Reliability Evaluation of Small Isolated Power Systems

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by

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DEDICATED TO
MY PARENTS
PHANINDRA BAHADUR KARKI
AND
GEETA DEVI KARKI

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RELIABILITY EVALUATION OF SMALL ISOLATED POWER SYSTEMS

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ABSTRACT

Probabilistic methods have largely replaced deterministic techniques in the assessment of generating capacity adequacy in large modern electric power utilities. In spite of their widespread application in large systems, probabilistic methods are not generally applied to small isolated power systems. A recent survey [6] by Newfoundland & Labrador Hydro indicates that all Canadian small isolated systems employ some type of deterministic method to assess the adequacy of the existing or proposed generating facilities to meet the total load requirement. These approaches do not normally include any explicit recognition of system risk and do not provide comparable risks for systems of different size or composition. The reluctance by system planners of small isolated systems to accept probabilistic methods in their present form dictates a need to develop new approaches to bridge the deterministic methods and the prevalent probabilistic techniques.

This thesis presents a new approach, known as system well-being analysis that links the accepted deterministic criteria with probabilistic methods. A description of the new evaluation techniques, new adequacy indices and comparative studies of the different indices and approaches are presented with the objective of providing practical probabilistic methods for capacity planning in small isolated power systems. A graphical user-interface software package named SIPSREL has been developed as a practical tool for small isolated system planning. It is hoped that probabilistic methods will be employed in practice in the adequacy evaluation of small isolated power systems using the methodologies and evaluation tools that have been developed in this research work.

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LIST OF ABBREVIATIONS

Column	C
Composite Customer Damage Function	CCDF
Conventional Capacity Outage Probability Table	CCOPT
Contingency Enumeration	CE
Capacity of the Largest Unit	CLU
Capacity of the Largest Unit in a State	CLUS
Capacity Outage Probability Table	COPT
Conditional Probability Capacity Outage Probability Table	CPCOPT
Capacity Reserve	CR
Capacity Reserve Margin	CRM
Daily Peak Load Variation Curve	DPLVC
Expected Energy not Supplied	EENS
Expected Energy not Supplied per Interruption	EENSPINT
Expected Energy Supplied	EES
Expected Health Duration	EHDUR
Expected Interruption Duration	EINTDUR
Expected Load Loss per Interruption	ELLPINT
Expected Load Loss per Year	ELLPYR
Expected Margin Duration	EMDUR
Expected Unserved Energy	EUE
Frequency of Interruptions	F
Frequency and Duration	F&D
Forced Outage Rate	FOR
Frequency of Margin	F(M)
Health Benefit Limit	HBL
Hierarchical Level	HL
Installed Capacity	IC
Identification Number	ID#
Interrupted Energy Assessment Rate	IEAR
Load Duration Curve	LDC
Load Forecast Uncertainty	LFU
Loss of Energy Expectation	LOEE
Loss of Health Expectation	LOHE
Loss of Load Expectation	LOLE
Loss of Load Probability	LOLP
Monte Carlo Simulation	MCS
Mean Time to Derate Repair	MTDR

Mean Time to Derate	MTTD
Mean Time to Failure	MTTF
Mean Time to Repair	MTTR
Probability of Health	P(H)
Peak Load	PL
Peak Load Carrying Capability	PLCC
Probability of Margin	P(M)
Small Isolated Power System	SIPS
Small Isolated Power System Reliability (Software)	SIPSREL
System Minutes	SM
Units per Million	UPM

1. INTRODUCTION

1.1 Power System Reliability

The determination of an appropriate generating reserve capacity margin is an important problem in power system planning. Too high a value will result in an overly reliable system with excessive investment costs, while too low a value will yield a low cost system with poor service continuity. System planners have continuously strived for better methods to help them decide the optimum investment in system facilities to meet the increasing demand with a reasonable level of reliability.

The term reliability is defined as "the probability of a device or system performing its purpose adequately for the period of time intended under the operating conditions encountered" [1]. Power system reliability involves two basic aspects: *system adequacy* and *system security* [2]. Adequacy relates to the availability of adequate facilities within the system to satisfy the consumer load demand, whereas, security relates to the ability of the system to respond to disturbances arising within the system. Reliability evaluation in this thesis is limited to the domain of adequacy assessment.

The basic techniques for adequacy assessment can be categorized in terms of their application to segments of a complete power system. The three basic functional zones are generation, transmission and distribution. Different combinations of these functional zones can be used to define hierarchical levels [2] in adequacy assessment and are shown in Fig. 1.1. Hierarchical level I (HL I) is concerned only with the generating facilities. Hierarchical level II (HL II) includes both generation and transmission facilities. Hierarchical level III (HL III) includes all three functional zones.

1.2 Adequacy Assessment at HL I and in Small Isolated Power Systems

Adequacy assessment at HL I is commonly referred to as 'generating capacity reliability evaluation' and is concerned with assessing the ability of the generating facilities to satisfy the total system load. The reliability of transmission and distribution systems are not considered at this level. The basic system model in an HL I study is shown in Fig. 1.2.

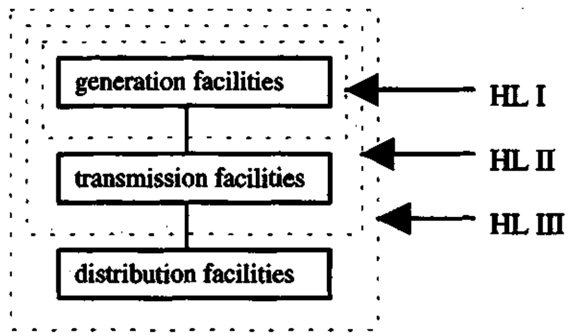


Fig. 1.1: Hierarchical Levels in Adequacy Studies

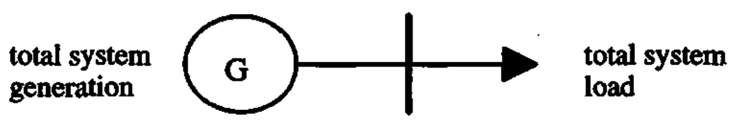


Fig. 1.2: Basic Model for HL I Study

The main concern in HL I evaluation is to estimate the generating capacity required to satisfy the total system load demand and to have sufficient capacity to perform corrective and preventive generating unit maintenance.

A small isolated power system (SIPS) as considered in this thesis is a relatively small system, situated at a remote site to serve a specific load or a small community, with no possibility of interconnected assistance from a neighboring system. Table 1.1 shows the number of SIPS within Canadian utilities and their relative sizes [6]. In many cases, a SIPS consists of a single generating plant with virtually no transmission and an extremely small and rather compact distribution system. The HL I model provides a practical representation of a SIPS. Under these conditions, HL I adequacy is an important parameter in the overall system evaluation of a SIPS.

Table 1.1: SIPS in Canadian Utilities

Utility	Number of SIPS	Total Installed Capacity (KW)	Size of Largest System (KW)	Size of Smallest System (KW)
Newfoundland Hydro	30	46,775	18,750	90
Hydro Quebec	21	56,000	11,200	550
Ontario Hydro	23	20,226	2,350	170
Manitoba Hydro	12	18,445	4,085	350
Saskatchewan Power	1	132	132	132
Alberta Power Ltd.	27	35,295	16,880	40
BC Hydro	9	35,550	9,420	1,850
NWT Power Corp.	47	188,000	52,560	70
Yukon Electrical	7	8,855	5,050	245

1.3 Historical Development of HL I Evaluation

HL I evaluation is used to determine the additional generating capacity above the peak demand, called reserve, which is required to ensure against excessive shortages and provide an acceptable level of adequacy. The earliest techniques used to determine the required level of capacity reserve were deterministic or rule of thumb methods. The common deterministic approaches include:

1. *Percent Margin or Capacity Reserve Margin (CRM)*:- The capacity reserve is a fixed percentage of the total installed capacity.

2. *Loss of the Largest Unit*:- The capacity reserve is equal to the capacity of the largest unit.

3. *Loss of the Largest Unit plus Percent Margin*:- The capacity reserve (CR) is equal to the capacity of the largest unit (CLU) plus a fixed percentage of either the peak load (PL) or the total installed capacity (IC) as defined by Equation (1.1) or (1.2).

$$CR = CLU + X * PL \tag{1.1}$$

$$CR = CLU + X * IC \tag{1.2}$$

where, X is a multiplication factor, usually between 5% to 15%

About thirty years ago, virtually all power utilities used one of the above deterministic methods to determine the required generating capacity. The selection of the reserve criterion has been largely based on past experience and judgment. The basic weakness of a deterministic approach is that it does not incorporate any explicit recognition of the actual risk. These methods cannot recognize the stochastic nature of component failures, of customer demands or of system behavior as a whole. The need for probabilistic evaluation of system behavior has been recognized since at least the 1930s [3] but lack of data, lack of realistic reliability techniques, limitations of computational resources, aversion to the use of probabilistic techniques and a misunderstanding of the significance and meaning of probabilistic criteria and risk indices were the main hurdles to the application of such methods in the past. None of these reasons are valid today and therefore most modern large power utilities employ probabilistic methods in generating capacity adequacy assessment. The available probabilistic methods consist of analytical and simulation techniques and use the following risk indices for HL I evaluation:

1. *Loss of Load Indices*:- The most widely used adequacy index today is the loss of load expectation (LOLE) [4]. A loss of load is considered to occur when the system generating capacity is less than the forecast system load. LOLE is measured in days/year or hours/year and is the expected number of days or hours in a year that the system load will exceed the total generating capacity.

2. *Loss of Energy Indices*:- Energy based indices are now receiving more attention, particularly in systems that have generating units with potential energy limitations [5]. Loss of energy indices have a more physical significance than the loss of load indices and the amount of trouble can be directly related to the customer interruption costs. Future indices may be energy based rather than focused on power or capacity. Loss of energy expectation (LOEE) or expected unserved energy (EUE) is the expected amount of energy in MWhr that can not be supplied by the system in a year. Units per million (UPM) and system minutes (SM) are other indices used by utilities and are defined by Equation (1.3) and (1.4) respectively.

$$UPM = LOEE * 10^6 / E \tag{1.3}$$

$$SM = LOEE * 60 / PL \tag{1.4}$$

where E = total energy demanded by the system load
PL = peak load

3. *Frequency and Duration Indices*:- Frequency and duration indices are generally not used as a basic criterion due to the complexity of the available techniques. They can

be easily estimated using simulation methods to extract valuable information about the system risk. Frequency of interruption, expected interruption duration, expected energy not supplied per interruption are some of the more useful frequency and duration indices.

The methods adopted by major power utilities for generating capacity adequacy evaluation have gradually shifted from deterministic to probabilistic over the last thirty years. Surveys on generating capacity adequacy criteria used by Canadian utilities were conducted in 1964, 1969, 1974, 1979 and 1987 [4]. As seen from Table 1.2, only one utility indicated that it used a probabilistic approach in 1964. Subsequent surveys showed more utilities adopting probabilistic methods. In 1987, only one utility was still using a deterministic capacity reserve criterion but with supplementary checks for a probabilistic LOLE index. Table 1.3 lists the criterion used by each participating utility in 1987.

Table 1.2: Criteria Used in Reserve Capacity Planning

		Survey Date					
	Criterion	1964	1969	1974	1977	1979	1987
Deterministic Methods	Percent Margin	1	4	2	2	3	1*
	Loss of Largest Unit	4	1	1	1	-	-
	Combination of 1 and 2	3	6	6	6	2	-
	Other Methods	2	1	-	-	-	-
Probabilistic Methods	LOLE	1	5	4	4	6	6
	EUE	-	-	-	-	-	2

* With supplementary checks for LOLE

Table 1.3: Basic Criteria and Indices in 1987

Utility/System	Criterion	Index
BC Hydro and Power Authority	LOLE	1 day/10 yrs
Alberta Interconnected System	LOLE	0.2 days/yr
Saskatchewan Power Corporation	EUE	200 UPM
Manitoba Hydro	LOLE	0.1 day/yr
Ontario Hydro	EUE	25 SM
Hydro Quebec	LOLE	2.4 hours/yr
New Brunswick Electric Power Commission	CRM*	CLU or 20%PL
Nova Scotia Power Corporation	LOLE**	0.1 days/yr
Newfoundland and Labrador Hydro	LOLE	0.2 days/yr

* With supplementary checks for LOLE

** With supplementary checks for CRM

1.4 Criteria Used by Small Isolated Power Systems

The discussion in the previous section clearly illustrates that the major power utilities in Canada utilize probability techniques in their basic capacity planning. This is not, however, the case with SIPS. Table 1.4 lists the criteria used by SIPS in Canadian utilities as shown in a survey report published in 1995 [6].

Table 1.4: Criteria Used by SIPS

Utility	Deterministic Criterion
Newfoundland Hydro	CR = CLU
Hydro Quebec	CR = 90%CLU + 10%IC for plants with 5 engines or less CR = 90%CLU + 90%CSU* + 10%IC for 6 engines or more
Ontario Hydro	CR = CLU
Manitoba Hydro	CR = 80%CLU + 20%IC
Saskatchewan Power	To strive for a safe and continuous supply of electricity.
Alberta Power Ltd.	CR = CLU CR = 90%CLU + 10%IC for remote sites
BC Hydro	CR = CLU
NWT Power Corp.	CR = CLU + 10% PL for PL < 3 MW CR = CLU + 5% PL for PL > 3 MW
Yukon Electrical	CR = CLU + 10% PL

* CSU = capacity of the smallest unit

There are many reasons for the reluctance to apply probabilistic techniques to SIPS [7]. One of them is the unavailability of appropriate data on generating unit performance and on the actual load demand. Many sites do not have full time operating personnel or continuous load demand metering. There are also concerns about the ability to interpret a single numerical risk index such as LOLE or LOEE and the lack of system operating information contained in a single risk index. The amount of capacity reserve available at different times is not reflected in the conventional risk indices, whereas, the SIPS planners are used to capacity planning based on the available reserve.

The shortage of data necessary for probabilistic methods should decrease with time as many SIPS are making efforts to collect appropriate data. The need for probabilistic techniques that take the existing deterministic criteria into account has been realized and methods to bridge the two techniques have been developed.

1.5 Bridging Deterministic and Probabilistic Methods

Some of the concerns expressed by SIPS planners, designers and operators regarding the use of a single risk index such as LOLE or LOEE can be alleviated by combining the deterministic and the probabilistic approaches into a single framework [7]. This approach, known as "*System Well-being Analysis*", is described in Fig. 1.3 in terms of healthy, marginal and at risk states.

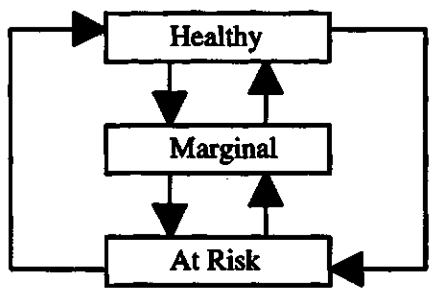


Fig. 1.3: Model for System Well-being Analysis

The combination of deterministic and probabilistic concepts occurs through the definition of the system operating states. A system operates in the healthy state when it has enough capacity reserve to meet a deterministic criterion such as the loss of the largest unit. Probability of health is the probability of finding the system in the healthy state. In the marginal state, the system is not in any difficulty but does not have sufficient margin to meet the specified deterministic criterion. Probability of margin is the probability of finding the system in the marginal state. In the at risk state, the load exceeds the available capacity. Probability of risk, also known as the loss of load probability (LOLP), is the probability of finding the system in the at risk state. Additional new health indices have been developed and are presented and used later in this thesis.

1.6 General Overview of the Thesis

The general objective of this research was to explore the different probabilistic techniques and to analyze how they can be applied to practical adequacy evaluation in

SIPS. A user-interface software package named *'SIPSREL'* has been developed with various options for evaluating the conventional probabilistic risk indices and the newly developed health indices using both analytical and Monte Carlo simulation methods. The software is intended for use by SIPS planners of any background and hopefully will help them adopt probabilistic techniques in their work.

Chapter 1 introduces the problem that has inspired the necessity for the studies in this thesis. System well-being analysis is introduced as a possible approach to incorporating both deterministic and probabilistic concepts in SIPS adequacy evaluation.

Chapter 2 describes the analytical and Monte Carlo simulation methods used to evaluate the conventional system risk indices. There are many factors which effect the system risk. The effects of load forecast uncertainty, planned maintenance and energy limitations are described. These considerations have been incorporated in the software SIPSREL.

Chapter 3 illustrates the new analytical techniques developed to evaluate system well-being indices. It also describes how Monte Carlo simulation can be used to estimate these indices and defines the system well-being frequency and duration indices and their significance in adequacy assessment of SIPS.

Chapter 4 describes the software "SIPSREL" and highlights the different tasks that it is designed to perform. The basic results obtained within the software for each different analysis is displayed for example purposes.

Chapter 5 compares the health, risk and deterministic indices to determine the most appropriate index for adequacy assessment. Chapter 6 identifies the limitations of the existing deterministic methods in capacity planning and proposes a new approach based on both health and risk indices.

Chapter 7 displays the results of Monte Carlo simulation applied to a SIPS and interprets the additional information extracted from the index distributions and the frequency and duration indices. Finally, Chapter 8 summarizes the thesis and highlights the conclusions.

2. EVALUATION OF CONVENTIONAL RISK INDICES

2.1 Basic Concepts

The basic approach to evaluating generating capacity adequacy consists of three parts; the generation model, load model and the risk model [3] as shown in Fig. 2.1. The generation model and the load model are combined to obtain the risk indices.

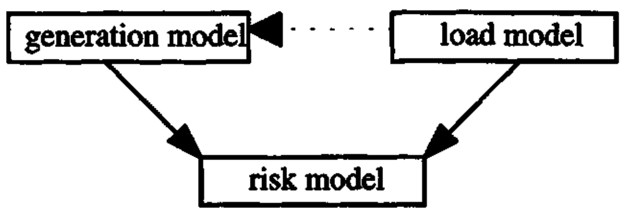


Fig. 2.1: Basic Concepts in HL I Evaluation

The basic generating unit parameter in the evaluation is the probability of finding the unit on forced outage or in the down state at some distant time in the future. This probability is defined as the unit unavailability, and historically in power system applications is known as the forced outage rate (FOR) [3]. It can be obtained using Equation (2.1).

$$\text{FOR} = \frac{\sum[\text{down time}]}{\sum[\text{down time}] + \sum[\text{up time}]} \qquad (2.1)$$

The generation model is in the form of a capacity outage probability table (COPT) in most analytical techniques. It is an array of capacity levels and the associated probabilities of existence. The table can be obtained by using a recursive technique in which generating units are added sequentially to obtain the final model [3]. The cumulative probability of a particular capacity outage state of 'X' MW after a unit, having 'n' number of states and 'C_i' MW capacity with 'p_i' probability, is added is given by Equation (2.2).

$$P(X) = \sum_{i=1}^{n} p_i * P'(X-C_i) \tag{2.2}$$

where P'(X) and P(X) denote the cumulative probabilities of the capacity outage state of X MW before and after the unit is added respectively. The above expression is initialized by setting $P'(X) = 1.0$ for $X \leq 0$ and $P'(X) = 0$, otherwise.

The load models normally used in power system reliability evaluation recognize the variation in load at different times within a period. The basic period used in system planning is a year. Different evaluation techniques and risk indices require different load models. The analytical methods use the daily peak load variation curve (DPLVC) or the load duration curve (LDC). Energy based assessment is not possible with a DPLVC. Monte Carlo simulation techniques normally use the chronological hourly load variation curve. The generation model (COPT in most cases) is combined with a particular load model to evaluate the desired risk index.

2.2 Loss of Load Indices

The system loss of load indices are obtained by convolving the COPT with the DPLVC or the LDC. A loss of load occurs when the system load exceeds the generating capacity at any instant. Fig. 2.2 illustrates the method of evaluating the loss of load indices (i.e., LOLE or LOLP).

Fig. 2.2 shows that when an outage X_k, with probability p_k, exceeds the reserve, it causes a load loss for a time t_k. Each outage state X_k, with probability p_k, is superimposed on the load model and the time t_k for each load loss event is calculated. The LOLE is given by Equation (2.3) [8].

$$\text{LOLE} = \sum_{k=1}^{n} p_k \cdot t_k \tag{2.3}$$

where, n = number of capacity outage states in the COPT
p_k = individual probability of capacity outage X_k
t_k = load loss occurring time due to outage X_k

If the time t_k is in per unit of the total time period, Equation (2.3) gives the LOLP instead of the LOLE. The unit of LOLE is in days/year or hours/year depending on whether a DPLVC or a LDC is used respectively as the load model .

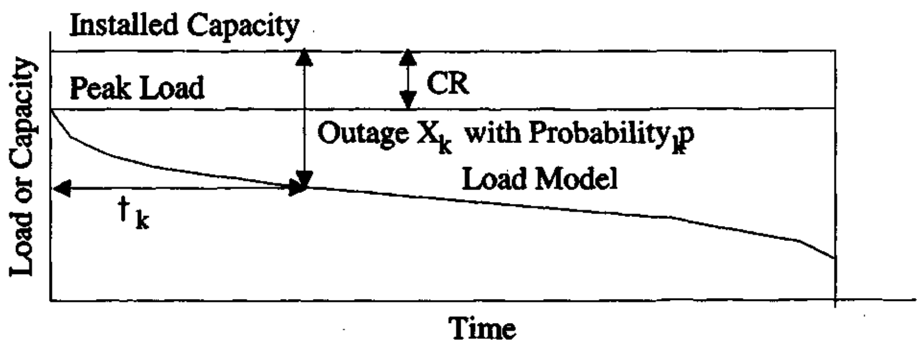


Fig. 2.2: Evaluation of Loss of Load Indices

2.3 Loss of Energy Indices

The loss of energy indices are obtained by convolving the COPT with the LDC of the system as described in Fig. 2.3. The area under the LDC is the total energy (E) demanded by the system in one year or a desired time period. When an outage X_k, with probability p_k, exceeds the reserve, it causes an energy curtailment E_k. Each outage state X_k in the COPT, with probability p_k, is superimposed on the LDC and the energy curtailed E_k for each load loss event is calculated. The loss of energy indices are obtained using the following equations [8]:

$$LOEE = \sum_{k=1}^{n} E_k \cdot p_k \tag{2.4}$$

$$UPM = \frac{LOEE}{E} \cdot 10^6 \tag{2.5}$$

$$SM = \frac{LOEE}{PL} \cdot 60 \tag{2.6}$$

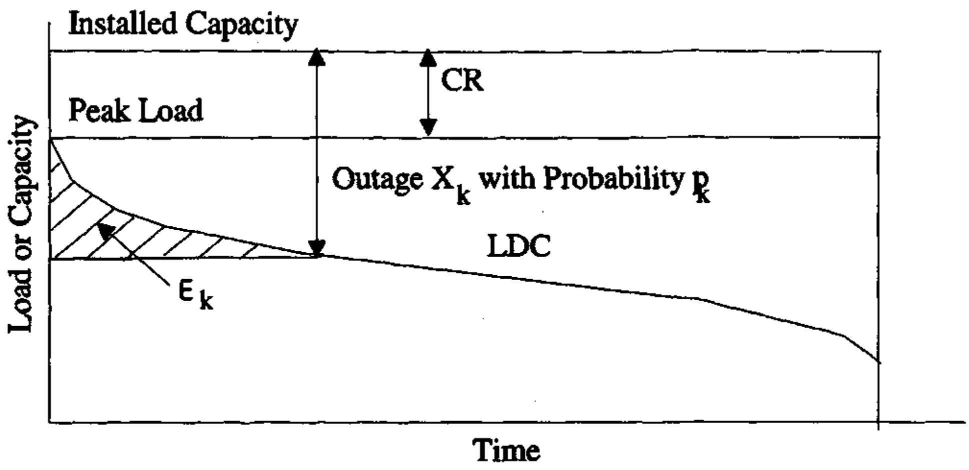


Fig. 2.3: Evaluation of Loss of Energy Indices

The expected energy supplied (EES) by each generating unit can also be calculated. The summation of the EES by each unit multiplied by its respective energy cost per KWh, gives the total production cost of the system. The generating units must be arranged in their economic loading order and their EES is obtained using Equation (2.7).The total production cost is then calculated using Equation (2.8).

$$EES_k = EENS_{k-1} - EENS_k \tag{2.7}$$

where, EES_k = Expected energy supplied by the k^{th} unit in the loading order
$EENS_k$ = Expected energy not supplied with the first k units in
$EENS_0$ = E = total energy demanded by the system load

$$\text{Production Cost} = \sum_{k=1}^{N} EES_k \cdot (\$/KWh)_k \tag{2.8}$$

where, N = number of generating units in the system
$(\$/KWh)_k$ = energy cost per KWh of the k^{th} unit in the loading order

2.4 Energy Limited Systems

A generating unit is said to be energy limited if its output capacity is dictated by the energy available. Run-of-the-river hydro installations with little or no storage and thermal units with variable flow availabilities of natural gas are examples of energy limited units. The flow rate determines the unit output capacity. The unit is then represented by a multi-state unit in which the capacity state corresponds to the water or natural gas flow rates [3]. The risk indices are evaluated by the methods described earlier for these types of energy limited systems.

Other types of energy limited units are those with storage facilities that permit energy to be stored and used during the peak load periods to reduce the requirement from more expensive peaking units. Hydro plants with storage reservoirs and fossil fired plants with limited fuel supplies are examples of these types of energy limited units. The risk indices in these cases can be evaluated using a different method, known as the load modification approach.

In the load modification approach, a 'peak shaving' technique can be used in which the capacity and energy probability distributions of the unit are used to modify the load duration curve [9]. The first step is to capacity modify the load duration curve using a conditional probability approach with the capacity probabilities of the first unit in the economic loading order. This is done using Equation (2.9) for all load levels, starting from the peak to zero:

$$D(L) = \sum_{k=1}^{N} d_k(L) \, . \, P_k \qquad (2.9)$$

where $D(L)$ = duration of load L on the capacity modified curve
N = number of capacity states of the generating unit
C_k = output capacity of the k^{th} capacity state of the unit
P_k = probability of capacity C_k
$d_k(L)$ = duration of load L on the original LDC when reduced by C_k MW.

A resulting capacity modified curve is then formed as shown in Fig. 2.4. The capacity modified curve is the equivalent load curve for the rest of the units in the system given the unit used to modify it is not energy limited. However, if the unit is energy limited, then the next step is to energy modify the capacity modified curve. This is done using Equation (2.10) for all load levels, starting from the peak to zero. A resulting energy modified curve is then formed as shown in Fig. 2.5. The energy modified curve becomes the equivalent load curve for the rest of the units in the system.

$$D(L) = d_c(L) \, . \, P[E(L)] + d_o(L) \, . \, \{1 - P[E(L)]\} \qquad (2.10)$$

where $D(L)$ = duration of load L on the energy modified curve
$d_c(L)$ = duration of load L on the capacity modified curve
$d_o(L)$ = duration of load L on the original LDC
$E(L)$ = area between the original and capacity modified curve above L MW
$P[E(L)]$ = probability of energy equaling or exceeding E(L) MW

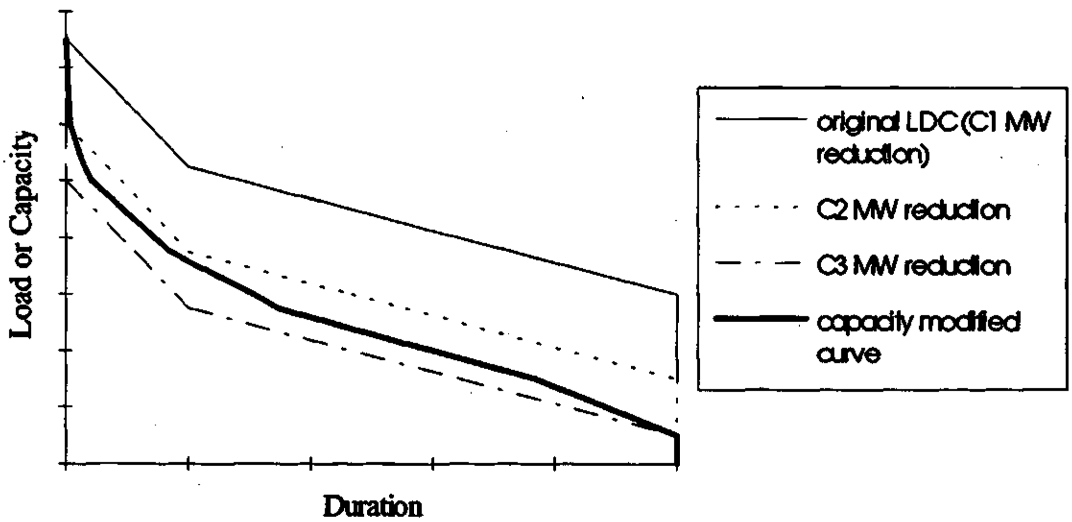


Fig. 2.4: Capacity Modified LDC Using a 3-State Unit

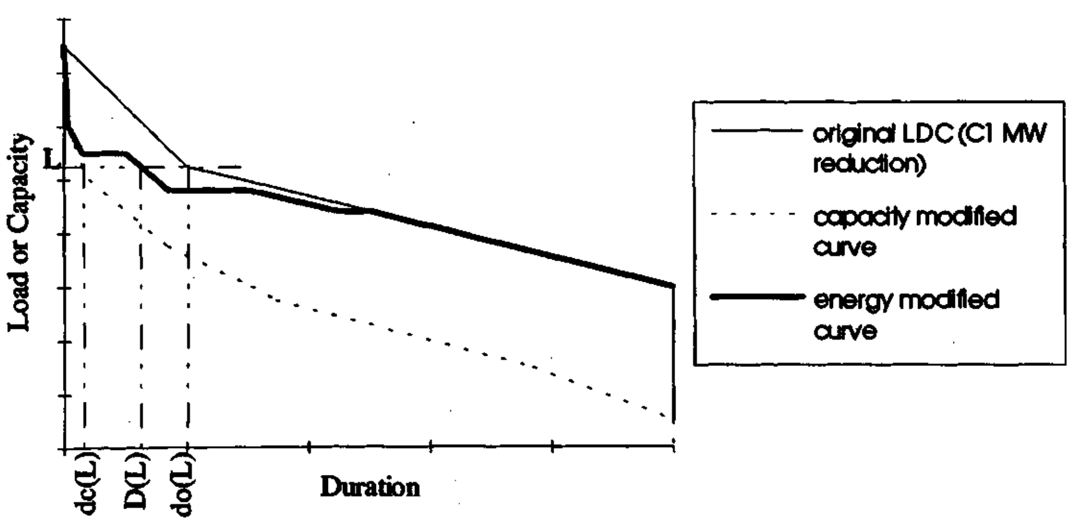


Fig. 2.5: Energy Modified Load Duration Curve

2.5 Planned Maintenance of Generating Units

The evaluation methods described so far assume that the load model and the capacity model apply to the entire period. However, in practice, units are removed from service for periodic scheduled maintenance. The capacity available for service is different during such periods. The developed software SIPSREL described later in this thesis assumes that only one unit is out at a time for maintenance in a SIPS.

In order to incorporate planned maintenance in adequacy evaluation, the total period is divided into sub-periods for each maintenance duration. The capacity model and the load model are found for each sub-period and the risk index is evaluated for each case. The sum of the risk indices in all the sub-periods gives the system risk index for the total period as expressed in Equations (2.11):

$$LOLE = \sum_{p=1}^{n} LOLE_p \qquad \text{and} \qquad LOEE = \sum_{p=1}^{n} LOEE_p \qquad (2.11)$$

where, n = number of maintenance sub-periods within the total period
LOLEp = LOLE for sub-period p.

Fig. 2.6 shows how the total period is divided into periods for maintenance [3]. The LDC obtained from the hourly load data within a sub-period is used as the load model for that particular sub-period.

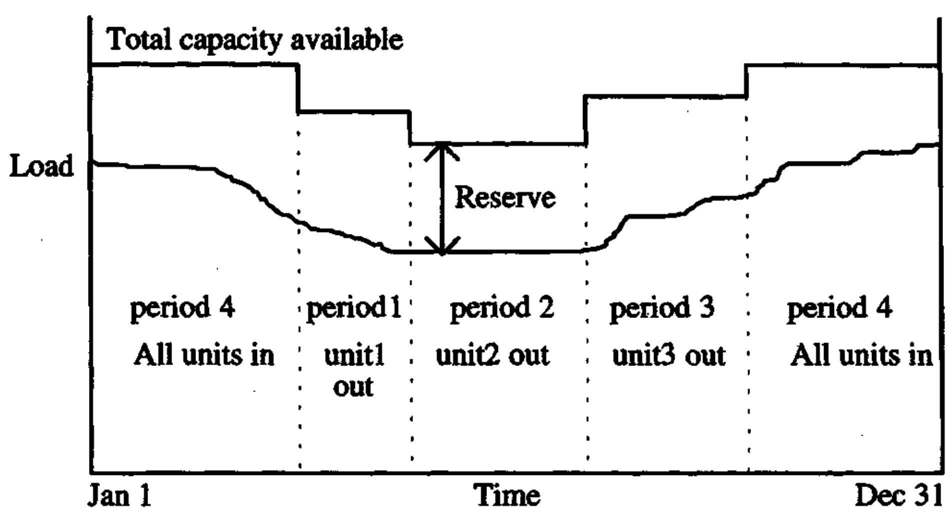


Fig. 2.6: Sub-division of the Total Maintenance Period

2.6 Load Forecast Uncertainty

Adequacy studies for capacity planning purposes use load models in which the peak loads are forecast based on past experience. The forecast peak loads differ from the actual values with a certain probability. The parameters of this probability distribution can be determined from past experience, future load modeling and possible subjective evaluation [3]. Published data suggest that the uncertainty can be reasonably described by a normal distribution, the mean of which, is the forecast peak load.

Load forecast uncertainty (LFU) is an extremely important parameter and in the light of the financial, societal and environmental uncertainties which electric power utilities face may be the single most important parameter in generating capacity reliability evaluation [3]. It can be included in the risk computations using the conditional probability approach. The LFU distribution is divided into class intervals, the number of which depends on the accuracy desired. Each class interval represents the deviation from the mean peak load and its probability. In the normal distribution, the mid-point distance of a class interval from the mean gives the deviation and the mid-point magnitude gives the probability of that deviation as shown in Fig. 2.7. The risk indices are evaluated for each class interval using its corresponding peak load. The sum of the risk index evaluated for each interval multiplied by its probability gives the system risk index considering LFU.

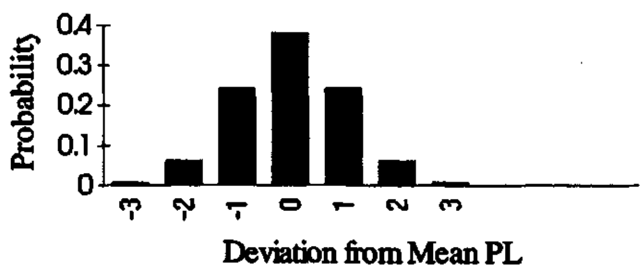


Fig. 2.7: Load Forecast Uncertainty Distribution

2.7 Adequacy Assessment by Monte Carlo Simulation

The adequacy evaluation methods described so far are all analytical approaches. Analytical techniques represent the system by a mathematical model and evaluate the

A state history for each individual unit can be generated on a time dependent basis as illustrated in Fig. 2.8. An outage history of the total capacity is obtained by combining the outage histories of all the units in the system.

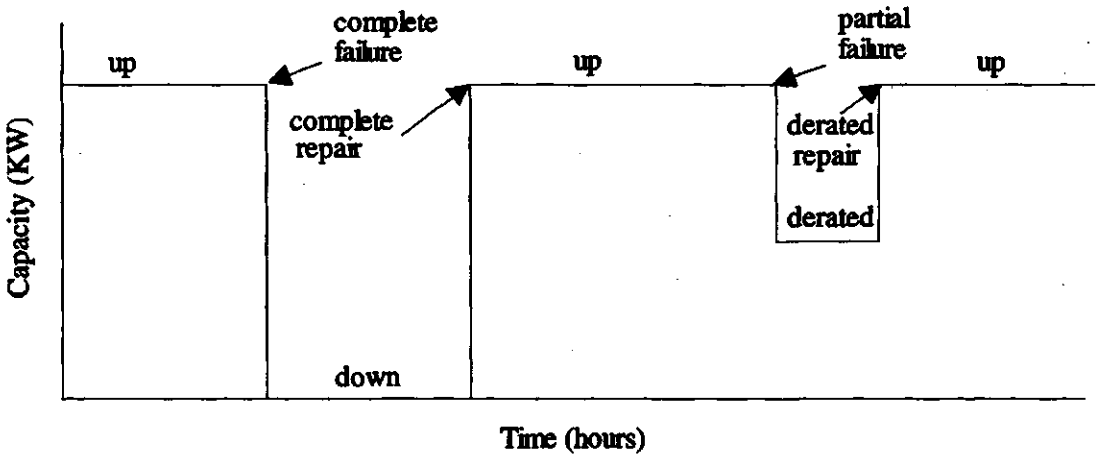


Fig. 2.8: Outage History of a Generating Unit

2.7.2 Combining the Generation and Load Models

The generation model is combined with the load model to obtain the system risk indices. The annual hourly load cycle is used in which it is assumed that the load changes discretely every hour and is constant throughout the hour. The total capacity of the system available at every hour is superimposed on the load in that hour as shown in Fig. 2.9 in order to evaluate the capacity reserves and deficiencies. The total number of interruptions n with the duration t_i and energy loss x_i at each interruption are recorded and used to calculate the basic adequacy indices by applying Equation (2.15 - 2.21).

$$\text{Loss of load expectation, LOLE} = \frac{\sum_{i=1}^{n} t_i}{N} \ \text{(h/yr)} \tag{2.15}$$

where, N = total number of simulated years

$$\text{Loss of energy expectation, LOEE} = \frac{\sum_{i=1}^{n} x_i}{N} \ \text{(KWh/yr)} \tag{2.16}$$

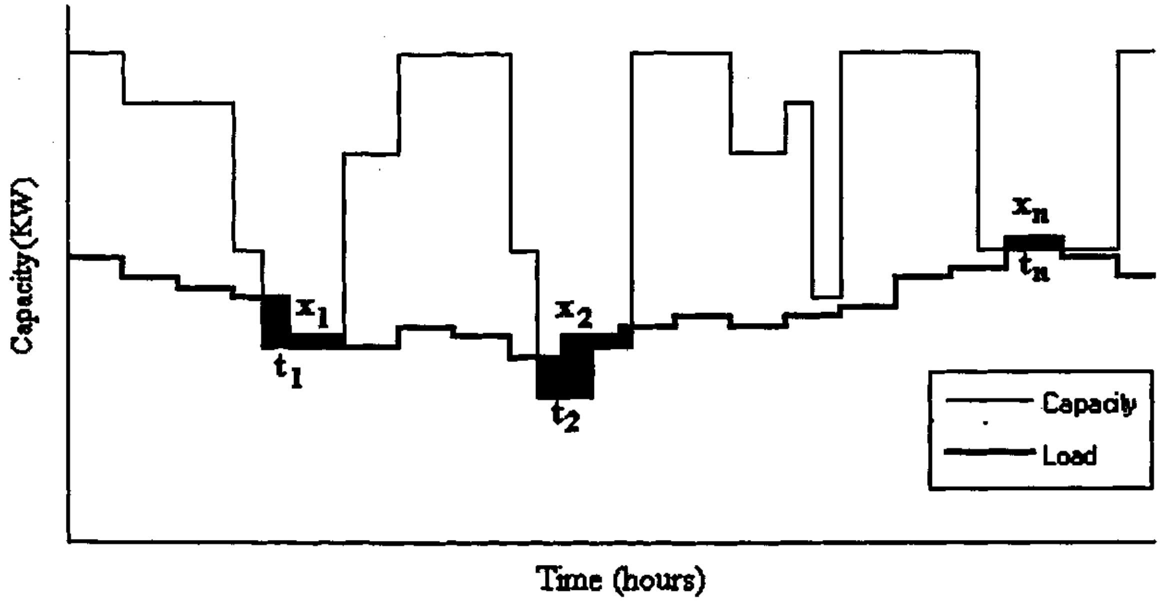


Fig. 2.9: Superimposition of Generation and Load Models

Expected load loss per year, $ELLPYR = \dfrac{\sum_{i=1}^{n} x_i / t_i}{N}$ (KW/yr) (2.17)

Frequency of interruptions, $F = \dfrac{n}{N}$ (int/yr) (2.18)

Expected interruption duration, $EINTDUR = \dfrac{\sum_{i=1}^{n} t_i}{n}$ (hr/int) (2.19)

Expected energy not supplied per interruption, $EENSPINT = \dfrac{\sum_{i=1}^{n} x_i}{n}$ (KWh/int) (2.20)

Expected load loss per interruption, $ELLPINT = \dfrac{\sum_{i=1}^{n} x_i / t_i}{n}$ (KW/int) (2.21)

2.7.3 Simulation Convergence and Computing Time Requirements

A major limitation of the MCS method is the amount of required computing time. The simulation must be run for a large number of years to obtain an acceptable confidence in the results. In order to reduce the simulation time and yet obtain a reasonable confidence in the results, it is necessary to determine the most appropriate time to stop the simulation. There are different stopping rules that can be used to track the convergence of the simulation process.

The stopping rule implemented in the program SIPSREL involves observing the so called "sample weight plot" [10]. This plot is an observation of the average of some variable of interest as the number of observations of that variable grows through the simulation, as shown in Fig. 2.10. If such a plot is observed as the simulation progresses, it should stabilize as the simulation approaches convergence. The LOEE has been observed to have the least tendency to converge when compared to the other risk indices [11]. It has therefore been taken as the variable to check for convergence. When the average value of the LOEE ceases to change significantly, the simulation can be terminated. Specification of a minimum number of simulated years is used to avoid premature convergence. On the other hand, specifying a maximum number of simulated years will avoid non-converging or poorly converging situations.

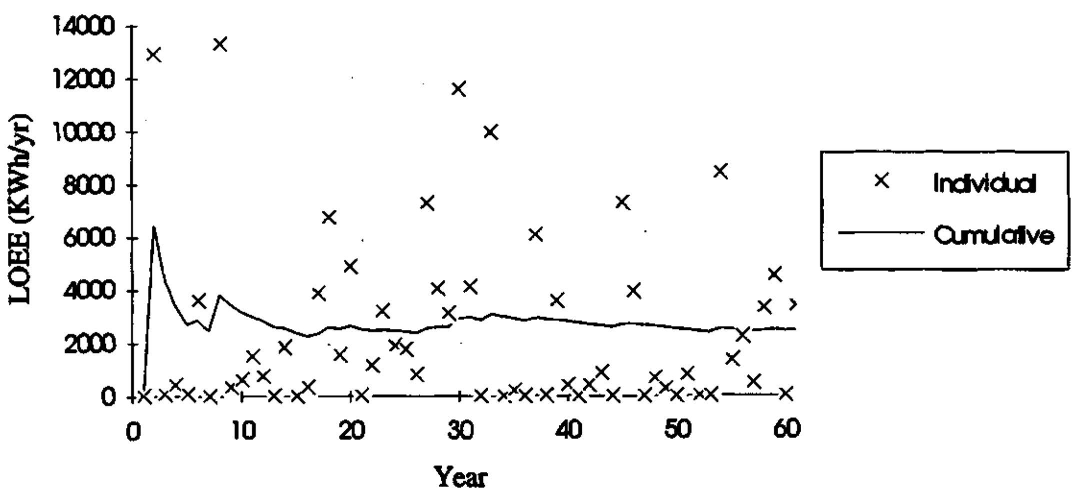


Fig. 2.10: Sample Weight Plot

2.8 Conclusion

The conventional risk parameters used for generating capacity adequacy evaluation are loss of load indices, loss of energy indices and frequency and duration indices. These parameters can be evaluated using either analytical techniques or by Monte Carlo simulation methods. The basic concept is to convolve the generation model and the load model to obtain the risk model. Different factors such as load forecast uncertainty, planned generating unit maintenance and energy limitations in the system can be incorporated in the analysis to include their effects on the risk indices.

The most common analytical techniques use a generation model in the form of a capacity outage probability table and are known as the COPT method. An alternative analytical technique, which gives the same results, is the load modification approach. Risk indices in energy limited systems with storage facilities can be evaluated using the load modification approach.

Analytical methods are generally employed to calculate the expected values of the loss of load indices (LOLE) and the loss of energy indices (LOEE, UPM, SM). MCS techniques can be used to provide index distributions in addition to the average values. The evaluation of frequency and duration indices becomes rather complex with analytical techniques but the indices are easily obtained using MCS methods. MCS generally requires a large computation time but is very useful when the system under evaluation becomes too complex for analytical techniques.

3. EVALUATION OF SYSTEM WELL-BEING INDICES

3.1 Introduction

The concept of system well-being analysis can be used to combine the deterministic and the probabilistic approaches into a single framework [7]. The magnitudes of the system capacity reserves are evaluated using probabilistic techniques which are then compared to an accepted deterministic criterion such as the loss of the largest unit in order to measure the degree of comfort in the system. Indices have been developed that can be used to assess a system from a deterministic aspect in addition to recognizing its stochastic behavior and inherent risks. An appreciation of the deterministic criterion that drives the probabilistic well-being indices makes these indices easily interpreted by SIPS planners who are more accustomed to a deterministic approach.

System well-being analysis [7] introduces the three well-being indices of probability of health P(H), probability of margin P(M) and probability of risk. The probability of risk, though considered as a well-being index, is actually the conventional risk index of the loss of load probability (LOLP). Other well-being indices, excluding the risk indices, are referred to as health indices throughout this thesis. Frequency and duration health indices are also presented in this thesis. Since the LOLE is the most widely used risk index, a new health index, with similar characteristics for the purpose of comparative adequacy studies, is introduced and is called the '*loss of health expectation (LOHE)*'. It is the expected duration in a year that the system does not meet the accepted deterministic criterion and is calculated using Equation (3.1).

$$\text{LOHE} = [1 - P(H)] * \text{Total Period in hrs or days} \quad (\text{h/yr or d/yr}) \qquad (3.1)$$

As shown in Table 1.4, conventional deterministic techniques make use of the capacity of the largest unit in the system (CLU) to determine the amount of capacity reserve needed in order to meet the accepted adequacy criterion. In system health analysis, the required amount of capacity reserve is determined by the capacity of the largest operating unit at a particular point in time. The capacity of the largest unit in a state (CLUS) can be different for different generation system states. The CLUS is equal to the CLU at those times when the largest unit in the system is in the up state.

The basic concepts underlying the evaluation of system health indices are very similar to those used to evaluate the system risk indices. In risk evaluation, the system reserve is examined for negative margins throughout the entire period. In health evaluation, the system reserve is compared with the CLUS throughout the total period. The system health indices can be evaluated using either analytical techniques or by MCS methods. The analytical contingency enumeration method can be used to evaluate the system well-being indices. A new approach developed in this research work is the '*Conditional Probability COPT (CPCOPT) Method*'. Distributions of the basic health indices and the frequency and duration health indices, obtained through the MCS method, are introduced and explained in this chapter.

3.2 Contingency Enumeration Approach

In the contingency enumeration approach, the generation model is built in the form of an array that lists all the different possible combinations of the existing generating unit outages, their probabilities and the CLUS during each contingency. If the system has 'n' generating units that can reside in 'm' states, the total number of contingencies in the generation model is m^n. The load model used in this approach is a constant load. If the annual peak load is used, the indices obtained are known as the annualized indices. If the load duration curve is taken as the load model, it must be divided into discrete load levels. The more steps, the better the load model will resemble the actual load curve.

Each contingency in the generation model is compared with the fixed load to determine the amount of capacity reserve available at each condition. When the available reserve is equal to or more than the CLUS, that particular contingency is designated as healthy. When the available reserve is less than the CLUS but greater than zero, the contingency is considered to be marginal and when it is less than zero, the contingency is said to be at risk. The probability of health is the summation of all the individual probabilities for which the contingencies are healthy. Similarly, the probability of margin is the summation of all the individual probabilities during which the contingencies are marginal and the probability of risk is the summation of all the at risk probabilities.

The contingency enumeration approach is illustrated in Table 3.1 using an example designated as System X which has the following generation and load parameters:

Unit 1 : 1000 KW, 5% FOR   Unit 2 : 500 KW, 5% FOR   Unit 3 : 500 KW, 5% FOR
Unit 4 : 500 KW, 5% FOR   Annual peak load = 1000 KW

Table 3.1: Contingency Enumeration Array

Units Out	Probability	Cap In (KW)	CLUS (KW)	Reserve (KW)	Health	Margin	Risk
None	0.81450625	2500	1000	1500	x	-	-
1	0.04286875	1500	500	500	x	-	-
2	0.04286875	2000	1000	1000	x	-	-
3	0.04286875	2000	1000	1000	x	-	-
4	0.04286875	2000	1000	1000	x	-	-
1,2	0.00225625	1000	500	0	-	x	-
1,3	0.00225625	1000	500	0	-	x	-
1,4	0.00225625	1000	500	0	-	x	-
2,3	0.00225625	1500	1000	500	-	x	-
2,4	0.00225625	1500	1000	500	-	x	-
3,4	0.00225625	1500	1000	500	-	x	-
1,2,3	0.00011875	500	500	-500	-	-	x
1,2,4	0.00011875	500	500	-500	-	-	x
1,3,4	0.00011875	500	500	-500	-	-	x
2,3,4	0.00011875	1000	1000	0	-	x	-
1,2,3,4	0.00000625	0	0	-1000	-	-	x
				Total =	0.985981	0.013656	0.000363

The system health, margin and risk probabilities as shown in Table 3.1 are 0.985981, 0.013656 and 0.000363 respectively. The LOHE can be calculated using Equation (3.1) and is 122.80 h/yr.

The technique illustrated in Table 3.1 can be extended to recognize unit deratings in addition to complete outages. Assume that in the above example, unit 1 and unit 2 can also reside in the following derated states:

Unit 1: Capacity	Probability
0 KW	0.05
500 KW	0.30
1000 KW	0.65

Unit 2: Capacity	Probability
0 KW	0.05
300 KW	0.15
500 KW	0.80

The contingency enumeration approach including the derated states is illustrated in Table 3.2. In the first column of the table, the derated units are denoted by italics and are underlined.

Table 3.2: Contingency Enumeration Array Including Derated Units

Units Out or *Derated*	Probability	Cap In (KW)	CLUS (KW)	Reserve (KW)	Prob of Health	Prob of Margin	Prob of Risk
None	0.46930000	2500	1000	1500	x	-	-
1	0.21660000	2000	500	1000	x	-	-
2	0.08799375	2300	1000	1300	x	-	-
1,2	0.04061250	1800	500	800	x	-	-
1	0.03610000	1500	500	500	x	-	-
2	0.02933125	2000	1000	1000	x	-	-
3	0.02470000	2000	1000	1000	x	-	-
4	0.02470000	2000	1000	1000	x	-	-
1,2	0.01353750	1500	500	500	x	-	-
1,3	0.01140000	1500	500	500	x	-	-
1,4	0.01140000	1500	500	500	x	-	-
2,1	0.00676875	1300	500	300	-	x	-
2,3	0.00463125	1800	1000	800	-	x	-
2,4	0.00463125	1800	1000	800	-	x	-
1,2,3	0.00213750	1300	500	300	-	x	-
1,2,4	0.00213750	1300	500	300	-	x	-
1,2	0.00225625	1000	500	0	-	x	-
1,3	0.00190000	1000	500	0	-	x	-
1,4	0.00190000	1000	500	0	-	x	-
2,3	0.00154375	1500	1000	500	-	x	-
2,4	0.00154375	1500	1000	500	-	x	-
3,4	0.00130000	1500	1000	500	-	x	-
1,2,3	0.00071250	1000	500	0	-	x	-
1,2,4	0.00071250	1000	500	0	-	x	-
1,3,4	0.00060000	1000	500	0	-	x	-
2,1,3	0.00035625	800	500	-200	-	-	x
2,1,4	0.00035625	800	500	-200	-	-	x
2,3,4	0.00024375	1300	1000	300	-	x	-
1,2,3,4	0.00011250	800	500	-200	-	-	-
1,2,3	0.00011875	500	500	-500	-	-	x
1,2,4	0.00011875	500	500	-500	-	-	x
1,3,4	0.00010000	500	500	-500	-	-	x
2,3,4	0.00008125	1000	1000	0	-	x	-
1,2,3,4	0.00003750	500	500	-500	-	-	x
2,1,3,4	0.00001875	300	300	-700	-	-	x
1,2,3,4	0.00000625	0	0	-1000	-	-	x
				Total =	0.965675	0.033100	0.001225

The system health, margin and risk probabilities as shown in Table 3.2 are 0.965675, 0.033100 and 0.001225 respectively. The LOHE is 300.69 h/yr.

The inclusion of load model representations is illustrated in the following example considering a straight line load duration curve with a load factor of 60%. The peak load is the same as in the fixed load case, i.e. 1000 KW. Derated states are not considered to simplify the example. Fig. 3.1 shows the load duration curve.

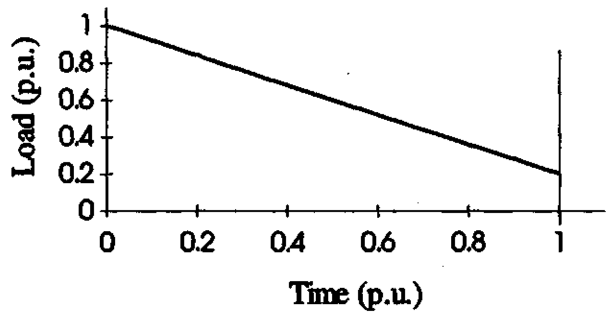


Fig. 3.1: LDC for System X

The LDC is divided into a number steps of discrete load levels. It is necessary to have a large number of discrete steps for reasonable accuracy. However, for the purpose of illustrating the method, only 10 steps are taken in this example as shown in Fig. 3.2.

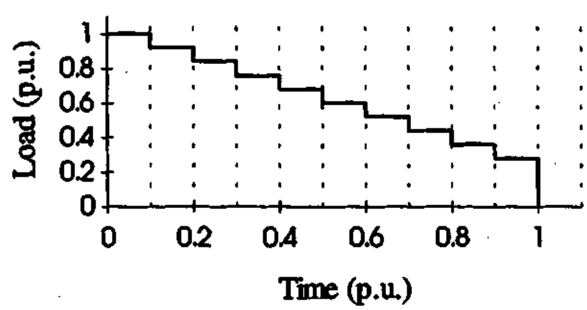


Fig. 3.2: 10-Step Load Model

The method described earlier is now repeated for each discrete load level and by comparing the available reserve with the CLUS, it is determined whether the system remains in the healthy, marginal or at risk state for each load level at each contingency. This is illustrated in Table 3.3.

Table 3.3: Discrete Load Step Array

Units Out	Probability	Cap In (KW)	CLUS (KW)	Discrete Load Levels (KW) 1000	920	840	760	680	600	520	440	360	280
None	0.81450625	2500	1000	H	H	H	H	H	H	H	H	H	H
1	0.04286875	1500	500	H	H	H	H	H	H	H	H	H	H
2	0.04286875	2000	1000	H	H	H	H	H	H	H	H	H	H
3	0.04286875	2000	1000	H	H	H	H	H	H	H	H	H	H
4	0.04286875	2000	1000	H	H	H	H	H	H	H	H	H	H
1,2	0.00225625	1000	500	M	M	M	M	M	M	M	H	H	H
1,3	0.00225625	1000	500	M	M	M	M	M	M	M	H	H	H
1,4	0.00225625	1000	500	M	M	M	M	M	M	M	H	H	H
2,3	0.00225625	1500	1000	M	M	M	M	M	M	M	H	H	H
2,4	0.00225625	1500	1000	M	M	M	M	M	M	M	H	H	H
3,4	0.00225625	1500	1000	M	M	M	M	M	M	M	H	H	H
1,2,3	0.00011875	500	500	R	R	R	R	R	R	R	M	M	M
1,2,4	0.00011875	500	500	R	R	R	R	R	R	R	M	M	M
1,3,4	0.00011875	500	500	R	R	R	R	R	R	R	M	M	M
2,3,4	0.00011875	1000	1000	M	M	M	M	M	M	M	M	M	M
1,2,3,4	0.00000625	0	0	R	R	R	R	R	R	R	R	R	R

The individual health, margin and risk probabilities for each discrete load level are multiplied by their duration probabilities. The summation of these products gives the system health, margin and risk probabilities as illustrated in Table 3.4.

Table 3.4: Combining Step Probabilities for Total Result

Step Load (KW)	time (p.u.)	Prob of Health	C2 * C3	Prob of Margin	C2 * C5	Prob of Risk	C2 * C7
1000	0.1	0.98598125	0.098598125	0.01365625	0.001365625	0.00036250	0.000036250
920	0.1	0.98598125	0.098598125	0.01365625	0.001365625	0.00036250	0.000036250
840	0.1	0.98598125	0.098598125	0.01365625	0.001365625	0.00036250	0.000036250
760	0.1	0.98598125	0.098598125	0.01365625	0.001365625	0.00036250	0.000036250
680	0.1	0.98598125	0.098598125	0.01365625	0.001365625	0.00036250	0.000036250
600	0.1	0.98598125	0.098598125	0.01365625	0.001365625	0.00036250	0.000036250
520	0.1	0.98598125	0.098598125	0.01365625	0.001365625	0.00036250	0.000036250
440	0.1	0.99951875	0.099951875	0.00047500	0.000047500	0.00000625	0.000000625
360	0.1	0.99951875	0.099951875	0.00047500	0.000047500	0.00000625	0.000000625
280	0.1	0.99951875	0.099951875	0.00047500	0.000047500	0.00000625	0.000000625
	Total:	P(Health) = 0.990042		P(Margin) = 0.009702		P(Risk) = 0.000256	

The system health, margin and risk probabilities as shown in Table 3.4 are 0.990042, 0.009702 and 0.000256 respectively. The LOHE is 87.23 h/yr.

If the load duration curve is divided into 100 discrete steps of 1% of the peak load level, it will appear as in Fig 3.3. In this case, the probabilities of health, margin and risk are 0.990990, 0.008779 and 0.000231 respectively. The LOHE is 78.93 h/yr

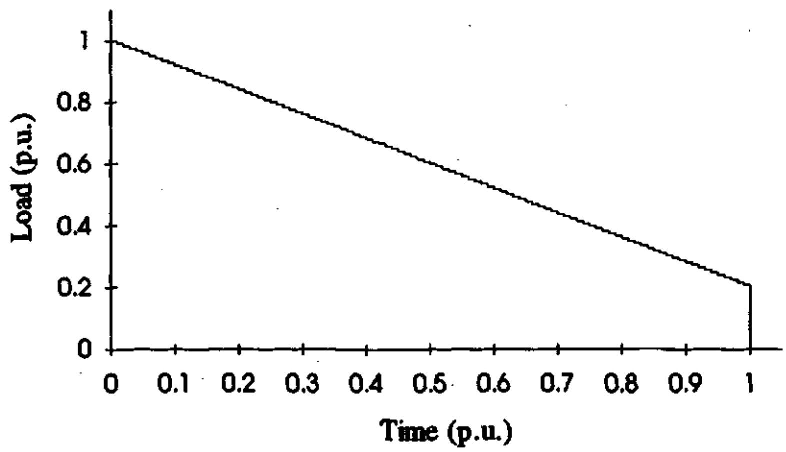


Fig. 3.3: 100-Step Load Model

3.3 Conditional Probability COPT Method

This is a new method developed in this research work to overcome some of the limitations of the existing contingency enumeration approach. In this method, the probability of risk or LOLP is evaluated using the conventional loss of load method by convolving the COPT with the load curve as described in Chapter 2. The probability of health is then evaluated by a similar method in which several COPT are developed using the conditional probabilities of the available states of the largest units and are convolved with the load curve. The probability of margin is calculated by subtracting the sum of the probabilities of health and risk from 1.0. The steps involved in the new approach are shown in Fig. 3.4.

The new method is illustrated by repeating the previous examples using the new approach. System X has four units with 5% FOR. Unit 1 is 1000 KW and units 2, 3, and 4 are 500 KW each. The load is constant at 1000 KW.

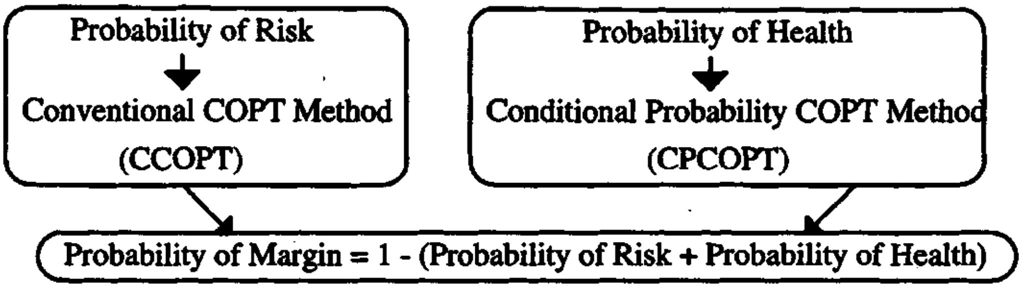


Fig. 3.4: Steps involved in the New Method

Step 1: The evaluation of the LOLP is shown in Table 3.5.

Table 3.5: Calculating the LOLP by the CCOPT Method

Capacity In (KW)	Cumulative Probability
2500	1.0
2000	0.18549370
1500	0.05688750
1000	0.00725000
500	0.00036250
0	0.00000625

Probability of Risk (LOLP) = 0.000363

Step 2: The evaluation of the Probability of Health, P(H) is shown in Table 3.6.

Table 3.6: Calculating the P(H) by the CPCOPT Method

Given Unit 1 is out (CLUS = 500 KW)

Cap In (KW)	Cumulative Probability
0 + 1500	0.857375
0 + 1000	0.992750
0 + 500	0.999875
0 + 0	1.0

Given Unit 1 is in (CLUS = 1000 KW)

Cap In (KW)	Cumulative Probability
1000 + 1500	0.857375
1000 + 1000	0.992750
1000 + 500	0.999875
1000 + 0	1.0

The results shown in Table 3.6 are combined as follows:

$$P(H) = P(H)_{1\ out} * P(1\ out) + P(H)_{1\ in} * P(1\ in)$$
$$= 0.857375 * 0.05 + 0.99275 * 0.95 = 0.985981$$

Step 3: The Probability of Margin, P(M) is calculated as follows:

$$P(M) = 1.0 - P(H) - LOLP$$
$$= 1.0 - 0.985981 - 0.000363 = 0.013656$$

The probabilities of health, margin and risk are 0.985981, 0.013656 and 0.000363 respectively. The LOHE is 122.80 h/yr. It can be seen that these results are identical to those obtained using the basic contingency enumeration approach.

Assume that unit 1 and unit 2 can also reside in the derated states described earlier. Table 3.7 and 3.8 show the required calculations.

Table 3.7: Calculating the LOLP by the CCOPT Method

Capacity In (KW)	Cumulative Probability	
2500	1.0	
2300	0.53070000	
2000	0.00270630	
1800	0.14737500	
1500	0.09750000	
1300	0.02067500	
1000	0.00938750	
800	0.00122500	Probability of Risk (LOLP) = 0.001225
500	0.00040000	
300	0.00002500	
0	0.00000625	

Table 3.8: Calculating the P(H) by the CPCOPT Method

COPT		Given unit 1 out	Given unit 1 derated	Given unit 1 in
		CLUS = 500 KW	CLUS = 500 KW	CLUS = 1000 KW
Cap In (KW)	Cum Prob	x = 0 KW	x = 500 KW	x = 1000 KW
x + 1500	0.722000	P(H) = 0.722		
x + 1300	0.857375			
x + 1000	0.978500		P(H) = 0.9785	P(H) = 0.9785
x + 800	0.992750			
x + 500	0.999500			
x + 300	0.999875			
x + 0	1.0			

$$P(H) = P(H)_{1\ out} * P(1\ out) + P(H)_{1\ derated} * P(1\ derated) + P(H)_{1\ in} * P(1\ in)$$
$$= 0.722 * 0.05 + 0.9785 * 0.3 + 0.9785 * 0.65 = 0.965675$$

$$P(M) = 1.0 - P(H) - LOLP$$
$$= 1.0 - 0.965675 - 0.001225 = 0.033100$$

The system health, margin and risk probabilities are 0.965675, 0.033100 and 0.001225 respectively. The LOHE is 300.69 h/yr. It can be seen that these results are identical to those obtained using the basic contingency enumeration approach.

Assume that the system has a straight line load duration curve with a load factor of 60% as in Fig. 3.1. The peak load is the same, i.e. 1000 KW. The derated states are not considered in this example.

Step 1: The first step is to evaluate the LOLP using the CCOPT method. The COPT is convolved with the LDC as shown in Fig. 3.5. The p.u. duration of the total period, for which an outage occurs at each capacity level, is calculated. The calculations involved are illustrated in Table 3.9.

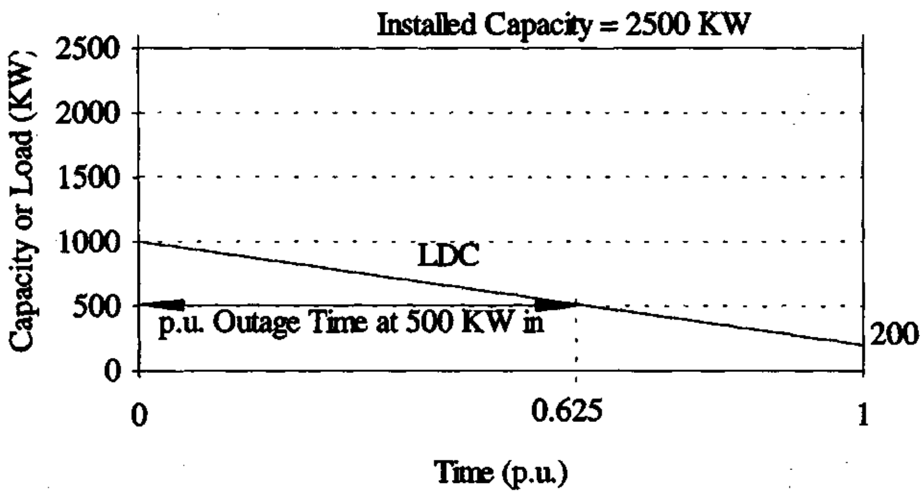


Fig. 3.5: Capacity and Load Conditions in the CCOPT Method

Table 3.9: Calculating the LOLP by the CCOPT Method

Cap In (KW)	Individual Probability	Outage Time (p.u.)	C2 * C3
2500	0.81450625	0	0
2000	0.12860625	0	0
1500	0.04963750	0	0
1000	0.00688750	0	0
500	0.00035625	0.625	0.000223
0	0.00000625	1	0.000006
		LOLP =	0.000229

Step 2: The second step is to evaluate the P(H) using the CPCOPT method. The COPT is convolved with the LDC using the p.u. duration of the total period for which the available reserve is equal to or greater than the CLUS at each capacity level. Fig. 3.6(a) and Fig 3.6(b) illustrate the application given that the largest unit is out and the largest unit is in respectively.

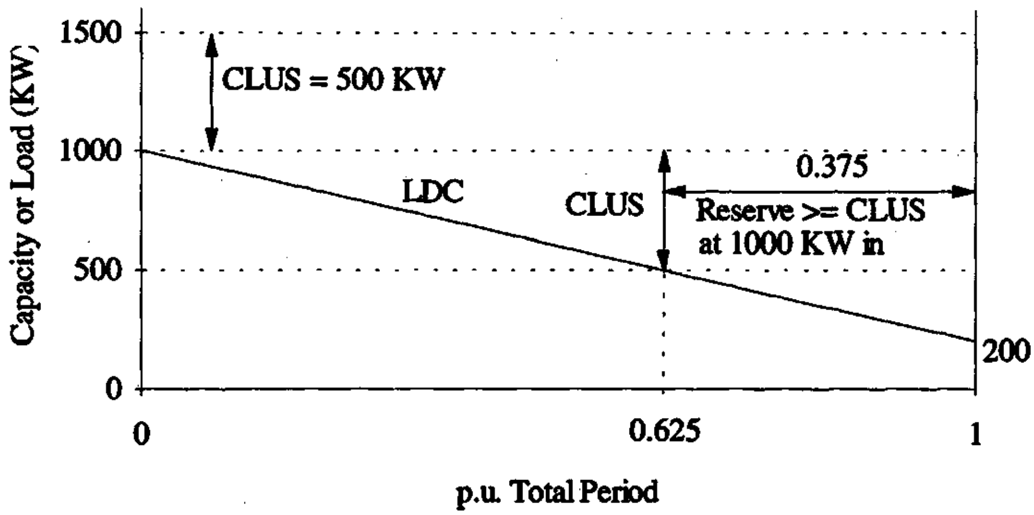


Fig. 3.6(a): Capacity and Load Conditions Given that Unit 1 is out

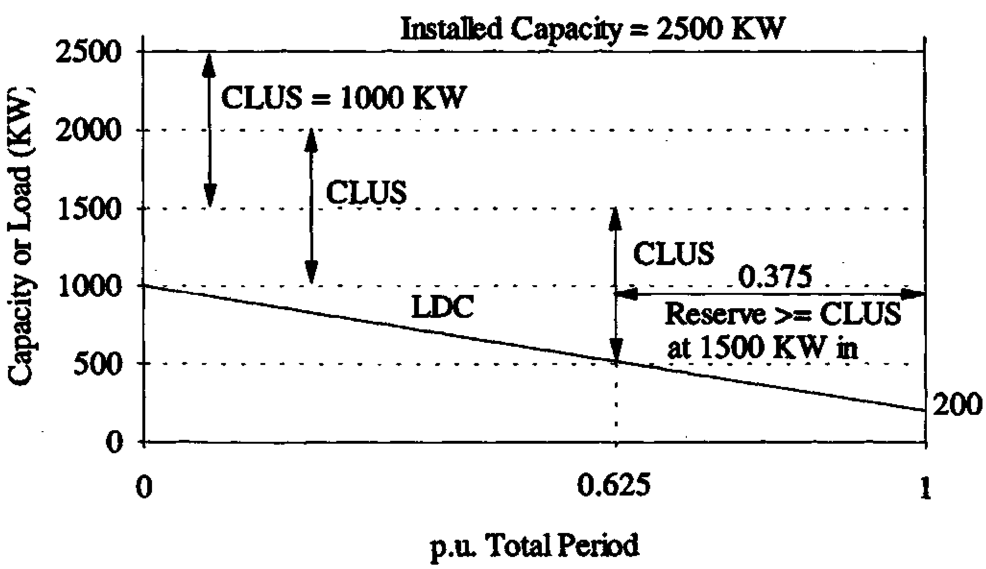


Fig. 3.6(b): Capacity and Load Conditions Given that Unit 1 is in

Fig. 3.6: Capacity and Load Conditions in the CPCOPT Method

The calculations involved in evaluating the probability of health are illustrated in Table 3.10. The P(H) is first evaluated for each condition. The system probability of health is determined by summing the products of each result and the corresponding conditional probability.

Table 3.10: Calculating the P(H) Using the CPCOPT Method

		Given Unit 1 Out x = 0 KW CLUS = 500 KW		Given Unit 1 In x = 1000 KW CLUS = 1000 KW	
Capacity In (KW)	Individual Probability	Reserve ≥ CLUS Time (p.u.)	C2 * C3	Reserve ≥ CLUS Time (p.u.)	C2 * C5
x + 1500	0.857375	1	0.857375	1	0.857375
x + 1000	0.135375	0.375	0.050766	1	0.135375
x + 500	0.007125	0	0	0.375	0.002672
x + 0	0.000125	0	0	0	0
		P(H) =	0.908141	P(H) =	0.995422

$$P(H) = P(H)_{1\ out} * P(1\ out) + P(H)_{1\ in} * P(1\ in)$$
$$= 0.908141 * 0.05 + 0.995422 * 0.95 = 0.991058$$

Step 3: The third step is to calculate the probability of margin:

$$P(M) = 1.0 - P(H) - LOLP$$
$$= 1.0 - 0.991058 - 0.000229 = 0.008713$$

The system health, margin and risk probabilities are 0.991058, 0.008713 and 0.000229 respectively. The LOHE is 78.33 h/yr

In order to further illustrate the CPCOPT method, another example is presented of a larger practical system with the following generation and load characteristics:

Unit 1 = 540 KW, 5% FOR Unit 2 = 270 KW, 5% FOR Unit 3 = 270 KW, 5% FOR
Unit 4 = 250 KW, 5% FOR Unit 5 = 250 KW, 5% FOR Unit 6 = 250 KW, 5% FOR

Peak Load = 1000 KW (The LDC for the system is shown in Fig. 3.7.)

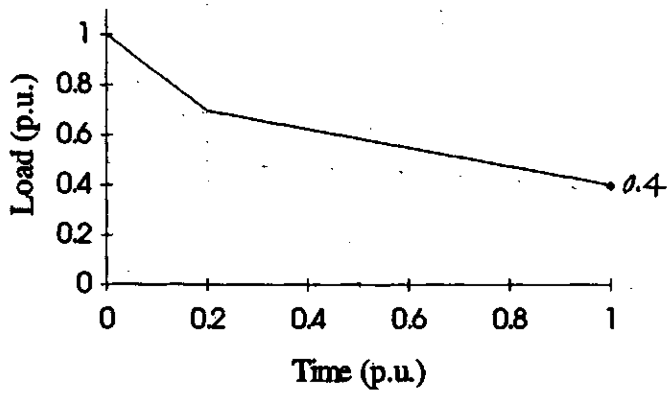


Fig. 3.7: System LDC

Tables 3.11 and 3.12 show the basic calculations.

Table 3.11: Calculating the LOLP by CCOPT Method

Cap In (KW)	Individual Probability	Outage Time (p.u.)	C2 * C3
1830	0.73509190	0	0
1580	0.11606710	0	0
1560	0.07737809	0	0
1330	0.00610880	0	0
1310	0.01221759	0	0
1290	0.04072531	0	0
1080	0.00010717	0	0
1060	0.00064303	0	0
1040	0.00643031	0	0
1020	0.00407253	0	0
810	0.00001128	0.12666667	0.00000143
790	0.00033844	0.14	0.00004738
770	0.00064303	0.15333333	0.00009860
750	0.00010717	0.16666667	0.00001786
540	0.00000594	0.62666667	0.00000372
520	0.00003384	0.68	0.00002301
500	0.00001692	0.73333333	0.00001241
270	0.00000059	1	0.00000059
250	0.00000089	1	0.00000089
0	0.00000002	1	0.00000002
		LOLP =	0.000206

Tables 3.12: Calculating the P(H) by the CPCOPT Method

Given Unit 1 is Out:

Given Unit 2 is Out:

		Given Unit 3 Out x = 0 KW CLUS = 250 KW		Given Unit 3 In x = 270 KW CLUS = 270 KW	
Cap In (KW)	Individual Probability	Reserve≥CLUS Time (p.u.)	C2 * C3	Reserve≥CLUS Time (p.u.)	C2 * C5
x + 750	0.857375	0.26666667	0.228633	0.83333333	0.714479
x + 500	0.135375	0	0	0.26666667	0.036100
x + 250	0.007125	0	0	0	0
x + 0	0.000125	0	0	0	0
		P(H) =	0.228633	P(H) =	0.750579

P(H) = 0.228633 * 0.05 + 0.750579 * 0.95 = 0.724482

Given Unit 2 is In:

CLUS = 270 KW

Cap In (KW)	Individual Probability	Reserve≥CLUS Time (p.u.)	C2 * C3
270 + 1020	0.81450625	1	0.814506
270 + 770	0.12860625	0.84666667	0.108887
270 + 750	0.04286875	0.83333333	0.035724
270 + 520	0.00676875	0.32	0.002166
270 + 500	0.00676875	0.26666667	0.001805
270 + 270	0.00011875	0	0
270 + 250	0.00035625	0	0
270 + 0	0.00000625	0	0
		P(H) =	0.963088

P(H) = 0.724482 * 0.05 + 0.963088 * 0.95 = 0.951157

Given Unit 1 is In:

CLUS = 540 KW

Cap In (KW)	Individual Probability	Reserve ≥CLUS Time (p.u.)	C2 * C3
540 + 1290	0.7737809	1	0.773781
540 + 1040	0.1221759	1	0.122176
540 + 1020	0.08145063	1	0.081451
540 + 790	0.00643031	0.86	0.005530
540 + 770	0.01286062	0.84666667	0.010889
540 + 750	0.00214344	0.83333333	0.001785
540 + 540	0.00011281	0.37333333	0.000042
540 + 520	0.00067688	0.32	0.000217
540 + 500	0.00033844	0.26666667	0.000090
540 + 270	0.00001187	0	0
540 + 250	0.00001781	0	0
540 + 0	0.00000031	0	0
		P(H) =	0.995961

Probability of System Health = 0.951157 * 0.05 + 0.995961 * 0.95 = 0.993721

Probability of Margin = 1.0 - 0.993721 - 0.000206 = 0.006073

The system health, margin and risk probabilities are 0.993721, 0.006073 and 0.000206 respectively. The LOHE is 55.19 h/yr.

3.4. Advantages of the Conditional Probability COPT Method over the Basic Contingency Enumeration Approach

The conditional probability COPT (CPCOPT) method is very similar to the conventional COPT (CCOPT) method used for evaluating the risk index, LOLP. The fact that the CCOPT method is widely employed in practical adequacy assessment clearly indicates its superiority over the basic contingency enumeration (CE) approach in evaluating LOLP or LOLE. For similar reasons, the CPCOPT method has distinct advantages over the contingency enumeration approach in evaluating the system health indices.

The capacity outage probability table (COPT) required in the new method is built using the same recursive technique (Equation 2.2) as that used in the CCOPT method and therefore a compact program applicable to any general system can be easily developed. The generation model also contains far less capacity levels compared to the CE approach because all the different contingencies in the latter approach which result in the same capacity level are grouped into one level in the new method. The previous examples show that the generation model of System X has 20 different contingencies and 16 more when derated units are considered using the CE approach. On the other hand, the COPT used by the new method has only 6 levels for risk evaluation and 4 levels for health evaluation and when the derated units are considered, only 5 more for risk and 3 more for health evaluation. Due to these reasons, the new method requires less computation time and memory space to build the generation model. Moreover, if a large number of generating units exist in the system or generating units with multiple states are involved, the CE approach becomes very cumbersome not only in terms of memory space and the computation time required but also in terms of developing a general program applicable to all system types.

In the CPCOPT method, the actual load duration curve is represented by a number of line segments, whereas, in the CE approach, it is represented by a number of discrete load levels. Therefore, a practical load duration curve is more accurately represented by the new method with comparatively far less load points. The CE approach will require a load model with a very large number of discrete steps in order to represent the load duration curve with the same accuracy. The new method is therefore very flexible in terms of easily incorporating a load model of any shape.

Once the COPT is developed in the CPCOPT method, it is repeatedly convolved with the load model to obtain the health indices. In the CE approach, all the different possible contingencies in the generation model must be convolved with all the numerous discrete load levels for the entire period. The load curve has to be divided into a large number of discrete loads in order to obtain reasonable accuracy in the results. The convolution of the generation model with the load model using the new method is much more efficient.

When a large number of units exist in a system, truncation of the generation model can be used to reduce the computer space and time at some cost in accuracy. In the CE approach, truncation is done by disregarding higher order contingencies. In the new method, truncation of the COPT is done by neglecting outage levels that result in a cumulative probability less than a practical value. A high order contingency does not always guarantee a low probability of occurrence as some of the contingencies of higher order may still have a significant probability.

The effect of truncating the generation model is significant with respect to the risk indices but has negligible effect on the calculation of the health indices. This is because the probability of the system being still healthy, after a large number of units are on outage, is insignificant. The new method exploits this fact to permit another type of truncation that reduces the computation time tremendously and yet produces the health indices with an accuracy much higher than that required for practical purposes. This truncation is done by recognizing only the few largest units in the system that may become the CLUS for comparison with the capacity reserve in order to determine the healthy states during the evaluation process. In health evaluation, when the largest unit in the system fails, the second largest unit becomes the CLUS. When the largest unit derates, the larger of the derated largest unit and the second largest unit becomes the CLUS. For the third largest unit to become the CLUS, both the first and second largest units in the system must be in the failed state. Similarly, for the fifth largest unit to be recognized as the CLUS, the four largest units in the system must have failed and the probability of the system then being healthy will be practically insignificant for virtually all systems. The probability of so many units all larger than the operating units being on outage simultaneously is very small. Truncating the generation model by recognizing only a few of the largest units as the probable CLUS for health evaluation greatly reduces the computation time without losing reasonable accuracy. The accuracy can be increased as desired by recognizing more units as the probable CLUS but with additional computation time.

The program SIPSREL identifies only the four largest units in the system for the purpose of comparison with the available reserve to determine if a system resident state is healthy. If more than four units, all larger than the remaining operating units, are out simultaneously, then the capacity of the fourth unit is assumed to be the CLUS. Despite this approximation, which saves considerable computer memory and computation time, the results obtained are well above the desired accuracy for practical purposes. This can be explained better with an example. Consider a system that has more than 5 units, each with a 5% FOR. The probability of more than four units, all larger than the remaining operating units, being on outage simultaneously is less than 0.05^5. At this stage, the probability of the reserve exceeding the CLUS, is extremely small. Assume that there is still a 10% chance of the system being healthy at this stage. A probability less than $0.05^5 * 0.1 = 0.00000003125$ will have been missed from the calculated probability of system health. It should not be perceived that the contingencies, for which more than four largest units are on outage simultaneously, are totally disregarded. This is not the case. All of these contingencies are considered in the COPT but the fourth largest unit is always taken as the CLUS during these contingencies. If the fifth largest unit in the system has the same size as the fourth largest unit, then a probability less than $0.05^6 * 0.1 = 1.5625E\text{-}9$ will have been missed from the calculated probability of health. For practical purposes, a probability of health index using four digits is more than reasonable. If the system had 20 generating units, the CE approach must take into account up to the tenth order of contingencies to achieve an equivalent accuracy ($260338 * 0.05^{10} * 0.95^{10} + 167960 * 0.05^{11} * 0.95^9 + 125970 * 0.05^{12} * 0.95^8 + \cdots > 1.576E\text{-}8$). This will result in $2^{20} / 2 = 524228$ contingencies.

In a small isolated system with a few generating units and a practical load duration curve, the health indices can easily be hand-calculated using the CPCOPT method. This is not the case with the CE approach.

3.5 Evaluation of Health Indices Using Monte Carlo Simulation

The evaluation of the system health and margin indices using Monte Carlo simulation is quite similar to the evaluation of risk indices. The advantages and limitations of the

MCS method have been described in the previous chapter. The main advantage of employing MCS in health analysis is to create the distributions of the health indices about their mean values. MCS also reveals additional information about the system health which can be quantified in terms of frequency and duration indices. These indices are developed in this thesis in a similar manner to the basic frequency and duration risk indices used in generating capacity adequacy assessment. The new health indices are introduced and described in this chapter.

The basic approach when applying MCS to health analysis is the same as that for risk analysis. The power system is modeled by specifying a set of "events" where an event is a random or deterministic occurrence that changes the "state" of the system [10]. All the assumptions and system parameters specified for risk analysis in Section 2.7 are applied here. The generation model required for health analysis and its superimposition on the load model are presented to illustrate the evaluation methodology.

3.5.1 Generation Model

It has been assumed in Section 2.7 that a generating unit can reside in either the up, down or derated states. The resident times are calculated by Equations (2.12 - 2.14). The state histories for all the individual units are generated on a time dependent basis and combined to form an outage history of the total system capacity. The CLUS among the operating units is identified at each change of state of the total system capacity and a history of the total capacity less the corresponding CLUS is also generated on a time dependent basis. The generation model, required for the MCS method, contains the outage history of the total capacity accompanied by the history of the total capacity less the corresponding CLUS at each capacity state. The generation model used for the evaluation of the health indices is shown in Fig. 3.8.

3.5.2 Combining the Generation and Load Models

The generation model is combined with the load model to obtain the health indices. The annual hourly load profile in which the load changes discretely every hour and is constant throughout the hour is used as the load model. The total capacity of the system available at every hour is superimposed on the load in that hour as shown in Fig. 3.9 in order to evaluate the capacity reserves. Whenever the capacity reserve is greater than or equal to the corresponding CLUS, the state is healthy and the duration 't(H)$_i$' for each of these healthy states is calculated. On the other hand, whenever the capacity reserve is less than the corresponding CLUS but greater than zero, the state is marginal and the duration 't(M)$_i$' for each of these marginal states is calculated. The total number of healthy states, 'n(H)', and the total number of marginal states 'n(M)', are recorded in order to calculate the health indices using Equations (3.2-3.5). The shaded area in Fig. 3.9 is the unsupplied energy 'x_i' for a duration 't(R)$_i$' at an interruption 'i' and are calculated to obtain the risk indices using Equations (2.15-2.21) as described in Section 2.7

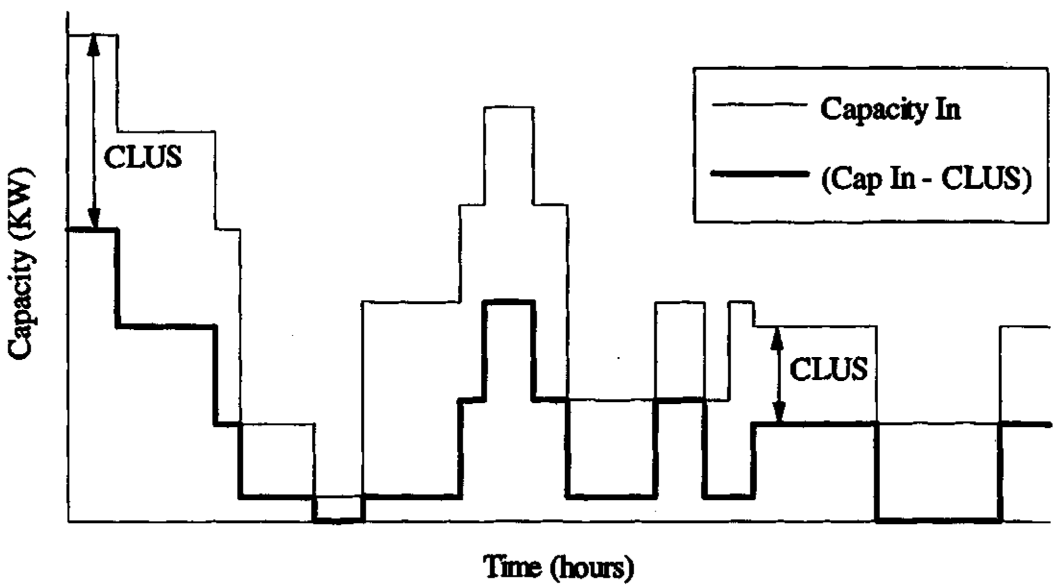


Fig. 3.8: Generation Model for System Health Evaluation by MCS

Equations (3.2 - 3.5) are used to calculate the basic health indices.

$$\text{Loss of health expectation, LOHE} = \text{Year in hrs} - \frac{\sum_{i=1}^{n(H)} t(H)_i}{N} \quad \text{(h/yr)} \qquad (3.2)$$

where, N = total number of simulated years

$$\text{Probability of health, } P(H) = \frac{\sum_{i=1}^{n(H)} t(H)_i}{N * \text{Year in hrs}} \tag{3.3}$$

$$\text{Probability of margin, } P(M) = \frac{\sum_{i=1}^{n(M)} t(M)_i}{N * \text{Year in hrs}} \tag{3.4}$$

$$\text{Probability of risk, LOLP} = \frac{\sum_{i=1}^{n(R)} t(R)_i}{N * \text{Year in hrs}} \tag{3.5}$$

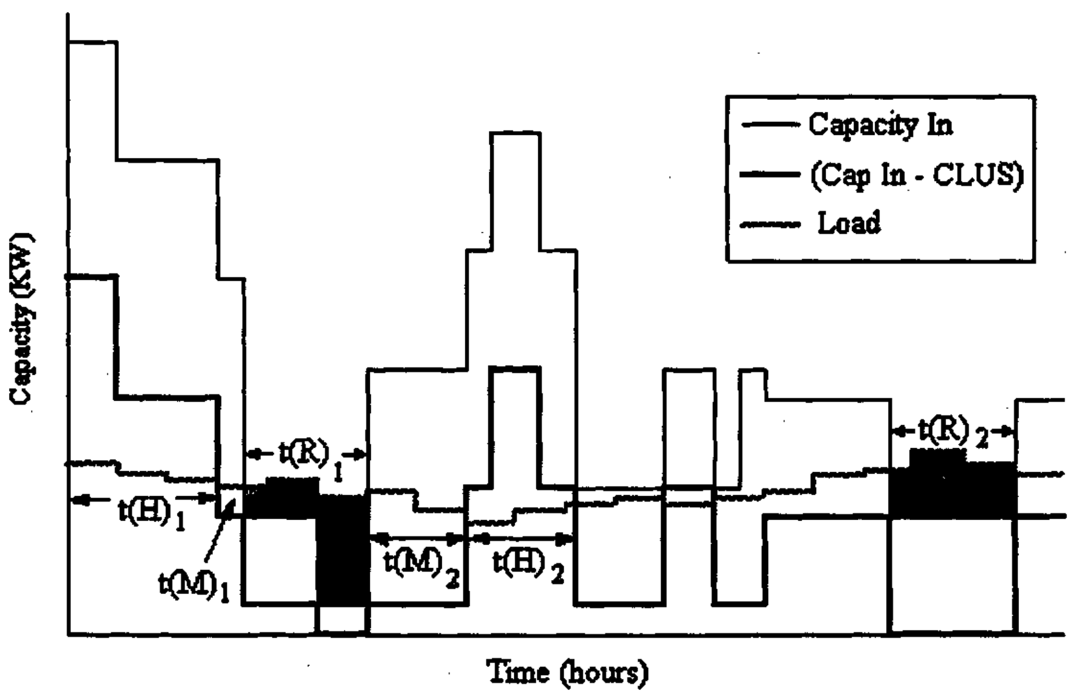


Fig. 3.9: Combining Generation Model and Load Model

Equations (3.6 - 3.8) are used to calculate the additional frequency and duration health indices. The frequency of margin in Equation (3.6) measures the expected number of times the marginal states are encountered in a year. In other words, it is the number of occurrences when the system is on the brink of failure. When the system risk is relatively high (i.e. not far below the accepted criterion), it is very desirable that the frequency of margin be relatively low. Using this index, the system planner can visualize the well being of the system in terms of the number of times it is exposed to situations when the reserve is inadequate from a deterministic perspective.

$$\text{Frequency of margin, } F(M) = \frac{n(M)}{N} \text{ (margin/yr)} \tag{3.6}$$

The expected health duration given by Equation (3.7) measures the average duration of the system in the healthy state. A higher expected health duration represents a more comfortable system at the same probability of health as it implies that the system slips away from the healthy state less often. This index provides additional system information to the basic probability of health.

$$\text{Expected health duration, EHDUR} = \frac{\sum_{i=1}^{n(H)} t(H)_i}{n(H)} \text{ (hr/healthy state)} \tag{3.7}$$

The expected margin duration given by Equation (3.8) is the average duration of the system in a marginal state. For the same probability of margin, the frequency of margin and the expected margin duration are inversely related. As to which of the two indices should be considered for a higher degree of system comfort is entirely dependent on the operating policies.

$$\text{Expected margin duration, EMDUR} = \frac{\sum_{i=1}^{n(M)} t(M)_i}{n(M)} \text{ (hr/ marginal state)} \tag{3.8}$$

3.6 Conclusion

System well-being analysis forms a bridge between the deterministic and probabilistic methods and defines indices that may be useful in practical adequacy assessment of SIPS. The probability of health, margin and risk are the basic system well-being indices. LOHE and three other frequency and duration indices, frequency of margin, expected health duration and expected margin duration are new indices introduced in this thesis.

Previous work in this area has been done using the contingency enumeration approach. A new analytical method known as the Conditional Probability COPT Method has been developed in this research work which is very efficient with respect to computation time and computer memory compared to the contingency enumeration approach. The new method has also made it possible to easily hand-calculate the health indices for a small system with a practical load curve.

The system well-being indices have also been evaluated using MCS methods in this research work. The average values and the distributions of the basic health indices and additional frequency and duration health indices can be easily estimated using the MCS method.

The existing methods and the new techniques developed in this research have been described and their methodologies illustrated in this chapter. The new techniques have been used in the program SIPSREL to evaluate the health indices presented in the subsequent case studies in this thesis.

4. SIPSREL: A SOFTWARE PACKAGE FOR ADEQUACY ASSESSMENT OF SMALL ISOLATED POWER SYSTEMS

4.1 Introduction

A software package named SIPSREL (Small Isolated Power System Reliability) has been developed during the research work for this thesis. The program contains probabilistic methods for adequacy studies on SIPS. The software can also be used for generating capacity adequacy assessment of larger systems. It is a menu-driven software package run on a PC with a minimum requirement of a 80286 microprocessor, 1 MB of memory, a Windows compatible display and Windows 3.0 or later operating system.

SIPSREL is composed of several different programs using analytical techniques and Monte Carlo simulation methods that can be activated very easily through graphical user interfacing to perform a specific adequacy assessment task. The evaluation techniques used in SIPSREL and the indices that can be evaluated are shown in Fig. 4.1.

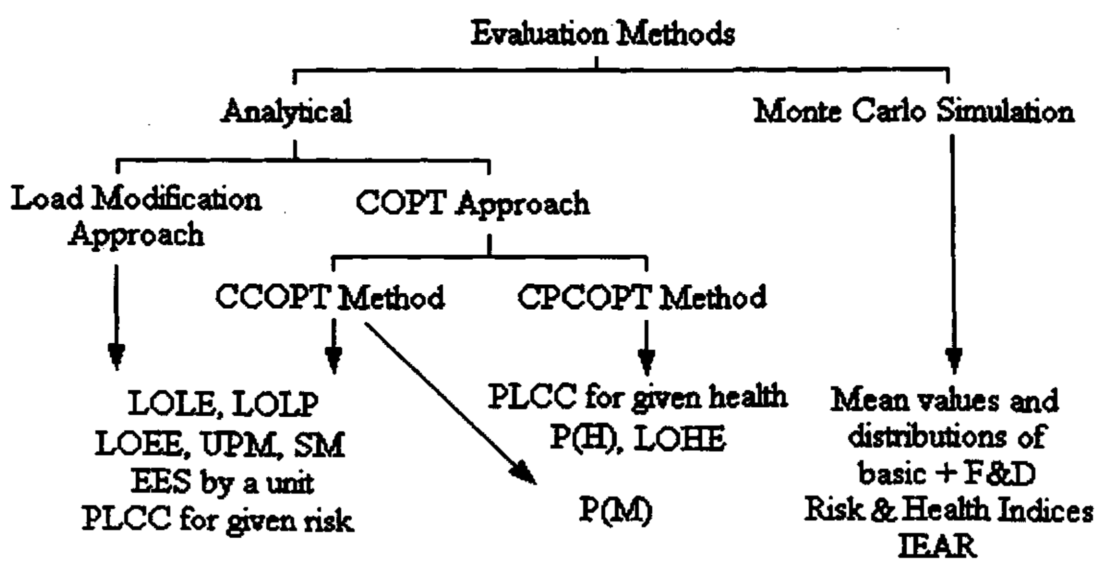


Fig. 4.1: Evaluation Methods used in SIPSREL

4.2 Analytical Methods in SIPSREL

The basic approach in analytical methods for risk analysis or system well-being analysis is to form a generation model and a load model and to convolve the two to obtain the risk or health indices described in Chapters 2 and 3. The generation model for SIPSREL requires the capacity, the FOR and the identification (ID) number of each unit in the system as the input data, arranged in the priority order. It can also incorporate generating units that may reside in one or more derated states. This flexibility not only takes into account unit deratings due to partial failure but also the first type of energy limitation discussed in Chapter 2, in which the capacity outputs depend on the flow availabilities of the substance that operates the prime mover such as a run-of-the-river hydro unit. The different capacity states for each unit and their corresponding probabilities are the required input data in this case. The load model may either be a fixed load to evaluate annualized indices or a DPLVC or a LDC represented by any number of points joined by line segments. The points of the load curve, the peak load and the total period under study are the required data for the load model.

The load forecast uncertainty may be considered as desired in any evaluation using SIPSREL. The LFU is represented by a discrete normal distribution as described in Chapter 2. The discrete steps denoting the deviations from the mean peak load and their corresponding probabilities are the required input data.

Planned maintenance may be taken into account if required. SIPSREL assumes that only one unit is out for maintenance at a time. This means that any number of units can be out for maintenance during the total period but overlapping maintenance outages are not allowed. The ID number of the unit on maintenance, the maintenance duration and the peak load within that duration are the required input data. Inclusion of planned maintenance in well-being analysis is not available in SIPSREL.

Energy limitations for units with storage facilities, as described in Chapter 2, can be considered if desired. The selection of this option by the user will activate a program that uses the load modification approach. When the effect of these types of energy limited units are included in the evaluation, the available energy states and their cumulative probabilities are additional data required in the generation model. SIPSREL does not have this option in the well-being analysis.

The different evaluation tasks that can be performed by SIPSREL using analytical techniques are listed below:

1. Evaluation of conventional probabilistic indices
   i) Change in system risk with peak load
   ii) Change in PLCC with system risk

2. Evaluation of expected energy supplied by each generating unit

3. Evaluation of system well-being indices
   i) Change in well-being indices with peak load
   ii) Change in PLCC with system health and risk

While performing any of the above evaluation tasks, the user can include the effects of load forecast uncertainty, planned maintenance, energy limitations, annualized fixed load or load curve shapes. The workbench in SIPSREL is shown in Fig. 4.2 from where the user can make a selection for a specific evaluation task and choose options to include the effects of one or more of those factors. SIPSREL shows the results not only in the numerical tabular form but also in the form of a graphical display.

4.3 Application of Analytical Tools in SIPSREL

The analytical tools available in the software SIPSREL can be used in a variety of adequacy studies and can take into account different factors that effect the analysis. A test system designated as System B is used as an example to illustrate all the different types of evaluation that can be done using the analytical techniques within SIPSREL. The generating facilities in System B are given in Table 4.1.

Table 4.1: Generating System of Test System B

Unit ID#	Type	Size (KW)	FOR (%)	Loading Order
1	Hydro	750	2	1
2	Diesel	500	5	3
3	Diesel	250	4	4
4	Diesel	500	5	2

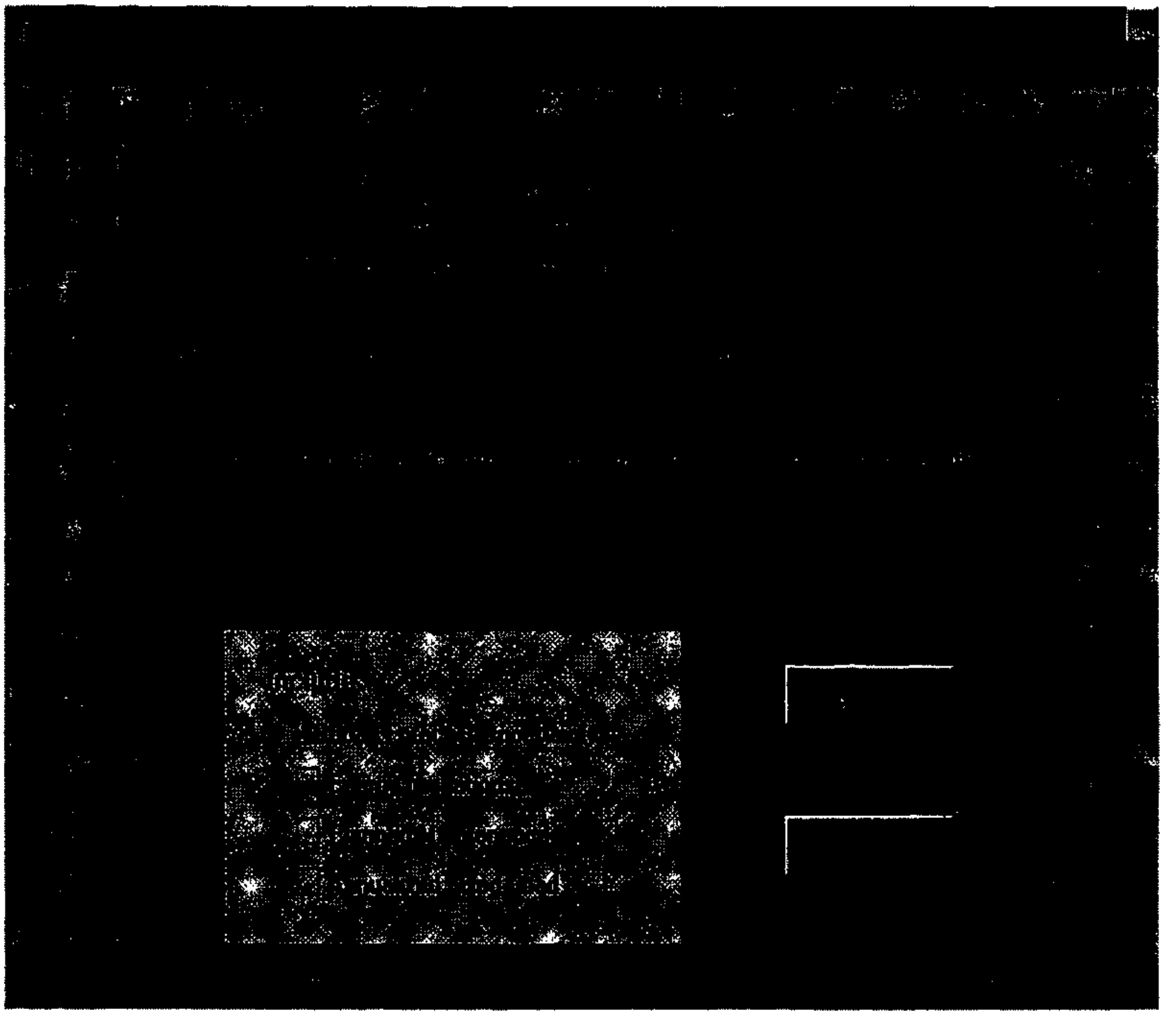


Fig. 4.2: Workbench in SIPSREL for Selecting an Evaluation Task

Unit #1 is a run-of-the-river hydro unit and its capacity output is dictated by the flow of the river. The output capacities and their corresponding probabilities of this energy limited unit are given in Table 4.2.

Table 4.2: Probable Output States of the Run-of-the-river Hydro Unit

Output Capacity (KW)	Individual Probability
0	0.020
250	0.192
500	0.480
750	0.308

Unit #2 can also reside in a derated state as shown in Table 4.3.

Table 4.3: Resident States of Unit #2

Output Capacity (KW)	Individual Probability
0	0.05
250	0.30
500	0.65

The load model for System B can be represented by either a load duration curve (LDC) as given in Table 4.4 or a daily peak load variation curve (DPLVC) as shown in Table 4.5. Both the load curves are illustrated in Fig. 4.2a. The peak load for the system is 1000 KW.

Table 4.4: LDC for System B

p.u. Period	0.0000	0.0064	0.0187	0.0513	0.1193	0.2979	0.7876	0.9539	1.0000
p.u. PL	1.0000	0.8506	0.8046	0.7471	0.6897	0.5977	0.4253	0.3333	0.2069

Table 4.5: DPLVC for System B

p.u. Period	0.0000	0.0064	0.0187	0.0513	0.1193	0.2979	0.7876	0.9539	1.0000
p.u. PL	1.0000	0.8510	0.8060	0.7500	0.6940	0.6030	0.4300	0.3400	0.2200

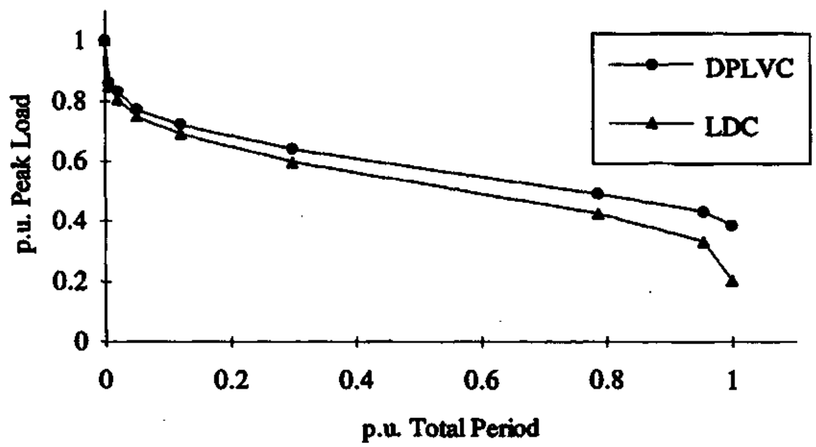


Fig. 4.2a: LDC and DPLVC for System B

A 6% annual increase in the yearly peak load has been predicted for System B. The forecast peak loads are given in Table 4.6.

Table 4.6: Annual Peak Load Forecast for System B

Year	1	2	3	4	5	6	7	8	9	10
PL (KW)	1060	1124	1191	1262	1338	1419	1504	1594	1689	1791

The load forecast uncertainty data used in the example is given in Table 4.7. The generating unit planned maintenance data for the year under study is shown in Table 4.8.

Table 4.7: Load Forecast Uncertainty Data for System B

Deviation From Mean Peak Load (%)	Probability
-9	0.006
-6	0.061
-3	0.242
0	0.382
+3	0.242
+6	0.061
+9	0.006

Table 4.8: Unit Maintenance Data for System B

Unit ID#	Maintenance Duration (hrs)	PL During Maintenance (p.u. of System PL)
2	120	0.85
3	48	0.92
4	72	0.76

4.3.1 Analytical Tools Employing the COPT Approach

The analytical tools in SIPSREL employ either the COPT approach or the load modification approach as illustrated in Fig. 4.1. The default setting is the COPT approach. The COPT is truncated for capacity outage states having cumulative probabilities less than 1E-08. The evaluations relating to system risk and production costs are done using the CCOPT method, whereas, evaluations of system health are done using the CPCOPT method. Whenever the CCOPT or CPCOPT methods are used by SIPSREL, the capacity outage probability table can also be viewed by the user as shown in Table 4.9.

Table 4.9: Capacity Outage Probability Table for System B

Capacity Out (KW)	Cumulative Probability
0	1.00000000
250	0.81741760
500	0.44099720
750	0.15683000
1000	0.03994360
1250	0.00767120
1500	0.00105720
1750	0.00008120
2000	0.00000200

Evaluation of Conventional Risk Indices

The LOLE, LOEE, UPM or SM can be calculated by SIPSREL for different peak loads using the LDC as the load model. The output from SIPSREL displays a table with values of the four indices at the different peak loads. A graph of each of these four indices can also be displayed by clicking them from a list box.

The risk indices for the forecast peak loads given in Table 4.6 are shown as obtained from SIPSREL, in Table 4.10 and Fig. 4.3 - 4.6.

Table 4.10: Risk Indices at Different Peak Loads (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	8.4971	0.971	208.625	58.250
1.060	12.6836	1.408	285.510	79.717
1.124	17.7388	2.076	396.985	110.842
1.191	23.8257	3.024	545.702	152.365
1.262	33.3755	4.398	748.902	209.101
1.338	48.9606	6.603	1060.484	296.097
1.419	71.1339	10.039	1520.234	424.464
1.504	101.9392	15.044	2149.500	600.161
1.594	152.3477	23.026	3104.146	866.708
1.689	213.2440	35.195	4477.904	1250.274
1.791	311.2094	53.792	6454.233	1802.084

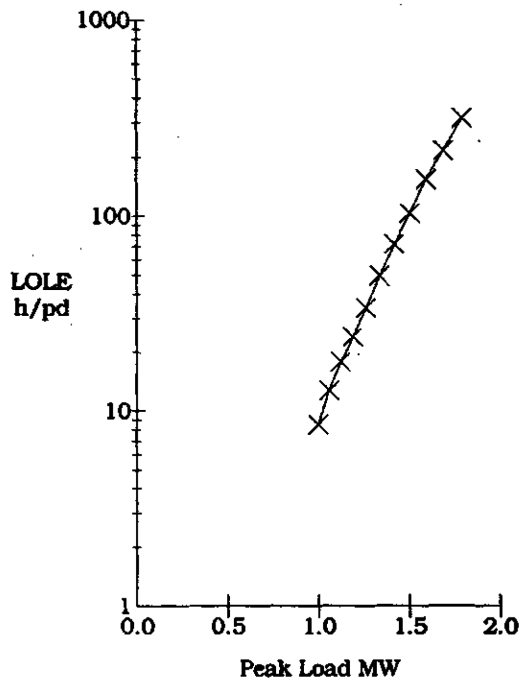


Fig. 4.3: LOLE at Different Peak Loads (Graph from SIPSREL)

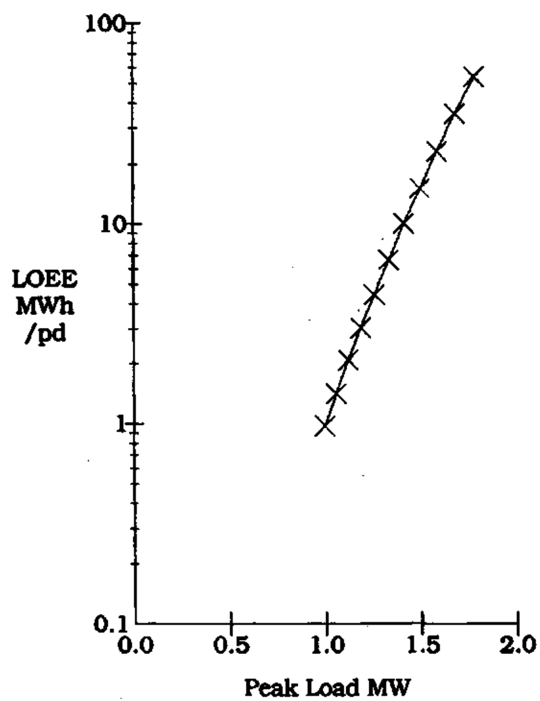


Fig. 4.4: LOEE at Different Peak Loads (Graph from SIPSREL)

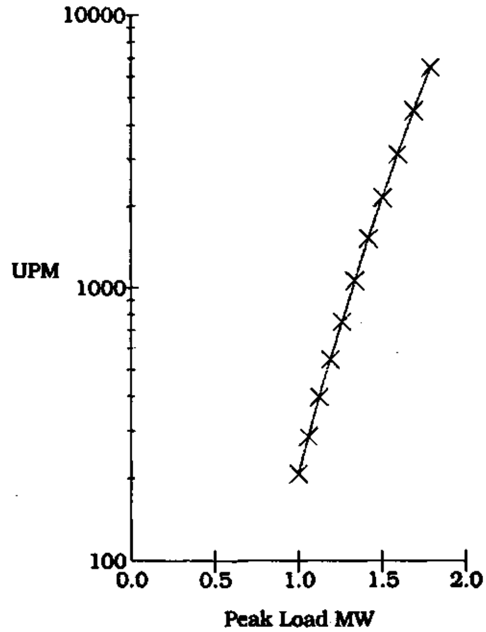


Fig. 4.5: UPM at Different Peak Loads (Graph from SIPSREL)

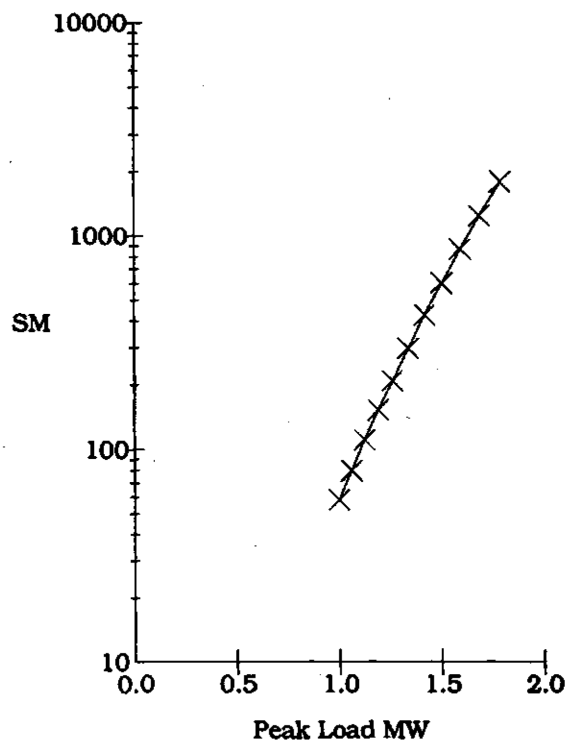


Fig. 4.6: SM at Different Peak Loads (Graph from SIPSREL)

Table 4.11 shows the results when the load forecast uncertainty given in Table 4.7 is taken into account. Graphical results similar to Fig. 4.3 - 4.6 can also be obtained from SIPSREL if desired.

Table 4.11: Risk Indices at Different Peak Loads with LFU (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	8.8599	0.989	211.561	59.070
1.060	12.7373	1.435	289.426	80.810
1.124	17.7627	2.111	401.521	112.109
1.191	24.2181	3.078	552.348	154.221
1.262	34.3272	4.503	762.548	212.911
1.338	50.1547	6.751	1077.929	300.968
1.419	71.8659	10.225	1539.518	429.848
1.504	103.9645	15.421	2190.329	611.561
1.594	152.8935	23.560	3156.774	881.402
1.689	218.1604	35.967	4548.551	1270.000
1.791	317.9407	55.068	6567.292	1833.652

risk 3

The results obtained, when the planned maintenance given in Table 4.8 is taken into account, are shown in Table 4.12. Graphical results similar to Fig. 4.3 - 4.6 can also be obtained from SIPSREL.

Table 4.12: Risk Indices Considering Planned Maintenance (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	9.4260	1.069	235.055	65.630
1.060	13.8317	1.538	318.638	88.967
1.124	19.1854	2.248	438.445	122.418
1.191	25.6852	3.251	597.727	166.891
1.262	35.8259	4.703	815.230	227.620
1.338	52.0801	7.012	1145.009	319.698
1.419	75.1423	10.588	1628.275	454.630
1.504	107.2089	15.786	2288.452	638.958
1.594	158.9520	24.023	3282.426	916.485
1.689	221.8991	36.534	4706.637	1314.139
1.791	322.3840	55.597	6748.837	1884.341

The results when both LFU and planned maintenance of the generating units are considered in the evaluation, are shown in Table 4.13 and Fig. 4.7 - 4.10.

Table 4.13: Risk Indices with LFU & Planned Maintenance (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	9.7861	1.089	238.131	66.488
1.060	13.8900	1.567	322.719	90.106
1.124	19.2183	2.285	443.246	123.759
1.191	26.1032	3.307	604.821	168.872
1.262	36.7753	4.811	829.247	231.534
1.338	53.2837	7.164	1163.016	324.725
1.419	75.9090	10.781	1648.424	460.256
1.504	109.2174	16.170	2330.223	650.621
1.594	159.6088	24.567	3336.312	931.531
1.689	226.8492	37.319	4778.784	1334.283
1.791	329.0634	56.886	6863.504	1916.357

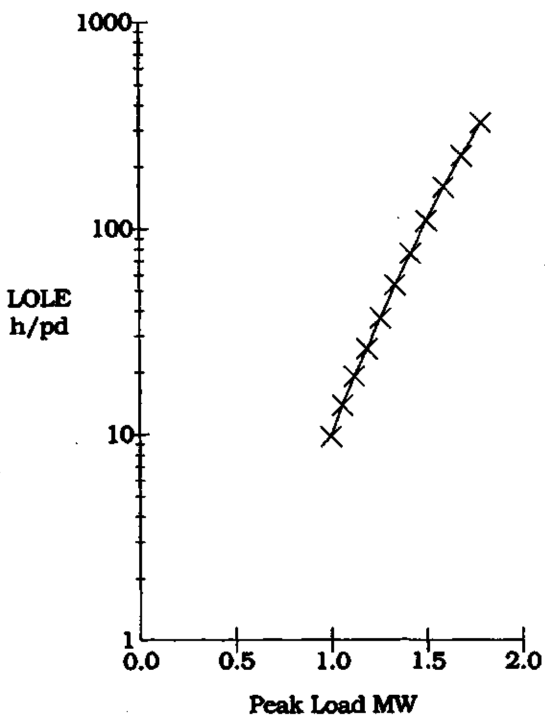


Fig. 4.7: LOLE with LFU & Planned Maintenance (Graph from SIPSREL)

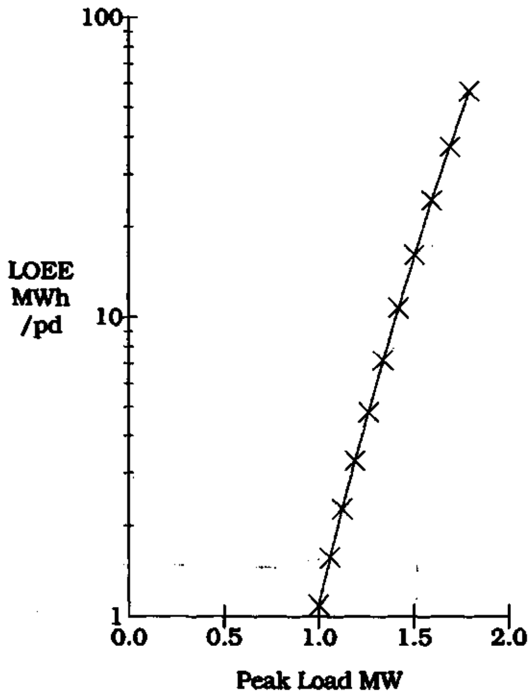


Fig. 4.8: LOEE with LFU & Planned Maintenance (Graph from SIPSREL)

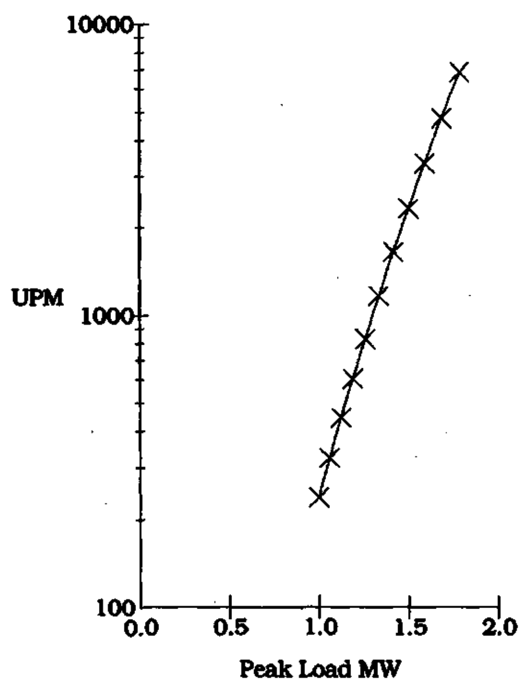


Fig. 4.9: UPM with LFU & Planned Maintenance (Graph from SIPSREL)

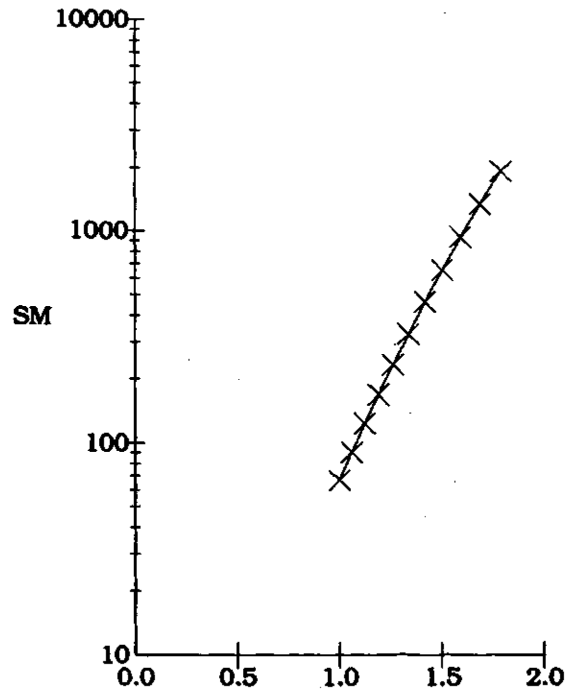


Fig. 4.10: SM with LFU & Planned Maintenance (Graph from SIPSREL)

The LOLE can also be calculated at different peak loads using the DPLVC in the load model. The LOLE for the forecast peak loads given in Table 4.6 are shown as obtained from SIPSREL, in Table 4.14 and Fig. 4.11.

Table 4.14: LOLE Using DPLVC (Table from SIPSREL)

PL(MW)	LOLE(d/pd)
1.000	0.3631
1.060	0.5449
1.124	0.7657
1.191	1.0215
1.262	1.4421
1.338	2.1188
1.419	3.0595
1.504	4.3975
1.594	6.5458
1.689	9.2554
1.791	13.3942

r,ßk2

The LOLE for System B can also be calculated as in the above cases to include the effect of load forecast uncertainty or planned maintenance using the DPLVC. The results including both factors are shown in Table 4.15 and Fig. 4.12.

Table 4.15: LOLE Using DPLVC Including LFU & Maintenance (Table from SIPSREL)

PL(MW)	LOLE(d/pd)
1.000	0.4197
1.060	0.5985
1.124	0.8284
1.191	1.1204
1.262	1.5829
1.338	2.2986
1.419	3.2733
1.504	4.7069
1.594	6.8612
1.689	9.7945
1.791	14.1989

The annualized LOLE can also be calculated by SIPSREL using only the annual peak loads in the load model. It may be calculated with or without considering LFU. The effect of planned maintenance cannot be incorporated when evaluating the LOLE at a fixed load throughout the year. The results obtained with LFU taken into consideration are shown in Table 4.16 and Fig. 4.13.

Table 4.16: Annualized LOLE Including LFU (Table from SIPSREL)

PL(MW)	Annualized LOLE(d/yr)
1.000	6.4398
1.060	13.7902
1.124	14.5794
1.191	17.4379
1.262	44.0599
1.338	56.9870
1.419	64.1923
1.504	128.9142
1.594	154.0147
1.689	170.1693
1.791	255.9028

Ude Wh. 8

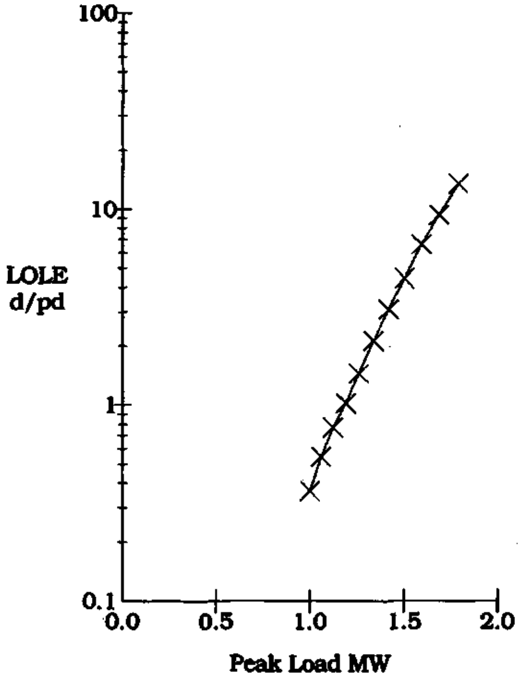


Fig. 4.11: LOLE Using DPLVC (Graph from SIPSREL)

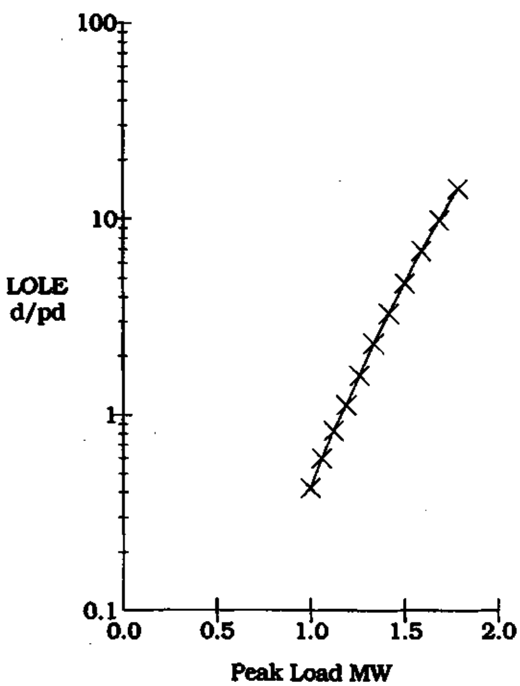


Fig. 4.12: LOLE Using DPLVC Including LFU & Maintenance (Graph from SIPSREL)

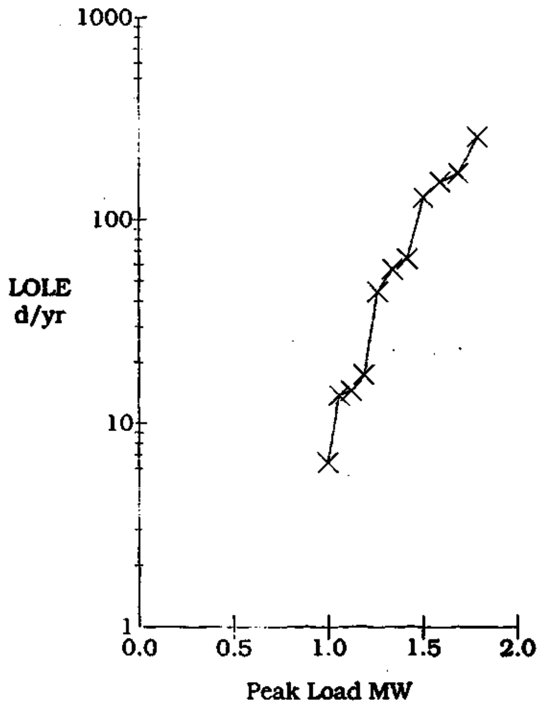


Fig. 4.13: Annualized LOLE Including LFU (Graph from SIPSREL)

Evaluation of PLCC for Different Risk Criteria

The peak load carrying capabilities for selected LOLE, LOEE, UPM or SM criteria can be obtained from SIPSREL using the LDC in the load model. The PLCC of System B for LOLE of 10, 20, 30, 40 and 50 h/yr are shown in Table 4.17 and Fig. 4.14.

Table 4.17: PLCC at Different LOLE Criteria (Table from SIPSREL)

LOLE(h/pd)	PLCC(MW)
10.0000	1.022
20.0000	1.151
30.0000	1.245
40.0000	1.293
50.0000	1.342

The PLCC of System B for LOEE of 1.5, 3.0, 4.5, 6.0 and 7.5 MWh/yr are shown in Table 4.18 and Fig. 4.15.

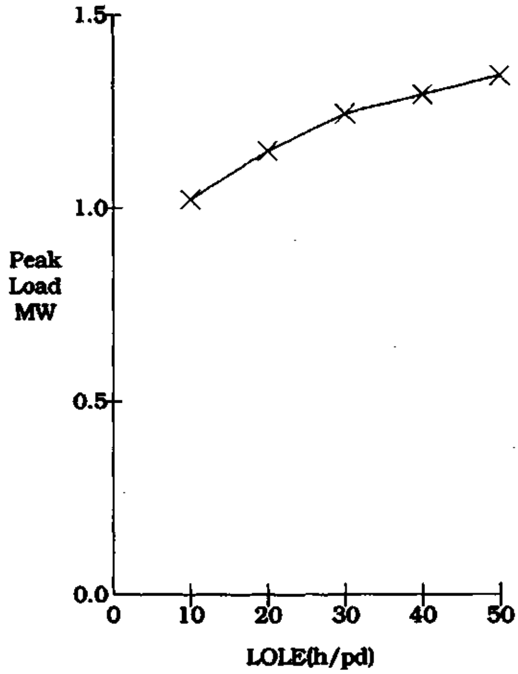


Fig. 4.14: PLCC for Different LOLE Criteria (Graph from SIPSREL)

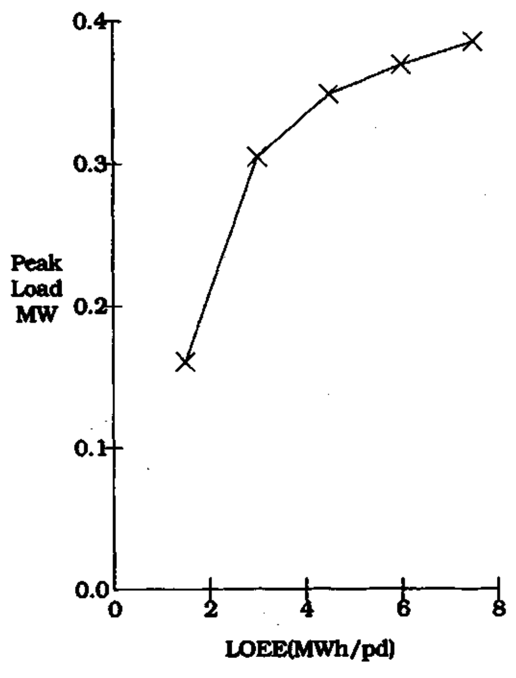


Fig. 4.15: PLCC for Different LOLE Criteria (Graph from SIPSREL)

Table 4.18: PLCC for Different LOEE Criteria (Table from SIPSREL)

LOEE(MWh/pd)	PLCC(MW)
1.5000	0.161
3.0000	0.305
4.5000	0.349
6.0000	0.370
7.5000	0.386

The PLCC of System B for UPM of 100, 200, 300, 400 and 500 are shown in Table 4.19 and Fig. 4.16

Table 4.19: PLCC for Different UPM Criteria (Table from SIPSREL)

UPM	PLCC(MW)
100.0000	0.856
200.0000	0.991
300.0000	1.069
400.0000	1.125
500.0000	1.172

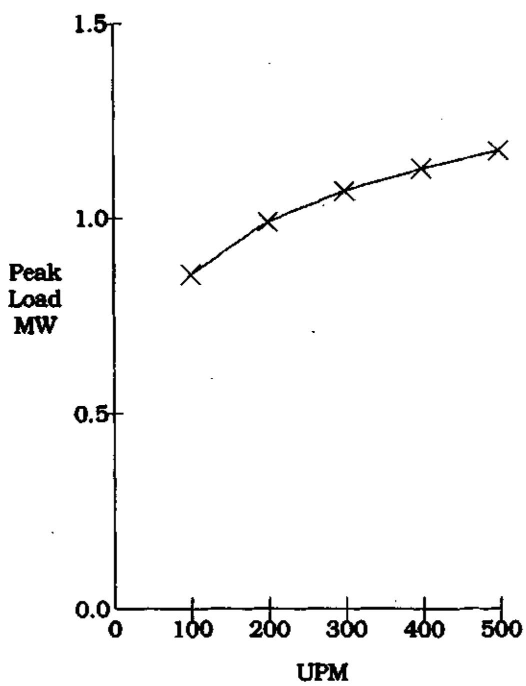


Fig. 4.16: PLCC for Different UPM Criteria (Graph from SIPSREL)

The PLCC of System B for SM of 50, 100, 150, 200 and 250 are shown in Table 4.20 and Fig. 4.17.

Table 4.20: PLCC for Different SM Criteria (Table from SIPSREL)

SM	PLCC(MW)
50.0000	0.970
100.0000	1.104
150.0000	1.187
200.0000	1.252
250.0000	1.301

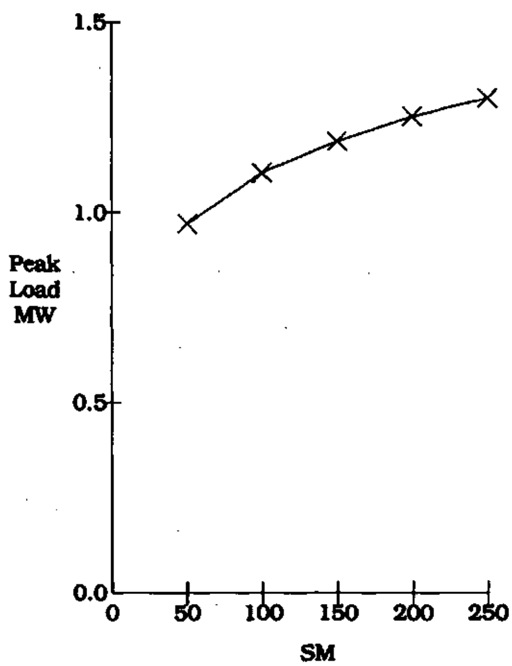


Fig. 4.17: PLCC for Different SM Criteria (Graph from SIPSREL)

The effect of LFU or planned maintenance or both can be incorporated while calculating the PLCC for selected different LOLE, LOEE, UPM or SM risk criteria. The output tables obtained from SIPSREL for each of these evaluations are grouped together in Tables 4.21 - 4.24. Graphical results similar to Fig. 4.14 - 4.17 can also be displayed in SIPSREL.

Table 4.21: PLCC for Different LOLE with LFU and Maintenance Considerations

Risk Criterion LOLE (h/yr)	PLCC (MW)		
	LFU Considered	Maintenance Considered	LFU & Maint. Considered
10	1.019	1.009	1.004
20	1.149	1.133	1.132
30	1.236	1.226	1.221
40	1.292	1.281	1.279
50	1.337	1.328	1.324

Table 4.22: PLCC for Different LOEE with LFU and Maintenance Considerations

Risk Criterion LOEE (MWh/yr)	PLCC (MW)		
	LFU Considered	Maintenance Considered	LFU & Maint. Considered
1.5	0.161	0.111	0.111
3.0	0.303	0.221	0.221
4.5	0.348	0.313	0.312
6.0	0.369	0.349	0.348
7.5	0.385	0.369	0.368

Table 4.23: PLCC for Different UPM with LFU and Maintenance Considerations

Risk Criterion UPM	PLCC (MW)		
	LFU Considered	Maintenance Considered	LFU & Maint. Considered
100	0.855	0.831	0.830
200	0.989	0.967	0.965
300	1.067	1.048	1.046
400	1.123	1.105	1.103
500	1.169	1.151	1.149

Table 4.24: PLCC for Different SM with LFU and Maintenance Considerations

Risk Criterion SM	PLCC (MW)		
	LFU Considered	Maintenance Considered	LFU & Maint. Considered
50	0.967	0.945	0.943
100	1.101	1.083	1.081
150	1.185	1.167	1.165
200	1.248	1.232	1.229
250	1.297	1.283	1.279

The PLCC of a system for different LOLE criteria in d/yr can also be calculated using the DPLVC in the load model. The PLCC of System B for LOLE of 1.0, 1.5, 2.0, 2.5 and 3.0 d/yr are shown in Table 4.25 and Fig. 4.18.

Table 4.25: PLCC for Different LOLE using the DPLVC (Table from SIPSREL)

LOLE(d/pd)	PLCC(MW)
1.0000	1.187
1.5000	1.268
2.0000	1.326
2.5000	1.370
3.0000	1.413

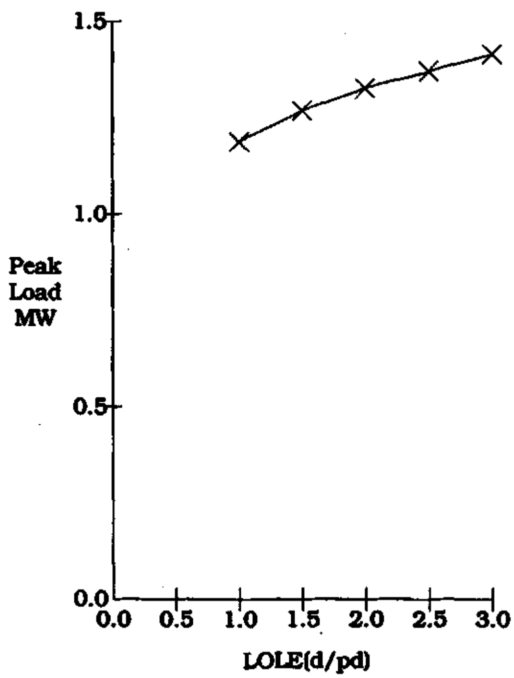


Fig. 4.18: PLCC for Different LOLE using the DPLVC (Graph from SIPSREL)

The effect of LFU or planned maintenance or both can be incorporated while calculating the PLCC at different LOLE criteria using the DPLVC as the load model. The output tables obtained from SIPSREL for each of these evaluations are grouped together in Table 4.26. Graphical results similar to Fig. 4.14 - 4.17 are also displayed by SIPSREL.

Table 4.26: PLCC Using DPLVC and Considering LFU and Maintenance

Risk Criterion LOLE (d/yr)	PLCC (MW)		
	LFU Considered	Maintenance Considered	LFU & Maint. Considered
1.0	1.183	1.171	1.166
1.5	1.265	1.257	1.252
2.0	1.321	1.311	1.308
2.5	1.369	1.358	1.356
3.0	1.411	1.399	1.398

The PLCC of a system for different annualized LOLE criteria can also be calculated by SIPSREL. It may be calculated with or without considering LFU. The effect of planned maintenance cannot be incorporated when a fixed load is assumed throughout the year. The results obtained considering LFU are shown in Table 4.27 and Fig. 4.19.

Table 4.27: PLCC for Annualized LOLE with LFU (Table from SIPSREL)

LOLE(d/pd)	PLCC(MW)
1.0000	0.728
1.5000	0.750
2.0000	0.750
2.5000	0.773
3.0000	0.943

Evaluation of the Expected Energy Supplied by Each Unit

Table 4.28 and Fig. 4.20 show the results when SIPSREL is applied to System B to evaluate the expected energy supplied by each unit. Table 4.29 and Fig. 4.21 show the results when the load forecast uncertainty given in Table 4.7 is included.

Table 4.28: Expected Energy Supplied by Each Unit in System B (Table from SIPSREL)

Loading Order	Unit ID#	EES(MWh)
1	1	3785.416
2	4	808.386
3	2	53.319
4	3	5.402

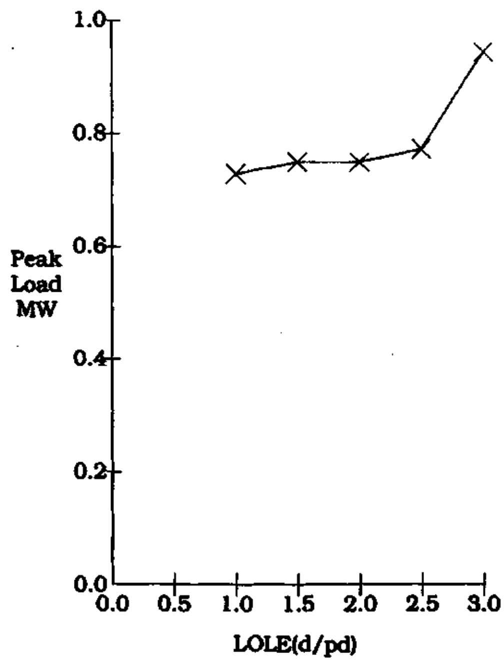


Fig. 4.19: PLCC for Annualized LOLE with LFU (Graph from SIPSREL)

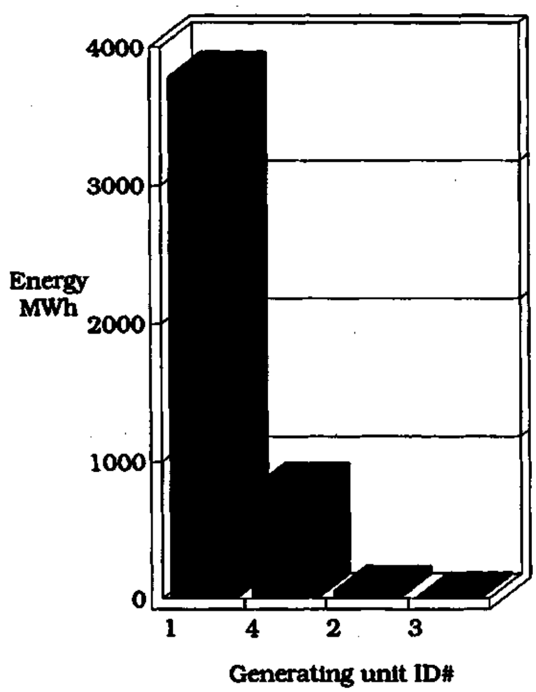


Fig. 4.20: Expected Energy Supplied by Each Unit in System B (Graph from SIPSREL)

Table 4.29: EES by Each Unit with LFU Considered (Table from SIPSREL)

Loading Order	Unit ID#	EES(MWh)
1	1	3783.345
2	4	809.903
3	2	53.790
4	3	5.467

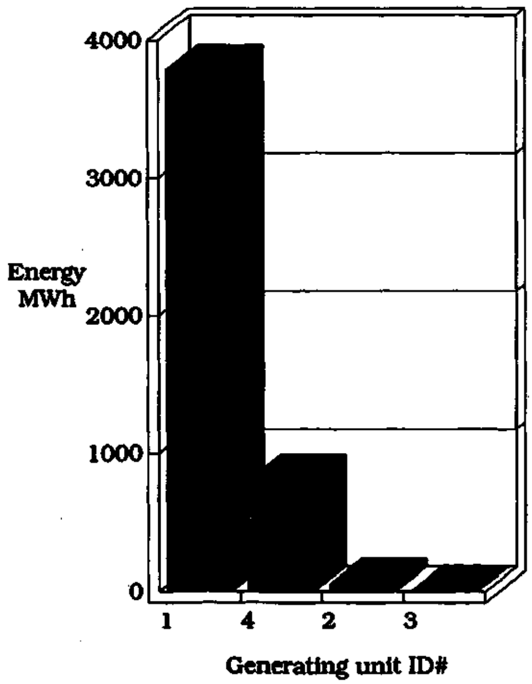


Fig. 4.21: EES by Each Unit with LFU Considered (Graph from SIPSREL)

The results obtained, when the planned maintenance given Table 4.8 is included, are shown in Table 4.30 and Fig. 4.22.The results when both LFU and planned maintenance of the generating units are considered are shown in Table 4.31 and Fig. 4.23

Table 4.30: EES by Each Unit Considering Planned Maintenance (Table from SIPSREL)

Loading Order	Unit ID#	EES(MWh)
1	1	3774.417
2	4	796.513
3	2	54.866
4	3	5.848

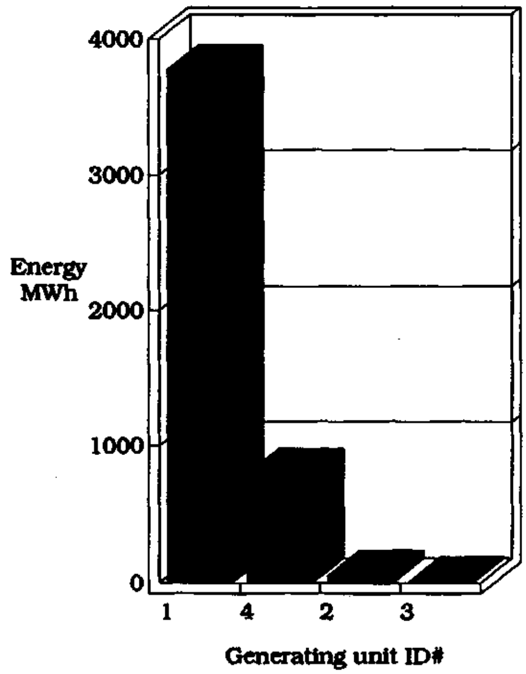


Fig 4.22: EES by Each Unit Considering Planned Maintenance (Graph from SIPSREL)

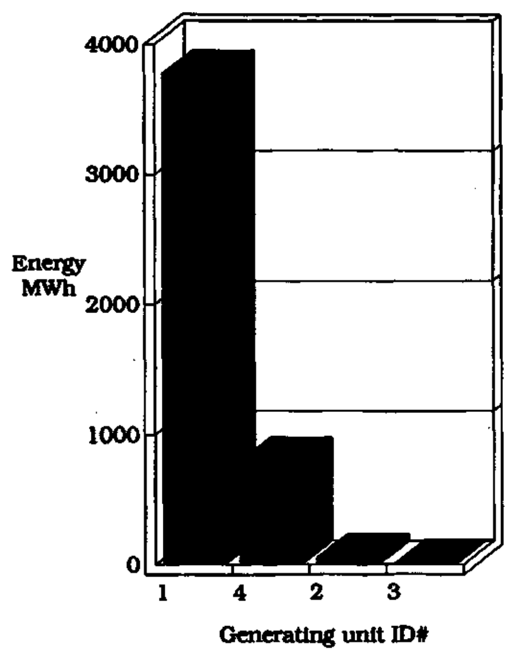


Fig. 4.23: EES by Each Unit Considering LFU and Planned Maintenance

Table 4.31: EES by Each Unit Considering LFU and Planned Maintenance

Loading Order	Unit ID#	EES(MWh)
1	1	3772.359
2	4	798.017
3	2	55.335
4	3	5.915

Evaluation of System Well-being Indices

The probability of health P(H), probability of margin P(M), probability of risk LOLP and loss of health expectation LOHE can be calculated using SIPSREL for different peak loads using either a LDC, DPLVC or a fixed load as the load model. When the user selects one output file from the 'Output File List', SIPSREL will display a table with the values of P(H), P(M) and LOLP at the different peak loads. When the other ouput file is selected, a table with the values of LOHE and LOLE is obtained. A graph for each of these indices can also be displayed by clicking them from a list box.

The well-being indices for the forecast peak loads given in Table 4.6 using the LDC are shown, as obtained from SIPSREL, in Table 4.32 and Fig. 4.24 - 4.27.

Table 4.32: Well-being Indices at Different PL (Tables from SIPSREL)

PL(MW)	Health	Margin	Risk
1.000	0.6620	0.3370	0.0010
1.060	0.6532	0.3453	0.0014
1.124	0.6428	0.3552	0.0020
1.191	0.6312	0.3660	0.0027
1.262	0.6175	0.3787	0.0038
1.338	0.5982	0.3963	0.0056
1.419	0.5731	0.4188	0.0081
1.504	0.5437	0.4447	0.0116
1.594	0.5105	0.4721	0.0174
1.689	0.4746	0.5010	0.0243
1.791	0.4283	0.5361	0.0355

PL(MW)	LOLE (h/pd)	LOHE (h/pd)
1.000	8.4971	2960.5840
1.060	12.6836	3037.6360
1.124	17.7388	3128.9980
1.191	23.8257	3230.2590
1.262	33.3755	3350.8930
1.338	48.9606	3520.1320
1.419	71.1339	3739.4840
1.504	101.9392	3997.4240
1.594	152.3477	4288.1520
1.689	213.2440	4602.2380
1.791	311.2094	5007.7120

0.6657 ... 0.307

0.6661 0.335

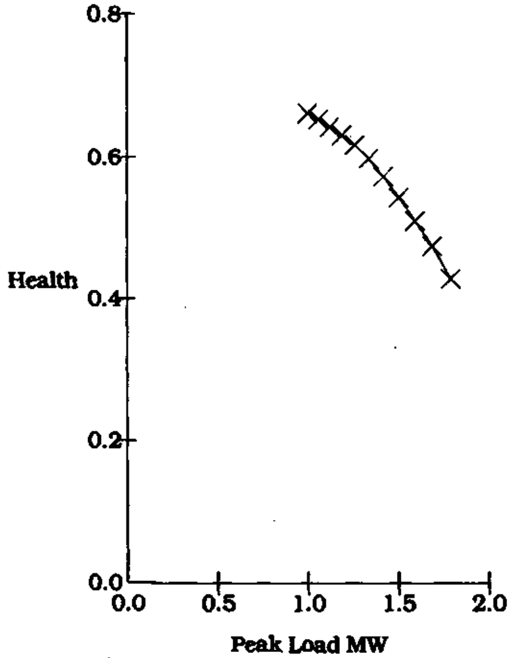


Fig. 4.24: P(H) for Different Peak Loads (Graph from SIPSREL)

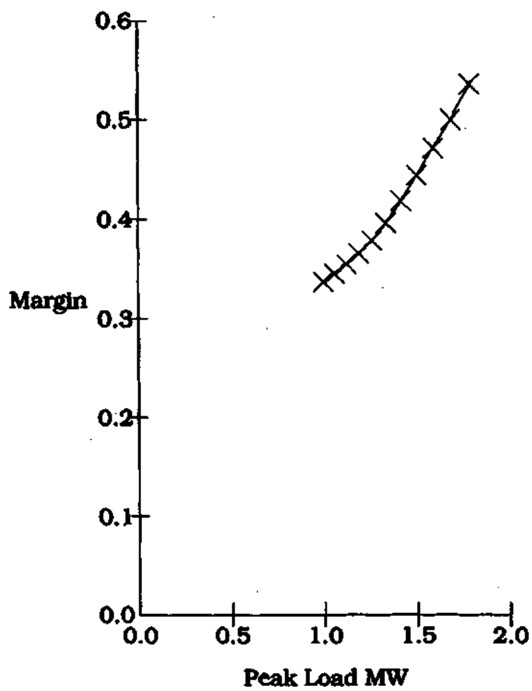


Fig. 4.25: P(M) for Different Peak Loads (Graph from SIPSREL)

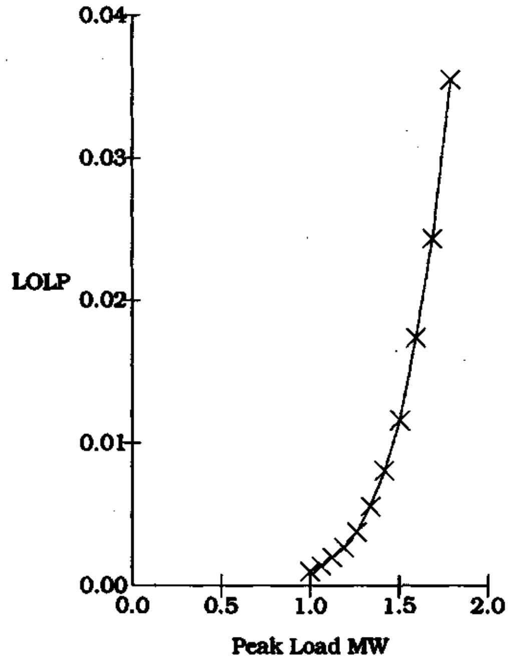


Fig. 4.26: LOLP for Different Peak Loads (Graph from SIPSREL)

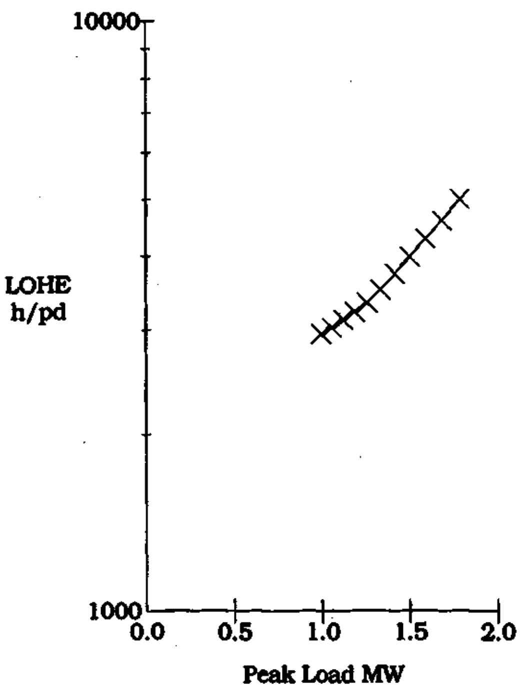


Fig. 4.27: LOHE for Different Peak Loads (Graph from SIPSREL)

Table 4.33 shows the results when the load forecast uncertainty given in Table 4.7 is included. Graphical results similar to Fig. 4.24 - 4.27 can also be obtained from SIPSREL.

Table 4.33: Well-being Indices for Different PL with LFU (Table from SIPSREL)

PL(MW)	Health	Margin	Risk
1.000	0.6615	0.3375	0.0010
1.060	0.6532	0.3454	0.0015
1.124	0.6428	0.3551	0.0020
1.191	0.6312	0.3661	0.0027
1.262	0.6169	0.3793	0.0039
1.338	0.5974	0.3969	0.0057
1.419	0.5731	0.4188	0.0081
1.504	0.5439	0.4444	0.0117
1.594	0.5106	0.4720	0.0174
1.689	0.4738	0.5016	0.0246
1.791	0.4283	0.5360	0.0357

healt 3

PL(MW)	LOLE (h/pd)	LOHE (h/pd)
1.000	8.8599	2965.2980
1.060	12.7373	3038.3900
1.124	17.7627	3128.7250
1.191	24.2181	3231.7490
1.262	34.3272	3358.3240
1.338	50.1547	3528.9230
1.419	71.8659	3742.4500
1.504	103.9645	3996.6400
1.594	152.8935	4287.3250
1.689	218.1604	4615.9710
1.791	317.9407	5008.5070

LoLeLohe 3

The well-being indices can also be evaluated by SIPSREL using the DPLVC as the load model. The results obtained are shown in Table 4.34 and Fig. 4.28 - 4.31.

Table 4.34: Well-being Indices using a DPLVC (Table from SIPSREL)

PL(MW)	Health	Margin	Risk
1.000	0.6614	0.3377	0.0010
1.060	0.6522	0.3463	0.0015
1.124	0.6413	0.3566	0.0021
1.191	0.6298	0.3674	0.0028
1.262	0.6152	0.3808	0.0040
1.338	0.5953	0.3989	0.0058
1.419	0.5699	0.4217	0.0084
1.504	0.5397	0.4483	0.0120
1.594	0.5060	0.4760	0.0179
1.689	0.4681	0.5065	0.0254
1.791	0.4220	0.5413	0.0367

helth1

PL(MW)	LOLE (d/pd)	LOHE (d/pd)
1.000	0.3631	123.6065
1.060	0.5449	126.9387
1.124	0.7657	130.9151
1.191	1.0215	135.1187
1.262	1.4421	140.4462
1.338	2.1188	147.7155
1.419	3.0595	156.9886
1.504	4.3975	168.0269
1.594	6.5458	180.3024
1.689	9.2554	194.1392
1.791	13.3942	210.9518

Lole-lohe 4

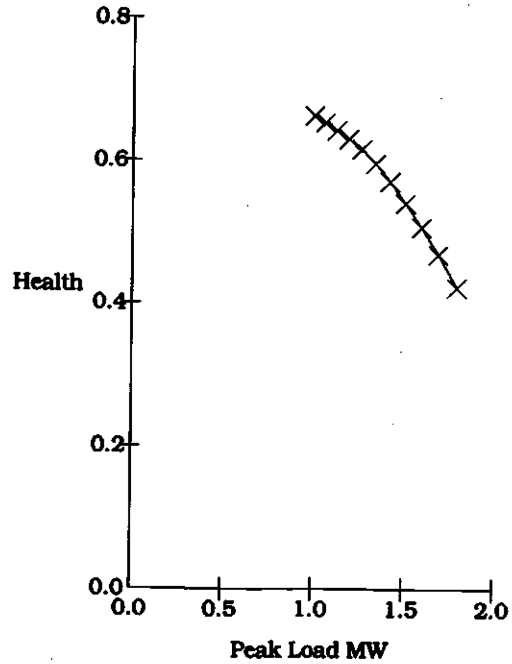


Fig. 4.28: P(H) using a DPLVC (Graph from SIPSREL)

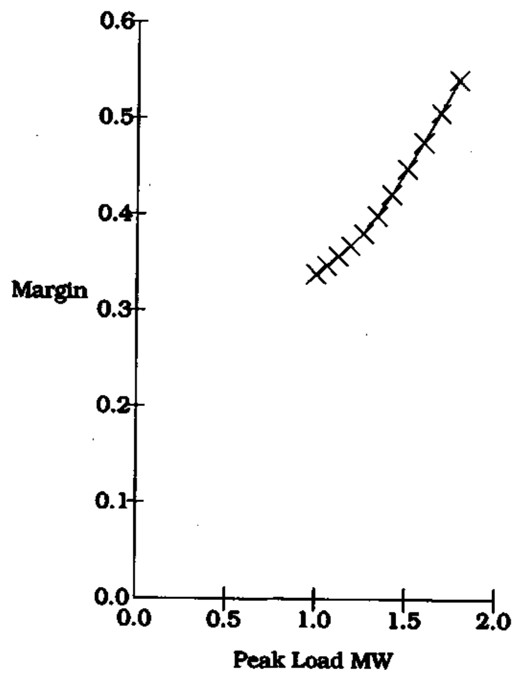


Fig. 4.29: P(M) using a DPLVC (Graph from SIPSREL)

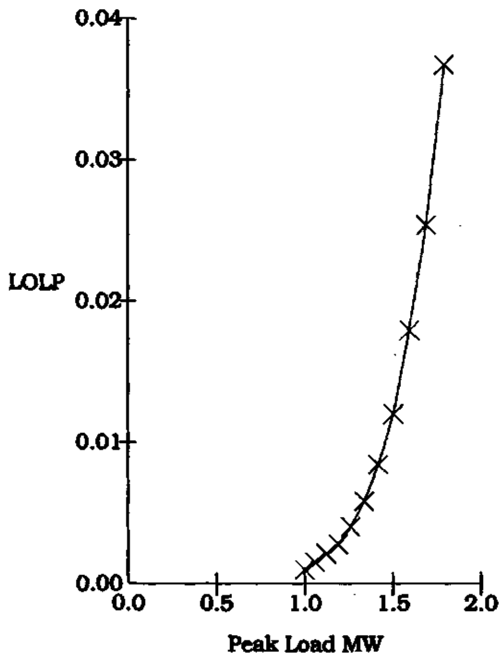


Fig. 4.30: LOLP using a DPLVC (Graph from SIPSREL)

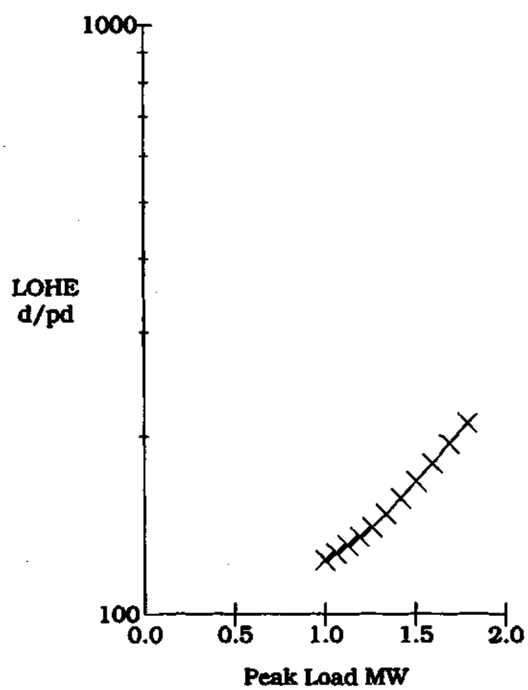


Fig. 4.31: LOHE using a DPLVC (Graph from SIPSREL)

The annualized well-being indices can also be calculated using SIPSREL considering only the annual peak load as the load model. It may be calculated with or without considering LFU. The results obtained without taking LFU into consideration are shown in Table 4.35 and Fig. 4.32 - 4.35.

Table 4.35: Annualized Well-being Indices (Table from SIPSREL)

PL(MW)	Health	Margin	Risk
1.000	0.5415	0.4508	0.0077
1.060	0.2845	0.6755	0.0399
1.124	0.2845	0.6755	0.0399
1.191	0.2845	0.6755	0.0399
1.262	0.0000	0.8432	0.1568
1.338	0.0000	0.8432	0.1568
1.419	0.0000	0.8432	0.1568
1.504	0.0000	0.5590	0.4410
1.594	0.0000	0.5590	0.4410
1.689	0.0000	0.5590	0.4410
1.791	0.0000	0.1826	0.8174

health5

PL(MW)	LOLE (d/yr)	LOHE (d/yr)
1.000	2.8000	167.3358
1.060	14.5794	261.1414
1.124	14.5794	261.1414
1.191	14.5794	261.1414
1.262	57.2430	365.0000
1.338	57.2430	365.0000
1.419	57.2430	365.0000
1.504	160.9640	365.0000
1.594	160.9640	365.0000
1.689	160.9640	365.0000
1.791	298.3574	365.0000

lolelohe5

Lolelohe7

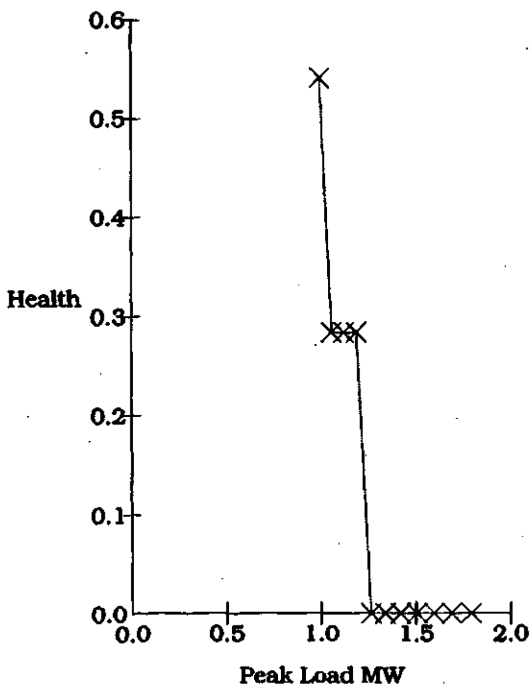


Fig 4.32: Annualized P(H) (Table from SIPSREL)

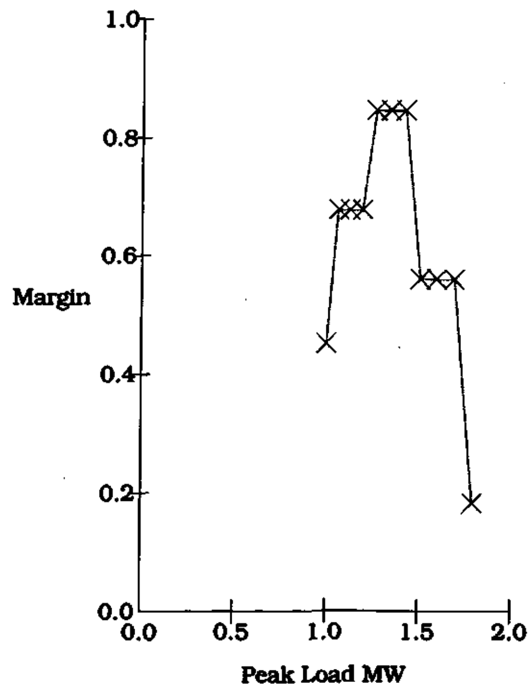


Fig 4.33: Annualized P(M) (Table from SIPSREL)

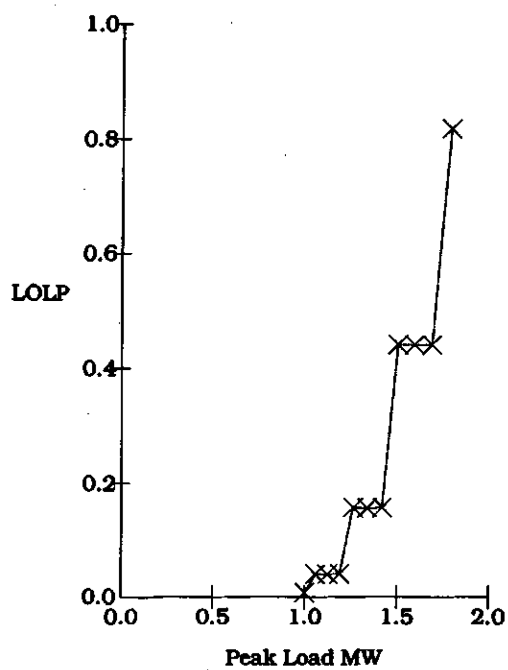


Fig 4.34: Annualized LOLP (Table from SIPSREL)

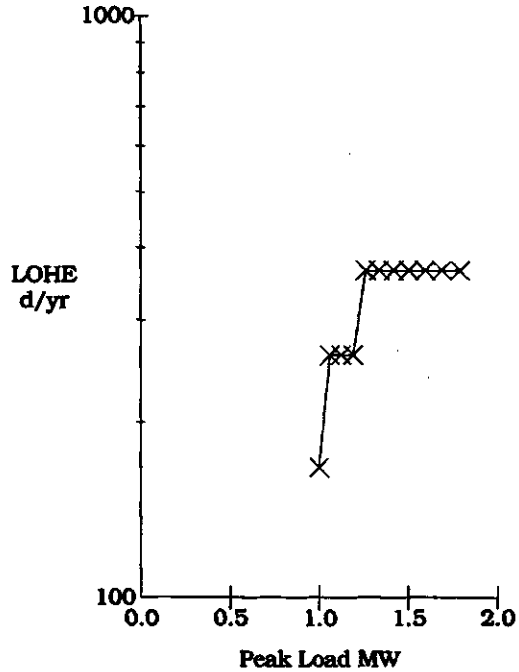


Fig 4.35: Annualized LOHE (Table from SIPSREL)

The effect of planned maintenance in system well-being analysis has not been incorporated in the SIPSREL software.

Evaluation of PLCC at Different Health Criteria

The peak load carrying capabilities for selected P(H) and LOLP criteria can be obtained from SIPSREL using either a LDC, DPLVC or a fixed load as the load model. The PLCC of System B for P(H) of 0.55. 0.60 and 0.65, using the LDC, are shown in Table 4.36 and Fig. 4.36. The PLCC of System B for LOLP of 0.001, 0.002 and 0.003 are shown in Table 4.37 and Fig. 4.37

Table 4.36: PLCC of System B for Different Health Criteria (Table from SIPSREL)

Health	PLCC(MW)
0.5500	1.487
0.6000	1.330
0.6500	1.083

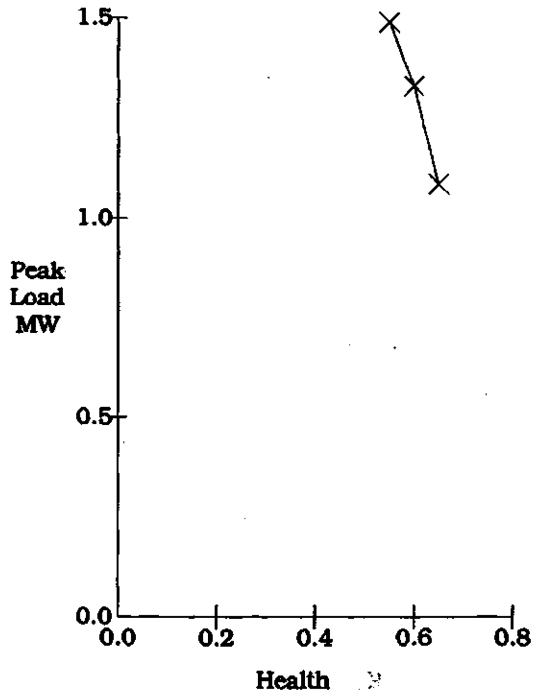
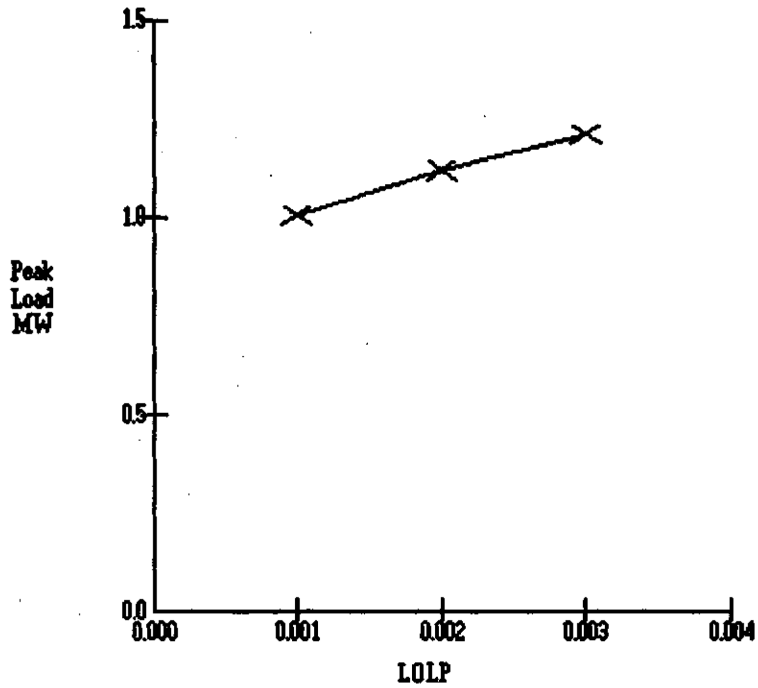


Fig. 4.36: PLCC of System B for Different Health Criteria (Graph from SIPSREL)



.Fig. 4.37: PLCC of System B for Different LOLP Criteria (Graph from SIPSREL)

Table 4.37: PLCC of System B for Different LOLP Criteria (Table from SIPSREL)

LOLP	PLCC(MW)
0.0010	1.005
0.0020	1.121
0.0030	1.212

The effects of LFU can be considered while calculating the PLCC for different health or LOLP criteria. The results obtained from SIPSREL for the PLCC of System B, with LFU, for different health and LOLP criteria are shown in Tables 4.38 and 4.39 respectively.

Table 4.38: PLCC with LFU for P(H) Criteria

Health	PLCC(MW)
0.5500	1.486
0.6000	1.327
0.6500	1.080

Table 4.39: PLCC with LFU for P(H) Criteria

LOLP	PLCC(MW)
0.0010	1.004
0.0020	1.121
0.0030	1.212

The peak load carrying capabilities for selected P(H) and LOLP criteria can also be obtained using the DPLVC in a similar manner. The PLCC for annualized health criteria or annualized LOLP criteria can also be calculated assuming a constant load throughout the year. In all of these evaluations the LFU can be included or omitted as desired. As in the previously illustrated cases, the results of these evaluations can be displayed in both tabular and graphical forms.

4.3.1 Analytical Tools Employing the Load Modification Approach

The programs for the load modification approach must be enabled when the effect of generating unit energy limitations are to be considered.. This is done by clicking at the option 'energy limitation' in Fig. 4.2. The LDC must always be used as the load model. This option is not available in well-being analysis.

Assume that Unit #1 in System B is not a run-of-the-river unit but a hydro unit with partial storage facilities. The probabilities of available capacity states and energy levels are given in Table 4.40 and Table 4.41 respectively.

Table 4.40: Available Capacity Levels for Unit #1

Output Capacity (KW)	Individual Probability
0	0.020
250	0.192
500	0.480
750	0.308

Table 4.41: Available Energy Levels for Unit #1

Available Energy (MWh)	Cumulative Probability
500	1.0
1000	0.8
1500	0.6
2000	0.4

The available capacity and energy data in Table 4.40 and Table 4.41 are used for Unit #1 in System B in the following examples.

<u>Evaluation of Conventional Risk Indices</u>

The LOLE, LOEE, UPM or SM can be calculated by SIPSREL for different peak loads considering the energy limitations for the unit with partial storage. The risk indices for the forecast peak loads given in Table 4.6 are shown as obtained from SIPSREL in Table 4.42 and Fig. 4.38 - 4.41.

Table 4.42: Risk Indices at Different PL (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	47.4110	4.203	903.298	252.210
1.060	52.7997	5.975	1211.283	338.202
1.124	58.6494	8.075	1543.728	431.024
1.191	87.6105	11.353	2048.448	571.947
1.262	97.1747	15.186	2585.892	722.006
1.338	135.1074	20.905	3357.529	937.455
1.419	273.1968	30.968	4689.771	1309.429
1.504	310.1782	45.655	6523.204	1821.342
1.594	450.1165	66.275	8934.793	2494.681
1.689	515.1799	94.030	11963.490	3340.322
1.791	903.6987	139.717	16763.900	4680.642

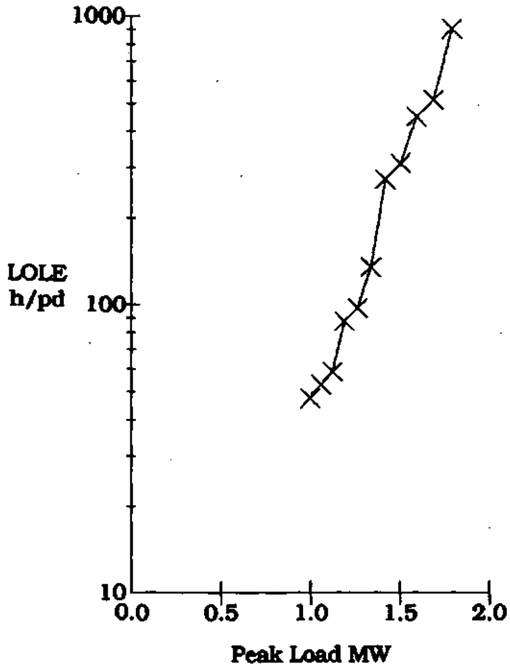


Fig. 4.38: LOLE for Different PL (Graph from SIPSREL)

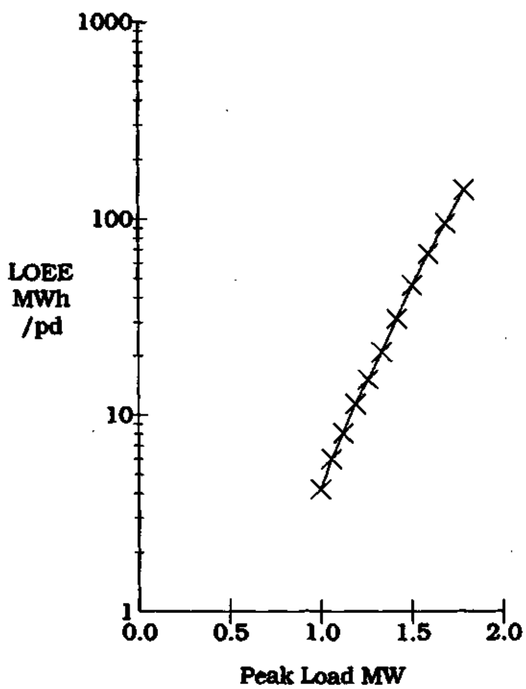


Fig. 4.39: LOEE for Different PL (Graph from SIPSREL)

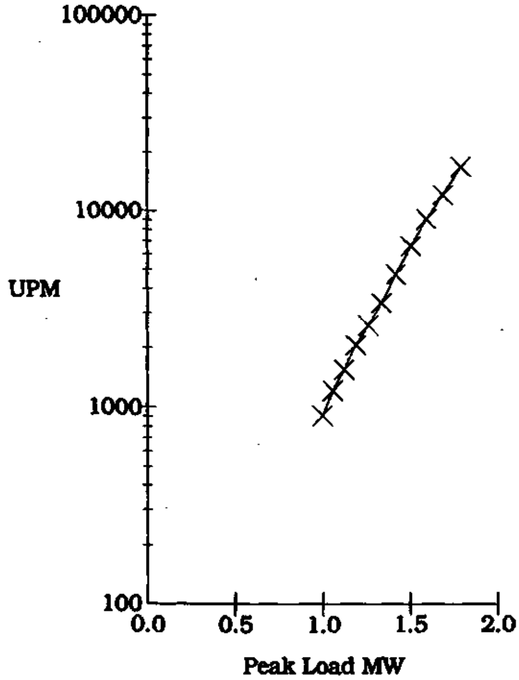


Fig. 4.40: UPM for Different PL (Graph from SIPSREL)

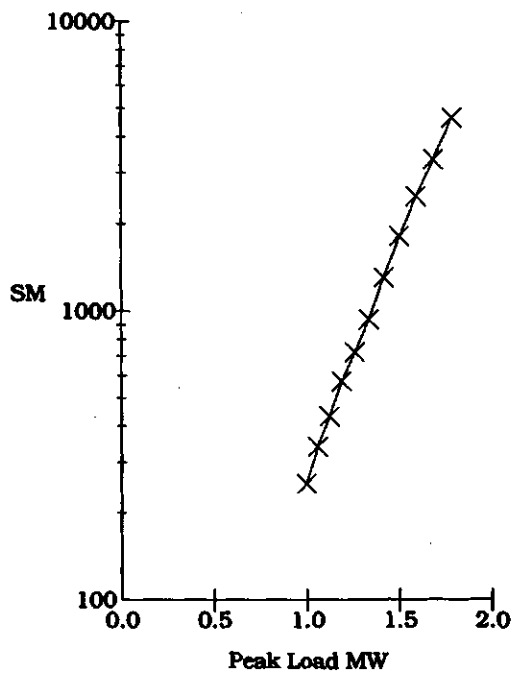


Fig. 4.41: SM for Different PL (Graph from SIPSREL)

The effect of LFU or planned maintenance or both can also be incorporated in the evaluation when energy limitations due to partial storage are considered. The output tables showing the results from SIPSREL are shown in Table 4.43 - 4.45. Graphical results similar to Fig. 4.38 - 4.41 can also be produced by the program.

Table 4.43: Risk Indices Considering LFU (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	46.6303	4.247	907.929	253.503
1.060	52.8340	6.006	1212.146	338.443
1.124	65.4561	8.269	1573.884	439.444
1.191	86.4590	11.413	2050.548	572.533
1.262	105.5350	15.466	2622.670	732.275
1.338	158.2941	21.454	3429.130	957.446
1.419	255.6014	31.533	4748.598	1325.854
1.504	337.8442	46.237	6572.181	1835.017
1.594	431.0376	66.991	8984.743	2508.627
1.689	603.9651	95.918	12142.040	3390.177
1.791	860.9133	141.941	16933.680	4728.047

Table 4.44: Risk Indices Considering Planned Maintenance (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	47.2738	4.046	874.714	244.229
1.060	52.8487	5.811	1184.800	330.808
1.124	58.9752	7.914	1521.747	424.886
1.191	87.7224	11.087	2011.576	561.652
1.262	97.8773	14.931	2556.755	713.871
1.338	135.8667	20.514	3313.575	925.182
1.419	271.6692	29.904	4553.585	1271.405
1.504	309.7427	44.517	6393.604	1785.156
1.594	448.5627	64.562	8747.605	2442.416
1.689	515.5627	92.240	11794.110	3293.029
1.791	898.6407	136.088	16406.590	4580.877

Table 4.45: Risk Indices Considering LFU & Maintenance (Table from SIPSREL)

PL (MW)	LOLE (h/pd)	LOEE (MWh/pd)	UPM	SM
1.000	42.7923	4.099	881.571	246.143
1.060	52.8881	5.843	1186.026	331.150
1.124	65.6051	8.076	1545.992	431.656
1.191	86.6389	11.156	2015.417	562.724
1.262	106.0322	15.163	2585.833	721.990
1.338	158.4604	20.966	3370.439	941.059
1.419	254.1074	30.601	4633.483	1293.713
1.504	313.5707	45.047	6435.936	1796.976
1.594	423.8230	65.431	8819.486	2462.486
1.689	561.2693	93.825	11936.220	3332.709
1.791	857.1600	138.493	16601.620	4635.332

Evaluation of PLCC at Different Risk Criteria

The peak load carrying capabilities for selected LOLE, LOEE, UPM or SM criteria can be obtained from SIPSREL considering generating unit energy limitations. The PLCC of System B, with Unit #1 as described in Tables 4.40 - 4.41, for LOLE of 10, 20, 30, 40 and 50 h/yr are shown in Table 4.46 and Fig. 4.42.

Table 4.46: PLCC for Different LOLE Criteria (Table from SIPSREL)

LOLE(h/pd)	PLCC(MW)
10.0000	0.684
20.0000	0.925
30.0000	0.967
40.0000	0.968
50.0000	1.028

The PLCC for LOEE of 1.5, 3.0, 4.5, 6.0 and 7.5 MWh/yr are shown in Table 4.47 and Fig. 4.43.

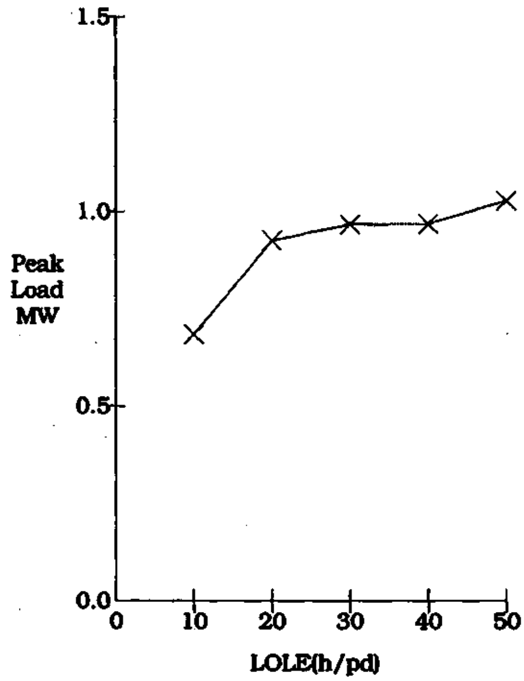


Fig. 4.42: PLCC for Different LOLE Criteria (Graph from SIPSREL)

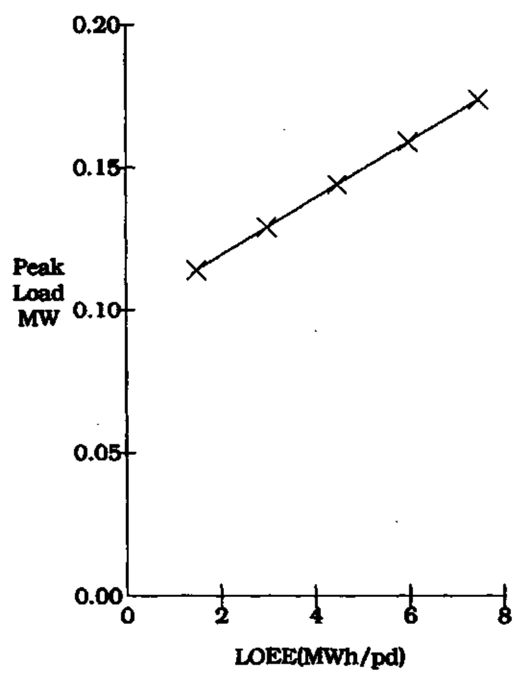


Fig. 4.43: PLCC for Different LOEE Criteria (Graph from SIPSREL)

Table 4.47: PLCC for Different LOEE Criteria (Table from SIPSREL)

LOEE(MWh/pd)	PLCC(MW)
1.500	0.114
3.000	0.129
4.500	0.144
6.000	0.159
7.500	0.174

The PLCC for UPM of 100, 200, 300, 400 and 500 are shown in Table 4.48 and Fig. 4.44.

Table 4.48: PLCC for Different UPM Criteria (Table from SIPSREL)

UPM	PLCC(MW)
100	0.601
200	0.698
300	0.760
400	0.819
500	0.868

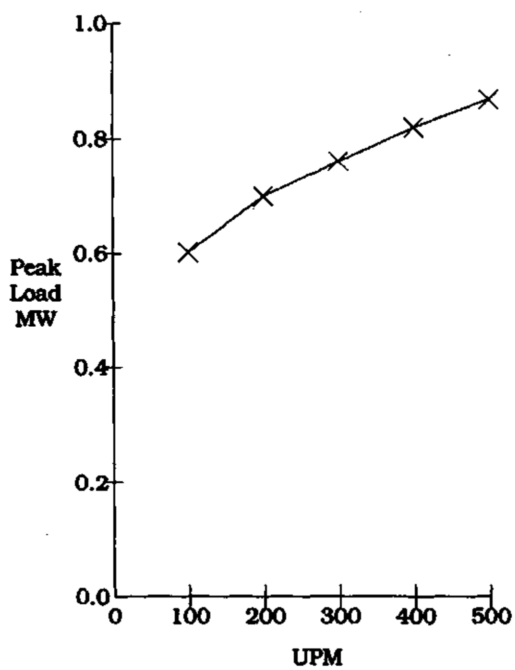


Fig. 4.44: PLCC for Different UPM Criteria (Graph from SIPSREL)

The PLCC for SM of 50, 100, 150, 200 and 250 are shown in Table 4.49 and Fig. 4.45.

Table 4.49: PLCC for Different SM Criteria (Table from SIPSREL)

SM	PLCC(MW)
50.0000	0.685
100.0000	0.798
150.0000	0.887
200.0000	0.960
250.0000	0.998

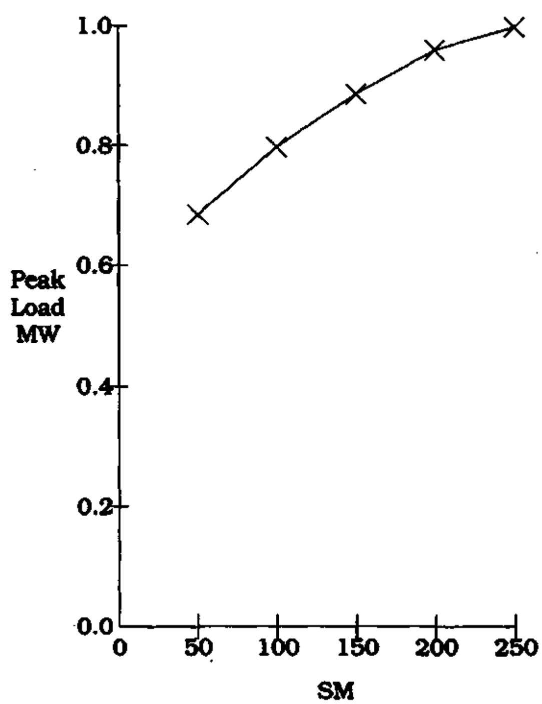


Fig. 4.45: PLCC for Different SM Criteria (Graph from SIPSREL)

The PLCC of the system for selected LOLE, LOEE, UPM and SM criteria can also be evaluated including the effects of LFU or planned maintenance or both. The results for these cases are not shown here.

Evaluation of Expected Energy Supplied by Each Unit

The expected energy supplied by each unit, when SIPSREL is applied to System B in which Unit #1 is described in Tables 4.40 - 4.41, is shown in Table 4.50 and Fig. 4.46.

Table 4.50: EES by each Unit (Table from SIPSREL)

Loading Order	Unit ID#	EES(MWh)
1	1	1400.363
2	4	3056.249
3	2	169.727
4	3	22.952

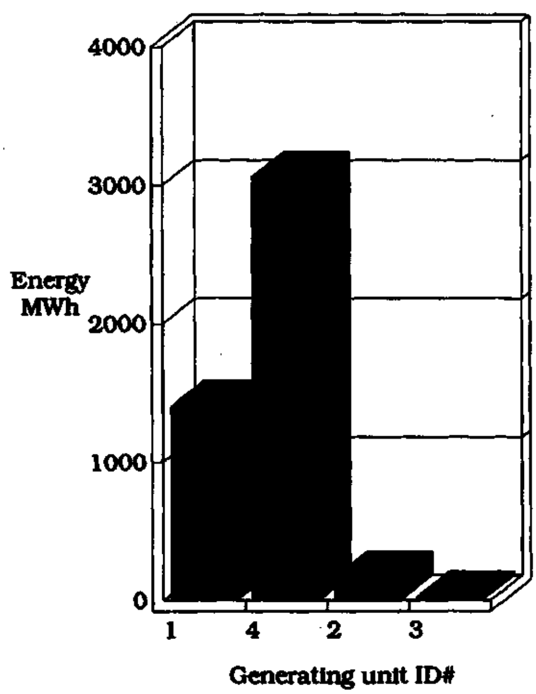


Fig. 4.46: EES by each Unit (Graph from SIPSREL)

The expected energy supplied by each unit can also be calculated when LFU and planned maintenance are considered in a system having energy limited units. The tables obtained from SIPSREL have been grouped together in Table 4.51 to show the results. SIPSREL can also produce a graph similar to Fig. 4.46 for each of these cases.

Table 4.51: EES by each Unit Considering LFU and Maintenance

Loading Order	Unit ID#	Expected Energy Supplied (MWh/yr)		
		with LFU	with Maintenance	with LFU & Maintenance
1	1	1400.252	1493.119	1492.905
2	4	3054.365	2948.909	2946.677
3	2	171.532	164.446	166.659
4	3	23.099	22.193	22.373

4.4 Monte Carlo Simulation Methods in SIPSREL

The MCS softwares available in SIPSREL analyze system risk and well-being based on the concepts described in Chapters 2 and 3. The generation model incorporates generating units with two or three resident states. The state space model used in SIPSREL for a 3-state unit and the transition rates between them is shown in Fig. 4.47. The data required for each generating unit are its capacity, MTTF and MTTR. When units with derated states are considered, the derated capacity, MTTD and MTDR are the additional data required in the generation model.

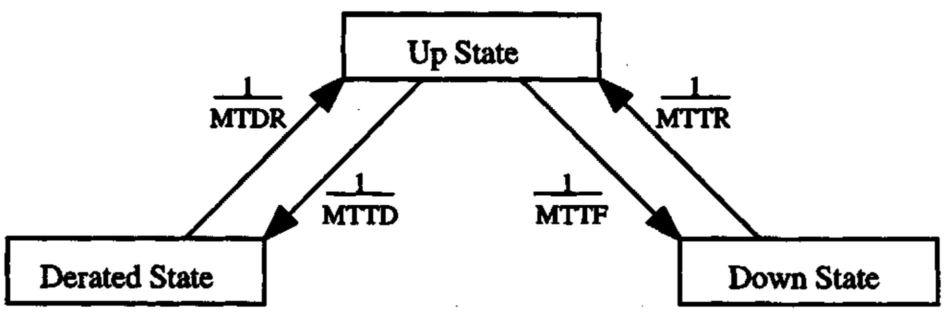


Fig. 4.47: State Space Model for 3-State Unit

The load model utilizes the hourly loads in a year arranged in chronological order and the system peak load. SIPSREL cannot consider the effects of LFU, planned maintenance or energy limitations in the MCS method.

The MCS calculation in SIPSREL can be used to analyze system risk and health in terms of the mean values and the distributions of the basic indices as well as the frequency and duration indices. The mean value and the distribution of the interrupted energy assessment rate (IEAR) [10] can also be estimated. The different evaluation tasks that can be performed by SIPSREL using the MCS method are listed below:

1. Evaluation of risk indices
   - i) Basic indices: LOLE, LOEE
   - ii) F&D indices: ELLPYR, ELLPINT, EENSPINT, EINTDUR, F

2. Evaluation of health indices
   - i) Basic indices: P(H), P(M)
   - ii) F&D indices: EHDUR, EMDUR, F(M)

3. Evaluation of IEAR

A stopping rule based on the convergence of LOEE has been incorporated in SIPSREL. The user may specify the accepted percentage deviation in LOEE and the number of consecutive years that must meet the accepted deviation for the simulation to converge. The minimum and maximum number of simulation years and a seed for the random number generator may also be specified by the user in the user interface text boxes. Default settings for these parameters are also available.

4.5 Application of the MCS Methods in SIPSREL

The various types of adequacy studies that can be done using SIPSREL with the MCS method are illustrated by application to test System C. The required generation data for the generating units in System C are given in Table 4.52.

Table 4.52: Generation Data for System C for MCS Method

Unit ID#	Full Capacity (KW)	MTTF (hr)	MTTR (hr)	Derated Capacity (KW)	MTTD (hr)	MTDR (hr)
1	750	1140	60	-	-	-
2	500	2190	45	200	4380	90
3	500	950	50	-	-	-

The hourly load in p.u. of the annual peak load for System C is taken to be the same as that for the IEEE-RTS [12]. The load model has 8736 hourly load levels. The annual peak load for System C is 900 KW.

The composite customer damage function (CCDF) for System C is used to estimate the IEAR. The CCDF used in the IEEE-RTS system has been extended from 8 to 16 hours, with the same slope as that between 4 to 8 hours, in order to cover all expected interruption durations for System C and is shown in Table 4.53 and Fig. 4.48.

Table 4.53: Composite Customer Damage Function for System C

Interruption Duration	1 min	20 min	1 hr	4 hr	8 hr	16 hr
Interruption Cost ($/KW)	0.73	2.42	5.27	19.22	41.45	85.91

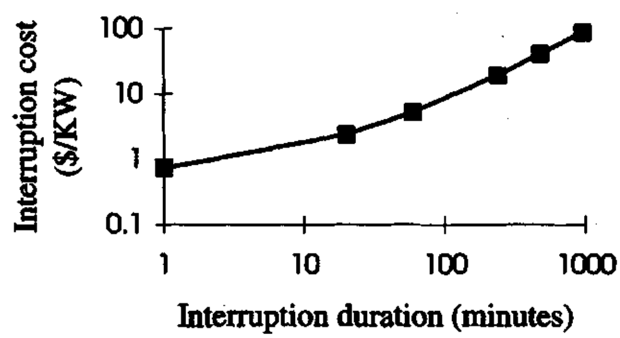


Fig. 4.48: Composite Customer Damage Function for System C

The SIPSREL default values of the stopping rule parameters are:

Minimum number of simulation years = 50
Maximum number of simulation years = 3000
Accepted % deviation in average LOEE = 0.8 %
Consecutive number of years for acceptance = 15

The simulation program was run using the default seed (0.24) for the random number generator. A graph, similar to that shown in Fig. 4..49, is displayed while the program runs, plotting the variation of the average LOEE value as the simulation progresses.

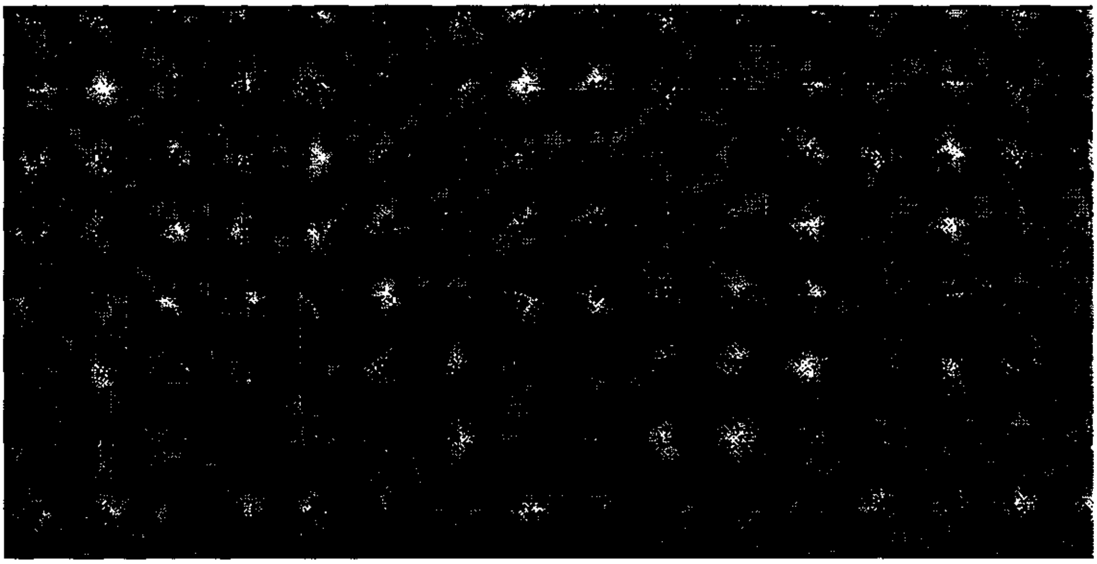


Fig. 4.49: Variation of Average LOEE as Simulation Progresses

A message is given to the user when the simulation process converges. The user can also stop the simulation run when desired. The simulation for System C converged in 367 simulation years using the default settings for the stopping rule parameters and random number seed. The mean value and the distribution of any index can be displayed by clicking it from the list of indices available in the list box in SIPSREL.

Evaluation of System Risk

The simulation software in SIPSREL can evaluate the basic conventional risk indices, the frequency and duration risk indices and their distributions. The distribution is displayed both in tabular and graphical forms. The results obtained for System C are shown as examples. The output display obtained from SIPSREL when the index LOEE is clicked is shown in Fig. 4.50.

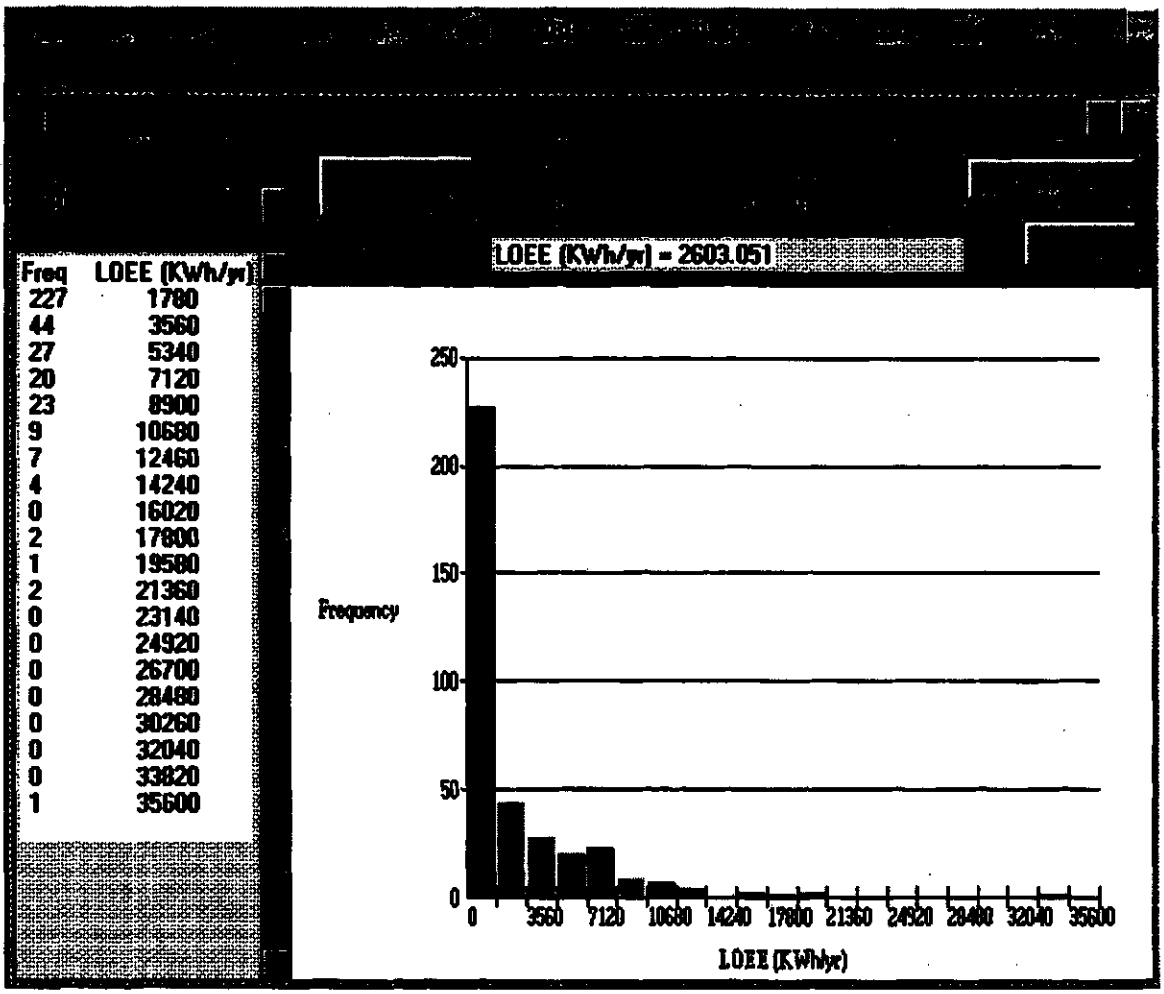


Fig. 4.50: Display of the LOEE Results from SIPSREL

The results obtained from SIPSREL for the mean values of the risk indices are grouped and shown in Table 4.54. Their distributions are shown in Fig. 4.51 - 4.56.

Table 4.54: Mean Risk Indices

Risk Index	Mean Value
LOLE (h/yr)	18.79
LOEE (KWh/yr)	2603.05
ELLPYR (KW/yr)	227.53
EINTDUR (h/int)	8.67
EENSPINT (KWh/int)	1201.66
ELLPINT (KW/int)	105.04
F (int/yr)	2.17

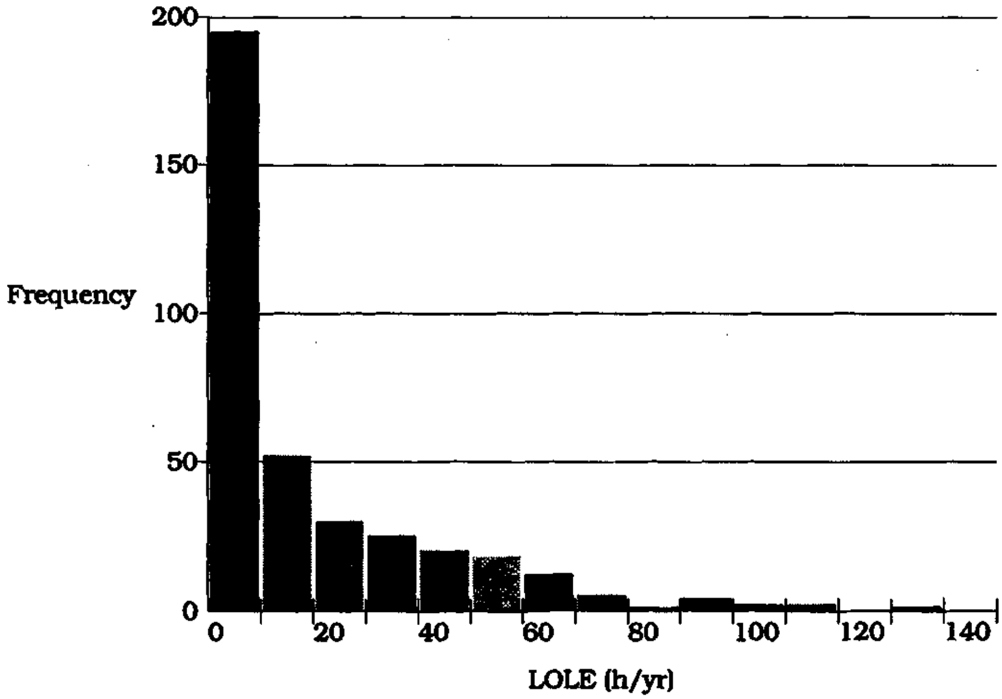


Fig. 4.51: Distribution of the LOLE

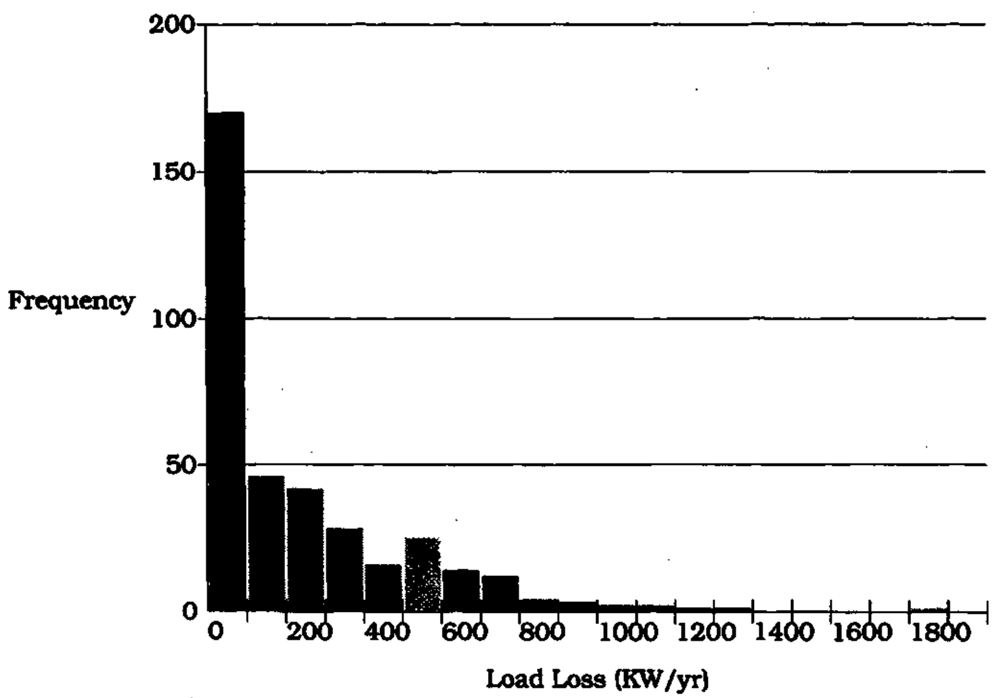


Fig. 4.52: Distribution of the ELLPYR

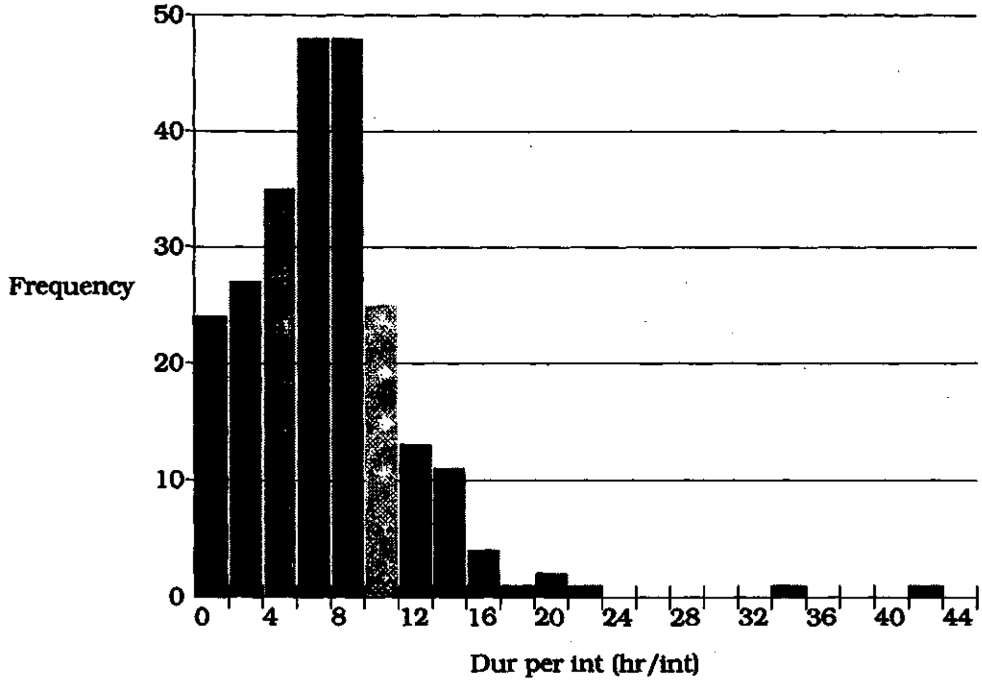


Fig. 4.53: Distribution of the EINTDUR

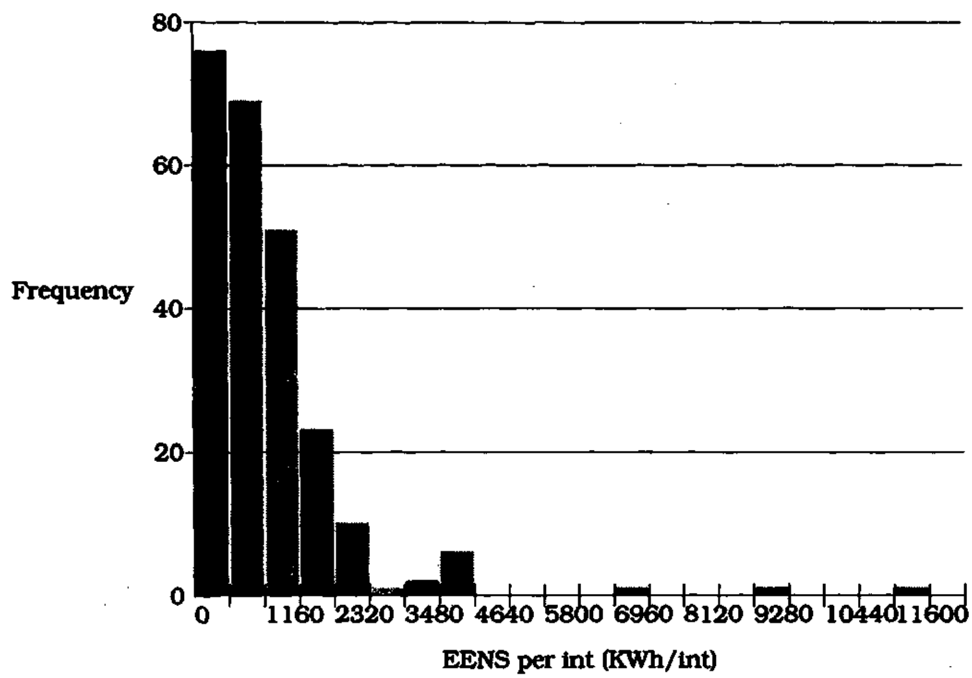


Fig. 4.54: Distribution of the EENSPINT

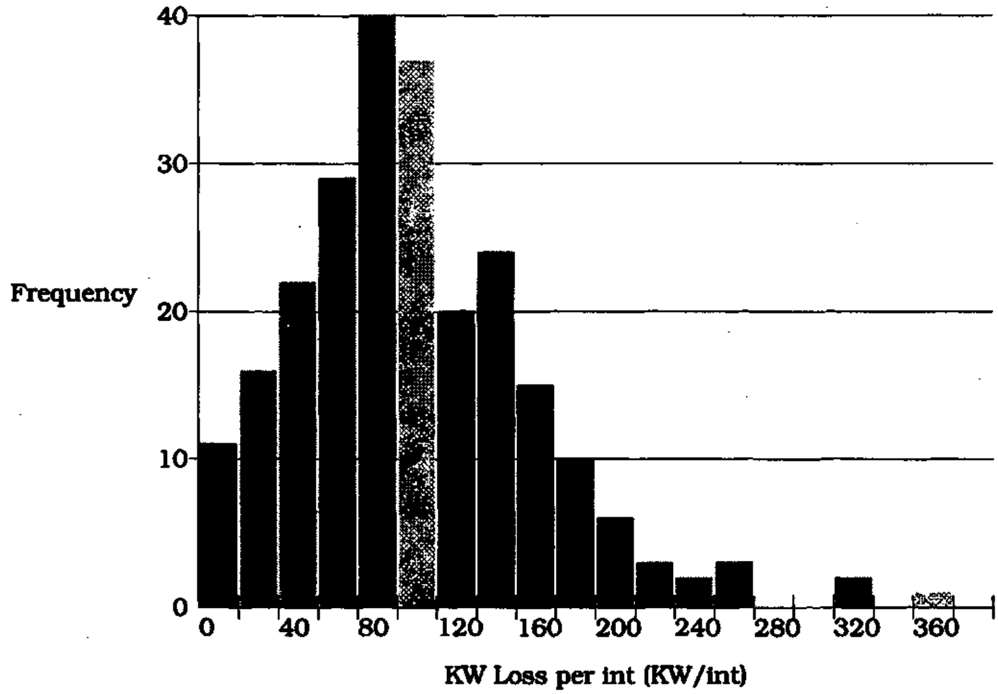


Fig. 4.55: Distribution of the ELLPINT

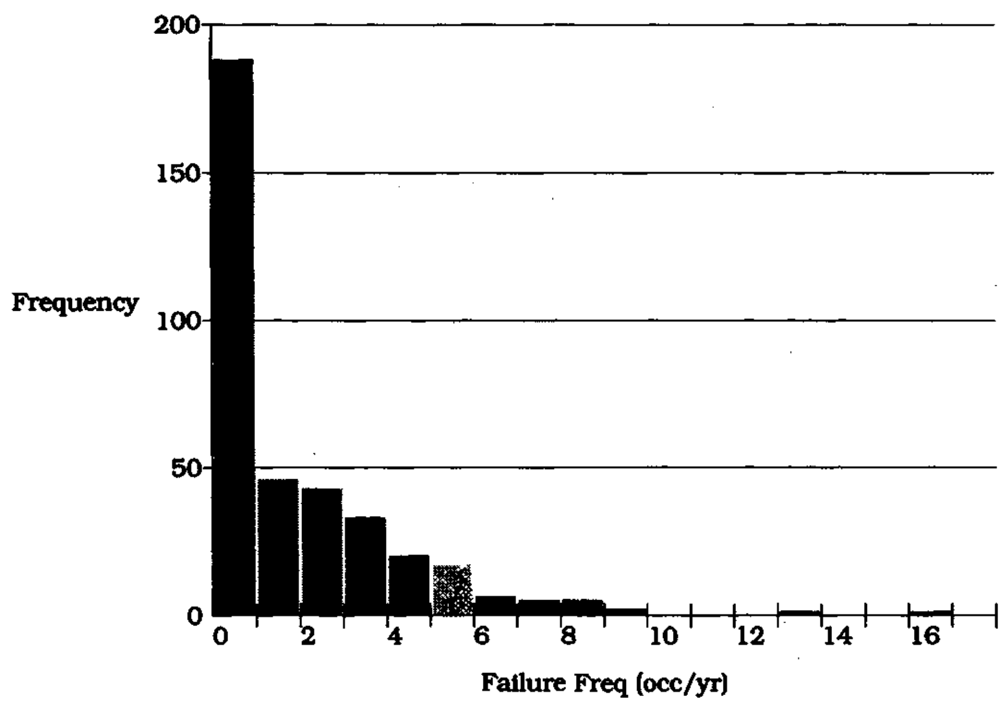


Fig. 4.56: Distribution of the Frequency of Interruption

Evaluation of System Health

The simulation in SIPSREL can evaluate the probability of health and margin, the frequency and duration health indices and their distributions. The distribution is displayed in both tabular and graphical forms. The results obtained for System C are shown as examples. The results for the mean values of the health indices are grouped and shown in Table 4.55. Their distributions are shown in Fig. 4.57 - 4.61.

Table 4.55: Mean Health Indices

Risk Index	Mean Value
Probability of Health (%)	92.4826
Probability of Margin (%)	7.3024
Expected Health Duration (h/health)	139.5011
Expected Margin Duration (h/margin)	10.7751
Frequency of Margin (margin/yr)	59.2044

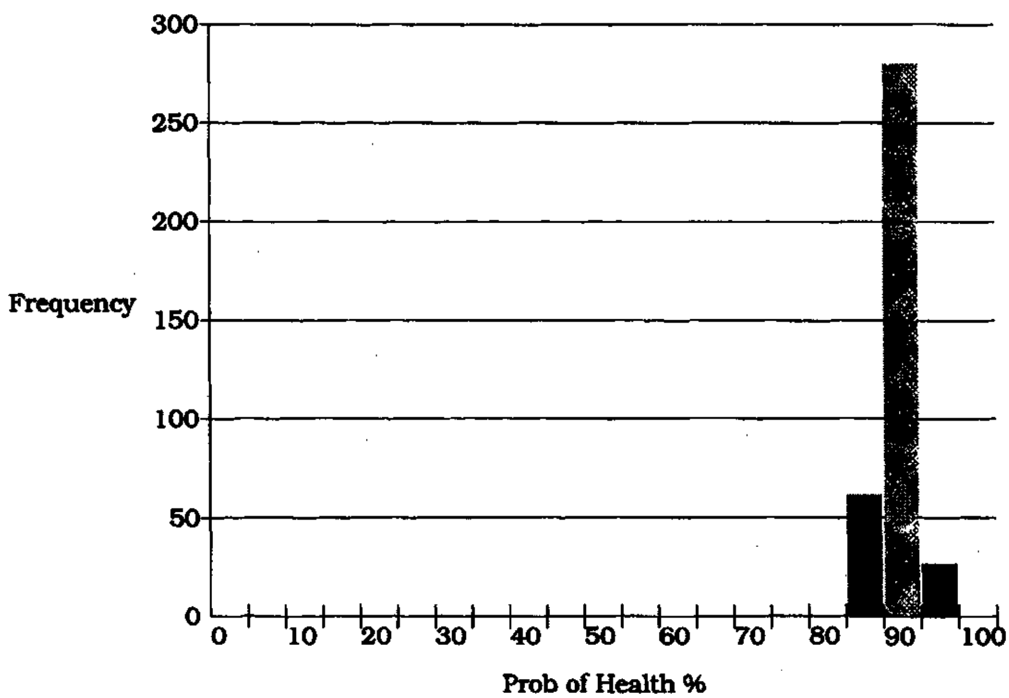


Fig. 4.57: Distribution of the Probability of Health

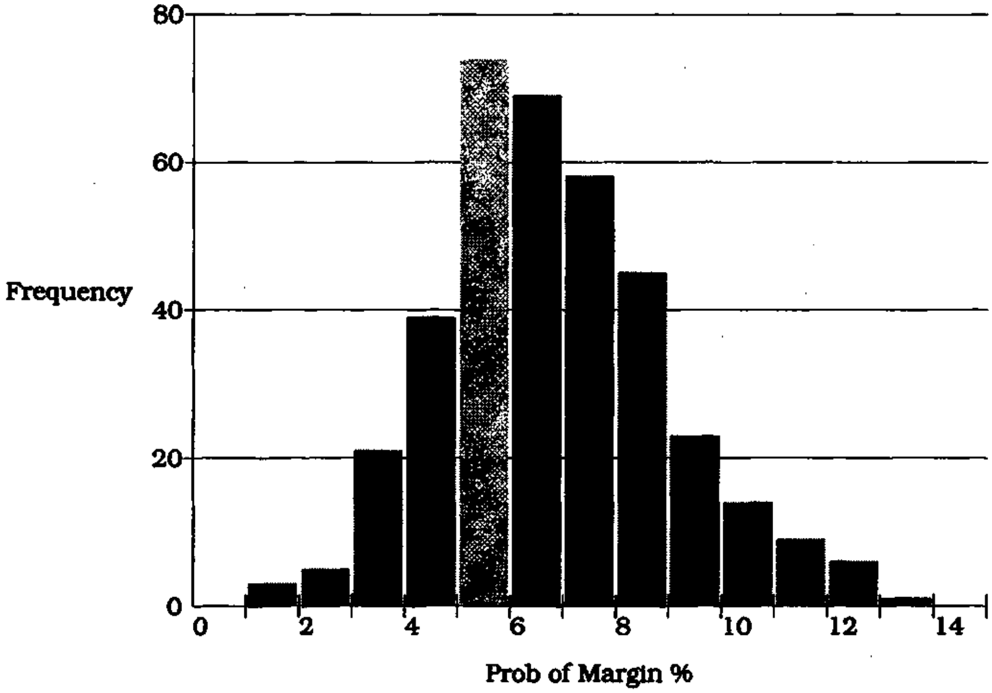


Fig. 4.58: Distribution of the Probability of Margin

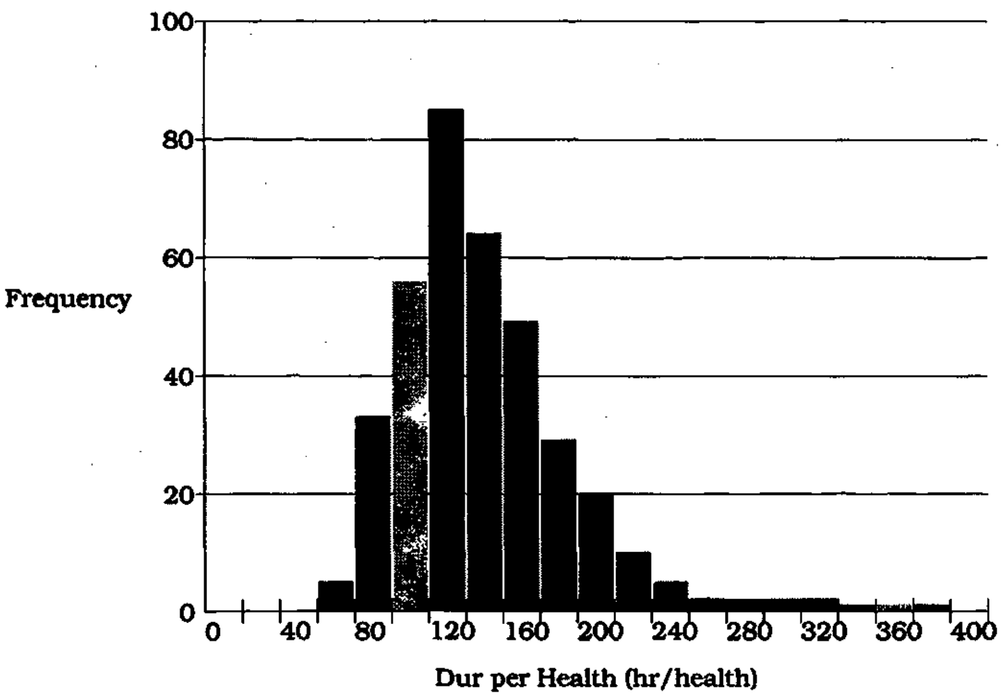


Fig. 4.59: Distribution of the Expected Health Duration

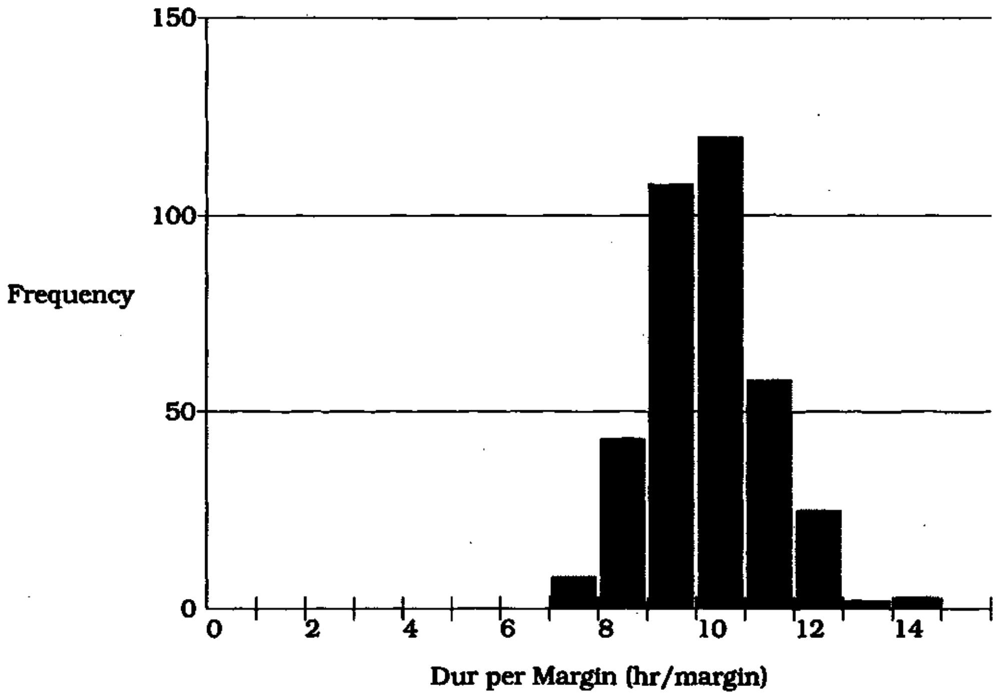


Fig. 4.60: Distribution of the Expected Margin Duration

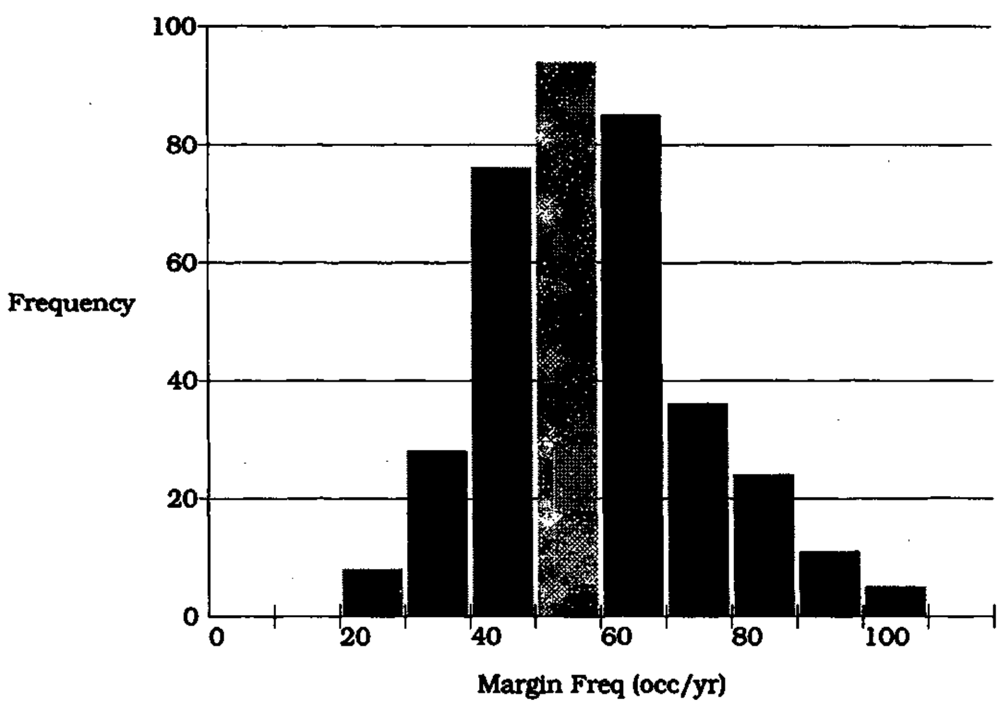


Fig. 4.61: Distribution of the Frequency of Margin

Evaluation of System IEAR

The IEAR for a system can be estimated by the MCS software in SIPSREL and requires the composite customer damage function data. Using the CCDF data in Table 4.53, the mean IEAR is 4.83 $/KWh and its distribution is given in Fig. 4.62.

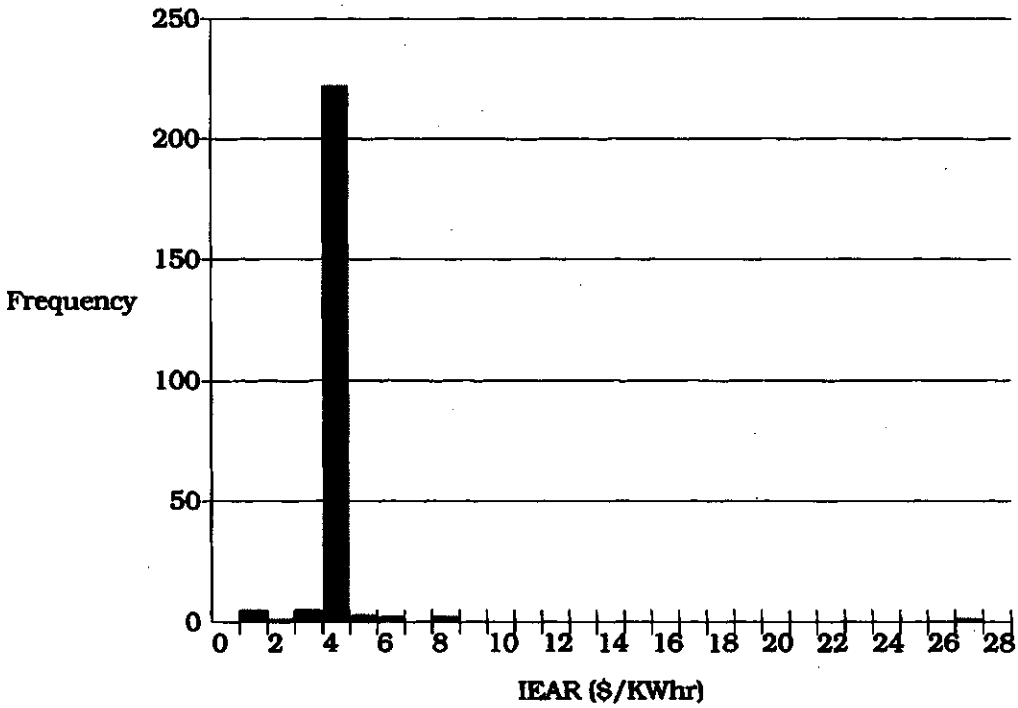


Fig. 4.62: Distribution of the IEAR

4.6 Conclusion

The software package SIPSREL has been developed to provide a handy tool for the application of probabilistic methods in adequacy studies of small isolated power systems. It can however also be utilized to assess the HL-I adequacy of larger systems. The software employs a graphical user interface and is very user-friendly and self-informative. The results for any evaluation are displayed in both tabular and graphical forms. SIPSREL includes tools that use both analytical techniques and MCS methods.

The analytical techniques used in SIPSREL make use of the 'CCOPT Method' the 'Load Modification Approach' and the 'CPCOPT Method' developed in this research work. The conventional risk indices, the system well-being indices, the peak load carrying capabilities at different risk and health criteria and the expected energy supplied by each unit in the system can be evaluated using the analytical tools. The effect of LFU, planned maintenance, unit derated states, energy limitations, load factor, shape of the load curve, the priority loading order, size and FOR of a unit can all be included in the evaluation. SIPSREL can use LDC, DPLVC or constant loads as the load model. It can also incorporate a load curve that has as many as 8760 points joined by line segments. The user is at liberty to select any option for the evaluation and to include any of the different factors that effect the analysis.

The MCS software in SIPSREL can estimate the mean values and the distributions of the basic risk and health indices, the frequency and duration risk and health indices and the IEAR of a system. It can incorporate the effect of unit derating in the evaluation. It requires a comprehensive load model with hourly loads for the entire period of one year. It also requires the mean resident times in the different unit states as generation data. SIPSREL has default settings for the stopping rule parameters and the random number seed. The user may change any of them as desired. As the simulation proceeds, the program displays a graph showing the variation of the cumulative average of the LOEE as it moves towards convergence.

SIPSREL has been developed with the aim of providing a practical tool for SIPS planners in order that they can experiment with probabilistic methods and hopefully eventually adopt them in system planning.

5. COMPARATIVE STUDY BETWEEN HEALTH, RISK & DETERMINISTIC INDICES

5.1 Introduction

The basic criteria used in the adequacy evaluation of SIPS are deterministic and can be expressed in general by Equation (5.1). The multiplication factor X is normally between 5 - 15% depending on the judgment of the planner and on past experience.

$$CR = CLU + X * PL \tag{5.1}$$

Large interconnected systems generally employ probabilistic methods for adequacy assessment. The most widely used criterion is the LOLE. A LOLE of about 0.1 d/yr or 2.4 h/yr is a normal criterion used by Canadian Utilities [4]. A reasonable adequacy criterion for a system in a developing country would be a LOLE of 2 d/yr [13].

System health analysis has been developed in order to provide probabilistic methods that are applicable to adequacy evaluation of SIPS. The system health is a probabilistic index that also incorporates a deterministic criterion such as the 'loss of the largest unit'. The probability of health may prove to be a useful criterion in the adequacy assessment of SIPS.

The three different criteria described above can be compared by applying them to a range of practical systems in order to determine the most suitable criterion for SIPS adequacy evaluation.

5.2 Variation in System Health and Risk at a Fixed Deterministic Criterion

There are many factors acting on a system that influence its adequacy but are not reflected in any way when the existing deterministic methods are used. Probabilistic methods can, however, incorporate the effect of all these factors in the adequacy evaluation. The risk and health indices therefore respond to these factors and vary accordingly. The risk and health indices for different systems are very likely to be different even if they all have a common deterministic adequacy measure due to their different unit sizes. The size of the units added for generation expansion greatly effects the risk and health indices even though the units may be added to maintain a fixed deterministic criterion.

5.2.1. Variation in System Health and Risk due to Changes in System Parameters Not Recognized by Deterministic Methods

Deterministic criteria do not reflect the variation in the system adequacy or the degree of comfort in a system influenced by changes in the forced outage rates of the generating units, the probability of residing in different derated states, the system load factor or the shape of the load curve. The impact of these factors on system health and risk has been studied using a practical system..

Test System (*Base Case*): The test system has the following generation and load characteristics:

Unit 1 = 270 KW, Unit 2 = 270 KW and Unit 3 = 540 KW; FOR of each unit = 5%
Installed Capacity = 1080 KW
CLU = 540 KW
System Peak Load = 491 KW, Load Factor = 70%

The LDC for the test system is shown in Fig. 5.1.

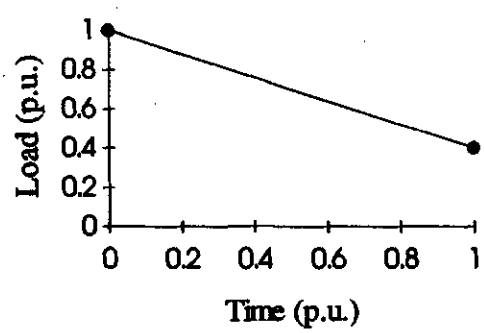


Fig. 5.1: LDC for the Test System (Base Case)

The following studies are variations on the base case.

Case (i): The FOR of each unit is changed to 2%.

Case (ii): The 540 KW unit can also reside in a derated state of 270 KW and the probabilities of residing in the up state, the derated state and the down state are 0.68, 0.30 and 0.02 respectively:

Case (iii): The load factor of the system is changed to 50%.

Case (iv): The load factor remains the same but the shape of the load curve is changed from a two-point straight line to the 3-point representation shown in Fig. 5.2.

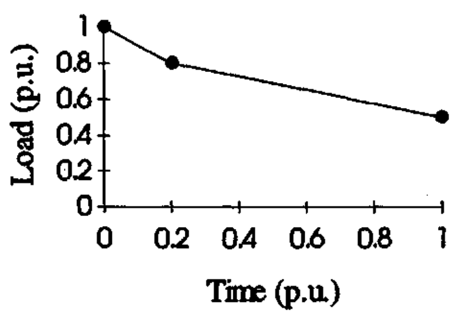


Fig. 5.2: LDC for the Test System (Case iv)

The three different criteria for the case studies of the test system are shown in Table 5.1:

Table 5.1: Different Criteria for Case Studies

Case Studies	Deterministic criterion	P(H)	LOLE (h/yr)
Base Case	CR = CLU + 10%PL	0.8912	32.31
Case (i)	CR = CLU + 10%PL	0.9556	5.22
Case (ii)	CR = CLU + 10%PL	0.9122	17.85
Case (iii)	CR = CLU + 10%PL	0.9318	19.82
Case (iv)	CR = CLU + 10%PL	0.8754	37.17

The deterministic criterion remains exactly the same for the different case studies but the system health and risk vary widely as illustrated in the Fig. 5.3 and Fig. 5.4 respectively.

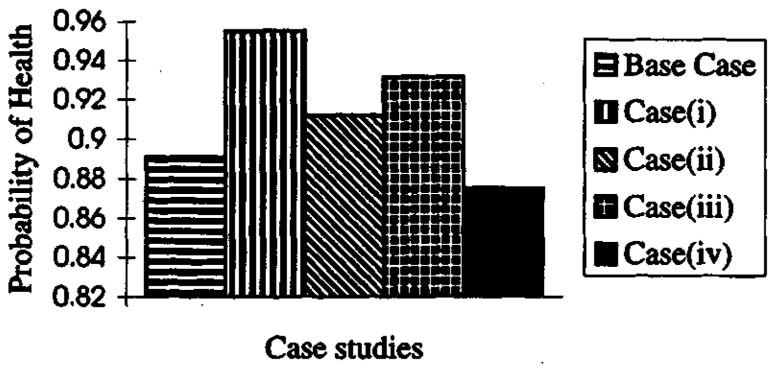


Fig. 5.3: Variation in P(H) for a Fixed Deterministic Criterion

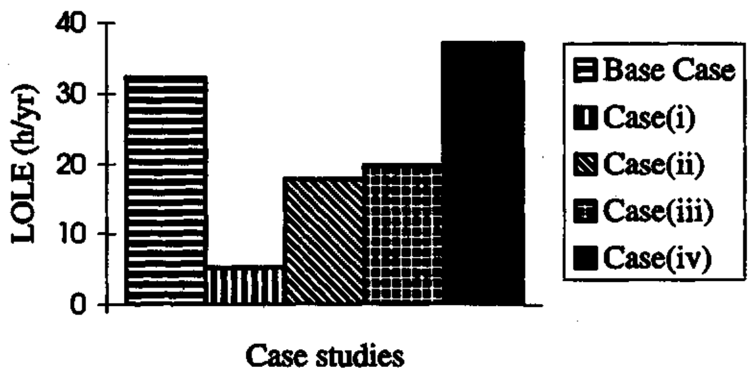


Fig. 5.4: Variation in LOLE for a Fixed Deterministic Criterion

The case studies done on the test system illustrate that the system health decreases and risk increases as the generating unit FOR or the load factor increases. The system health and risk also vary depending on the shape of the load curve and the unit deratings. The deterministic criterion does not reflect any differences in the above case studies.

There are many other factors that influence the system adequacy that can be incorporated in probabilistic risk and health analysis but are not recognized at all by the deterministic criteria. Some of these factors are load forecast uncertainty, forced outage rate uncertainty, energy limitations of generating units, planned maintenance of units, operating constraints, etc.

5.2.2. Variation in System Health and Risk in Different Systems Having the Same Deterministic Criterion

When comparing different systems at a fixed deterministic criterion, the system health and risk vary depending on the unit size configuration of the system. Four practical systems P, Q, R and S with different unit configurations as shown in Table 5.2 have been analyzed. The FOR of all the generating units are assumed to be 5%. The peak load for each system is such that all four systems meet the same deterministic criterion of 'Capacity Reserve = CLU + 10% PL'. The load duration curve for the four systems is assumed to be the same and is shown in Fig. 5.5 and Table 5.3. The system load factor is 53.1%.

Table 5.2: Test Systems P, Q, R and S

Test System	Unit 1 (KW)	Unit 2 (KW)	Unit 3 (KW)	PL (KW)
System P	270	270	270	491
System Q	270	270	540	491
System R	270	540	540	736
System S	270	540	725	736

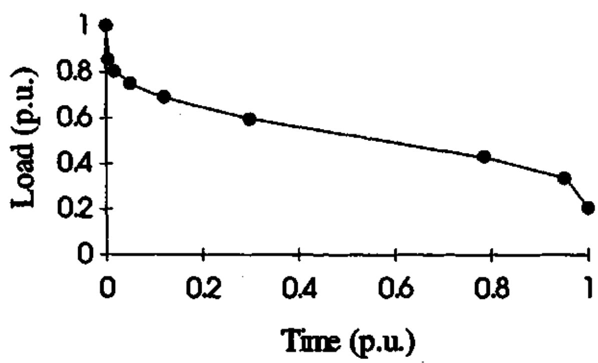


Fig. 5.5: LDC for Systems P, Q, R and S

Table 5.3: LDC for Systems P, Q, R and S

p.u. PL	1.0000	0.8506	0.8046	0.7471	0.6897	0.5977	0.4253	0.3333	0.2069
p.u. Period	0.0000	0.0064	0.0187	0.0513	0.1193	0.2979	0.7876	0.9539	1.0000

The deterministic criteria for the four systems P, Q, R, and S are the exactly the same but the LOLE and the probabilities of health are quite different and are shown in Table 5.4 and Fig. 5.6 - 5.7.

Table 5.4: P(H) and LOLE of Different Systems with the same Deterministic Criterion

Test System	Deterministic criterion	P(H)	LOLE (h/yr)
System P	CR = CLU + 10%PL	0.9340	28.16
System Q	CR = CLU + 10%PL	0.9340	19.14
System R	CR = CLU + 10%PL	0.9091	22.47
System S	CR = CLU + 10%PL	0.9091	21.09

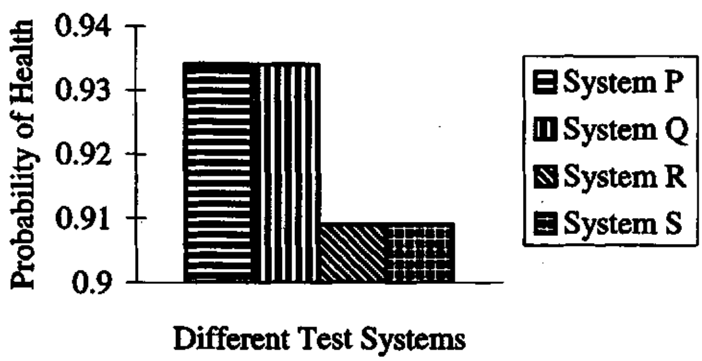
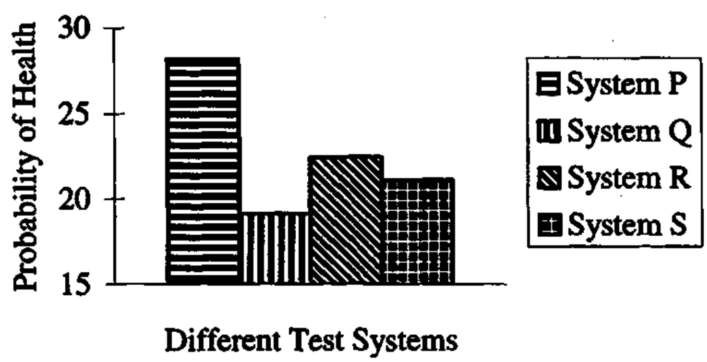


Fig. 5.6: P(H) for Different Systems with the same Deterministic Criterion



5.2.3. Variation in System Health and Risk due to the Size of the Unit Added using a Constant Deterministic Criterion

The size of the unit to be added to an existing system significantly affects the system health and risk even if the unit was added to maintain a constant deterministic criterion. The characteristics of the system health and risk with the addition of a single unit with different sizes to each of the test systems were investigated. The peak load at the moment of unit addition is such that a constant deterministic criterion of 'CR = CLU + 10%PL' is always maintained. The results are shown in Tables 5.5 - 5.8.

Table 5.5: Adding a Unit to System P

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	491	582	673	736	736	736	736	736	736	736	736
P(H)	0.9340	0.9592	0.9725	0.9759	0.9759	0.9759	0.9759	0.9759	0.9759	0.9759	0.9759
LOLE (h/yr)	28.16	16.68	11.30	11.74	8.01	6.97	6.90	6.83	6.83	6.83	6.83

Table 5.6: Adding a Unit to System Q

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	491	582	673	736	809	945	982	982	982	982	982
P(H)	0.9340	0.9592	0.9725	0.9759	0.9697	0.9541	0.9492	0.9492	0.9492	0.9492	0.9492
LOLE (h/yr)	19.14	11.43	7.52	6.90	7.81	11.21	12.61	11.70	11.63	11.63	11.63

Table 5.7: Adding a Unit to System R

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	736	827	918	982	1055	1191	1227	1227	1227	1227	1227
P(H)	0.9091	0.9243	0.9403	0.9492	0.9573	0.9640	0.9648	0.9648	0.9648	0.9648	0.9648
LOLE (h/yr)	22.47	18.27	14.40	12.61	11.54	13.15	14.20	10.39	9.74	9.73	9.73

Table 5.8: Adding a Unit to System S

	Base Case	Size of the unit added (KW)									
		100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	736	827	918	982	1055	1191	1227	1395	1395	1395	1395
P(H)	0.9091	0.9243	0.9403	0.9492	0.9573	0.9640	0.9648	0.9539	0.9539	0.9539	0.9539
LOLE (h/yr)	21.09	17.35	13.63	11.70	10.21	10.00	10.39	13.68	11.42	11.26	11.26

The variation in system health with increase in the size of the unit added to System Q in order to maintain a constant deterministic criterion is shown in Fig. 5.8.

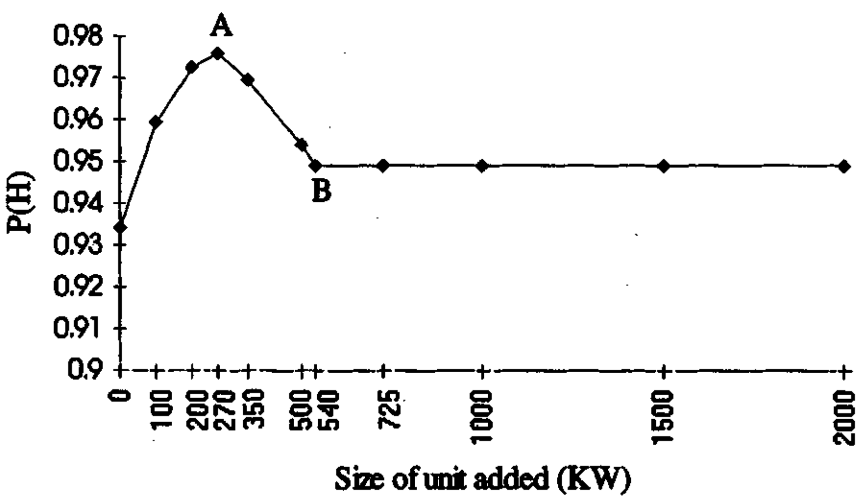


Fig. 5.8: P(H) of System Q with Added Unit Size at a Fixed Deterministic Criterion

When units of different sizes are added to a system to maintain a constant deterministic criterion, the system health varies in a certain manner. As the size of the added unit is increased, the probability of health for the system also increases up to a point A as illustrated in Fig. 5.8. This point can be designated as the '*health benefit limit*' of the system. After the size of the added unit exceeds the health benefit limit, the system health degrades. As shown in Fig. 5.8, the probability of health decreases from point A to B, the latter point being the CLU of the system. After the size of the added unit exceeds the CLU, the system health remains constant.

The health benefit limit (HBL) of a system can be determined by plotting the health characteristic of the system as shown in Fig. 5.8. The HBL of a system depends on the unit size configuration, the FOR and the system load characteristics. The system HBL is always less than or equal to the CLU of the system. Adding a unit larger in size than the system HBL involves more investment for no additional health benefit. Appreciation of the HBL can be very useful to those system planners that use deterministic criteria.

The system health characteristics as a function of the size of the unit added in order to maintain a constant deterministic criterion, are compared for the four systems in Fig. 5.9. It can be seen from Fig. 5.9 that the HBL for Systems Q and S are less than their CLU, whereas, for Systems P and R, the HBL are equal to their CLU. In general, the HBL is less than the CLU in systems that have a single largest unit and in systems that have more units equal in size to the CLU, the HBL is equal to the CLU.

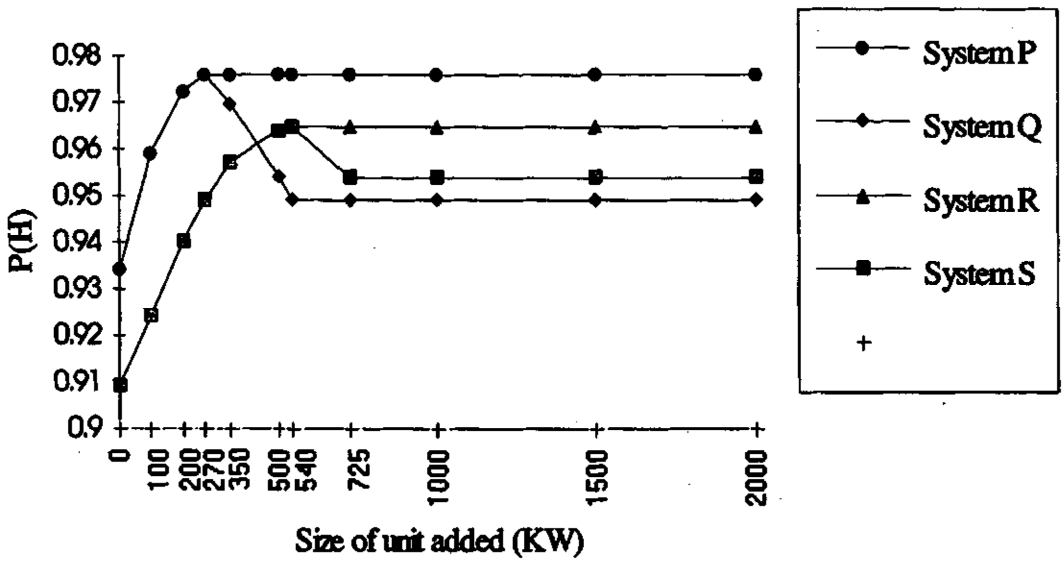


Fig. 5.9: P(H) when Different Sized Units are Added at a Fixed Deterministic Criterion

The system risk characteristics as a function of the size of the unit added to a system to maintain a constant deterministic criterion are shown in Fig. 5.10. The LOLE initially decreases with increase in size of the added unit and then increases as the unit size approaches the CLU. After the size of the added unit exceeds the CLU, the LOLE again decreases and then finally remains constant when the added unit size exceeds some value greater than the CLU.

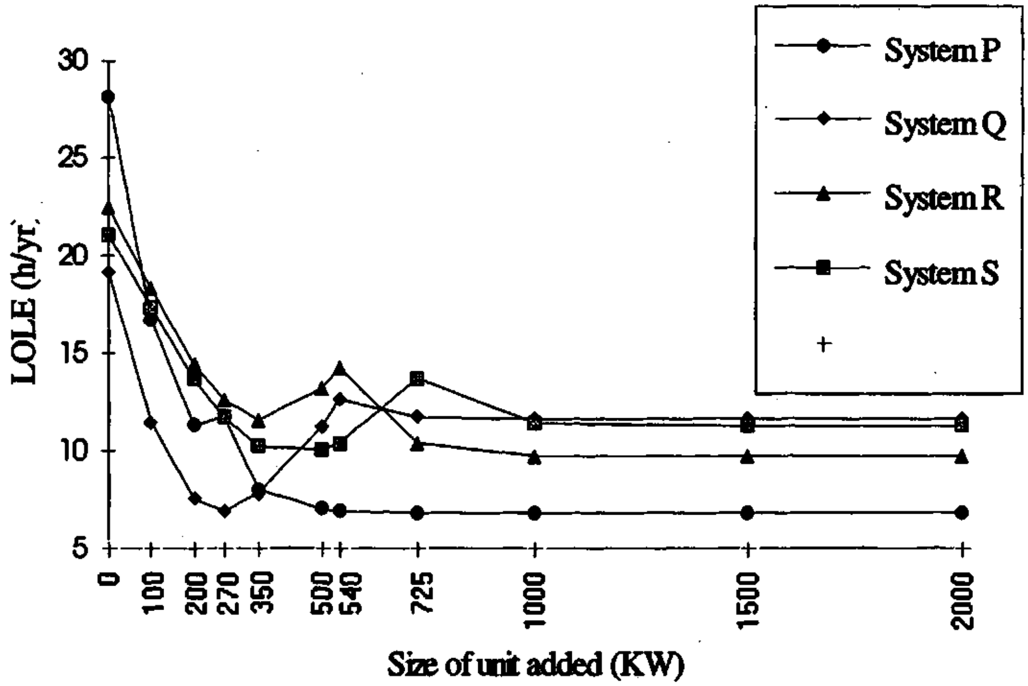


Fig. 5.10: LOLE when Different Sized Units are Added at a Fixed Deterministic Criterion

It can be seen from Fig. 5.10 that for System Q, there is a considerable increase in system risk when the added unit is between 270 and 540 KW and then from 540 to 725 KW there is only a slight decrease in risk before it becomes constant after 725 KW. When a unit is added to System Q with a constant deterministic criterion, its size therefore should not exceed 270 KW from a risk benefit point of view. In the case of System P, there is only a slight increase in system risk when the added unit is between 200 and 270 KW and from 270 to 540 KW, there is a significant decrease in risk. Therefore, when a unit is added to System P with a constant deterministic criterion, there is a risk benefit up to 540 KW and then for a larger unit the risk is constant. If a choice has to made between a 200 KW unit and a 270 KW unit to be added to System P to maintain the same deterministic criterion, Fig. 5.10 clearly shows that the 200 KW unit should be chosen to provide a lower system risk.

5.3 Variation in System Health at a Fixed Risk

The LOLE is the most widely used risk criterion in generating capacity adequacy assessment and accepted by most large utilities in capacity planning. When capacity planning is done using this risk criterion, new units are added to the system to maintain a constant LOLE. The system health characteristics, when a different size unit is added to the four test systems at a constant risk level, have been evaluated and are shown in Tables 5.9 - 5.12. The peak load at the moment of unit addition is such that a constant LOLE of 10 h/yr is always maintained. The value of the index X in the deterministic criterion 'CR = CLU + X% PL' has also been calculated.

Table 5.9: Adding a Unit to System P

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	398	537	660	724	758	779	780	782	782	782	782
P(H)	0.9734	0.9735	0.9749	0.9785	0.9713	0.9673	0.9669	0.9666	0.9666	0.9666	0.9666
X %	35.68	19.18	12.12	11.88	6.86	3.98	3.85	3.58	3.58	3.58	3.58

Table 5.10: Adding a Unit to System Q

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	421	567	703	780	843	921	928	942	943	943	943
P(H)	0.9638	0.9638	0.9649	0.9669	0.9629	0.9585	0.9579	0.9557	0.9556	0.9556	0.9556
X %	28.27	12.87	5.26	3.85	5.58	12.92	16.38	14.65	14.53	14.53	14.53

Table 5.11: Adding a Unit to System R

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	489	660	822	928	1025	1139	1163	1219	1233	1233	1233
P(H)	0.9541	0.9544	0.9560	0.9579	0.9617	0.9713	0.9737	0.9659	0.9639	0.9639	0.9639
X %	65.64	37.88	22.87	16.38	13.17	15.01	16.08	10.75	9.49	9.49	9.49

Table 5.12: Adding a Unit to System S

	Base Case	Size of the unit added (KW)									
		100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	489	661	829	942	1051	1191	1219	1318	1359	1362	1362
P(H)	0.9541	0.9542	0.9549	0.9557	0.9580	0.9640	0.9659	0.9633	0.9589	0.9584	0.9584
X %	65.64	37.67	21.83	14.65	10.37	9.99	10.75	16.46	12.95	12.70	12.70

The system health characteristics as a function of the size of the unit added to maintain a constant risk of LOLE = 10 h/yr for the four systems are shown in Fig. 5.11.

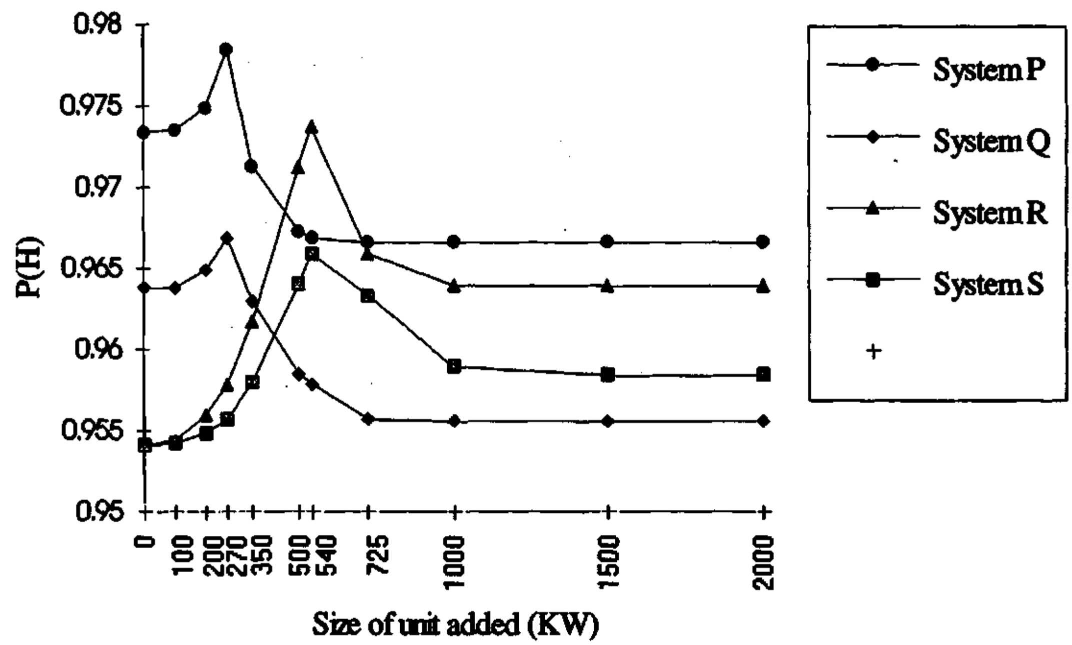


Fig. 5.11: P(H) when Different Sized Units are Added at a Fixed LOLE

It can be observed from Fig. 5.11 that the system probability of health increases as the size of the added unit increases up to the health benefit limit. After the size of the added unit exceeds the system HBL, its probability of health decreases with an increase in unit size and eventually remains constant when the unit size exceeds some value equal to or larger than the CLU.

A knowledge of the system HBL is useful not only when the deterministic criterion is used for unit additions (as described in the previous section) but also when a risk criterion such as the LOLE is used. Adding a new unit larger than the system HBL in order to maintain a constant LOLE will result in the system being less healthy, even though the risk remains the same.

5.4 Variation in System Risk at a Fixed Health

The system health is a new probabilistic index that incorporates the deterministic criterion and could be very useful in adequacy assessment of SIPS. If capacity planning is done using the health criterion, new units are added to the system to maintain a constant probability of health. The system risk characteristics, at a constant health level, with the addition of a unit of different sizes to the four test systems have been evaluated and are shown in Tables 5.13 - 5.16. The peak load at the moment of unit addition is such that a constant probability of health of 0.95 is always maintained. The value of X in the deterministic criterion 'CR = CLU + X% PL' has also been calculated.

Table 5.13: Adding a Unit to System P

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	457	615	755	837	837	837	837	837	837	837	837
LOLE (h/yr)	20.80	20.95	24.96	30.52	20.08	16.28	16.06	15.77	15.76	15.76	15.76
X %	18.16	4.07	-1.99	-3.23	-3.23	-3.23	-3.23	-3.23	-3.23	-3.23	-3.23

Table 5.14: Adding a Unit to System Q

	Base	Size of the unit added (KW)									
	Case	100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	457	615	755	837	903	968	977	977	977	977	977
LOLE (h/yr)	14.23	14.24	15.03	16.06	14.51	12.53	12.34	11.48	11.42	11.42	11.42
X %	18.16	4.07	-1.99	-3.23	-1.44	7.44	10.54	10.54	10.54	10.54	10.54

Table 5.15: Adding a Unit to System R

	Base Case	Size of the unit added (KW)									
		100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	504	681	857	977	1099	1292	1338	1338	1338	1338	1338
LOLE (h/yr)	10.96	11.06	11.55	12.34	14.30	20.11	21.52	16.02	14.45	14.36	14.36
X %	60.71	33.63	17.85	10.54	5.55	1.39	0.9	0.9	0.9	0.9	0.9

Table 5.16: Adding a Unit to System S

	Base Case	Size of the unit added (KW)									
		100	200	270	350	500	540	725	1000	1500	2500
PL (KW)	504	681	857	977	1099	1292	1338	1425	1425	1425	1425
LOLE (h/yr)	10.96	10.97	11.15	11.50	12.35	15.17	16.02	15.18	12.56	12.36	12.36
X %	60.71	33.63	17.85	10.54	5.55	1.39	0.9	7.72	7.72	7.72	7.72

The system risk characteristics as a function of the size of the unit added to maintain a constant probability of health of 0.95 for the four systems are shown in Fig. 5.12.

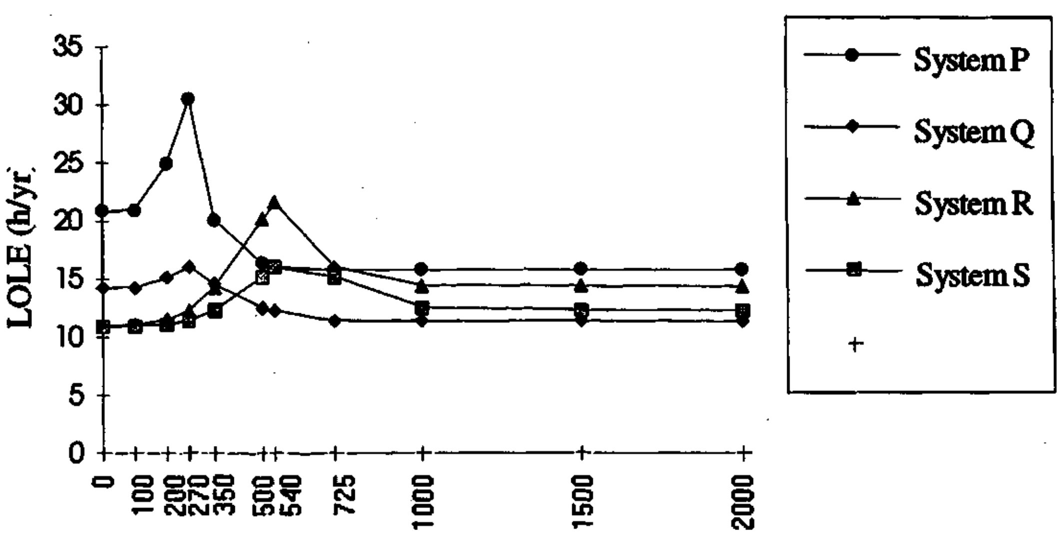


Fig. 5.12: LOLE when Different Sized Units are Added at a Fixed P(H)

It can be observed from Fig. 5.12 that as the size of the unit increases to the system HBL at a constant probability of health, the system risk also increases. After the size of the added unit exceeds the system HBL, the risk decreases with an increase in unit size and eventually remains constant when the unit size exceeds some value equal to or larger than the CLU.

If new units are added to a system using the probability of health as the accepted criterion, the system risk is maximum when the added unit size is equal to the HBL of the system. Therefore, whenever a new unit with a size equal to or close to the system HBL is to be added at a constant health criterion, a supplementary check for LOLE is necessary to prevent exposure of the system to an unacceptable risk level.

5.5 The Most Suitable Adequacy Index for SIPS

The earliest methods used for system generation planning were deterministic. Modern large power utilities use the system risk indices for generation adequacy evaluation. The conventional risk indices have not been accepted in adequacy studies of SIPS and deterministic criteria are still applied. The system health index has been developed to bridge the gap between the two techniques and be a practical tool in the adequacy assessment of SIPS. However, its applicability is yet to be tested in practice. This section analyzes the three different methods for generation planning by application to the four test systems P, Q, R and S in order to determine the adequacy index that is the most suitable for SIPS.

Consider the three different indices for System P. The deterministic criterion is 'CR = CLU + 10% PL', the LOLE is 28.16 h/yr and the P(H) is 0.934. The PLCC of the system for each of these three criteria, when different size units are added, are shown in Table 5.17 and Fig. 5.13.

The PLCC of a system, at a constant criterion using any of the three indices, increases as the size of the added unit increases up to a certain limit. After exceeding that limit, the PLCC of the system remains constant for larger unit additions. As seen from Fig. 5.13, there is a similarity in behavior between the PLCC characteristics for both the health and deterministic criteria. They both increase until the size of the added unit is equal to the CLU and then remain constant for larger unit additions. The risk characteristic behaves quite differently. The PLCC, at a constant risk, increases even after the size of the added unit is much larger than the CLU.

Table 5.17: Comparing the three Adequacy Criteria using System P

	PLCC (KW) of System P allowed by different adequacy criteria								
	Base	Size of the unit added (KW)							
	Case	100	200	270	350	540	725	1000	2500
CLU. + 10%PL	491	582	673	736	736	736	736	736	736
P(H) = 0.934	491	659	804	895	895	895	895	895	895
LOLE = 28.16 h/yr	491	653	769	828	887	944	951	951	951

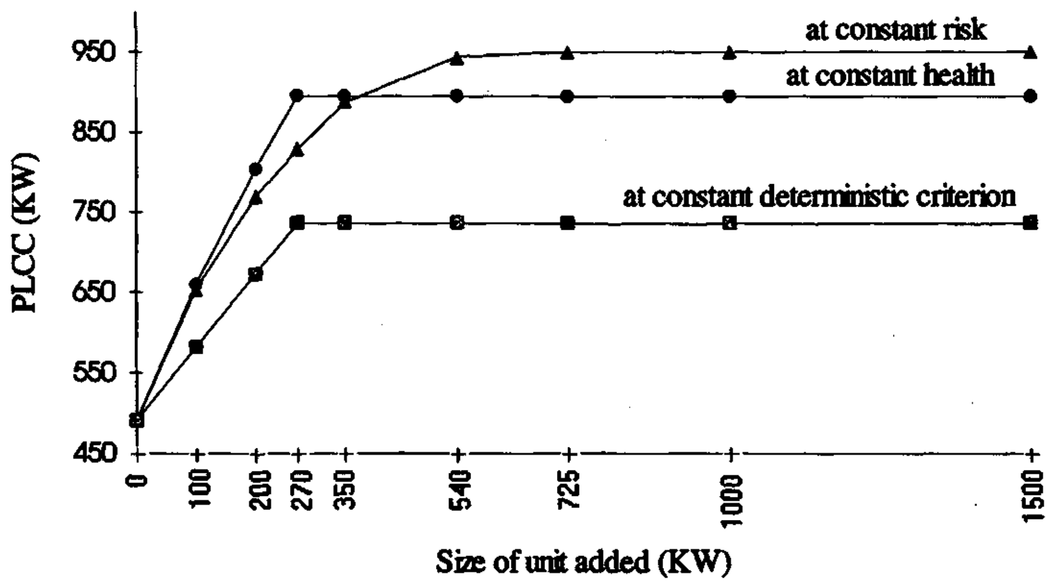


Fig. 5.13: Comparing the three Adequacy Criteria using System P

In the example shown by Fig. 5.13, the deterministic criterion is the most stringent among the three when a unit of any size is to be added. It permits a much smaller peak load to be carried compared to the health or risk criterion for any size unit addition.

However, this does not mean that the deterministic criterion demands a more reliable system. If the FOR of the units in the system were higher or the load factor were higher, the PLCC allowed by the health or risk criteria could be much smaller than that permitted by the deterministic criterion. There are many other factors that affect the PLCC using the probabilistic risk or health criteria. On the other hand, the deterministic criterion may demand a system too reliable than can be economically justified. The deterministic methods do not recognize the stochastic nature of unit outages and load variations. They do not normally include any explicit recognition of system risk and do not provide comparable risks for systems of different size or composition. They also do not incorporate the influence of different factors, such as, LFU, planned maintenance, energy limitations, operating constraints, etc. Due to these reasons, large utilities have discarded these methods and adopted the probabilistic techniques. A deterministic criterion is not considered to be an appropriate adequacy index, even though it is widely used in SIPS.

The system risk indices are the most widely used adequacy criteria in large systems. However, the risk indices do not provide any information on the magnitude of the available capacity reserve. This should be of great interest to SIPS planners who employ deterministic methods. Concerns about the ability to interpret a single numerical risk index such as the LOLE and the lack of system operating information contained in a single risk index have made SIPS planners reluctant to use risk indices in practice. The question that should be asked is "is the probability of health a better criterion than the LOLE in the adequacy assessment of a SIPS?". In an attempt to provide an answer, the LOLE criterion is compared with the probability of health criterion by application to the four test systems, P, Q, R and S. The examples illustrate that some of the factors upon which the answer depends are the configuration of the existing unit sizes in a system, the size of a new unit to be added to the system and the initial system criterion that drives the adequacy assessment.

The base case peak loads of the four systems were taken such that the probability of health for all the systems is 0.95. The peak loads for systems P, Q, R and S are therefore 457, 457, 504 and 504 KW respectively. The corresponding LOLE for these peak loads are taken as the accepted system risk criteria. The heath criteria for all the systems are the same, i.e. a probability of health of 0.95. The PLCC at both of these criteria, when a new unit with different sizes is added, were calculated for all the four systems. The results are shown in Tables 5.18 - 5.21 and Fig. 5.14 - 5.17.

Table 5.18: Comparing the P(H) and LOLE Criteria for System P

	PLCC (KW) of System P allowed by different adequacy criteria									
	Base	Size of the unit added (KW)								
	Case	100	200	270	350	540	725	1000	1500	2500
P(H) = 0.95	457	615	755	837	837	837	837	837	837	837
LOLE = 20.80 h/yr	457	614	736	796	841	881	886	886	886	886

Table 5.19: Comparing the P(H) and LOLE Criteria for System Q

	PLCC (KW) of System P allowed by different adequacy criteria									
	Base	Size of the unit added (KW)								
	Case	100	200	270	350	540	725	1000	1500	2500
P(H) = 0.95	457	615	755	837	903	977	977	977	977	977
LOLE = 14.23 h/yr	457	615	748	821	900	1012	1036	1039	1040	1040

Table 5.20: Comparing the P(H) and LOLE Criteria for System R

	PLCC (KW) of System P allowed by different adequacy criteria									
	Base	Size of the unit added (KW)								
	Case	100	200	270	350	540	725	1000	1500	2500
P(H) = 0.95	504	681	857	977	1099	1338	1338	1338	1338	1338
LOLE = 10.96 h/yr	504	679	843	951	1045	1180	1238	1255	1255	1255

Table 5.21: Comparing the P(H) and LOLE Criteria for System S

	PLCC (KW) of System P allowed by different adequacy criteria									
	Base	Size of the unit added (KW)								
	Case	100	200	270	350	540	725	1000	1500	2500
P(H) = 0.95	504	681	857	977	1099	1338	1425	1425	1425	1425
LOLE = 10.96 h/yr	504	680	852	965	1071	1238	1342	1383	1387	1387

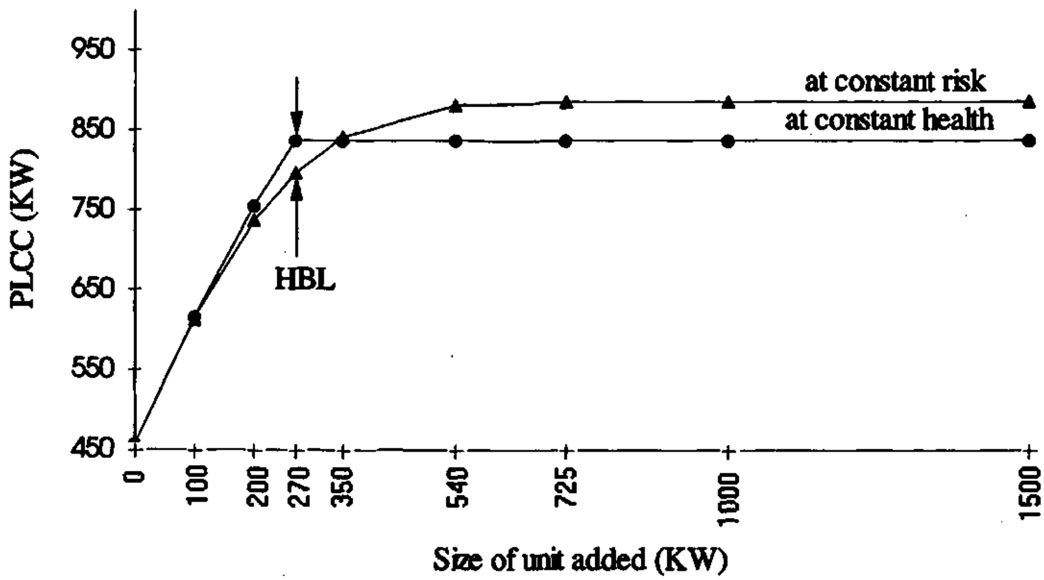


Fig. 5.14: Comparing the P(H) and LOLE Criteria for System P

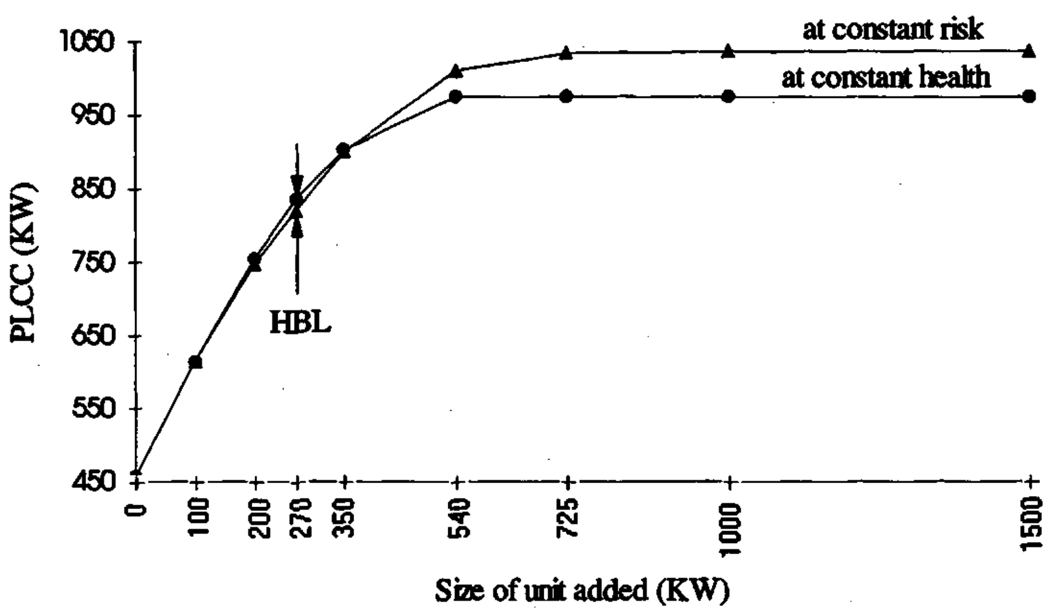


Fig. 5.15: Comparing the P(H) and LOLE Criteria for System Q

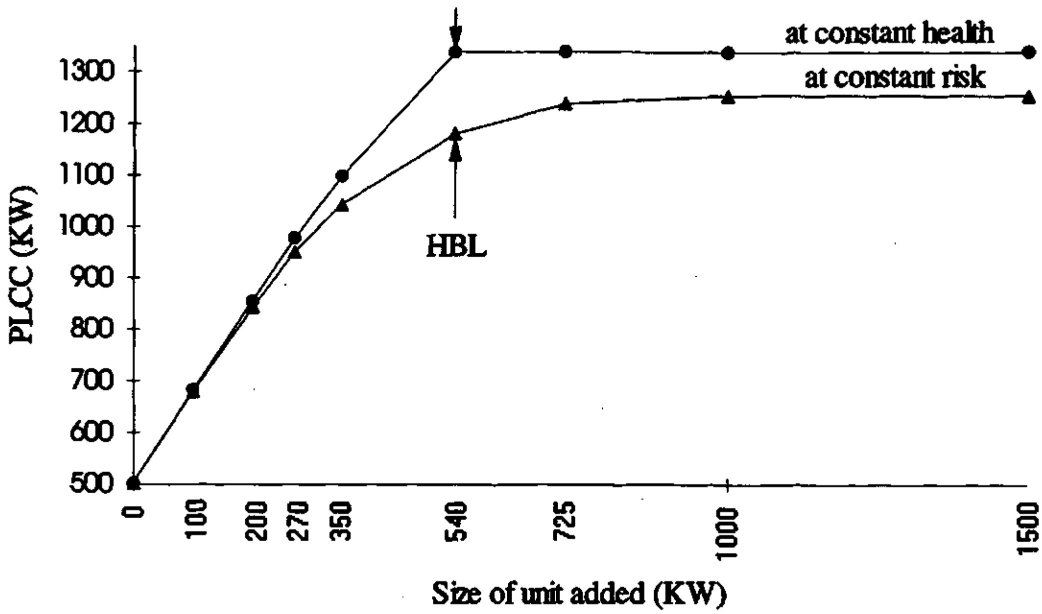


Fig. 5.16: Comparing the P(H) and LOLE Criteria for System R

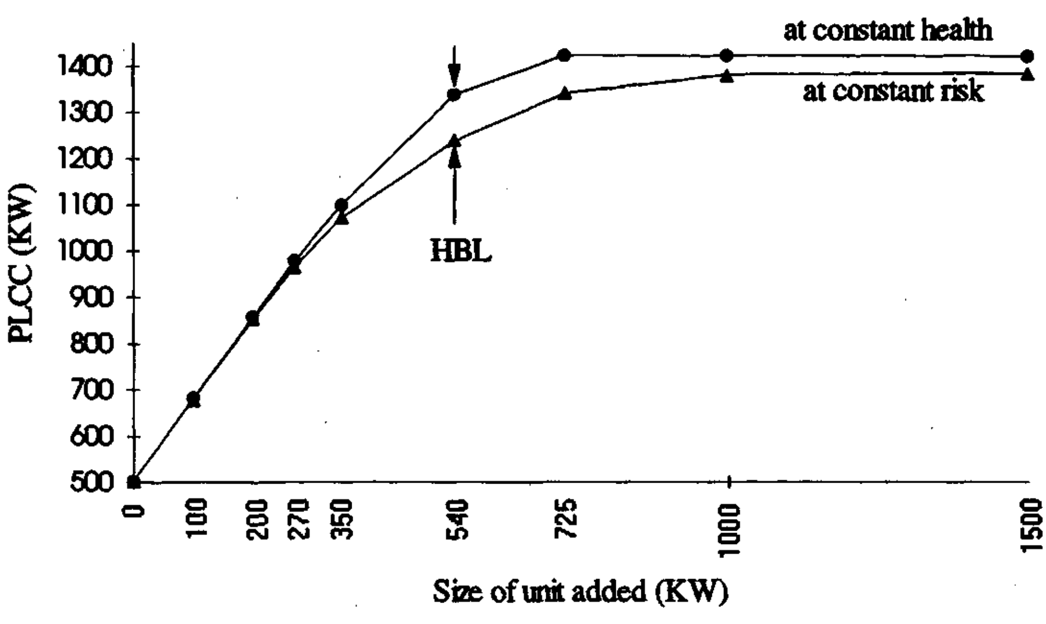


Fig. 5.17: Comparing the P(H) and LOLE Criteria for System S

Figures 5.14 to 5.17 illustrate that the PLCC increases as the size of the added unit increases up to a certain limit and then remains constant. The PLCC permitted by the LOLE criterion is different than that allowed by the P(H) criterion. It is seen that sometimes the health index is more restrictive (i.e. permits a smaller load to be carried) than the risk index and at other times the opposite is true. For Systems P and Q, the risk index is more restrictive when the size of the added unit is less than 350 KW and for a larger unit, the health index is more restrictive. In other words, if the health criterion is used in Systems P and Q for adding a unit smaller than 350 KW, the system risk will be higher than it was for the base case. On the other hand, if the LOLE criterion is used in Systems P and Q for adding a unit larger than 350 KW, the initial health criterion will be violated. For Systems R and S, the risk index is always more restrictive. An important point shown in the figures for all the four systems is that the risk index is always more restrictive than the health index when the size of the added unit is equal to the system HBL. The figures show that for a range of unit sizes close to the system HBL, the risk index is always more restrictive and the difference in PLCC allowed by the two indices is a maximum when the size of the added unit is equal to the HBL.

Figures 5.16 and 5.17 show that for Systems R and S, the LOLE is a more restrictive index when a unit of any size is added. The initial health criterion of P(H) = 0.95 was changed to P(H) = 0.88 for Systems R and S and similar studies were performed to compare the health and risk indices. The results are shown in Table 5.22 - 5.23 and Fig. 5.18 - 5.19.

Table 5.22: Comparing the P(H) and LOLE Criteria for System R

	PLCC (KW) of System P allowed by different adequacy criteria									
	Base	Size of the unit added (KW)								
	Case	100	200	270	350	540	725	1000	1500	2500
P(H) = 0.88	960	1093	1232	1324	1429	1683	1683	1683	1683	1683
LOLE = 44.40 h/yr	960	1087	1205	1282	1369	1527	1635	1705	1715	1715

Table 5.23: Comparing the P(H) and LOLE Criteria for System S

	PLCC (KW) of System P allowed by different adequacy criteria									
	Base	Size of the unit added (KW)								
	Case	100	200	270	350	540	725	1000	1500	2500
P(H) = 0.88	960	1093	1232	1324	1429	1683	1880	1880	1880	1880
LOLE = 33.84 h/yr	960	1088	1210	1287	1376	1555	1687	1814	1846	1846

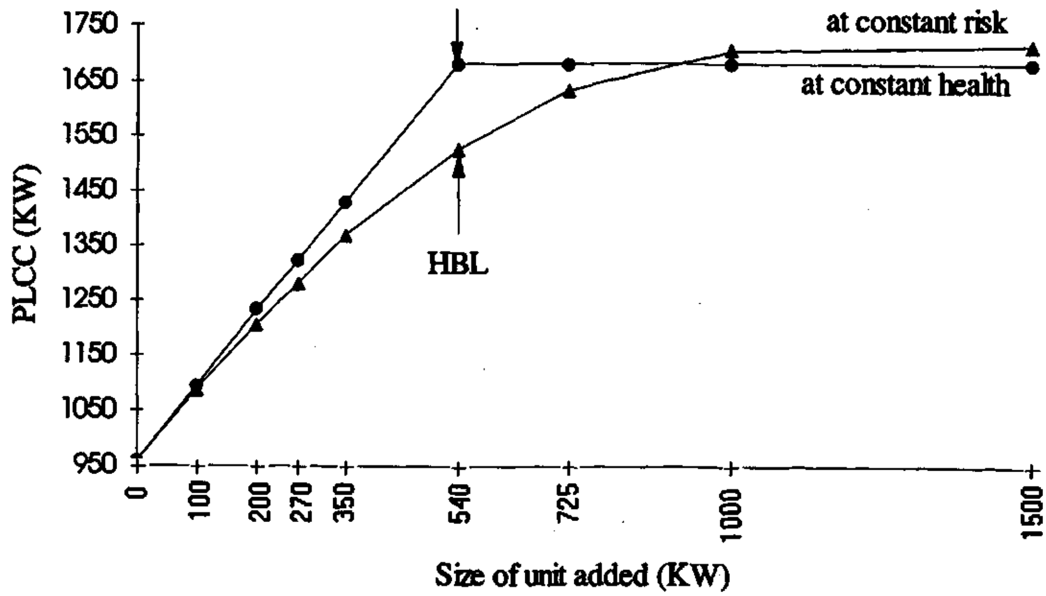


Fig. 5.18: Comparing the P(H) and LOLE Criteria for System R

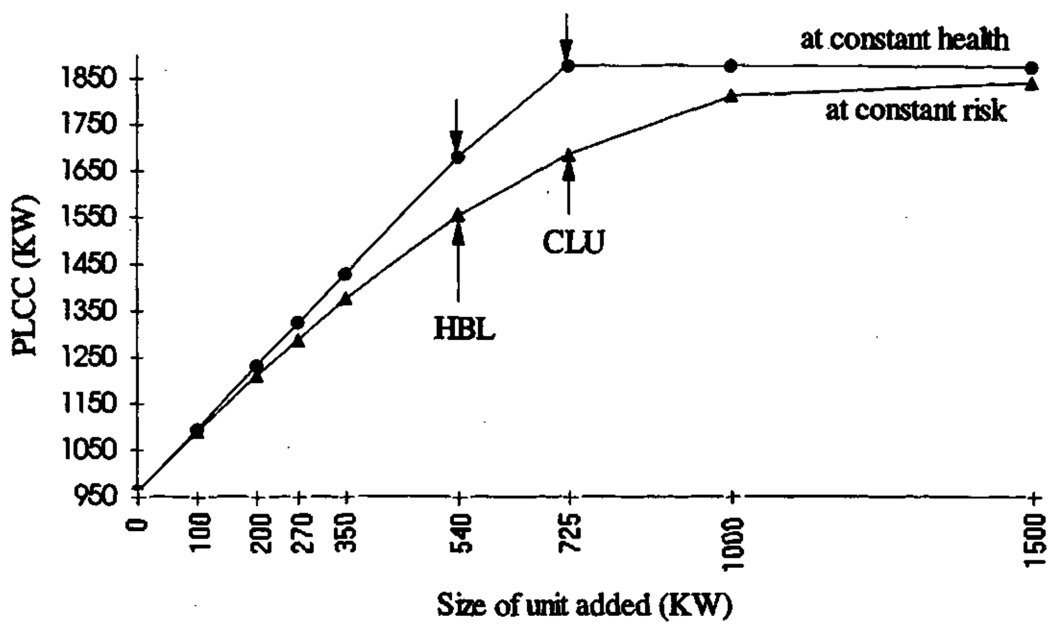


Fig. 5.19: Comparing the P(H) and LOLE Criteria for System S

When P(H) = 0.88 rather than the 0.95 used in the previous example, Fig. 5.18 shows that the health index is more restrictive for System R when a unit larger than 850 KW is added. In the case of System S, Fig. 5.19 shows that the LOLE is a more restrictive index when a unit of any size is added. Figures 5.18 and 5.19 also confirm that the risk index is always more restrictive than the health index when the size of the added unit is equal to the system HBL. Fig. 5.19, however, shows a different characteristic from Figures 5.13 - 5.18 regarding the maximum difference in PLCC allowed by the two indices. In this case, the maximum difference is observed when the size of the added unit is equal to the CLU instead of the HBL as in the previous cases.

The health and risk indices for System S are shown in Table 5.24 and Fig. 5.20 when the accepted health criterion was further changed to P(H) = 0.80.

Table 5.24: Comparing the P(H) and LOLE Criteria for System S

	PLCC (KW) of System P allowed by different adequacy criteria									
	Base	Size of the unit added (KW)								
	Case	100	200	270	350	540	725	1000	1500	2500
P(H) = 0.80	1130	1268	1403	1502	1614	1883	2136	2136	2136	2136
LOLE = 75.85 h/yr	1130	1265	1395	1485	1583	1808	1958	2099	2156	2159

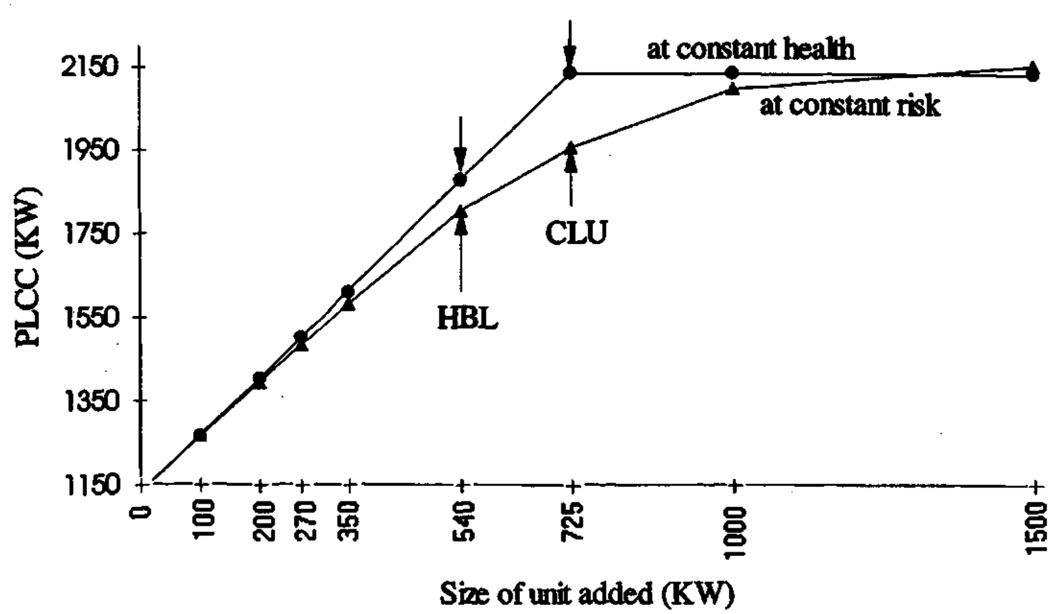


Fig. 5.20: Comparing the P(H) and LOLE Criteria for System S

In this case, as shown in Fig. 5.20, the health index is more restrictive for System S when a unit larger than 1350 KW is added. The accepted health or risk criterion will also affect the comparison between the two indices. When a lower probability of health or a higher LOLE is taken as the accepted system criterion, the health index will tend to be more restrictive than the risk index and vice-versa.

5.6 Conclusion

Deterministic indices do not respond to changes in generating unit FOR, unit deratings, changes in load factor or changes in the shape of the load curve. They cannot incorporate the effect of many other factors such as the LFU, planned maintenance and energy limitations. They cannot be used to compare the adequacy of different systems. Different systems with the same deterministic adequacy measure may be exposed to quite different levels of risk or different degrees of comfort. The addition of a new unit to maintain a constant deterministic criterion does not result in a constant risk or a constant health. The system risk and health vary depending on the size of the unit to be added. Deterministic criteria are not as consistant as the probabilistic risk or health indices.

The term 'health benefit limit' has been defined as the size of the new unit to be added at a constant deterministic criterion that results in the highest system health probability. The system HBL is either equal to or less than the CLU of the system and can be determined from the plot of the system health probability against the size of the added unit at a constant deterministic criterion. In general, the HBL is less than the CLU in systems that have a single largest unit. The system HBL is equal to the CLU in systems that have several units equal in size to the CLU.

An appreciation of the system HBL can be of use to deterministic criterion users as well as risk criterion users in capacity planning. Adding a new unit equal to or less than the size of the system HBL ensures a healthier system when either a deterministic criterion or a risk criterion is used. There is a system health penalty for adding a larger unit. Knowledge of the system HBL can also be useful when capacity planning is done using the health criterion. Since the system risk is maximum when the unit added to maintain a constant health criterion is equal in size to the system HBL, a supplementary check for LOLE should be done to avoid violating the system risk when a unit close in size to the system HBL is to be added.

There are many factors that effect the risk and health indices and compel them to behave in different ways. Depending on the system unit size configuration, either the health or the risk index can become the most restrictive. Taking a lower health probability or a higher LOLE as the accepted criterion will tend to make the health probability more restrictive than the LOLE and vice-versa. Either the risk or the health index is the more appropriate index under different circumstances. Since SIPS planners are reluctant to use risk indices in practice, it appears resonable that both health and the risk indices be used together in adequacy evaluation of SIPS.

6. CAPACITY PLANNING IN SMALL ISOLATED POWER SYSTEMS

6.1 Introduction

The installed capacity of a system must be expanded with time to meet the increasing load demand. System planners normally predict future load growth based on data from past experience and on future anticipation. As the system load increases, the system becomes less reliable. There comes a point in time when new generating units must be added in order to maintain an acceptable level of system reliability.

There are many factors that need to be considered before additional generating units are installed. The investment in the capacity expansion and the level of reliability to be achieved are greatly influenced by the types and sizes of the units and the dates when they will be brought into operation. Capacity planning involves a study of the effects of all of these different factors on the economy and reliability of a system, in order to make a decision about the optimum sizes and dates of the units to be added.

The existing methods used for capacity planning in SIPS are basically deterministic techniques and are described in this chapter. Larger systems use conventional risk methods with LOLE as the most widely used criterion. Capacity planning using a LOLE criterion is also illustrated. A new system health index designated as the loss of health expectation, LOHE, with similar characteristics as the conventional LOLE, has been used in this thesis so that capacity planning using the two methods can be compared more easily and depicted on the same graph. The term LOHE has already been defined in Chapter 3.

Capacity planning using deterministic methods, conventional risk methods and system health methods are illustrated and compared by application to System P described in Section 5.2.2. System P has three 270 KW units with 5% FOR and its LDC is given in Fig. 5.5. The system peak load is taken as 475 KW. The annual peak load forecast is shown in Table 6.1.

Table 6.1: Annual Peak Load Forecast for System P

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PL(KW)	525	580	640	705	775	855	940	1035	1145	1265	1385	1525	1678	1850	2035

The PLCC determined by the deterministic criterion of 'CR = CLU + 10%PL' is 491 KW. This load level has been to used to establish criterion values for both LOLE and LOHE. At 491 KW, the LOLE is 28.16 h/yr and the LOHE is 577.80 h/yr. Capacity planning in System P is, therefore, illustrated in this chapter using 'CR = CLU + 10%PL', 'LOLE = 28 h/yr' and 'LOHE = 578 h/yr' as the accepted criterion for the deterministic, risk and health methods respectively.

6.2 Capacity Planning using a Deterministic Criterion

In capacity planning using deterministic methods, a new unit must be added to the system before the accepted deterministic criterion is violated. The assumption has been made that 270 KW units with 5% FOR are to be added to maintain the deterministic criterion. Table 6.2 shows how the deterministic index X, the system risk and the system health vary with time of no capacity is added.

Table 6.2: Changes in Deterministic Index X, LOLE and LOHE with Time

Year	0	1	2	3	4	5
PL(KW)	475	525	580	640	705	775
X %	13.68	2.86	-6.90	-15.63	-23.40	-30.32
LOLE (h/yr)	24.88	34.48	46.63	60.40	103.18	190.47
LOHE (h/yr)	515.41	697.76	884.23	1066.68	1393.23	1995.46

The underlined figure in Table 6.2 indicates that the deterministic criterion has been violated in Year 1. In order to maintain X above 10%, a new unit must be added in Year 0. Table 6.3 shows the changes in X, LOLE and LOHE after the unit addition.

Table 6.3: Changes in System Indices after the 1st Unit is Added

Year	0	1	2	3	4	5
PL(KW)	475	525	580	640	705	775
X %	70.53	54.29	39.66	26.56	14.89	4.52
LOLE (h/yr)	1.64	2.28	3.21	4.33	8.47	17.06
LOHE (h/yr)	49.41	67.64	88.51	110.71	167.69	280.72

Table 6.3 shows that X is less than 10% in Year 5 and therefore a new unit must be brought into operation in Year 4 to maintain the deterministic criterion. Table 6.4 shows the changes in X, LOLE and LOHE after the second unit is added.

Table 6.4: Changes in System Indices after the 2nd Unit is Added

Year	4	5	6	7	8	9
PL(KW)	705	775	855	940	1035	1145
X %	53.19	39.35	26.32	14.89	4.35	-5.68
LOLE (h/yr)	0.63	1.34	2.97	4.96	11.19	29.54
LOHE (h/yr)	16.43	30.25	57.36	88.75	161.99	325.06

Table 6.4 shows that the next new unit must be added in Year 7. Table 6.5 shows the dates on which additional 270 KW units with a 5% FOR must be brought in to the system to maintain the accepted deterministic criterion. The system risk and health due to the unit additions are also listed in the table.

Table 6.5: Dates for Unit Addition by Deterministic Criterion

270 KW Units Added		1st Unit	2nd Unit	3rd Unit
Date for Addition		Year 0	Year 4	Year 7
LOLE (h/yr)	before addition	24.8793	8.4660	4.9637
	after addition	1.6406	0.6288	0.3963
LOHE (h/yr)	before addition	515.4111	167.6868	88.7497
	after addition	49.4056	16.4269	9.1531

Chapter 5 showed that the health benefit limit of System P is 270 KW, which is also the CLU of the system. It is noted that adding a unit larger than the system HBL will not create a higher system health. If a 540 KW unit with a 5% FOR is added in Year 0 instead of a 270 KW, the maximum LOLE and LOHE will be 5.20 and 167.69 h/yr respectively before another unit is added in Year 4. This shows that there is no improvement in system health by adding a unit larger than the system HBL although there is an improvement in system risk. In systems that have the HBL less than the CLU, the system health will be lower when a unit larger than the HBL is added to maintain a fixed deterministic criterion.

Table 6.5 shows that although the new units have been added in order to maintain a constant deterministic criterion, the system reliability in terms of system risk and health is seen to be increasing with time. System planners using the deterministic method should realize this situation and that the necessary balance between the economics and system reliability can be seriously disrupted.

If it is assumed that all the units have a 10% FOR, Table 6.6 shows the unit addition dates and the corresponding system risk and health. Table 6.6 can be compared with Table 6.5 to observe the tremendous increase in system risk and decrease in system health with the increase in the unit FOR. This situation is not recognized by the deterministic methods.

Table 6.6: Addition of 10% FOR Units by Deterministic Criterion

270 KW Units Added		1st Unit	2nd Unit	3rd Unit
Date for Addition		Year 0	Year 4	Year 7
LOLE	before addition	98.89	45.41	33.52
(h/yr)	after addition	12.89	6.37	5.09
LOHE	before addition	1056.45	504.02	322.31
(h/yr)	after addition	194.65	91.27	62.40

Capacity planning using a deterministic criterion, as described in this section, does not provide the ability to determine the optimum investment in additional generating capacity required to maintain an acceptable level of system reliability. This is because it does not recognize many factors that effect system reliability, such as the unit FOR, the load factor, the shape of the load curve, the fact that the units may reside in derated states or may be energy limited, the planned outage of units for maintenance, the uncertainty in forecasting load, etc.

6.3 Capacity Planning using a Risk Criterion

Capacity planning is normally done in large systems using probabilistic techniques. Some utilities employ loss of energy risk indices such as LOEE, UPM or SM but the most widely used risk index is the LOLE. The LOLE can be evaluated for all the forecast peak loads and for different size unit additions using a forecast annual load curve. The LOLE for different unit additions is normally plotted against the annual peak loads in a semi-log graph. Unit addition dates are determined so that the system LOLE always remains below the accepted criterion. The method is described using System P.

Assume that new units rated at 270 KW and with 5% FOR are to be added to System P in order to meet the increasing load with an acceptable LOLE of 28 h/yr. Table 6.7 and Fig. 6.1 shows the LOLE at different peak loads with the 270 KW unit additions

Fig. 6.1 illustrates that additional units of 270 KW size and 5% FOR must be brought into operation in System P in the Years 0, 5 and 8 in order to maintain the system risk below the accepted LOLE criterion of 28 h/yr.

Table 6.7: Variation in LOLE with PL and Units Added

	PL	LOLE (h/yr) After Adding 270 KW Units		
Year	(KW)	No Unit Added	1 Unit Added	2 Units Added
0	475	24.8793	1.6404	.1018
1	525	34.4769	2.2802	.1418
2	580	46.6265	3.2070	.2070
3	640	60.4012	4.3339	.2905
4	705	103.1850	8.4660	.6288
5	775	190.4682	17.0642	1.3399
6	855	353.2452	34.9653	2.9698
7	940	537.7088	56.1462	4.9637
8	1035	905.5215	111.8670	11.1862
9	1145	1579.1590	246.9858	29.5391
10	1265	2508.1000	464.9847	59.5776
11	1385	3585.2280	841.3849	137.2659
12	1525	4807.3670	1539.1910	307.7866
13	1680	5902.5400	2558.4380	633.0197
14	1850	6860.5080	3656.2820	1240.1430
15	2035	7509.6290	4860.5590	2192.7200

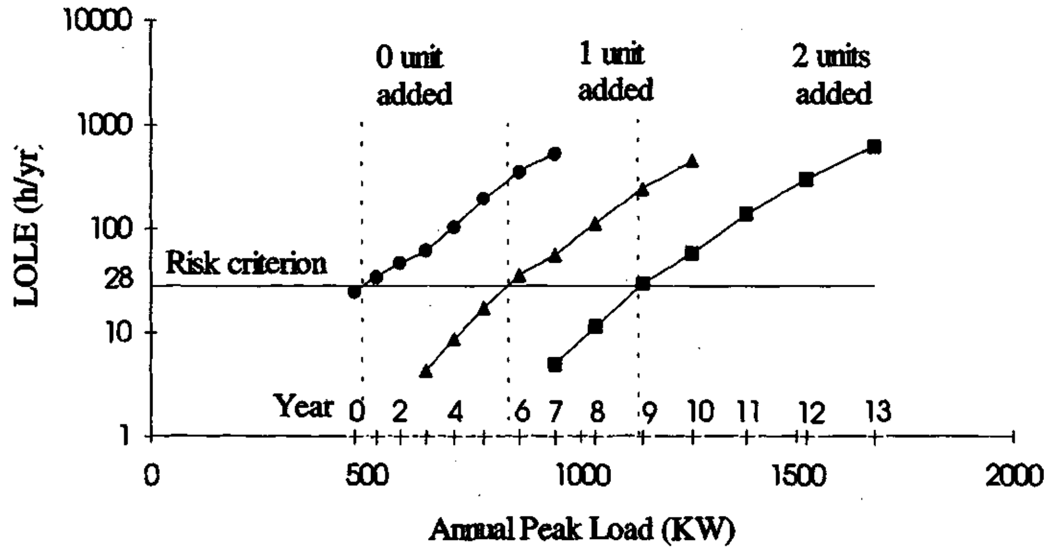


Fig. 6.1: Determining Dates for 270 KW Unit Additions in System P

Unlike the deterministic methods, the risk criterion approach can incorporate all the major factors in the calculation of system risk and is therefore widely accepted for capacity planning in major large interconnected power utilities throughout the world. This approach has, however, not been accepted as a useful method in SIPS. The system HBL can provide useful information about the system health in deciding the size of the additional unit in this method. The addition of a unit larger than the HBL will give a lower system health when the accepted risk criterion is reached as the system load increases with time. When a 270 KW unit is added, the LOHE will be 280 h/yr before the next unit should be added to maintain the LOLE below 28 h/yr. When a 540 KW unit is added, the LOHE will be 708 h/yr before another unit is added. Adding a unit smaller or equal to the system HBL will prevent a violation of the system health when capacity planning is performed using the risk criterion.

6.4 Capacity Planning using Risk and Health Criteria

Chapter 5 shows that either the health or the risk index can be the determining factor in adding capacity depending on the configuration of the system, the size of the unit to be added or the accepted system planning adequacy criterion. Employing both the health and the risk criteria in capacity planning will ensure that both the system risk and the probable capacity reserve will be within acceptable limits.

Different schemes for adding two new units to System P have been studied. The accepted risk and health criteria are:

Risk criterion: LOLE = 28 h/yr
Health criterion: LOHE = 578 h/yr

Scheme 1: The sizes and FOR of the new units to be added are:

Unit 4 = 540 KW, FOR = 5%
Unit 5 = 375 KW, FOR = 5%

The LOLE and LOHE at the forecast peak loads, when the new units are added to System P, are shown in Table 6.8 and Fig. 6.2. The base case is the original system.

Table 6.8: Variation in LOLE and LOHE with PL as Units are Added in Scheme 1

	PL	Base Case		Unit 4 added		Units 4 & 5 added	
Year	(KW)	LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)
0	475	24.8793	515.4111	1.2440	49.4056	.0636	3.6790
1	525	34.4769	697.7652	1.7238	67.6412	.0909	5.1091
2	580	46.6265	884.2301	2.3344	88.5063	.1273	6.8410
3	640	60.4012	1066.6790	3.0286	110.7149	.1687	8.7322
4	705	103.1850	1393.2290	5.2015	167.6868	.2961	13.9703
5	775	190.4682	1995.4570	9.6388	280.7174	.5478	24.3342
6	855	353.2452	2945.7410	18.0374	482.8699	1.0807	44.3211
7	940	537.7088	3947.6830	27.6153	708.2074	1.8635	70.1026
8	1035	905.5215	5083.9940	47.6585	1114.4450	3.4510	118.9344
9	1145	1579.1590	6164.1550	88.2089	1808.4090	6.8826	211.9922
10	1265	2608.1000	7128.2660	151.0358	2834.1080	14.8990	400.7963
11	1385	3585.2280	7645.4590	244.6198	3788.2400	26.9023	628.5466
12	1525	4807.3670	8131.3970	414.9851	4973.5680	56.2487	1069.2920
13	1680	5902.5400	8446.2790	707.6873	6029.7270	111.4651	1794.4700
14	1850	6860.5080	8527.1880	1281.6210	6943.8420	240.0678	2814.0350
15	2035	7509.6290	8599.8740	2191.7320	7564.1410	439.1013	3874.5240

Fig. 6.2 and Table 6.9 illustrate when the additional units must be brought into the system as required by separate application of the health and the risk criteria.

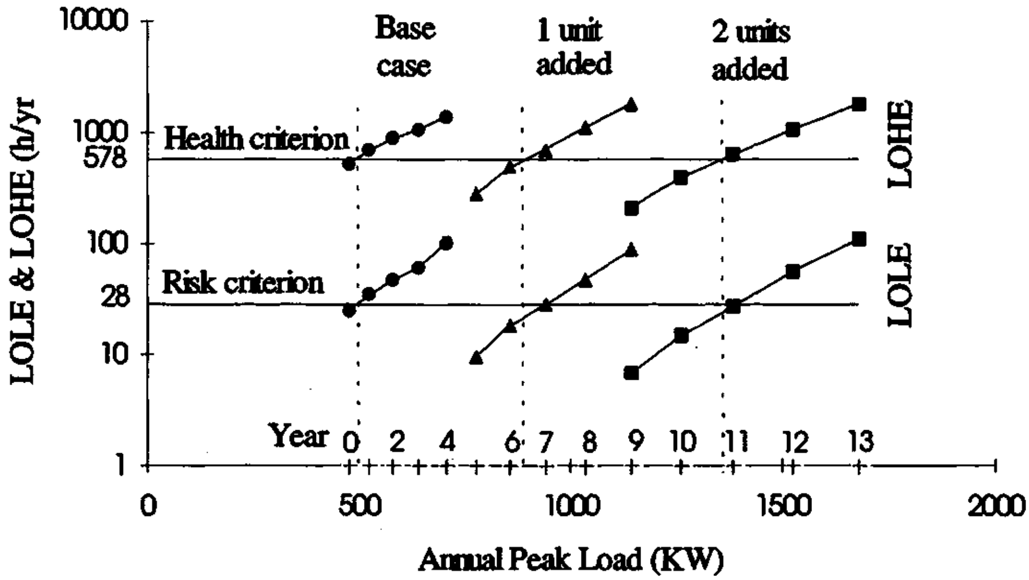


Fig. 6.2: Capacity Planning of System P in Scheme 1

Table 6.9: Dates for Unit Additions in Scheme 1

	unit 4 (540 KW) added	unit 5 (375 KW) added	next unit added
Health Criterion	Year 0	Year 6	Year 10
Risk Criterion	Year 0	Year 7	Year 11

Adding the new units using only the LOLE criterion will violate the system health in the Year 6 and Year 10. In this case, the health index is a more restrictive criterion than the risk index. The new units are added as required by the LOHE criterion and in doing so meet both the risk and health criteria.

Scheme 2: The sizes and FOR of the new units to be added are:
Unit 4 = 270 KW, FOR = 5%
Unit 5 = 270 KW, FOR = 5%

The LOLE and LOHE at the forecast peak loads, when the new units are added to System P, are shown in Table 6.10 and Fig. 6.3.

Table 6.10: Variation in LOLE and LOHE with PL as Units are Added in Scheme 2

Year	PL (KW)	Base Case		Unit 4 added		Units 4 & 5 added	
		LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)
0	475	24.8793	515.4111	1.6404	49.4056	0.1018	4.0288
1	525	34.4769	697.7652	2.2802	67.6412	0.1418	5.5482
2	580	46.6265	884.2301	3.2070	88.5063	0.2070	7.4723
3	640	60.4012	1066.6790	4.3339	110.7149	0.2905	9.6533
4	705	103.1850	1393.2290	8.4660	167.6868	0.6288	16.4269
5	775	190.4682	1995.4570	17.0642	280.7174	1.3399	30.2469
6	855	353.2452	2945.7410	34.9653	482.8699	2.9698	57.3609
7	940	537.7088	3947.6830	56.1462	708.2074	4.9637	88.7497
8	1035	905.5215	5083.9940	111.8670	1114.4450	11.1862	161.9960
9	1145	1579.1590	6164.1550	246.9858	1808.4090	29.5391	325.0573
10	1265	2608.1000	7128.2660	464.9847	2834.1080	59.5776	583.4413
11	1385	3585.2280	7645.4590	841.3849	3788.2400	137.2659	988.7280
12	1525	4807.3670	8131.3970	1539.1910	4973.5680	307.7866	1710.9100
13	1680	5902.5400	8446.2790	2558.4380	6029.7270	633.0197	2732.0020
14	1850	6860.5080	8527.1880	3656.2820	6943.8420	1240.1430	3820.6610
15	2035	7509.6290	8599.8740	4860.5590	7564.1410	2192.7200	4995.7380

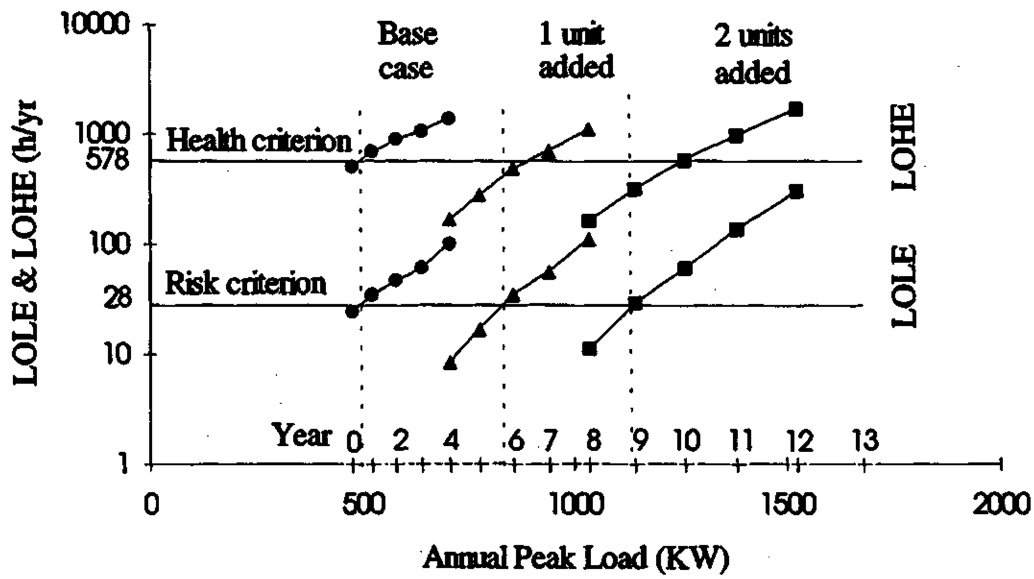


Fig. 6.3: Capacity Planning of System P in Scheme 2

Fig. 6.3 and Table 6.11 illustrate when the additional units must be brought into the system as required by separate application of the health and the risk criteria.

Table 6.11: Dates for Unit Additions in Scheme 2

	unit 4 (540 KW) added	unit 5 (375 KW) added	next unit added
Health Criterion	Year 0	Year 6	Year 9
Risk Criterion	Year 0	Year 5	Year 8

Adding the new units using only the health criterion will violate the system risk in Year 5 and Year 8. In this case, the risk index is a more restrictive criterion than the health index. The new units are added as required by the LOLE criterion and in doing so meet both the risk and health criteria.

Scheme 3: The sizes and FOR of the new units to be added are:

Unit 4 = 270 KW, FOR = 5%
Unit 5 = 540 KW, FOR = 5%

The LOLE and LOHE at the forecast peak loads, when the new units are added to System P, are shown in Table 6.12 and Fig. 6.4.

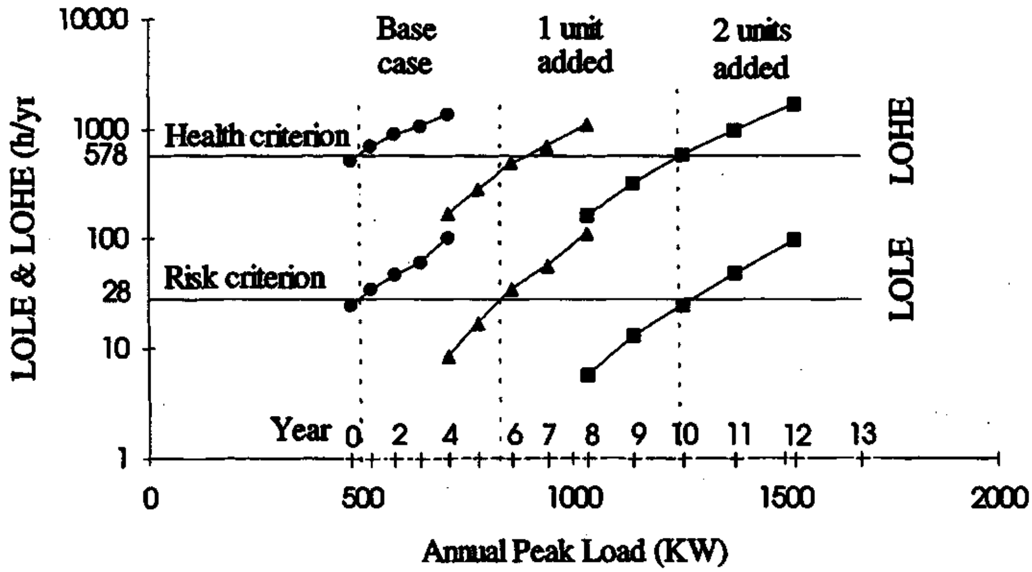


Fig. 6.4: Capacity Planning of System P in Scheme 3

Table 6.12: Variation in LOLE and LOHE with PL as Units are Added in Scheme 3

	PL	Base Case		Unit 4 added		Units 4 & 5 added	
Year	(KW)	LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)
0	475	24.8793	515.4111	1.6404	49.4056	0.0820	4.0288
1	525	34.4769	697.7652	2.2802	67.6412	0.1140	5.5482
2	580	46.6265	884.2301	3.2070	88.5063	0.1605	7.4723
3	640	60.4012	1066.6790	4.3339	110.7149	0.2171	9.6533
4	705	103.1850	1393.2290	8.4660	167.6868	0.4254	16.4269
5	775	190.4682	1995.4570	17.0642	280.7174	0.8590	30.2469
6	855	353.2452	2945.7410	34.9653	482.8699	1.7692	57.3609
7	940	537.7088	3947.6830	56.1462	708.2074	2.8496	88.7497
8	1035	905.5215	5083.9940	111.8670	1114.4450	5.7432	161.9960
9	1145	1579.1590	6164.1550	246.9858	1808.4090	13.0459	325.0573
10	1265	2608.1000	7128.2660	464.9847	2834.1080	24.8463	583.4413
11	1385	3585.2280	7645.4590	841.3849	3788.2400	48.6722	988.7280
12	1525	4807.3670	8131.3970	1539.1910	4973.5680	96.9186	1710.9100
13	1680	5902.5400	8446.2790	2558.4380	6029.7270	192.0195	2732.0020
14	1850	6860.5080	8527.1880	3656.2820	6943.8420	362.5225	3820.6610
15	2035	7509.6290	8599.8740	4860.5590	7564.1410	704.0516	4995.7380

Fig. 6.4 and Table 6.13 illustrate when the additional units must be brought into the system as required by separate application of the health and the risk criteria.

Table 6.13: Dates for Unit Addition in Scheme 3

	unit 4 (540 KW) added	unit 5 (375 KW) added	next unit added
Health Criterion	Year 0	Year 6	Year 9
Risk Criterion	Year 0	Year 5	Year 10

Adding the new units using only the health criterion will violate the system risk in Year 5 and using only the risk criterion will violate the system health in Year 9. In this case, both the health and risk index are the more restrictive at different times. The first new unit must be added as required by the LOLE criterion and the second new unit must be added as required by the LOHE criterion in order to meet both criteria.

This conclusion is based on an analysis of System P and may not be applicable to other systems. Consider System S, which has a quite different system configuration than System P. System S has three generating units of sizes 270 KW, 540 KW and 725 KW with 5% FOR and its LDC is given in Fig. 5.5. The system peak load is taken as 700 KW. The annual peak load forecast for System S is shown in Table 6.14.

Table 6.14: Annual Peak Load Forecast for System S

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PL(KW)	605	665	730	805	890	980	1080	1190	1310	1445	1590	1750	1925	2120	2335

The PLCC determined by the deterministic criterion of 'CR = CLU + 10%PL' is 736 KW. At a peak load of 736 KW, the LOLE is 21.09 h/yr and the LOHE is 796.09 h/yr for System S. The accepted health and risk criteria for capacity planning in System S are, therefore, LOHE = 796 h/yr and LOLE = 21 h/yr respectively.

Assume that it has been decided to add the following two units at appropriate times so that the system does not violate either of the two criteria.

Unit 4 = 540 KW, FOR = 5%
Unit 5 = 1000 KW, FOR = 5%

The LOLE and LOHE at the forecast peak loads, when the new units are added to System S, are shown in Table 6.15 and Fig. 6.5.

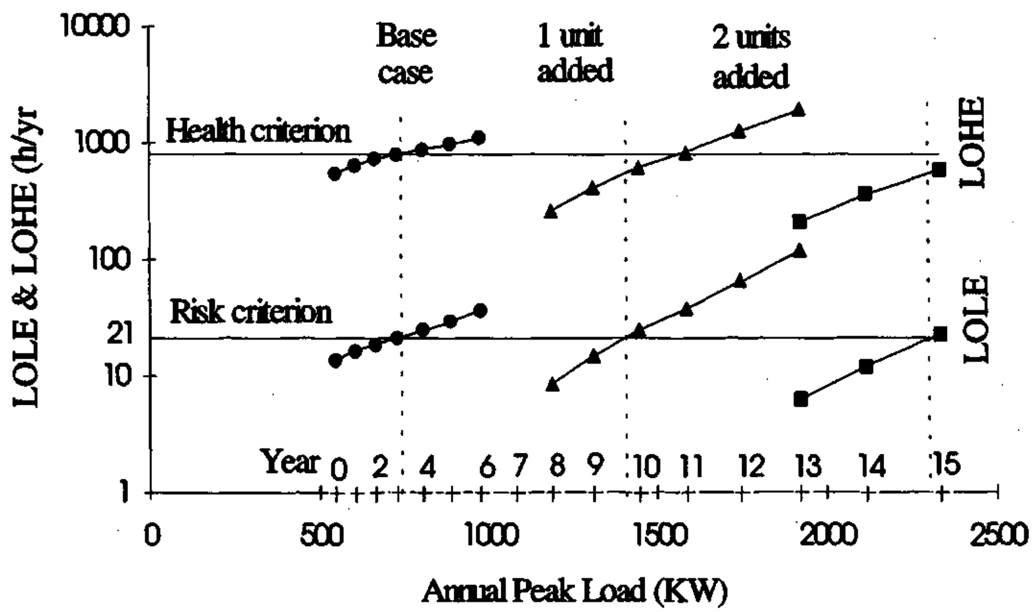


Fig. 6.5: Variation in LOLE and LOHE with PL as Units are Added to System S

Table 6.15: Variation in LOLE and LOHE with PL as Units are Added to System S

Year	PL (KW)	Base Case		Unit 4 added		Units 4 & 5 added	
		LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)	LOLE (h/yr)	LOHE (h/yr)
0	550	13.6200	539.1505	0.6818	39.9116	0.0341	2.6436
1	605	16.3369	640.8815	0.8216	47.6549	0.0411	3.1636
2	665	18.5540	720.3450	0.9451	53.9738	0.0473	3.5970
3	730	20.8210	789.1339	1.1035	60.4175	0.0552	4.0695
4	805	24.1954	876.3036	1.3720	69.7992	0.0686	4.7937
5	890	28.8561	966.0239	1.8105	82.3848	0.0905	5.8396
6	980	36.6571	1100.8940	2.5344	102.0125	0.1267	7.5083
7	1080	57.7313	1442.0770	4.4666	152.6383	0.2235	11.8755
8	1190	100.3281	2155.3330	8.5341	260.6141	0.4272	21.1382
9	1310	167.5981	3111.5380	14.6144	407.1570	0.7342	34.2417
10	1445	261.6898	4232.1850	24.1478	609.5173	1.2186	53.4167
11	1590	389.6919	5347.1110	37.6527	838.4930	1.9194	77.6950
12	1750	549.5220	6348.8530	64.7208	1253.0320	3.3419	124.1364
13	1925	826.6683	7215.5090	118.8256	1921.8710	6.2863	208.9779
14	2120	1375.1750	7744.6800	225.4451	2887.1750	12.0619	358.5320
15	2335	2288.0220	8225.6790	405.1582	3946.8940	22.7381	582.2451

Fig. 6.5 and Table 6.16 illustrate when the additional units must be brought into the system as required by separate application of the health and the risk criteria.

Table 6.16: Dates for Unit Addition in System S by the Health and Risk Criteria

	unit 4 (540 KW) added	unit 5 (375 KW) added	next unit added
Health Criterion	Year 3	Year 10	Year 15
Risk Criterion	Year 3	Year 9	Year 14

In this case, the new units are added as required by the LOLE criterion and in doing so meet both the accepted system health and risk criteria.

Fig. 6.6 illustrates the LOLE and LOHE curves to determine the dates for new unit additions if the same risk and health criteria used in System P (i.e. LOLE = 28 h/yr and LOHE = 578 h/yr) are taken as the accepted criteria for System S. Table 6.17 shows when the additional units must be brought into the system as required by separate application of the health and the risk criteria.

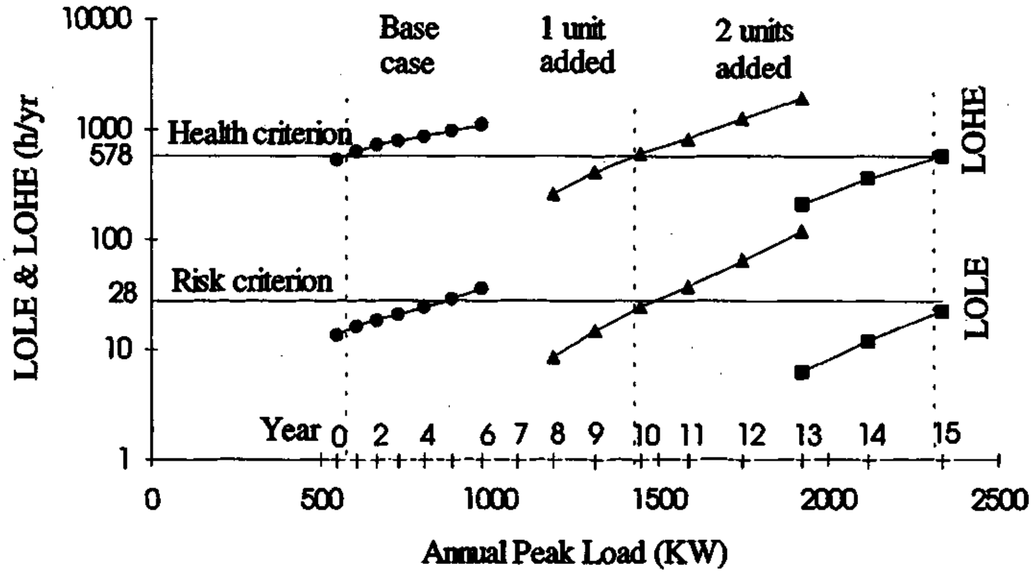


Fig. 6.6: Capacity Planning with Different Set of Accepted Criteria

Table 6.17: Unit Addition Dates for Different Health and Risk Criteria

	unit 4 (540 KW) added	unit 5 (375 KW) added	next unit added
Health Criterion	Year 0	Year 9	Year 14
Risk Criterion	Year 4	Year 10	Year 15

In total contrast to the previous case, the new units must be added as required by the LOHE criterion in order to meet both criteria when the accepted criteria are the same as that of System P. Ideally, a single set of health and risk criteria should be selected and used for all SIPS in a single utility system.

In practice, large units tend to reside in derated states in addition to being fully available or forced out of service. The effect of unit deratings can be incorporated in capacity planning using both the risk and health criteria. Assume that Unit 3 in System S can reside in 725 KW, 270 KW and 0 KW states with probabilities of 0.65, 0.30 and 0.05 respectively and Unit 5 can reside in 1000 KW, 725 KW, 540 KW and 0 KW states with probabilities of 0.5, 0.3, 0.15 and 0.05 respectively. The accepted health and risk criteria are LOHE of 796 h/yr and LOLE of 21 h/yr. The LOLE and LOHE at the forecast peak loads, when the new units are added to System S, are shown in Table 6.18 and Fig. 6.7.

Table 6.18: Variation in LOLE and LOHE with PL Considering Unit Deratings

Year	PL (KW)	Base Case LOLE (h/yr)	Base Case LOHE (h/yr)	Unit 4 added LOLE (h/yr)	Unit 4 added LOHE (h/yr)	Units 4 & 5 added LOLE (h/yr)	Units 4 & 5 added LOHE (h/yr)
0	550	17.6673	615.9532	0.8842	47.5922	0.0493	4.2471
1	605	21.6944	742.0998	1.0895	57.7765	0.0615	5.0914
2	665	26.0439	860.5663	1.3196	67.9958	0.0764	6.0067
3	730	34.1462	1034.8560	1.7698	84.9898	0.1091	7.7198
4	805	49.8801	1345.3730	2.6563	116.7064	0.1752	11.0427
5	890	70.5662	1707.2530	3.9201	156.9642	0.2725	15.5080
6	980	98.0095	2159.4480	5.6821	209.3904	0.4089	21.4671
7	1080	140.7863	2740.0970	8.9292	288.3291	0.6650	31.1611
8	1190	218.4473	3542.6440	15.7637	424.0236	1.2222	49.3847
9	1310	330.9144	4447.6030	25.9694	599.9439	2.0624	74.3726
10	1445	530.2609	5379.4680	46.4580	874.8755	3.9064	119.1291
11	1590	872.0149	6288.4200	82.2311	1280.3140	7.1639	190.7271
12	1750	1303.0290	7022.3200	147.9920	1871.9450	14.2891	315.7481
13	1925	1859.1800	7639.5610	251.3233	2678.9830	26.8484	504.2979
14	2120	2600.8390	8023.9450	463.3241	3688.6160	53.9790	833.3730
15	2335	3558.4330	8373.3370	815.6104	4731.0650	105.9440	1313.2670

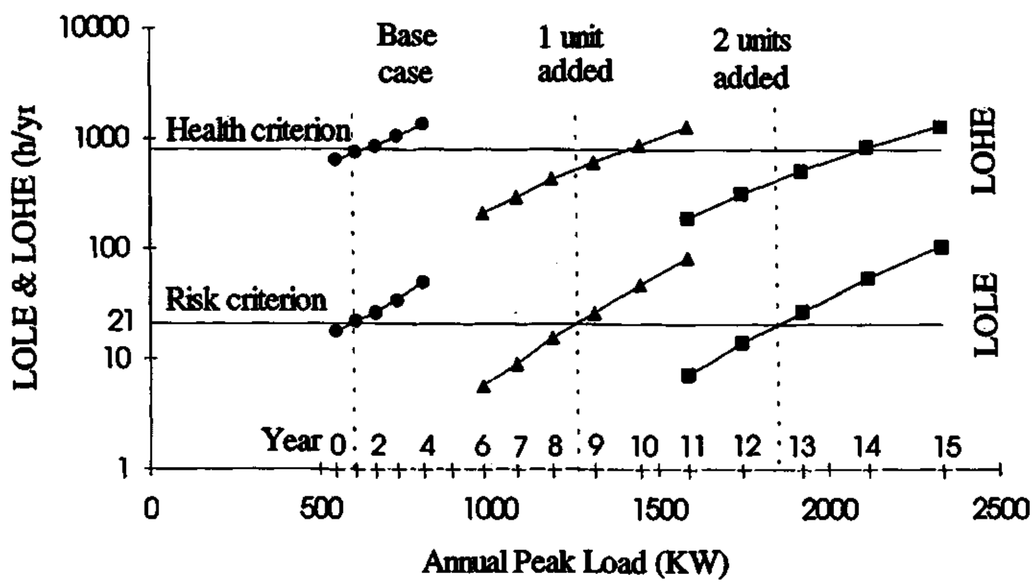


Fig. 6.7: Capacity Planning Considering Unit Deratings

Fig. 6.7 and Table 6.19 illustrate when the additional units must be brought into the system as required by separate application of the health and the risk criteria.

Table 6.19: Unit Addition Dates Considering Unit Deratings

	unit 4 (540 KW) added	unit 5 (375 KW) added	next unit added
Health Criterion	Year 1	Year 9	Year 13
Risk Criterion	Year 0	Year 8	Year 12

The forecast peak loads for System S given in Table 6.14 cannot be predicted in practice with 100% certainty. The uncertainty in the load forecast will effect the capacity planning. These effects can be incorporated in the method using both the health and risk criteria. Consider System S without any unit deratings and the LFU data given in Table 6.20.

Table 6.20: LFU Data For System S

% Deviation from Mean PL	Probability
-30 %	0.006
-20 %	0.061
-10 %	0.242
0 %	0.382
+10 %	0.242
+20 %	0.061
+30 %	0.006

The LOLE and LOHE at the forecast peak loads when the new units are added to System S, are shown in Table 6.21 and Fig. 6.8.

Fig. 6.8 illustrates when the additional units must be brought into the system, with LFU considered, as required by the health and the risk criteria separately. The results are shown in Table 6.22. This can be compared with Table 6.16 when LFU is not considered. In general, incorporation of LFU results in a unit being added to the system at an earlier date than when the LFU is ignored.

Table 6.21: Effect of LFU on the Variation in LOLE and LOHE

Year	PL (KW)	Base Case LOLE (h/yr)	Base Case LOHE (h/yr)	Unit 4 added LOLE (h/yr)	Unit 4 added LOHE (h/yr)	Units 4 & 5 added LOLE (h/yr)	Units 4 & 5 added LOHE (h/yr)
0	550	13.3379	527.7068	0.6696	39.1070	0.0335	2.5914
1	605	15.9784	625.0874	0.8094	46.6315	0.0405	3.1010
2	665	18.4639	710.1915	0.9575	53.6939	0.0479	3.5944
3	730	21.1315	789.1428	1.1462	61.1934	0.0573	4.1484
4	805	24.7399	875.8472	1.4446	71.0592	0.0722	4.9253
5	890	30.8651	993.5295	1.9993	86.9624	0.1000	6.2468
6	980	42.7942	1196.9470	3.1045	116.6725	0.1553	8.7829
7	1080	67.6066	1599.0910	5.4181	177.0294	0.2713	13.9985
8	1190	111.6756	2263.7200	9.5544	279.7953	0.4796	23.0664
9	1310	178.2948	3144.1340	16.0220	425.7539	0.8075	36.5094
10	1445	275.8009	4193.7420	26.5583	629.6676	1.3492	56.7140
11	1590	406.6816	5238.1890	44.3225	917.1613	2.2812	87.9649
12	1750	606.6924	6206.7260	78.4270	1366.8950	4.1092	142.8503
13	1925	947.1777	7014.8810	143.2389	2030.9220	7.6785	237.6228
14	2120	1515.1580	7643.5030	259.6306	2912.9250	14.4885	392.2954
15	2335	2324.4100	8084.7910	458.7121	3932.8110	27.4591	632.4172

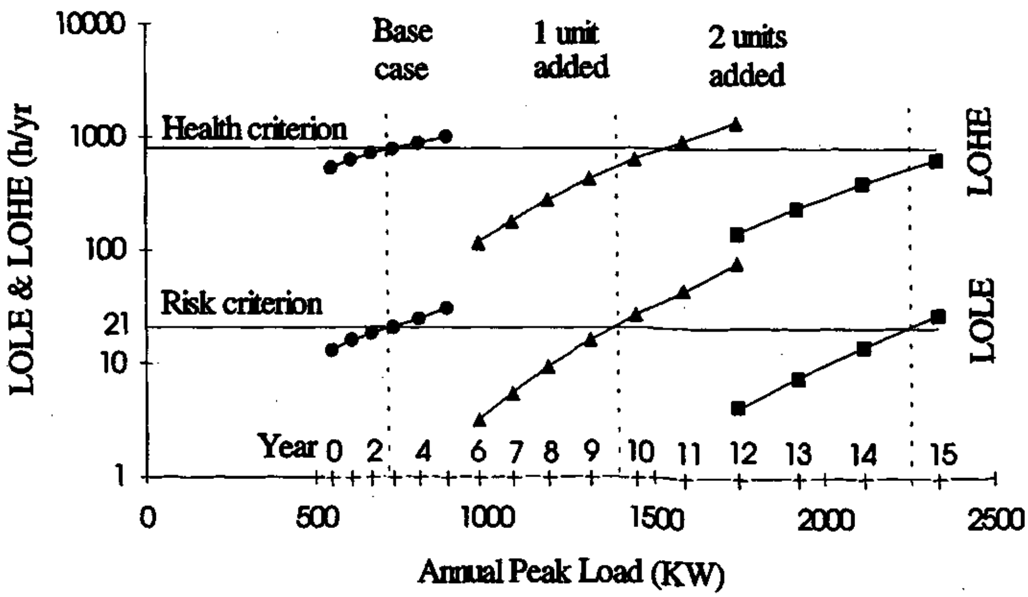


Fig. 6.8: Capacity Planning Considering LFU

Table 6.22: Unit Addition Dates Considering LFU

	unit 4 (540 KW) added	unit 5 (375 KW) added	next unit added
Health Criterion	Year 3	Year 10	Year 15
Risk Criterion	Year 2	Year 9	Year 14

The examples presented illustrate the incorporation of generating units derated states and load forecast uncertainty in capacity planning using the new method employing both the system health and risk criteria. It has also been shown how the LOLE and LOHE govern the capacity expansion when a different set of indices are selected as the accepted system criteria.

The applications using Systems P and S show that the addition date for a new unit in order to meet the increasing load is sometimes governed by the system health criterion and at other times by the system risk criterion. This depends on the system configuration, the size of the unit to be added and also on the accepted health and risk criteria that drive the capacity planning. It is not an easy task to say which of the two indices is more appropriate for capacity planning without performing the relevant system health and risk studies.

Using both the health and risk criteria together always maintains the system within the accepted risk level and degree of comfort. This method of capacity planning using both LOLE and LOHE criteria should be very useful to SIPS planners who are reluctant to use the LOLE method alone. Using both criteria, the SIPS planner also generates system operating information regarding the amount of probable reserve available in addition to the system risk level.

6.5 Conclusion

Capacity planning in SIPS is traditionally done using deterministic methods. These methods do not recognize many of the characteristics inherent in system generation and load and also many other factors that effect the risk and degree of comfort in a system. Large utilities normally use system risk criteria such as LOLE in capacity planning. This chapter presents a method that employs both risk and health indices as capacity planning criteria. It is believed that this approach can prove useful to SIPS planners.

Appreciation of the health benefit limit of a system may provide useful information when deciding the size of a unit to be added when using either a deterministic method or the LOLE method in capacity planning. The system health improves with the selection of a larger unit until the HBL of the system is reached when either method is used for capacity planning. Adding a unit of any size larger than the CLU, using a deterministic criterion, will provide the same degree of comfort in the system. When a unit larger than system HBL is added using a LOLE criterion, the system health may drop below the acceptable level.

The unit size configuration of a system, the size of the new units to be added and the accepted system play a significant role in determining which is the more restrictive index, the LOLE or the LOHE. Using only one of the two criteria in driving the capacity planning may violate the other accepted criterion. Using both the indices will ensure that the system is reliable from both aspects. It is believed that capacity planning using both LOLE and LOHE criteria may prove useful in practical application to SIPS.

7. APPLICATION OF MCS METHODS TO SIPS

7. Introduction

The MCS software in SIPSREL imitates the actual process and random behavior of the system under study for a large number of simulated years in order to assess different aspects of system health and risk. The basic concepts in system risk and health analysis using the MCS method are discussed in Chapters 2 and 3 respectively. It is a very flexible method since it can incorporate the effect of many factors that act on the particular system under study and take into account all the system constraints. The MCS method also provides more information on the level of risk and the degree of system comfort by providing additional frequency and duration indices and the distribution of the evaluated indices about their mean values.

MCS is not recommended for simple evaluation of the basic risk and health indices of a SIPS since it requires a considerable amount of time to run the simulation program. The application is, however, necessary when the distribution of an adequacy index is required in order to estimate its severity in any single year. MCS can be used to assess the effect on the system adequacy of changes in unit failure and repair rates and to verify the results obtained by analytical methods. The MCS method is therefore a very useful tool for specific SIPS adequacy studies regarding system risk and health.

7.2 Comparison Between MCS and the Analytical Methods

There are advantages and disadvantages associated with the MCS method when compared with the analytical techniques. The main disadvantage of the MCS method is that it requires a much longer solution time. The analytical methods always give the same numerical result for the same problem. The result obtained by the MCS method depends on the seed of the random number generator and the number of simulations. The inherent inconsistency associated with simulation may affect the confidence of the user. The main advantage of the MCS method is that it can incorporate and simulate any system characteristic that can be recognized, whereas, the model used in the analytical approach is usually a simplification of the system, sometimes to an extent that it becomes totally unrealistic [1]. The MCS method can provide a wide range of output parameters including all the moments and complete probability density functions, whereas the analytical techniques usually provide only the expected values.

Both the MCS and the analytical methods have their own merits and demerits and neither approach can be considered superior to the other. The more appropriate method should be chosen for a particular type of evaluation depending on the system, its characteristics and the required depth and detail of the analysis.

The basic system risk and health indices obtained when both the MCS and the analytical methods are applied to System S are shown in Table 7.1. System S has three generating units of sizes 270 KW, 540 KW and 725 KW. Each unit has a FOR of 5%, a mean time to failure of 950 hr and a mean time to repair of 50 hr. The IEEE-RTS hourly load data, which is in percent of the annual peak load, is used as the hourly load for System S. The peak load is 615 KW.

Table 7.1: Comparing Results from the MCS and Analytical Methods

	MCS Method		Analytical Method
Random Number Seed	0.24	0.29	
Simulation Years	1579	1040	
LOLE (h/yr)	20.715	20.527	20.044
LOEE (MWh/yr)	2.767	2.739	2.707
Probability of Health	0.911	0.912	0.912
Probability of Margin	0.086	0.086	0.086

Table 7.1 shows that the basic indices estimated by MCS are almost the same as those obtained by the analytical techniques. The table also shows that the risk and health indices obtained by the MCS method are not exactly the same when different random

number seeds are used. The number of simulation years required for the convergence of the simulation process are also different for the different seeds. The differences in the results provided by the two methods are insignificant for all practical purposes. The MCS method should be used if the accuracy of the mathematical models used to represent the actual system in the analytical techniques need to be verified.

7.3 Additional Adequacy Information by MCS

The MCS method is very useful when information about system adequacy other than the expected values of the basic health and risk indices are desired. The frequency and duration risk and health indices and the distribution of the indices about the mean values are some of the additional results that can be obtained from MCS. The method can also be used to evaluate the system customer interruption costs.

7.3.1 Distribution of the Adequacy Indices

The analytical techniques usually give only the expected values of the risk and health indices, whereas the MCS method can produce the distribution of these indices about the mean values. The distributions can be used to provide additional information on the anticipated severity of system risk or health in any single year.

The distributions of the basic risk and health indices (i.e. LOLE, LOEE, probability of health and probability of margin) of System S, obtained when a random number seed of 0.29 was used for 1040 simulation years, are shown in Fig. 7.1 - 7.4.

The expected energy not supplied by System S is 2.739 MWh/yr. The distribution of LOEE in Fig. 7.2 has the energy not supplied as high as 42 MWh/yr in any single year. It also indicates that the likelihood of this is 1 in 1040 years. Similarly, the probability of health for System S is 0.912 but Fig. 7.3 shows there is still a chance of one in 1040 years that the probability of health for any single year may be less than 0.80. On the other hand, the probability of health is greater than 0.95 in any single year with a likelihood of 39 out of 1040 years. This information is very useful when evaluating the severity of system risk and health.

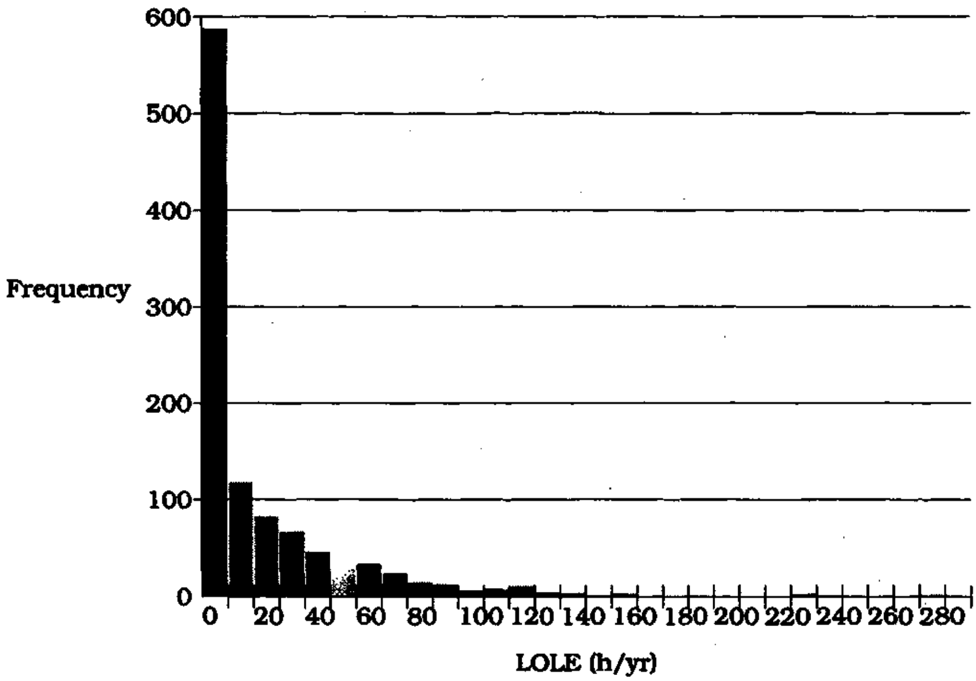


Fig. 7.1: Distribution of the LOLE for System S (Mean Value = 20.527 h/yr)

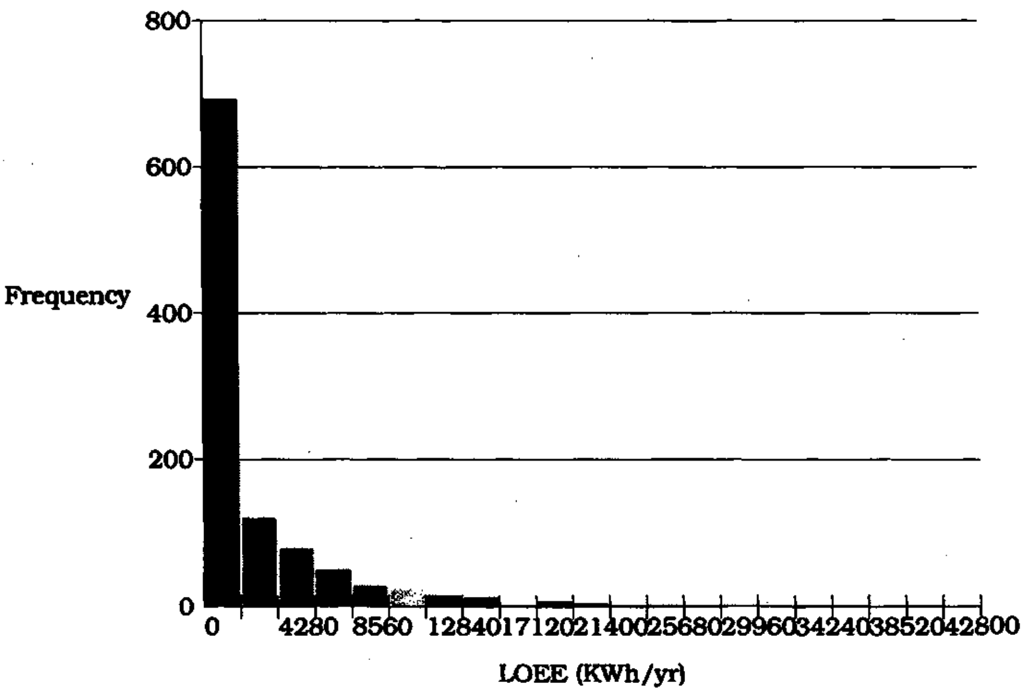


Fig. 7.2: Distribution of the LOEE for System S (Mean Value = 2.739 MWh/yr)

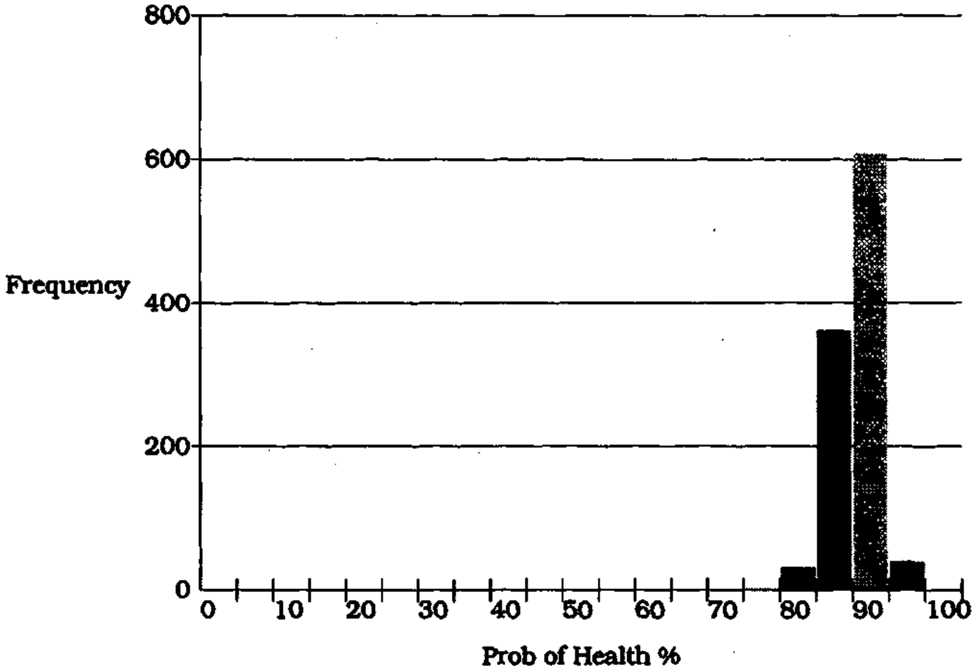


Fig. 7.3: Distribution of the P(H) for System S (Mean Value = 0.912)

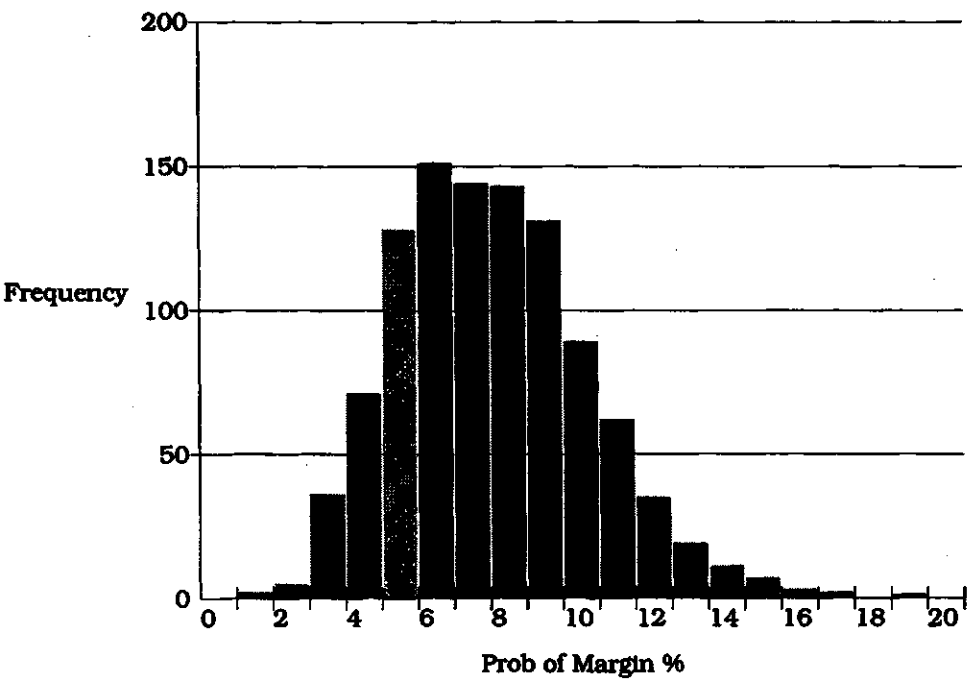


Fig. 7.4: Distribution of the P(M) for System S (Mean Value = 0.086)

7.3.2 Frequency & Duration Risk and Health Indices

The analytical techniques for evaluating the frequency and duration risk indices are relatively complex and the mathematical model used for evaluating the results is usually a simplification of the actual system. The evaluation of frequency and duration risk indices are not normally done in practical adequacy studies. They are, however easily estimated by MCS methods when further information about the system regarding the frequency and duration of interruptions and the expected values of different parameters during an interruption are desired. Analytical techniques for evaluating the frequency and duration health indices have not been developed in this research work.. The MCS method has been used to obtain these indices. The frequency and duration (F&D) health indices developed in this thesis are described in Chapter 3.

F&D Risk Indices

The frequency and duration risk indices and their distributions are shown in Fig. 7.5 - 7.9.

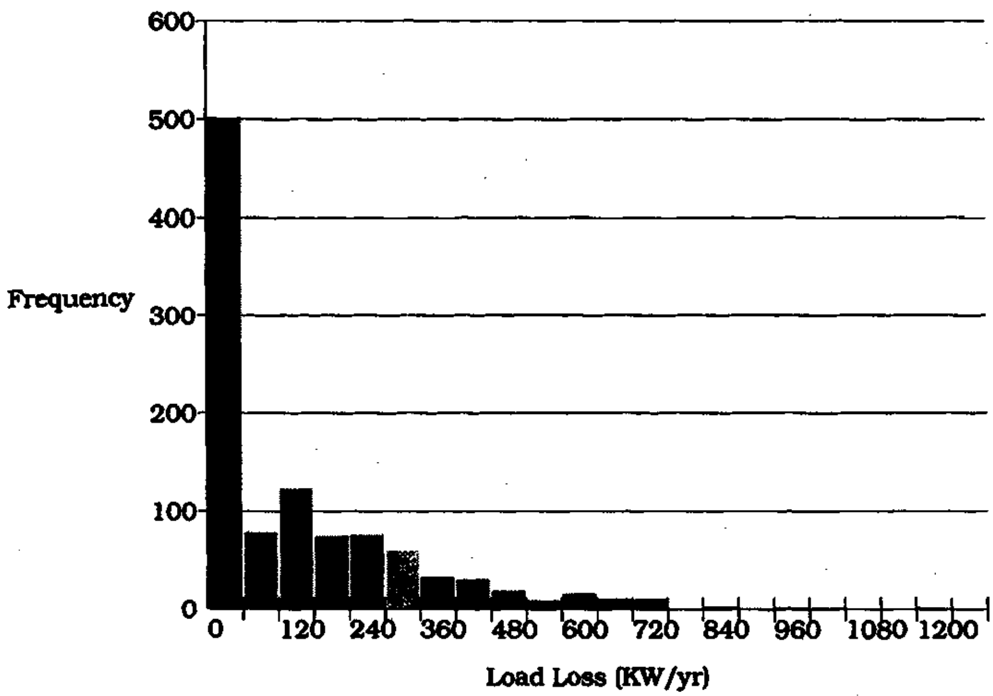


Fig. 7.5: Distribution of the ELLPYR for System S (Mean Value = 146.641 KW/yr)

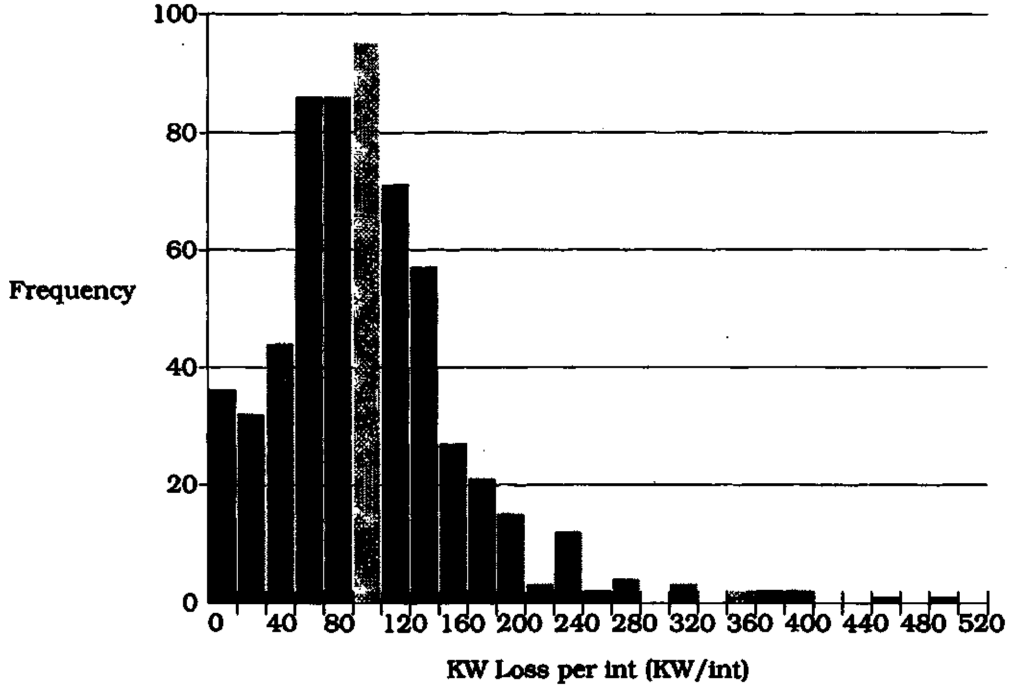


Fig. 7.6: Distribution of the ELLPINT (Mean Value = 103.746 KW/int)

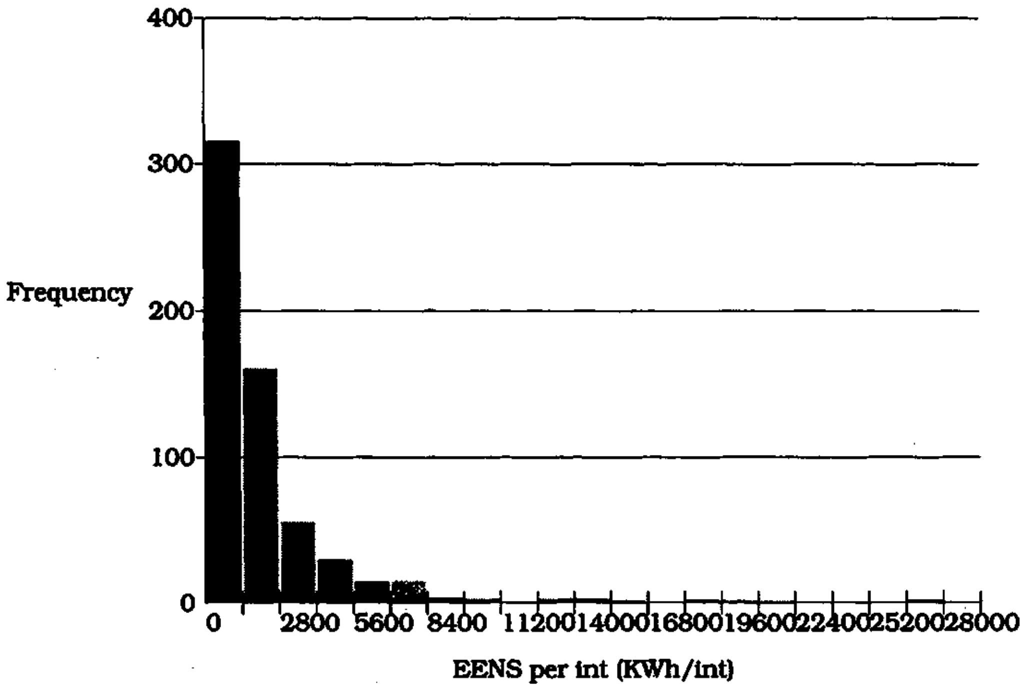


Fig. 7.7: Distribution of the EENSPINT (Mean Value = 1938 KWh/int)

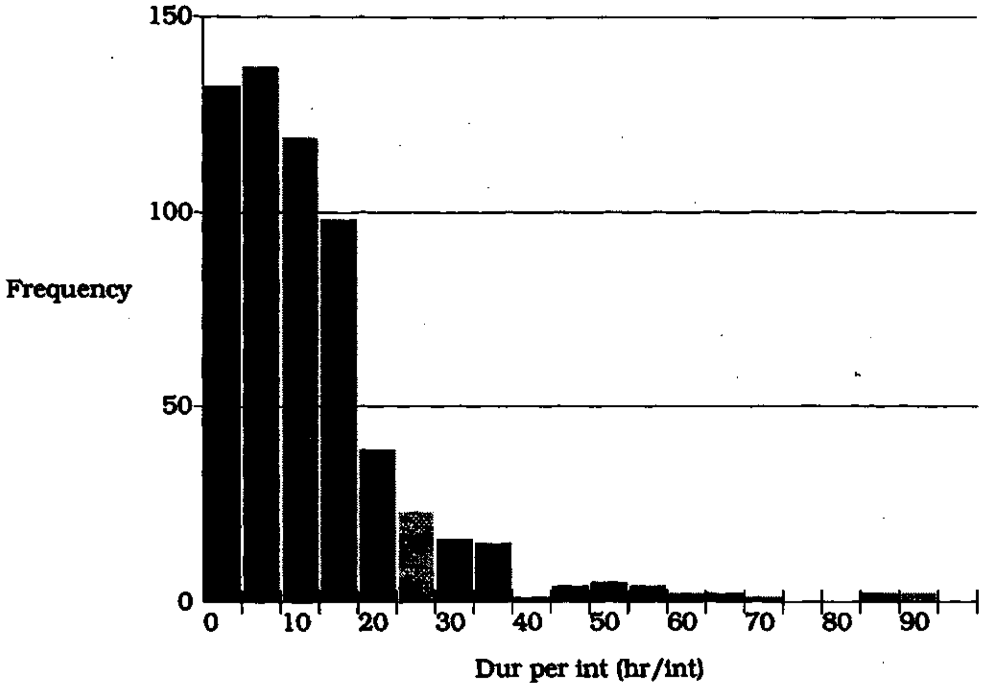


Fig. 7.8: Distribution of the EINTDUR (Mean Value = 14.52 hr/int)

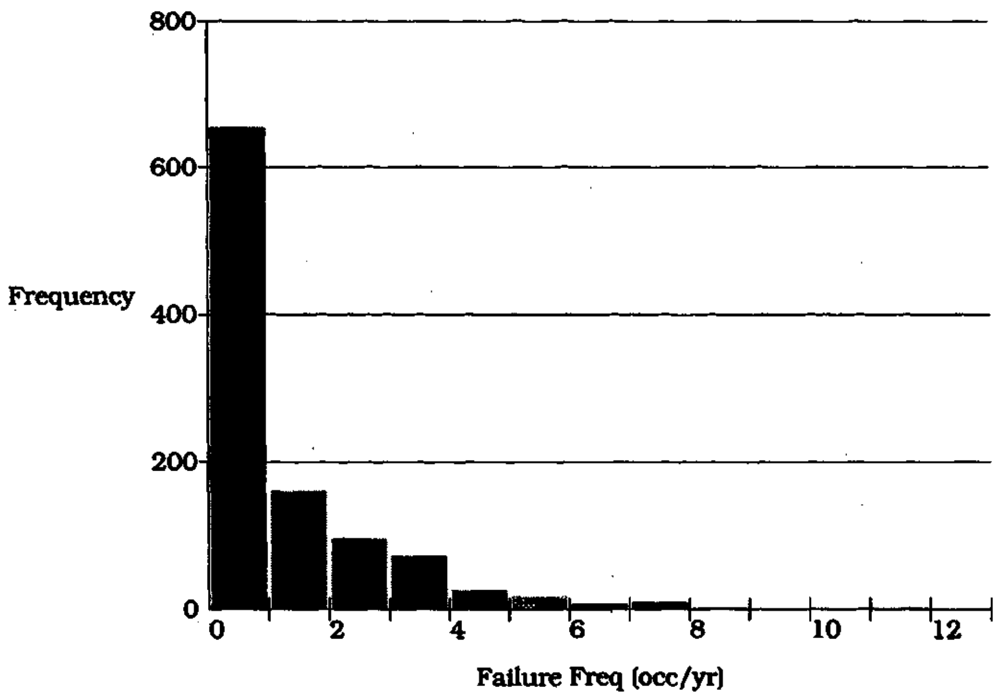


Fig. 7.9: Distribution of the Frequency of Interruption (Mean Value = 1.41 occ/yr)

F&D Health Indices

The frequency and duration health indices and their distributions are shown in Fig. 7.10 - 7.12. The expected health duration (EHDUR) of System S is 218.09 hours per healthy state. This means that the average duration of the system in the healthy state is 218.09 hours before it goes to the marginal or failed states. The expected margin duration (EMDUR) of System S is 20.20 hours per marginal state. This means that the average duration of the system in a state, that violates the deterministic criterion without actual system failure, is 20.20 hours. Both the EHDUR and EMDUR of the system are useful operating information. Another useful index is the frequency of margin which is the average number of occurrences per year of the marginal state. The frequency of margin of System S is 37.11 occurrences per year. This is the number of times the deterministic criterion is violated without system failure. The distributions of these indices measure the severity of health in System S. Fig. 7.12 shows that the marginal state may be encountered as many as 76 times in any single year and as few as only 12 times in any single year. However, the likelihood of either occurrence is only one in 1040 years. It can also be observed from Fig. 7.12 that the probability of having a frequency of margin greater than 50 occ/yr in any single year is 13.2%. There is a wide range of information that can be obtained from the distributions of the frequency and duration health indices.

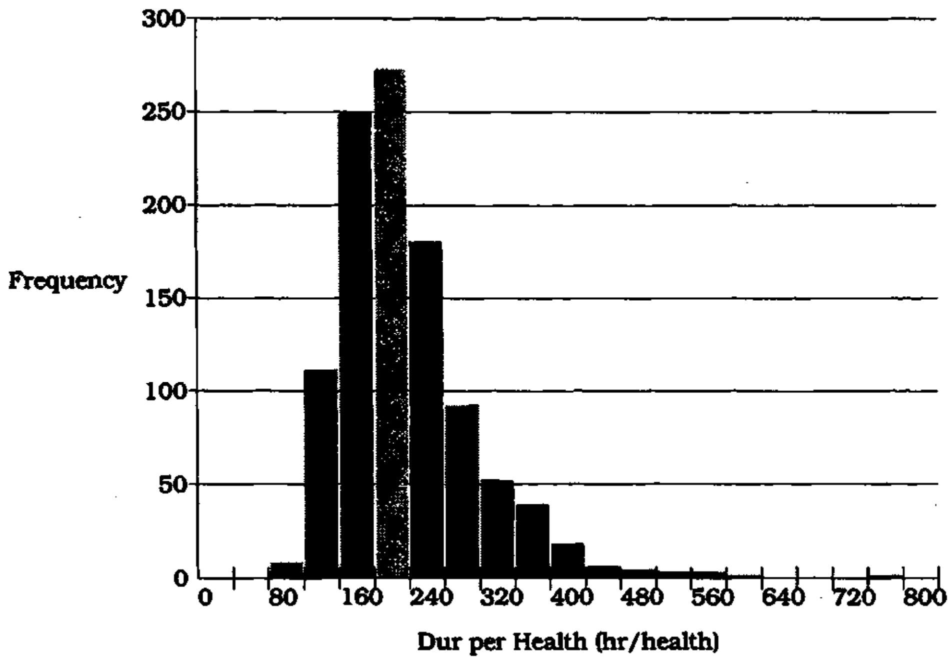


Fig. 7.10: Distribution of the EHDUR for System S (Mean Value = 218.09 hr/health)

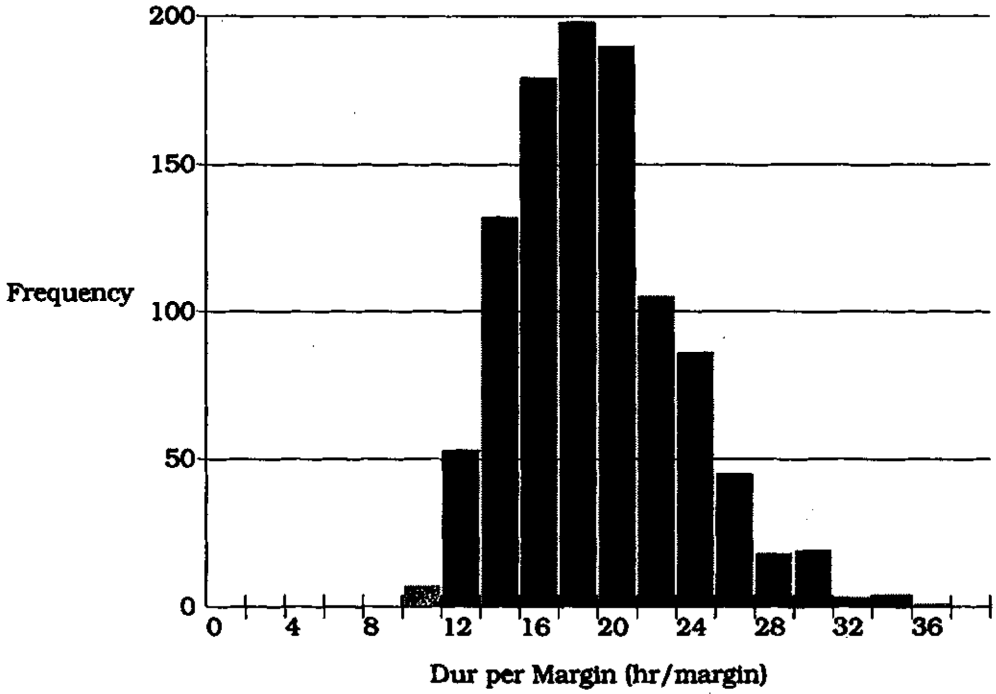


Fig. 7.11: Distribution of the EMDUR (Mean Value = 20.20 hr/margin)

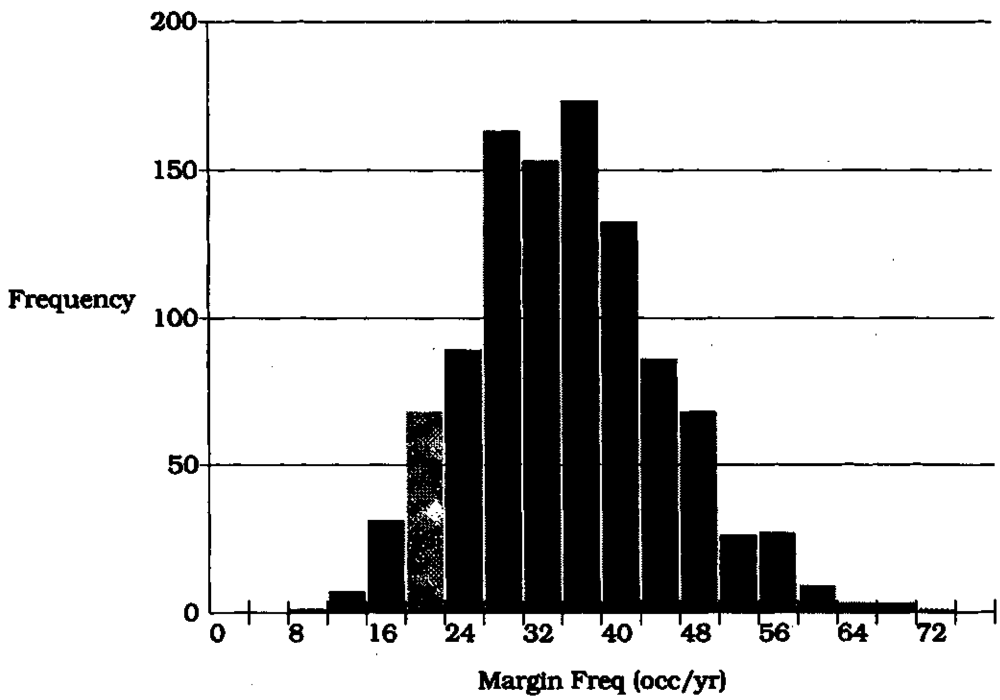


Fig. 7.12: Distribution of the Frequency of Margin (Mean Value = 37.11 occ/yr)

7.3.3 Customer Interruption Costs

The MCS method can be used to calculate reliability worth more accurately than can the analytical methods. The system interruption costs vary non-linearly with the duration of interruption. The monetary value in $/KW for customer interruptions of different durations and for different types of customer in the system are generally obtained from customer surveys. The survey data are analyzed to obtain a customer damage function for each customer group, which is a plot of the $/KW against different interruption durations. The customer damage functions for all the consumer groups are then combined to obtain a composite customer damage function (CCDF) for the system under study.

The CCDF used in the IEEE-RTS system was extended from 8 to 16 hours, with the same slope as that between 4 to 8 hours, in order to cover all the expected interruption durations and was used for System S. It is given in Table 7.2 and Fig. 7.13.

Table 7.2: CCDF for System S

Interruption Duration	1 min	20 min	1 hr	4 hr	8 hr	16 hr
Interruption Cost ($/KW)	0.73	2.42	5.27	19.22	41.45	85.91

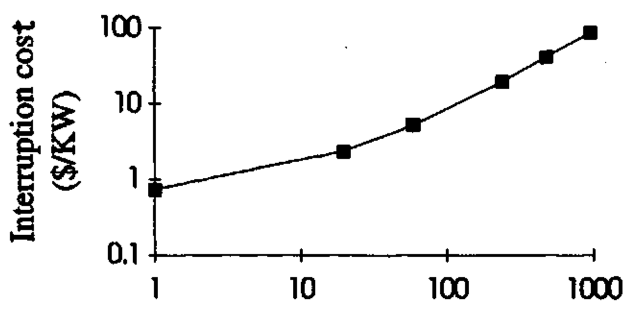


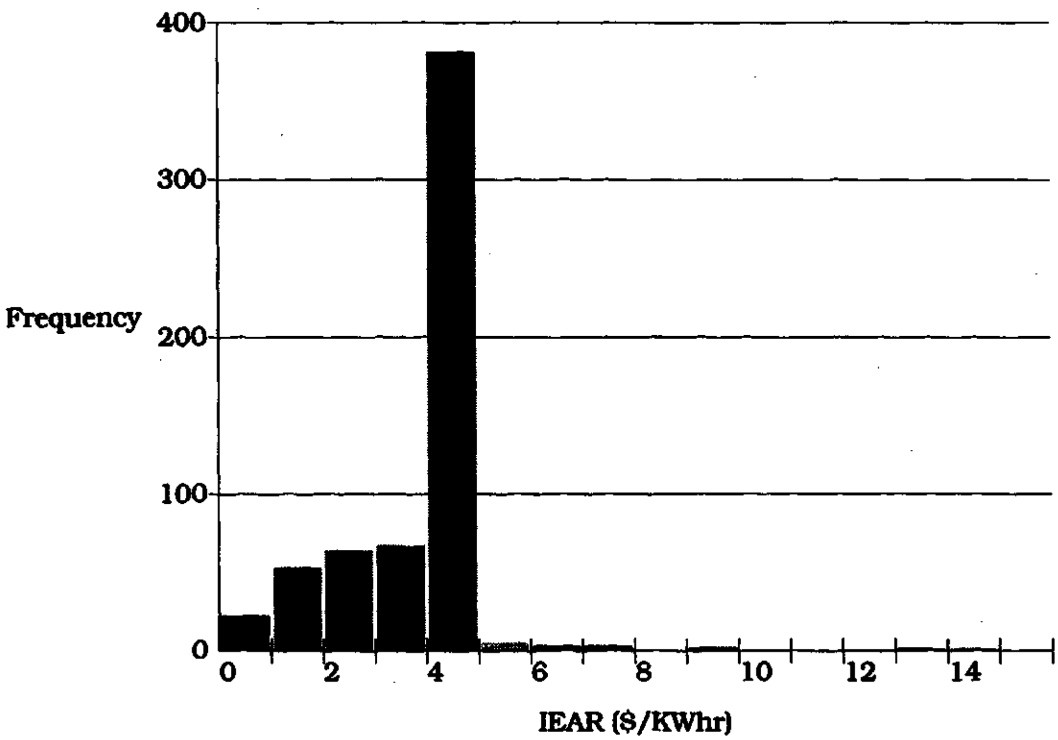
Fig. 7.13: CCDF for System S

The duration, the load loss in KW and the energy loss in KWh for each interruption occurring throughout the year is determined using the MCS method. The interrupted energy assessment rate (IEAR) is calculated using Equation (7.1).

$$IEAR = \frac{\sum_{i=1}^{n} ci(ri)*li}{\sum_{i=1}^{n} ei} \quad (\$/KWh) \tag{7.1}$$

where, $c_i(r_i)$ = interruption cost in \$/KW for duration r_i
r_i = duration in hours of interruption i
l_i = load loss in KW of interruption i
e_i = energy loss in KWh of interruption i
n = total number of interruptions

The IEAR for System S, estimated by the MCS method, is 3.27 \$/KWh and its distribution is shown in Fig. 7.14.



7.14: Distribution of the IEAR for System S (Mean Value = 3.27 \$/KWh)

The total customer interruption cost for the system can then be calculated by multiplying the IEAR by the expected energy not supplied as shown in Equation (7.2).

$$\text{Total Customer Interruption Cost} = \text{IEAR} * \text{LOEE} \ \ (\$/\text{yr}) \qquad (7.2)$$

The LOEE of System S obtained by the MCS method is 2739 KWh/yr. The total customer cost is, therefore $8956.53 per year.

7.4. Impact of Changes in Unit Failure and Repair Rates on the System Indices

The changes in system health and risk indices brought about by variation in the forced outage rates of the generating units are illustrated in Chapter 5 using analytical methods. The effect of changes in the generating unit failure and repair rates on the system health and risk indices cannot be recognized by the basic analytical techniques since different values of failure and repair rates may produce the same FOR. Complex analytical methods known as 'Frequency and Duration Techniques' are available for these types of study but again the representation of the actual system may have to be distorted to fit into the mathematical models used by these techniques. These studies can, however, be easily done using the MCS method.

The MTTF and MTTR for all the three units in System S are 950 hours and 50 hours respectively and their FOR is 5%. Table 7.3 compares the adequacy indices of System S for the case when the MTTF and MTTR are changed to 475 hours and 25 hours respectively while maintaining the same FOR. The output parameters for both cases are produced using two different random number seeds in order to provide a better appreciation of the comparison.

When the generating unit MTTF and MTTR are reduced by a factor of 2 (i.e. the failure and repair rates are doubled), the basic risk and health indices, LOLE, LOEE, probability of health and probability of margin do not change. There is, however, a significant change in the frequency and duration indices of health and risk and in the IEAR of the system although the FOR of all the units remain the same.

Table 7.3: Effects of Changes in Unit Failure and Repair Rates

	MTTF = 950 hr, MTTR = 50 hr		MTTF = 475 hr, MTTR = 25 hr	
	Seed = 0.29	Seed = 0.24	Seed = 0.29	Seed = 0.24
Simulation Years	1040	1579	1037	1845
LOLE (h/yr)	20.527	20.715	20.778	20.140
LOEE (MWh/yr)	2.739	2.767	2.802	2.683
Prob of Health	0.912	0.911	0.911	0.912
Prob of Margin	0.086	0.086	0.086	0.086
ELLPYR (KW/yr)	146.641	154.111	257.994	250.394
ELLPINT (KW/int)	103.746	104.438	112.838	111.293
EENSPINT (KWh/int)	1938	1876	1226	1192
EINTDUR (h/int)	14.52	14.04	9.09	8.95
F (occ/yr)	1.41	1.47	2.29	2.25
EHDUR (h/health)	218.09	215.40	152.95	152.39
EMDUR (h/margin)	20.20	20.07	14.07	14.04
F_m (occ/yr)	37.11	37.61	53.53	53.67
IEAR ($/KWh)	3.27	3.39	4.27	4.29

7.5 Conclusion

The basic system risk and health indices can easily be evaluated using analytical techniques which require relatively short computation times. However, when the effects of many different factors and many other constraints on the system are to be taken into account, the system under study becomes very complex and cannot be accurately evaluated by analytical methods. Under these circumstances, the MCS method is very useful since it can simulate the actual process of any type of system.

The MCS method can produce many other indices in addition to the basic risk and health indices. The analytical techniques for evaluating the frequency and duration risk indices are relatively complex and cannot incorporate the effects of many different factors that exist in a practical system. Analytical methods for evaluating the frequency and duration health indices have not been developed in this research work. These indices have been obtained using MCS.

The MCS method can also generate the distributions of the risk and health indices about their mean values. The distributions reveal useful information about the severity of system risk or health in any single year and the occurrence probabilities.

8. SUMMARY AND CONCLUSIONS

Novel probabilistic approaches and evaluation tools have been developed and are described in this thesis which provide system adequacy assessment methods that are responsive to the stochastic behavior of a system and are practically applicable to small isolated power systems. A recent survey [6] indicates that all Canadian SIPS use some type of deterministic method to assess the adequacy of the existing or proposed generating facilities to meet the total load requirement. On the other hand, most large Canadian utilities have relinquished conventional rule-of-thumb methods and moved to more responsive probabilistic techniques [4]. Realizing the reluctance of SIPS planners to use conventional probabilistic techniques, a new approach, known as system well-being analysis [7], that links the accepted deterministic criteria with probabilistic methods has been studied . Development work on system well-being analysis has been presented in this thesis which describes new evaluation methods, new adequacy indices and comparative studies of the different indices and techniques.

A software package named SIPSREL was developed during the research work described in this thesis with the aim of providing a practical tool for SIPS planners so that they can experiment with probabilistic techniques and eventually use them in system planning. The software is designed to apply probabilistic methods to adequacy studies of small isolated power systems. It can, however, also be utilized to assess the HL-I adequacy of larger systems. It employs a graphical user interface and is user-friendly and self-informative. The results for an evaluation are displayed in both tabular and graphical forms. It includes tools that use analytical techniques as well as Monte Carlo simulation methods. SIPSREL has been used in this thesis to obtain the results for all the necessary evaluations. In most cases, the output table or the graph from SIPSREL has been directly pasted into this thesis.

The conventional probabilistic techniques usually applied in the adequacy assessment of large systems are discussed in this thesis. The conventional risk indices used for generating capacity adequacy evaluation are loss of load, loss of energy and frequency and duration indices. These indices can be evaluated using either analytical techniques or by Monte Carlo simulation methods. The basic approach is to convolve the generation and load models to obtain the risk model. Different factors act upon the system and influence the level of system risk. The effects of load forecast uncertainty, planned maintenance of generating units and energy limitations in the system are described in detail as these factors are incorporated in the software SIPSREL. The analytical techniques used in SIPSREL for conventional risk evaluation are the capacity outage probability table method and the load modification approach. The risk indices in energy limited systems with storage facilities can be evaluated by the latter approach. These techniques together with the MCS method for risk evaluation are described in this thesis.

The conventional probabilistic techniques do not appear to prove useful to SIPS planners who routinely employ deterministic methods in adequacy studies. System well-being analysis has been developed to form a bridge between the deterministic and probabilistic methods and to define indices that may be practically useful in SIPS adequacy assessment. The probability of health, margin and risk are the basic system well-being indices. Loss of health expectation, frequency of margin, expected health duration and expected margin duration are new indices introduced in this thesis. The basic method for system well-being evaluation is an analytical technique known as the 'Contingency Enumeration Approach'. This thesis presents a new analytical method known as the 'Conditional Probability COPT Method' which is very efficient in regard to computation time and computer memory when compared to the contingency enumeration approach. The new analytical method has made it possible to evaluate the well-being indices of larger systems with any shape load curve. It has also made it possible to easily hand-calculate the health indices for small systems with practical load curves. This thesis also introduces the concepts and application of MCS methods in well-being analysis. MCS software in addition to the new analytical techniques have been incorporated in SIPSREL to evaluate well-being indices.

The different study types that can be done using SIPSREL and a range of results obtained using practical system examples are illustrated in this thesis. The conventional risk indices, the system well-being indices, the peak load carrying capabilities for different risk and health criteria and the expected energy supplied by each unit in the system can be evaluated using the analytical tools. The effect of load forecast uncertainty, planned maintenance, unit deratings with any number of states, energy limitations, load factor, shape of the load curve, the priority loading order, unit sizes and forced outage rates can all be included in the evaluation. SIPSREL can use load curves with daily or hourly peak loads or just constant loads in the load model to extend its application from systems having sophisticated system data to systems lacking adequate data. The distributions of the basic risk and health indices, frequency and duration risk and health indices and the interrupted energy assessment rate of a system can be evaluated using the MCS tools in SIPSREL. The MCS method requires a comprehensive load model with hourly loads for an entire year and the resident times in the different states of each unit as the input data. Depending on the type of evaluation to be done, the user can select method, any particular evaluation process, one or more of the factors that effect the evaluation process, use either default or modified parameters and obtain numerical as well as graphical results. It is expected that SIPSREL will prove a useful tool in adequacy studies of SIPS using probability methods.

The application of MCS to SIPS to estimate different risk and health indices is described in this thesis. The basic system risk and health indices can be easily evaluated by analytical techniques and requires relatively short computation times. However, when the effects of many different factors and system constraints are to be taken into account, the system under study can become very complex and cannot be accurately evaluated using analytical methods. Under these circumstances, the MCS method is very useful since it can be used to simulate the actual process of any type of system. The MCS method can produce other indices, such as frequency and duration indices, in addition to the basic risk and health indices. The analytical techniques used to evaluate frequency and duration indices are relatively complex and have not yet been developed for well-being analysis. The MCS method is, therefore, very useful when additional risk and health indices are to be evaluated for specific SIPS adequacy. The MCS method can also be used to generate the distributions of the risk and health indices about their mean values. These distributions indicate the severity of system risk or health in any year and the probability of occurrence. The MCS method can prove very useful in those situations when the solutions are not easily tractable by analytical techniques.

A range of adequacy studies are presented in this thesis using SIPSREL by application to actual small isolated power systems with different configurations to compare the various techniques. Comparative studies have also been done on the different types of adequacy indices and criteria that can be used for capacity planning in order to determine the most appropriate method and planning criteria that can be used in adequacy evaluation of a SIPS.

The studies illustrate that deterministic indices do not respond to changes in unit forced outage rates, unit deratings, changes in load factor or in the shape of the load curve. Deterministic techniques cannot incorporate the effect of many other factors such as load forecast uncertainty, planned maintenance or energy limitations in system adequacy evaluation and cannot be used to compare the adequacy of different systems. Different systems having the same deterministic measure of adequacy are very likely to be exposed to diverse levels of risk or have different degrees of system comfort. The addition of a new unit to maintain a constant deterministic criterion does not result in a constant system risk or a constant system health. Adequacy indices based on deterministic methods are not as responsive nor meaningful as probabilistic risk or health indices.

A new term called the 'Health Benefit Limit' is introduced in this thesis. It is the size of an additional generating unit that results in the highest system health probability when added to maintain a constant deterministic criterion . It is either equal to or less than the capacity of the largest unit in the system and can be determined from the plot of the system health probability against the size of unit added at a constant deterministic criterion. The health benefit limit of a system depends on the system configuration. In general, it is less than the capacity of the largest unit in systems that have a single largest unit and is equal to the capacity of the largest unit in systems that have several units equal in size to the largest unit. Appreciation of the system health benefit limit can provide useful information when deciding the size of a unit to be added using either a deterministic method or the LOLE method in capacity planning. The system health improves with the selection of a larger unit until the health benefit limit of the system is reached when either method is used for capacity planning. There is a system health penalty associated with adding a larger unit. It can also be useful when capacity planning is done using the system health criterion. Since the system risk is a maximum when the unit added to maintain a constant health criterion is equal in size to the system health benefit limit, a supplementary check for LOLE should be done to prevent violating the system risk criterion whenever a unit close in size to the system health benefit limit is to be added.

The studies done in this thesis indicate that there are many factors that effect the system risk and health indices and compel them to behave in different ways. Either the health or the risk index can prove to be restrictive depending on different factors such as the unit size configuration of the system and the sizes of the units to be added to the system. Taking a lower health probability or a higher LOLE as the accepted criterion will tend to make the health probability a more restrictive index than the LOLE and vice-versa. Both the risk and the health indices appear to be the more appropriate under different circumstances. Since SIPS planners are reluctant to use risk indices in practice, it appears reasonable to use the health and the risk indices jointly in the adequacy evaluation of SIPS. A method has been presented in this thesis that employs both risk and health indices as accepted criteria in capacity planning. Using only one of the two criteria in capacity planning may violate the other accepted criterion. Using both indices will ensure that the system is reliable from both aspects. Capacity planing using both LOLE and LOHE criteria as illustrated in this thesis should prove useful in practical application to SIPS.

It is hoped that probabilistic methods will be employed in practice in the adequacy evaluation of small isolated power systems using the methodologies and evaluation tools that have been developed in this research work.

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