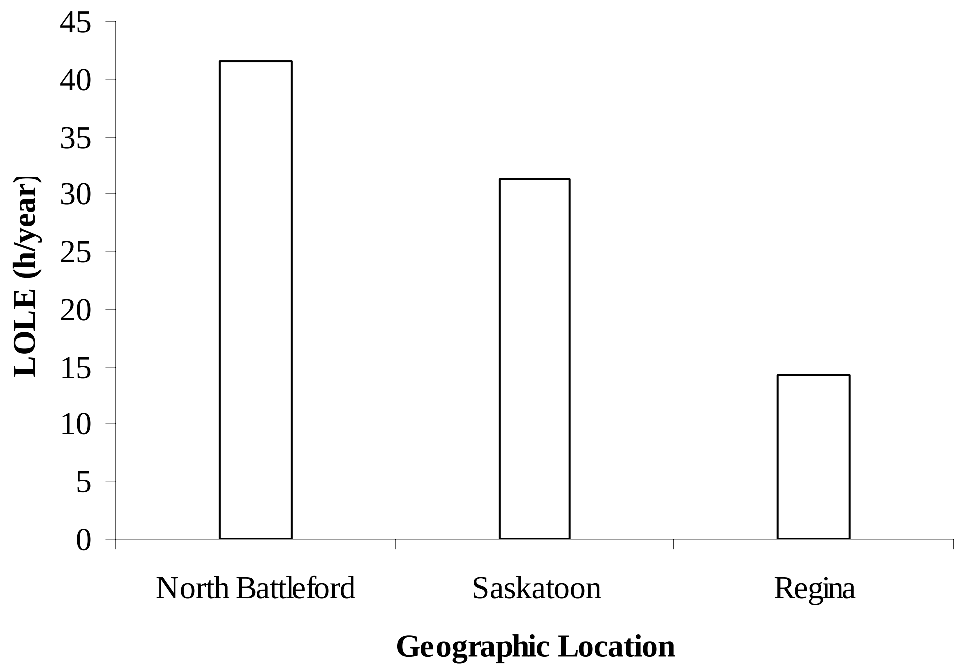


Figure 4.10: System LOLE at three locations with different wind regimes (Case 6)

Similar studies at different locations have been conducted for an integrated PV-diesel system using atmospheric data from two different locations in Canada. The monthly average atmospheric data for the Swift Current and Toronto sites are shown in Tables 3.2 and 3.3 respectively. Figure 4.11 shows the system risk for Case 4 with the weather characteristics represented by these two locations. It can be seen that the utilization of an integrated PV-diesel system provides better system reliability at Swift

Current than at Toronto. The monthly mean solar radiation values are higher at Swift Current than at Toronto. The Swift Current data is, therefore used in most of the PV related studies described later in this thesis.

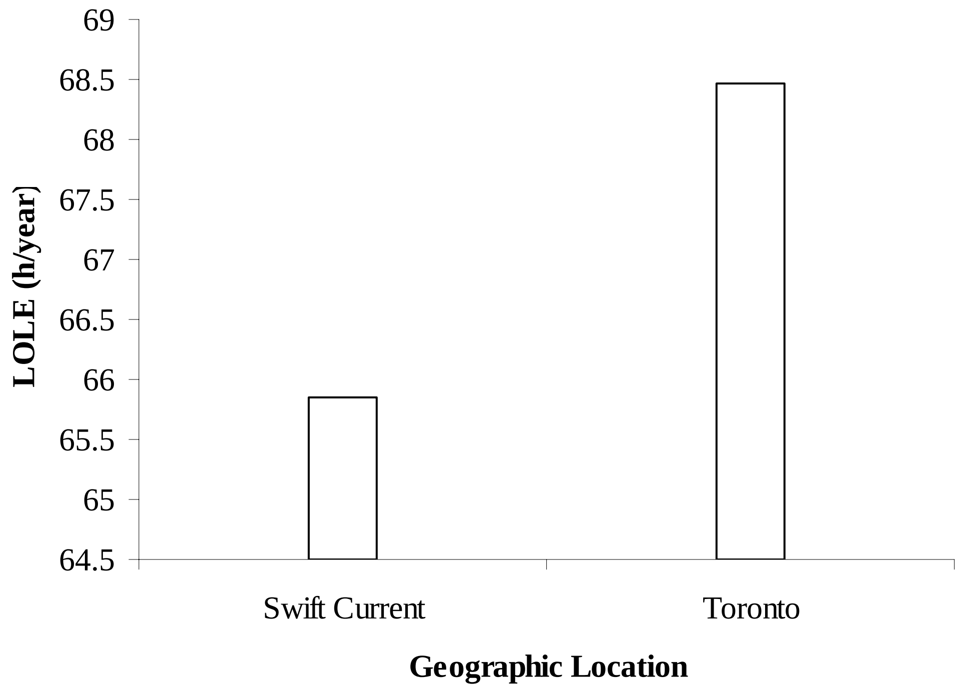


Figure 4.11: System LOLE at different locations with different solar radiation patterns (Case 4)

4.4 Summary and Conclusions

Applications of the models and methodologies developed in Chapter 3 for generating capacity adequacy evaluation of SIPS using sequential Monte Carlo simulation are presented in this chapter. A series of adequacy analyses have been conducted on different hypothetical systems with different energy compositions and energy storage capacity levels. The adequacy of a SIPS is influenced by many factors such as the energy storage capacity, the system load, the generating unit FOR and the total installed capacity, in addition to the available site resources at the system location.

The provision of energy storage can have a significant positive impact on the system reliability performance. The level of SIPS adequacy can be increased by installing additional energy storage capacity. Due to the energy limited nature of SIPS site resources, minimal incremental benefits are obtained if the energy storage capacity exceeds certain limits. The performance of a SIPS with no energy storage or minimal storage is quite different from that of the same system with substantial storage. The relatively high reliability benefits achieved by the increased energy storage are of course accompanied by increased costs.

The adequacy of SIPS degrades with increase in the system load. The relative decrease in system reliability is, however, different when different types of energy sources are included in the system. The level of SIPS adequacy is also influenced by the system load profile. The system risk is lower for a residential load model than for the other two models considered in this thesis.

The reliability of SIPS degrades significantly with increase in conventional generating unit FOR. Variations in the FOR of the non-conventional units, however, do not have significant impacts on the system adequacy.

SIPS adequacy can be improved by adding additional capacity. Wind energy is generally better than solar energy when comparing equal capacity additions in the same system. The optimum ratio of wind and solar energy for a given SIPS is difficult to determine due to the fact that the performance and reliability of a SIPS are influenced by many system factors.

The site resources in the form of available wind and solar energy at the system geographic location dictate the benefits that can be obtained from these renewable sources. A SIPS containing wind energy situated at a location with a high mean wind speed obviously provides higher system reliability than one at a location with lower mean wind speed. In a system containing solar energy, greater benefits are realized when the site is at a location with a high mean solar radiation. These conclusions are obvious in a qualitative sense. The techniques presented in this thesis, however, illustrate that it is possible to quantify these phenomena and to determine the actual and relative benefits associated with the factors that influence the system reliability.

Wind energy is generally a better choice than solar energy from an adequacy point of view. When both wind and solar energy sources are included in a SIPS that is operating with reasonable storage capability, the adequacy will lie between that of wind and solar energy. These conclusions, however, are entirely dependent on the actual site energy sources.

5. INCORPORATING RELIABILITY INDEX DISTRIBUTIONS IN SMALL ISOLATED SYSTEM RELIABILITY PERFORMANCE ASSESSMENT

5.1 Introduction

Probabilistic techniques are widely used in power system reliability evaluation. The average or mean values of a wide range of indices are used to assess the reliability of generation, transmission and distribution systems. These mean values are extremely valuable and are the primary indices in generation adequacy studies of power systems containing both conventional generating units and unconventional energy sources such as wind and solar energy. Reliability studies using the mean values of the reliability indices for power systems containing wind energy, solar energy and energy storage are presented in Chapter 4. The mean values, however, cannot provide any information on the variation of the reliability indices about their means. Additional information can, however, be created which can prove useful in a wide range of systems and applications.

Due to the highly dispersed nature of site resources such as wind and sunlight, the reliability performance of a power system containing these energy sources is quite variable and the evaluation techniques based only on mean values are sometimes inadequate for a complete assessment of such systems. It is therefore, necessary to investigate the variation of the reliability indices around their mean values in order to provide detailed information on system reliability performance. A probability distribution of a reliability index can present a pictorial representation of the manner in which the parameter varies. It includes important information on significant events which might occur occasionally but could have serious system effects. The utilization of reliability index distributions in distribution system evaluation is proposed and summarized in [21, 27]. These concepts are extended and applied to small isolated system reliability performance in this chapter [95].

A range of visual illustrations of the distributional variations associated with reliability indices for small isolated power systems using wind energy and energy storage is presented. The applications of these distributions in reliability evaluation and prediction are discussed in detail using hypothetical example systems. The impacts of selected generation and system parameters on these distributions are also investigated.

5.2 Construction of Reliability Index Distributions

As noted in Chapter 2, one advantage of the Monte Carlo technique is its ability to provide information related to the probability distributions of the reliability indices in addition to their mean or average values. In order to illustrate the types of results that can be obtained using MCS and the benefits of additional information, a range of reliability index frequency distributions have been constructed in the studies described in following sections of this chapter. The reliability index frequency distributions can be constructed in two steps:

1. Record the values of interest in the simulation and establish the statistically sound observations.
2. Group and condense the observations into frequency distributions.

In constructing the frequency distribution in Step 2 described above, attention must be given to selecting the appropriate number of class intervals, obtaining a suitable class width of each grouping, and establishing the boundary and mid-point of each class grouping.

The number of class intervals to be used primarily depends on the number of observations. If there are too many or too few class intervals, little new information is learned. In this thesis, Sturges's rule [96] is used in most cases to determine the class intervals. This is illustrated in Appendix D.

5.3 Basic Case Studies

Three basic system configurations with different energy and storage combinations are considered in the following studies. The system data for each case are shown in Table 5.1. The reliability data for the diesel unit and WTG are the same as those shown in Table 4.2. The hourly chronological load shape of the IEEE-RTS [86] with a peak load of 40kW was used in most of the cases considered. Actual wind data from the Regina site have been used unless otherwise specified. It is assumed that the WTG have operating parameters of cut-in, rated and cut-out wind speeds of 12 km/h, 38 km/h and 80 km/h respectively. An energy storage charging (discharging) rate of 60 kWh/h is considered in these studies.

Table 5.1: Example system data

Case No.	Type of generation and/or storage	Number of generators and/or storage	Rating of generators and/or storage
1	Diesel (D)	3	20 kW
2	Diesel (D) Wind (W)	2 2	20 kW 30 kW
3	Diesel (D) Wind (W) Storage (S)	2 2 1	20 kW 30 kW 300 kWh

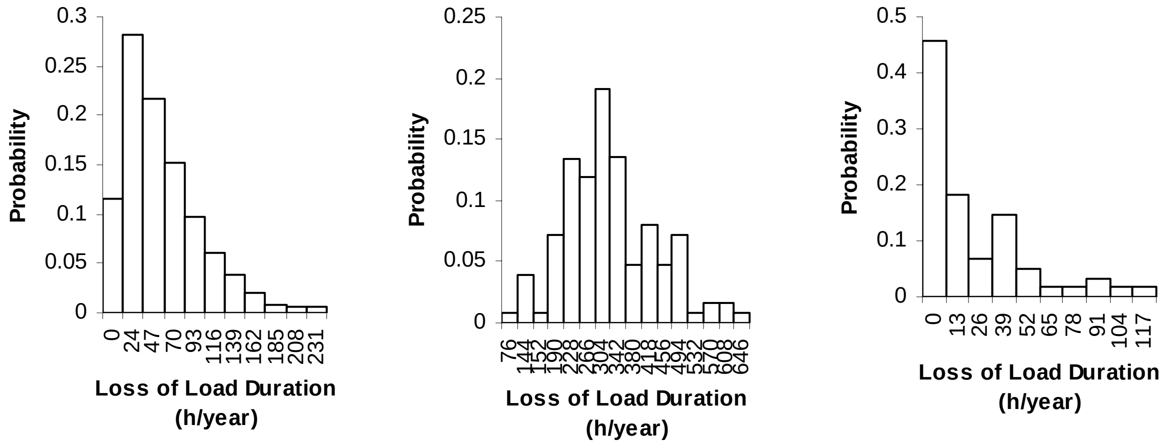
The mean values of the five basic indices for the systems shown in Table 5.1 are presented in Table 5.2. These results constitute a reference set of basic adequacy indices for the example systems considered. The distributions associated with these indices are presented later. A total of 6000 annual replications were used in each analysis to create the indices and the associated distributions. This is in excess of that required to determine the mean index values. The simulations were increased to create meaningful distributions. The data ranges in each case are quite different, as can be seen in the following figures. In order to create reasonable distributions containing data in each class interval, the class interval widths are different in each case.

Table 5.2: Basic reliability indices for the systems shown in Table 5.1

Case No.	LOLE (h/yr)	LOEE (kWh/yr)	ELOLF (occ/yr)	EESBSF (kWh/yr)	EDFOSF (occ/yr)
1	46.06	342.30	4.21	0	0
2	305.39	2075.72	60.35	0	0
3	14.33	175.63	1.60	1803.65	59.36

A range of reliability index relative frequency distributions were constructed in order to illustrate the results that can be obtained using sequential MCS and the benefits associated with this additional information. Figures 5.1 and 5.2 respectively show the distributions of the annual loss of load duration and the annual outage frequency for the three basic system configurations. It can be seen that the shapes of the distributions are, different for the different cases in both figures. The distribution histograms of the loss of load duration and the outage frequency for Cases 1 and 3 tend to be exponential. The probability associated with zero values are, however, much higher for Case 3 than for Case 1. The probability of a zero value in a given reliability index distribution is an important adequacy parameter. It indicates the likelihood of there being no interruptions in the interval considered and a high value of this probability is desirable. The distributions of the loss of load duration and the outage frequency for Case 2 are highly dispersed compared to those of the other two cases. The probabilities of zero values are virtually zero for Case 2.

Figures 5.1 and 5.2 indicate that values much greater than the mean occur with significant probability for Case 2 due to the fact that there are relatively high levels of wind penetration and no energy storage in this case. The probabilities of the annual loss of load durations and the frequencies greater than the mean values for Case 3 are relatively small. These events can occur, however, as shown in Figure 5.1 and should not be discarded from consideration.

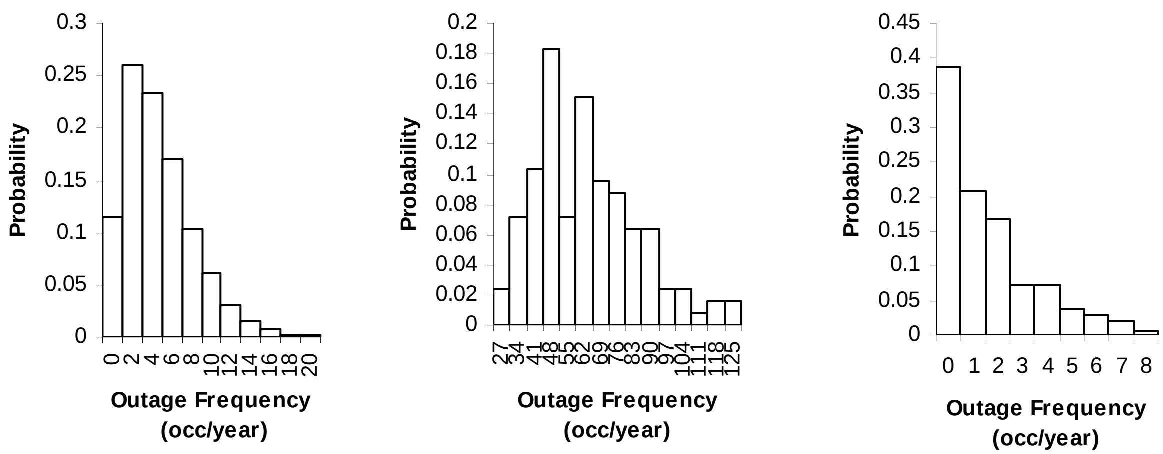


a) Case 1 (D)
LOLE=46.06 h/year

b) Case 2 (D, W)
LOLE=305.39 h/year

c) Case 3 (D, W, S)
LOLE=14.33 h/year

Figure 5.1: Annual loss of load duration distributions for the three system configurations



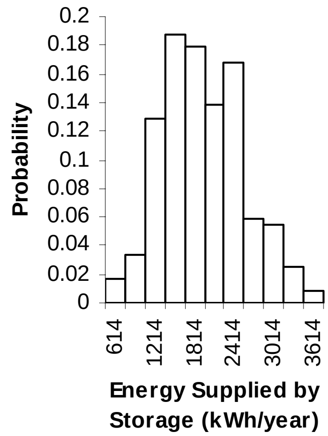
a) Case 1 (D)
ELOLF=4.21 occ/year

b) Case 2 (D, W)
ELOLF =60.35 occ/year

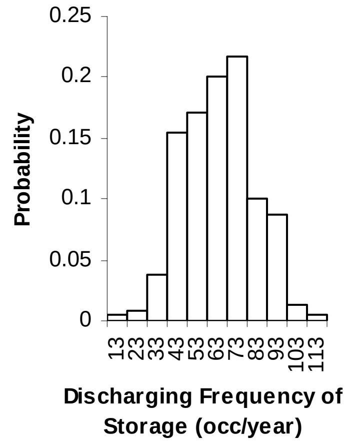
c) Case 3 (D, W, S)
ELOLF =1.60 occ/year

Figure 5.2: Annual outage frequency distributions for the three system configurations

The distributions related to energy storage performance for Case 3 are shown in Figure 5.3. It can be seen that the probabilities in the distribution tail of the energy supplied by the storage system and the discharging frequency of energy storage are relatively small. This suggests that the Mean values provide a reasonable representation of the storage performance.



a) Case 3 (D, W, S)
EESBSF=1803.65 kWh/year



b) Case 3 (D, W, S)
EDFOSF=59.36 occ/year

Figure 5.3: Distributions of (a) annual energy supplied by the storage system and (b) annual discharging frequency of the energy storage for Case 3

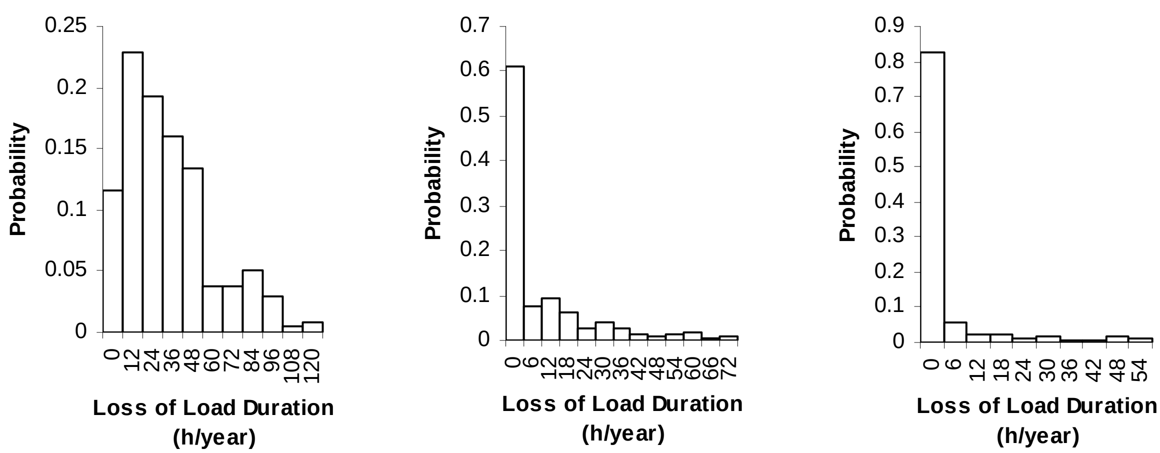
5.4 Sensitivity Studies

The impact on the mean values of selected generating unit and system parameters are discussed in Chapter 4. These parameters may have a significant impact on the reliability index distributions depending on a number of factors such as the system configuration, storage capacity, load model, generating unit unavailability, renewable energy penetration level in addition to site resource. These issues are addressed in the following subsections using Case 3 as an example.

5.4.1 Impact of Energy Storage Capacity

The previous chapter shows that the presence of an energy storage device can significantly enhance the reliability of a system using wind and/or solar energy. In order to appreciate the impact of energy storage capacity (ESC) on the reliability index distributions, the frequency histograms of annual loss of load duration and energy supplied by the storage were determined for Case 3 with three different energy storage levels and are shown in Figures 5.4 and 5.5 respectively. It can be seen from Figure 5.4 that the probability associated with a zero value increases and the value of a large loss of load duration decreases with the addition of energy storage capacity. Loss of load durations significantly larger than the mean with significant probability exist in the smaller energy storage case.

The distributions of energy supplied by the storage as shown in Figure 5.5 are generally normal in form for all the storage sizes considered. The probabilities associated with minimum energy supplied from the storage remain almost unchanged while the probabilities of higher energy levels supplied from the storage increase significantly when the storage capacity is increased. Figure 5.5 shows that it is virtually impossible to extract 3600 kWh/yr or more from a 200 kWh energy storage facility in this case. This is mainly due to the 60 kWh/h charging (discharging) rate constraint. Observations such as this are useful in determining the best energy storage size for a given system in a particular location.

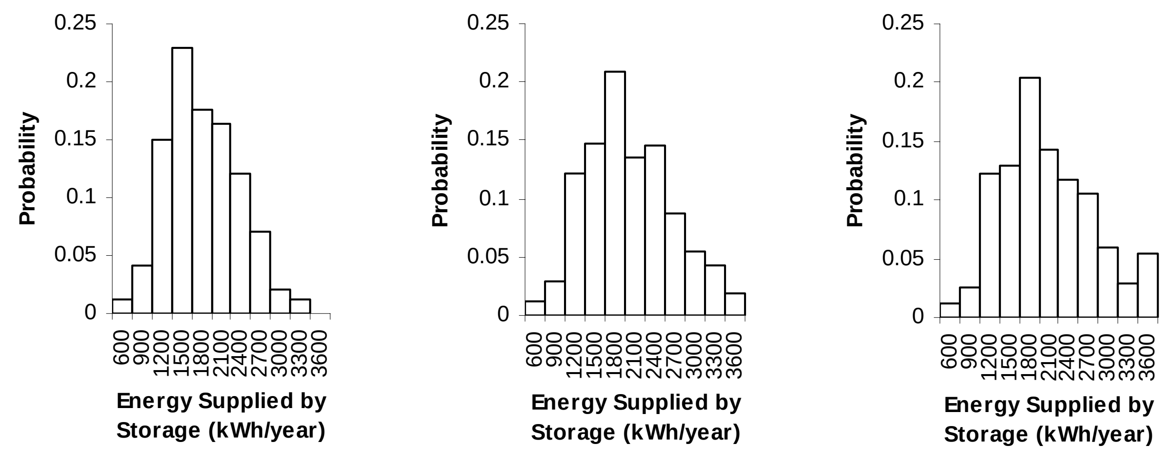


a) LOLE=28.37 h/year ESC=200 kWh

b) LOLE=8.10 h/year ESC =400 kWh

c) LOLE=3.57 h/year ESC = 600 kWh

Figure 5.4: Effect of energy storage on the distributions of annual loss of load duration



a) EESBSF=1669.90 kWh/year ESC=200 kWh

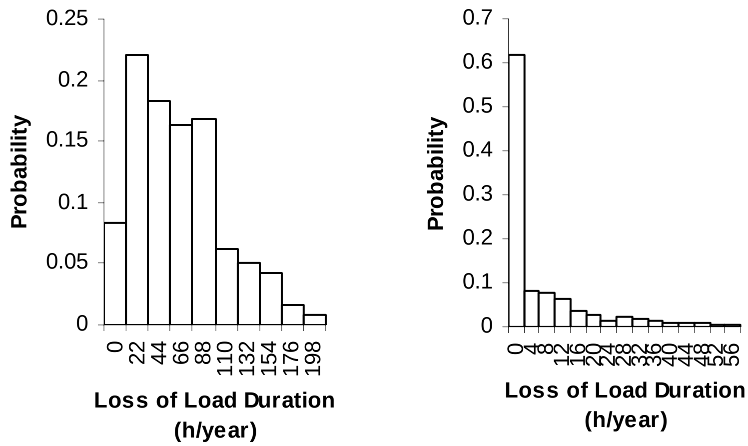
b) EESBSF=1868.66 kWh/year ESC=400 kWh

c) EESBSF=1923.32 kWh/year ESC=600 kWh

Figure 5.5: Effect of energy storage capacity on the distributions of annual energy supplied by the storage

5.4.2 Impact of the Renewable Energy Penetration Level

Studies were conducted to investigate the effect of the wind energy penetration level on the annual loss of load duration distribution. The configuration in Case 3 was expanded by adding 20 kW blocks of WTG. The annual loss of load duration distributions for 20 kW and 120 kW WTG additions are shown in Figure 5.6, where it can be seen that the shape of the distribution changes with increased wind energy penetration. The probability of zero annual loss of load duration increases as wind capacity is added to the system. It can be seen from Figure 5.6 a) that values greater than the mean occur with noticeable probability in the small wind energy penetration case. These values decrease with more wind additions as shown in Figure 5.6 b). The probability of a loss of load duration greater than the mean value, therefore, decreases with increase in wind energy penetration. Increasing the wind energy penetration will increase the generating capacity and hence increase the overall system adequacy.



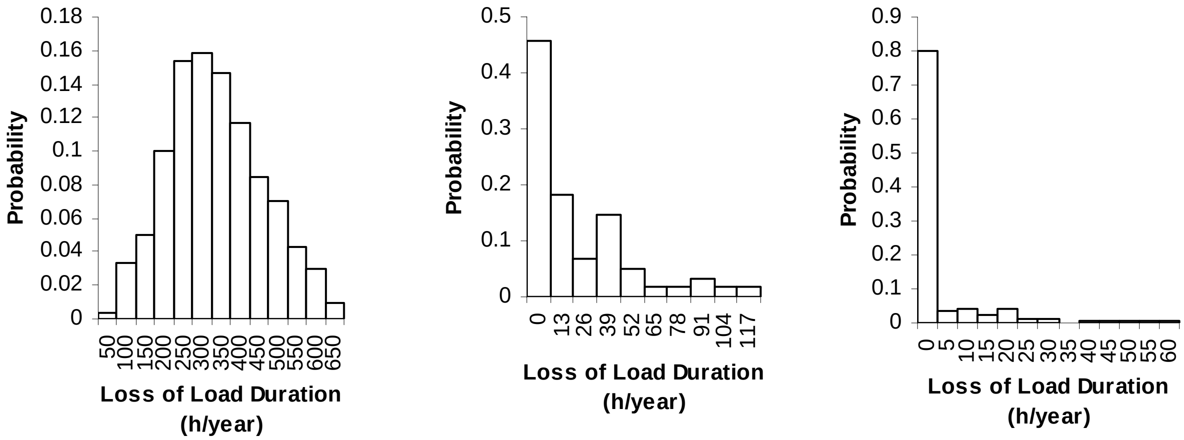
a) LOLE=53.53 h/year
20kW Wind Added

b) LOLE=5.79 h/year
120kW Wind Added

Figure 5.6: Effect of wind energy penetration level on the annual loss of load duration distribution

5.4.3 Impact of System Load

The distributions of annual loss of load duration and energy supplied by the storage for Case 3 with the three different load models are shown in Figures 5.7 and 5.8 respectively. The three load models are a constant load at the peak value, the IEEE-RTS load model and a residential load. The distribution of the annual loss of load duration for the constant load shown in Figure 5.7 is highly dispersed with no zero value and values much greater than the mean of 312.52 h/yr occur with significant probability. Loss of load duration distributions for the other two load models are exponential or hyper-exponential in form. The major difference in these two cases is that the probability of a zero value is higher for the residential load. The distribution variations in the annual loss of load durations for the different load characteristics are important, as different loss of load durations have different economic impacts on industrial, commercial and residential customers etc. Quantitative evaluations of those impacts require detailed information on the probability of the loss of load durations.



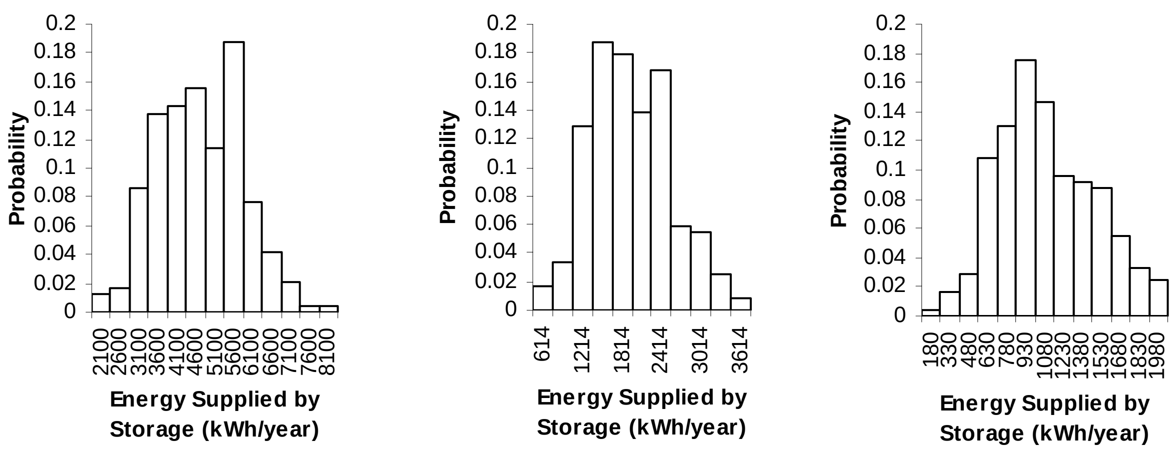
a) LOLE=312.52 h/year
Constant Load

b) LOLE=14.33 h/year
IEEE-RTS Load

c) LOLE=3.64 h/year
Residential Load

Figure 5.7: Effect of the load profile on the annual loss of load duration distribution

The probability histograms of the energy supplied by the energy storage for the three load profiles are shown in Figure 5.8. These distributions are generally symmetrical in form. It is important to note that the load profile has considerable impact on the maximum and minimum values of energy extracted from the energy storage. It is, therefore, important to carefully consider the load profile in evaluations of systems with energy storage.



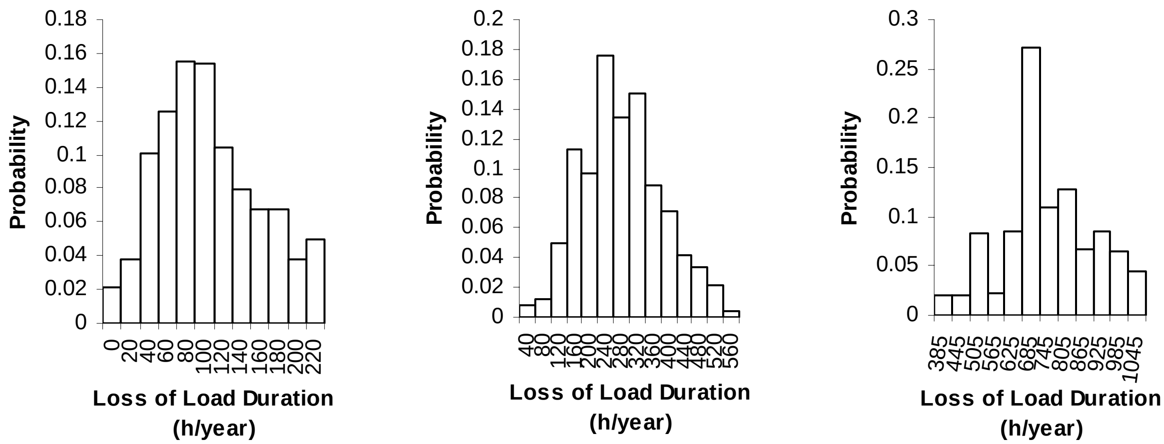
a) **EESBSF=4475.16 kWh/year**
Constant Load

b) **EESBSF=1803.65 kWh/year**
IEEE-RTS Load

c) **EESBSF =1023.41 kWh/year**
Residential Load

Figure 5.8: Effect of the load profile on the distributions of the annual energy supplied by the energy storage

Figure 5.9 shows the variation in the annual loss of load duration distributions for Case 3 with annual peak load. The peak load was varied from 50 kW to 70 kW in steps of 10 kW while maintaining the basic shape of the IEEE-RTS load curve. It can be seen from Figure 5.9 that these distributions are different in form compared to the one shown in Figure 5.1 for Case 3. The system peak load is 40 kW in Figure 5.1. It can be seen from these figures that the annual loss of load duration is very sensitive to load growth. In these situations, additional generating capacity and/or energy storage must be installed. As noted earlier, most utilities use probabilistic techniques in conventional generating unit capacity planning. SIPS generation planning is different from that of conventional systems as it involves both conventional and unconventional generating units and energy storage facilities. It is, therefore, advisable that both the expected risk indices and their distributions be used in an evaluation of capacity and/or storage expansion in small isolated systems.



a) LOLE=97.23 h/year
PL=50kW

b) LOLE=260.93 h/year
PL=60kW

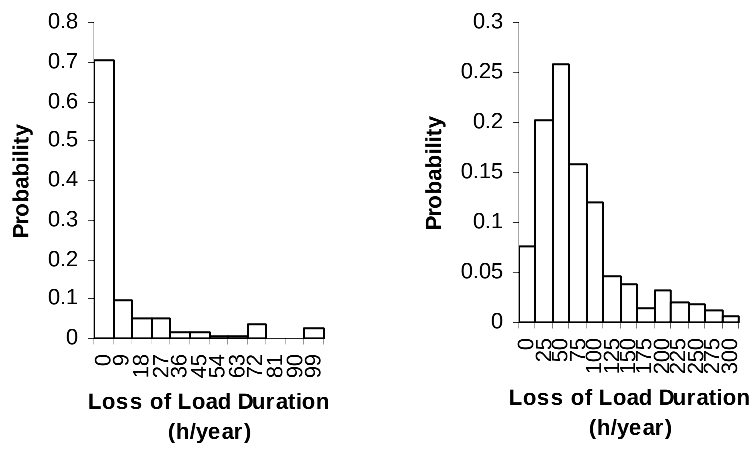
c) LOLE =716.83 h/year
PL=70kW

Figure 5.9: Effect of the annual peak load on the annual loss of load duration distribution

5.4.4 Impact of Generating Unit FOR

Unscheduled generating unit outages have a significant impact on the reliability of a power system. The bulk of the unscheduled outages associated with conventional units such as diesel, fossil and nuclear units are due to random generating unit equipment failures. These outages are incorporated in conventional generating system reliability assessment using the concept of forced outage rate [1]. A WTG or PV can experience an unscheduled outage from a component failure, a site resource deficiency or both. Site resource deficiencies are due to wind speed or sunlight deficiencies and are incorporated in the time series model used in the MCS simulation technique. In order to illustrate the effects of generating unit equipment failures on the reliability index distributions of a SIPS, the FOR of the WTG and diesel units for Case 3 were changed from 2% to 10%. The system annual loss of load duration distributions are compared in Figures 5.10 and 5.11.

Figure 5.10 shows the effects of increasing the diesel unit FOR from 2% to 10% while keeping the WTG FOR unchanged. When the diesel unit FOR is 2%, the distribution of the annual loss of load duration is hyper-exponential in form with a high probability of a zero value. When the FOR is increased to 10%, the distribution becomes more normal but with a long tail. Values greater than the mean occur with noticeable probability in this case. Increasing the diesel unit FOR to 10% will increase the number of coincident outage events. These outages result from a conventional unit outage overlapping a wind resource deficiency or a WTG equipment outage.

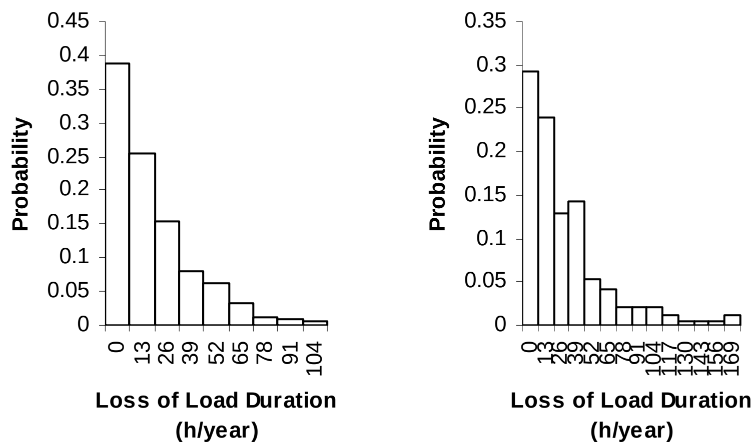


a) LOLE=8.80 h/year
Diesel Unit FOR=2%

b) LOLE =65.37 h/year
Diesel Unit FOR=10%

Figure 5.10: Effect of diesel unit FOR on the annual loss of load duration distribution

Figure 5.11 shows the effects of increasing the WTG unit FOR from 2% to 10% while keeping the diesel unit FOR unchanged. Compared with the results shown in Figure 5.10, the FOR of the WTG has relatively little impact on the annual loss of load duration distribution. The inherent energy limited nature of the WTG unit offsets the FOR effect on the system reliability performance. The power output of the WTG is largely dictated by the available wind resources. The fluctuating wind resources mask the effect of WTG failures and repairs described by the FOR. This result is very similar to that obtained from using mean reliability index values.



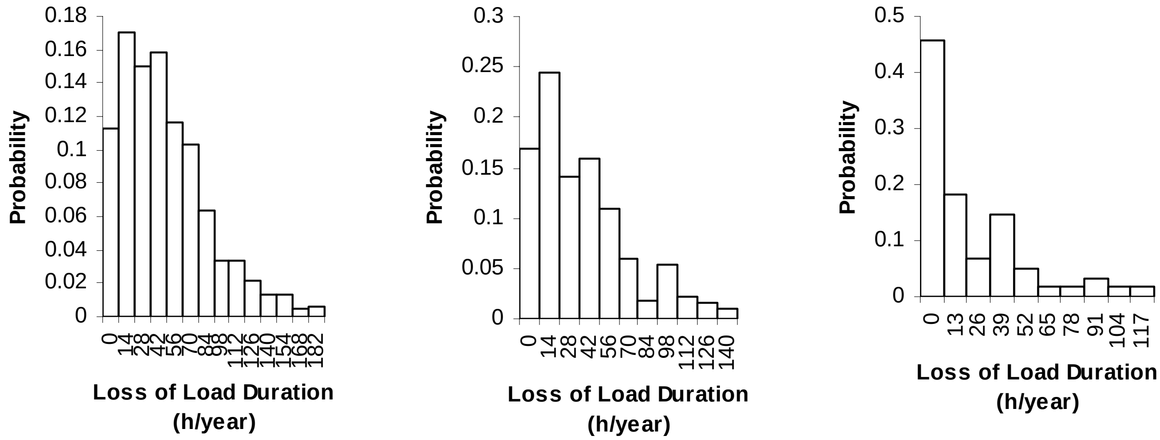
a) LOLE=12.17 h/year
WTG FOR=2%

b) LOLE =13.16 h/year
WTG FOR=10%

Figure 5.11: Effect of WTG unit FOR on the annual loss of load duration distribution

5.4.5 Impact of Geographic Location

The power and energy outputs of a SIPS are highly dependent on the site resource at the particular site. The site resources vary with the physical characteristics of the different geographic locations. The impact of geographic location on annual loss of load duration distributions is illustrated by comparing the LOLE of the same system at three different site locations. Mean wind data for the three different sites shown in Table 3.1 are used in these analyses. Figure 5.12 shows the annual loss of load duration distributions for Case 3 for the three wind characteristics. The shapes of the annual loss of load duration distributions are different for all three locations. The probability of a zero value of the annual loss of load duration increases as the mean wind speed increases. The maximum annual loss of load durations are significantly different for the three locations.



a) LOLE=41.44 h/year
North Battleford

b) LOLE=31.28 h/year
Saskatoon

c) LOLE=14.33 h/year
Regina

Figure 5.12: Effect of geographic location on the annual loss of load duration distribution

5.5 Summary and Conclusions

A series of probability distributions associated with generating capacity adequacy indices and their possible application in power system reliability evaluation is presented and discussed in this chapter. Reliability index distributions associated with generating capacity adequacy parameters such as the loss of load expectation, expected outage frequency, expected energy supplied by the energy storage and energy storage system discharging frequency etc. are presented and examined.

The major parameters associated with the site resources, the generating units, energy storage and the system load have different impacts on system reliability performance. These impacts are traditionally examined using expected reliability indices. These parameters will continue to be the main indices in system reliability performance evaluation. The associated reliability index distributions can, however, provide considerable additional information and a more physical appreciation of the effects of parameter variation. The utilization of reliability index distributions in generating capacity adequacy evaluation is a relatively new approach. This technique complements the conventional expected values and can be used in reliability worth assessment of capacity expansion options. Reliability cost/worth concepts are applied in Chapter 9.

Overall system adequacy can be enhanced by adding more energy storage capacity and/or by increasing the renewable energy penetration level. The distribution variations in annual loss of load durations show that the probability associated with a zero value increases and the value of a large loss of load duration decreases with improvement in system adequacy.

Both system peak load and load profile effect the reliability index distributions. The annual loss of load duration is very sensitive to load growth. The load profile has, however, considerable impact on the maximum and minimum values of energy extracted from the energy storage system.

The probability of longer loss of load durations increases with increase in conventional generating unit FOR. Variations in FOR of the non-conventional units, however, do not have significant impacts on the reliability index distributions.

The loss of load duration distributions are different for different geographic locations. The probability of a zero value for the annual loss of load duration increases as the mean wind speed increases.

6. IMPACTS OF LARGE SCALE UTILIZATION OF WIND AND/OR SOLAR ENERGY IN ELECTRIC POWER SYSTEMS

6.1 Introduction

Wind and/or solar energy are widely used in remote sites, requiring relatively small amounts of power. In these isolated applications, wind and/or solar energy are normally used in combination with conventional generators such as diesel engines and contain energy storage facilities. The reliability impact on these small isolated power systems of wind and/or solar energy sources as well as storage elements is illustrated in previous chapters.

The world-wide demand for wind energy especially in large grid-connected applications has been growing rapidly over the last two decades [97]. Solar energy projects have also shown steady growth in the last 15 years [97]. Much of these demands have been driven by the need for electric power from "cleaner energy sources". There is a large potential for wind and/or solar energy projects in grid-connected applications [2, 3]. It is, therefore, important to evaluate the impacts of utilizing significant amounts of wind and/or solar energy sources in large on-grid power systems.

The simulation models and technique described in the previous chapters have been modified and applied in a wide range of studies in order to examine the reliability contribution of wind and/or solar energy in a power system containing a number of conventional generating units. The reliability of combined systems containing a single wind farm or solar park and multiple wind farms and/or solar parks has been studied. Key parameters that influence the reliability contribution, such as the site location, the system load level and the installed WTG and/or PV capacity have been considered and are illustrated in this chapter. The system reliability is examined in terms of the LOLE, LOEE, ELOLD and ELOLF. Probability distributions associated with the LOLE index are also presented.

The wind data from the Regina, Saskatoon and North Battleford sites and atmospheric data from the Swift Current and Toronto sites are utilized. The conventional generating unit ratings and reliability data from the RBTS [68] are used in the following analyses to illustrate the proposed concepts. The generating unit ratings and reliability data of the RBTS are given in Appendix E. A wind farm is assumed to be composed of a number of identical WTG. A solar park is considered to be composed of a number of identical PV generating units, which are composed of a number of identical panels.

6.2 Single Site Case Studies

The relative benefits of adding different types of energy sources to the RBTS have been analyzed. The RBTS is expanded in different ways by adding equal capacity in the form of conventional units, PV and WTG. The total capacity added in each case is 22.5 MW (or 22.5 MW_p) and annual peak load is 185 MW (unless specifically indicated). The added conventional capacity is in the form of 7.5 MW and 15 MW units with FOR of 0.01 and 0.02 respectively. The wind farm consists of identical VESTAS V29 225-50, 29 !O! turbines with FOR of 0.04. The additional PV generating units are composed of identical CANROM30 PV panels with FOR of 0.03.

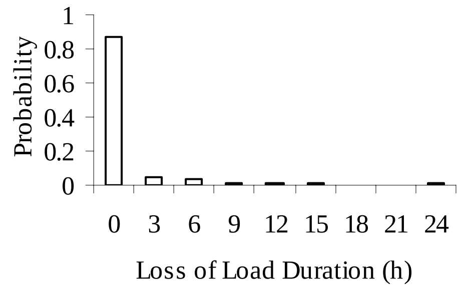
A comparison of the system reliability indices for different capacity addition cases is shown in Table 6.1. It can be seen from Table 6.1 that the adequacy of the RBTS is improved for each case but not to the same degree. The conventional generators are much superior to PV or WTG when comparing reliability benefits from a given capacity addition. Adequacy comparisons of non-conventional energy sources show that the maximum improvement occurs when adding a wind farm (with Regina data) to the RBTS while the minimum improvement occurs when adding a solar park (with Toronto data) to the RBTS. The system reliability improvement for the Regina wind data is more significant than that for the other two wind farm locations as Regina has a higher mean wind speed and, therefore, provides a better wind resource. The reliability benefit obtained from the Swift Current solar park is higher than that from the Toronto solar park as the Swift Current site has a higher monthly average solar radiation level than the Toronto site.

Table 6.1: Reliability indices for the original RBTS and different expansions

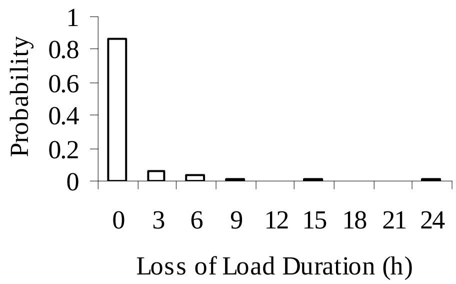
Case	LOLE (hours/year)	LOEE (MWh/year)	ELOLD (hours/occ.)	ELOLF (occ./year)
Original	1.1470	10.6972	5.3110	0.2160
Toronto (PV added)	0.9748	9.9959	3.5353	0.2693
Swift Current (PV added)	0.9520	9.9641	3.4051	0.2863
North Battleford (WTG added)	0.9205	6.0729	3.7629	0.1996
Saskatoon (WTG added)	0.8742	5.6447	4.3680	0.2001
Regina (WTG added)	0.7512	4.6252	4.6417	0.2005
Conventional unit added	0.0982	0.8217	4.4961	0.0218

Figure 6.1 shows the distributions of the loss of load duration (LOLD) created from 6000 replications for the original RBTS and the six different additions. The distributions are exponential in form and are quite similar to each other. All of the distributions are highly skewed with a very high probability of zero values. Loss of load durations higher than the averages are observed in all cases. The probabilities associated with these higher values are, however, quite small.

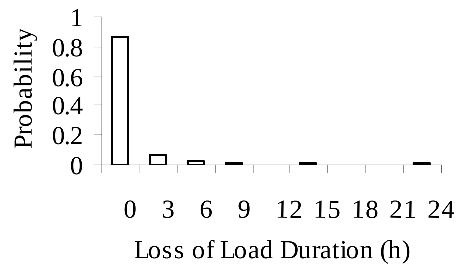
Although the addition of different energy sources to the RBTS can reduce the average value of the LOLE, it has relatively little impact on the general shape of the distributions of the LOLD. Comparing the LOLD distribution of original RBTS with those of other cases, it can be concluded that the distributions of the LOLD are largely dominated by the original RBTS generation and load characteristics.



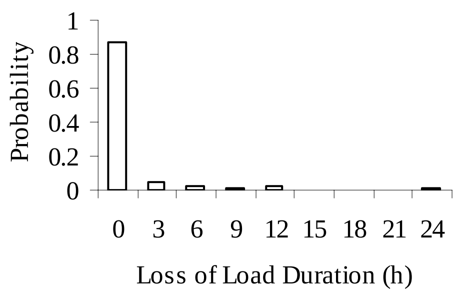
(a) Original System



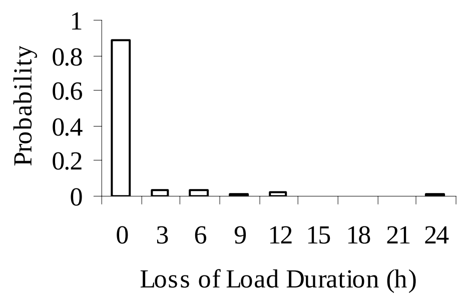
(b) RBTS Containing PV, Toronto Data



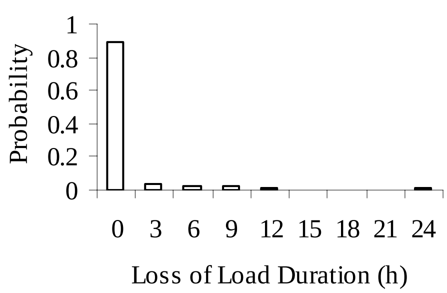
(c) RBTS Containing PV, Swift Current Data



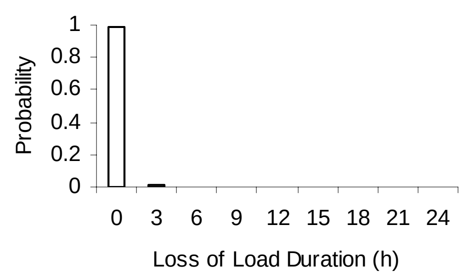
(d) RBTS Containing WTG, North Battleford Data



(e) RBTS Containing WTG, Saskatoon Data



(f) RBTS Containing WTG, Regina Data



(g) RBTS with the Addition of Conventional Units

Figure 6.1: Distributions of the loss of load duration for different RBTS cases

A noticeable difference in these distributions is the change in the probabilities of zero LOLD as shown in Table 6.2. It can be seen from Table 6.2 that the variation in the probabilities of zero LOLD are directly related to the LOLE values shown in Table 6.1. An implication of this is that the average value of the loss of load duration (LOLE) provides a relatively good indication of reliability performance in these cases.

Table 6.2: Probabilities of zero value for the LOLD distributions shown in Figure 6.1

Case	Probability of Zero LOLD
Original	0.862523
Toronto (PV added)	0.865356
Swift Current (PV added)	0.874021
North Battleford (WTG added)	0.875521
Saskatoon (WTG added)	0.884853
Regina (WTG added)	0.894184
Conventional unit added	0.984839

The LOLD distributions shown in Figure 6.1 are quite different from those obtained from the simulation results of small isolated systems presented in Chapter 5. In small isolated applications, wind and/or solar energy penetration is much higher than that in large systems. Fluctuating wind and/or solar resources have strong impacts on isolated system reliability performance. These effects are reflected by significant changes in both average values and in the distributions of the reliability indices. The reliability benefits of adding unconventional generating capacity are clearly illustrated in Figure 6.1 and Table 6.2.

6.2.1 Renewable Energy Penetration

As noted earlier, the generation and load characteristics of the RBTS containing wind and/or solar energy are quite different from that of a small isolated system. The impact of wind and/or solar energy penetration on small isolated system reliability has been investigated using both mean values and reliability index distributions in the previous chapters. The addition of 22.5 MW WTG or 22.5 MW_p PV capacity to the RBTS improves the reliability of the combined system. The WTG or PV capacity added to the RBTS was changed and the combined system reliability is analyzed using both mean values and distributions of the LOLE index.

Figure 6.2 shows the change in LOLE as additional WTG or PV capacity is added to the RBTS. It can be seen from Figure 6.2 that there is a reliability benefit from both the wind energy conversion system (WECS) and the PV conversion system (PVCS) capacity. The changes in the LOLE are significant in the beginning and tend to saturate when more WTG are added while the decreases in the LOLE are relatively flat with the increases in PV capacity. It can also be seen in this figure that the same WECS produces different reliability contributions in wind farms with different wind regimes. The same PVCS also produces different reliability contributions in solar parks with different atmospheric conditions. The curves for Regina data and Swift Current data show better reliability performance for wind farms and solar parks respectively. The change in LOLE with additional renewable energy capacity is, however, relatively more significant for the Regina site than for the other sites.

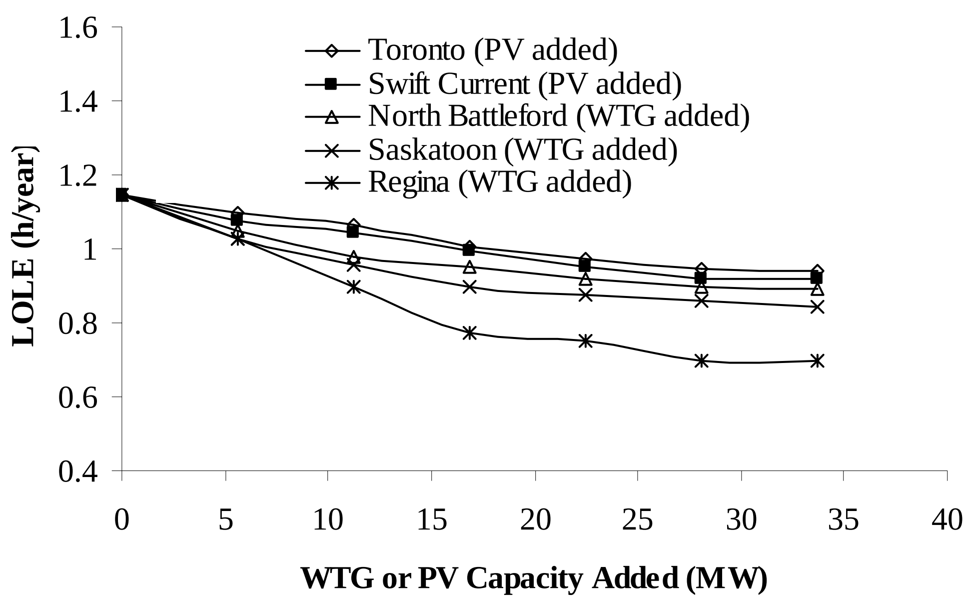
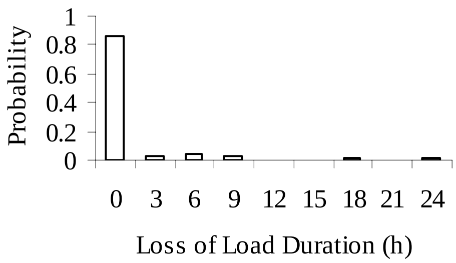


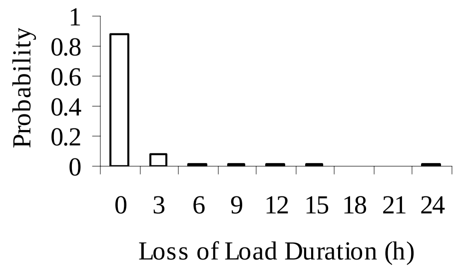
Figure 6.2: LOLE versus wind or solar energy penetration (RBTS)

Figure 6.3 shows the change in the LOLD distributions as additional WTG capacity (Regina data) is added to the RBTS. The LOLD distribution for the combined system containing 100 VESTAS V29 225-50, 29 !O! turbines is shown in Figure 6.1 (f) and is therefore not included in Figure 6.3.



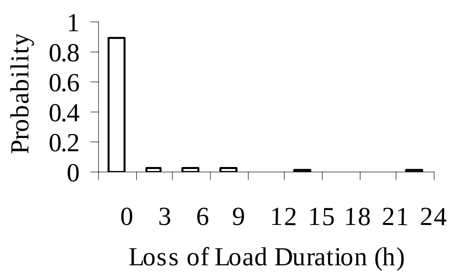
(a) 5.625 MW WTG added to the RBTS

Regina Data, LOLE=1.0285 h/year



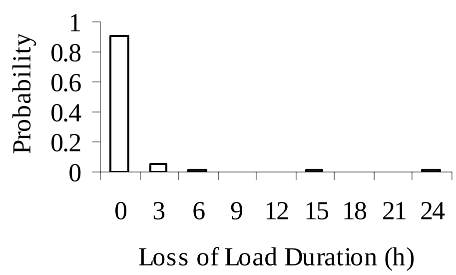
(b) 11.25 MW WTG added to the RBTS

Regina Data, LOLE=0.8990 h/year



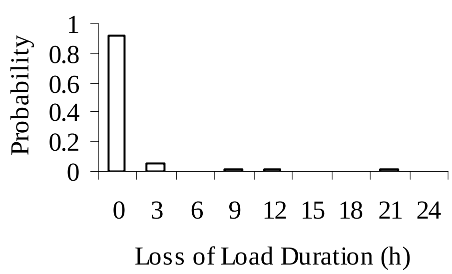
(c) 16.875 MW WTG added to the RBTS

Regina Data, LOLE=0.7714 h/year



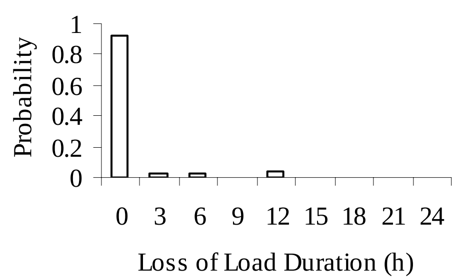
(d) 28.125 MW WTG added to the RBTS

Regina Data, LOLE=0.6999 h/year



(e) 33.75 MW WTG added to the RBTS

Regina Data, LOLE=0.6947 h/year



(f) 39.375 MW WTG added to the RBTS

Regina Data, LOLE=0.6922 h/year

Figure 6.3: Change in LOLD distributions versus wind energy penetration (Regina data, RBTS)

All of the distributions shown in Figure 6.3 are exponential in form with very high probabilities of zero LOLD values. The probability of zero values increases with the addition of more wind capacity to the RBTS as shown in Table 6.3. The decreases in the average LOLD and therefore the improvement in the reliability of the combined RBTS are mainly due to increases in the zero LOLD probabilities. In addition, LOLD values higher than the LOLE with noticeable probabilities are observed in some cases such as (a), (b) and (d) in Figure 6.3. The contribution of the longer loss of load events to the mean value is, however, small compared to that of the no loss of load events in each case. The probabilities of high LOLD values become negligible with increases in wind energy penetration.

Table 6.3: Probabilities of zero value for the LOLD distributions shown in Figure 6.3

WTG Added (MW)	Probability of Zero LOLD
5.625	0.864356
11.25	0.883853
16.875	0.894184
22.5	0.899017
28.125	0.903516
33.75	0.918680
39.375	0.920013

6.2.2 Incremental Peak Load Carrying Capability

The LOLE index of the RBTS incorporating WECS and PVCS of 22.5 MW and 22.5 MW_p respectively is plotted as a function of the annual peak load in Figure 6.4. The annual peak load was varied from 175 MW to 205 MW with a 5 MW increase in each step. It can be seen from Figure 6.4 that there are load carrying capability benefits from the WECS and PVCS additions. This benefit can be presented in terms of the incremental peak load carrying capability (IPLCC) [1]. Simulation results show that the LOLE for the original RBTS with an installed capacity of 240 MW and an annual peak load of 185 MW is approximately 1.1470 hours/year. Figure 6.4 shows that after 22.5 MW_p PVCS (Toronto data) is added to the RBTS, the combined system can carry a peak load of 186.66 MW at the LOLE of 1.1470 hour/year. The IPLCC in this case is, therefore, 1.66 MW. If 22.5 MW_p PVCS (Swift Current data) is added to the RBTS, the IPLCC increases to 2.09 MW. The IPLCC is approximately 2.52 MW, 2.98 MW and 4.35 MW respectively after the WECS with the North Battleford, Saskatoon and Regina wind regimes are added to the RBTS.

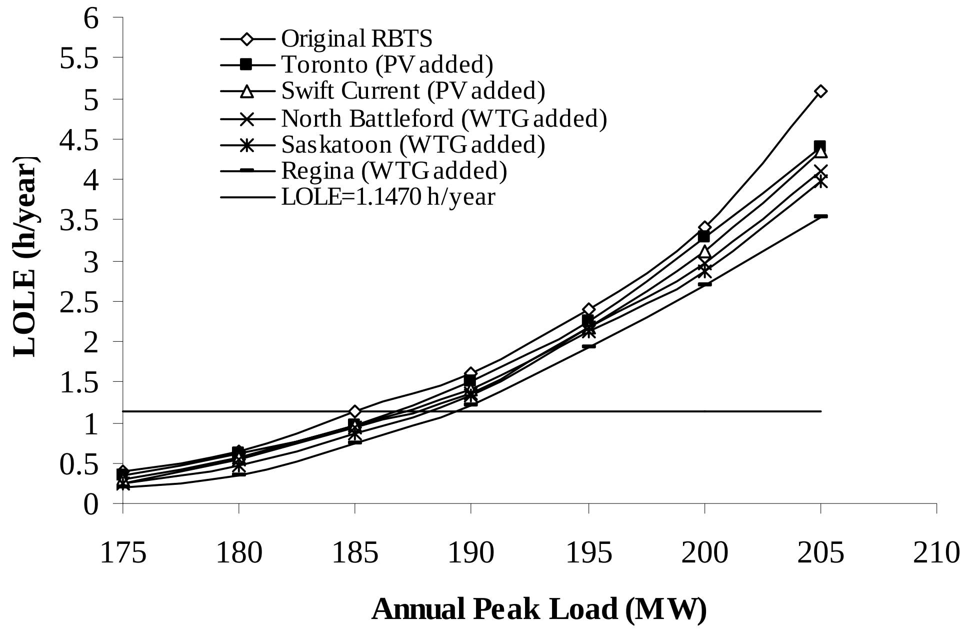
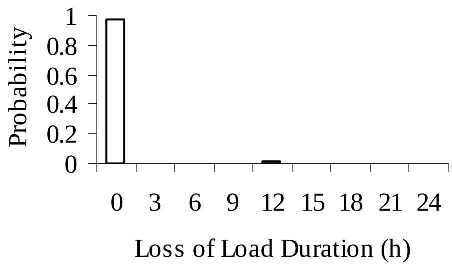


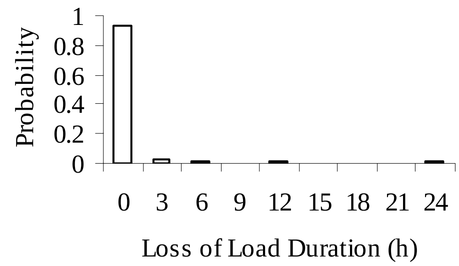
Figure 6.4: LOLE versus annual peak load (RBTS)

Figure 6.5 shows the LOLD distributions for the RBTS incorporating 22.5 MW WTG for different system annual peak loads. Only the results obtained using the Regina wind data are shown in this figure. The loss of load distribution corresponding to the annual peak load of 185 MW is shown in Figure 6.1 (f) and is therefore not included in Figure 6.5. It can be seen from Figure 6.5 that the system annual peak load has a significant impact on the distributions of the LOLD. The probability of zero LOLD decreases with increase in the annual peak load. The probabilities associated with longer LOLD increase with increase in the annual peak load. These probabilities become clearly observable when the peak load exceeds a certain value, in this case 190 MW. The decrease in the probability of zero LOLD and the increase in the probability of longer LOLD result in reduced system adequacy and peak load carrying capability. This is in general agreement with the reliability appreciation obtained using the LOLE. Figure 6.4

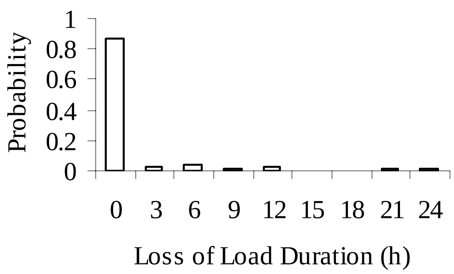
shows that the combined RBTS with a 22.5 MW wind farm located at the Regina site cannot carry a peak load of 190 MW at the LOLE of 1.1470 hour/year.



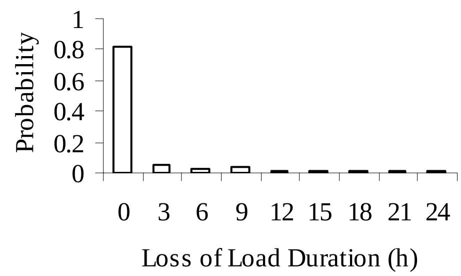
(a) Peak Load=175 MW
RBTS with 22.5 MW WTG
Regina Data, LOLE=0.2005 h/year



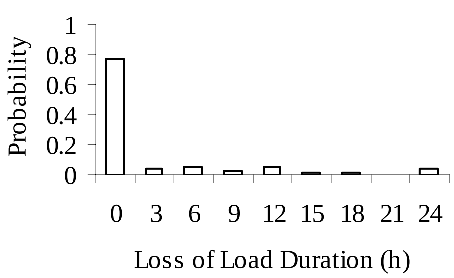
(b) Peak Load=180 MW
RBTS with 22.5 MW WTG
Regina Data, LOLE=0.3539 h/year



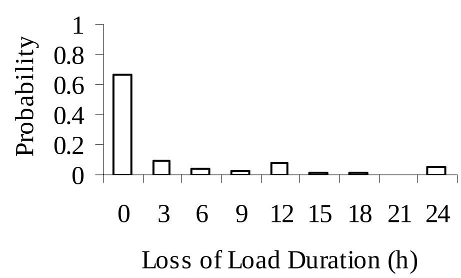
(c) Peak Load=190 MW
RBTS with 22.5 MW WTG
Regina Data, LOLE=1.2066 h/year



(d) Peak Load=195 MW
RBTS with 22.5 MW WTG
Regina Data, LOLE=1.9290 h/year



(e) Peak Load=200 MW
RBTS with 22.5 MW WTG
Regina Data, LOLE=2.6962 h/year



(f) Peak Load=205 MW
RBTS with 22.5 MW WTG
Regina Data, LOLE=3.5386 h/year

Figure 6.5: Change in LOLD distributions versus annual peak load variation (Regina data, RBTS)

6.2.3 Energy Storage

Energy storage facilities have a significant positive impact on the reliability of small isolated power systems [90-94]. The reliability of such systems can be greatly enhanced by the provision of energy storage facilities. It is also financially viable to use energy storage in small off-grid applications. Large scale on-grid applications of wind and/or solar energy may not include storage facilities due to economic considerations. It is, however, of interest to investigate the possible impacts of energy storage on large on-grid systems that utilize significant amount of wind and/or solar energy. Table 6.4 presents the LOLE in hours/year for the cases shown in Table 6.1 with three different energy storage capacity levels. It can be seen from this table that the LOLE values reduce for each case with the addition of energy storage capability.

Table 6.4: LOLE for different cases with different energy storage capacity levels

Energy Storage Capacity (MWh)	Toronto (PV added)	Swift Current (PV added)	North Battleford (WTG added)	Saskatoon (WTG added)	Regina (WTG added)
0	0.9748	0.9520	0.9305	0.8742	0.7512
300	0.8524	0.8354	0.7700	0.7232	0.6097
600	0.7760	0.7652	0.6651	0.6456	0.5422

In order to further examine the effects of energy storage capability, the storage capacity was changed from 0 MWh to 600 MWh and the corresponding LOLE index calculated for each case, as presented in Table 6.1. It is assumed that there are no restrictions on the energy storage charging and discharging capability. The simulation results are shown in Figure 6.6. It can be seen from this figure that the LOLE decreases with the addition of more storage capacity. Figure 6.6 indicates that significant reliability benefits can be obtained by utilizing energy storage in large on-grid applications. These benefits will, however, have to be evaluated by incorporating the costs and practicality of creating the required storage facilities.

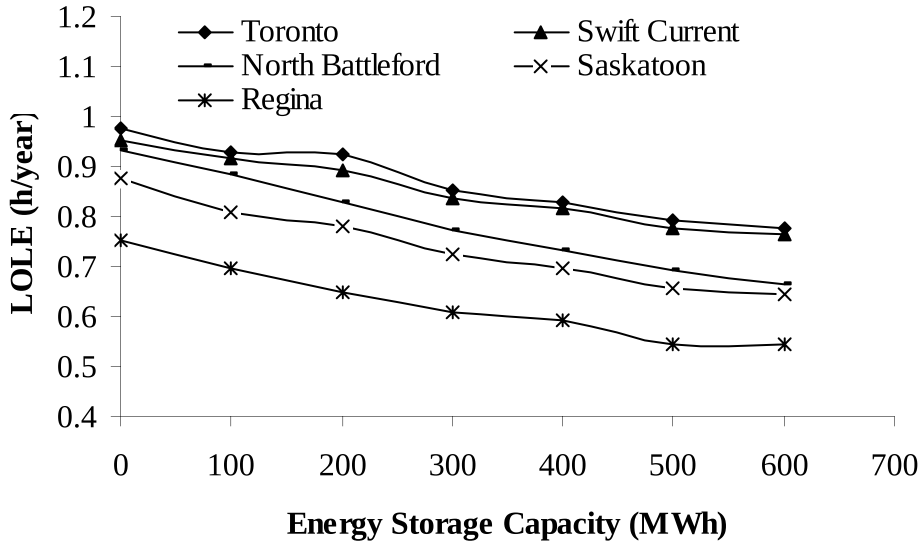


Figure 6.6: LOLE versus energy storage capacity (RBTS, without restrictions)

Figure 6.7 shows similar study results but with some restrictions on the energy storage charging and discharging capability. The maximum charging and discharging rate is assumed to be 5 MWh/h. It can be seen from Figure 6.7 that the reduction in LOLE with storage capacity is much less pronounced under this condition. There is relatively little reliability benefit in utilizing energy storage with these restrictions in this case.

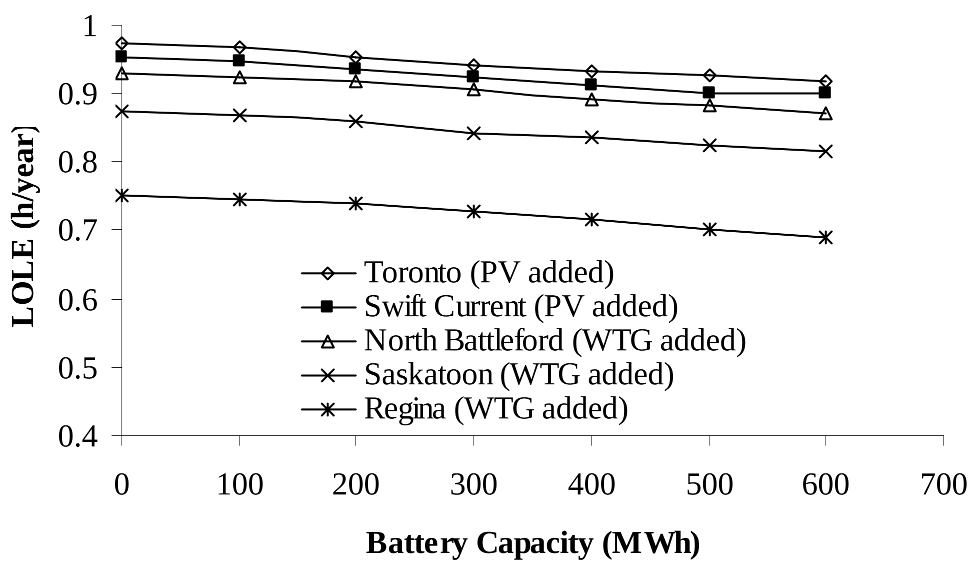


Figure 6.7: LOLE versus energy storage capacity (RBTS, with restrictions)

6.2.4 Risk Based Equivalent Capacity Ratio

Electric power from a WTG or a PV unit is intermittent and non-dispatchable as the outputs of these non-conventional generating units depend strongly on the site resource availability. Previous discussions show that a 1 MW WTG or a 1 MW_p PV cannot carry the same amount of load as a 1 MW conventional generating unit. The reliability contribution of a non-conventional wind or solar energy based generating unit is, therefore, different from that of a conventional generating unit. This effect can be examined by adding different units in the RBTS or replacing different units in the RBTS by the required number of WTG or PV units while maintaining a specific reliability criterion [98-100]. The system LOLE in the original RBTS is 1.1470 hours/year. It is assumed that this value of LOLE is acceptable for the system under study and chosen as the risk criterion in the following analyses.

One of the 5 MW hydro units is first removed from the RBTS and replaced by WTG or PV units. Figure 6.8 shows the variation in the LOLE as a function of the added WTG or PV capacity for different locations. The LOLE criterion of 1.1470 hours/year is also shown in this figure. The LOLE increases from 1.1470 hours/year to 1.6491 hours/year after the 5 MW hydro unit is removed from the RBTS.

Figure 6.8 shows that the LOLE decreases with increasing WTG or PV capacity. The degree of decrease is, however, not the same when adding wind farm or solar park at different locations. The required WTG (or PV) capacities to replace a 5 MW hydro unit are also different for different energy sources and different site locations. When the Regina wind data is used, the LOLE is restored to 1.1470 hours/year if 42.16 MW of WTG is added. This indicates that 42.16 MW of WTG is able to replace a 5 MW conventional generating unit if the wind farm is assumed to be located at the Regina site.

The equivalence between a conventional unit and a WTG (or PV) can be represented by the ratio of WTG (or PV) capacity to the conventional unit capacity. This ratio is referred to as the risk-based equivalent capacity ratio (RBECR) in this thesis. If the RBECR is 10, then 1 unit of conventional generating capacity is equivalent to 10 unit of WTG (or PV) capacity, or 1 unit of WTG (or PV) is equivalent to 0.1 unit of conventional generating unit.

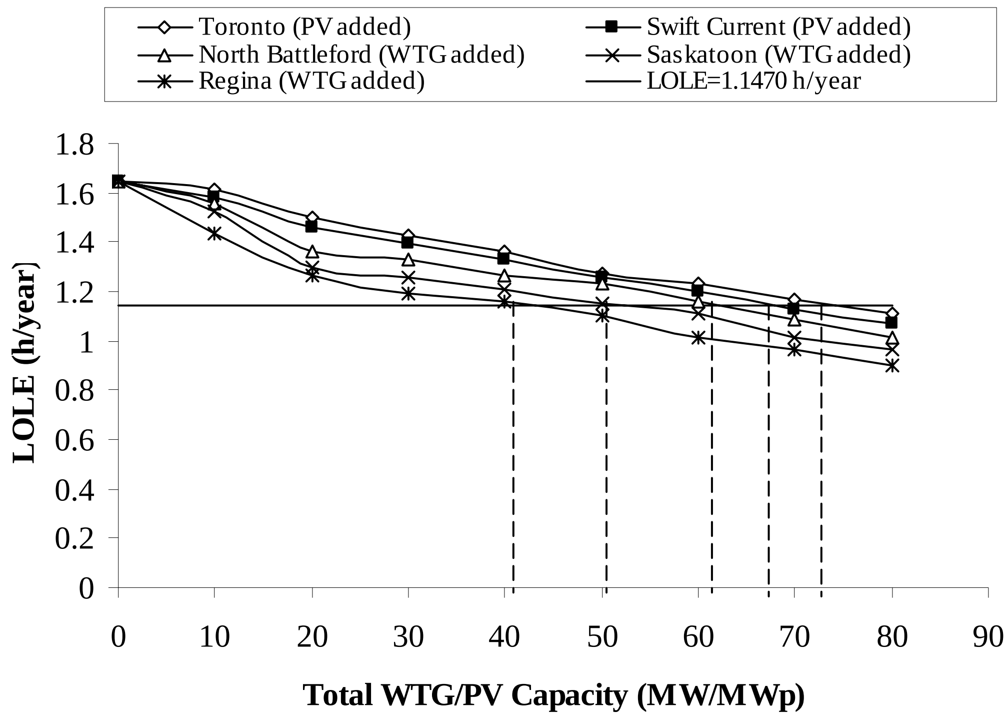


Figure 6.8: LOLE versus total WTG or PV capacity assuming a 5 MW hydro unit is removed from the RBTS

Table 6.5 shows the WTG or PV capacity required to maintain a LOLE of 1.1470 hours/year and the corresponding RBECR values. The simulation results show that 1 unit of conventional capacity is approximately equivalent to 12 and 10 unit of WTG capacity for the North Battleford site and Saskatoon site data respectively. In order to meet the adequacy criterion of 1.1470 hours/year, 73.33 MW_p PV capacity is required to replace a 5 MW conventional unit for the Toronto site while 67.87 MW_p PV capacity is needed for the Swift Current site.

Table 6.5: WTG or PV unit capacity relative to a 5 MW conventional generation unit

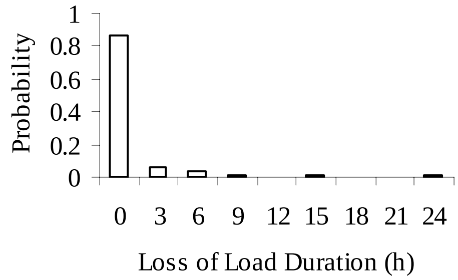
Cases	Capacity needed (MW or MW_p)	RBECR (WTG or PV Capacity/ 5)
Toronto (PV added)	73.33	14.67
Swift Current (PV added)	67.87	13.57
North Battleford (WTG added)	62.13	12.43
Saskatoon (WTG added)	51.11	10.22
Regina (WTG added)	42.16	8.43

The previous study shows that different wind or solar capacity is needed at different locations to replace a 5 MW conventional unit in order to maintain a fixed adequacy criterion. Figure 6.9 compares the LOLD distributions of the original RBTS and those of the combined RBTS assuming that a 5 MW Hydro unit is removed. These distributions were recreated by replacing the 5 MW conventional unit with the required WTG or PV capacities presented in Table 6.5. Although the same random number seed is used in each case, the average value obtained is a little bit different from the value of 1.1470 hour/year. The reason is that the equivalent capacity needed for each case is obtained from Figure 6.8 using linear intropolation. The relative error is, however, not significant and can be neglected. It can be seen from Figure 6.9 that although the average value of LOLE is virtually the same, the loss of load duration distributions are slightly different in each case.

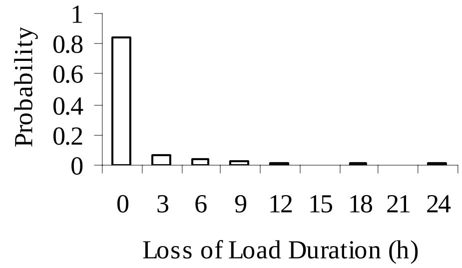
Table 6.6 shows the probability of zero LOLD for each case shown in Figure 6.9. It can be seen from Table 6.6 that the change in the probability of zero LOLD is not significant with different system configurations.

Table 6.6: Probabilities of zero value for the LOLD distributions shown in Figure 6.9

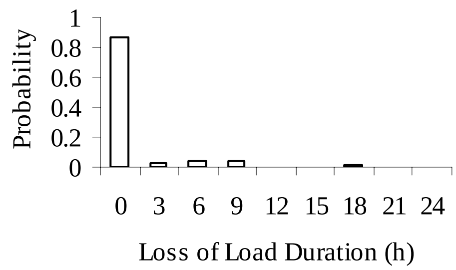
WTG Added (MW)	Probability of Zero Value
Original RBTS	0.862523
Toronto (PV added)	0.838194
Swift Current (PV added)	0.838360
North Battleford (WTG added)	0.866517
Saskatoon (WTG added)	0.882856
Regina (WTG added)	0.899027



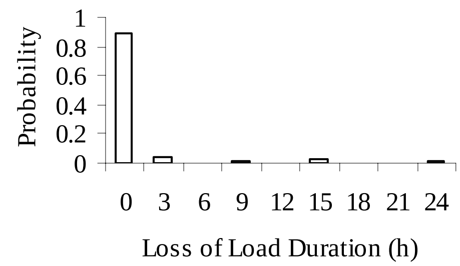
(a) Original RBTS
LOLE=1.1470 h/year



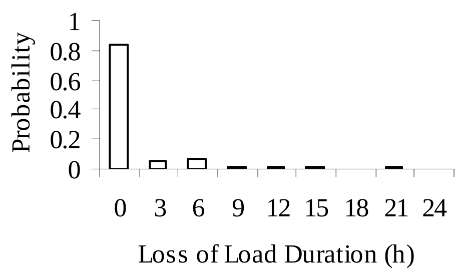
(b) RBTS with 42.16 MW WTG
Regina Data, LOLE=1.1418 h/year



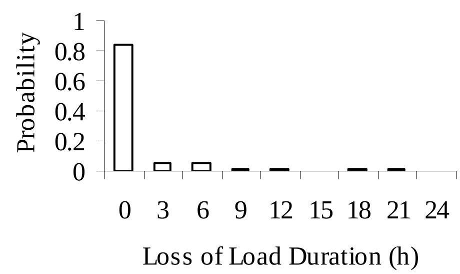
(c) RBTS with 51.11 MW WTG
Saskatoon Data, LOLE=1.1515 h/year



(d) RBTS with 62.13 MW WTG
North Battleford Data, LOLE=1.1495 h/year



(e) RBTS with 67.87 MW_p PV
Swift Current Data, LOLE=1.1435 h/year



(f) RBTS with 73.33 MW_p PV
Toronto Data, LOLE=1.1583 h/year

Figure 6.9: Distributions of the loss of load duration for different cases related to a 5 MW conventional generation unit

A similar study was conducted by removing a 10 MW thermal unit from the RBTS. The results are shown in Figure 6.10 and Table 6.7. It can be seen that when a 10 MW unit is removed from the RBTS, it is not possible to maintain the LOLE reliability criterion of 1.1470 hours/year by replacing the conventional unit with PV. The system reliability level can, however, be restored by adding 101.77 MW and 95.76 MW of WTG at the North Battleford and Saskatoon sites respectively. If the Regina wind speed data is used, only 80 MW of WTG are needed to replace the 10 MW unit. The RBECR obtained by removing a 10 MW conventional unit from the RBTS and replacing it by WTG as shown in Table 6.7 are similar to those shown in Table 6.5.

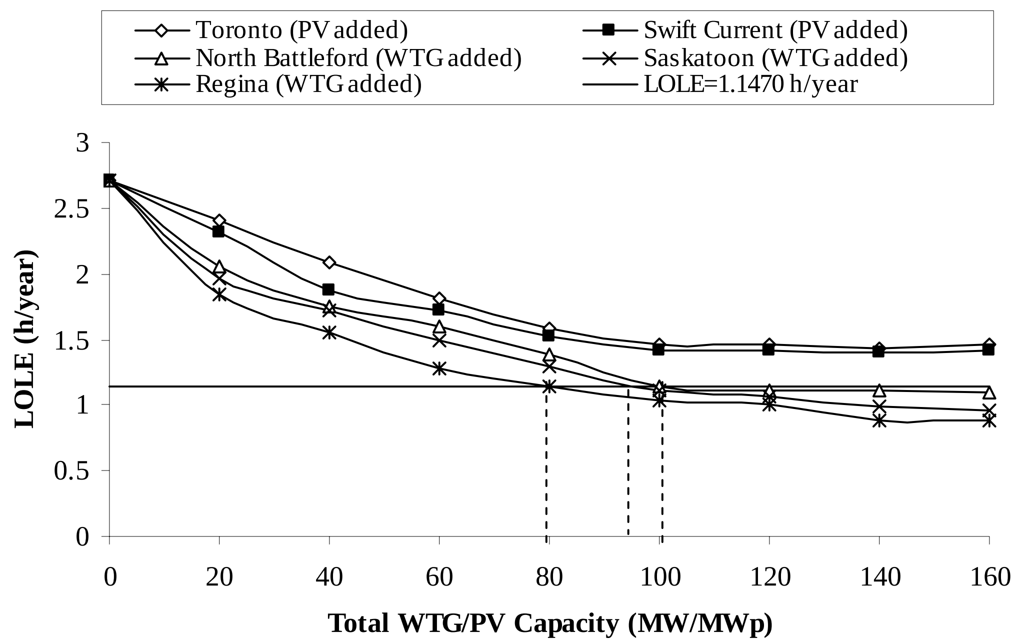
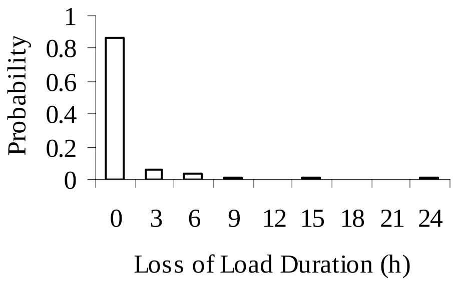


Figure 6.10: LOLE versus total WTG or PV capacity assuming a 10 MW thermal unit is removed from the RBTS

Table 6.7: WTG or PV unit capacity relative to a 10 MW conventional generation unit

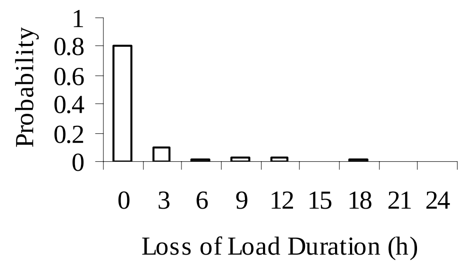
Cases	Capacity needed (MW or MW_p)	RBECR (WTG or PV Capacity/ 10)
Toronto (PV added)	Not possible	Not possible
Swift Current (PV added)	Not possible	Not possible
North Battleford (WTG added)	101.77	10.18
Saskatoon (WTG added)	95.76	9.58
Regina (WTG added)	80.00	8.00

Figure 6.11 compares the LOLD distributions of the original RBTS and those of the combined systems with the same reliability level as the original RBTS assuming that a 10 MW unit is removed from the RBTS. These distributions are recreated by replacing the 10 MW conventional unit with the required WTG capacities presented in Table 6.7. Table 6.8 shows the probability of zero LOLD for the each case shown in Figure 6.11. The conclusions in this case are similar to those obtained with a 5 MW unit removal.



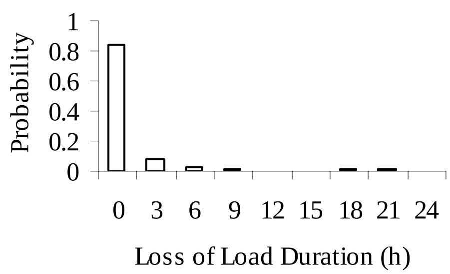
(a) Original RBTS

LOLE=1.1470 h/year



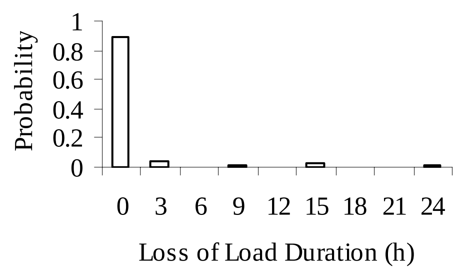
(b) RBTS with 80.00 MW WTG

Regina Data, LOLE=1.1475 h/year



(c) RBTS with 95.76 MW WTG

Saskatoon Data, LOLE=1.1461 h/year



(d) RBTS with 101.77 MW WTG

North Battleford Data, LOLE=1.1537 h/year

Figure 6.11: Distributions of the loss of load duration for different cases related to a 10 MW conventional generation unit

Table 6.8: Probabilities of zero value for the LOLD distributions shown in Figure 6.11

WTG Added (MW)	Probability of Zero Value
Original RBTS	0.862523
North Battleford (WTG added)	0.808032
Saskatoon (WTG added)	0.821196
Regina (WTG added)	0.841193

A final study was conducted in which a 20 MW thermal unit was removed from the RBTS. The results are shown in Figure 6.12 and Table 6.9. It can be seen from Figure 6.12 and Table 6.9 that if a 20 MW conventional generating unit is removed from the RBTS, the system reliability level can not be maintained by adding WTG or PV. The 20 MW conventional unit could possibly be replaced by WTG or PV if these generating units are installed at a site with abundant wind and/or solar resources. Similar studies on the RBTS involving increasing the mean wind speed up to a certain level show that larger conventional units can be replaced by WTG [100].

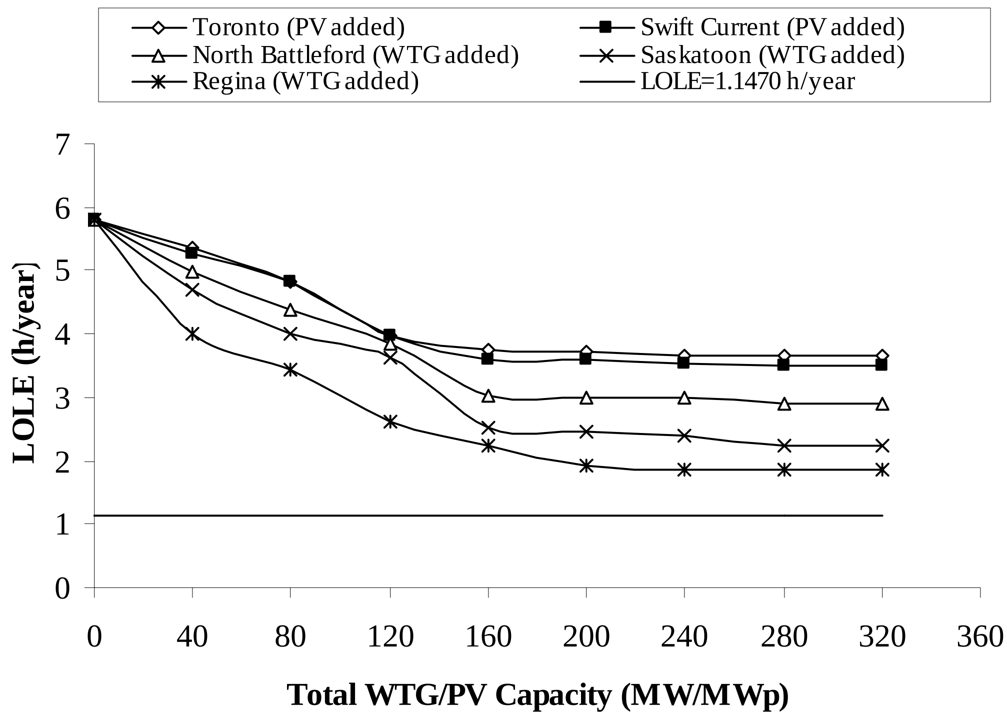


Figure 6.12: LOLE versus total WTG or PV capacity assuming a 20 MW thermal unit is removed from the RBTS

Table 6.9: WTG or PV unit capacity relative to a 20 MW conventional generation unit

Cases	Capacity needed (MW or MW_p)	RBECR (WTG or PV capacity/20)
Toronto (PV added)	Not possible	Not possible
Swift Current (PV added)	Not possible	Not possible
North Battleford (WTG added)	Not possible	Not possible
Saskatoon (WTG added)	Not possible	Not possible
Regina (WTG added)	Not possible	Not possible

6.3 Multiple Site Case Studies

The previous analyses deal with the adequacy assessment of combined systems containing a single a wind farm or a solar park. This section investigates the adequacy of combined systems containing multiple wind farms or solar parks. Wind data from Regina and Saskatoon sites and solar data from Swift Current and Toronto sites are used in the following analysis. The RBTS was modified by adding two wind farms or solar parks or a wind farm and a solar park to compare the relative reliability benefits. The total capacity added in each case is 22.5 MW in the case of WTG addition and 22.5 MW_p in the case of PV addition. The total capacity is equally shared by each site for the multiple site cases. A description of different system configurations designated as A, B, C, D, E, F, G and H respectively and the site data used in the simulations are presented in Table 6.10.

Table 6.10: Combined RBTS with different system configurations

Case	System Configuration	Site Data
A	Original system	N/A
B	Single solar park	Swift Current
C	Two solar parks, different atmospheric conditions	Swift Current Toronto
D	Two solar parks, same atmospheric condition	Swift Current
E	Two wind farms, different wind regime	Regina Saskatoon
F	Single wind farm	Regina
G	A wind farm and a solar park	Regina Swift Current
H	Two wind farms, same wind regime	Regina

Table 6.11 shows the basic adequacy indices for the eight different system configurations shown in Table 6.10. It can be seen from Table 6.11 that after adding a single wind farm at the Regina (Case F), the LOLE decreases from 1.1470 hour/year (Case A) to 0.7512 hour/year. Table 6.11 also shows that if the WTG units are located at two independent sites (Case H) which have the same wind regime (Regina) as in Case F, the LOLE decreases to 0.6959 hour/year. The reliability benefits obtained from the two

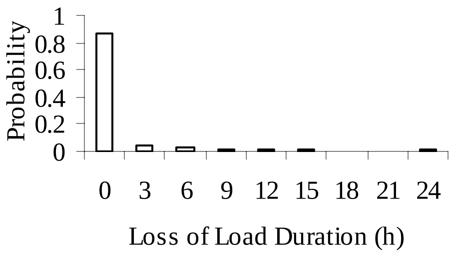
wind farm case, but with different wind regimes (Case E), is lower than those obtained from Cases G and H mainly due to the lower mean wind speed at the Saskatoon site. This example clearly illustrates the reliability benefits of wind energy independence. Similar conclusions can be drawn for the RBTS cases containing solar energy (Cases B, C and D). When a wind farm and a solar park assuming using data from the Regina and Swift Current sites are respectively added to the RBTS (Case G), the LOLE decreases from 1.1470 hour/year (Case A) to 0.7355 hour/year.

Table 6.11: Reliability indices for the RBTS before and after adding 22.5 MW or MW_p WTG or PV units (Single and multiple sites comparisons)

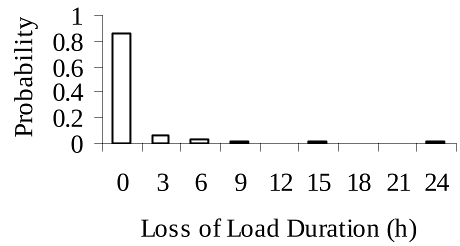
Case	LOLE (hours/year)	LOEE (MWh/year)	ELOLD (hours/occ.)	ELOLF (occ./year)
A	1.1470	10.6972	5.3110	0.2160
B	0.9520	9.9641	3.4051	0.2863
C	0.9282	9.5182	3.4151	0.2718
D	0.9220	9.0559	3.3945	0.2716
E	0.7802	4.8235	4.0927	0.1906
F	0.7512	4.6252	4.6417	0.2005
G	0.7355	4.5361	2.8151	0.2613
H	0.6959	4.2620	3.3328	0.2088

Wind and solar energy independence can make a positive reliability contribution to a power system utilizing non-conventional energy sources. A WTG or a PV unit produces no power or little power if the wind or sunlight is insufficient at a particular site location. It is quite possible that there is no wind or sunlight at a specific time at a given site. All of the WTG or PV units at a specific location make no contribution to the system under these circumstances. If the units are located at two different independent sites, the possibility of there being no wind or sunlight simultaneously at both sites is much less and therefore, the possibility of no WTG or PV power is decreased substantially. Reliability performance of a WTG or PV depends strongly on the site resource availability. Distributing WTG or PV to independent sites is of considerable benefit in improving the reliability of a power system utilizing wind and/or solar energy.

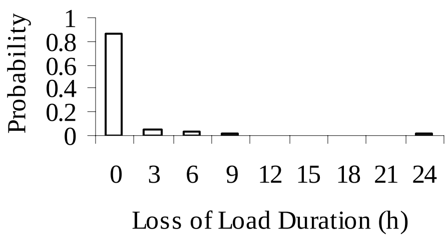
Figure 6.13 shows the LOLD distribution for each case shown in Table 6.10. The distributions shown in Figure 6.13 are quite similar to those discussed previously and therefore similar conclusions can be drawn.



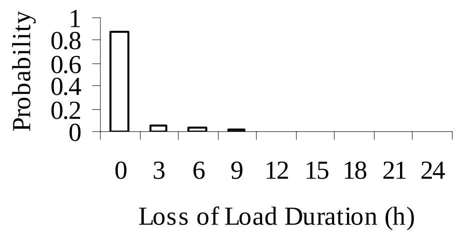
(a) Case A, LOLE=1.1470 h/year



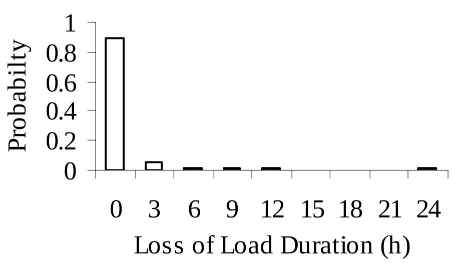
(b) Case B, LOLE=0.9520 h/year



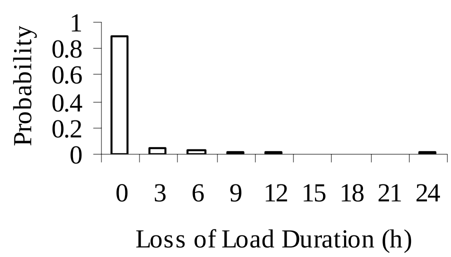
(c) Case C, LOLE=0.9282 h/year



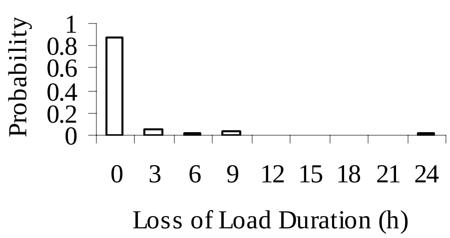
(d) Case D, LOLE=0.9220 h/year



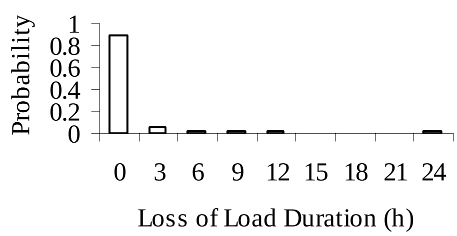
(e) Case E, LOLE=0.7802 h/year



(f) Case F, LOLE=0.7512 h/year



(g) Case G, LOLE=0.7355 h/year



(h) Case H, LOLE=0.6959 h/year

Figure 6.13: Distributions of the loss of load duration for the different cases shown in Table 6.10

6.4 Summary and Conclusions

The simulation models and methodology described in previous chapters for generating capacity adequacy evaluation of small isolated power systems are modified and applied to the RBTS in this chapter. A series of adequacy analyses have been conducted using both mean values and the distributions of selected reliability indices in order to investigate the impacts of adding different energy sources to the RBTS. Both single site cases and multiple site cases are examined.

The reliability benefits obtained from the addition of conventional generators are much greater than that obtained by an equal capacity addition of PV or WTG. The reliability benefits of adding a single wind form or solar park to a given power system are analysed in regard to selected parameters such as site resource availability, system peak load, renewable energy penetration and energy storage capability. All of these factors have significant impacts on the overall system reliability as measured by the mean values of the reliability indices.

The variation in the LOLD distributions with changes in selected parameters is relatively small compared with the results obtained from the small isolated system studies. The LOLD distributions associated with the RBTS are largely dominated by the load/capacity characteristics of the original system. The sensitivities of the LOLD distributions to changes in the selected parameters are more noticeable by comparing the changes in the probability of zero values.

Different conventional generating units were removed from the RBTS and replaced by WTG or PV units in the single site case studies, while maintaining the reliability criterion. In the studies shown in this chapter, the system reliability can be maintained if a 5 MW unit is replaced by either WTG or PV units, but the required capacity is not the same for each case considered. If a 10 MW conventional unit is removed from the RBTS, the reliability criterion cannot be maintained by replacing this unit by PV. The system reliability cannot be maintained if a 20 MW unit is replaced by either WTG or PV in the RBTS.

Analyses have been conducted for multiple site cases in order to investigate the reliability benefits of wind or solar energy independence in an existing power system. The studies show that there is a strong reliability benefit associated with wind or solar energy independence. This is due to the fact that the effective combined availability of the wind or solar resources in multiple independent sites is normally higher than that in a single site. This could be an important area for further research.

7. INCORPORATING WELL-BEING CONSIDERATIONS IN GENERATING SYSTEMS USING ENERGY STORAGE

7.1 Introduction

The increasing utilization of wind and solar energy for power supply in remote locations involves serious consideration of the reliability of these unconventional energy sources. Most utilities use deterministic criteria in the planning and design of these systems. The main disadvantage of deterministic criteria is that they do not recognize and reflect the inherent random nature of the site resources, the system behavior, and the customer demands etc. Probabilistic techniques can be used to overcome this drawback and incorporate the inherent uncertainty in these factors. Power system planners and designers sometimes experience difficulties in interpreting and using probabilistic reliability indices. This difficulty can be alleviated by incorporating deterministic considerations into a probabilistic evaluation using the well-being concept described in Chapter 2.

Considerable attention has been devoted in the literature to the application of the well-being method in conventional power system reliability evaluation [29-42]. These works are mainly concentrated on the development of analytical evaluation methods for well-being analysis of power systems using conventional energy sources. These techniques are, however, not applicable for the well-being analysis of power systems using unconventional energy sources and energy storage. A simulation technique is presented in this chapter which extends the conventional well-being approach to generating systems using wind energy, solar energy and energy storage [101]. The proposed technique is illustrated and applied in this chapter to several SIPS. The effects on the system well-being of some of the major system parameters and the deterministic criteria are illustrated. The distributions of the well-being indices are also presented

7.2 Deterministic Criteria Used in Small Isolated Power System Planning

As noted earlier, the basic criteria used in SIPS planning are deterministic. Many utilities evaluate SIPS reliability using physical and observable reserve margins based on their past experiences obtained from conventional capacity planning. Different criteria are used to define an acceptable level of system reliability. The most commonly used deterministic criteria in SIPS planning are the capacity reserve margin (CRM), loss of the largest unit (LLU) and combinations of these. These techniques are widely used by SIPS planners in the reliability analysis of systems without energy storage facilities. When energy storage is considered, the storage reserve capacity can be determined in terms of the number of required days of battery back-up. This is known as the number of autonomous days (NAD) or hours (NAH) [87]. If a system contains only WTG or PV units, the NAD or NAH value indicates the number of consecutive days or hours that the total system load can be supplied by the energy storage system given that there is no power available from the WTG or PV systems [87-89].

The actual storage system back-up capacity required (SSBC) is the NAD multiplied by the average daily load (DL_{ave}) of the system.

$$SSBC = NAD * DL_{ave} \tag{7.1}$$

The NAD or NAH method does not consider the continuous variation in the site resources and the system load and their impacts on the storage capability. This method has not been applied to SIPS containing conventional units such as diesel engines, as the NAD or NAH is conventionally associated with only generation shortages due to wind and/or solar resource deficiencies. The basic assumption in the NAD or NAH method is that the storage facility will supply energy to the system during the specified time intervals when there is any generation shortage. For example, if the NAH is four hours, the energy in the storage facility should be enough to supply the load demand for at least four hours when the load exceeds the available generation. This concept is illustrated by application in this chapter.

7.3 Proposed Evaluation Technique

The basic idea of the well-being technique is illustrated in Figure 2.10. The system is considered to be in the healthy state when it has enough reserve margin to satisfy a deterministic criterion such as the CRM, NAD or NAH etc. The system is considered to be in the marginal state when the system has no difficulty in meeting the load requirement but does not have sufficient reserve to meet the specified deterministic criterion. The system resides in the risk state when the load exceeds the available capacity.

System well-being analysis incorporates the accepted deterministic criteria in a probabilistic framework. The possible system reserve margins are compared to desirable margins determined using the accepted deterministic criteria to measure the degree of system comfort. Several indices have been developed to assess the system from a deterministic point of view, while recognizing its stochastic behavior and inherent risks [29-42]. These indices can be readily interpreted by power system planners, operators and decision-makers who are more familiar with and prefer to use deterministic criteria. The basic well-being indices are the probability of health, margin and risk. The conventional risk associated with a generating system is the probability of being in the risk state, and usually designated as the loss of load probability (LOLP). The degree of comfort associated with operating the system within the accepted deterministic criterion is given by the probability of residing within the healthy state P(H). The marginal state probability P(M) is the probability of finding the system in a condition that violates the accepted deterministic criterion but is not in a capacity deficiency. Additional indices associated with system well-being analysis, such as the loss of health expectation (LOHE), can also be used if required. The Monte Carlo simulation (MCS) technique was used in the studies described in this chapter. In the MCS method, the generation model is superimposed on the load model as shown in Figure 2.9 to obtain the various reliability indices. The extension of this basic method to evaluate system well-being indices is shown in Figure 7.1.

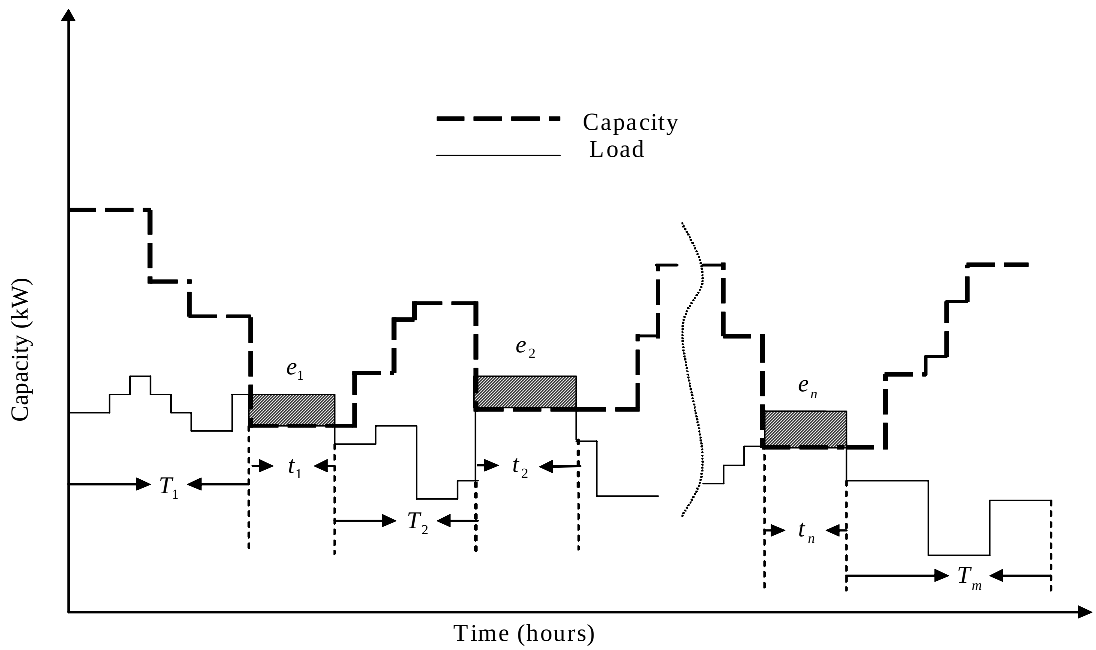


Figure 7.1: Superimposition of capacity states and the chronological load pattern for system well-being analysis (The shaded areas represent a negative margin)

In Figure 7.1, the periods in which the available capacity exceeds the load are shown as T_i and the periods in which the load exceeds the capacity are shown as t_i. The energy curtailed in each case is e_i. The effect of energy storage is incorporated in the capacity profile shown in Figure 7.1.

The conventional risk indices for a SIPS can be obtained by recording the loss of load duration t_i and the energy loss e_i due to load curtailment. The well-being indices can be obtained using the time duration T_i and t_i. If the energy stored in the storage system (ESISS) is equal to or greater than the average load (AL) or the peak load (PL) multiplied by the accepted NAH, the system condition is healthy and the corresponding duration T_i is a healthy state duration designated as T_i(H) for each healthy state. On the other hand, whenever the ESISS is less than the AL or PL multiplied by the NAH, the condition is marginal and the corresponding duration T_i is a marginal state duration and designated as $T_i(M)$. This procedure is described mathematically by Equation (7.2).

$$T_i = \begin{cases} T_i(H), & if \ \text{ESISS} \geq NAH * PL\,(or\ AL) \\ T_i(M), & if \ \text{ESISS} < NAH * PL\,(or\ AL) \end{cases} \tag{7.2}$$

The total number of times that the system in the healthy state n(H), marginal state n(M) and risk state n(R) are recorded in the simulation in order to calculate the well-being indices using (7.3)-(7.9).

Loss of health expectation:

$$LOHE = 8760 - \frac{1}{N}\sum_{i=1}^{n(H)} T_i(H) \tag{7.3}$$

Healthy state probability:

$$P(H) = \frac{1}{8760N}\sum_{i=1}^{n(H)} T_i(H) \tag{7.4}$$

Marginal state probability:

$$P(M) = \frac{1}{8760N}\sum_{i=1}^{n(M)} T_i(M) \tag{7.5}$$

Frequency of health:

$$F(H) = \frac{n(H)}{N} \tag{7.6}$$

Frequency of margin:

$$F(M) = \frac{n(M)}{N} \tag{7.7}$$

Expected healthy duration:

$$EHD = \frac{1}{n(H)} \sum_{i=1}^{n(H)} T_i(H) \tag{7.8}$$

Expected margin duration:

$$EMD = \frac{1}{n(M)} \sum_{i=1}^{n(M)} T_i(M) \tag{7.9}$$

The frequency and duration well-being indices provide additional adequacy information. The frequency and duration of a state are inversely related for a given state probability. The frequency of health and margin measure the expected number of times the healthy and marginal states are encountered in a year. The frequency of health is the number of occurrences when the system has enough storage capacity or capacity reserve to satisfy a deterministic criterion. The frequency of margin is the number of occurrences when the system violates the accepted deterministic criteria without system failure. The expected health duration measures the average duration of the system in the healthy state. A high value of the EHD represents a more comfortable system at the same healthy state probability as it implies that the system resides in the healthy state longer. The expected marginal duration is the average duration of the system in the marginal state.

Most utilities use probabilistic techniques in conventional generating unit capacity planning. SIPS generation planning is different from that of conventional systems as it involves both conventional and unconventional generating units and energy storage facilities. The proposed well-being technique presented in this chapter provides an additional methodology for a complete evaluation of capacity and/or storage expansion in small stand-alone systems utilizing wind and solar energy.

7.4 Application of the Proposed Technique

A range of studies was performed to examine the well-being of SIPS using energy storage. The example systems use data from different site locations in Canada. Three basic system configurations with different energy and storage combinations are considered. The system data for each case are shown in Table 7.1. The hourly chronological load shape of the IEEE-RTS [86] is used with a peak load of 40 kW unless otherwise specified. The deterministic criterion used to define the healthy state is that the storage system can supply the system peak load for the next four hours (NAH= 4 hours), unless otherwise specified. The system is assumed to be located at a geographic location with atmospheric conditions represented by the Swift Current solar radiation data and the Regina wind speed data.

Table 7.1: Example System Data

Case	Generation and storage	No.	Rating	FOR (%)	Failure rate per year	MTTF (h)	MTTR (h)
1	Diesel (D)	2	20 kW	5	9.2	950	50
	Solar (PV)	2	30 kW_p	3	3	2910	90
	Storage (S)	1	300 kWh	N/A	N/A	N/A	N/A
2	Diesel (D)	2	20 kW	5	9.2	950	50
	Wind (W)	1	30 kW	4	4.6	1920	80
	Solar (PV)	1	30 kW_p	3	3	2910	90
	Storage (S)	1	300 kWh	N/A	N/A	N/A	N/A
3	Diesel (D)	2	20 kW	5	9.2	950	50
	Wind (W)	2	30 kW	4	4.6	1920	80
	Storage (S)	1	300 kWh	N/A	N/A	N/A	N/A

Table 7.2 shows the basic well-being indices for the three systems given in Table 7.1. It can be seen from Table 7.2 that the level of system well-being is different in each case. A comparison of the reliability benefits associated with using unconventional energy sources such as wind and solar energy depend largely on the resources at the site locations. In these systems, the wind-diesel system provides better system reliability in

terms of the degree of system comfort than that of the solar-diesel system. This is due to the fact that the PV arrays generate little or no energy during the night. When both PV arrays and WTG are combined with diesel units, the degree of system comfort is between that of the solar-diesel and the wind-diesel configurations. The values shown in Table 7.2 constitute a reference set of system well-being indices for the systems considered in this chapter.

Table 7.2: Basic well-being indices for the systems shown in Table 7.1

Case	P(H)	P(M)	LOLP	LOHE (h/yr)
1	0.985629	0.006854	0.007517	125.89
2	0.993742	0.003816	0.002442	54.82
3	0.994812	0.003552	0.001636	45.45

Generating capacity well-being in SIPS depends on many different factors such as the storage capability, the system load, the renewable energy penetration level, the generating unit forced outage rate, the site resource availability and the deterministic criterion used in the evaluation. The impacts of some of these factors on the three basic system configurations are illustrated in the following sections.

7.4.1 Effect of Energy Storage Capacity

As noted earlier, the deterministic criterion (NAH) used to define the healthy state of a SIPS depends on the energy storage capability. The energy storage capability is, therefore, one of the most important elements that influence SIPS well-being. The three basic system configurations with different storage facilities were investigated in order to appreciate the impact of energy storage capacity on SIPS well-being. The system well-being indices were determined as a function of the energy storage capacity.

Figure 7.2 shows the healthy, marginal and risk state probabilities for the three basic system configurations with different energy storage capacity levels ranging from 100 kWh to 600 kWh. In each case, the healthy state probability increases as the energy storage capacity increases. The marginal and risk state probabilities decrease with increase in the storage capability.

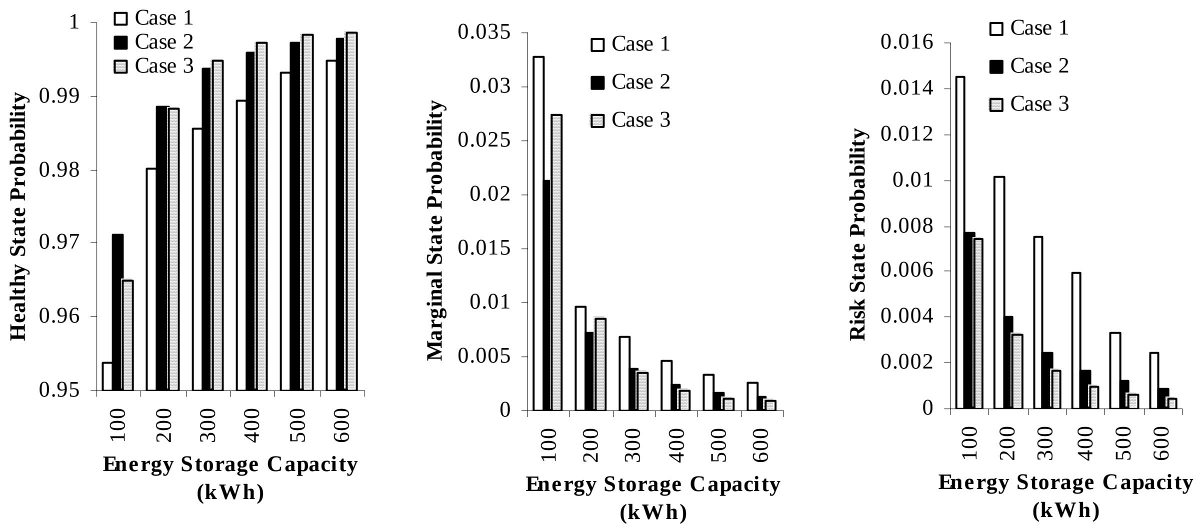


Figure 7.2: Effect of the energy storage capacity on system health, margin and risk

Figure 7.2 shows that the addition of storage capacity to a given system has a strong positive effect on the system well-being. Determination of the optimum additions to the system in order to maintain the acceptable risk and/or health levels is an important system planning task. Figure 7.2 also shows that the wind-diesel units provide better system health than the solar-diesel units for all energy storage capacity levels. The reliability is generally between those of the other two alternatives when the wind-solar-diesel combination has storage capacity in excess of a certain value (in this case it is approximately 200 kWh). Integration of wind, solar and diesel generation gives, however, better system health than the combination of wind or solar energy with diesel generation when there is relatively small storage in the system. The reliability of a SIPS is strongly affected by the site resources, and the results obtained in different situations depend strongly on the meteorological data used in the evaluation. Accurate and detailed data for the actual site location is, therefore, an essential requirement for an accurate evaluation of a generating system using renewable energy sources.

Figure 7.3 shows the LOHE as a function of the energy storage capacity for the three basic system configurations. It can be clearly seen from Figure 7.3 that the addition of a suitable energy storage system significantly improves the system reliability as measured by the LOHE. The results also show that the incremental benefit decreases with the addition of more storage capacity.

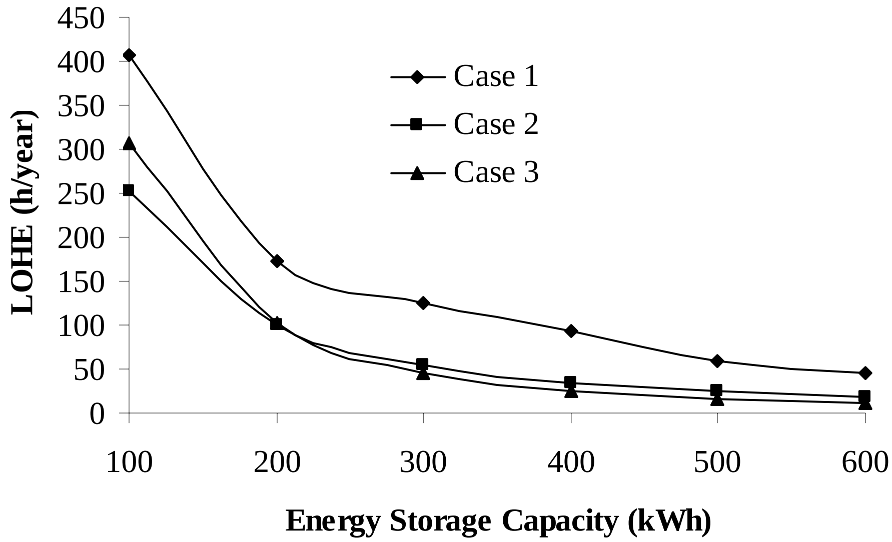


Figure 7.3: Effect of the energy storage capacity on the LOHE

7.4.2 Effect of Renewable Energy Penetration Level

The studies performed previously are based on the system generation facilities presented in Table 7.1 and specified storage capacities and load levels. These generation facilities may not meet the growing future load demand at an acceptable level of health and/or risk. In such cases, additional generating facilities may be added to the system to maintain the system reliability. Due to the high cost and potential environmental impacts associated with conventional units, the addition of renewable generation can be beneficial in small isolated applications from both reliability and economic points of view. In order to illustrate the impact of renewable energy penetration levels on SIPS well-being, different well-being indices were calculated by expanding the generating capacity of Case 2 with some modifications to the original system configuration. The wind and solar units are removed from Case 2 and the system expanded using equal step increases in wind and solar generation respectively with the other system parameters unchanged. The wind and solar capacity added in each step are 20 kW.

Figure 7.4 shows the effect on the health, margin and risk state probabilities of increasing renewable energy penetration levels. It can be seen from Figure 7.4 that the healthy state probability increases as the renewable energy capacity increases. The marginal and risk state probabilities decrease with increase in the renewable energy capability.

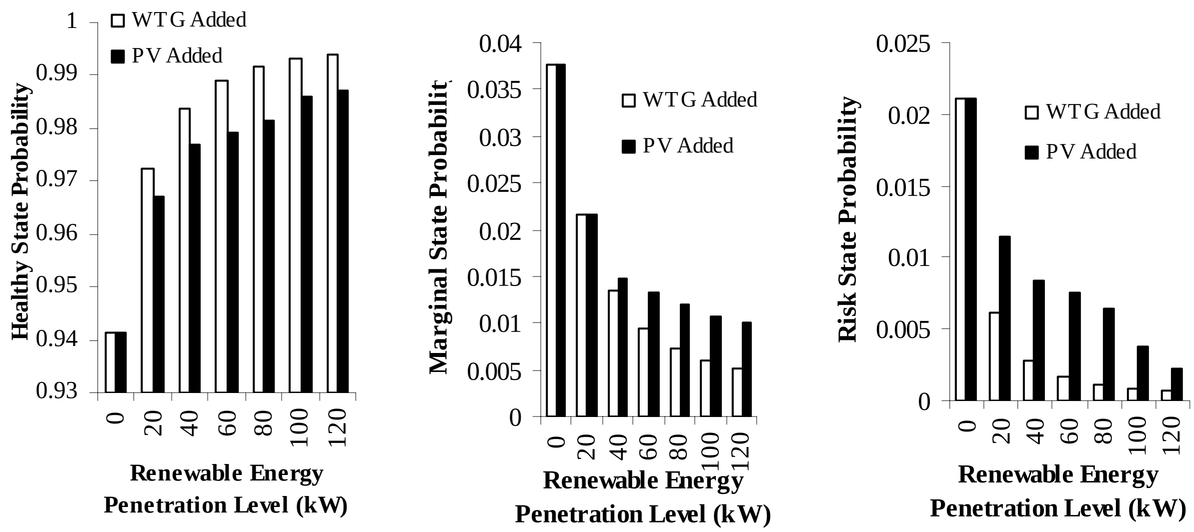


Figure 7.4: Effect of the renewable energy penetration level on system health, margin and risk

Figure 7.5 shows the LOHE as a function of the wind and solar capacity added to the system. The LOHE decreases with increase in the renewable energy penetration. It can be seen that the addition of either wind or solar generation improves the system well-being but not to the same degree. The well-being benefits decrease with increased penetration of wind or solar energy and reach a point when no reliability improvement can be obtained by further increases. This information is very useful in capacity expansion planning for a given site location.

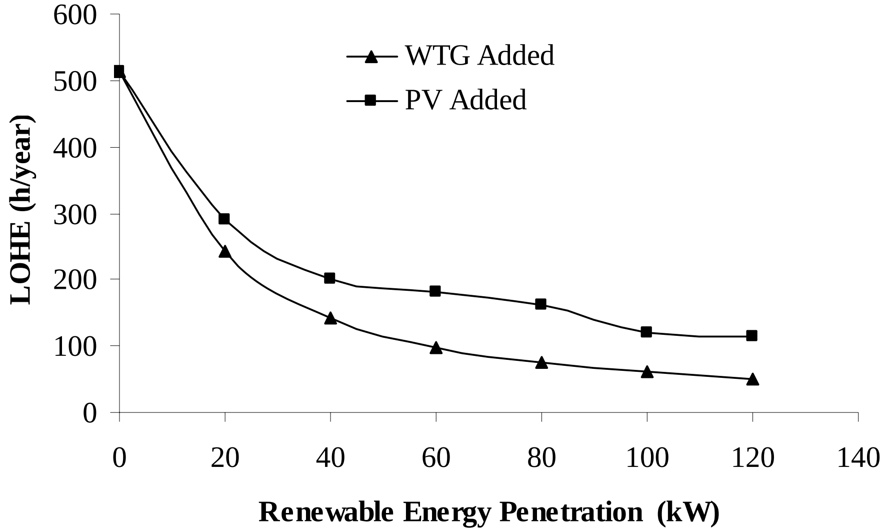


Figure 7.5: Effect of the renewable energy penetration level on the LOLE

7.4.3 Effect of Generating Unit FOR

In order to illustrate the effects of different types of energy generating unit FOR on a SIPS well-being, the FOR of WTG, PV array and diesel unit are varied from 2% to 10% in equal steps of 0.02 in Cases 1 and 3. The system well-being indices are compared for the following scenarios.

1. Changing all the diesel units FOR from 2% to 10% keeping the PV units FOR unchanged for Case 1.
2. Changing all the PV units FOR from 2% to 10% keeping the diesel units FOR unchanged for Case 1.
3. Changing all the diesel units FOR from 2% to 10% keeping the WTG units FOR unchanged for Case 3.
4. Changing all the WTG units FOR from 2% to 10% keeping the diesel units FOR unchanged for Case 3.

Figure 7.6 shows the influence of the FOR on the LOHE for the scenarios listed above. It can be seen that the system LOHE increases significantly as the FOR of the diesel unit increases. On the contrary, the changes in FOR of the unconventional units have much less influence on the system LOHE. The reason is that the site resource fluctuation and the dependency associated with similar units offset the effect of the FOR on the system reliability performance. The energy availability of the renewable sources is largely dictated by the available site resources. The fluctuating site resources mask the effects of failures and repairs of the unconventional units and hence minimize the effect of unconventional unit FOR.

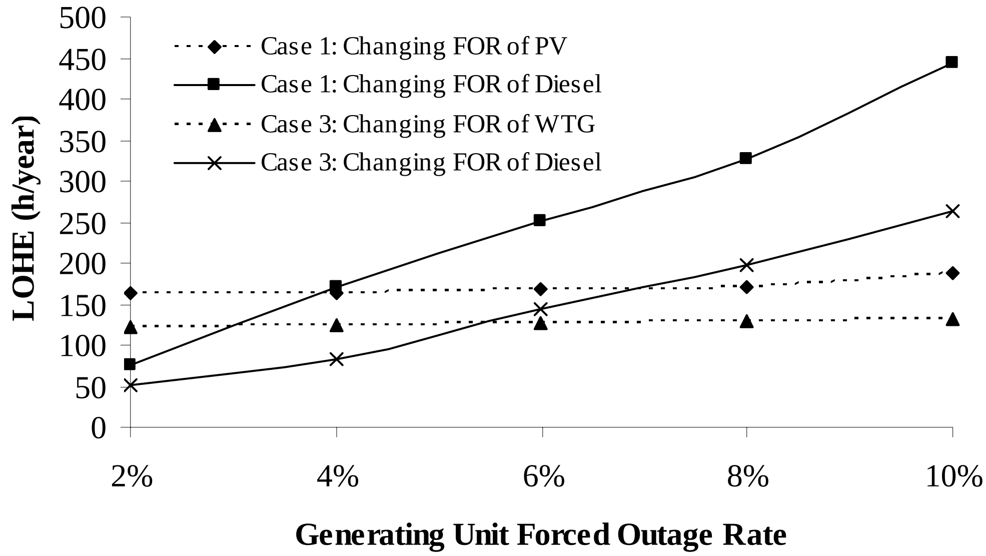


Figure 7.6: Effect of the generating unit FOR on the LOHE

7.4.4 System Load Considerations

Deterministic criteria normally use the peak load as the single load parameter. The system load, however, normally varies with time and this variability should be taken into consideration. The load variation pattern and the peak value both impact the system reliability. These effects have been considered and the results are shown in Figure 7.7 and Figure 7.8 respectively.

Figure 7.7 shows the LOHE of the three systems shown in Table 7.1 for three different load profiles. The system LOHE is lowest for the residential load model for each configuration. When the IEEE-RTS load model is used, the LOHE is higher than the value obtained for the residential load. A constant load at the peak value produces the highest LOHE, as expected.

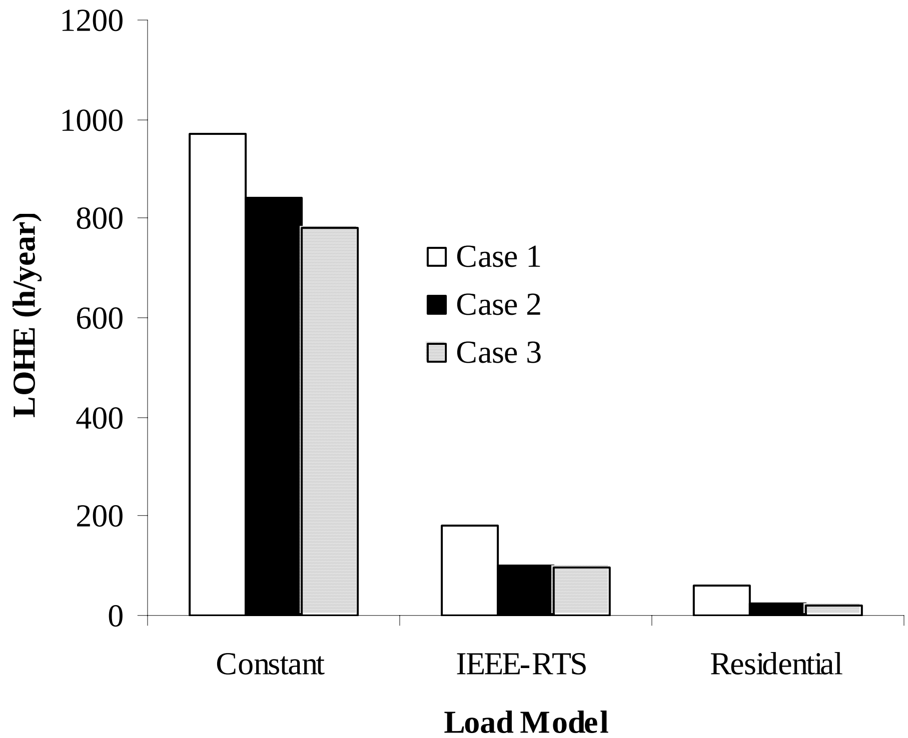


Figure 7.7: Effect of different load models on the LOHE

Figure 7.8 shows the LOHE for the three basic system configurations as functions of the annual peak load. The peak load is varied from 40 kW to 70 kW with equal steps of 5 kW while maintaining the basic shape of the IEEE-RTS load curve. It can be seen from Figure 7.8 that the LOHE increases almost linearly with the annual peak load when the annual peak load is under a certain value, in this case 55 kW. When the peak load exceeds this value, the index increases sharply. The results also show that system well-being performance measured in terms of LOHE is sensitive to load growth. In these situations, additional generating capacity and/or energy storage must be installed.

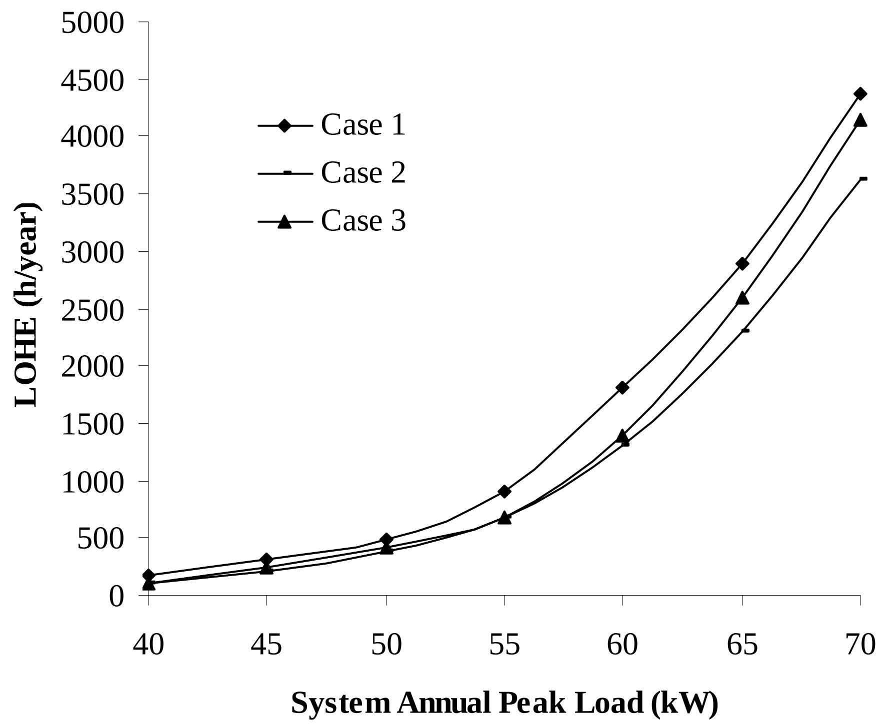


Figure 7.8: Effect of the annual peak load on the LOHE

7.4.5 Effect of Site Resources

As noted earlier, the reliability performance of a SIPS depends strongly on the site resource such as wind and sunlight. The weather characteristics associated with site resources very with the different geographic locations. The example systems with integrated solar-diesel and wind-diesel shown in Cases 1 and 3 have been examined to analyze the effect on the system well-being considering different geographic locations. The system with PV units (Case 1) has been considered using the atmospheric data from two different Canadian locations: Swift Current and Toronto.

Figure 7.9 shows the healthy state probabilities for Case 1 with weather characteristics represented by these two locations. It can be seen that the utilization of an integrated PV-diesel system provides better system health in the Swift Current case than in Toronto case. The reason for this is that the monthly average solar radiation values are higher in Swift Current than in Toronto. The Swift Current data is used in all of the other PV related studies described in this chapter.

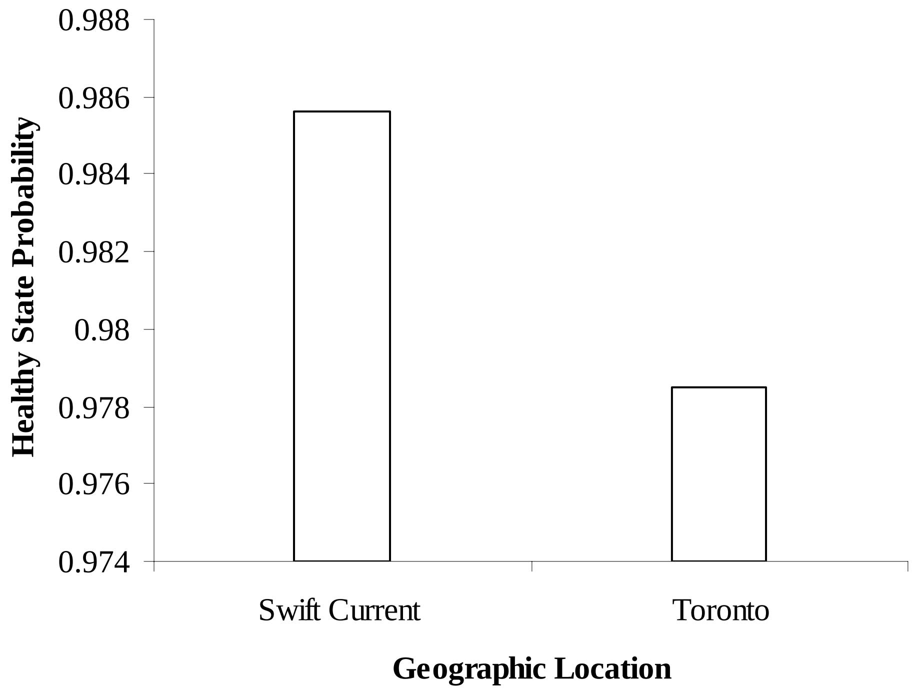


Figure 7.9: Comparison of healthy state probabilities at different locations with different solar radiation pattern (Case 1)

In order to illustrate the impact of wind resources on system health, the system with WTG units (Case 3) has been investigated using the wind data from three different Canadian locations: North Battleford, Saskatoon and Regina.

Figure 7.10 compares the system health for Case 3 with the wind characteristics represented by the three different locations. A wind-diesel system situated at a location with a higher mean wind speed has higher system health. The Regina site has the highest average wind speed and as expected, the system health at this location is better than that at the other two sites. The wind data from the Regina site is used in all of the other studies related to wind energy conversion systems described in this chapter.

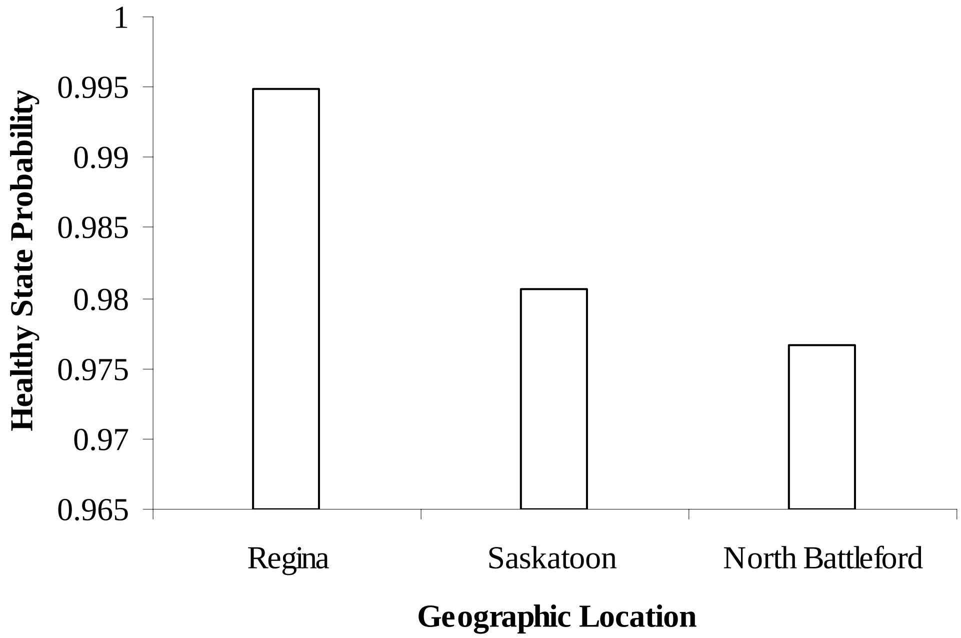


Figure 7.10: Comparison of healthy state probabilities at different locations with different wind regimes (Case 3)

7.4.6 Effect of Deterministic Criterion

The major contribution of the proposed technique is the incorporation of the conventional deterministic criteria used in SIPS planning in a probabilistic evaluation. The well-being indices calculated using this technique can be used in practical power system generating capacity and storage reserve analysis. The desired generating and/or storage reserve margins should be determined such that a specified system risk, a specified system health or both are satisfied. The acceptable risk or health levels are management decisions based on economic considerations. Different utilities may use different deterministic criteria in their capacity or storage planning. These criteria have different impacts on the system operating states. In order to illustrate these effects, the NAH values were changed from 1 hour to 7 hours and the corresponding well-being indices were calculated. Figure 7.11 shows the variation in the system health, margin and risk probabilities with the NAH. It can be seen that the healthy state probabilities decrease, the marginal state probabilities increase and the risk state probabilities remain unchanged with increase in the NAH value for all the three basic system configurations. The healthy state probability is directly related to the accepted deterministic criterion. The more demanding the deterministic criterion, the less health the system has. The risk state probability is a fixed value at a given location for a SIPS with given generating unit, storage and load conditions. The sum of the three operating state probabilities is unity, and therefore, the marginal state probability increases as the healthy state probability decreases. The wind-diesel system provides better health than the solar-diesel system for all the NAH values considered. The health of the wind-solar-diesel system is between that of the wind-diesel and solar-diesel system when the NAH is less than 4 hours. If the NAH is more than 4 hours, the wind-solar-diesel system is superior to the wind-diesel system in terms of system health.

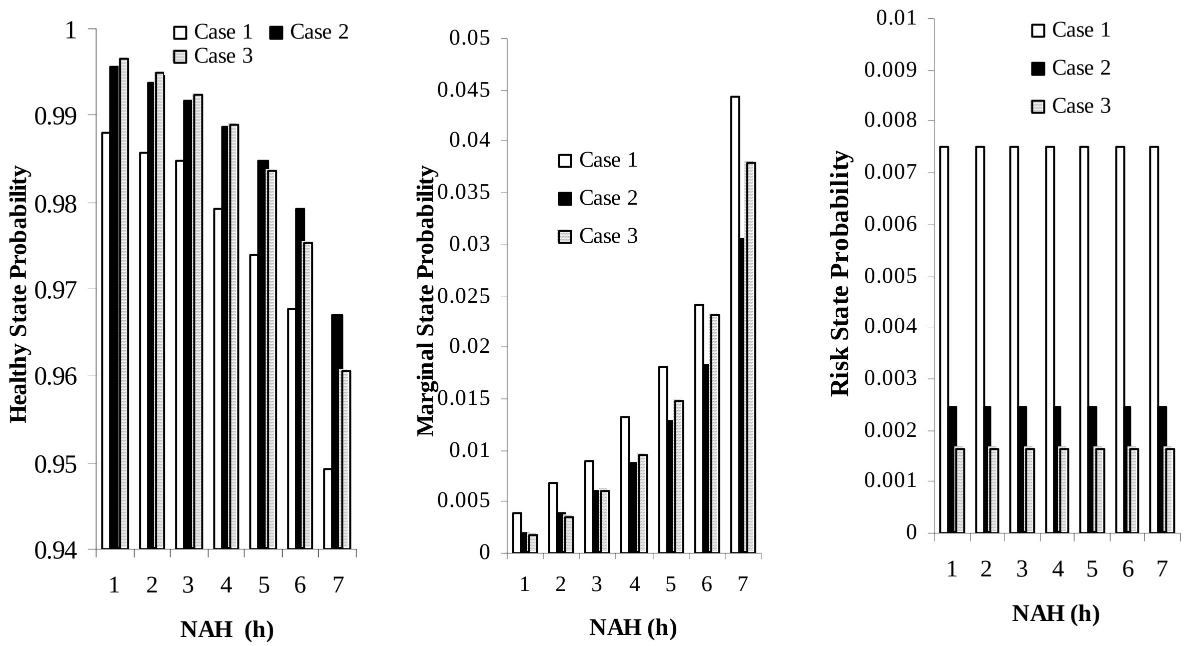


Figure 7.11: Impact of deterministic criterion on system health, margin and risk

Figure 7.12 shows the LOHE as function of the NAH. It can be seen that the LOHE increases with the increase in NAH but not to the same degree. The increment in the LOHE value is almost linear when the NAH is less than a certain value. This is 4 hours in this case. When the NAH exceeds this value, the LOHE increases sharply.

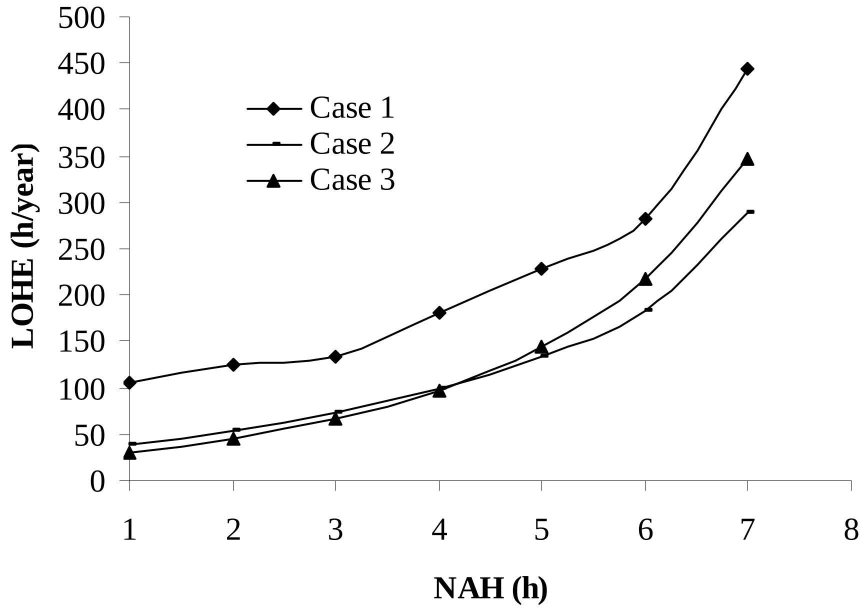
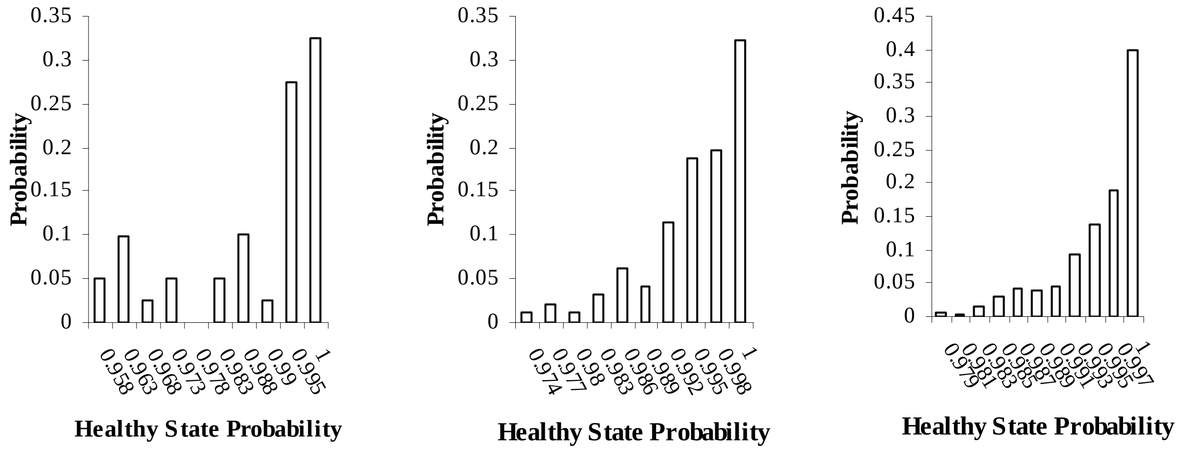


Figure 7.12: Impact of deterministic criterion on LOHE

7.5 Evaluation of Well-being Index Distributions

The main advantage of using MCS in system reliability analysis is in its ability to provide the distributions of the indices about their mean values. The distributions can provide additional information on system well-being performance and used to provide a better appreciation and a more complete evaluation of SIPS reliability.

A set of histograms was obtained using the proposed method described in Chapter 5. The frequency distributions of the healthy state probability for the three basic system configurations are shown in Figure 7.13. Figure 7.13 shows that some healthy state probability values less than the mean occur with relatively high frequency. On the other hand, probabilities of health greater than the mean occur with significantly higher frequency. The marginal state and risk state probabilities for the cases considered in this thesis are shown in Figures 7.14 and 7.15 respectively. The results show that values much greater than the mean occur with significant probability for Cases 1 and 2. This is due to the effect of the PV units in these two configurations which generate no energy during nighttime. This information is very useful when evaluating the variability in the system degree of comfort.

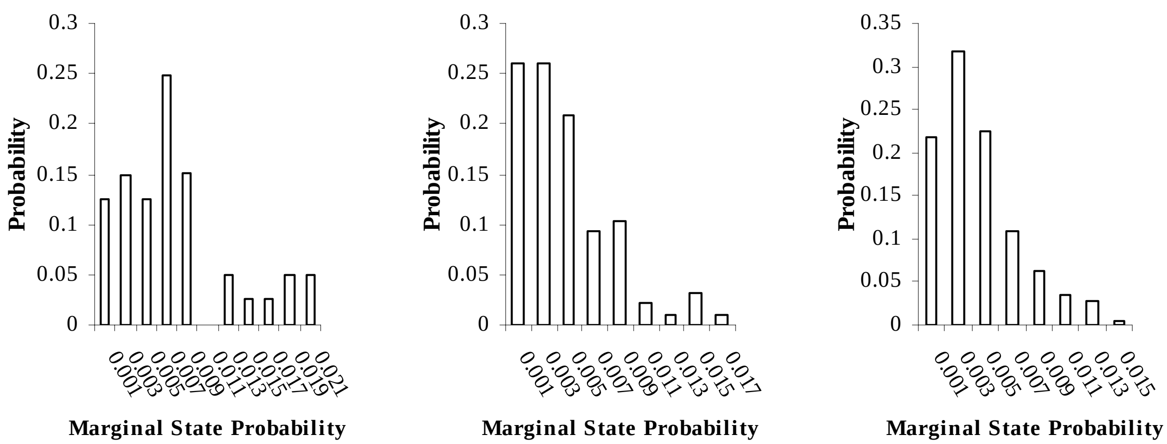


Case 1
Mean = 0.985629

Case 2
Mean = 0.993742

Case 3
Mean =0.994812

Figure 7.13: Healthy state probability distributions

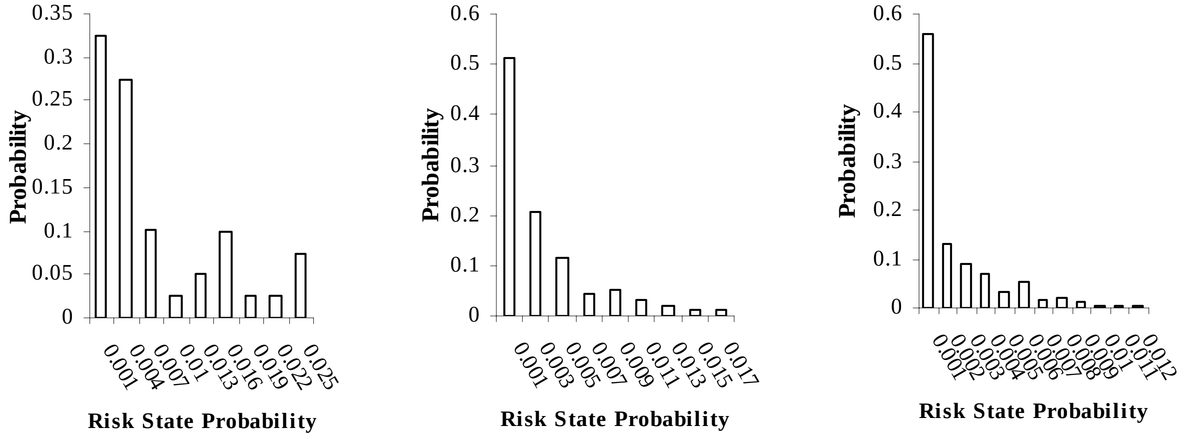


Case 1
Mean = 0.006854

Case 2
Mean = 0.003816

Case 3
Mean = 0.003552

Figure 7.14: Marginal state probability distributions



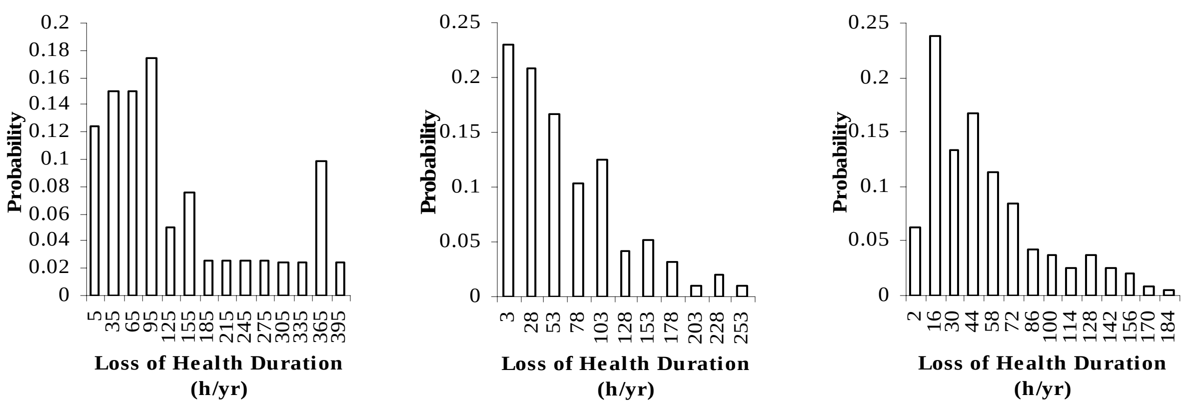
Case 1
Mean = 0.007517

Case 2
Mean = 0.002442

Case 3
Mean = 0.001636

Figure 7.15: Risk state probability distributions

Figure 7.16 shows the relative frequency distributions of the annual loss of health duration for the three basic system configurations. The distributions of the loss of health duration for Cases 1 and 2 are more dispersed compared to that of Case 3. The results also show that values that are much greater than the mean occur with significant probability for all cases. This is most probably due to site resource deficiencies at the system location during a particular period of time. In such situations, the addition of back-up generation such as a small diesel engine may be considered in order to maintain the system health level.



Case 1
Mean = 125.89 h/yr

Case 2
Mean = 54.82 h/yr

Case 3
Mean = 45.45 h/yr

Figure 7.16: Distributions of loss of health duration

Another useful index is the marginal state frequency, which is the average number of occurrences per year of the marginal state. This index measures the number of times the deterministic criterion is violated without system failure. A comparison of the marginal state frequency distributions for the three basic systems is shown in Figure 7.17. Figure 7.17 shows that the marginal state is encounter 24, 16 and 14 times in a single year for Cases 1, 2, and 3 respectively. The corresponding probabilities associated with these high frequencies of encountering the marginal state are, however, relatively small in all these cases.

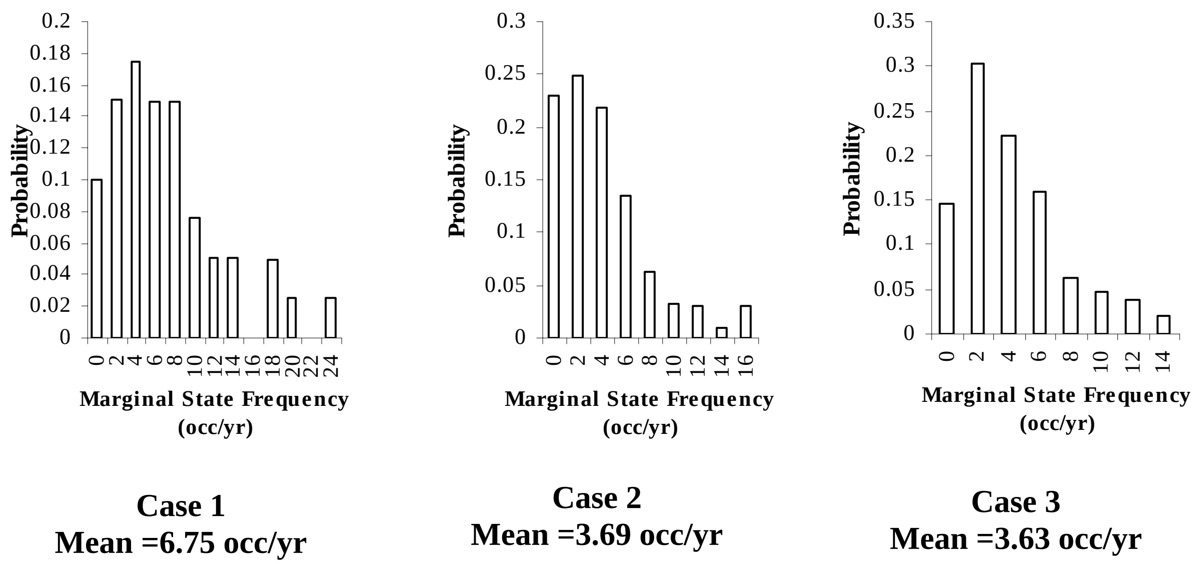


Figure 7.17: Margin state frequency distributions

7.6 Summary and Conclusions

This chapter presents a new simulation approach for the reliability assessment of small isolated power systems using wind and/or solar energy operating in parallel with energy storage. This approach combines probabilistic indices with commonly used deterministic criteria in generating systems with storage facilities to assess the well-being of these systems. The overall system well-being is defined in terms of the system health and margin based on the accepted deterministic criterion in addition to the conventional risk index. The technique is illustrated in this chapter using three basic system configurations with different energy compositions and energy storage capacity levels.

The addition of energy storage capacity to a given system has a strong positive effect on the system well-being. The general well-being approach [29] has been extended in this research to include energy storage facilities using the NAH concept to define the healthy state criterion.

Wind-diesel systems provide better system health than the solar-diesel combinations for all the energy storage capacity levels considered in this thesis. The system degree of comfort is generally between those of the other two alternatives when the wind-solar-diesel combination has storage capacity in excess of a certain value. Integration of wind, solar and diesel generation gives, however, better system health than the combination of wind or solar energy with diesel generation when there is relatively small storage in the system.

The system health increases with increase in the renewable energy penetration. The system degree of comfort in satisfying the deterministic criterion, however, decreases with increased penetration of wind or solar energy and saturates when the renewable energy penetration reaches a certain point.

The degree of system comfort in satisfying the deterministic criterion degrades with increase in conventional generating unit FOR. Variations in the FOR of the non-conventional units, however, do not have significant impacts on the system well-being.

The system health decreases significantly with increase in system load. The relative decrease in the degree of system comfort in satisfying the deterministic criterion is, however, different when different types of energy sources are included in the system. The degree of system comfort is also influenced by the system load profile.

Different deterministic criteria have different impacts on the system well-being indices. The perceived system health decreases as the deterministic criterion become more demanding. The healthy state probabilities decrease, the marginal state probabilities increase and the risk state probabilities remain unchanged in this case. The wind-diesel system provides better health than the solar-diesel system for all the deterministic criteria considered in this thesis. The health of the wind-solar-diesel system is between that of the wind-diesel and solar-diesel system when the deterministic criteria measured in NAH is less than certain values. If the NAH exceeds some values, the wind-solar-diesel system is superior to the wind-diesel system in terms of system health.

8. RELIABILITY ASSESSMENT OF SMALL ISOLATED POWER SYSTEMS CONSIDERING DIFFERENT OPERATING STRATEGIES

8.1 Introduction

As noted earlier, the inclusion of WTG, PV and energy storage facilities in small isolated applications has a positive impact on overall system reliability performance. The studies conducted in the previous chapters do not consider the dispatch order of the different energy systems and the storage and assume that all units have the same priority for satisfying the system demand. These studies also impose no operating constraints on diesel units and assume that all the diesel units are continuously serving the system load. In practice, the renewable energy sources usually have priority over the conventional sources in satisfying system electricity demands. On the other hand, the diesel units are usually not operated continuously in order to save fuel. It is, therefore, both necessary and important to develop models and techniques to assess the relative benefits of different operating strategies associated with SIPS and examine the key variables that dictate or affect the economics involved. At the present time, there is relatively little published material in this area. Most of the pioneering research on the operating strategies of SIPS has been conducted by Reading University and the Rutherford Appleton Laboratory. Their research mainly focuses on the short term operational problems and economics associated with the wind/diesel integration [102]. The simulation approaches developed in the previous chapters to assess the reliability performance of small isolated power systems are not directly applicable to operating strategy analysis of SIPS using both conventional and unconventional energy sources, and storage facilities. An analytical method for the evaluation of the performance of a hybrid system considering SIPS operating constraints is presented in [17]. The wind generation was constrained to be less than a predetermined value in order to maintain system stability. The same operating constraint was later applied to small isolated power systems using a sequential Monte Carlo simulation method [65]. Energy storage elements were not considered in these studies. As noted in previous discussions, most small isolated applications require storage capability. Introduction of a storage medium into the system can provide a variety of operating flexibilities, which can have significant impacts on system reliability and economics. A new simulation technique is presented in this chapter to evaluate different operating strategies in regard to reliability and diesel fuel savings [103]. Application of the technique is illustrated using several SIPS, both with and without energy storage, and the four different operating scenarios described in the following section. The advantages and disadvantages of these strategies are analyzed with reference to reliability, diesel fuel savings, back-up diesel average start-stop cycles and average diesel running times etc.

8.2 Review of Small Isolated Power System Operating Strategies

One of the most promising applications for wind and solar energy is their use in electric power systems for remote isolated locations. The majority of these remote customers are presently supplied by diesel generators. Diesel generators are relatively cheap and reliable due to their high level of development. The high cost of diesel fuel together with the inherent difficulties of delivering it to remote locations, however, results in high final generating costs for diesel plants. Wind and solar energy are expected to find applications in these areas, with WTG and PV arrays viewed primarily as fuel savers. Organizations around the world are developing and testing a variety of small power systems utilizing wind and solar energy in isolated remote locations.

Considerable power fluctuations can be expected from a WTG or a PV unit due to the highly variable nature of the wind speed and the solar radiation. This can make the electrical output unsuitable for direct use in isolated applications. A simple and common method of using wind and solar energy in remote areas is to operate the WTG and/or the PV unit in parallel with diesel generators in order to reduce the average diesel load and hence save fuel. This mode of operation is particularly suitable for systems with relatively small renewable energy penetrations. The discussions presented in previous chapters considered only this mode of operation. This can result in some energy wastage when there is sufficient wind and/or solar energy available, especially at high renewable energy penetrations. For wind-diesel systems, stability may also be a problem if the WTG output is large. Another possible mode of operation is to run a back-up diesel intermittently to make up sudden power shortages and save fuel. This mode is unattractive because the possible large number of back-up diesel start-stop cycles resulting from variability of the resource energy and the system load. These problems can be alleviated to some extent by adding energy storage devices such as batteries to the system. The addition of energy storage to a small isolated system can provide a means of dealing with, or at least reducing, the adverse operating characteristics associated with systems without storage. It can be seen in the following discussions that energy storage can have a significant impact on the problem of a high number of diesel start/stop cycles. In addition, energy storage can enhance the system reliability, reduce the energy wastage and hence minimize fuel consumption. If there is only one diesel unit in the system, it is inevitable that there will be discontinuities in supply when operating the diesel unit intermittently. One possible way to alleviate this problem is that once the diesel has been started it is not shut down until the power from the WTG and/or PV unit exceeds the load by some predetermined margin [102]. This method may alleviate the supply discontinuities to some extent but at the cost of additional fuel consumption and low renewable energy utilization. Another possibility is to use two diesel units, the first running continuously and the second running intermittently [102]. Single diesel configurations, in many cases, cannot supply reliable power economically and therefore multi-diesel systems are considered to be viable and cost-effective power sources for remote isolated locations. Multi-diesel systems can be operated in the following modes depending on the reliability requirements and economic considerations. The most common operating strategies for multi-diesel systems are: continuous diesel operation without storage (CD-without), continuous diesel operation with storage (CD-with), intermittent back-up diesel operation without storage (ID-without), intermittent back-up diesel operation with storage (ID-with).

8.3 Proposed Evaluation Technique

Computer simulation techniques can provide a useful tool for assessing different system configurations and operating strategies. The highly fluctuating nature of wind and solar resources and the operating complexity due to wind-solar-diesel integration necessitate the employment of stochastic simulation approaches to incorporate the inherent variabilities. The simulation technique developed in previous chapters for the reliability evaluation of SIPS was modified to evaluate different system configurations and operating strategies in integrated wind-solar-diesel systems. In the MCS method, the generation model is superimposed on the load model as shown in Figure 8.1 to obtain the various reliability indices. In Figure 8.1, the periods in which the load exceeds the available base load capacity are shown as t_i and during this time the back-up diesel generator (if any) may be operated as required. The possible energy curtailed in each case is e_i.

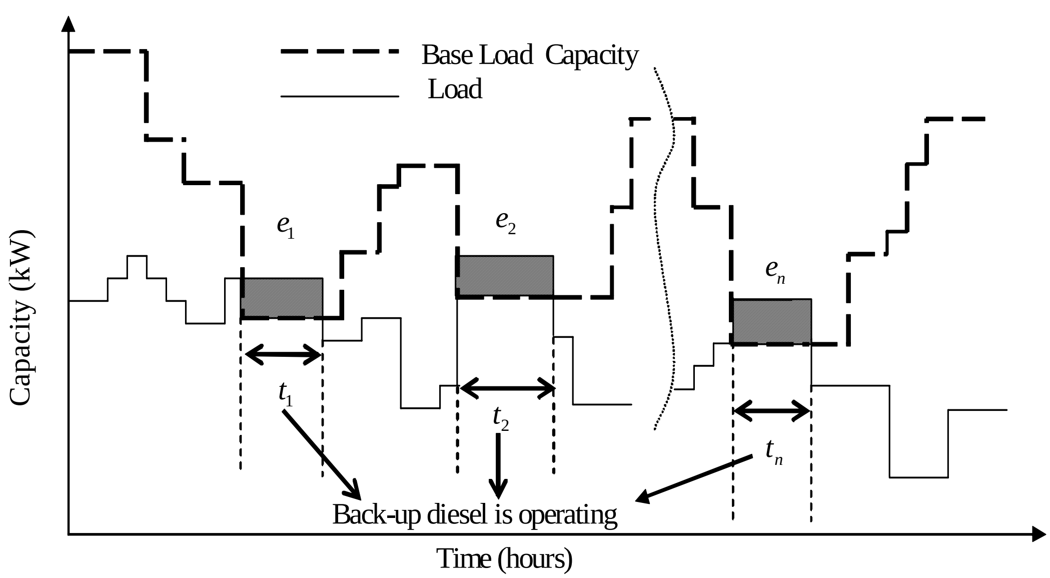


Figure 8.1: Superimposition of capacity states and the chronological load pattern incorporating different operating strategies

The generation and the load are modeled in one hour time steps in this analysis. Smaller or larger steps can be used if required. The following operating policy is applied in the simulation algorithm:

- Whenever the total available generation exceeds the load, the excess energy is stored in the energy storage facilities and used whenever there is a generation shortage, if the system contains energy storage.
- The electric power generated by the unconventional generating units has priority in satisfying system load demand over that available from all the diesel generators.
- The electric power generated by both conventional and unconventional generating units has priority in satisfying system load demand over that available in the energy storage system, if the system contains energy storage.
- The back-up diesel is started whenever the total electric power generated by all unconventional generating units and base load diesel generators falls below the load and stopped whenever the total electric power rises above the load if the system contains no energy storage.
- The back-up diesel is started whenever the total electric power from all unconventional generating units, the base load diesel generators and the energy storage system falls below the load and stopped whenever the total electric power rises above the load, if the system contains energy storage.

The commonly used reliability indices such as the LOLE and LOEE for a number of sample years (N) can be obtained by recording the possible loss of load duration t_i , the possible energy loss e_i and the total number of load curtailments n using Equations (8.1) and (8.2) respectively.

$$LOLE = \begin{cases} \dfrac{1}{N}\sum_{i=1}^{n(C)} t_i(C) \ \ Continous\ \ Diesel \\ \dfrac{1}{N}\sum_{i=1}^{n(I)} t_i(I) \ \ Intermittent\ \ Diesel \end{cases} \tag{8.1}$$

$$LOEE = \begin{cases} \dfrac{1}{N}\sum_{i=1}^{n(C)} e_i(C) \;\; Continous \;\; Diesel \\ \dfrac{1}{N}\sum_{i=1}^{n(I)} e_i(I) \;\; Intermittent \;\; Diesel \end{cases} \tag{8.2}$$

The fuel energy saved due to the wind energy sources, solar energy sources and energy storage is directly proportional to the total energy supplied by them. If $ESBWTG_i$, $ESBPV_i$ and $ESBES_i$ are the energy supplied by the WTG, PV and the energy storage in hour i, the expected energy supplied by WTG (EESBWTG), the expected energy supplied by PV (EESBPV) and the expected energy supplied by the energy storage (EESBES) can be calculated using Equations (8.3) to (8.5) respectively.

$$EESBWTG = \frac{1}{N}\sum_{i=1}^{i=8760N} ESBWTG_i \tag{8.3}$$

$$EESBPV = \frac{1}{N}\sum_{i=1}^{i=8760N} ESBPV_i \tag{8.4}$$

$$EESBES = \frac{1}{N}\sum_{i=1}^{i=8760N} ESBES_i \tag{8.5}$$

8.4 Application of the Proposed Technique

A range of studies was performed using the proposed technique to examine the benefits associated with integrated wind-solar-diesel systems. The analyses mainly focus on comparative studies of different operating strategies in terms of system reliability and fuel saving. The system data for the four basic operating conditions are given in Table 8.1. The hourly chronological load shape of the IEEE-RTS [86] is used with a peak load of 40 kW. The system is assumed to be located at a geographic location with wind regime represented by the Regina site and the solar resources represented by the Swift Current site. The operating parameters of cut-in, rated and cut-out wind speeds of the two 30 kW wind generators in Table 8.1 are 12 km/h, 38 km/h and 80 km/h respectively.

A starting failure probability of 4% is included in the evaluation when the back-up diesel is required, unless otherwise specified. A heat rate of 3.2 kWh/liter is used in the fuel saving calculations.

Table 8.1: System data for the four basic SIPS operating modes

	Generation and storage	No.	Rating	FOR (%)	Failure rate per year
CD-without	Base Load Diesel WTG and/or PV	2 2	20 kW 30 kW and/or 30 kW_p	5 4 and/or 3	9.2 4.6 and/or 3
CD-with	Base Load Diesel WTG and/or PV Energy Storage	2 2 1	20 kW 30 kW and/or 30 kW_p 300 kWh	5 4 and/or 3 NA	9.2 4.6 and/or 3 NA
ID-without	Base load Diesel WTG and/or PV Back-up Diesel	1 2 1	20 kW 30 kW and/or 30 kW_p 20 kW	5 4 and/or 3 5	9.2 4.6 and/or 3 9.2
ID-with	Base Load Diesel WTG and/or PV Back-up Diesel Energy Storage	1 2 1 1	20 kW 30 kW and/or 30 kW_p 20 kW 300 kWh	5 4 and/or 3 5 NA	9.2 4.6 and/or 3 9.2 NA

8.4.1 Reliability

Figure 8.2 compares the adequacy of the four basic system operating strategies for systems with different energy compositions given in Table 8.1. It can be seen that the adequacies of the systems with storage are much better than those of the systems without storage. As noted earlier, the reliability benefits obtained from using energy storage are accompanied by additional system costs such as equipment, installation and maintenance cost. The addition of energy storage to a SIPS can, however, eliminate some adverse operating problems and improve renewable energy utilization. Simulation results show that intermittent diesel operation results in 550.45, 498.45 and 483.57 starts and stops per year for wind/diesel, wind-solar-diesel and solar-diesel respectively if the system contains no storage. These numbers can be reduced to 47.52, 98.79 and 46.61 respectively by introducing a 300 kWh energy storage system for each case. Determination of the optimum storage additions to these systems in order to maintain the acceptable reliability level at a reasonable cost is an important system planning task.

Figure 8.2 shows the reliability of CD-without is better than that of the ID-without and the adequacy of CD-with is superior to that of the ID-with for all the cases in Table 8.1.

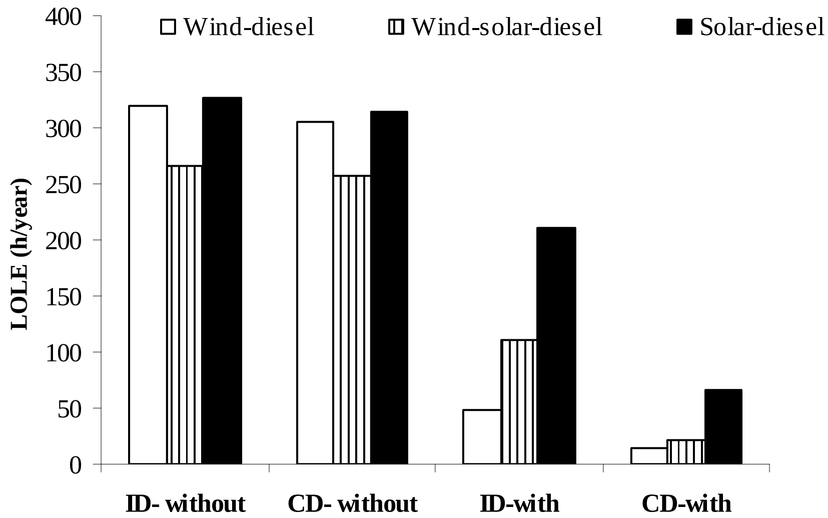


Figure 8.2: Adequacy comparison for different operating strategies

Figure 8.3 shows the variation of the LOLE for intermittent operation of the back-up diesel unit with different energy storage capacity levels ranging from 100 kWh to 600 kWh. The LOLE decreases as the energy storage capacity increases.

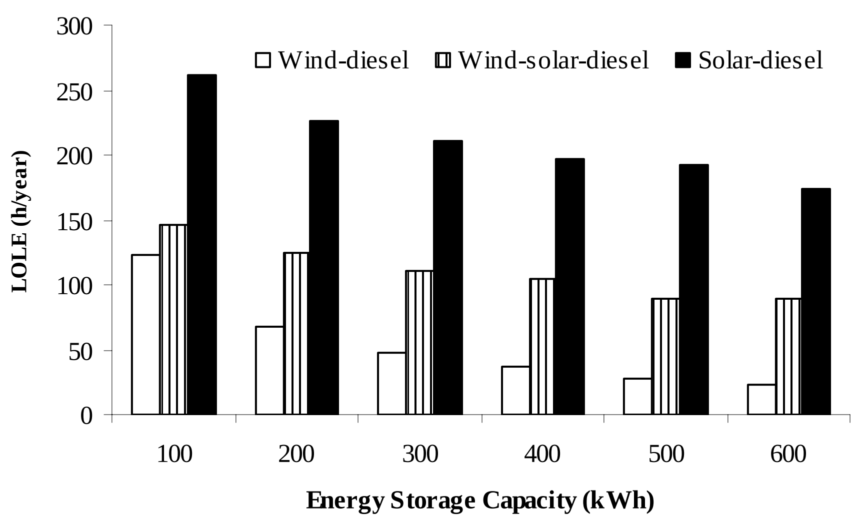


Figure 8.3: Effect of the energy storage capacity on LOLE
(intermittent diesel operation)

Figure 8.4 shows the variation of LOHE for intermittent operation of the back-up diesel unit with different energy storage capacity levels ranging from 100 kWh to 600 kWh. The LOHE also decreases as the energy storage capacity increases. These results are similar to those obtained for continuous diesel operation described in Chapter 6. Continuous diesel operation, however, consumes more fuel than intermittent diesel operation. The actual benefits associated with these operating strategies should, therefore, be compared in terms of both reliability and fuel savings.

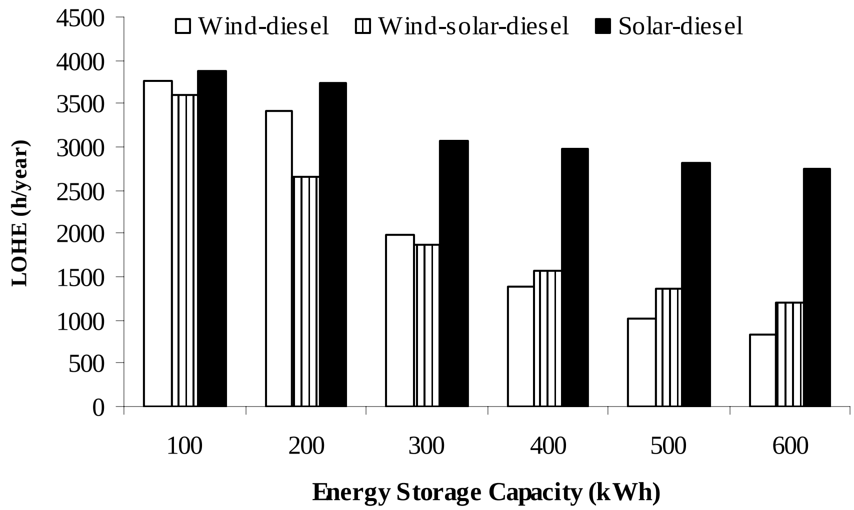


Figure 8.4: Effect of the energy storage capacity on LOHE (intermittent diesel operation)

8.4.2 Fuel Savings

A major benefit in utilizing wind and solar energy is the significant reduction in the system operating costs due to fuel savings. Figure 8.5 compares the fuel savings for the four different operating modes for the systems given in Table 8.1. It can be seen that the systems with storage are superior to systems without storage in terms of fuel savings. The reason for this is that the fuel saved with no storage operation is due only to the renewable energy utilized, while the fuel saving in systems operating with storage is due not only to utilized renewable energy but also to the storage of excess renewable energy. Figure 8.5 shows that intermittent diesel operation saves more fuel than continuous diesel operation. More fuel savings can be achieved from wind-solar diesel integration than from wind-diesel integration when the system has no storage. It is important to note that the results obtained from these studies depend on the input data used in the calculations. Different results can be obtained for different locations. A comparison of the benefits associated with using renewable energy depends on many factors such as the energy storage capacity, the site resource availability, the back-up diesel starting failure probability and the renewable energy penetration in the system etc. These factors have been considered and some selected results are presented in the following analyses.

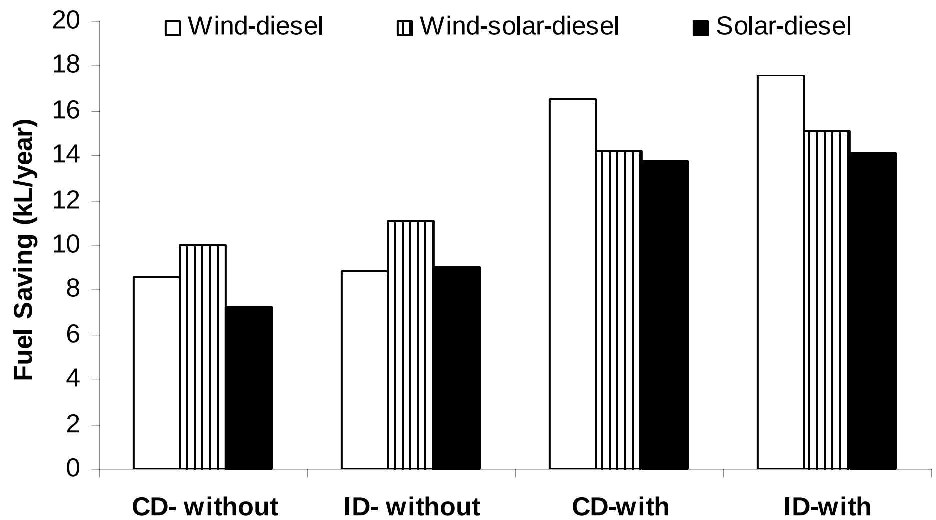


Figure 8.5: Fuel saving comparison for different operating strategies

One aspect of storage operation that can be readily evaluated in economic terms is its ability to improve renewable energy utilization, thereby reducing diesel fuel consumption. Fuel saved, and hence the economic benefit arising from the use of storage, depends on the quantity of energy supplied by the storage to the load in a given period of time as described by Equation (8.5). Figure 8.6 shows the fuel savings for both continuous and intermittent operation of the back-up diesel unit with different energy storage capacity levels ranging from 100 kWh to 600 kWh. In Figure 8.6, Curves 1 to 6 represent: (1) Wind and Intermittent Diesel, (2) Wind and Continuous Diesel, (3) Wind/Solar and Intermittent Diesel, (4) Wind/Solar and Continuous Diesel, (5) Solar and Intermittent Diesel and (6) Solar and Continuous Diesel. In each case, the amount of fuel saved increases as the energy storage capacity increases. The increase in fuel savings due to increased energy storage capacity is, however, relatively insignificant when the energy storage capacity exceed a certain value. This is 400 kWh in this case. The reason for this is that the diesel units can also contribute to energy storage when the available generation exceeds the system load. Charging the energy storage facility from the diesel units is an attractive option. During the times of low demand, the energy storage facility can provide an additional “dump” load, for the diesel to avoid having to run the diesel at low load for a long period. At low loads, a diesel unit usually operates at much lower efficiency. On the other hand, during low wind and/or sunlight periods, the energy storage facility can be periodically recharged to avoid the damage caused by allowing them to stand discharged for long periods.

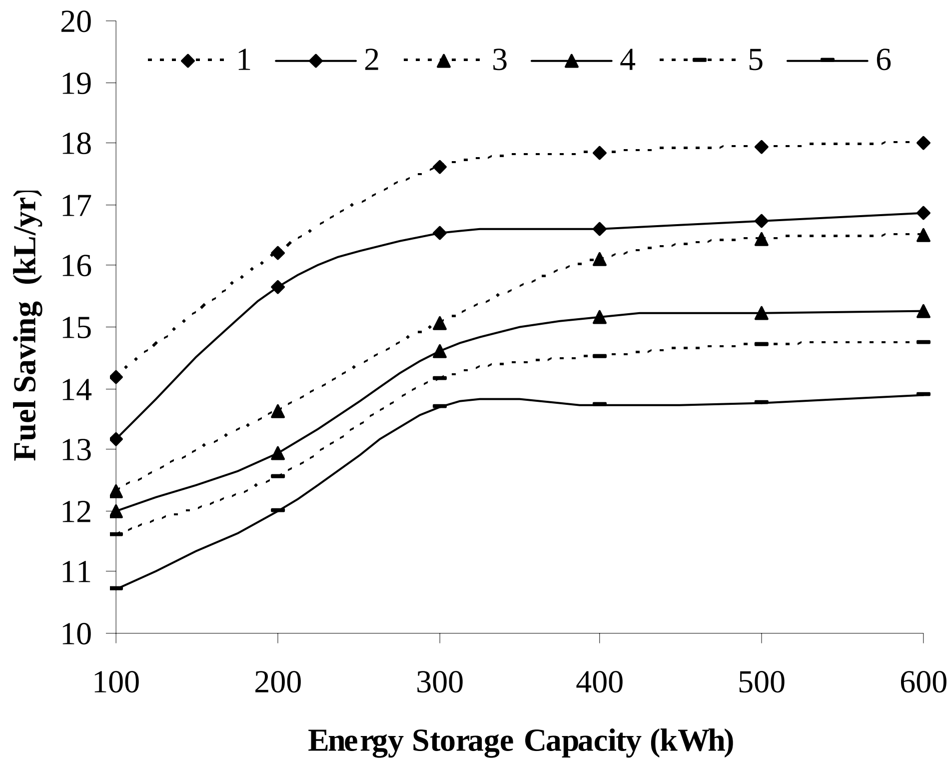


Figure 8.6: Effect of the energy storage capacity on fuel saving

One of the most important factors influencing SIPS reliability and operating cost is the probability of back-up diesel starting failure. Figure 8.7 shows the variation in the fuel savings with the back-up diesel starting failure probability. It can be seen that the fuel saved decreases significantly with increase in the back-up diesel unit starting failure probability.

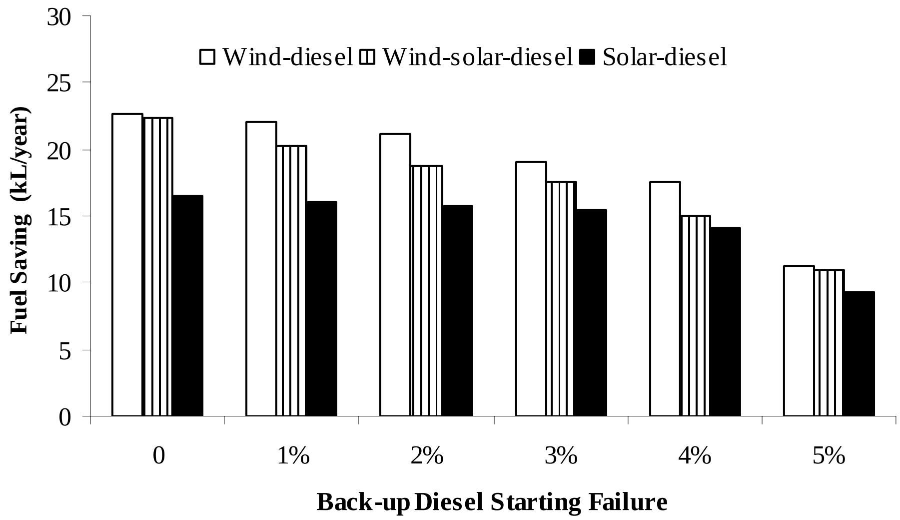
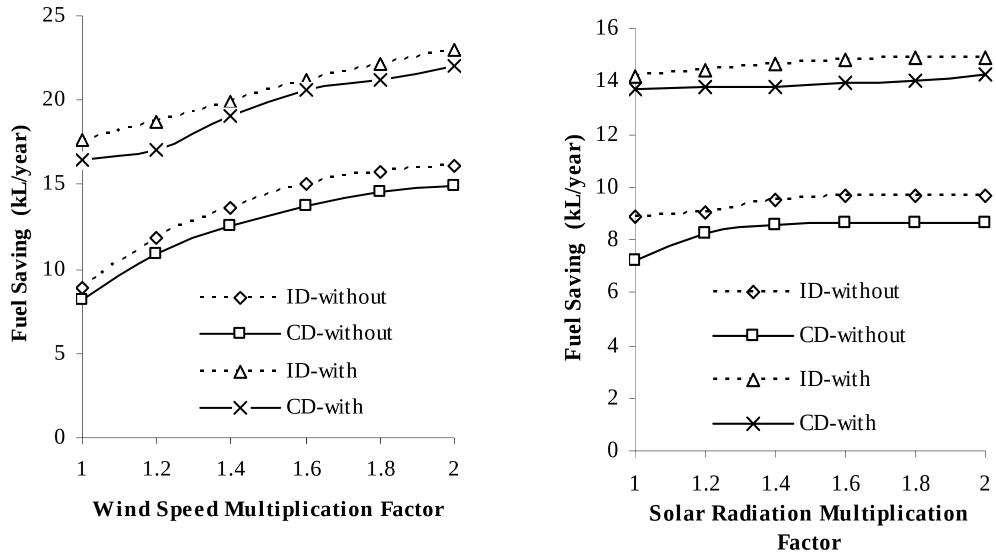


Figure 8.7: Effect of the back-up diesel starting failure on fuel saving

The operating cost of an isolated system strongly depends on the wind and solar resource availability. In order to illustrate the impact of wind and solar resources, the hourly mean wind speeds and solar radiation have been modified by simple multiplication factors ranging from 1 to 2.0 and used to calculate the fuel savings for the four operating scenarios.

Figure 8.8 shows the change in fuel savings with the increase in wind speed and solar radiation. It can be seen from the results that the amount of fuel saved increases as the average wind speed and solar radiation increase. The reason is that if there is sufficient wind or solar energy available at the site, the WTG or PV can satisfy the system demand most of the time and therefore more diesel fuel can be saved.

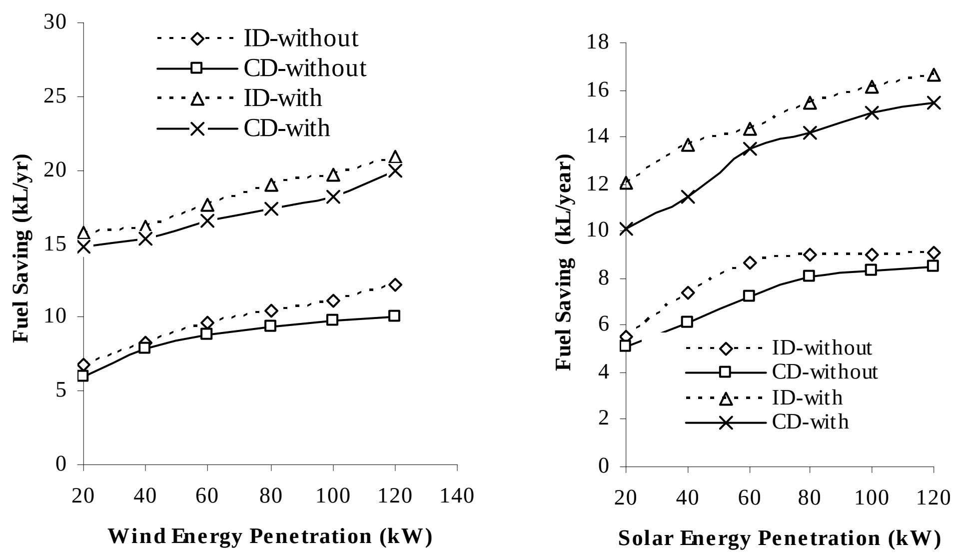
Figure 8.9 illustrates the increase in fuel savings with increasing wind and solar energy penetration. Although appreciable fuel savings can be achieved by increasing wind or solar penetrations for a given system, several significant problems can ensue. The most important one is that the higher the average WTG or PV output, the lower is the average diesel load, resulting in low efficiency operation of the diesel units. In addition, prolonged low-load running of the diesels will give rise to maintenance problems. Figure 8.9 also shows that fuel savings decrease with further wind or solar penetration. It is, therefore, extremely important to note that caution must be exercised when determining the level of wind or solar penetration for a given system.



a) Effect of Wind Speed

b) Effect of Solar Radiation

Figure 8.8: Effect of the wind speed and solar radiation on fuel savings



a) Effect of Wind Penetration

b) Effect of Solar Penetration

Figure 8.9: Effect of the wind and solar energy penetration on fuel savings

8.4.3 Back-up Diesel Start-Stop Cycling and Running Time

As noted in previous discussions, intermittent operation of back-up diesel is superior to continuous diesel operation in certain conditions. One of the major operating problems associated with intermittent diesel is the high number of diesel start/stop cycles when the system contains no storage or very small storage. The addition of energy storage to a wind/diesel system can eliminate this problem to some extent. Figure 8.10 shows the annual average diesel starts as a function of energy storage capacity ranging from 100 to 600 kWh for intermittent diesel systems specified in Table 8.1. It can be seen that the number of diesel starts decreases with increase in energy storage capacity. On the contrary, a decrease in energy storage capacity should result in an increase in diesel start/stop cycles and may lead to an increase in the energy storage charge/discharge rate and affect the energy storage life. The proposed technique can be used to examine these problems based on a particular system configuration for a given site considering different operating options. It can be seen from Figure 8.10 that the impact of energy storage capability on diesel start/stop cycle is more significant for wind-diesel and wind-solar-diesel systems than for a solar-diesel system.

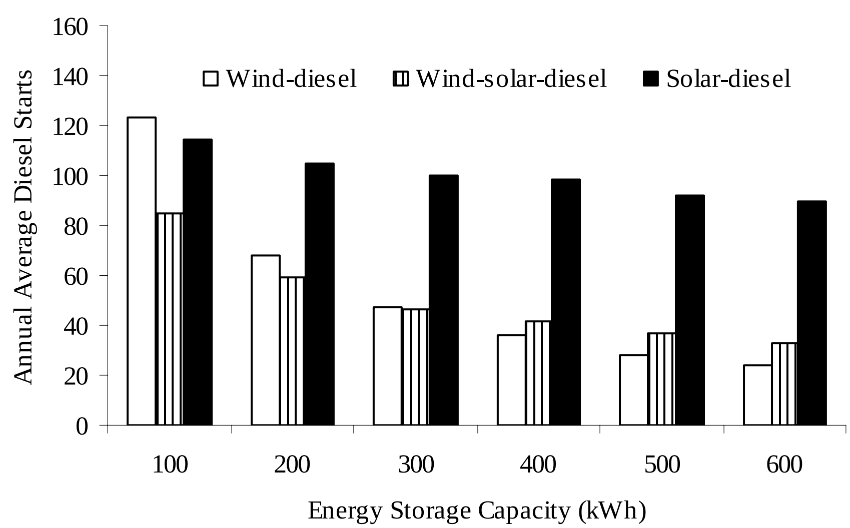
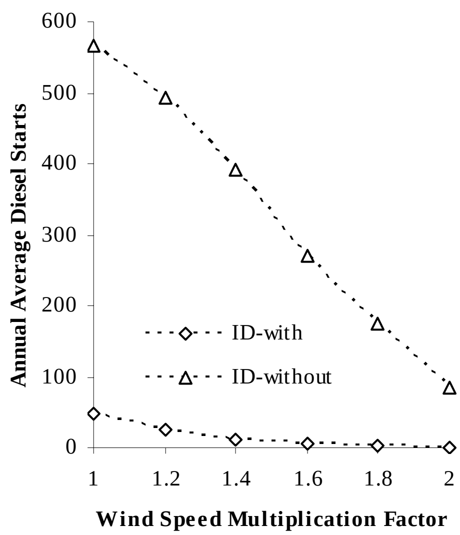
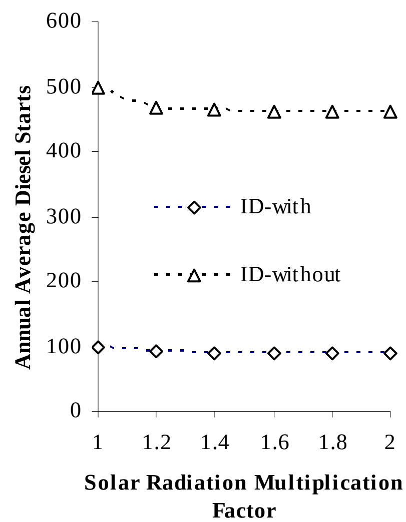


Figure 8.10: Effect of the energy storage capacity on back-up diesel starts (intermittent diesel operation)

Figure 8.11 shows the effect of wind speed and solar radiation on the back-up diesel start/stop cycles. It can be seen from Figure 8.11 (a) that the reduction in diesel starts due to wind speed is significant for the no battery case. The impact of wind speed on the number of diesel starts is, however, negligible when the system contains energy storage. Figure 11 (b) shows that the impact of solar radiation on the number of diesel starts is, however, not significant for solar diesel systems. Figure 8.12 shows the number of diesel starts as functions of wind or solar energy penetration. Increase in the wind or solar energy penetration does not significantly reduce the number of diesel starts, especially in the case of no storage for a particular site. These results can provide important information on back-up diesel unit efficiency and maintenance requirements.

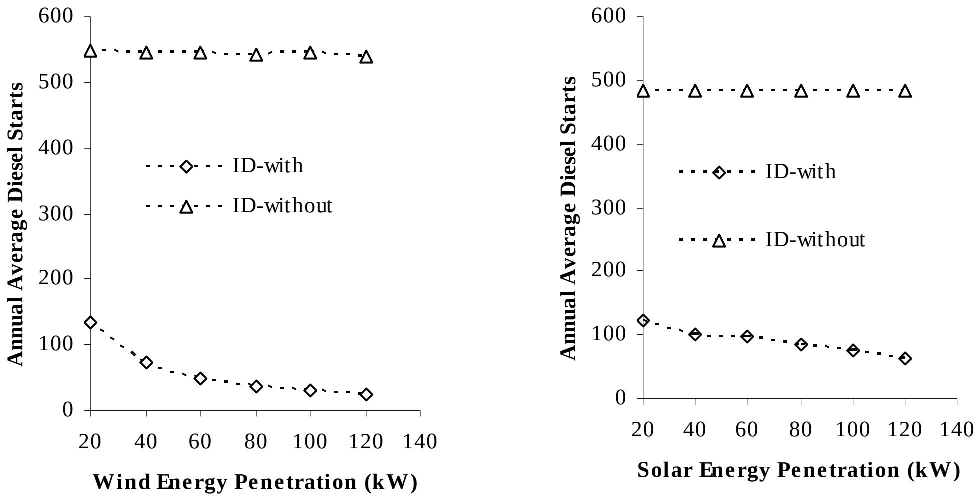


a) Effect of Wind Speed



b) Effect of Solar Radiation

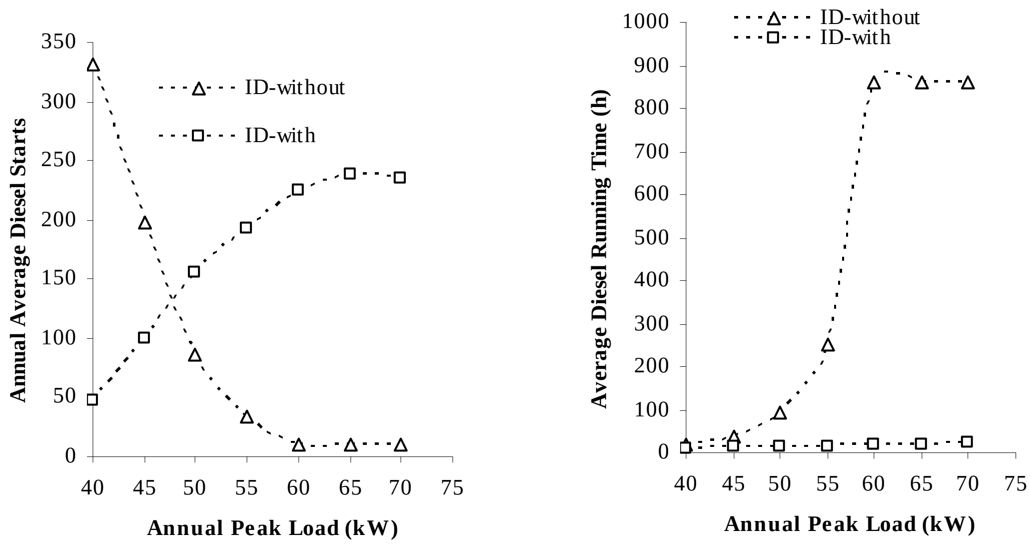
Figure 8.11: Effect of the wind speed and solar radiation on back-up diesel starts



a) Effect of Wind Penetration b) Effect of Solar Penetration

Figure 8.12: Effect of the wind and solar energy penetration on back-up diesel starts

The studies performed previously are based on a specified load profile. Changes in system load are likely to occur frequently in a particular application and could affect the system reliability and cost. Figure 8.13 shows the impact of system load variation on diesel start-stop cycles and running time for the intermittent diesel operation for the wind-diesel systems shown in Table 8.1. The variation in the system load was modeled by increasing the peak value from 40 kW to 70 kW while maintaining the basic shape of the IEEE-RTS load curve. It can be seen that the number of back-up diesel starts decreases and average running time increases with increase in system peak load to a certain value (in this case 60kW) when the system contains no energy storage. When the system contains energy storage, the number of back-up diesel starts increases and the running time remains virtually unchanged with increase in system peak load. Similar results are obtained for solar-diesel and wind-solar-diesel systems. The high number of diesel start/ stop cycles (ID-with) and the significantly long running time (ID-without) due to load growth strongly affect the overall system reliability and cost. These can be alleviated by adding an appropriate mix of generating capacity and storage to the system to provide a power output profile that closely matches the load variation profile.



a) Back-up Diesel Starts with Load Growth

b) Back-up Diesel Running Time with Load Growth

Figure 8.13: Effect of system load on: a) Back-up diesel starts, b) Back-up diesel running time

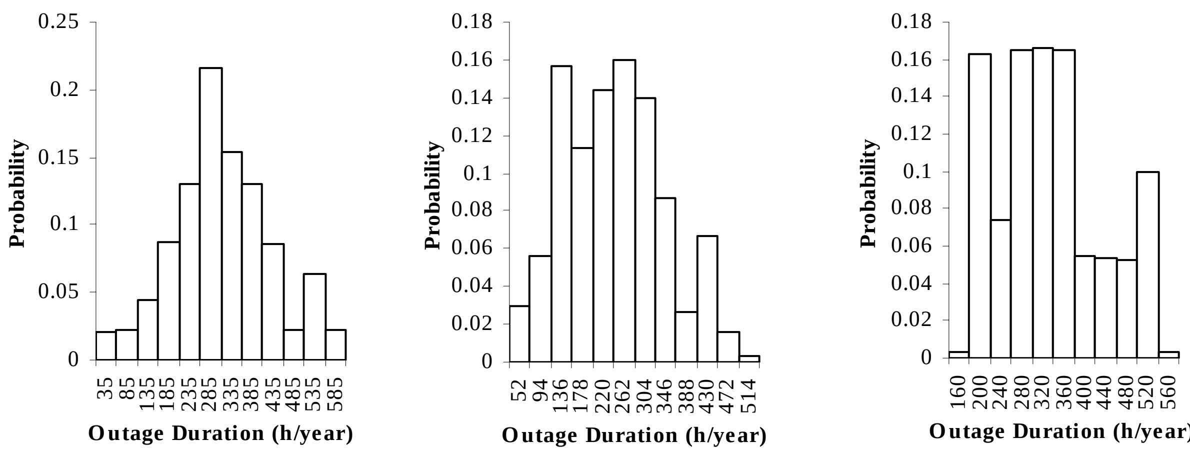
8.4.4 Evaluation of Index Distributions

As noted earlier, the Monte Carlo simulation method can be used to calculate both the expected values of the various reliability indices, and the frequency and probability distributions of these parameters. The probability distribution of the reliability indices presents a pictorial representation of the manner in which a parameter varies. It includes important information on significant events which might occur occasionally but could have serious system effects.

The reliability index distributions associated with continuous diesel operation have been obtained and are discussed in detailed in Chapter 5. In this section, the distributions of some of the selected parameters for intermittent diesel operation are shown and analyzed. The distributions of annual outage duration, annual fuel saving and annual diesel start/stop cycles for 6000 sample years, are shown in Figures 8.14 to 8.19.

Figure 8.14 shows the distributions of the annual outage duration for the ID-without cases shown in Table 8.1. It can be seen from Figure 8.14 that the distributions of the annual outage duration for wind-diesel and wind-solar-diesel cases are more dispersed than that for the solar-diesel case due to the wind speed fluctuation. Outage durations longer than the LOLE with noticeable probability are observed for each ID-without case. Outage durations much longer than the LOLE with significant probability are also observed for the solar diesel systems.

Figure 8.15 shows the distributions of the annual outage duration for the ID-with cases shown in Table 8.1. Outage duration distributions for the ID-with cases are shifted to the left compared with those for the ID-without cases shown in Figure 8.14. Outage durations longer than the LOLE with significant probability are also observed for each ID-with case in Figure 8.15. It also can be seen that the wind-diesel system with energy storage has a small probability of 0.083486 of having no interruptions in a year. The probabilities of having no interruptions for the wind-solar diesel and solar diesel systems are effectively zero.

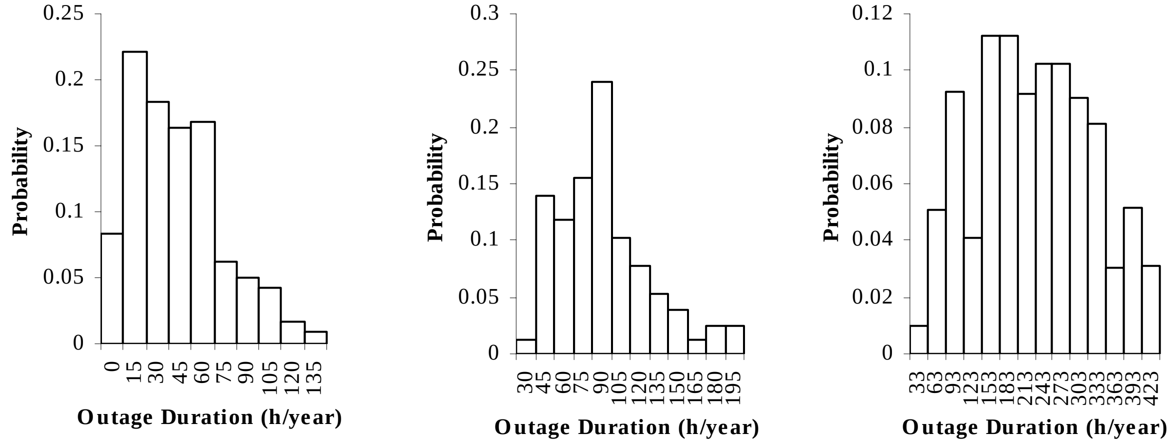


a) Wind-Diesel
LOLE=319.26 h/year

b) Wind-Solar-Diesel
LOLE=265.34 h/year

c) Solar-Diesel
LOLE=326.75 h/year

Figure 8.14: Annual outage duration distributions for the ID-without cases



a) Wind-Diesel
LOLE=47.52 h/yr

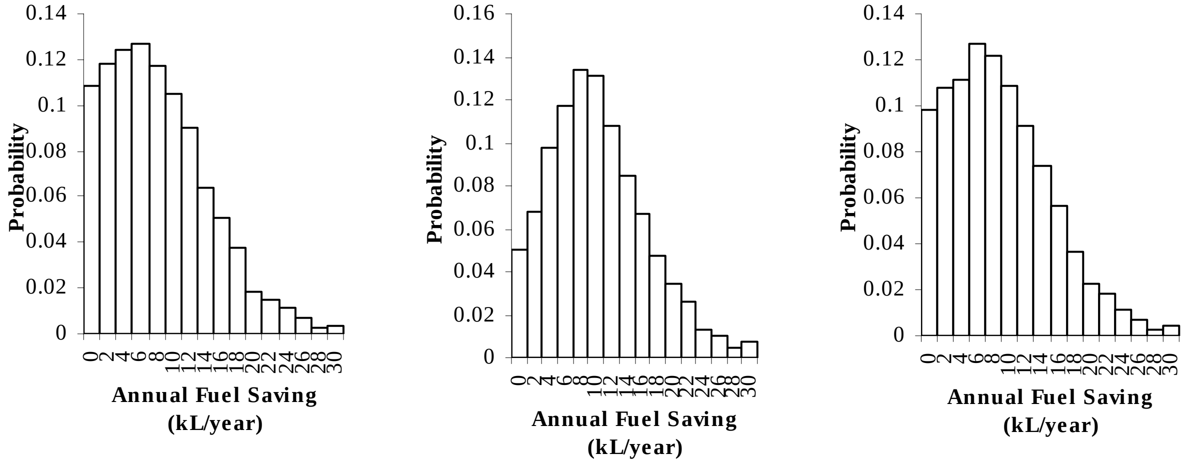
b) Wind-Solar-Diesel
LOLE=111.35 h/yr

c) Solar-Diesel
LOLE=210.01 h/yr

Figure 8.15: Annual outage duration distributions for the ID-with cases

Figure 8.16 shows the distributions of the annual diesel fuel savings in kL for the ID-without cases. The annual diesel fuel savings follow the exponential distribution when there is no storage in the system. It can be seen from Figure 8.16 that the probability of no fuel saving for the wind-diesel, wind-solar-diesel and solar-diesel systems are 0.108149, 0.049852 and 0.097984 respectively. The maximum fuel saving that can be achieved from these no energy storage cases is approximately 30 kL/yr with a small probability.

Figure 8.17 shows the distributions of the annual diesel fuel savings in kL for the ID-with cases. It is interesting to note that the distributions of the annual diesel fuel saving change from exponential to basically normal with the addition of energy storage. The probabilities of no fuel savings for the wind-diesel, wind-solar-diesel and solar-diesel systems drop to 0.016331, 0.011165 and 0.039327 respectively. The probability of maximum diesel fuel savings increases slightly with the addition of energy storage capability.

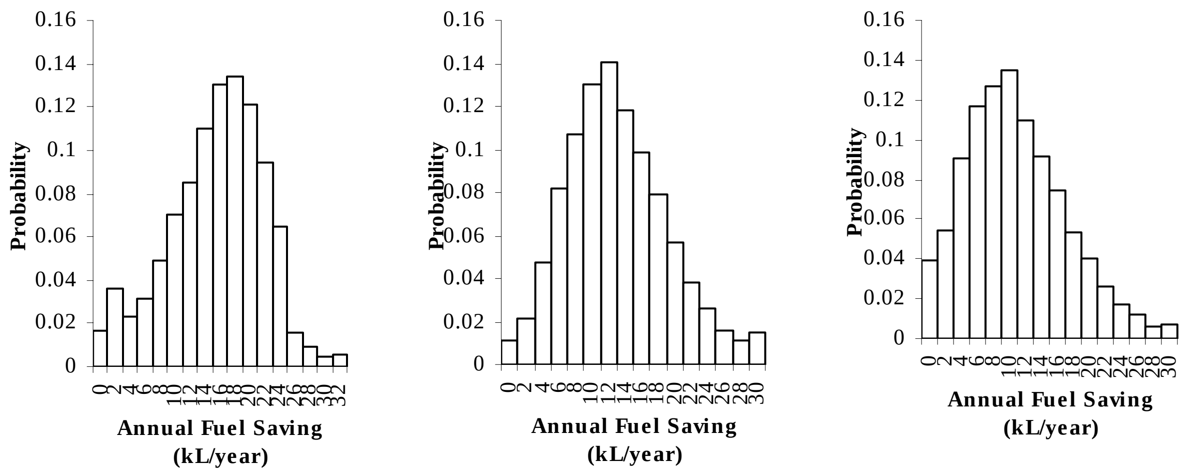


a) Wind-Diesel Annual Average Fuel Saving=8.84 kL/yr

b) Wind-Solar-Diesel Annual Average Fuel Saving=11.10 kL/yr

c) Solar-Diesel Annual Average Fuel Saving=8.99 kL/yr

Figure 8.16: Annual fuel saving distributions for the ID-without cases



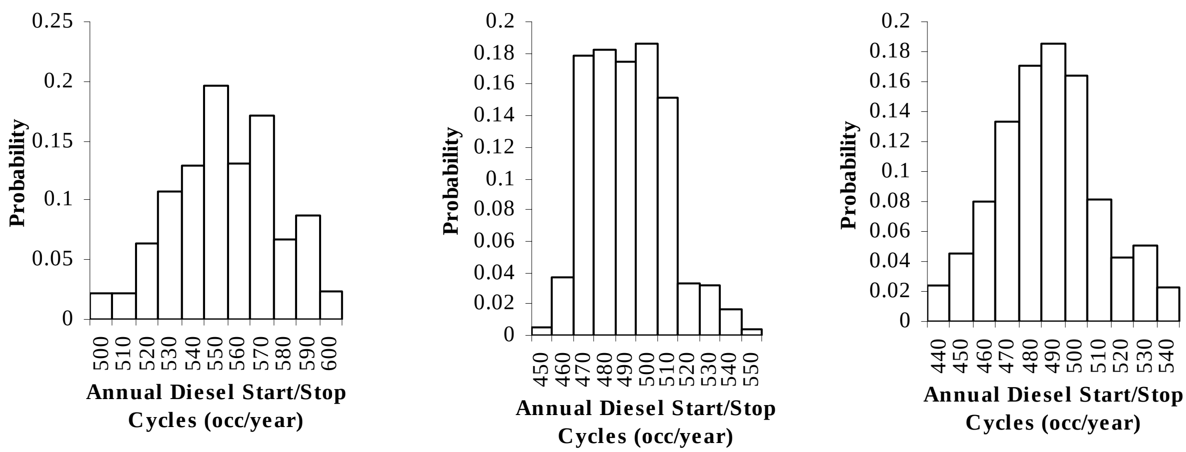
a) Wind-Diesel Annual Average Fuel Saving=17.62 kL/year

b) Wind-Solar-Diesel Annual Average Fuel Saving=15.06 kL/year

c) Solar-Diesel Annual Average Fuel Saving=14.14 kL/year

Figure 8.17: Annual fuel saving distributions for the ID-with cases

Figures 8.18 and 8.19 show the distributions of diesel start/stop cycles for the ID-without and ID-with cases respectively. It can be seen from Figures 8.18 and 8.19 that the distributions of diesel start/stop cycles tend to be more normal. Start/stop cycles greater than the average values with significant probabilities are observed for both the ID-without and ID-with cases. For example, the expected start/stop cycles for the wind-diesel system without storage is 550.45 but Figure 8.18 (a) shows that there is a chance of 1029 out of 6000 years that the probability of diesel start/stop cycles will be greater than 570. On the other hand, for the same system, the probability of diesel start/stop cycles is less than 500 in any single year with a likelihood of 130 out of 6000. This information is useful when comparing the reliability performance of the same system at different geographic locations.

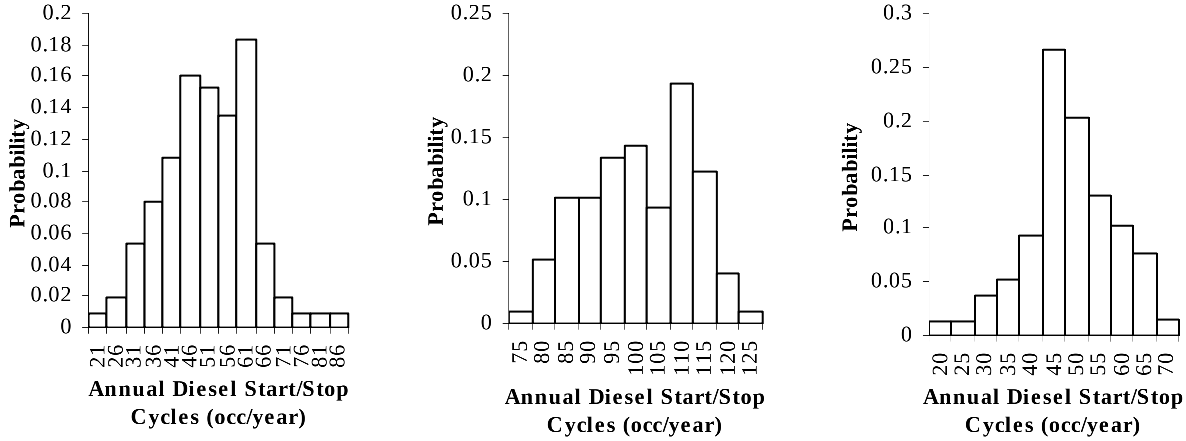


a) Wind-Diesel
Annual Average Diesel
Start/Stop=550.45 occ/year

b) Wind-Solar-Diesel
Annual Average Diesel
Start/Stop=498.45 occ/year

c) Solar-Diesel
Annual Average Diesel
Start/Stop=483.57 occ/year

Figure 8.18: Annual diesel start/stop distributions for the ID-without cases



a) Wind-Diesel
Annual Average Diesel
Start/Stop=47.52 occ/year

b) Wind-Solar-Diesel
Annual Average Diesel
Start/Stop=98.79 occ/year

c) Solar-Diesel
Annual Average Diesel
Start/Stop=46.61 occ/year

Figure 8.19: Annual diesel start/stop distributions for the ID-with cases

8.5 Summary and Conclusions

This chapter presents a sequential simulation technique to evaluate different operating strategies for power systems using wind and/or solar energy as well as energy storage facilities. The integration of wind and/or solar energy into small isolated diesel plants can improve the overall system reliability and significantly reduce the system operating costs. These integrations, however, introduce some operating concerns that affect the system reliability and economics. Four types of operating strategies are discussed and evaluated. These are continuous diesel operation without storage, continuous diesel operation with storage, intermittent back-up diesel operation without storage and intermittent back-up diesel operation with storage. The advantage and disadvantage of these strategies are analyzed and compared with reference to reliability, diesel fuel savings, back-up diesel average start-stop cycles and average running time etc. The probability distributions associated with these parameters are also constructed and analyzed.

The reliability of continuous diesel operation is better than that of intermittent diesel operation for the same systems. The adequacies and the degree of system comfort in satisfying the deterministic criterion for the systems with energy storage are much better than those of systems without energy storage for all of the operating strategies considered.

The major benefit of adding wind and solar energy in small isolated application is the significant reduction in the system operating costs due to fuel savings. Systems with energy storage can save more fuel than systems without energy storage. Intermittent diesel operation saves more fuel than continuous diesel operation. Wind energy and solar energy can make a significant contribution to the adequacies and economics of SIPS if the systems are located at sites with high average wind speeds and/or solar radiation levels. More fuel savings can be achieved from higher renewable energy penetration.

The availability of back-up diesel is an important factor influencing SIPS reliability and operating cost. The fuel saving benefits decreases significantly with increase in the back-up diesel unit starting failure probability.

The high number of diesel start/ stop cycles associated with intermittent diesel operation have negative effects on the overall system reliability and cost. Utilization of energy storage can alleviate this problem to some extent. The number of back-up diesel start/ stop cycles decreases with increase in the energy storage capability. This number also decreases significantly with increase in wind speed if there is no energy storage in the system. The wind and solar resource availability, however, does not have significant impact on the number of back-up diesel start/ stop cycles if the system contains energy storage. The high number of back-up diesel start/stop cycles cannot be reduced significantly by adding more renewable generation to a given system. System load variations also affect the number of back-up diesel start/ stop cycles and the running time and hence have impacts on the overall system reliability and costs.

9. RELIABILITY COST/WORTH MODELING AND THE EFFECTS OF WIND ENERGY, SOLAR ENERGY AND ENERGY STORAGE UTILIZATION IN ELECTRIC POWER SYSTEMS

9.1 Introduction

The focus in power system planning is usually directed to the areas of reliability and the investment/operation alternatives associated with determining a desired reliability level. Reliability analyses of power systems containing wind energy, solar energy and/or energy storage have been presented in the previous chapters. This chapter is directed towards the development of models and techniques for the economic assessment of these systems.

The conventional reliability cost/worth evaluation techniques are extended and modified in this chapter to assess the economic aspects of power systems containing conventional units, WTG, PV and energy storage. The different cost factors related to electric power system planning are considered and modeled. These factors include the costs associated with the required investments and the operation of the system together with the customer unsupplied energy costs due to electric supply interruptions. Two different approaches for evaluating reliability cost and reliability worth are developed and discussed. These approaches are then applied to conduct a range of economic studies using the system data presented in the previous chapters. The research described in this chapter is focused on small isolated system analyses.

9.2 Reliability Cost/Worth Evaluation Models

Reliability cost/worth evaluation is an important aspect in electric power system planning, operation and optimization. Any investment in utilizing unconventional energy sources and storage facilities should be evaluated in terms of both the reliability and costs of the system and the reliability worth to the customers. There are different costs associated with a power system containing wind energy, solar energy and energy storage. These costs can be generally grouped in the two different categories of utility costs and customer interruption costs (CIC). The utility costs include the costs associated with the required investments and the operation of the system. The utility costs can be further divided into fixed costs and variable costs. The fixed costs include such factors as generating unit, storage system, installation and design costs etc. The variable costs mainly consist of fuel costs and the maintenance costs of the generating units and energy storage system. The customer interruption costs are the customer unsupplied energy costs due to electric supply interruptions. The sum of the utility costs and the customer interruption costs is designated as the total cost in this thesis.

9.2.1 Utility Costs

The overall utility cost can be incorporated in a single function designated as the utility cost function (UCF) shown in Equation (9.1). This UCF can be used in a wide range of economic analyses in power system planning.

$$UCF = \sum_{i=1}^{N_t} (\alpha_i P_i + C_i^O + C_i^M) + \sum_{j=1}^{N_c} C_i^F + \beta W_S \qquad (9.1)$$

where:

α_i -the installed generating unit cost in \$/kW or \$/MW of the ith generating unit

P_i -the power rating of the ith generating unit in kW or MW

C_i^O -other constant costs such as design and installation costs associated with the ith generating unit

C_i^M -the maintenance cost of ith generating unit

C_i^F -the fuel cost of ith conventional generating unit

β -the combined unit cost of the installed energy storage system in \$/kWh or \$/MWh [64]

W_S -the installed capacity of the energy storage system in kWh or MWh

N_t -the total number of generating units

N_c - the total number of conventional generating units

Energy storage systems require replacement during the life time of the system. In order to reflect this fact in the evaluation, the combined costs of the storage system is used instead of the installed energy capacity unit cost. The combined cost is, therefore, the present value of the purchase and replacement cost of the storage system. Typical fixed costs and variable costs associated with different generating unit types and energy storage for small isolated systems are presented in Table 9.1. It is assumed that the maintenance costs are a fixed percent of the unit costs in Table 9.1. It should be noted that the values in Table 9.1 are general indications only and may not reflect specific market or local site installation conditions.

Table 9.1: Typical cost data for different generating units and storage in small isolated applications

Unit or storage	Unit cost or combined cost of storage ($/kW or $/kWh)	Other constant costs ($/kW)	Maintenance cost (percentage of unit costs)
Diesel	300	600	2%
WTG	1,200	450	2%
PV	11,000		0%
Storage	450		0%

9.2.2 Customer Interruption Costs

Customer interruption costs are directly related to the type of customer and the duration of interruptions. The evaluation of customer interruption costs is usually conducted using sector customer damage functions (SCDF) or composite customer damage functions (CCDF) depending on the customer groups involved [1]. The interruption costs for various outage durations can be obtained through customer surveys of the different customer groups [1]. The SCDF used in this research work are shown in Table 9.2 [1].

Table 9.2: Sector interruption cost estimates expressed in $/kW

	Interruption Durations				
User Sector	1 minute	20 minutes	1 hour	4 hour	8 hour
Large Users	1.0050	1.5080	2.2250	3.9680	8.2400
Industrial	1.6250	3.8680	9.0850	25.1630	55.8080
Commercial	0.3810	2.9690	8.5520	31.3170	83.0080
Agricultural	0.0600	0.3430	0.6490	2.0640	4.1200
Residential	0.0010	0.0930	0.4820	4.9140	15.6900
Government & Institute	0.0440	0.3690	1.4920	6.5580	26.0400
Office & Buildings	4.7780	9.8780	21.0650	68.8300	119.1600

The SCDF can be combined to obtain the system CCDF using Equation (9.2) [1].

$$CCDF = \sum_{i=1}^{n} k_i SCDF_i \tag{9.2}$$

where:

k_i -the per unit energy consumption of customer sector i

$SCDF_i$ -the sector customer damage function of customer i

n-the number of customer sectors

The CCDF is a measure of the cost associated with power interruptions as a function of the interruption duration for the customer mix in the given system. The system CCDF, which is calculated from the SCDF shown in Table 9.2 for the IEEE-RTS [86] is shown graphically in Figure 9.1.

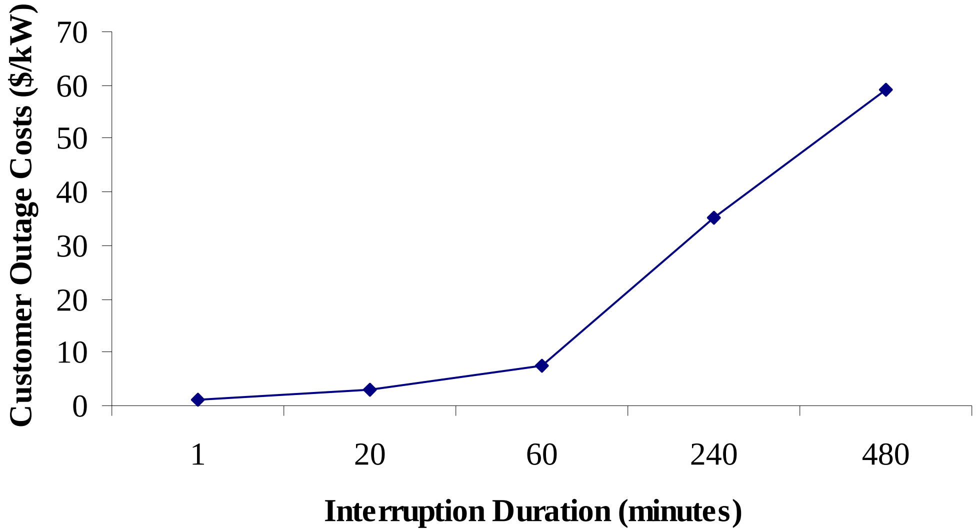


Figure 9.1: Composite customer damage function for the IEEE-RTS

9.3 Reliability Cost/Worth Evaluation Techniques

Generally, the utility costs increase and the customer interruption costs decrease as the reliability level increases, as illustrated in Figure 9.2. Traditionally, electric utilities have been primary interested in utility costs in their planning and customer interruption costs were not extensively considered. The objective of the traditional approach is to find an optimal utility cost (point A) while ensuring that the supply reliability is equal to a pre-established objective (Point R). This approach is designated as the Optimal Utility Cost Method (OUCM) in this thesis. An alternative approach to incorporating both factors is to use a reliability cost and reliability worth philosophy in the evaluation. This approach is designated as the Reliability Cost/Worth Method (RCWM) in this thesis. The basic objective of the RCWM is to determine an optimal reliability level (R_{opt}) at which the total costs are minimum [1]. Both techniques have their merits and demerits. The OUCM is simple and easy to use. The major disadvantage is that it requires a pre-specified reliability target in the planning process. In the RCWM, the system reliability level is not a pre-determined value, but is an outcome of an optimization process.

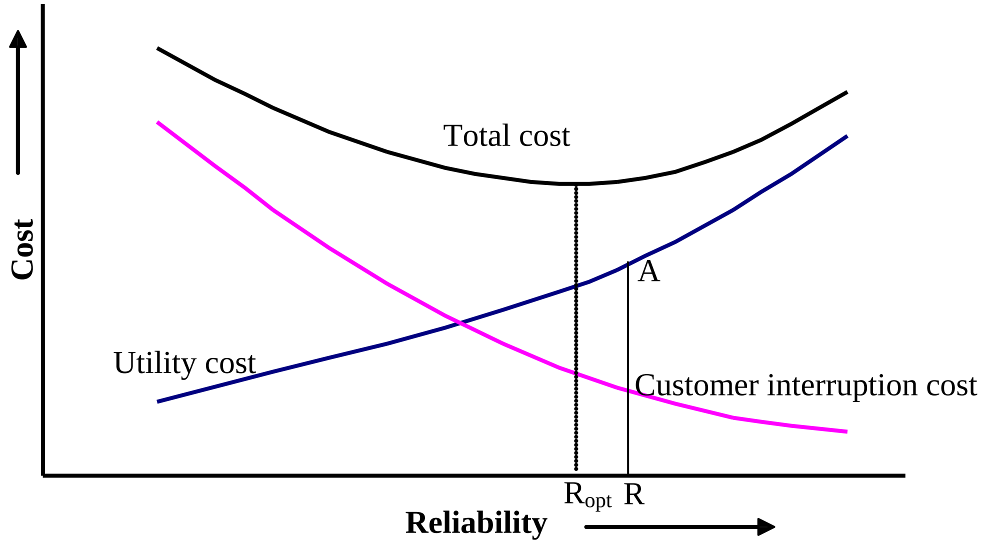


Figure 9.2: System reliability and costs

9.3.1 Optimal Utility Cost Method (OUCM)

In the OUCM, a reliability criterion, either deterministic or probabilistic, is selected to evaluate the costs associated with different alternatives. The probabilistic criterion most often used in the OUCM is the LOLE. In order to maintain a specified reliability level with increasing system load, it may be necessary to add extra generating unit and/or energy storage capacity. The method is examined for the two cases of without and with energy storage.

a) Systems without energy storage

If a system contains no energy storage, the benefits of different generating unit additions to the system can be evaluated in terms of the utility costs at a particular risk level for a given site location. Figure 9.3 illustrates the relationship between a risk index and non-conventional unit capacity additions to a given system for two different locations. In Figure 9.3, R_c is the reliability criterion, C_1 and C_2 are the additional renewable capacities needed to keep the expanded generating system at risk level R_c for Locations 1 and 2 respectively. The system costs associated with different system expansions can be calculated and compared using Equation (9.1). The important planning task is the selection of the most beneficial option in terms of the reliability and costs. This kind of analysis is presented in detailed in [99] using the RBTS as an example.

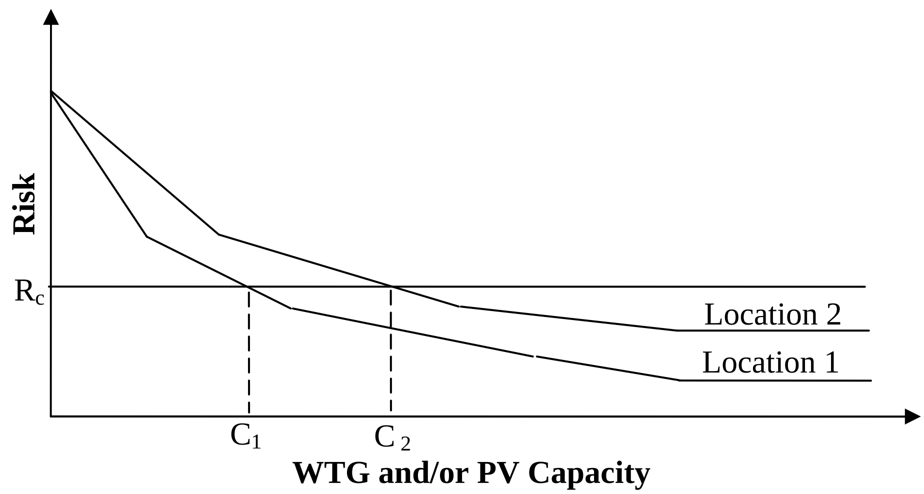


Figure 9.3: Variation of reliability indices with WTG and/or PV capacity

b) Systems with energy storage

If the system contains energy storage, it is important to find the optimal sizes of the non-conventional generating unit and the storage system capacity so that the total utility cost is minimized at a given risk level. The process presented in [64] is extended and modified in this thesis to evaluate the utility costs for power systems utilizing conventional units, WTG, PV and energy storage. The cost optimization problem is to minimize the UCF as defined in Equation (9.1) subject to the constraint of a pre-determined reliability criterion. This is under the assumption that the total capacity of conventional units are known and fixed for a given system, if the system contains any conventional generating units. As noted in previous studies, additions of WTG, PV and/or energy storage to a given system improve the system reliability. Utilization of these non-conventional energy sources also has positive economic impacts such as fuel savings in a given system. The utility costs can be determined for a range of alternatives including all possible combinations of WTG and/or PV and the storage system capacities subject to the following inequality constraints:

$$\begin{aligned} W_{S_{\min}} &\leq W_S \leq W_{S_{\max}} \\ P_{\min} &\leq P \leq P_{\max} \end{aligned} \tag{9.3}$$

W_S and P are the energy storage capacity and the total non-conventional unit capacity respectively in Equation (9.3). The variables W_S and P are not continuous and usually change in well defined discrete steps. Change in W_S is due to the addition of more storage capacity and the change of P is due to the addition of more WTG and/or PV units to the system. The number of combinations of energy storage and non-conventional unit capacities is, therefore, restricted.

Figure 9.4 illustrates the relationship between a reliability index and renewable energy capacity additions to a given system for three energy storage capabilities designated as W_{B1}, W_{B2} and W_{B3}. The curves in Figure 9.4 are designated as equal energy storage capacity curves (EESCC) in this thesis and R_c is the reliability criterion. This reliability level can be satisfied by several alternatives. The optimum solution is the one which results in the lowest system cost as defined in Equation (9.1).

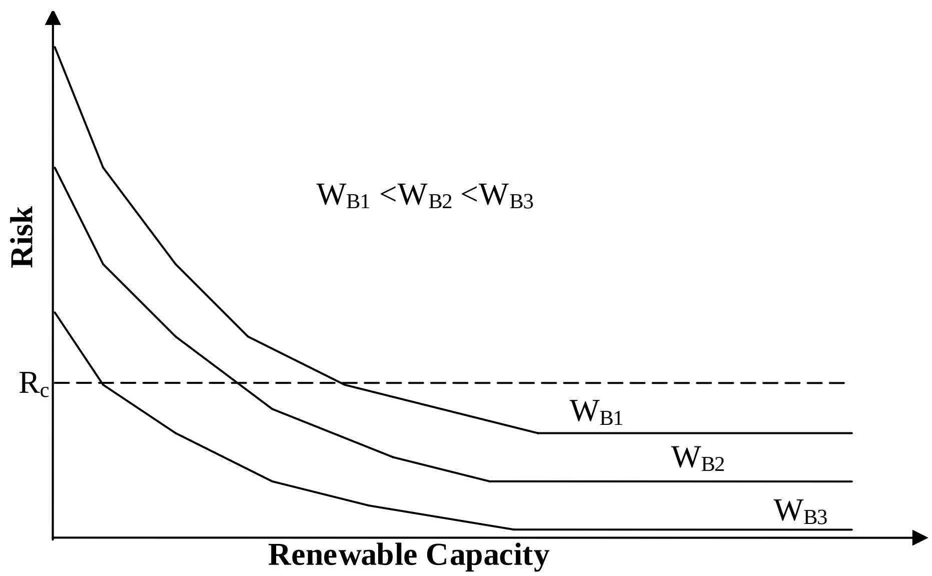


Figure 9.4: Equal energy storage capacity curves

Another alternative is to use equal renewable energy capacity curves (ERECC). An ERECC is the relationship between a reliability index and energy storage capacity for a fixed non-conventional unit capacity condition. Three curves designated as P_1, P_2 and P_3 and the reliability criterion R_c are shown in Figure 9.5. The reliability level can be satisfied by several alternatives. The lowest cost of these options can also be determined using Equation (9.1).

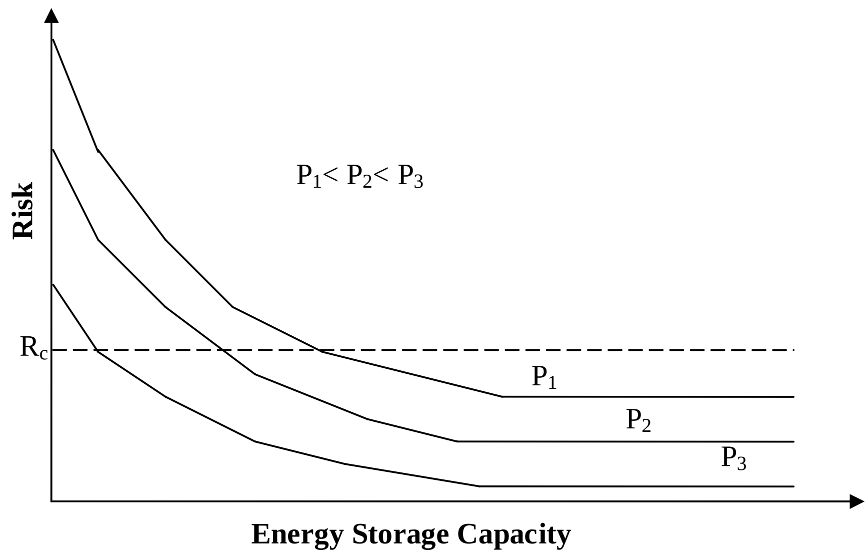


Figure 9.5: Equal renewable energy capacity curves

The EESCC and ERECC approaches can be combined to obtain the relationship between the renewable energy capacity and the energy storage capacity with the risk levels as parameters. Figure 9.6 illustrates this relationship using the LOLE index as a parameter. The curves shown in Figure 9.6 are designated as equal risk curves (ERC) in this thesis. Figure 9.6 can be used to determined the minimum cost combination of non-conventional unit capacity and energy storage capacity for a given reliability level. The objective of this approach is to find an optimal utility cost as indicated by points A, B and C for different risk levels represented by LOLE 1, LOLE 2 and LOLE 3 respectively. This approach is an effective tool for designing and planning small isolated systems containing energy storage. Customer interruption costs are not directly considered in this approach as they would be basically constant for each of the designated risk levels. Customer unsupplied energy costs due to electric supply interruptions are directly considered in the evaluation using the RCWM technique presented in the following subsection.

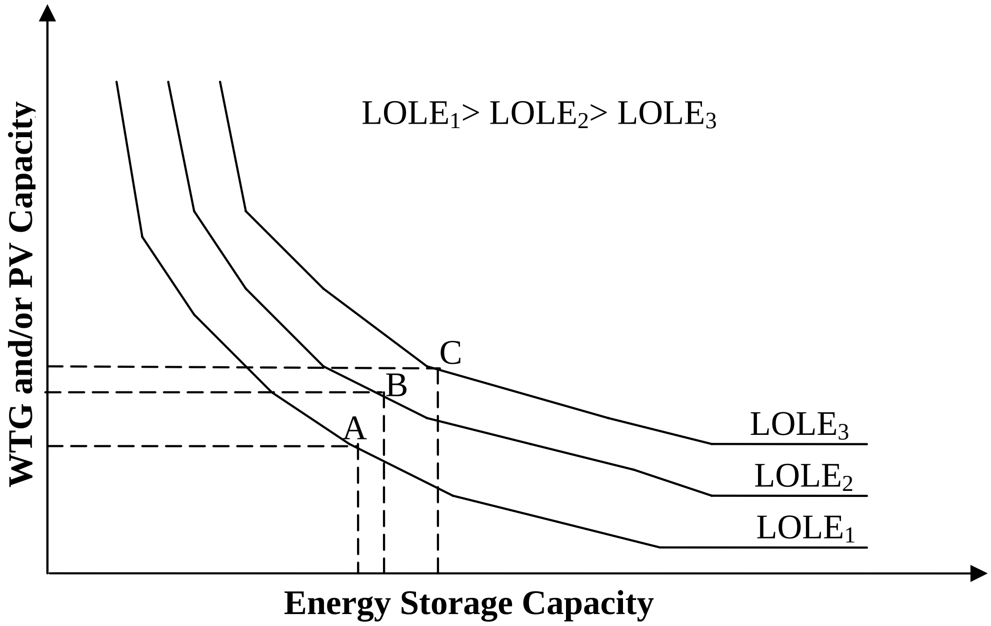


Figure 9.6: Equal risk curves

9.3.2 Reliability Cost/Worth Method (RCWM)

The basic objective of the reliability cost/worth approach is to determine an optimal reliability level at which the total costs (sum of the utility costs and customer interruption costs) are minimized [1]. The probabilistic criterion most often used in the RCWM is the LOEE. The utility costs can be calculated using Equation (9.1) and the customer interruption costs can be calculated as follows using Monte Carlo simulation:

1. Calculate the duration and the expected energy not supplied at each interruption.
2. The average load loss during the i^{th} interruption is then calculated by dividing the expected energy not supplied during that interruption by the duration of outage.

$$L_i = \frac{EENS_i}{d_i} \tag{9.4}$$

Where:

$EENS_i$ - Expected energy not supplied in kWh or MWh in the i^{th} interruption

d_i - Outage duration (hour) of the i^{th} interruption

L_i - Average load loss in kW or MW in the i^{th} interruption

3. The interruption cost per kW or MW for the outage is obtained from the system SCDF or CCDF and multiplied by the load loss to get the customer outage cost in dollars for the i^{th} outage.

$$CIC_i = C(d_i)L_i \tag{9.5}$$

Where:

d_i - Outage duration (hour) of the i^{th} interruption

$C(d_i)$ - Interruption cost in i^{th} interruption from CDF (\$/kW)

L_i - Average load loss in kW or MW in the i^{th} interruption

4. The system customer outage cost in dollars is finally calculated by adding cost associated with each interruption.

$$CIC = \sum_{i=1}^{N} CIC_i \tag{9.6}$$

Where: N is the total number of interruptions.

The basic customer outage cost data are not always available for every outage duration. Logarithmic interpolation, therefore, was used to evaluate the costs between the existing data points and extrapolation was used to calculate the other costs. The interpolation and extrapolation techniques are given respectively in Appendices E and F.

The customer outage costs decrease and the utility costs increase as additional generating and/or energy storage capacity are added to a system as shown in Figure 9.2.

The RCWM can be used to determine an optimum adequacy level incorporating both the costs of providing reliability and the worth of having that reliability. This approach is often used to evaluate the optimum reserve margin in conventional generation planning. Once the optimal generating reserve is determined, the target adequacy level is also determined. The RCWM also can be used to determine the optimum addition of non-conventional generating capacity and/or storage capacity to a small isolated system. This is illustrated in the following using the example systems described in previous chapters.

9.4 System Studies

The described reliability cost/worth evaluation models and techniques are applied to examine the economic impact of power systems utilizing wind energy, solar energy and energy storage in this section. Different system configurations are investigated and analyzed. The economic assessment of systems containing wind energy and/or solar energy and energy storage is conducted using small isolated example systems considering different operating strategies. The fixed and variable costs associated with small isolated systems shown in Table 9.1 are used in following analyses. All of the fixed costs expended during the life time of a project or equipment are converted to a series of consecutive equal payments occurring in each year as presented in Equation (9.7) [104].

$$A = P\left[\frac{i(1+i)^N}{(1+i)^N - 1}\right] \tag{9.7}$$

Where:

P - Present sum of money at time zero

i - Annual interest rate

N - Total number of interest periods

A - A uniform series of payments

The lifetime of WTG and PV units is assumed to be 20 years and the annual interest rate is assumed to be 12% in following analysis. The combined costs associated with energy storage are also considered on a 20 year base. The economic benefits due to fuel savings are also incorporated. A fuel cost of $1.1/liter and a heat rate of 3.2 kWh/liter are used for the diesel units. Other annual fixed charges such as taxes, insurances and depreciation are not included in the studies.

9.4.1 Application of the OUCM

In order to illustrate the use of the previously developed methods, studies have been conducted on various alternatives using the small isolated system cases. Figure 9.7 shows the equal energy storage capacity curves obtained using the data shown in Tables 4.1 and 4.2 for Case 6. All of the diesel units are assumed to be continuously operated and the wind regime is assumed to be represented by the Regina site. The system annual peak load is 40 kW. The selected risk level is a LOLE of 30 h/year as shown in Figure 9.7.

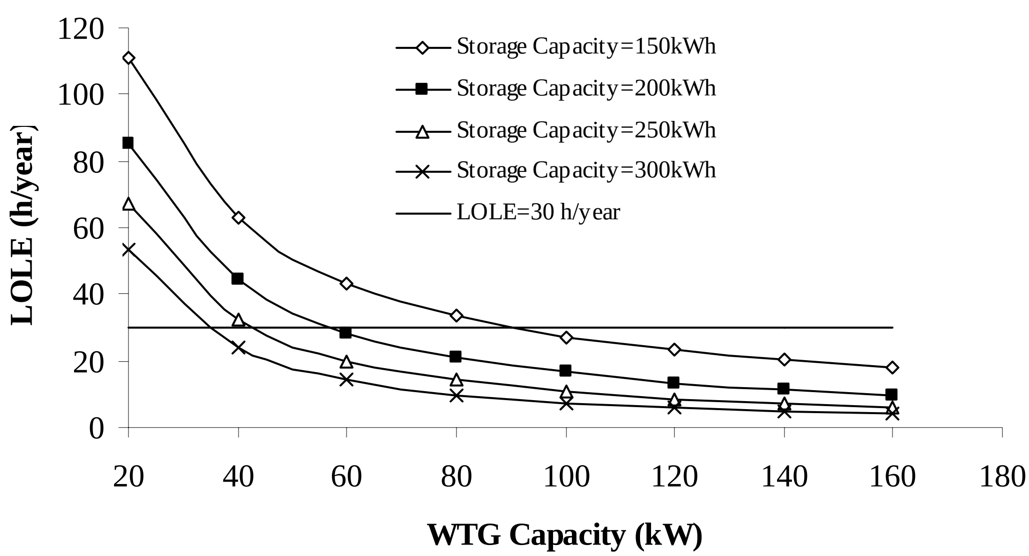


Figure 9.7: Equal energy storage capacity curves
(Wind-diesel continuous, Regina data)

The utility costs associated with the four different storage capacity levels at a LOLE of 30 h/year are compared in Table 9.3. The annual fixed costs and production costs associated with the diesel generating units are not included in Table 9.3. It can be seen from Table 9.3 that although the system load can be satisfied by all of the four different alternatives at a LOLE of 30 h/year, the annual utility costs associated with these system configurations are different. The minimum cost alternative in this case requires a total WTG capacity of 44 kW and a 250 kWh energy storage system in addition to the two diesel units. The total WTG capacity and energy storage capacity are 91 kW and 150 kWh respectively for the maximum cost alternative. The difference between the maximum and the minimum cost is approximately $3, 810.00/year.

Table 9.3: Annual utility costs for the different alternatives shown in Figure 9.7 at a LOLE of 30 h/year (Wind-diesel continuous, Regina data)

Alternative	1	**2**	3	4
WTG capacity (kW)	36	**44**	58	91
Storage capacity (kWh)	300	**250**	200	150
Unit costs ($ k)	43.20	**52.80**	69.60	109.20
Storage costs ($ k)	135.00	**112.50**	90.00	67.50
Other constant costs ($ k)	16.20	**19.80**	26.10	40.95
Total capital costs ($ k)	194.40	**185.10**	185.70	217.65
Annualized capital cost ($ k/year)	23.95	**22.80**	22.88	26.81
Savings due to reduced fuel usage ($ k/year)	15.78	**15.52**	15.28	15.72
Annual utility costs ($ k/year)	8.17	**7.28**	7.60	11.09

Figure 9.8 shows the ERECC obtained using the data shown in Tables 4.1 and 4.2 for Case 6. The annual utility costs associated with the four different renewable energy capacity levels shown in Figure 9.8 at a LOLE of 30 h/year are compared in Table 9.4. It can be seen from Table 9.4 that the optimum choice in terms of annual utility cost is Alternative 4. The annual utility cost for Alternative 4 is approximately $7,310.00/year. This value is very close to the minimum annual cost of $7,280.00 for Alternative 2 in Table 9.3 for the fixed energy storage case analysis. The total WTG capacity and the energy storage capacity are approximately 40 kW and 250 kWh respectively for both these minimum cost cases. It can be, therefore, concluded that there is an optimum point

where the annual utility cost associated with the non-conventional generating units and the energy storage are minimum at a certain reliability level for a specific site and a given load condition. Finding the optimum match between the total renewable energy capacity and the energy storage for systems at a predetermined reliability level is an important planning task. This analysis can be conducted using the ERC.

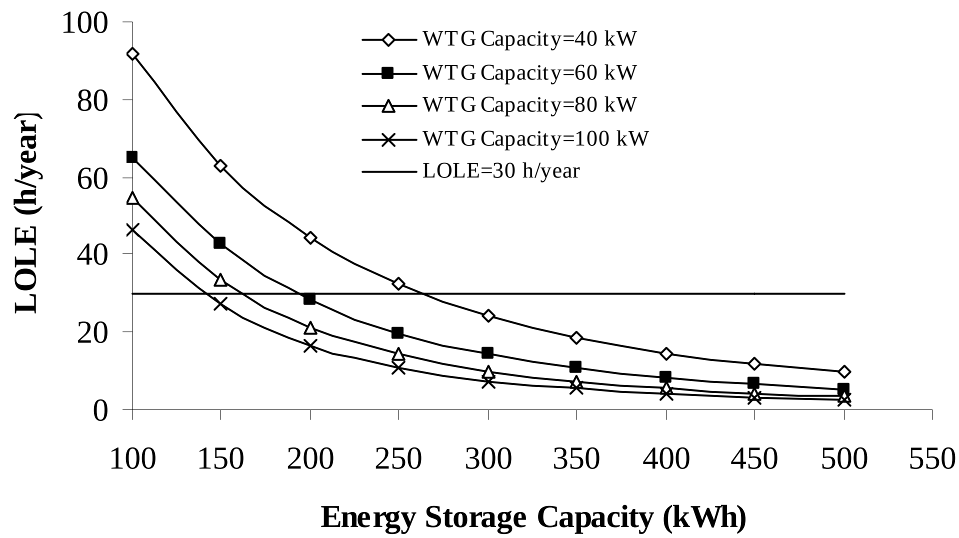


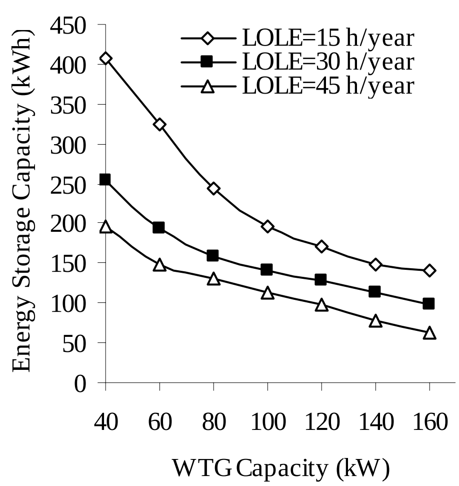
Figure 9.8: Equal renewable energy capacity curves
(Wind-diesel continuous, Regina data)

Table 9.4: Annual utility costs for the different alternatives shown in Figure 9.8 at a LOLE of 30 h/year (Wind-diesel continuous, Regina data)

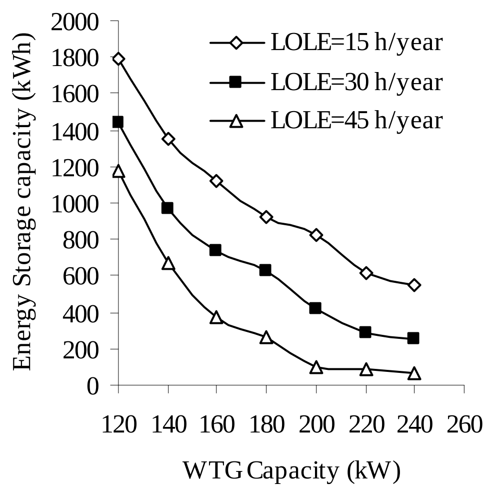
Alternative	1	2	3	**4**
WTG capacity (kW)	100	80	60	**40**
Storage capacity (kWh)	143	164	194	**264**
Unit costs ($ k)	120.00	96.00	72.00	**48.00**
Storage costs ($ k)	64.35	73.80	87.30	**118.80**
Other constant costs ($ k)	45.00	36.00	27.00	**18.00**
Total capital costs ($ k)	229.35	205.80	186.30	**184.80**
Annualized capital cost ($ k/year)	28.26	25.35	22.95	**22.77**
Savings due to reduced fuel usage ($ k/year)	15.17	15.93	15.12	**15.46**
Annual utility costs ($ k/year)	13.09	9.42	7.83	**7.31**

Figure 9.9 shows the ERC obtained for both continuous and intermittent diesel operation for wind-diesel systems using Regina data. A diesel unit starting probability of 0.9 is included for the intermittent diesel operation case analyses. The ERC are shown for the three LOLE levels of 15 h/year, 30 h/year and 45 h/year in Figure 9.9. In the continuous diesel case (Case (a) of Figure 9.9), the total WTG capacity was varied from 40 kW to 160 kW in steps of 20 kW and the required energy storage capacity was determined. In the intermittent diesel case (Case (b) of Figure 9.9), the total WTG capacity was varied from 120 kW to 240 kW in steps of 20 kW and the required energy storage capacity was determined.

All the points in the P-W plane above a certain curve imply power supply possibilities with reliability levels better than the one determined by the curve itself. As an example, if the storage capacity in the continuous case is 150 kWh, the load demand can be satisfied by adding approximately 60 kW WTG at a LOLE of 45 h/year (Case (a) of Figure 9.9). If the total WTG capacity is increased to 100 kW, the LOLE approaches 30 h/year (Case (a) of Figure 9.9). The optimum combination of WTG capacity and energy storage capacity can, therefore, be determined by considering various alternatives on a designated ERC.



(a) Continuous Diesel



(b) Intermittent Diesel

Figure 9.9: Equal risk curves (Wind-Diesel, Regina data)

Table 9.5 shows the annual utility costs associated with the different combinations of WTG capacity and energy storage capacity at the three different LOLE values for the continuous diesel operation case shown in Case (a) of Figure 9.9. It can be seen from Tables 9.5-I, 9.5-II and 9.5-III that the total system load can be satisfied by different system configurations at a specified reliability level. The minimum costs associated with the three reliability levels are different. The optimum systems in terms of minimum cost for all of the three reliability levels are highlighted in Tables 9.5-I, 9.5-II and 9.5-III. As shown in Table 9.5-I, the optimum choice with a LOLE of 15 h/year is Alternative 3, which requires a total WTG capacity of 80 kW and a 243 kWh energy storage system in addition to the two diesel units. The annual utility cost for this case is $12,870.00/year.

Table 9.6 shows the annual utility costs associated with the different combinations of WTG capacity and energy storage capacity at the three different LOLE values for the intermittent diesel operation case shown in Case (b) of Figure 9.9. It can be seen from Table 9.6 that the optimum systems in terms of minimum cost at a LOLE of 15 h/year, 30 h/year and 45 h /year are Alternatives 6, 6 and 5 respectively. The annual utility costs associated with these alternatives are approximately $36,780.00/year, $19,860.00/year and $8,730.00/year respectively.

Tables 9.5 and 9.6 show that the annualized capital costs and the savings due to reduced fuel usage decrease with increase in the LOLE criterion. The degree of decrease in annualized capital costs is, however, higher than that of the fuel cost savings. The savings due to reduced fuel usage offset the capital costs. This effect becomes more significant with increase in the LOLE criterion. Although the total capital cost is higher than that of the continuous case at a specific reliability level, intermittent diesel operation saves more fuel. Intermittent diesel operation is superior to continuous diesel operation when the savings due to reduced fuel usage are more significant. The site resource, system configuration, system load, the diesel fuel price and the starting probability of the back-up diesel unit are the major factors that influence the fuel saving effect. If the starting probability of the back-up diesel unit is assumed to be 1 and other information remains unchanged, the annual utility cost of the intermittent case is

$4,240.00/year, at a LOLE of 45 h/year. This is less than the annual utility cost of $4,970.00/year for the continuous case at the same reliability level.

Table 9.5-I: Annual utility costs for the different alternatives shown in Figure 9.9 at a LOLE of 15 h/year (WD-continuous, Regina data)

Alternative	1	2	**3**	4	5	6	7
WTG capacity (kW)	40	60	**80**	100	120	140	160
Storage capacity (kWh)	407	324	**243**	196	172	149	140
Unit costs ($ k)	48.00	72.00	**96.00**	120.00	144.00	168.00	192.00
Storage costs ($ k)	183.15	145.80	**109.35**	88.20	77.40	67.05	63.00
Other constant costs ($ k)	18.00	27.00	**36.00**	45.00	54.00	63.00	72.00
Total capital costs ($ k)	249.15	244.80	**241.35**	253.20	275.40	298.05	327.00
Annualized capital cost ($ k/year)	30.70	30.16	**29.73**	31.19	33.93	36.72	40.29
Savings due to reduced fuel usage ($ k/year)	16.06	16.22	**16.86**	16.69	16.88	16.26	16.44
Annual utility costs ($ k/year)	14.64	13.94	**12.87**	14.50	17.05	20.46	23.85

Table 9.5-II: Annual utility costs for the different alternatives shown in Figure 9.9 at a LOLE of 30 h/year (WD-continuous, Regina data)

Alternative	**1**	2	3	4	5	6	7
WTG capacity (kW)	**40**	60	80	100	120	140	160
Storage capacity (kWh)	**255**	194	159	140	127	112	99
Unit costs ($ k)	**48.00**	72.00	96.00	120.00	144.00	168.00	192.00
Storage costs ($ k)	**144.75**	87.30	71.55	63.00	57.15	50.40	44.55
Other constant costs ($ k)	**18.00**	27.00	36.00	45.00	54.00	63.00	72.00
Total capital costs ($ k)	**180.75**	186.30	203.55	228.00	255.15	281.40	308.55
Annualized capital cost ($ k/year)	**22.27**	22.95	25.08	28.09	31.43	34.67	38.01
Savings due to reduced fuel usage ($ k/year)	**15.47**	15.62	15.73	15.96	16.02	15.96	15.57
Annual utility costs ($ k/year)	**6.80**	7.33	9.35	12.13	15.41	18.71	22.44

Table 9.5-III: Annual utility costs for the different alternatives shown in Figure 9.9 at a LOLE of 45 h/year (WD-continuous, Regina data)

Alternative	**1**	2	3	4	5	6	7
WTG capacity (kW)	**40**	60	80	100	120	140	160
Storage capacity (kWh)	**195**	149	131	114	97	79	62
Unit costs ($ k)	**48.00**	72.00	96.00	120.00	144.00	168.00	192.00
Storage costs ($ k)	**87.75**	67.05	58.95	51.30	43.65	35.55	27.90
Other constant costs ($ k)	**18.00**	27.00	36.00	45.00	54.00	63.00	72.00
Total capital costs ($ k)	**153.75**	166.05	190.95	216.30	241.65	266.55	291.90
Annualized capital cost ($ k/year)	**18.94**	20.46	23.53	26.65	29.77	32.84	35.96
Savings due to reduced fuel usage ($ k/year)	**13.97**	13.09	15.03	14.96	15.34	13.96	14.14
Annual utility costs ($ k/year)	**4.97**	5.37	8.50	11.69	14.43	18.88	21.82

Table 9.6-I: Annual utility costs for the different alternatives shown in Figure 9.9 at a LOLE of 15 h/year (WD-intermittent, Regina data)

Alternative	1	2	3	4	5	**6**	7
WTG capacity (kW)	120	140	160	180	200	**220**	240
Storage capacity (kWh)	1790	1354	1120	918	820	**618**	545
Unit costs ($ k)	144.00	168.00	192.00	216.00	240.00	**264.00**	288.00
Storage costs ($ k)	805.50	609.30	504.00	413.10	369.00	**278.10**	245.25
Other constant costs ($ k)	54.00	63.00	72.00	81.00	90.00	**99.00**	108.00
Total capital costs ($ k)	1003.50	840.30	768.00	710.10	699.00	**641.10**	641.25
Annualized capital cost ($ k/year)	123.63	103.53	94.62	87.48	86.12	**78.98**	79.00
Savings due to reduced fuel usage ($ k/year)	41.14	40.55	42.40	41.01	40.98	**42.20**	42.01
Annual utility costs ($ k/year)	82.49	62.97	52.22	46.47	45.14	**36.78**	36.99

Table 9.6-II: Annual utility costs for the different alternatives shown in Figure 9.9 at a LOLE of 30 h/year (WD-intermittent, Regina data)

Alternative	1	2	3	4	5	**6**	7
WTG capacity (kW)	120	140	160	180	200	**220**	240
Storage capacity (kWh)	1437	970	734	625	414	**283**	255
Unit costs ($ k)	144.00	168.00	192.00	216.00	240.00	**264.00**	288.00
Storage costs ($ k)	646.65	436.50	330.30	281.25	186.30	**127.35**	114.75
Other constant costs ($ k)	54.00	63.00	72.00	81.00	90.00	**99.00**	108.00
Total capital costs ($ k)	844.65	667.50	594.30	578.25	516.30	**490.35**	510.75
Annualized capital cost ($ k/year)	104.06	82.24	73.22	71.24	63.61	**60.4**1	62.92
Savings due to reduced fuel usage ($ k/year)	39.55	40.20	39.93	39.22	38.90	**40.55**	39.00
Annual utility costs ($ k/year)	64.51	42.04	33.29	32.02	24.71	**19.86**	23.92

Table 9.6-III: Annual utility costs for the different alternatives shown in Figure 9.9 at a LOLE of 45 h/year (WD-intermittent, Regina data)

Alternative	1	2	3	4	**5**	6	7
WTG capacity (kW)	120	140	160	180	**200**	220	240
Storage capacity (kWh)	1173	669	370	261	**104**	90	69
Unit costs ($ k)	144.00	168.00	192.00	216.00	**240.00**	264.00	288.00
Storage costs ($ k)	527.85	301.05	166.50	117.45	**46.80**	40.50	31.05
Other constant costs ($ k)	54.00	63.00	72.00	81.00	**90.00**	99.00	108.00
Total capital costs ($ k)	725.85	532.05	430.50	414.45	**376.80**	403.50	427.05
Annualized capital cost ($ k/year)	89.42	65.56	53.04	51.06	**46.42**	49.71	52.61
Savings due to reduced fuel usage ($ k/year)	39.30	39.16	39.44	38.50	**37.69**	39.01	38.88
Annual utility costs ($ k/year)	50.12	26.39	13.60	12.56	**8.73**	10.70	13.73

Figure 9.10 shows the ERC obtained for the solar-diesel system (Tables 4.1 and 4.2 for Case 4) using Swift Current data. A diesel unit starting probability of 0.9 was

used for the intermittent diesel operation case analyses. The costs analyses for the continuous and intermittent diesel operation cases are presented in Tables 9.7 and 9.8 respectively. Due to the high capital cost of PV, the minimum cost alternatives are the ones that utilize less PV capacity for both continuous and intermittent diesel operation cases. The total fixed costs decrease with increase in the LOLE criterion.

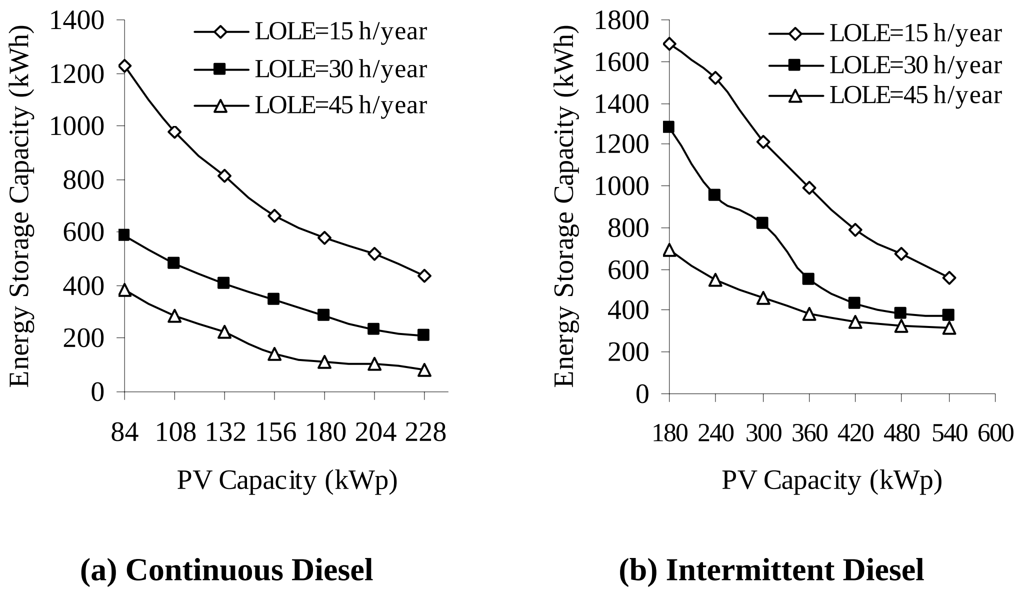


Figure 910: Equal risk curves (Solar-diesel, Swift Current Data)

Table 9.7-I: Annual utility costs for the different alternatives shown in Figure 9.10 at a LOLE of 15 h/year (SD-continuous, Swift Current data)

Alternative	**1**	2	3	4	5	6	7
PV capacity (kW)	**84**	108	132	156	180	204	228
Storage capacity (kWh)	**1230**	979	810	661	583	518	434
Unit costs ($ k)	**924.00**	1188.00	1452.00	1716.00	1980.00	2244.00	2508.00
Storage costs ($ k)	**553.50**	440.55	364.50	297.45	262.35	233.10	195.30
Total capital costs ($ k)	**1477.50**	1628.55	1816.50	2013.45	2242.35	2477.10	2703.30
Annualized capital cost ($ k/year)	**182.03**	200.64	223.79	248.06	276.26	305.18	333.05
Savings due to reduced fuel usage ($ k/year)	**24.87**	23.65	23.98	24.65	24.90	25.01	24.88
Annual utility costs ($ k/year)	**157.16**	176.99	199.81	223.41	251.36	280.17	309.11

Table 9.7-II: Annual utility costs for the different alternatives shown in Figure 9.10 at a LOLE of 30 h/year (SD-continuous, Swift Current data)

Alternative	**1**	2	3	4	5	6	7
PV capacity (kW)	**84**	108	132	156	180	204	228
Storage capacity (kWh)	**586**	481	407	345	285	232	213
Unit costs ($ k)	**924.00**	1188.00	1452.00	1716.00	1980.00	2244.00	2508.00
Storage costs ($ k)	**263.70**	216.45	183.15	155.25	128.25	104.40	95.85
Total capital costs ($ k)	**1187.70**	1404.45	1635.15	1871.25	2108.25	2348.40	2603.85
Annualized capital cost ($ k/year)	**146.32**	173.03	201.45	230.54	259.74	289.33	320.79
Savings due to reduced fuel usage ($ k/year)	**16.87**	16.65	16.98	17.65	16.90	17.01	16.88
Annual utility costs ($ k/year)	**129.46**	156.38	184.47	212.89	242.84	272.32	296.85

Table 9.7-III: Annual utility costs for different alternatives shown in Figure 9.10 at LOLE=45 h/year (SD-continuous, Swift Current data)

Alternative	**1**	2	3	4	5	6	7
PV capacity (kW)	**84**	108	132	156	180	204	228
Storage capacity (kWh)	**381**	283	223	143	114	102	83
Unit costs ($ k)	**924.00**	1188.00	1452.00	1716.00	1980.00	2244.00	2508.00
Storage costs ($ k)	**171.45**	127.35	100.35	64.35	51.30	45.90	37.35
Total capital costs ($ k)	**1095.45**	1315.35	1552.35	1780.35	2031.30	2289.90	2545.35
Annualized capital cost ($ k/year)	**134.96**	162.05	191.25	219.34	250.26	282.12	313.59
Savings due to reduced fuel usage ($ k/year)	**14.81**	13.62	13.89	13.56	14.09	14.10	13.88
Annual utility costs ($ k/year)	**120.15**	148.43	177.36	205.78	236.17	268.02	289.65

Table 9.8-I: Annual utility costs for the different alternatives shown in Figure 9.10 at a LOLE of 15 h/year (SD-intermittent, Swift Current data)

Alternative	**1**	2	3	4	5	6	7
PV capacity (kW)	**180**	240	300	360	420	480	540
Storage capacity (kWh)	**1682**	1524	1216	996	785	678	557
Unit costs ($ k)	**1980.00**	2640.00	3300.00	3960.00	4620.00	5280.00	5940.00
Storage costs ($ k)	**756.90**	685.80	547.20	448.20	353.25	305.10	250.65
Total capital costs ($ k)	**2736.90**	3325.80	3847.20	4408.20	4973.25	5585.10	6190.65
Annualized capital cost ($ k/year)	**337.19**	409.74	473.98	543.09	612.70	688.08	762.68
Savings due to reduced fuel usage ($ k/year)	**29.78**	29.56	28.78	29.16	29.90	28.11	29.84
Annual utility costs ($ k/year)	**307.41**	380.18	445.20	513.93	582.80	659.97	732.85

Table 9.8-II: Annual utility costs for the different alternatives shown in Figure 9.10 at a LOLE of 30 h/year (SD-intermittent, Swift Current data)

Alternative	**1**	2	3	4	5	6	7
PV capacity (kW)	**180**	240	300	360	420	480	540
Storage capacity (kWh)	**1285**	949	819	544	429	385	374
Unit costs ($ k)	**1980.00**	2640.00	3300.00	3960.00	4620.00	5280.00	5940.00
Storage costs ($ k)	**578.25**	427.05	368.55	244.80	193.05	173.25	168.30
Total capital costs ($ k)	**2558.25**	3067.05	3668.55	4204.80	4813.05	5453.25	6108.30
Annualized capital cost ($ k/year)	**315.18**	377.86	451.97	518.03	592.97	671.84	752.54
Savings due to reduced fuel usage ($ k/year)	**27.30**	26.96	26.86	27.61	26.97	27.10	28.04
Annual utility costs ($ k/year)	**287.88**	350.90	425.11	490.42	566.00	644.74	724.50

Table 9.8-III: Annual utility costs for the different alternatives shown in Figure 9.10 at a LOLE of 45 h/year (SD-intermittent, Swift Current data)

Alternative	**1**	2	3	4	5	6	7
PV capacity (kW)	**180**	240	300	360	420	480	540
Storage capacity (kWh)	**696**	549	459	381	349	330	316
Unit costs ($ k)	**1980.00**	2640.00	3300.00	3960.00	4620.00	5280.00	5940.00
Storage costs ($ k)	**313.20**	247.05	206.55	171.45	157.05	148.50	142.20
Total capital costs ($ k)	**2293.20**	2887.05	3506.55	4131.45	4777.05	5428.50	6082.20
Annualized capital cost ($ k/year)	**282.52**	355.68	432.01	508.99	588.53	668.79	749.33
Savings due to reduced fuel usage ($ k/year)	**23.00**	23.61	24.06	23.13	24.07	24.01	23.94
Annual utility costs ($ k/year)	**259.52**	332.07	407.95	485.86	564.46	644.78	725.39

9.4.2 Application of the RCWM

The application of the RCWM for small isolated systems is illustrated using the example system data shown in Tables 4.1 and 4.2. Both continuous and intermittent diesel operation cases are considered. Additional facilities are in the form of WTG, PV and energy storage. Two types of analyses have been conducted to examine the economic impacts of WTG, PV or energy storage in terms of the total cost. In the first case, the energy storage capacity is assigned a designated value and subsequent WTG or PV capacity is added to the system. The minimum total cost is determined in each case. The designated storage capacity is then changed and the process repeated. The optimum WTG or PV addition is the one that corresponds to the least total cost for the energy storage capacity levels considered. The second approach is to set the WTG or PV capacity at a given value while subsequently adding energy storage to the system. The optimum energy storage addition is the one that corresponds to the least total cost for the WTG or PV capacity levels considered. The minimum total costs obtained from the two different approaches are the same for a given system. The choice of which approach to use will depend upon the emphasis placed by the utility regarding WTG, PV or energy storage facilities. The fixed cost associated with the two 20 kW diesel units and the annual production costs of these conventional units are not included in the studies described in this chapter. It should be noted that the resulting reliability of the system, as expressed by the LOLE, is the reliability level that is associated with the system having the lowest total cost. The LOLE is not an initial system design parameter in this case.

Case 1: Wind-diesel- storage system-continuous diesel operation

In this case, the base system consists of two 20 kW diesel units and an energy storage facility. Both of the diesel units are assumed to be operated continuously. Energy storage capacities are first fixed at different levels ranging from 100 kWh to 450 kWh in equal increments of 50 kWh. For each energy storage level, wind generation is added in the form of 2*10 kW WTG. The WTG capacities are then fixed at different levels ranging from 20 kW to 160 kW in equal increments of 20 kW. Energy storage systems are subsequently added at each WTG capacity level. Table 9.9 shows the minimum total costs for different energy storage levels obtained with the subsequent addition of 20 kW of WTG to the system. The minimum total cost occurs at an energy storage capacity of 200 kWh when 40 kW of WTG is added to the system.

Table 9.9: Case 1 analysis: Minimum total costs for different energy storage capacities (Regina data)

Energy storage capacity (kWh)	WTG capacity (kW) at minimum total cost	Minimum total cost ($ k/year)
100	40	13.53
150	40	11.97
200	**40**	**11.96**
250	40	12.77
300	40	14.12
350	20	15.78
400	20	17.18
450	20	18.87

Table 9.10 shows the sensitivity of the utility costs, the customer interruption costs the total costs and the LOLE for the 200 kWh energy storage case with the subsequent addition of WTG to the system.

Table 9.10: Case 1 cost analysis (Energy storage capacity=200 kWh, Regina data)

WTG capacity added (kW)	20	**40**	60	80	100	120	140	160
Storage capacity (kWh)	200	**200**	200	200	200	200	200	200
Unit costs ($ k)	24	**48**	72	96	120	144	168	192
Storage costs ($ k)	90	**90**	90	90	90	90	90	90
Other constant costs ($ k)	9	**18**	27	36	45	54	63	72
Total capital costs ($ k)	123	**156**	189	222	255	288	321	354
Annualized capital cost ($ k/year)	15.1536	**19.2192**	23.2848	27.3504	31.4160	35.4816	39.5472	43.6128
Maintenance cost ($k/year)	0.4	**0.8**	1.2	1.6	2.0	2.4	2.8	3.2
Savings due to reduced fuel usage ($ k/year)	13.7844	**15.0916**	15.6232	15.8800	16.0405	16.1554	16.2348	16.2923
Annual utility costs ($ k/year)	1.8492	**5.0876**	9.1016	13.3905	17.7755	22.2062	26.6724	31.1605
Customer interruption costs ($ k/year)	12.4415	**6.8711**	4.6056	3.5115	2.8272	2.3379	1.9995	1.7543
Total costs ($ k/year)	14.2907	**11.9587**	13.7072	16.9020	20.6027	24.5441	28.6719	32.9147
LOLE (h/year)	84.95	**44.28**	28.37	21.08	16.58	13.39	11.27	9.90

The unit costs, storage costs and the other constant costs in Table 9.10 are based on the cost data presented in Table 9.1. The total capital costs are the sum of the unit costs, storage costs and the other constant costs. The annualized capital costs are calculated using Equation (9.7). The annual utility costs are the sum of the annualized capital costs and the maintenance cost minus the savings due to reduced fuel usage. The customer interruption costs are obtained directly from the sequential simulation. The total costs are the sum of the annual utility costs and the customer interruption costs. The results given in the last three rows of Table 9.10 are shown graphically in Figure 9.11. It can be seen from Figure 9.11 that the customer interruption costs decrease rapidly as additional

WTG capacity is added to the system and the utility costs increase. The least cost wind addition is 40 kW of WTG.

Figure 9.12 compares the changes in the total costs with WTG additions for different energy storage capacity levels for Case 1 using Regina data. It can be seen from Figure 9.12 that the lowest total cost is for the addition of 40 kW of WTG with an energy storage capacity of 200 kWh.

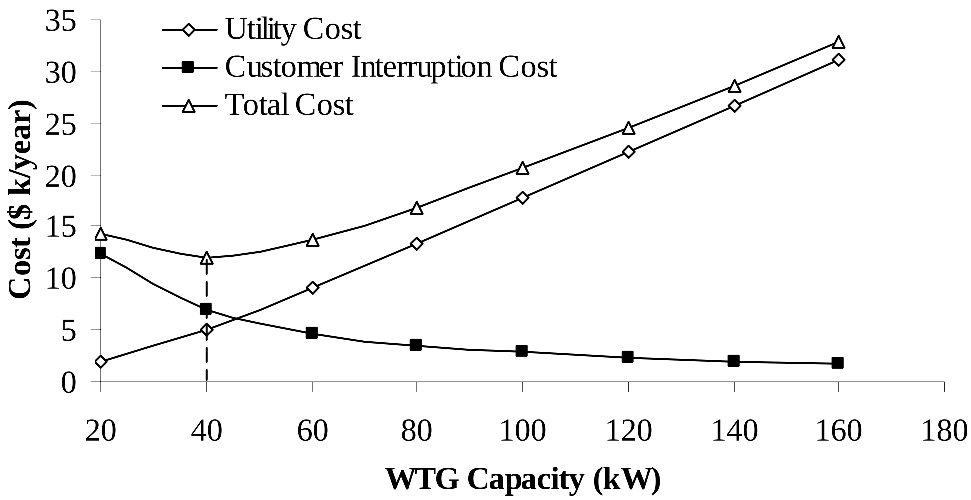


Figure 9.11: Change in utility, customer, and total costs with WTG additions (Case 1, Energy storage capacity=200 kWh, Regina data)

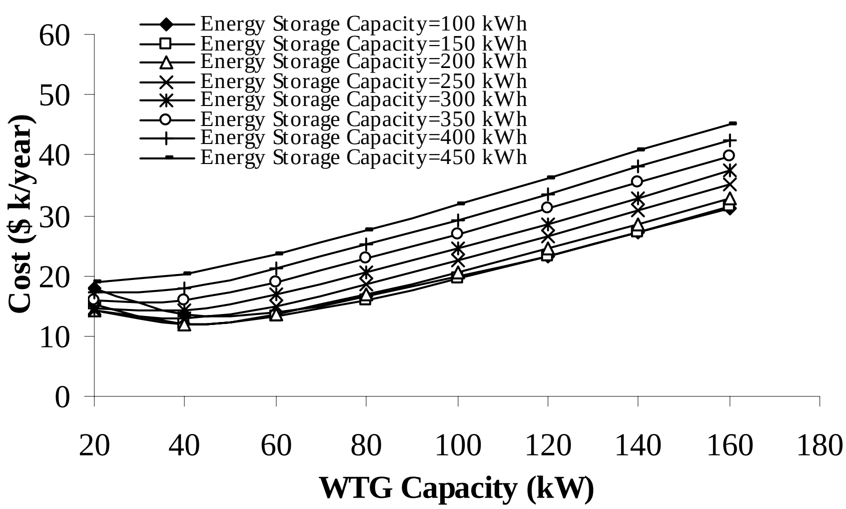


Figure 9.12: Changes in the total costs with WTG additions for different energy storage capacity levels (Case 1, Regina data)

Table 9.11 shows the minimum total costs for different WTG capacity levels obtained with the subsequent addition of 50 kWh energy storage increments to the system. The minimum total cost occurs at a WTG capacity of 40 kW when 200 kWh energy storage is added to the system. The minimum cost of $11,960/year is the same as that obtained in the fixed energy storage case study presented in Table 9.9.

Table 9.11: Case 1 analysis: Minimum total costs for different WTG capacities (Regina data)

WTG capacity (kW)	Energy storage capacity (kWh) at minimum total cost	Minimum total cost ($ k/year)
20	400	13.39
40	**200**	**11.96**
60	150	13.17
80	150	16.01
100	150	19.48
120	150	23.30
140	100	27.14
160	100	31.16

Table 9.12 shows the sensitivity of the utility costs, the customer interruption costs and the total costs for the 40 kW WTG capacity case with the subsequent addition energy storage to the system.

The results given in the last three rows of Table 9.12 are shown graphically in Figure 9.13. It can be seen from Figure 9.13 that the customer interruption costs decrease rapidly as additional energy storage capacity is added to the system and the utility costs increase. The least cost energy storage addition occurs with the addition of an energy storage system with a capacity of 200 kWh.

A comparison of the changes in the total costs with energy storage additions for different WTG capacity levels for Case 1 using Regina data is shown in Figure 9.14. It can be seen from Figure 9.14 that the lowest total cost is with the addition of an energy storage facility of 200 kWh in capacity for the 40 kW WTG case.

Table 9.12: Case 1 cost analysis-(WTG capacity=40 kW, Regina data)

WTG capacity (kW)	40	40	**40**	40	40	40	40	40
Storage capacity added (kWh)	100	150	**200**	250	300	350	400	450
Unit costs ($ k)	48	48	**48**	48	48	48	48	48
Storage costs ($ k)	45	67.5	**90**	112.5	135	157.5	180	202.5
Other constant costs ($ k)	18	18	**18**	18	18	18	18	18
Total capital costs ($ k)	111	133.5	**156**	178.5	201	223.5	246	268.5
Annualized capital cost ($ k/year)	13.6752	16.4472	**19.2192**	21.9912	24.7632	27.5352	30.3072	33.0792
Maintenance cost ($k/year)	0.96	0.96	**0.96**	0.96	0.96	0.96	0.96	0.96
Savings due to reduced fuel usage ($ k/year)	13.7384	14.5619	**15.0916**	15.4641	15.7338	15.9213	15.9703	16.0459
Annual utility costs ($ k/year)	0.8968	2.8453	**5.0876**	7.4871	9.9894	12.5739	15.2969	17.9933
Customer interruption costs ($ k/year)	12.6374	9.1284	**6.8711**	5.2835	4.1343	3.3353	3.1266	2.8044
Total costs ($ k/year)	13.5341	11.9738	**11.9587**	12.7705	14.1237	15.9091	18.4235	20.7977
LOLE (h/year)	91.86	63.01	**44.28**	32.37	24.15	18.60	14.63	11.81

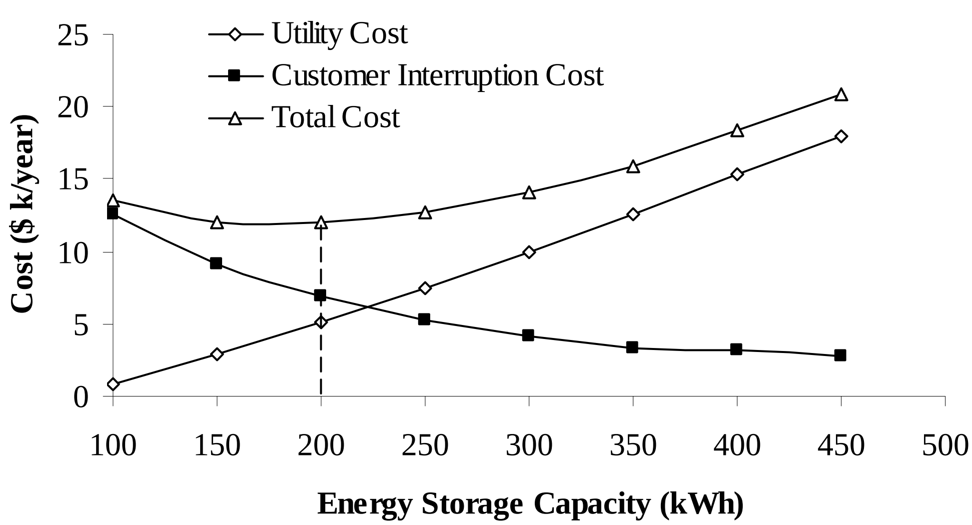


Figure 9.13: Change in utility, customer, and total costs with energy storage additions (Case 1, WTG capacity=40 kW, Regina data)

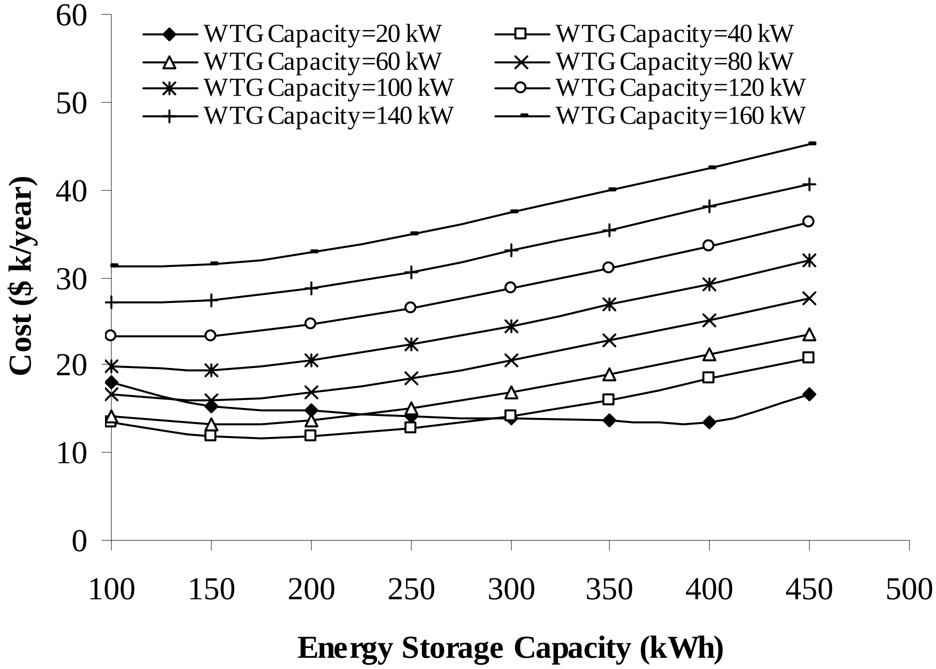


Figure 9.14: Changes in total costs with energy storage additions for different WTG capacity levels (Case 1, Regina data)

Case 2: Wind-diesel-storage system-intermittent diesel operation

The base system in this case is that of Case 1 but one of the diesel units is assumed to be operated intermittently. Energy storage capacities are first fixed at levels ranging from 100 kWh to 800 kWh in equal increments of 100 kWh. For each of these energy storage levels, WTG capacity is added in the form of 2*10 kW WTG. WTG capacities are then fixed at different levels ranging from 20 kW to 160 kW in equal increments of 20 kW. Energy storage capacity is subsequently added for each WTG capacity level. Figures 9.15 and 9.16 respectively show the sensitivity of the utility costs, customer interruption costs and the total costs for an energy storage capacity of 200 kWh with subsequent additions of WTG capacity, and WTG capacity fixed at 60 kW with subsequent additions of energy storage. The least cost wind addition is the addition of 60 kW WTG. The least cost energy storage addition is a facility with a capacity of 200 kWh. The minimum total cost in both Figures 9.15 and 9.16 is $23,722/year. The resulting LOLE associated with the minimum total cost is 67.79 h/year.

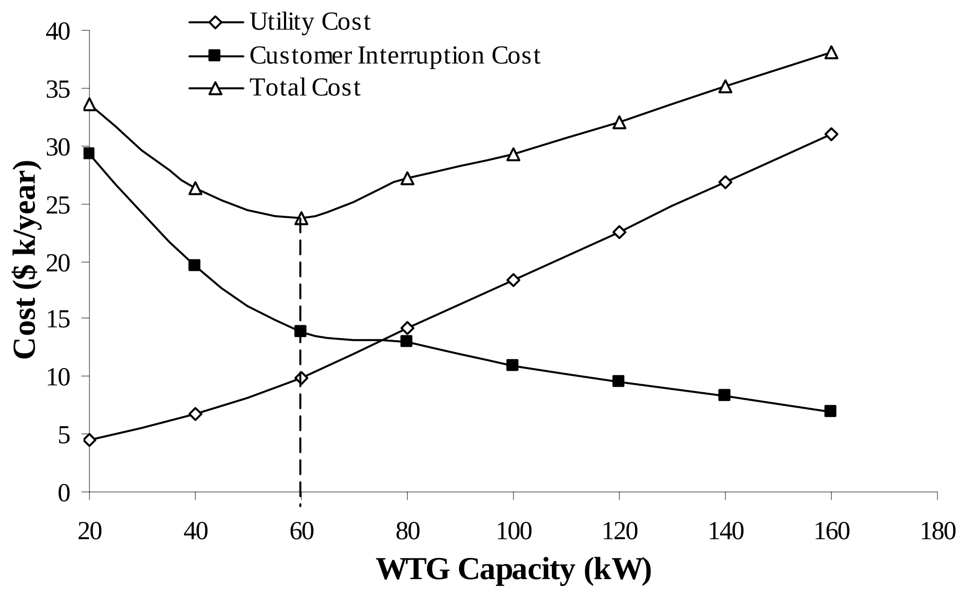


Figure 9.15: Change in utility, customer, and total costs with WTG additions (Case 2, Energy storage capacity= 200 kWh, Regina data)

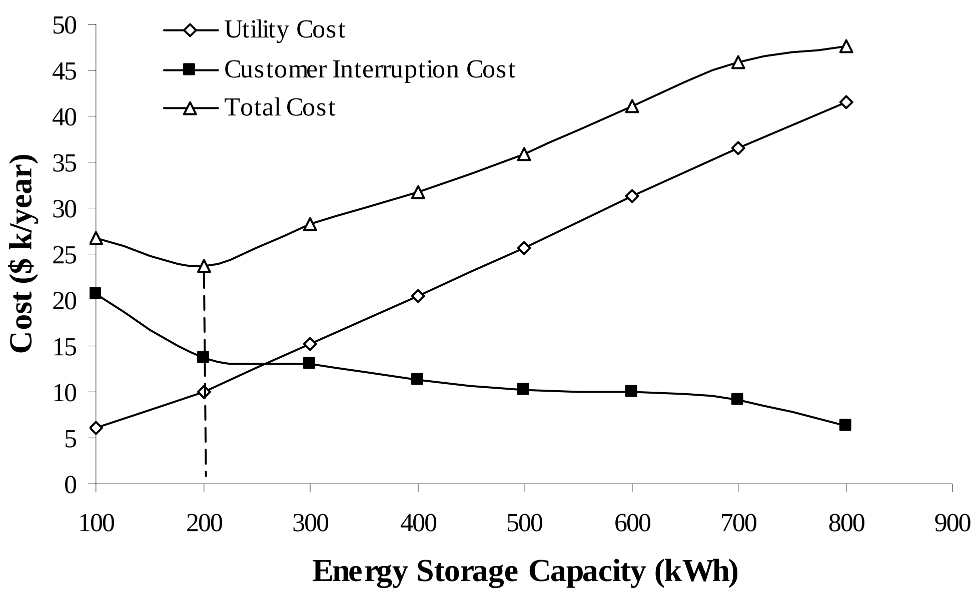


Figure 9.16: Change in utility, customer, and total costs with energy storage additions (Case 2, WTG capacity= 60 kW, Regina data)

Case 3: Solar-diesel- storage system-continuous diesel operation

Similar studies have been conducted on solar-diesel-storage systems. The energy storage capacities considered range from 100 kWh to 800 kWh in steps of 100 kWh. Solar capacities are added in steps of 2*10 kW_p PV for each energy storage level. The PV capacity is then analyzed at levels ranging from 0 kW_p to 160 kW_p in steps of 20 kW_p. Energy storage capacities in steps of 100 kWh are added subsequently for each PV capacity level. Figure 9.17 shows the change in the utility costs, the customer interruption costs and the total costs for the energy storage capacity of 300 kWh with subsequent additions of PV capacity. The least cost system is the system with no PV addition. The total cost calculated for Figure 9.17 is $33,904/year. The resulting LOLE associated with the minimum total cost is 185.06 h/year.

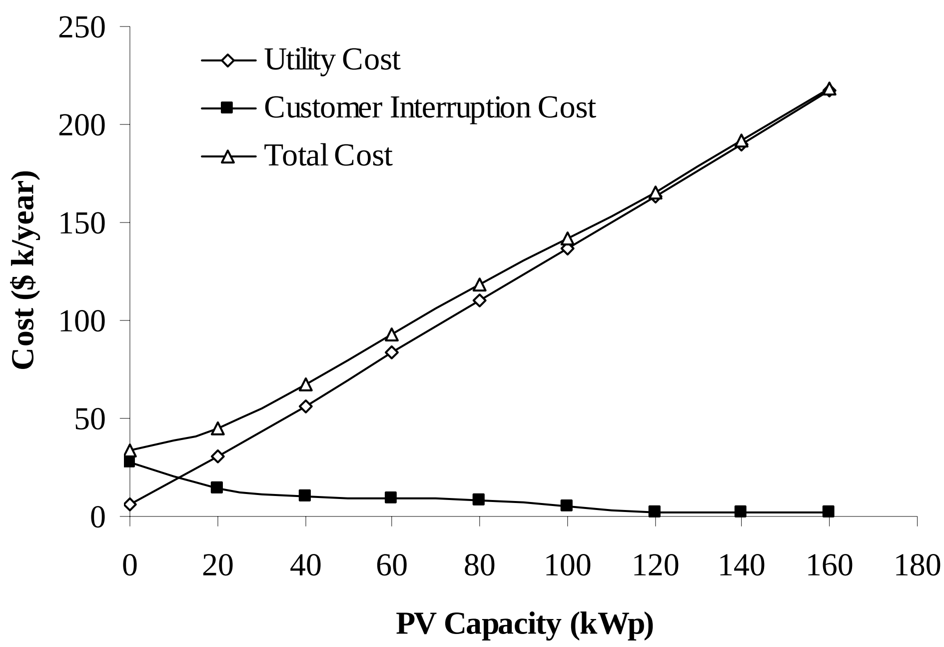


Figure 9.17: Change in utility, customer, and total costs with PV additions (Case 3, Energy storage capacity=300 kWh, Swift Current data)

Case 4: Solar-diesel- storage system-intermittent diesel operation

In this case, one of the diesel units is operated intermittently. Figure 9.19 shows the change in the utility costs, the customer interruption costs and the total costs for the energy storage capacity at 100 kWh with subsequent additions of PV capacity. The least cost PV addition occurs with no PV in the system. The total cost calculated for Figure 9.18 is $56,872/year. The resulting LOLE associated with the minimum total cost is 338.41 h/year.

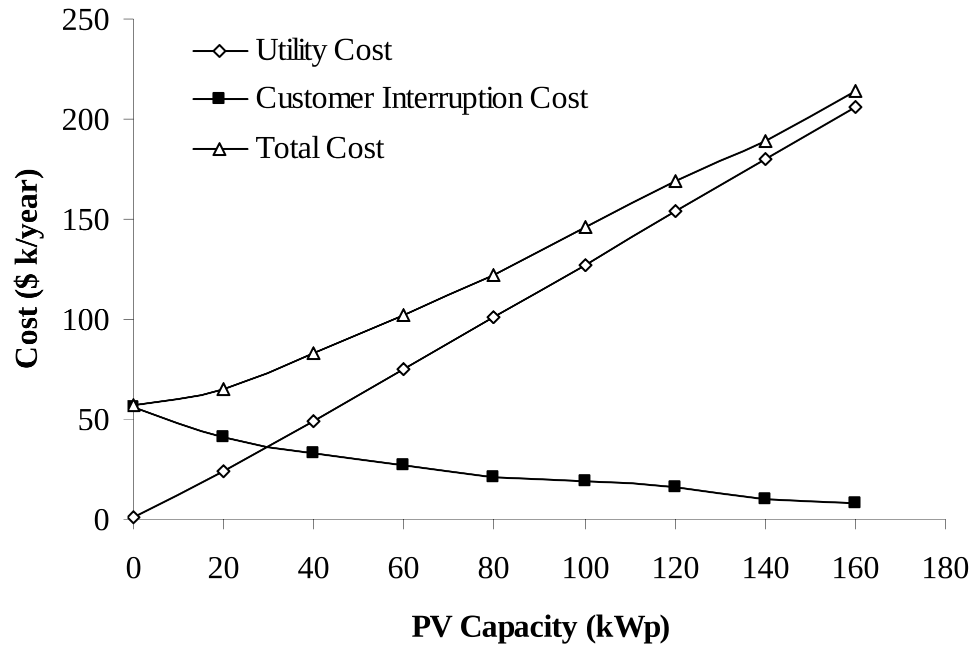
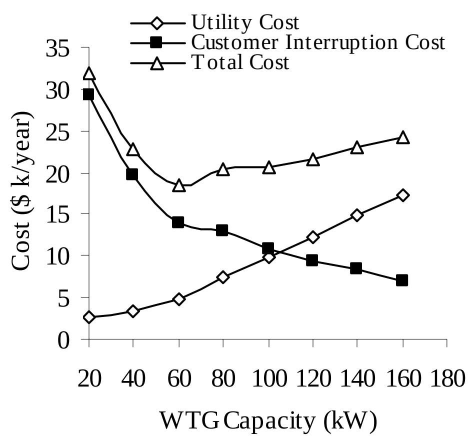


Figure 9.18: Change in utility, customer, and total costs with PV additions (Case 4, Energy storage capacity=100 kWh, Swift Current data)

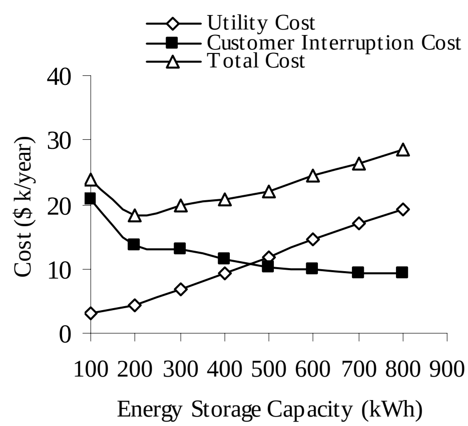
Case 5: Sensitivity study using Case 2 as an example

The non-conventional generating unit costs, energy storage costs, fuel costs and the customer interruption cost parameters are the most important factors influencing the economics of a power system with these facilities. Several sensitivity studies were performed using Case 2 as an example. The per kilowatt cost of WTG, the per kilowatt hour cost of energy storage, the per liter fuel cost and the customer interruption cost were varied and the changes in the minimum total costs were observed. The per kilowatt cost of WTG, the per kilowatt hour cost of energy storage and the fuel cost are reduced to half of the values used in Case 2 in the following analyses. The customer interruption costs were reduced to half and also doubled related to the original values in Case 2.

Figure 9.19 shows the variation in the utility costs, the customer interruption costs and the total costs when the WTG and energy storage costs are reduced by a half. It can be seen from Figure 9.19 that the minimum total cost condition remains unchanged for both fixed energy storage and fixed WTG cases. The total cost is, however reduced from $23,722/year to $18,178/year.



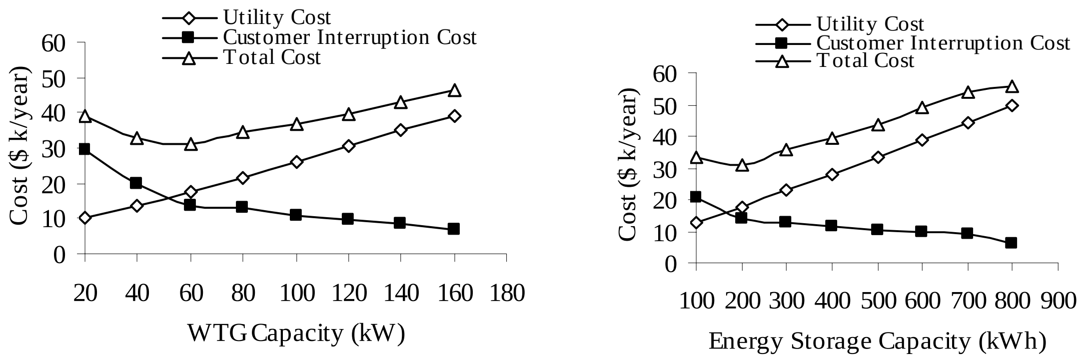
a) Per kilowatt costs of WTG is reduced
Total cost is $18,178/year at 60 kW
Energy storage capacity= 200 kWh
LOLE=67.79 h/year, Regina data



b) Per kilowatt hour costs of storage is reduced
Total cost is $18,178/year at 200 kWh,
WTG Capacity= 60 kW
LOLE=67.79 h/year, Regina data

Figure 9.19: Effects of WTG and energy storage costs on the total costs

Figure 9.20 shows the variation in the utility costs, customer interruption costs and the total costs when the fuel costs are reduced to half of the value used in Case 2. It can be seen from Figure 9.20 that the total cost increases from $23,722/year to $31,122/year. The increase in total cost in this case is due to the relative decrease in savings.

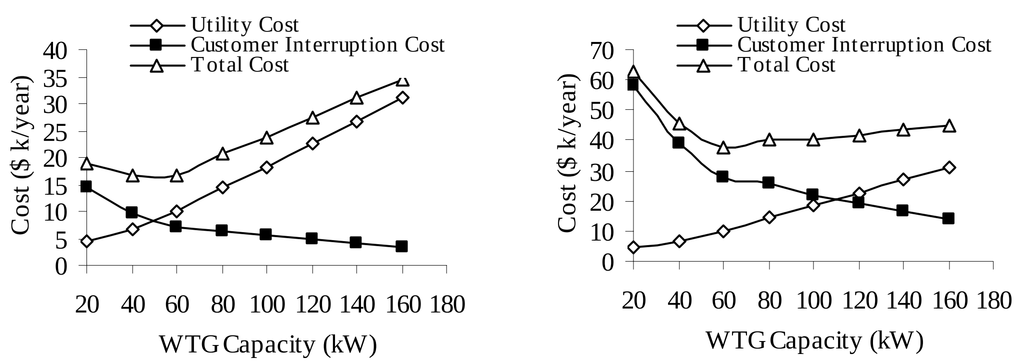


a) Fuel cost is reduced
Total cost is $31,122/year at 60 kW
Energy storage capacity= 200 kWh
LOLE=67.79 h/year, Regina data

b) Fuel cost is reduced
Total cost is $31,122/ at 200 kWh
WTG Capacity= 60 kW
LOLE=67.79 h/year, Regina data

Figure 9.20: Effects of diesel fuel costs on the total costs

Figure 9.21 shows the variation in the utility costs, customer interruption costs and the total costs for the fixed energy storage case when the customer interruption cost is reduced to half or doubled. The results show that the minimum total cost occurs at 40 kW and 60 kW respectively when the CIC is reduced to halved and doubled.



a) CIC is reduced to half
Total cost is $16,509.20/year at 40 kW
Energy Storage capacity= 200 kWh
LOLE=178.34 h/year, Regina data

b) CIC is doubled
Total cost is $37,520.07/year at 60 kW
Energy storage capacity= 200 kWh
LOLE=67.79 h/year, Regina data

Figure 9.21: Effects of customer interruption costs on the total costs

9.5 Summary and Conclusions

Evaluation techniques for performing reliability cost/worth studies on a power system using wind energy, solar energy and energy storage systems are presented in this chapter. Two major methods designated as the optimal utility cost method and the reliability cost/worth method are developed and discussed. These approaches are then used to conduct a range of economic analyses on various example systems. Different diesel unit operating strategies are also incorporated in the evaluation

In the OUCM, the minimum cost for a given system at a specified reliability level is determined using three different curves. These curves are the equal energy storage capacity curves, equal renewable energy capacity curves and the equal risk curves. The results obtained using these curves show that a particular system load can be satisfied at specified risk levels by a number of alternatives with different costs. The optimum combination of the total non-conventional generating unit capacity and the energy storage can be determined for a given level of reliability. The annualized capital costs and the savings due to reduced fuel usage decrease with increase in the LOLE criterion. The savings due to reduced fuel usage can offset the capital costs and this effect becomes more significant with increase in the LOLE criterion. Intermittent diesel operation is superior to continuous diesel operation when the savings due to reduced fuel usage is significant.

When different alternatives are compared at a specified reliability level, the utility costs for all the alternatives can be quite different. The customer interruption costs for these alternatives may be similar due to the specified reliability requirement. In this case, the differences in the total utility cost between the individual alternatives are dominated by the fixed and the variable utility costs. The optimum alternative can be selected using the OUCM when the reliability criterion is fixed at a specified level.

In the RCWM, the system reliability level is not an initial system design parameter, but is an outcome of the optimization process. The optimal reliability level is determined by balancing the cost of reliability to the system and the reliability worth to customers. The results obtained show that the customer interruption costs decrease as additional renewable capacity and energy storage capacities are added to the system and the utility costs increase. The total costs are the sum of customer interruption costs and the utility costs. The target or optimum reliability of the system, as expressed by the LOLE, is the reliability level that is associated with the system having the lowest total cost. Two cases of fixed energy storage and fixed renewable generating capacity are considered. The minimum total cost determined using these two methods are the same for a given system at a specific site location. The choice of which approach to use will depend upon the emphasis placed by the utility regarding WTG, PV or energy storage facilities.

10. SUMMARY AND CONCLUSIONS

Utilization of renewable energy resources such as wind and solar energy for electric power supply is being given very serious consideration around the world due to global environmental concerns associated with conventional generation and potential energy shortages due to increasing electricity demand. Many people consider wind and solar energy to be encouraging and promising alternatives for power generation because of their tremendous environmental, social and economic benefits, together with public support and government incentives.

The wind and sunlight, however, are unstable and variable energy sources, and behave far differently than conventional sources. Energy storage systems are, therefore, often required to smooth the fluctuating nature of the energy conversion system especially in small isolated applications. The actual benefits obtained and the adequacy of power supply associated with such energy systems can be quantitatively assessed using reliability evaluation techniques. This thesis employs a sequential Monte Carlo simulation approach to develop a comprehensive technique for generating capacity adequacy and related economic evaluation of power systems containing wind energy, solar energy and energy storage. The technique combines the development of the generation model, the chronological load model and the energy storage model to determine the reliability and economic indices.

A generating capacity adequacy study is an assessment of the capability of the generating facilities to satisfy the total system load demand. It involves the development of generation and load models and the combination of these models to obtain a reliability index. The conventional criteria used by utilities for generation planning are usually based on either a deterministic or a probabilistic philosophy. Deterministic methods cannot completely recognize and reflect the risk associated with a given system, and therefore electric power utilities are slowly changing from using deterministic criteria to probabilistic criteria.

The basic approaches used in the probabilistic evaluation of generating capacity adequacy can be categorized as being either analytical or Monte Carlo simulation methods. In an analytical approach, the generation model is a generating capacity outage probability table, which contains the capacity and probability of each outage state of the generating system. The load model is either a daily peak load variation curve or an hourly load duration curve. In the sequential Monte Carlo simulation approach, the generation model is constructed by creating an artificial history of the generating unit behaviors. The load model is described by an hourly load variation profile. The reliability indices in both of the approaches are calculated by combining the generation with the load.

The conventional probabilistic approaches are not considered to be directly applicable to power systems containing wind energy, solar energy and energy storage. The main problem with an analytical technique is that it cannot completely incorporate the chronological variations in the generation and load elements. A time sequential Monte Carlo simulation approach has been, therefore, used in this research to develop adequacy and related cost/worth evaluation models for these systems. A time series representation in the form of an auto-regressive and moving average model has been used to simulate the fluctuating wind speeds. The available wind power was obtained by applying the relationship between the power output of the WTG and the wind speed. A widely used computer program called WATGEN was adapted to generate the atmospheric data. The generated power from a PV generating unit was computed on the basis of the voltage-current characteristics of the generating unit. The overall system generation model was obtained by combining the operating histories of all the generating units in the system and incorporates the failure and repair characteristics of the units. A time series energy storage model was developed from the generation and load time series. The reliability evaluation model was obtained by combining the generation with the load and the available energy storage facilities.

One of the advantages of Monte Carlo simulation is that this method can provide reliability index distributions in addition to the mean values. A probability distribution of a reliability index can present a pictorial representation of the manner in which the parameter varies. The utilization of reliability index distributions in generating system adequacy evaluation is presented throughout this thesis.

System well-being analysis combines the deterministic and probabilistic methods and provides indices that can be useful in power system reliability assessment. The well-being approach described in this thesis combines probabilistic indices with commonly used deterministic criteria such as number of autonomous hour [87] in generating systems with storage facilities to assess the well-being of these systems. The overall system well-being is defined in terms of the system health and margin based on the accepted deterministic criterion, in addition to the conventional risk index.

Different operating modes have significant impact on the system reliability and economics. The basic Monte Carlo simulation technique can be extended to evaluate different operating strategies for power systems using wind energy, solar energy and energy storage facilities. Four different operating modes for SIPS are proposed and evaluated in this thesis. These are continuous diesel operation without storage, continuous diesel operation with storage, intermittent back-up diesel operation without storage and intermittent back-up diesel operation with storage.

Reliability cost/worth assessment involves the evaluation of the costs associated with different system configurations and the corresponding worth associated with the differences. A major objective of reliability cost/worth assessment is to determine the costs associated with different alternatives at a specified reliability level or the optimum level of service reliability. Two methods designated as the optimal utility cost method and the reliability cost/worth method are developed and described in this thesis for the economic assessment of power systems containing wind energy, solar energy and energy storage.

The developed models and methodologies have been applied to perform a wide range of reliability and related economic studies on power systems containing wind energy, solar energy and energy storage. These studies focus on the adequacy and economics of power systems containing different energy sources and different energy storage capacity levels. Both mean values and distributions of the reliability index are used in these studies. The results obtained from the studies show that the reliability and economics of such system depends on many factors such as the energy storage capacity, the availability of the site resources, the generating unit forced outage rates, the system load profile and peak load, the installed generating capacity, the system operational constraints, the fixed and variable costs associated with the generating units and storage facilities, and the customer interruption costs.

A range of reliability studies has been conducted on SIPS both in terms of system risk and health. These studies show that the performance of a SIPS containing a significant WTG or PV component depends on the dispersed site resources and the reliability is usually unacceptably low when there is no storage or relatively small storage in the system. The provision of energy storage has a significant positive impact on the system reliability and economics. It is, therefore both important and necessary to provide reasonable energy storage in SIPS applications.

The relative reliability benefits obtained from providing energy storage facilities were investigated by changing the energy storage capacity. The reliability performance of a SIPS is strongly influenced by the capacity of the energy storage facilities in the system and can be increased by adding additional energy storage capacity. The incremental reliability benefit is, however, not significant when the energy storage capacity exceeds the upper limits for a given location. Different deterministic criteria have different impacts on the system well-being indices. The perceived system health decreases as the deterministic criterion associated with energy storage become more demanding.

The level of reliability provided by a SIPS is largely dictated by the availability of the site resources in the form of wind and solar energy at the system geographic location. The system reliability increases when the mean wind speed at a WECS location increases and the solar radiation level at a PVCS location increases. As the PVCS produce no energy during the nighttime, wind energy is generally a better choice than solar energy based on reliability and economic considerations. In some cases, increased reliability benefits can be obtained by using wind and solar together rather than adding either wind or solar source to the system. The actual selection depends on the system energy storage capacity, the availability of the site resources at the system location and the various costs associated with the system.

The reliability of a SIPS degrades significantly with increase in the conventional generating unit FOR. Variations in the FOR of the non-conventional units, however, do not have significant impacts on the system reliability. The reliability of a SIPS decreases with increases in the system load. The relative decrease in system reliability depends on the available energy storage levels and the system energy composition. Variations in the load pattern have a significant impact on the system reliability. The system loss of load expectation is considerably lower when a residential load model is used compared to the reliability obtained using a constant load at the peak value or a composite residential, commercial, industrial load representation such as the IEEE-RTS load model.

The addition of further wind and solar capacity to a SIPS will improve the system reliability. Adding wind energy generating units produces more favorable results than adding the same capacity in the form of PV generating units. The optimum ratio of wind and solar energy for a given SIPS is difficult to determine due to the fact that the reliability performance of a SIPS is influenced by many system factors.

The developed models and methodologies were also used to perform a range of studies on the RBTS. The studies show that a WECS and a PVCS provides much less adequacy improvement in the combined generation system than would conventional generating units with the same capacity. Different conventional generating units were removed from the RBTS and replaced by WTG or PV units while maintaining the reliability criterion. Studies show that the system reliability can be maintained if a small unit (5 MW unit) is replaced by either WTG or PV units, but the required capacity is not the same for different locations. The system reliability cannot be maintained if a larger unit (20 MW unit) is replaced by either WTG or PV in the RBTS. This indicates that WTG or PV units have difficulty in replacing the reliability role that a larger conventional generating unit plays in a power system. The multiple site case studies show that wind or solar energy independence has a significant positive effect on the reliability performance of WTG or PV units.

Reliability and economic studies have been performed on SIPS considering different operating strategies. The reliability of continuous diesel operation is better than that of intermittent diesel operation for the same system. The adequacies and the degree of system comfort in satisfying the deterministic criterion for the systems with energy storage are much better than those of systems without energy storage for the operating strategies considered. The major benefit of integrating wind and/or solar energy with conventional generation is the significant reduction in the system operating costs due to fuel savings. Systems with energy storage can save more fuel than systems without energy storage. Intermittent diesel operation saves more fuel than continuous diesel operation for the same system or for different systems at a specified reliability level. More fuel savings can be achieved from higher renewable energy penetration or by installing the systems at sites with high average wind speeds and/or solar radiation levels. The availability of back-up diesel is an important factor influencing SIPS reliability and operating cost. The fuel saving benefits decreases significantly with increase in the back-up diesel unit starting failure probability. The high number of diesel start/ stop cycles associated with intermittent diesel operation have negative effects on the overall system performance. Utilization of energy storage can alleviate this problem to some extent. The number of back-up diesel start/ stop cycles decreases with increase in the energy storage capability. This number also decreases significantly with increase in wind speed if there is no energy storage in the system. The wind and solar resource availability, however, does not have significant impact on the number of back-up diesel start/ stop cycles if the system contains energy storage. The high number of back-up diesel start/stop cycles cannot be reduced significantly by adding more renewable generation to a given system. System load variations also affect the number of back-up diesel start/ stop cycles and the running time and hence have impacts on the overall system reliability and operating costs for all the operating modes considered in this thesis.

A series of probability distributions associated with generating capacity adequacy and economic indices and their possible application in power system reliability and cost/worth evaluation is presented and discussed in this thesis. Reliability index distributions can provide considerable additional information and a more physical appreciation of the system reliability and economics. The distribution variations in annual loss of load durations for SIPS show that the probability associated with a zero value increases and the value of a large loss of load duration decreases with improvement in system adequacy. The variations of the loss of load duration distributions for SIPS are significant with changes in system peak load, load profile, conventional generating unit FOR and geographic locations. The variation in the reliability index distributions for the RBTS with changes in these parameters is, however, relatively small. The reliability index distributions associated with the RBTS are largely dominated by the load/capacity characteristics of the original system. The sensitivities of the reliability index distributions to changes in the selected parameters are noticeable when comparing the changes in the probability of zero values for the RBTS.

Economic evaluation of power systems containing wind energy, solar energy and energy storage has been conducted considering the different cost factors and operating strategies associated with such systems. When different alternatives are compared for selection at a specified reliability level, the optimum alternative can be selected using the optimum utility cost method. The reliability cost/worth method provides valuable power system planning information and can be used to optimize the total monetary costs considering both utility cost concerns and customer satisfaction. In this method, the system reliability level is not an initial system design parameter, but is an outcome of the optimization process. The target or optimum reliability of the system, as expressed by the loss of load expectation, is the reliability level that is associated with the system having the lowest total cost. Two cases of fixed energy storage and fixed renewable generating capacity are considered. The minimum total cost determined using these two methods are the same for a given system at a specific site location. The choice of which approach to use will depend upon the emphasis placed by the utility regarding WTG, PV or energy storage facilities.

In conclusion, the models, methodologies, results and discussion presented in the thesis provide valuable information for electric power utilities engaged in planning and operating power systems containing wind energy, solar energy and energy storage.

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APPENDIX A:

TECHNICAL DATA FOR VESTAS V29 225-50, 29 !O! TURBINE

(a) VESTAS V29 225-50, 29 !O!

VESTAS-manufacturer

V29-type/version

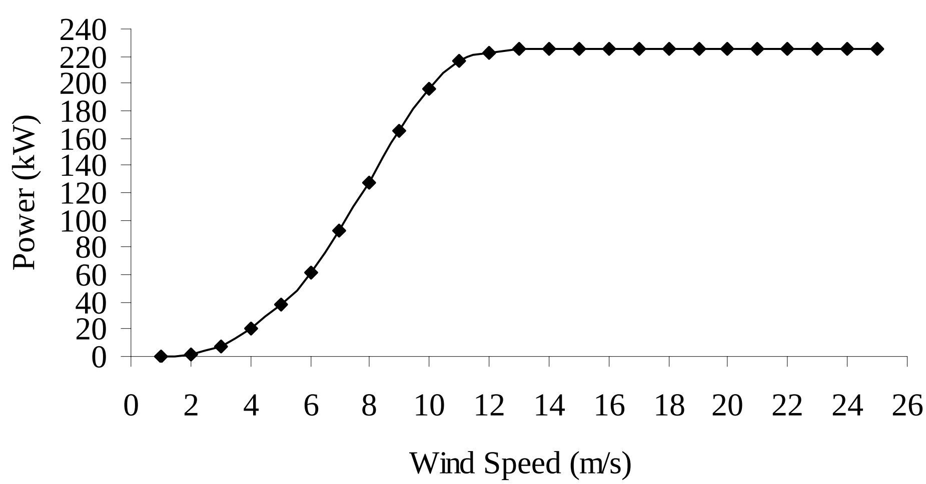
225-rated power (kW)

50-secondary generator power (kW)

29-rotor diameter (m)

!O!-tower type (tubular)

(b) VESTAS V29 225-50, 29 !O!
Wind turbine generator power curve



APPENDIX B:

PARAMETERS DEFINING THE CURRENT-VOLTAGE RELATIONSHIP OF A CANROM30 SOLAR PANEL

DESCRIPTION	VALUE	UNIT
Number of series group in parallel	2	
Number of modules in series	1	
Area per model	0.5	m^2
Tracking method	No	
Collector slope	60	degree
Collector azimuth	0	degree
Reference array operating temperature	25	$°C$
Reference radiation level	1000	W/m^2
Reference MPP voltage	16	V
Reference MPP current	2	A
Reference open circuit voltage	19.5	V
Reference short circuit current	2.6	A
Array resistance	0.06	Ω
Wind speed correction factor	1	
Alpha	0.0025	
Beta	0.5	
Gamma	0.0029	
Solar cell absorbance	0.9	
Front panel emmissivity	0.95	
Front panel transmittance	0.95	
Back panel emmissivity	0.9	
Back panel transmittance	0.9	

APPENDIX C:

LOAD DATA

Table C.1: Weekly peak load as a percentage of annual peak

Week	Peak Load (%)	Week	Peak Load (%)
1	86.2	27	75.5
2	90	28	81.6
3	87.8	29	80.1
4	83.4	30	88
5	88	31	72.2
6	84.1	32	77.6
7	83.2	33	80
8	80.6	34	72.9
9	74	35	72.6
10	73.7	36	70.5
11	71.5	37	78
12	72.7	38	69.5
13	70.4	39	72.4
14	75	40	72.4
15	72.1	41	74.3
16	80	42	74.4
17	75.4	43	80
18	83.7	44	88.1
19	87	45	88.5
20	88	46	90.9
21	85.6	47	94
22	81.1	48	89
23	90	49	94.2
24	88.7	50	97
25	89.6	51	100
26	86.1	52	95.2

Table C.2: Daily peak load as a percentage of weekly peak

Day	Peak Load (%)
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table C.3: Hourly peak load as a percentage of daily peak

	Spring/Fall Weeks 9-17 & 31-43		Summer Weeks 18-30		Winter Week 1-8 & 44-52	
Hour	Weekday	Weekend	Weekday	Weekend	Weekday	Weekend
12-1 am	63	75	64	74	67	78
1-2	62	73	60	70	63	72
2-3	60	69	58	66	60	68
3-4	58	66	56	65	59	66
4-5	59	65	56	64	59	64
5-6	65	65	58	62	60	65
6-7	72	68	64	62	74	66
7-8	85	74	76	66	86	70
8-9	95	83	87	81	95	80
9-10	99	89	95	86	96	88
10-11	100	92	99	91	96	90
11-12 pm	99	94	100	93	95	91
12-1	93	91	99	93	95	90
1-2	92	90	100	92	95	88
2-3	90	90	100	91	93	87
3-4	88	86	97	91	94	87
4-5	90	85	96	92	99	91
5-6	92	88	96	94	100	100
6-7	96	92	93	95	100	99
7-8	98	100	92	95	96	97
8-9	96	97	92	100	91	94
9-10	90	95	93	93	83	92
10-11	80	90	87	88	73	87
11-12	70	85	72	80	63	81

APPENDIX D:

BRIEF INTRODUCTION TO STURGES'S RULE

Sturges's Rule is described in detail in [96]. It can be used to obtain a reasonable approximation of the number of class intervals to be needed when creating a histogram from a group of data.

(1) Determination of the number of class intervals

$$K = 1 + 3.3\log_{10}^{N} \tag{D1}$$

where: K-number of class intervals

N-total number of observations

(2) Determination of the class width

When developing the frequency distribution, it is desirable that each class interval should contain enough data to represent the information in that class. The class width W can, therefore, be determined from the number of class intervals K and the range of the observation R i.e. the difference between the maximum and the minimum values of the observed data.

$$W = \frac{R}{K} \tag{D2}$$

(3) Determination of the boundary of each class interval

In order to avoid the overlapping of classes, it is necessary to establish clearly defined class boundaries for each class interval. The starting values of each class can be obtained by beginning with the minimum observed value X_{min} and adding to it successively the class interval width W.

Starting value of first class $X_{1s} = X_{min}$

Starting value of second class $X_{2s} = X_{1s} + W$

Starting value of ith class $X_{is} = X_{(i-1)s} + W$

The end values of each class can be determined by adding to the starting values of the class the quantity (W-E) where E is the measurement accuracy.

End value of first class $X_{1e} = X_{1s} + (W-E)$

End value of second class $X_{2e} = X_{2s} + (W-E)$

End value of i^{th} class $X_{ie} = X_{is} + (W-E)$

(4) Determination of the class mid-point

The class mid-point is the point halfway between the boundaries of each class and is representative of the data within that class. For the i^{th} class:

$$\overline{X}_i = \frac{X_i + X_i + (W - E)}{2} \tag{D3}$$

APPENDIX E:

GENERATING UNIT RATINGS AND RELIABILITY DATA FOR THE RBTS

Rated power (MW)	Unit type	No. of units	Failure rate (f/year)	Repair time (hour)	Forced outage rate (FOR)
5	hydro	2	2.0	45	0.010
10	thermal	1	4.0	45	0.020
20	hydro	4	2.4	55	0.015
20	thermal	1	5.0	45	0.025
40	hydro	1	3.0	60	0.020
40	thermal	2	6.0	45	0.030

APPENDIX F:

LOGARITHMIC INTERPOLATION PROCEDURE

Most of CDF data from the surveys are available for outage durations of 1,2,4,8 and 24 hours. In order to calculate the interruption cost between two existing outage durations, it is usual to interpolate the interruption cost values using a linear relationship on a logarithmic scale. This procedure is illustrated by the following equation:

$$\log C(d) = \frac{1}{(\log d_{i+x} - \log d_i)} \times \{\log C(d_{i+x}) \times [\log d - \log d_i] - \log C(d_i) \times [\log d - \log d_{i+x}]\}$$

Where:

$C(d_i)$ = The interruption cost in \$/kW for a duration of i hour(s)

$C(d_{i+x})$ = The interruption cost in \$/kW for a duration of i+x hour(s)

$C(d)$ = The interruption cost in \$/kW for a duration of d hours which is between i and i+x hour(s).

Note: $C(d_i)$ and $C(d_{i+x})$ are the available outage duration values from the survey data.

APPENDIX G:

LINEAR EXTRAPOLATION

The interruption cost value is calculated on a linear scale when the interruption duration exceeds the available interruption data. The linear extrapolation equation is shown below.

$$C(d) = \frac{1}{(d_{i+x} - d_i)} \times [C(d_{i+x}) - C(d_i)] \times (d - d_{i+x}) + C(d_{i+x})$$

Where:

$C(d_i)$ = The interruption cost in $/kW for a duration of i hour(s)

$C(d_{i+x})$ = The interruption cost in $/kW for a duration of i+x hour(s)

$C(d)$ = The interruption cost in $/kW for a duration of d hours which is greater than i+x hour(s).