MONTECARLO AND ANALYTICAL METHODS FOR FORCED OUTAGE RATES CALCULATION OF PEAKING UNITS

A Thesis

by

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ABSTRACT

All generation facilities have to report their generator un-availabilities to their respective Independent System Operators (ISOs). The un-availability of a generator is determined in terms of its probability of failure.

Generators may serve the role of two kinds, base units which operates all the time and the others are peaking units which operate only for periods of time depending on load requirement. Calculation of probability of failure for peaking units using standard formulas gives pessimistic results owing to its time spent in the reserve shut down state. Therefore the normal two state representation of a generating unit is not adequate. A four state model was proposed by an IEEE committee to calculate the forced outage rate (unavailability) of such units.

This thesis examines the representation of peaking units using a four-state model and performs the analytical calculations and Monte Carlo simulations to examine whether such a model does indeed represent the peaking units properly.

DEDICATION

DEDICATED TO MY FAMILY

ACKNOWLEDGEMENTS

I take this opportunity to express my sincere thanks to many people who made this thesis possible and my stay at Texas A & M, a cherishable one.

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NOMENCLATURE

FOR	Forced Outage Rate
LOLE	Loss of Load Expectation
HLOLE	Hourly Loss of Load Expectation
EFORd	Equivalent Forced Outage Rate on Demand
λ	Failure Rate
μ	Repair Rate
IEEE	Institute of Electrical and Electronics Engineers
RTS	Reliability Test System

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CHAPTER I

INTRODUCTION

1.1 Introduction

The goal of a power system is to supply electricity to customers in an economic and reliable manner. To ensure continuity of supply, planning and operating generating and transmission facilities are crucial [1]. The criteria used to plan may be deterministic or probabilistic.

Typical deterministic criteria used in practical applications are:

1) Planning generating capacity – installed capacity equal the expected maximum demand plus a fixed percentage of the expected maximum demand.
2) Operating Capacity – spinning capacity equals expected load demand plus a reserve equal to one or more largest units.
3) Planning network capacity – The networks are so planned that a single contingency or a combination of two contingencies will not jeopardize the ability of the system to supply load to customers. This often called n-1 or n-k criteria.

The knowledge of various reliability parameters of the power system and its components is important to run it in a reliable manner. One of the important components of a power system is the generators. Others being transmission lines, transformers, distribution equipment etc. Of all equipment, generators are observed to fail more frequently. Especially the large generators may spend considerable time in the de-rated states. The reliability of generation system has received considerable attention in the power industry. This thesis presents methods to determine the reliability indices of the generators which are discussed in the next section. The equivalence of two methods is examined and the advantages and disadvantages are also discussed.

1.2 Power System Reliability

Reliability is the probability of a device or system performing its function adequately, for the period of time intended, under the specified operating conditions. The reliability of a power system pertains to its ability to satisfy its load demand under the specified operating conditions and supporting policies.

Some of the most commonly used reliability measures are as follows

1. *Forced Outage Rate* (FOR) is the probability of failure of a generator and it is usually measured as a ratio of failure hours to total service hours. This index, being a probability measure is dimensionless. It should be noted that that when FOR is used for transmission line, it indicates the failure rate of the line.
2. *Loss of Load Probability* (LOLP) is the probability that a system will fail to satisfy its load demand under the specified operating conditions and policies. This index, being a probability measure is also dimensionless.
3. *Loss of Load Expectation* (LOLE) is the expected period of time during which the system will fail to meet its load demand, over a given period. Typical unit is *hours/year,* and the LOLE in *hours/year* can be obtained by multiplying the LOLP by 8760 (hours in a year).

4. *Expected Un-served Energy* (EUE) is the expected amount of energy which the system will be unable to supply to the consumers as a result of failures. This index is alternatively known as *Expected Energy Not Served* (EENS). Typical unit of measure is *MWhr/year*. This parameter helps in planning and expansion of the system.

1.3 Importance of Research

The generator unit is usually represented by a set of states in which it can reside. The states of a generator using a two state model are UP and DOWN, i.e., working state and failed state. The unit transits from one state to another in accordance with the transition rates called as failure rate and repair rate. These states represent the actual operating conditions of a generator unit.

A two-state model is a reasonable representation of a smaller unit. For larger units three state models are used but are often reduced to two state equivalent models. In a system with generators and loads, the generators are dispatched according to the load requirement. The load on the system would be non-uniform throughout the operation. The units supplying the continuous part of load are called base load units. Then there are cycling units that are taken out when not needed. The units serving during the peak hours are the peaking units. These units operate for relatively short-periods of time depending on the load profile. Probabilities of failure of peaking units cannot be calculated as a ratio of failure times to total failure times and operating times, as such a calculation gives pessimistic results.

Many attempts were made to address this problem; a four-state model was developed to differentiate the peaking generator from a base unit [2]. The effect of startup failures, startup delays, de-rated generator states are incorporated in [3] and [4]. Accurate calculation of reliability indices for peaking units is important for planning studies.

1.4 Problem Statement

The two main approaches for reliability parameters evaluation are

1) Analytical Methods and
2) Simulation Techniques

1) Analytical Methods

In analytical methods, state space methods and min cuts methods are used. In state space approach, system is represented in all its possible states and their reliability indices are calculated by mathematical equations. Majority of techniques in generation reliability are analytically based. This is now changing, and an increasing interest is being shown in modeling the system behavior more comprehensively and in evaluating a more informative set of system reliability indices. This implies the need to consider Monte Carlo simulation.

2) Simulation Techniques

Monte-Carlo simulation creates artificial histories of the system by using the probability distributions of component state residence times. For a network, a specific state of the system components corresponds to specific states for the load points. In other words, supply outage may cause loss of load. If there is surplus generation, some amount of generation outage may not necessarily cause loss of load. Generation capacity reliability evaluation is concerned with the adequacy of generation to supply the load. Hence, every state change in Monte Carlo of any system component requires an evaluation of the status of load demand satisfaction.

The reliability indices are then estimated by statistical inference from service hours and failure hours which is same as if done on a real system. Both the methods have their own advantages and disadvantages in reliability evaluation. The equivalence of analytical and Monte-Carlo methods are observed. Representation of peaking units in four-state model and calculation of reliability indices and HLOLE using two main approaches is carried out. In this thesis, Sequential Monte Carlo simulation is used for reliability parameters evaluation.

CHAPTER II

BACKGROUND AND LITERATURE REVIEW

2.1 Two State Model of Base Units

Reliability analysis of the power network is done by modeling the components of the network using their failure and repair characteristics. Frequently used model for generators is a two-state Markov model of full capacity or zero capacity. Figure 1 shows a 2-state Markov model of a generator with failure and repair transition rates.

Any generator can be represented by two states, namely UP (working) and DOWN (failure) states as shown in Figure 1.

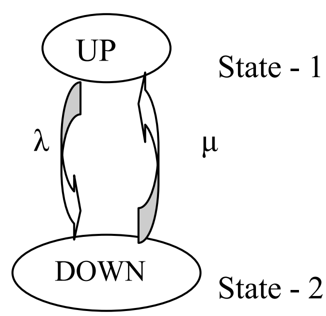

Fig 1: Generator two state model

Let UP state be ‘1’ and DOWN state be ‘2’

Transition from 1 to 2 is failure rate. It is defined as the mean number of transitions from up to down state per unit of time in state 1.

$$\lambda = n_{12}/T_1$$

$$= 1/(T_1/n_{12})$$

$$= 1/MUT$$

Where MUT = mean up time; n_{12} are number of transitions from state 1 to 2.

Similarly transition from 2 to 1 state = repair rate

$$\mu = n_{21}/T_2$$

$$= 1/(T_2/n_{21})$$

$$= 1/MDT$$

Where MDT = mean down time of a component.

Frequency of encountering state 2 from state 1 is the expected (mean) number of transitions from state 1 to state 2 per unit time.

$Fr(1\rightarrow 2)$ = Frequency of transition from state 1 to state 2.

$$= n_{12}/T$$

$$= (T_1/T)*(n_{12}/T_1)$$

$$= p_1*\lambda_{12}$$

Where p_1=steady state probability of system in state 1.

$P_1+P_2= 1$; the generator can reside either in UP or DOWN state.

In steady state, the frequency of entering a state is equal to frequency of exiting a state.

$P_1*\lambda = P_2*\mu$; where λ=failure rate and μ=repair rate.

Thus $P_1=\frac{\mu}{\lambda+\mu}$ and $P_2 = \frac{\lambda}{\lambda+\mu}$

This model can be used if the generator is a base unit, i.e., operates all the time.

2.2 Four State Model of Peaking Units

Peaking units operate for relatively short periods and thus have more than two states that they can reside in. Thus the basic two-state model is extended to four-state model designed by IEEE Task Force of Probability Methods Subcommittee, two of them being the reserve shut down states and other two states are the working states [2] and are shown in Figure 2.

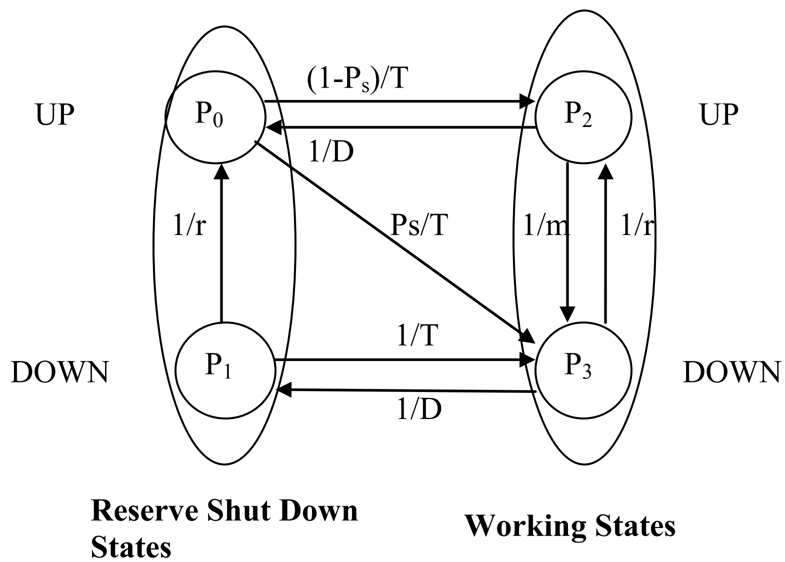

Fig 2: Four state model of a generator

The states of the model are

P_0 – Probability of Reserve Shut down period.

P_1 – Probability of Forced Out but not in need.

P_2 – Probability of generator in Service when in need.

P_3 – Probability of Forced Out when needed.

The respective parameters are defined as

T – Average reserve shutdown time between periods of need, exclusive of periods for maintenance or other planned unavailability.

D – Average in-service time per occasion of demand in hours

m – Average in-service time between occasions of forced outage

r – Average repair time per forced outage occurrence in hours

Ps – Probability of a starting failure resulting in inability to serve load during all or part of a demand period.

All the above parameters can be calculated from regularly reported data.

The conditional probability of a generator not able to serve the load, given the demand period, is $\frac{P_3}{P_2 + P_3}$ which is called as forced outage rate.

$$r = \frac{1}{\mu} = \text{MTTF} = \text{Mean Time to Failure}$$

$$m = \frac{1}{\lambda} = \text{MTTR} = \text{Mean Time to Recover}$$

CHAPTER III

METHODS FOR CALCULATING FORCED OUTAGE RATES

The methods for calculating the forced outage rates of the peaking units are:

1) Markov Process (Analytical method)
2) Monte-Carlo Simulation

3.1 Analytical Method

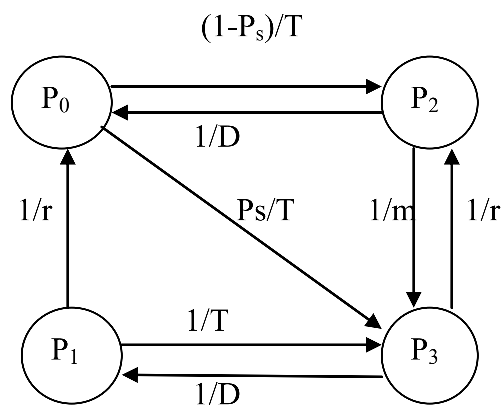

Fig 3: Four state model of a peaking unit

The analytical method is commonly used by the industry to calculate the FOR of the peaking units.

The frequency of entering into a state = frequency of exiting a state,

Frequency balance equations for all the states are written as

$$P_0 * \left[\frac{1-P_s}{T} + \frac{P_s}{T}\right] = P_1 * \left[\frac{1}{r}\right] + P_2 * \left[\frac{1}{D}\right]$$

$$P_1 * \left[\frac{1}{T} + \frac{1}{r}\right] = P_3 * \left[\frac{1}{D}\right]$$

$$P_2 * \left[\frac{1}{D} + \frac{1}{m}\right] = P_0 * \left[\frac{1-P_s}{T}\right] + P_3 * \left[\frac{1}{r}\right]$$

$$P_3 * \left[\frac{1}{D} + \frac{1}{r}\right] = P_1 * \left[\frac{1}{T}\right] + P_0 * \left[\frac{P_s}{T}\right] + P_2 * \left[\frac{1}{m}\right]$$

$$P_1 + P_2 + P_3 + P_0 = 1$$

Solving the above equations, the probabilities of each state are found [6].

$$P_0 = \frac{r(T^2 m + DT(T+m) + DT^2 m)}{(D+T)(Dr^2 + mr^2 + DTm + DTr + Dmr + Tmr + P_s mr^2 - Tmr^2)}$$

$$P_1 = \frac{Tr^2 (D + m + P_s m - Tm)}{(D+T)(Dr^2 + mr^2 + DTm + DTr + Dmr + Tmr + P_s mr^2 - Tmr^2)}$$

$$P_2 = \frac{D^2 Tm + Dmr(T^2 - P_s T + D)}{(D+T)(Dr^2 + mr^2 + DTm + DTr + Dmr + Tmr + P_s mr^2 - Tmr^2)}$$

$$P_3 = \frac{D}{D+T} - \frac{D^2 Tm + Dmr(T^2 - P_s T + D)}{(D+T)(Dr^2 + mr^2 + DTm + DTr + Dmr + Tmr + P_s mr^2 - Tmr^2)}$$

Here Ps = probability of starting failure resulting in inability to serve load. If Ps is assumed to be zero, i.e., all the generators are assumed to start without failure whenever they are started from reserve shut down or after recovering from failure, The probabilities of all states are

$$P_0 = \frac{rT^2 m + DT^2 + DTm + DT^2 m}{(D+T)(Dr^2 + DTm + DTr + Dmr + Tmr)} \qquad (1)$$

$$P_1 = \frac{DTr^2}{(D+T)(Dr^2 + DTm + DTr + Dmr + Tmr)} \qquad (2)$$

$$P_2 = \frac{D^2mT + D^2mr + DrmT}{(D+T)(Dr^2 + DTm + DTr + Dmr + Tmr)} \tag{3}$$

$$P_3 = \frac{D^2rT + D^2r^2}{(D+T)(Dr^2 + DTm + DTr + Dmr + Tmr)} \tag{4}$$

The probability of failure of a generator from figure 2 is given as, $P = \frac{P_1 + P_3}{P_1 + P_3 + P_2}$

Where $P_1 + P_3$ give the total down time of any generator, which includes reserve shut down hours during which the generator is not in need (state-1).

Thus above probability P when calculated for a peaking unit gives pessimistic results. To address this problem, another reliability parameter named as equivalent forced outage rate on demand (*EFORd*) is defined.

Calculation of *EFORd* uses the failure hours during demand and thus defines the exact forced outage rate of a generator.

The probability of Equivalent forced outage rate on demand (*EFORd*) of a generator is defined as, $EFORd = \frac{P_3}{P_3 + P_2}$.

When the values of P_2 and P_3 from equations (3) and (4) given above are substituted in the above equation, the Equivalent Forced Outage Rate on demand (EFORd) is calculated.

$$EFORd = \frac{DTr + Dr^2}{DTr + Dr^2 + DTm + Dmr + Tmr}$$

The above equation can be represented by

$$EFORd = \frac{F_f * FOH}{F_f * FOH + SH}$$

$$EFORd = \frac{F_f * (P_1 + P_3)}{F_f * (P_1 + P_3) + P_2}$$

FOH = forced outage hours; hours in state-1 and state-3.

SH = service hours; hours in state-2.

F_f = weighing factor on forced outage hours to reflect the cumulative forced outage hours occurring during periods of demand [2], [5] and [6].

$$F_f = \frac{\left(\frac{1}{r} + \frac{1}{T}\right)}{\left(\frac{1}{r} + \frac{1}{T} + \frac{1}{D}\right)} \text{. ------- (5)}$$

Thus F_f*FOH gives the number of hours spent by generator in state-3.

As per the four-state model, the probability of the forced out state of a peaking generator is EFORd = $\frac{P_3}{P_2 + P_3}$

The parameters in equation (5) are obtained from historical data, and later the probabilities are computed.

Historical data, however, cannot be appropriately used if the load profile or the usage of generators changes. Monte-Carlo method is proposed for computation of forced outage rates.

3.1.1 Unit Addition Method

This method is used for embedding a unit in the generation system model. It evaluates the probabilities of all possible states of generation in a system.

The Generation system model is described by

C_i = ith element of C

= discrete capacity outage levels

P_i = ith element of P

= probability of capacity outage greater than or equal to C_i

F_i = ith element of F

= frequency of capacity outage greater than or equal to C_i

System Illustration

The reliability indices FOR and HLOLE for a system are evaluated using unit addition method. The load model of the system is given in Table 1.

TABLE 1
Simple system load model

Hour	Load (MW)	P(Load)
1 to 4	48	0.5
4 to 8	102	0.333
8 to 12	152	0.1667
12 to 16	102	
16 to 24	48	

The system has 4 generators; each has a full generation capacity of 50MW or 0MW when failed. The failure rates of each generator is 0.1 per day and mean repair time is 24 hours. So $\lambda = 0.1$ and $\mu = 1$.

Probability of failure of each unit is = 0.1/1.1 =0.09091

Probability of repair of each unit is = 1.0/1.1 = 0.9091

All the possible generation states are obtained by adding one unit at a time, adding first unit of 50MW; possible states and their cumulative probabilities are in Table 2.

TABLE 2
Capacity outages and cumulative probabilities after adding first unit

States	C_i	P_i (Cumulative Capacity Outage Probability)
1	0	$P_1 = 1$
2	50	$P_2 = 0.09091$

Adding second unit of 50MW; possible states and cumulative probabilities are in Table 3

TABLE 3
Capacity outages and cumulative probabilities after adding second unit

States	C_i	P_i	P_i
1	0	1	$P_1 = 1$
2	50	0.9091*0.09091+0.09091*1	$P_2 = 0.17356$
3	100	0.09091*0.09091	$P_3 = 0.00826$

Adding third unit of 50MW; cumulative probabilities of all states are given in Table 4.

TABLE 4
Capacity outages and cumulative probabilities after adding third unit

States	C_i	P_i	P_i
1	0	1	$P_1 = 1$
2	50	0.9091*0.17356+0.09091*1	$P_2 = 0.2487$
3	100	0.9091*0.00826+0.09091*0.17356	$P_3=0.02329$
4	150	0.00826*0.09091	$P_4= 0.000751$

Adding fourth unit of 50MW; cumulative probabilities of states are given in Table 5.

TABLE 5
Capacity outages and cumulative probabilities using unit-addition

States	C_i	P_i	P_i
1	0	1	$P_1 = 1$
2	50	0.9091*0.2487+0.09091*1	$P_2 = 0.317$
3	100	0.9091*0.02329+0.09091*0.2487	$P_3=0.04378$
4	150	0.9091*0.000751+0.09091*0.02329	$P_4 = 0.0028$
5	200	0.09091*0.000751	$P_5 = 0.0001$

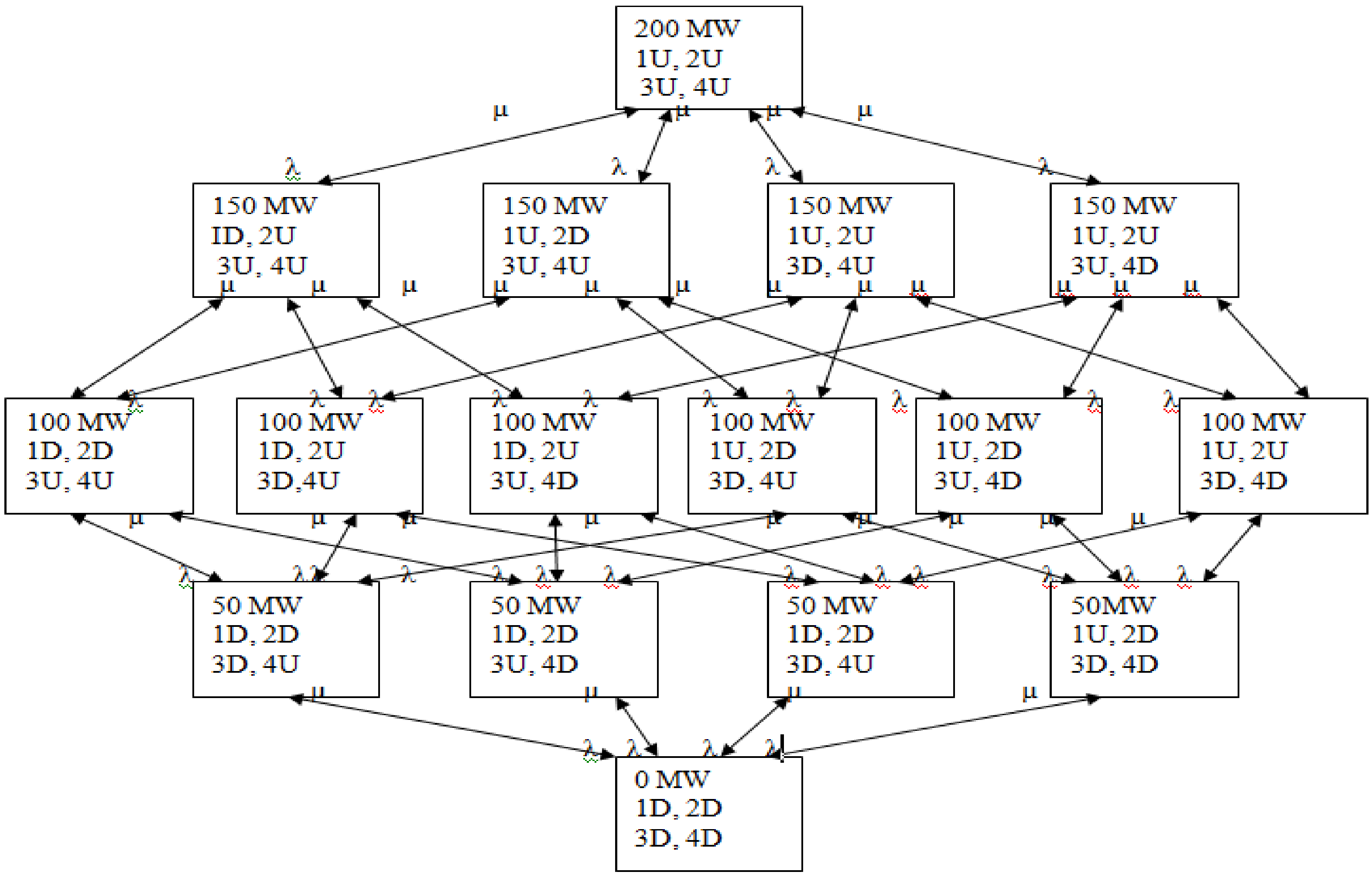

Fig 4: 15 State Markov model

Figure 4 shows the 15 state Markov model of the system, each state shows the total generation capacity and respective generation states.

This can be reduced to a total of 5 states as shown in figure 5.

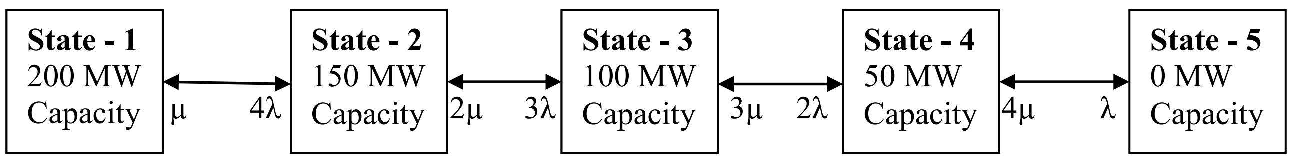

Fig 5: 5 State model

The probability of each state is

$$P'_1 = \frac{\mu^4}{(\mu+\lambda)^4} \quad P'_2 = \frac{4\mu^3\lambda}{(\mu+\lambda)^4} \quad P'_3 = \frac{6\mu^2\lambda^2}{(\mu+\lambda)^4} \quad P'_4 = \frac{4\lambda^3\mu}{(\mu+\lambda)^4} \quad P'_5 = \frac{\lambda^4}{(\mu+\lambda)^4}$$

The probabilities and cumulative probabilities of each state are given in Table 6.

TABLE 6
Capacity outages and cumulative probabilities using Markov process

States	Capacity Outage	State Probabilities (P'_i)	Cumulative Probabilities
1	0	0.68304	P_1 = 0.68304+0.3169 = 1
2	50	0.2732	P_2 = 0.2732+0.04378 = 0.3169
3	100	0.04098	P_3= 0.04098+0.0028 = 0.04378
4	150	0.002732	P_4 = 002732+0.0000683=0.0028
5	200	0.0000683	P_5 = 0.0001

From the load data, probability of loss of load is evaluated.

$$HLOLE = \left[\sum_{i=1}^{m} (P_i - P_{i+1}) * P_l (C - C_i - M) \right] * D = 1.619 \text{hours/day}$$

$$= 590.935 \text{ hours/year}$$

Where

P_i = cumulative probability of generation

P_l = cumulative probability of Load

m = number of generation states

M = Margin for LOLE calculation.

D = Duration of Study; here D = 24 hours.

3.1.2 IEEE Reliability Test System Illustration

The IEEE Reliability Test System (RTS) was developed by the Subcommittee on the Application of Probability Methods in the IEEE Power Engineering Society to provide a common test system which could be used for comparing the results obtained by different methods.

A test power system called as IEEE-RTS is used to compare the analytical and Monte-Carlo methods. The system consists of 32 generators; the hourly load on the system and bus load data is defined. The peak load for the system is 2850MW and all other loads are percentages of the peak loads. The installed capacity of the system is 3405MW. Single area generating capacity reliability evaluation is done on the system.

The failure and repair rates of all the generators are given. Detailed Information for IEEE-RTS is given in Appendix –A.

Method for evaluating all the states of the generator

When first generator (400MW) is added, the states of generator are 0MW and 400MW. When second generator (400MW) is added, the states are 0, 400, 800MW. When third generator (350MW) is added, the states are 0, 350, 400, 750, 800, 1150MW and so on, all the generators are added and all possible states of the generator are found. For all the 32 generators in the system, 3180 generator states are obtained. Now for finding the probability of capacity outages for all possible generator states,

After adding first unit, the capacity outage table is given in Table 7.

TABLE 7
Capacity outages and cumulative probabilities after adding first unit

States	C_i	P_i
1	0	P_1=1
2	400	P_2=0.12

Where

C_i = capacity outage and P_i's are the cumulative probabilities of capacity outages >=C_i

When 2nd unit (with forced outage rate 0.12) is added, pf = 0.12 and ps = 0.88

TABLE 8
Capacity outages after adding second unit

Capacity_outage before adding 2nd unit	New Capacity_outage after adding 2nd unit	Cumulative Probabilities
0	400	P_2
400	800	P_3

TABLE 9
Capacity outages and cumulative probabilities after adding second unit

Capacity Outages	P_i	P_i
0	$P(C_i \geq 0) = ps*P(C_i \geq 0) + pf*P(C_i \geq 0)$	$P_1 = 1$
400	$P(C_i \geq 400) = ps*P(C_i \geq 400) + pf*P(C_i \geq 0)$	$P_2 = 0.2256$
800	$P(C_i \geq 800) = pf*P(C_i \geq 400)$	$P_3 = 0.0144$

Table 8 and 9 shows the capacity outages and cumulative probabilities after adding second unit. After 350MW (FOR = 0.08) unit is added, all possible capacity outages and their cumulative probabilities are given in Table 10.

TABLE 10
Capacity outages and cumulative probabilities after adding third unit

Capacity outages	Cumulative Probabilities	P_i
0	P(C_i≥0) = ps*P(C_i≥0) + pf*P(C_i≥0)	1
350	P(C_i≥350) = ps*P(C_i≥400) + pf*P(C_i≥0)	0.28755
400	P(C_i≥400) = ps*P(C_i≥ 400) + pf *P(C_i≥ 400)	0.2256
750	P(C_i≥750) = ps*P(C_i≥ 800) + pf *P(C_i≥ 400)	0.031296
800	P(C_i≥800) = ps*P(C_i≥ 800) + pf*P(C_i≥ 800)	0.0144
1150	P(C_i≥1150) = pf*P(C_i≥ 800)	0.001152

This procedure is carried out until all 32 generators are added and their respective cumulative probabilities of capacity outages are found.

The load data information at each hour is used to calculate the probability of load.

For calculating loss of load in the system;

Loss of load occurs when the demand is not met by the generation. The probability of all generation capacities being less than load and probability of that load hour is taken into consideration and is calculated as;

$$HLOLE = \sum_{i=1}^{8760} P(Gen\_Capacity < Load_i) * P(Load_i)$$

Where i=load hour in a year.

P(Gen_capacity<$Load_i$) = Cumulative probability of generator being less than $Load_i$.

P($Load_i$) = Probability of load being $Load_i$.

3.2 Monte Carlo Simulation

Monte Carlo simulation simulates the failures and repairs of the generators by taking into account the randomness of generator failures and repairs. It is flexible for implementing complicated operations such as load uncertainty, weather effects and starting and shutting down generators in response to load.. Since it can mimic a real system, any operating characteristic can be implemented. The main advantages of the sampling simulation techniques are high flexibility and detail in the simulation of complex system operation and/or configuration conditions.

Disadvantages may or may not be (according to different situations which the utilities must face as regards the cost of computing time), the rather long CPU time which depends on the level of detail used in modeling the system and particularly its operation, and on the level of statistical convergence of the simulation process results; the number of samples generated are very large and depends on the system reliability level.

Monte-Carlo methods can be classified as

1) Random Sampling or Non-sequential sampling

Random sampling or non-sequential sampling, consists of performing random sampling over the aggregate of all possible states the system can assume during the period of our interest, i.e., the state of each component is sampled and system state is non-chronologically determined.

a) Proportional Probability Method

b) Probability Distribution Method

2) Sequential sampling

In sequential method, mathematical model of the system is made to generate artificial history of failures and recoveries of generators, i.e., system state is sequentially determined. It is appropriate for both independent and dependant events.

a) Fixed Time Interval Method

b) Next Event Method

The detailed explanation of these methods is given in [7].

Sequential method requires more calculation time than random sampling method.

In this thesis, Monte-Carlo's Sequential sampling Fixed Time Interval method is used. In this method, a time interval of Δt is chosen, Δt depends on various operative considerations. In this case Δt is chosen to be 1 hour, since the load requirement in the IEEE-RTS model changes every hour. The state residence times of each component are determined by distributions of continuous random variables. Therefore determining the value of random variable is an essential step.

3.2.1 Random Number Generation

A random number can be generated by either a physical or a mathematical method. The mathematical method is most common as it can guarantee reproducibility and can be easily performed on a digital computer. A random number generated by a mathematical method is not really random and therefore is referred to as pseudo-random number. In principle, a pseudo-random number sequence should be tested statistically to assure its randomness.

The basic requirements for a random number to be used in Monte-Carlo simulation are as follows.

1) Uniformity: The random numbers should be uniformly distributed in interval [0, 1].
2) Independent: There should be minimal correlation between random numbers
3) Long Cycle Time: The repeat period should be sufficiently large.

Let z be the random number in the range 0 or 1 with a uniform probability density function.

$$\text{Let } F(z) = \left\{ \begin{array}{c} 0, Z < 0 \\ z, 0 <= Z <= 1 \\ 1, Z > 1 \end{array} \right\}$$

Let $F(x)$ be the distribution function from which the random observations are to be generated, and $z=F(x)$

Solving the equation for x gives a random observation of X. Thus, the generated observations have $F(x)$ as the probability distribution.

$$z = F(x)$$

$$x = F^{-1}(z) = \psi(z)$$

Now, x is the random number generated. To determine its probability distribution,

$$Pr(x \leq X) = Pr(F(x) \leq F(X)) = Pr(z \leq F(X)) = F(x)$$

The distribution function of x is *F(x)* as required. Many techniques were developed for efficient random numbers generation.

Exponential distribution has the probability distribution of the following;

$P(x \leq X) = 1 - e^{-\rho x}$; where $1/\rho$ is the mean of the random variable X.

Let z be the random variable between 0 and 1, $z = 1 - e^{-\rho x}$;

If z is a random variable, then $1 - z$ is also a random variable.

Then $z = e^{-\rho x}$

$$x = \frac{-\ln(z)}{\rho}$$

Which is the desired random observation from the exponential distribution have $1/\rho$ as the mean. ρ here can be failure (λ) or repair (μ) transition rate of the generator. x is the time of a generator in a particular state which is failure time when $\rho = \lambda$ and it is the repair time when $\rho = \mu$.

These steps are carried out until a statistical convergence of the probability indices calculated are seen. Statistical inferences like failure hours during needed state and reserve shut down state, service hours during needed and reserve shut down state are drawn from this simulation. After sufficient amount of time, this statistical information is used to evaluate various probability parameters.

For each generator, when committed into service, the corresponding failure time is determined and when it is in failed state, its recovery time is determined, thus for each generator, the total failure time and total service time is determined and hence its probability of failure is determined.

3.2.2 Steps for Monte-Carlo Simulation

1) Starting at t = 0; time is advanced by $\Delta t = 1$, the generators are dispatched in their priority order according to the load requirement. The expected failure times of all the generators committed into service are calculated.
2) Additional generators are committed to service to compensate some sudden or unexpected generators failure (reserve capacity). This is concerned with the adequacy of generation to supply the load, transmission constraints are not considered.
3) The load requirement at every hour is checked and additional generators are committed if required and generators which are not required are put to reserve shut down if they satisfy the criteria for shut down.
4) The minimum UP and DOWN time of different generators and their respective transition rates are given in [8].
5) Then the system is checked for occurrence of any event. The event could be either committing a new generator into service, failure of an existing generator or recovery of a new generator.
6) Failure of a generator is observed during its operation. It is assumed that the generator fails after the designated failure time which is determined when it is put into service.
7) The generator is expected to start without any failure after its repair. Hence starts up failures are neglected.

Operating considerations taken into account are;

1) Any generator when scheduled to work should be in service for a minimum UP time as given in [8].

2) Reserve capacity of the system is at least the maximum unit of the generator in the system, thus providing security during (n-1) service contingency.

3) Generator (usually base units) cannot be switched ON within 1 - 2 hours after it is shut down, hence if a generator is needed after two or three hours of its non-requirement, it should not be shut down.

After all these conditions are taken into account during the simulation, service times and failure times of all the generators are collected. The probabilities of failures of all generators are calculated as

$$FOR = \frac{Failure\_times\_during\_needed\_state}{Failure\_times\_during\_needed\_state + Service\_hours\_during\_need}$$

Loss of load in the system is defined as an instant when the available generation is not sufficient to serve the load, thus leading to curtailment of load. This might occur due to the failure of generators at that instant or sudden increase in load. Loss of load in the system can be determined using the simulation when the demand is observed to be greater than the generation available. The simulation gives more realistic results as it mimics the real system operation with high flexibility and detail.

CHAPTER IV

RESULTS AND CONCLUSIONS

Using the IEEE-RTS data, Monte Carlo program is written taking all operating considerations into account. To validate the accuracy of the program, a simple daily load cycle is used as shown in Figure 6.

1 – 8 hours: 1400MW

9 – 16 hours: 2600 MW

17 – 24 hours: 1400MW

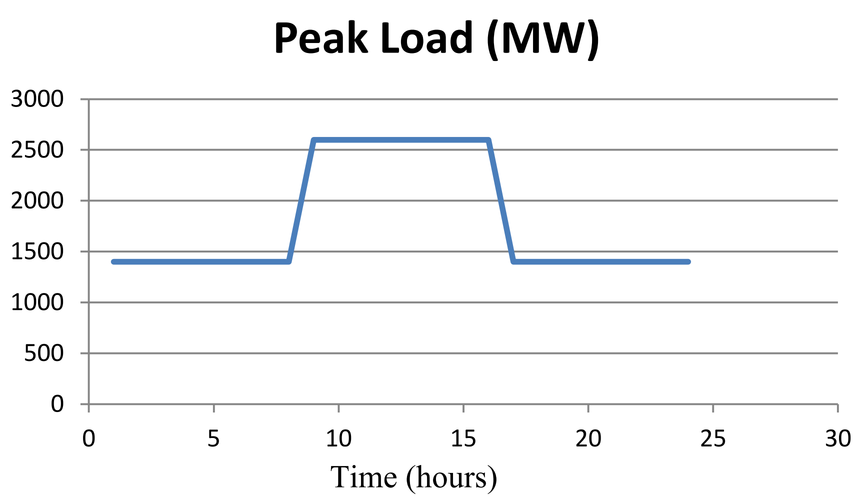

Fig 6: Load model

For hours 1 – 8, to serve the load of 1400MW, generators 400 MW (2), 350 MW (1) and 197 MW (3) are committed to service, which provide a total generation of 1741 MW.

During peak loading hours 9 – 16 hours, additional generators 155 MW (4) and 100 MW (3), total 2661 MW are brought into service. The peaking units are put to reserve shut down from hours 17 – 24 hours and 1 – 8 hours the next day. This cycle is repeated throughout.

The failure transition rates of peaking units are reduced to $1/100^{th}$ of their actual value to increase the probability that the generators do not fail. The duty cycle values of all generators are collected from the simulation.

From the load cycle, it's observed that if the units did not fail the duty cycle of peaking units would be

$$D = \frac{service\_times}{actual\_starts} = \frac{8}{1};$$

Peaking units operates for 8 hours daily and each generator starts once from its reserve shut down state. Also during this process we assume that the generators don't fail since their failure rates are negligible.

The simulation results also give the same value for duty cycle D, which supports the accuracy of the program to collect the failure and service hours. The simulation is run with the load cycle given in the IEEE-RTS. The generator failure times and service times are collected and forced outage rates (FORs) are calculated. Data such as number of starts, Failure times, Service times, Number of Shut-downs, Number of Failures, etc are collected from the simulation. The above data collected is used to find various parameters like *Ff*, *Fp*, *D, T* and *EFORd* as is the standard practice.

$$D = \frac{service\_times}{actual\_starts};\ Fp = \frac{service\_times}{Available\_hours};\ D + T = \frac{Available\_hours}{Total\_starts}$$

$$r = \frac{1}{\mu};\ m = \frac{1}{\lambda};\ Ff = \frac{\frac{1}{r} + \frac{1}{T}}{\frac{1}{r} + \frac{1}{T} + \frac{1}{D}};\ EFORd = \frac{Ff * FOH}{Ff * FOH + SH}$$

The FORs from simulation, EFORds from analytical methods are shown in Table 11.

TABLE 11
FORs from simulation and EFORDs from analytical method

Generator	FOR (from Monte Carlo)	EFORd (from Analytical Method)	Generator	FOR (from Monte Carlo)	EFORd (from Analytical Method)
1.	0.12	0.12	17.	0.0010	0.0005
2.	0.12	0.12	18.	0.0007	0.0003
3.	0.08	0.08	19.	0.0008	0.0004
4.	0.0500	0.0500	20.	0.0019	0.0012
5.	0.0500	0.0500	21.	0.0020	0.0011
6.	0.0500	0.0500	22.	0.0024	0.0014
7.	0.0400	0.0400	23.	0.0044	0.0032
8.	0.0400	0.0400	24.	0.0790	0.0323
9.	0.0400	0.0400	25.	0.0767	0.0303
10.	0.0041	0.0031	26.	0.0892	0.0343
11.	0.0046	0.0032	27.	0.0889	0.0314
12.	0.0041	0.0027	28.	0.0119	0.0065
13.	0.0048	0.0031	29.	0.0153	0.0092
14.	0.0012	0.0005	30.	0.0147	0.0080
15.	0.0003	0.0001	31.	0.0094	0.0050
16.	0.0007	0.0002	32.	0.0101	0.0056

The loss of load expectation for various peak loads observed is given in Table 12 and [9]

TABLE 12
HLOLE results from unit-addition and analytical method

System Model	Reliability Indices Obtained by UNIT ADDITION METHOD	Reliability Indices Obtained by MONTE-CARLO METHOD
	LOLE (hr/year)	LOLE(hr/year)
IEEE-RTS (Peak Load = 2850MW)	9.389	10.77
IEEE-RTS (Peak Load = 3050MW)	32.3389	34.28
IEEE-RTS (Peak Load = 2650MW)	3.1502	2.59

4.1 Conclusion

The data for analytical method is obtained from historical data. So when the load data changes, the historical data may not be valid. Monte-Carlo simulation takes changing load into account, and thus gives more valid results as it does not depend on the historical data but more intrinsic parameters of failure and repair rates as well as load characteristics. The use of analytical methods for calculating the EFORD thus may need to be revisited.

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APPENDIX A

THE IEEE 24 – BUS RELIABILITY TEST SYSTEM

The IEEE Reliability Test System (RTS - 79) is an enhanced test system which was developed with the objective of providing a comparative and benchmark studies to be performed on new and existing reliability evaluation techniques. Details of the RTS and its components are available in [8]. The first version of the IEEE-RTS was developed and published in 1979 by the Application of Probability Methods (APM) Sub-committee of the Power System Engineering Committee. After it was developed in 1979, system data has been enhanced twice in 1986 and 1996.

The IEEE-RTS is a 24 – bus system, with 32 generators and 38 transmission lines. The configuration is shown in Fig. 7 and the generation data is given in Tables 17.

Load Model: The basic annual peak load for the test system is 2850 MW. Table 13 gives data on weekly peak loads in percentage of the annual peak load. If week 1 is taken as January, Table 13 describes a winter peaking system. If week 1 is taken as a summer month, a summer peaking system can be described. Table 14 gives a daily peak load cycle, in percentage of the weekly peak. The same weekly peak load cycle is assumed to apply for all seasons. The data in Table 13 and Table 14 together with the annual peak define a daily load model of 52 x 7 = 364 days with Monday as the first day of the year. Table 13 gives weekday and weekend hourly load models for each of three seasons. Combination of Tables 13, 14 and 15 with the annual peak load defines an hourly load model of 364 x 24 = 8736 hours. Table 17 gives the number of generators, their transition rates, minimum UP and DOWN times and their priority order of commitment.

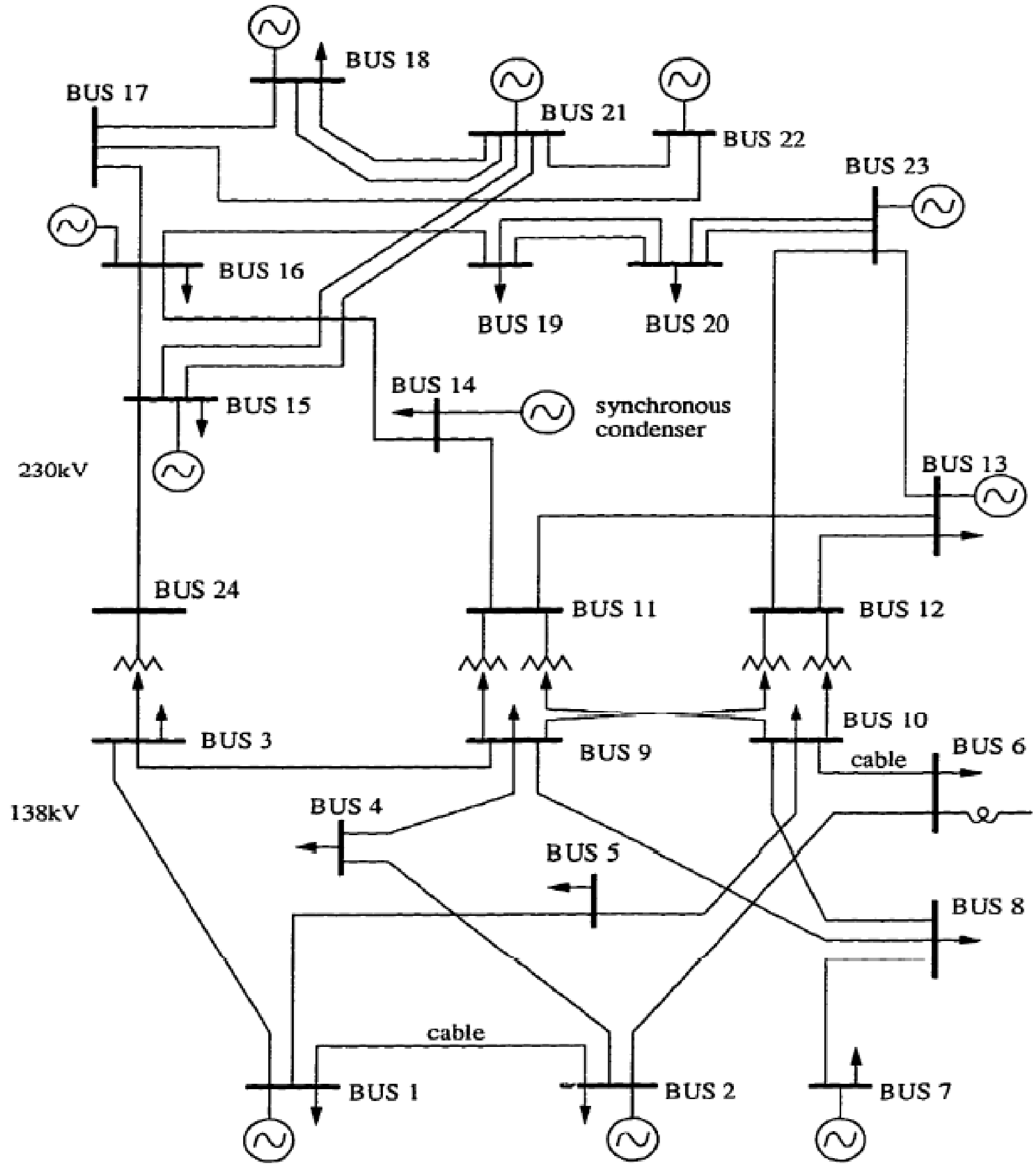

Fig 7: IEEE-RTS area-1

TABLE 13
Weekly peak load in percentage of annual load

WEEK	PEAK LOAD	WEEK	PEAK LOAD	WEEK	PEAK LOAD	WEEK	PEAK LOAD
1	86.2	14	75.0	27	75.5	40	72.4
2	90.0	15	72.1	28	81.6	41	74.3
3	87.8	16	80.0	29	80.1	42	74.4
4	83.4	17	75.4	30	88.0	43	80.0
5	88.0	18	83.7	31	72.2	44	88.1
6	84.1	19	87.0	32	77.6	45	88.5
7	83.2	20	88.0	33	80.0	46	90.9
8	60.6	21	85.6	34	72.9	47	94.0
9	74.0	22	81.1	35	72.6	48	89.0
10	73.7	23	90.0	36	70.5	49	94.2
11	71.5	24	88.7	37	78.0	50	97.0
12	72.7	25	89.6	38	69.5	51	100.0
13	70.4	26	86.1	39	72.4	52	95.2

TABLE 14
Daily loads in percent of weekly peak

DAY	PEAK LOAD
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

TABLE 15
Hourly peak load in percent of daily load

HOUR	WINTER WEEKS		SUMMER WEEKS		SPRING/FALL WEEKS	
	1-8 & 44-52		18-30		9-17 & 31-43	
	WKDY	WKND	WKDY	WKND	WKDY	WKND
12-1 am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-noon	95	91	100	93	99	94
noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95

TABLE 15 continued

HOUR	WINTER WEEKS		SUMMER WEEKS		SPRING/FALL WEEKS	
	1-8 & 44-52		9-17 & 31-43		1-8 & 44-52	
	WKDY	WKND	WKDY	WKND	WKDY	WKND
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Where WKDY = week day   WKND = week end

TABLE 16
Generator locations in IEEE-RTS

BUS	UNIT (MW)	UNIT (MW)	UNIT (MW)	UNIT (MW)	UNIT (MW)	UNIT (MW)
1	20	20	76	76		
2	20	20	76	76		
7	100	100	100			
13	197	197	197			
15	12	12	12	12	12	155
16	155					
18	400					
21	400					
22	50	50	50	50	50	50
23	155	155	350			

TABLE 17
Generator data in IEEE-RTS

UNIT GRO UP	UNIT SIZE (MW)	UNIT TYPE	FORCED OUTAGE RATE	MTTF (Hour)	MTTR (Hour)	No OF UNITS IN AREA-1	PRIORITY ORDER	MINIMUM DOWN TIME (Hours)	MINIMUM UP TIME (Hours)
U400	400	Nuclear	0.12	1100	150	2	1	1	1
U350	350	Coal/Steam	0.08	1150	100	1	2	48	24
U197	197	Oil/Steam	0.05	950	50	3	3	10	12
U155	155	Coal/Steam	0.04	960	40	4	4	8	8
U100	100	Oil/Steam	0.04	1200	50	3	5	8	8
U76	76	Coal/Steam	0.02	1960	40	4	6	4	8
U50	50	Hydro	0.01	1980	20	6	7	NA	NA
U20	20	Oil/CT	0.10	450	50	4	8	1	1
U12	12	Oil/Steam	0.02	2940	60	5	9	2	4