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ASSESSMENT OF THE IMPACT OF A WIND ENERGY CONVERSION SYSTEM ON ELECTRICAL UTILITY PLANNING

by

Peter Uko

A thesis
presented to the School of Graduate Studies
in partial fulfillment of the
requirements for the degree of
Master of Applied Science
in the
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ABSTRACT

Methodologies suitable for use by electric utilities to assess the impact of including a Wind Energy Conversion System (WECS) in their generation mix are developed. The approach utilizes already available planning techniques accessible to utilities with modifications to include a WECS. Two ways of modelling a WECS are presented. Firstly a WECS is modelled as a multistate unit whose derated capacities are caused by wind variability and forced outages. Secondly, a WECS hourly output is taken as a negative demand which is subtracted from the utility's chronological load curve. A subsection of this second model, which is verified, is in terms of the statistical cumulants of the random variable describing the wind power output duration curve. The limitation of this subsection is discussed.

The assessment is based on comparison of total utility generation system costs with and without a WECS. The value of a WECS to the utility is taken as the benefits derived from displaced cost of energy and capacity of conventional plants.

Because of the uncertainty in the economic assumptions made, this study includes a variation in the key assumptions, so as to investigate their effect on the results obtained.

The results show that a WECS, at least, improves generation system reliability in terms of the loss of load probability and expected energy not served. As a result of this, it is possible to displace some conventional units' capacity with a WECS. The value of a WECS varies with wind regime, planned generation mix and such economic factors as escalation rate of fuel and operation and maintenance costs. This implies that the value of a WECS is utility specific. In addition, it is shown that increased penetration levels of a WECS may not be economically viable.

ACKNOWLEDGEMENT

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GLOSSARY OF TERMS

<u>Capacity Displacement</u>: The amount of conventional generating capacity, if any, that might be omitted from a utility's planned future requirements because of the planned addition of wind machines.

<u>Cut In Wind Speed</u>: The speed at which a wind turbine begins to produce power.

<u>Cut Out Wind Speed</u>: The speed at which a wind turbine's power is brought to zero to avoid damage.

<u>Energy Displacement</u>: The amount of electrical energy that need not be generated because of the energy produced by installed wind machines.

<u>Effective Load Carrying Capability</u>: The allowable increase in utility system annual peak load that can be accommodated, while maintaining a fixed level of system reliability, by installing a new generating unit.

<u>Equivalent Capacity</u>: The capacity that could be removed from the generating system after adding a new generating unit, to maintain the same loss of load probability as in the original system.

Equivalent Load Duration Curve: Probability distribution of demand including the effect of the random failures of generating units.

Expected Energy Not Served: Energy demanded of system but not delivered to load because of failures of all the generating units in the system.

Forced Outage Rate: The fraction of time that a generating unit will not function when it is called upon to operate, excluding scheduled maintenance time and idle time.

Intermittent Source: A generating source driven by energy that is not continuously available.

Levelization: The process by which a series of non-uniform future payments is converted to a uniform (level) series of payments whose present worth is equal to that of the original non-uniform series.

Load Duration Curve: This curve relates the customer's load level to the duration of time that each load level is equalled or exceeded.

Loss of Load Probability: The expected value of days per year or hours per year of a condition of insuficient generation available for the load or the probability that some portion of the load will not be satisfied by the generating capability.

Penetration: Installed capacity of a particular type of generator expressed as a percentage of installed system capacity .

Reserve Margin: The excess of available generating capacity over peak load, expressed as a percentage of peak load.

NOMENCLATURE

WECS	Wind Energy Conversion System
WTG	Wind Turbine Generator
LOLP	Loss Of Load Probability
E(ENS)	Expected Energy Not Served
LDC	Load Duration Curve
ELDC	Equivalent Load Duration Curve
PODC	Power Output Duration Curve
WVDC	Wind Velocity Duration Curve
V_R	Wind turbine generator rated velocity
V_{CI}	Wind turbine generator cut in velocity
V_{CO}	Wind turbine generator cut out velocity
P_R	Wind turbine generator rated power
O&M	Operation and Maintenance

TABLE OF CONTENTS

Appendix Page

LIST OF TABLES

LIST OF FIGURES

Chapter I

INTRODUCTION

1.1 MOTIVATION AND BACKGROUND

After the 1973 oil embargo, it dawned on a number of people - seemingly all at the same time - that energy resources are not, at least, at the present level of technology, without limit. This awareness stimulated the interest of many electric utilities towards the use of unconventional but renewable energy sources. Wind power is a renewable resource and has been known to man for many centuries.

Early in this century, much of rural America used wind power to pump water and generate its electricity [40]. Since wind is abundant in some areas (the upper limit on the practically exploitable energy annually available from wind power in the United States is roughly 1-2 x 10^{12} KWh per year [10]), replenishable and clean, it is considered one of the most important energy sources. Manufacturers and utilities alike have committed capital as well as human resources to the development of wind power generation.

Pacific Gas and Electric Co., for example, has included 82.5 MW of wind power in its generation expansion plans for 1990. Southern California Edison Co. has included 43 MW of capacity displacement by wind power in its plan for 1990. Hawaiian Electric Co., Inc., has signed an agreement to purchase up to 80 MW of wind generated power by 1985 from a private firm that will retain ownership of the wind machines [40].

Wind is intermittent in nature and any power source that depends on wind as its input will fluctuate from zero to maximum within a small time interval. The integration of such an intermittent energy source into a utility resource plan poses many a problem to system planners [11]. It is on this premise that the motivation to develop a methodology suitable for use by electric utilities to assess the impact of including a WECS in their generation mix was conceived.

1.2 APPROACH

The output of a WTG can either be fed directly into the transmission grid or stored for use at need. Anticipated problems that could arise from the incorporation of storage systems for a WECS have been mentioned by Davitian [10]. Marsh [2] showed that the existence of system energy storage has little effect on wind power plant value. This study considers the operation of a WECS on a non-demand basis, that is, without storage.

1.2.1 WECS modelling

Two models may be used in representing the WECS power output. In the first model, wind turbine generators may be represented as multistate generators whose derated capacities are proportional to wind variability. The resulting probability density function of derated capacities is convolved with the load probability distribution along side with conventional units for the period under consideration. Production costs and reliability analyses are performed on the equivalent load duration curve (ELDC), as is the practice [13].

In the second model, the hourly WECS expected power output for each period is obtained. This hourly WECS expected power output is subtracted from the actual utility's hourly load. The difference is eventually recombined into a WECS - modified LDC. Conventional units are committed following a prescribed merit order based on their marginal costs, to meet the load demand after wind modification

The use of the second model has been reported by some investigators [2], [5], [7]. Although the same general conclusions can be made from results of the two models, the first model is obtained from a more detailed probabilistic representation of wind energy as will be described. The results presented in this study are based on the first model since it allows for a more straightforward representation of a WECS capital as well as O&M costs.

1.2.2 Project Outline

A typical hypothetical electric utility, as given by the IEEE Reliability Test System [37], is defined as the base case. Two planning strategies supposedly to be considered by this hypothetical utility are analyzed. Firstly, the utility considers a plan in which the aim is to evaluate the savings or loss in primary energy requirement as a result of the introduction of a WECS in their planned generation mix. Secondly, the utility proposes a plan where its concern is to evaluate the possibility of postponing planned conventional capacities as a result of the introduction of a WECS.

In both cases, the utility wants to know whether it would be profitable to keep on increasing the WECS penetration so long as the resources are available.

As a way of finding out the effects of the assumptions made, this study also includes a sensitivity analysis of the key parameters used. Parameters such as forced outage rates of the wind turbines, oil costs and operation and maintenance cost are varied and the effect on the final results examined.

Assessment, as reported in this thesis, is based on costs and reliability results obtained with and without a WECS in the energy and capacity displacement modes.

The project is divided into four major sections as shown in Fig. 1.

Chapter two gives methods of analyzing wind data to obtain the required models for simulation. In Chapter three, the methodology is detailed. Load models, generating units' models and simulation methods are discussed.

Results from Chapter three show that there is savings in terms of cost of fuel and conventional capacity displaced when a WECS is added to the generation mix. The method of appraising these savings with a view to finding out whether it benefits the utility is discussed in Chapter four. Also in this Chapter, a total utility system cost approach is used to compare each change case with the base case. Production cost results for the base case are escalated over the life of the WTGs. A levelized present worth equivalent cost is obtained. This formed the total utility system cost for the base case.

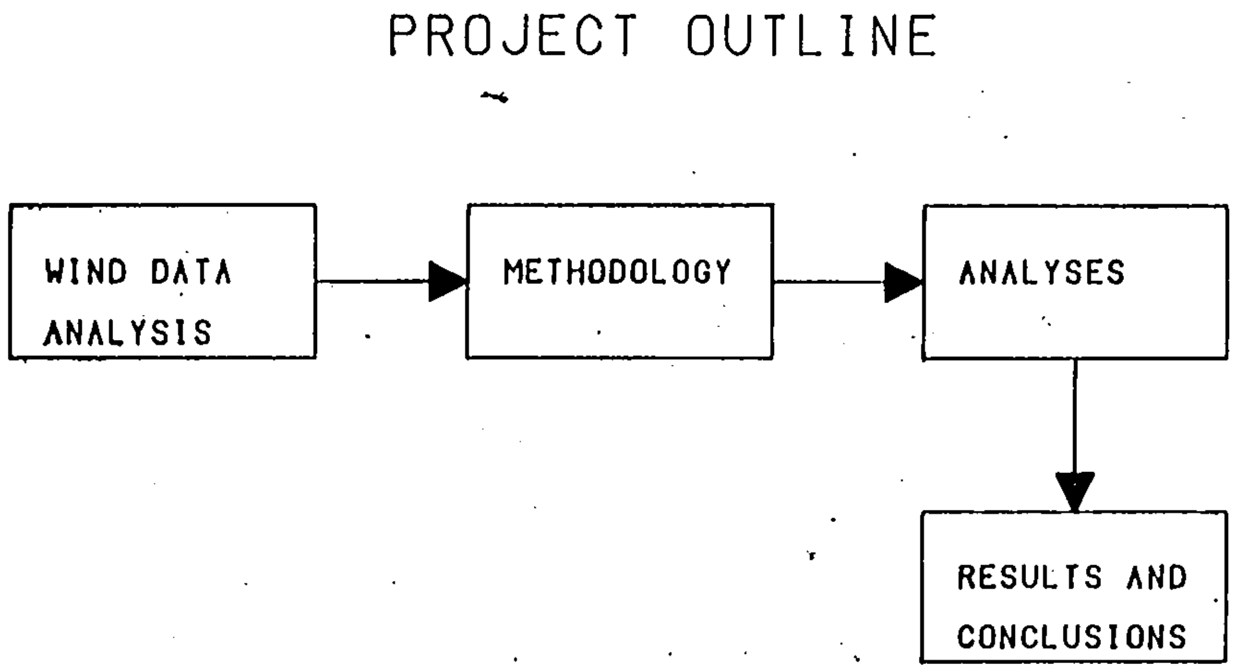


FIGURE 1. PROJECT OUTLINE

For each change case, the Total utility system cost = Levelized production costs + Fixed charges on WTGs + Levelized WTGs operation and maintenance (O&M) costs - Fixed charges on any conventional unit displaced. Forced outages of WTGs, generation mix, oil cost and operation and maintenance costs are varied over a range that includes several possibilities. The simulation is repeated for each case.

Chapter five presents the results. Reasons for the results obtained are also given. In summary, it is seen that:

1. The LOLP and E(ENS) improve as a WECS is introduced to the generation mix.
2. The value of a WECS increases substantially with slight increase in fuel cost.
3. It is possible to postpone the installation of a conventional unit when a WECS is installed.
4. The value of a WECS is sensitive to wind regime, generation mix, fuel escalation rate and operation and maintenance costs.
5. The value of a WECS will differ from utility to utility.

6. There is an optimum value for a WECS penetration for each utility.

Conclusions and areas that require further investigation are given in Chapter six.

1.3 LIMITATIONS

The limitations of this study are a result of several assumptions which are necessary to conduct the analysis to a fruitful end. Pointing out these limitations here will help to avoid misinterpretation of the results obtained.

The assumptions made are:

1. The WTGs are considered as must run units.
2. Monthly utility load models and monthly wind profiles are used.
3. Time of day correlation between wind energy and demand is neglected.

Where time of day correlation is evident from feasibility studies, hourly distributions must be used as will be described later.

Generally, inadequacy in data collection dominates the study limitations. However, the study adopted a systematic approach whose variables can simply be substituted for actual data in order to obtain specific results.

Chapter II

WIND DATA ANALYSIS

2.1 INTRODUCTION

The primary cause of wind is differential heating of the earth's surface by the sun. This differential heating makes wind highly variable and site specific. To obtain adequate wind data at any site requires several years of wind speed recordings including direction. Lack of such complete information handicaps realistic calculations. Melton [1], in his study of the loss of load probability and capacity credit of a WECS with the Hawaiian Electric Company data, utilized many years of wind data. Such data, apart from being far-fetched for many sites, requires an enormous amount of processing. A probabilistic approach for modelling wind using known distributions is often used. For modelling wind variability, the Rayleigh and Weibull distributions have been extensively used since they give reasonable fits to the observed wind velocities [3],[6],[21],[24].

2.2 WIND VELOCITY DURATION CURVE

The wind velocity duration curve (WVDC) is a plot of wind velocity versus the time the velocity equals or exceeds the value in question. A typical WVDC is shown in Fig. 2

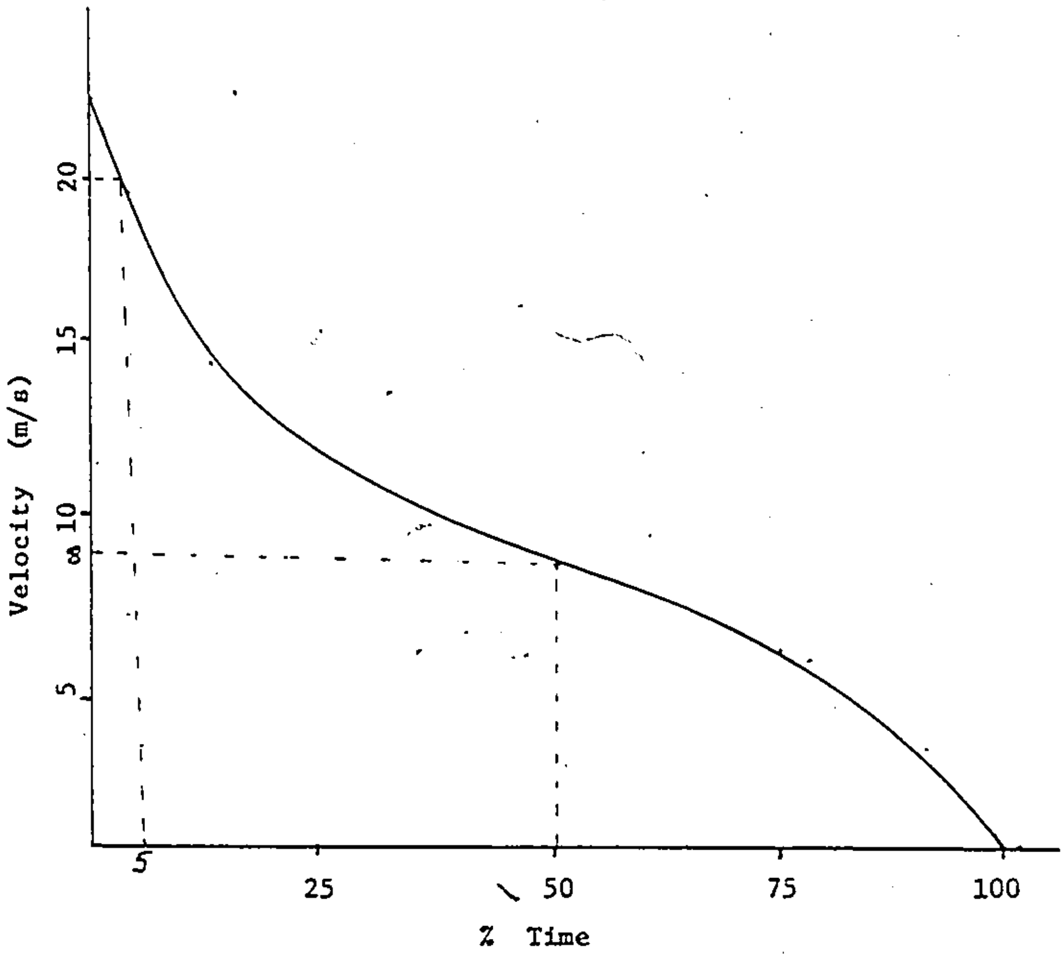


Figure 2: A typical Wind Velocity Duration Curve

Fig.2 can be plotted from hourly (averaged over a few minutes duration) wind velocity data obtained over many years for the site under consideration, otherwise a probability model for wind speed distribution is used.

The Rayleigh density function is defined as:

$$f(v) = \frac{\pi}{2}\frac{v}{\bar{v}^2}\exp\left[-\frac{\pi}{4}\left(\frac{v}{\bar{v}^2}\right)^2\right] \qquad (2.1)$$

and that of Weibull as:

$$f(v) = \frac{\beta v^{\beta-1}}{\alpha^{\beta}}\exp\left[-\left(\frac{v}{\alpha}\right)^{\beta}\right] \qquad (2.2)$$

where v = Wind velocity

$\bar{v}$ = Mean wind velocity

and α and β are the parameters of the distribution.

The Rayleigh distribution, being a one parameter distribution, is easy to evaluate. The Weibull distribution is an improvement on the Rayleigh distribution but requires the evaluation of two parameters (α and β). However, when $\beta = 2$ and $\alpha = \frac{2\bar{v}}{\sqrt{\pi}}$, the Weibull distribution reduces to that of Rayleigh.

2.2.1- Determination of Weibull Parameters

The Weibull cumulative distribution function is given by:

$$F(v) = 1 - \exp[-(\frac{v}{\alpha})^{\beta}] \tag{2.3}$$

The nth moment is:

$$\overline{v}^{n} = \int_{0}^{\infty} v^{n} f(v)\,dv \tag{2.4}$$

The first and second moments which are the mean and variance respectively are:

$$\overline{v} = \alpha\Gamma(1 + 1/\beta) \tag{2.5}$$

$$\alpha_{v}^{2} = \alpha^{2}\{\Gamma(1 + 2\beta^{-1}) - \Gamma^{2}(1 + \beta^{-1})\} \tag{2.6}$$

where:

$$\Gamma(\beta) = \int_{0}^{\infty} v^{\beta-1} e^{-v} dv \tag{2.7}$$

$$(\frac{\sigma}{\overline{v}})^{2} = \frac{\Gamma(1 + 2/\beta)}{\Gamma^{2}(1 + 1/\beta)} - 1 \tag{2.8}$$

If the mean velocity and variance are known, using(2.5) and (2.6), α and β are found and the distribution plotted with(2.3).

However if only the mean velocity is known, a good estimate of β and the calculation of α from (2.5) may still lead to good results [21].

In many cases wind data [36] is given as % of the time wind is within a given interval. Typical values may be obtained as shown in Table 1.

TABLE 1

Wind For Ottawa International Airport(1979)

	Wind Speed Interval (Km/h)					
MONTH	1-5	6-11	12-19	20-28	29-38	39-49
	% of time					
Jan	3	29	27	23	6	4
Feb	4	33	29	23	5	-
Mar	6	41	21	15	7	1
Apr	4	28	31	24	7	1
May	8	42	22	14	3	1
Jun	8	42	23	18	1	-
Jul	11	50	21	5	-	-
Aug	13	48	18	8	-	-
Sep	12	46	22	9	-	-
Oct	10	42	23	14	2	-
Nov	11	47	20	10	1	-
Dec	6	35	28	20	4	1

If the data is well behaved, least square approximation may be used to obtain the parameters α and β. Rewriting (2.3) as

$$1 = F(v) = \exp[-\ (\frac{v}{\alpha})^{\beta}] \tag{2.9}$$

and taking the logarithm of each side twice yields:

$$\ln(-\ \ln(1-F(v)) = \beta \ln v - \beta \ln \alpha \tag{2.10}$$

This is in the form

$$Y = AX + B \tag{2.11}$$

where A and B are the parameters of the regressed data, say for each month, and may be evaluated by the equation

$$A = \frac{\Sigma XY - \frac{\Sigma X \Sigma Y}{n}}{\Sigma X^2 - \frac{(\Sigma X)^2}{n}} \tag{2.12}$$

and

$$B = \frac{1}{n}\ (\Sigma Y - A\Sigma X) \tag{2.13}$$

where n is the number of points.

From (2.10),

$$\beta = A \tag{2.14}$$

$$\alpha = \exp\left[-\ \frac{B}{\beta}\right] \tag{2.15}$$

2.3 POWER OUTPUT VERSUS WIND VELOCITY CURVE

The curve of wind power output versus wind velocity describes the performance of a given wind plant on a specific wind regime. A typical curve of this type is shown in Fig.3

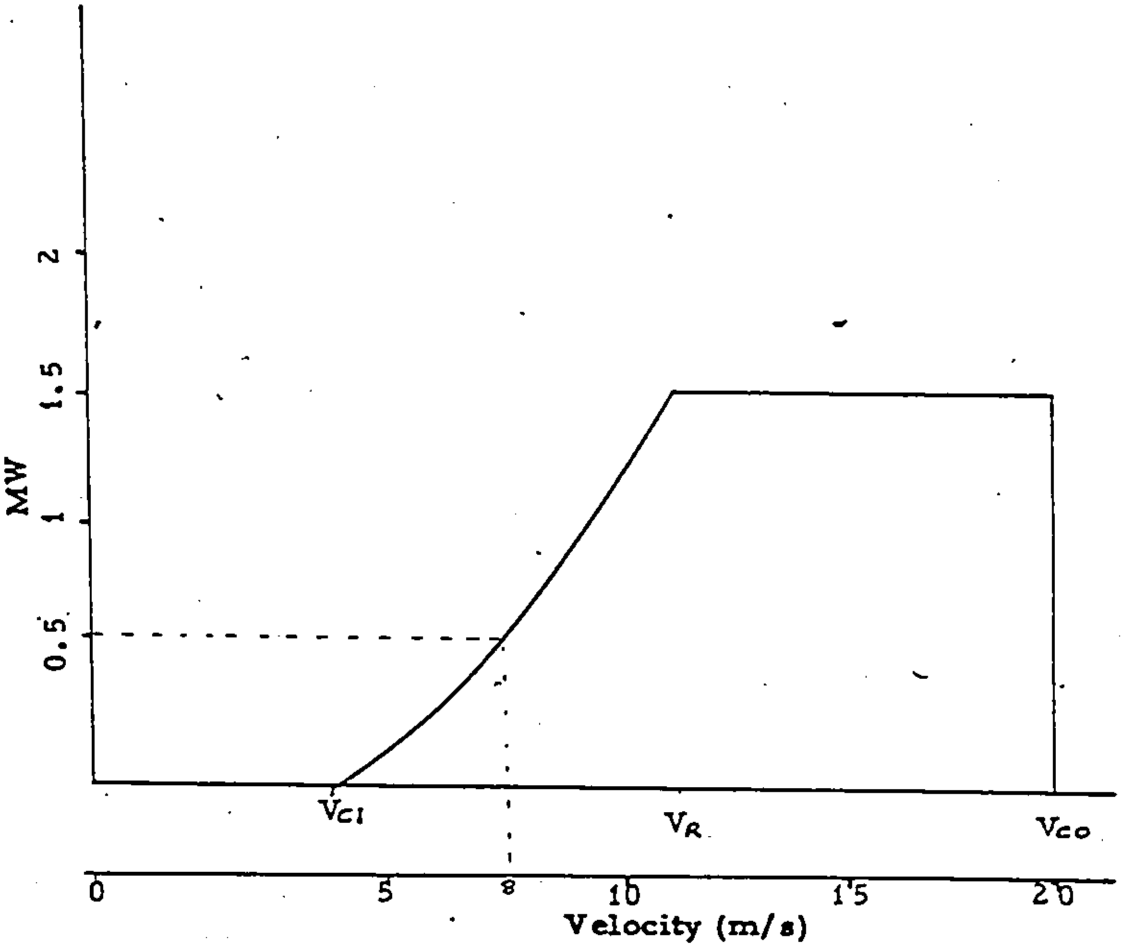


Figure 3: Power Characteristics of Individual WECS

The parameters of this curve are the cut in velocity V_{CI}, the rated power P_R, the rated velocity V_R and the cut out velocity V_{CO}. In addition to the above parameters, the wind plant power output is a function of the rotor shaft power, mechanical transmission efficiency and generator efficiency.

2.4 POWER OUTPUT DURATION CURVE(PODC)

This curve gives the probability of exceeding any given power level of the wind turbine generator. A typical PODC is shown in Fig.4 The curve is obtained by combining the wind velocity duration curve and the power output versus wind velocity curve.

The way the PODC is obtained is illustrated with the following simple example: Suppose we want to know the fraction of time the wind turbine exceeds a power level of 0.5MW. Consider a cut out velocity of 20 m/s. From the power output versus wind velocity curve, the wind turbine exceeds 0.5MW at a velocity between 8 and 20 m/s. From the WVDC, the wind velocity exceeds 8 m/s about 50% of the time and exceeds 20 m/s about 5% of the time. Hence 0.5MW will be generated 45% of the time. Performing this calculation a number of times for different power levels yields the PODC.

The integral under the PODC is the average power generated by the wind turbine generator in question.

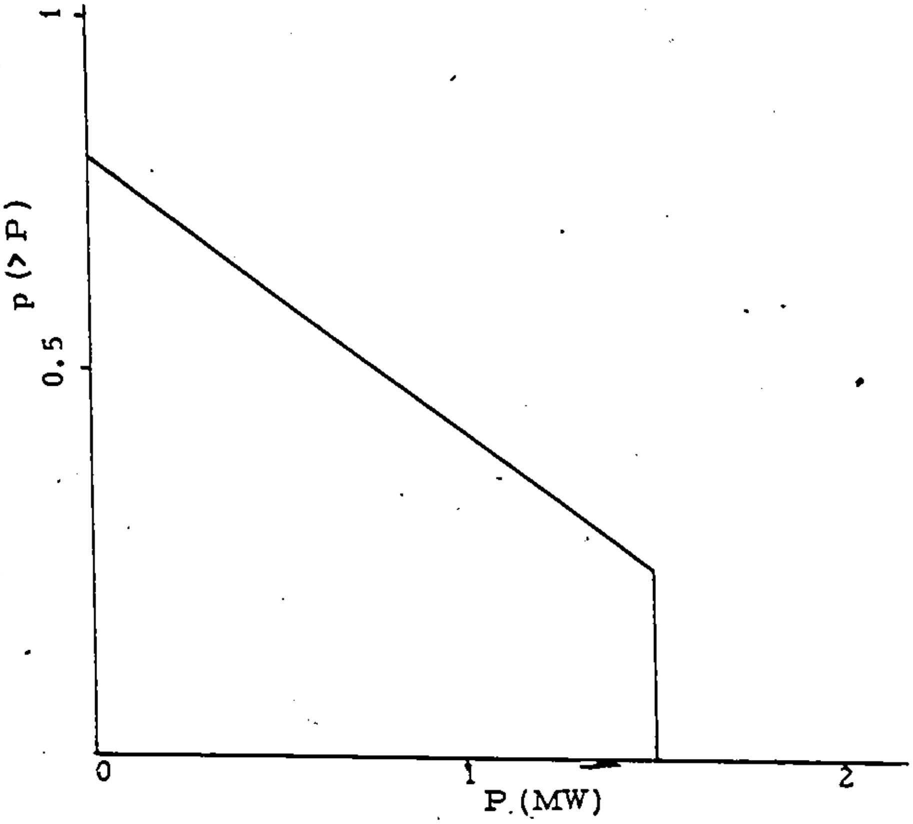


Figure 4: Power Output Duration Curve

2.5 WECS AVAILABILITY PROBABILITY MATRIX

The availability matrix gives a complete probabilistic description of the WECS output power. The following steps describe the procedure for obtaining this matrix:

1. From the PODC, obtain hourly array output power. If the wind characteristics are relatively uniform over the array and the WTGs in the array are identical, the array could be modelled as one machine. Otherwise it should be modelled separately and treated as different generators in the simulation.

2. Derate the array capacity to as many levels as is computationally feasible (20 uniform ~~in~~termediate values between maximum capacity and zero capacity are used in this study).

3. Sort the hourly power output occurrences into an m by n matrix where the rows represent zero output power, rated output power, and k uniform intermediate values. The columns are the 24 hours of the day.

4. Divide each element of the matrix by the number of days in the period considered. If a 30 day month is considered and 10 values of 1.5MW occurred at say 1 a.m., the probability of having 1.5MW at 1 a.m. is 10/30 =0.3333.

Table 2 shows the form of the availability matrix.

A typical WECS availability matrix is shown in Table 3.

TABLE 2

Monthly Availability Matrix

	HOUR OF THE DAY			
Power level	1	2	3	24
PMW	p(1,1)	p(1,2)	p(1,3)	p(1,24)
0.95P	p(2,1)	p(2,2)	p(3,2)	p(2,24)
0.90P	p(3,1)	p(3,2)	p(3,3)	p(3,24)
0.05P	p(21,1)	p(21,2)	p(21,3)	p(21,24)
0.00P	p(22,1)	p(22,2)	p(22,3)	p(22,24)

A multistate representation of a WECS is obtained directly from this matrix. If the period is on an hourly basis, the unit availability probability density function is made up of the derated capacity states with their associated availabilities for the hour in question. If a period of more than one hour is considered, the average of the hourly availabilities may be taken. It can be observed from Table 3 that the multistate representation does not just give the average power output of the WECS array for each hour but also portrays the variability within each hour by the many probable states. The number of states could be doubled

TABLE 3

Availability Matrix with Typical Values

POWER OUTPUT (MW)	HOUR OF THE DAY			
	1	2	3	24
75.000	.548	.546	.516	.387
73.125	.032	.065	.000	.032
69.375	.129	.065	.194	.097
65.625	.000	.032	.000	.065
1.875	.065	.097	.032	.000
0.000	.000	.124	.065	.097

without substantial increase in computing time. One other advantage of the multistate representation is that the WTGs are treated in the same way as conventional units in the simulation process, with the same LDC for each penetration level examined. With the modified LDC model, each penetration level requires a different LDC. This makes the programming more complicated.

The array unit availability capacity probability density function, for the months of January and August, as are used in this study, is shown in Table 4. The remaining months are described in the Appendix.

TABLE 4

Multistate Representation of Units

CAPACITY(MW)	AVAILABILITY	
	JAN	AUG
75.000	0.48362	0.34609
73.125	0.06473	0.04632
69.375	0.08966	0.06416
65.625	0.02115	0.01514
61.875	0.01861	0.01332
58.125	0.01241	0.00881
54.375	0.01237	0.00885
50.625	0.01233	0.00883
46.875	0.01121	0.00802
43.125	0.00739	0.00529
39.375	0.00989	0.00708
35.625	0.00621	0.00444
31.875	0.00489	0.00351
28.125	0.00369	0.00265
24.375	0.00369	0.00265
20.625	0.04273	0.03058
16.875	0.00739	0.00529
13.125	0.00123	0.00088
9.375	0.00123	0.00088
5.625	0.01490	0.01066
1.875	0.05913	0.04232
0.000	0.11150	0.36417

If the hourly expected power output is desired, this is found by summing the products of power levels times availabilities in the corresponding column of the availability matrix of Table 3.

Chapter III

METHODOLOGY

3.1 INTRODUCTION

In system planning involving choice between alternatives, costs are used as the major criteria for selecting the least cost investment that meets the demand for power with a given reliability level. A very important step in this process is the availability of a good forecast of what the demand would be in the period to be simulated. Annual production costs (fuel, operation and maintenance) for alternate expansions of the system's capacity which will have the same reliability in serving the forecasted demand are determined by probabilistic simulation methods. If annual fixed charges on investment are added to the annual production costs, the total annual revenue requirements are obtained. The expansion with the lowest present worth of revenue requirements is selected. Based on this choice of expansion, one question to be answered is:

> Will it be viable to include a WECS in the generation mix ?

The answer to this question will be based on finding out whether the total utility system cost will be less when a WECS is introduced. If the answer is positive, the next question would be:

> Could any of the planned capacity be dropped when a WECS is introduced ?

3.2 LOAD MODEL.

The most often used load model is the load duration curve (LDC). The LDC is a function which relates the customer's load level to the duration of time that each load level is equalled or exceeded. This LDC is obtained from the forecast of the expected hourly load. This expected hourly load is ~~the~~ mean value of the expected demand for that hour. As was pointed out by Fegan et al. [19], these mean forecasts give a trajectory for the load over the interval considered. In reality there are several other trajectories for the same period. The only confidence of the forecaster as to the validity of his forecast is that his chosen trajectory lies within an acceptable confidence interval. Weather uncertainty dominates this short term random variability. The deterministic component of load can be conceived of as the expected customers' load, with the random component distributed around it, usually in a normal manner [34].

To make this notion clearer, each point in the curve is seen as the mean of several other curves that form a normal distribution as shown in Fig. 5. More peaked normal distributions would occur in seasons when the weather and customer reaction to weather are more certain and broad when the weather and customer reaction to weather are less certain.

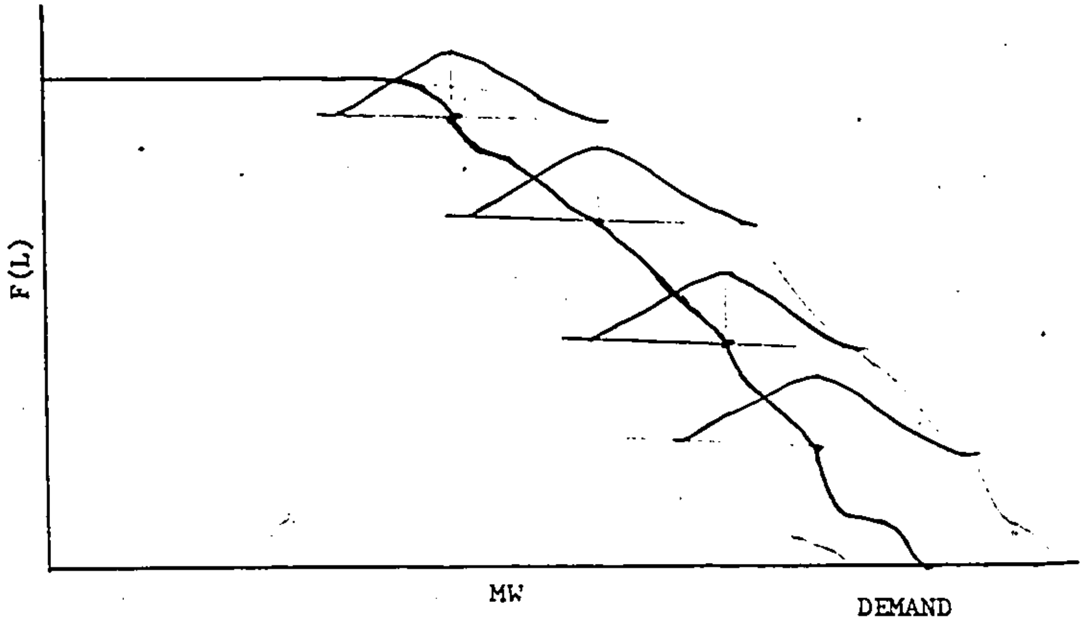


Figure 5: Load Distribution Including Random Demand

3.2.1 Load Data

The IEEE Reliability Test System [37] load model is used for this study. The data is given in the Appendix. From the data, the hourly expected load is computed. The load curve for the month of January is shown in Fig.6.

The monthly load curves are converted to LDCs. By reversing the role of the axes and normalizing the time, the LDCs are interpreted as load probability distributions or sometimes called normalized LDCs. The load distribution used throughout this work is the normalized LDC. However, the prefix 'normalized' will subsequently be dropped. As discussed previously, the LDC is constructed from mean values. The actual value may not lie exactly on the curve, thus making these values expected values. It is in this context that we can regard the ordinate of the distribution to represent the probability that the given capacity value is equalled or exceeded. Such a curve for the month of January is shown in Fig.7.

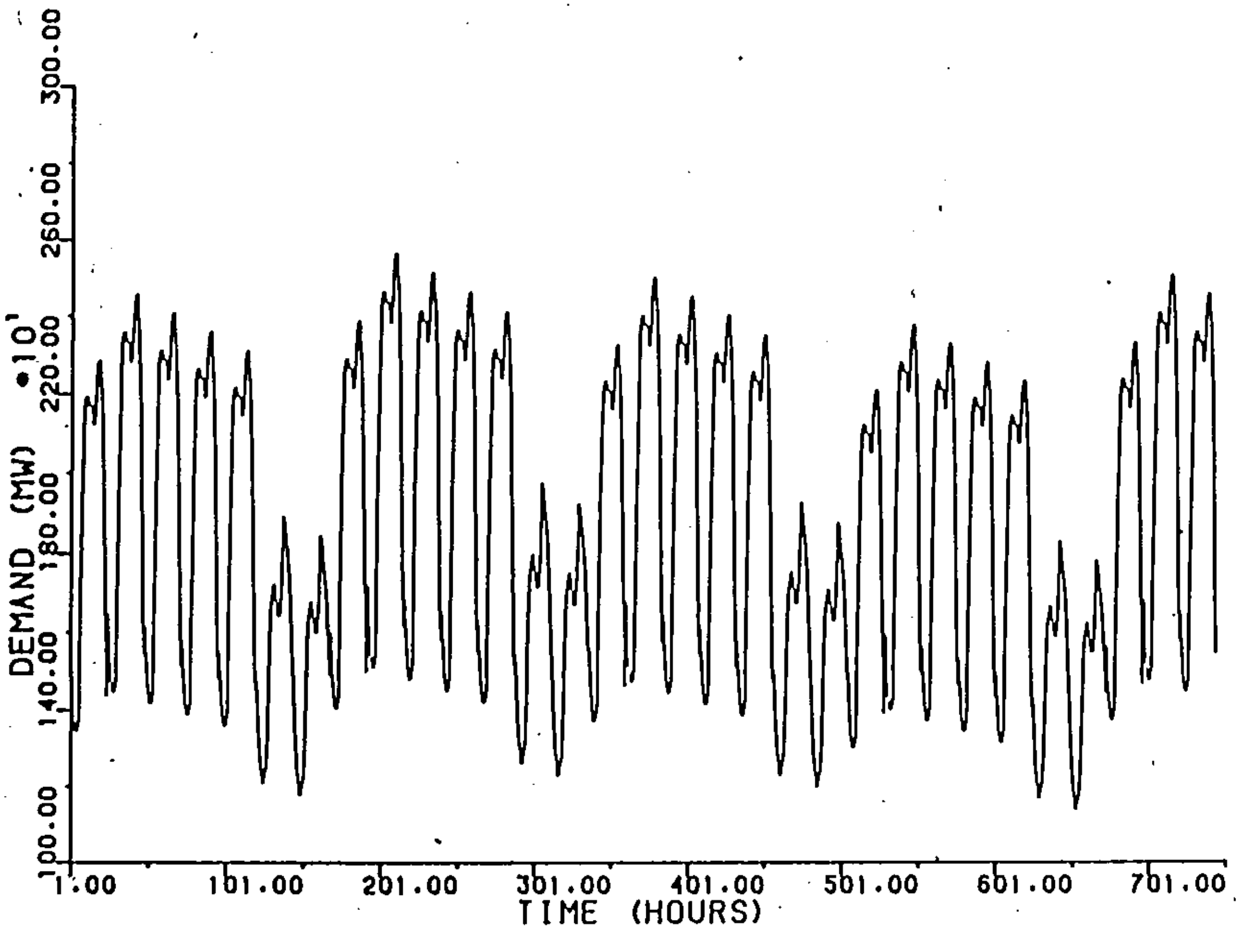


Figure 6. January Load Curve (Base Year)

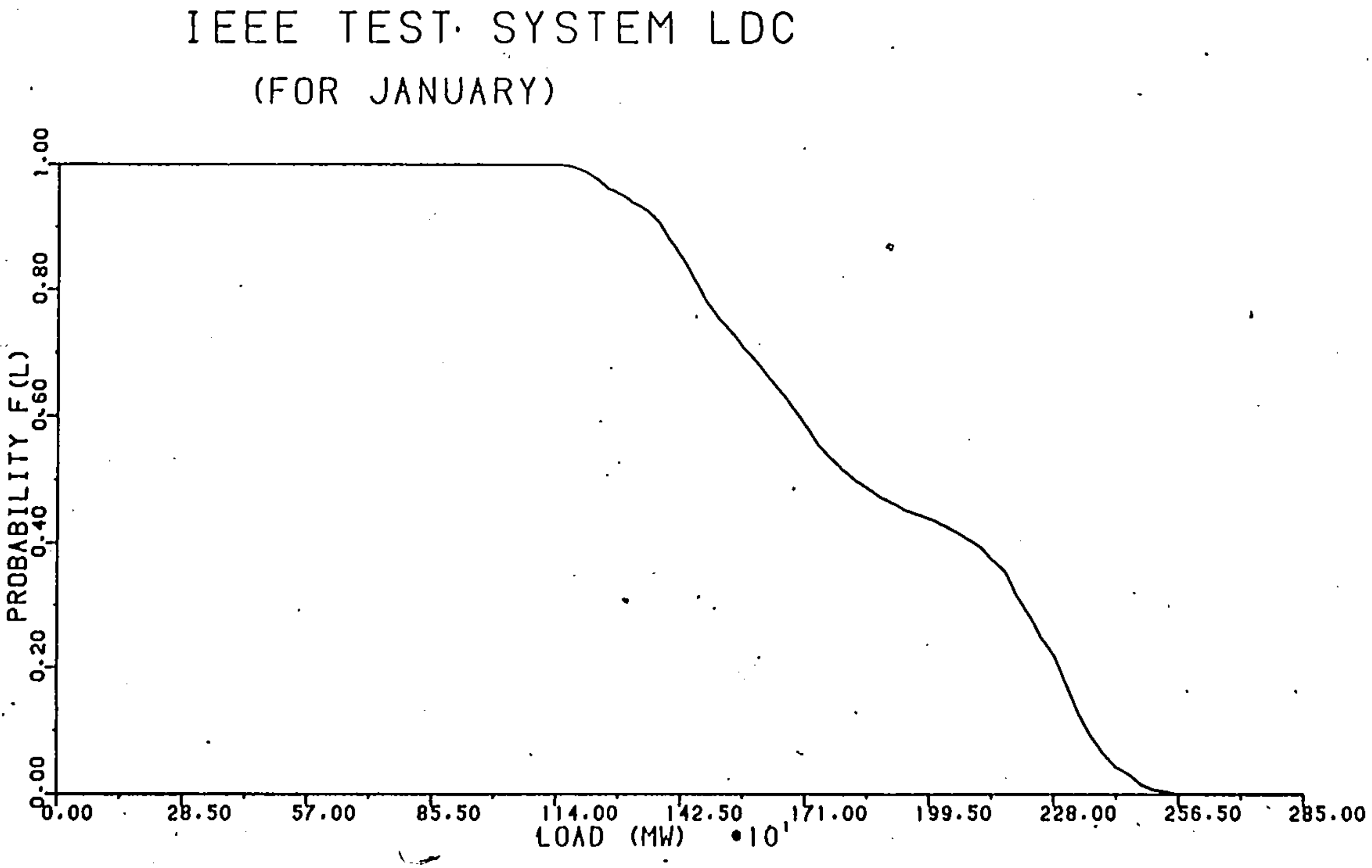


Figure 7. Load Probability Distribution For January (Base Year)

3.3 GENERATION SYSTEM RELIABILITY

The most widely used measures of generation system reliability are the loss of load probability (LOLP) and the expected energy not served E(ENS) indices of reliability [13]. These indices provide a consistent and sensitive measure of generation system reliability. The LOLP, as used in planning , is not a probability as such but a probabilistic measurement of the expected number of days per year in which the available capacity cannot meet the peak demand. Several factors affect generation system reliability. Among these factors are the planned and forced outage rates, as well as the size and number of units.

3.3.1 Generating Unit Model

Generating units are fraught with technical problems that can force them off line at random. To represent this failure probabilistically, units are modelled as probability density functions, that describe the probability that a unit will be forced off line or, conversely, that the unit will be available to generate electricity.

To obtain the forced outage rate of a generating unit, the random failure and repair of the unit is regarded as a zeroeth order, discrete state, continous transition Markovian stochastic process [13]. This process is characterized by lack of memory and can be represented by:

$$P\{X(t) \leq x/X(t_1) = x_1, X(t_2) = x_2, \ldots, X(t_n) = x_n\} \qquad (3.1)$$

$$= P\{X(t) \leq x/X(t_n) = x_n\}$$

$$(t_1 < t_2 < .. < t_n < t).$$

That is, the conditional distribution of the future $X(s+t)$, given the present $X(t)$ and the past $X(u)$, $u < t$, is independent of the past.

For conventional generating units, a two state model suffices for planning purposes [32]. More than two states may be used if desired.

Consider a generating unit with two states 1 and 2 which are collectively exhaustive and mutually exclusive. Fig.8 gives the state space diagram for a simple system.

Define:

$P_i(t)$ = the probability of finding a generating unit in state i, where i = 1 is the state corresponding to maximum available capacity and i = 2 corresponds to the state of no availability.

λ = transition rate from state 1 to state 2

$1/\lambda$ = average time a generating unit stays in the up state.

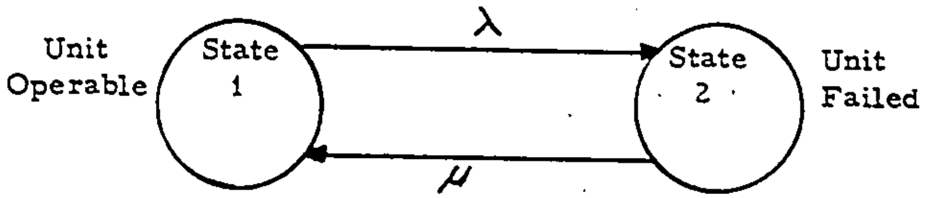


Figure 8: Generating Unit State Space Diagram

μ = transition rate from state 2 to state 1.

1/μ = average time a generating unit stays in the down state.

The above information is obtained by recording the random performance of a unit over some period of time.

If the failure and repair states are characterized by exponential distributions, then

$e^{-\lambda t}$ = probability of unit being available up to time t.

$$= 1 - \lambda\Delta t + \frac{\lambda^2\Delta t}{2} + \ldots\ldots\ldots$$

$$\approx 1 - \lambda\Delta t \qquad (\lambda<1)$$

$\simeq$ probability of unit being available during time Δt

where

$\lambda\Delta t$ = probability of transferring in time Δt from state 1 to state 2

similarly

$e^{-\mu t}$ = probability of unit being unavailable up to time t.

$\simeq$ 1 − $\mu\Delta t(\mu<1)$

$\simeq$ probability of unit being unavailable in time Δt .

where

$\mu\Delta t$ = probability of transferring in time Δt from state 2 to state 1

The following relationships are obvious

$$P_1(t+\Delta t) = P_1(t)(1-\lambda\Delta t) + P_2(t)\mu\Delta t \qquad (3.2)$$

$$P_2(t+\Delta t) = P_2(t)(1-\mu\Delta t) + P_1(t)\lambda\Delta t \qquad (3.3)$$

Rearranging terms

$$\frac{P_1(t+\Delta t) - P_1(t)}{\Delta t} = -\lambda P_1(t) + \mu P_2(t) \qquad (3.4)$$

$$\frac{P_2(t+\Delta t) - P_2(t)}{\Delta t} = \lambda P_1(t) - \mu P_2(t) \tag{3.5}$$

Or, in the limit,

$$\begin{bmatrix} \dot{P}_1(t) \\ \dot{P}_2(t) \end{bmatrix} = \begin{bmatrix} -\lambda & \mu \\ \lambda & -\mu \end{bmatrix} \begin{bmatrix} P_1(t) \\ P_2(t) \end{bmatrix} \tag{3.6}$$

Since we assumed that the only possible states for a generating unit are the up and down states, then the two states define all possible states we ever expect to find and as such:

$$P_1(t) + P_2(t) = 1 \tag{3.7}$$

Setting the derivatives of (3.4) and (3.5) to zero and solving for $P_1(t)$ and $P_2(t)$ as $t \to \infty$, yields

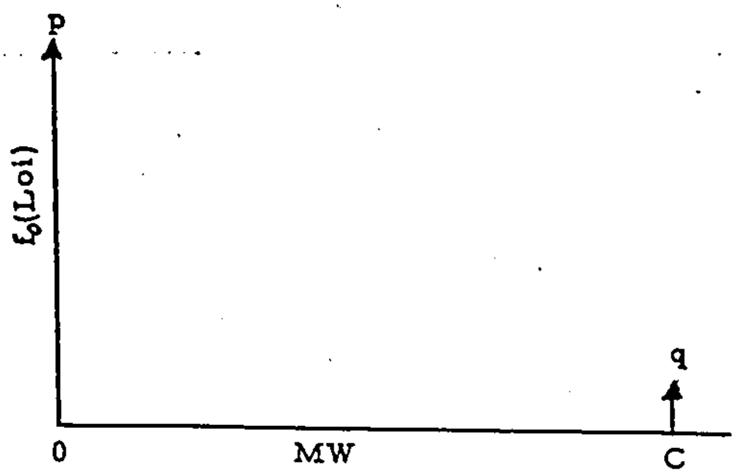
$$P_1(t) = \frac{\mu}{\lambda+\mu} = p \tag{3.8}$$

$$P_2(t) = \frac{\lambda}{\lambda+\mu} = q \tag{3.9}$$

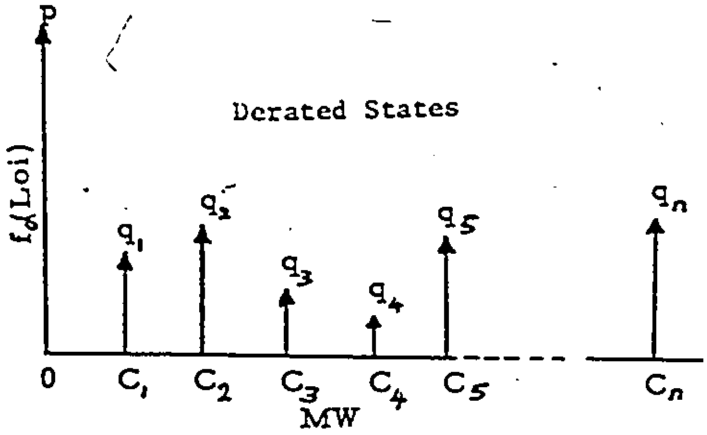
where p and q are the unit availability and forced outage rate, respectively.

A generating unit power output can be probabilistically represented as a forced outage capacity density function as shown in Fig.9. Fig.9a gives the simplest probabilistic model of this form. Often experienced failure of auxiliary components such as valves, reheaters, pumps, fans, boilers, bearing oil etc, call for a more detailed model for the generating unit. This is accomplished with the multistate model of Fig.9b. In the derated state, a portion of the capacity may be out of service randomly due to aforementioned reasons which reduce the capacity of the unit. A probability value is assigned to the existence of that capacity state. However, as was mentioned earlier, with conventional units, two state representation suffices for planning purposes.

A WTG unit availability capacity probability density function was given in Table 4. To include the effects of the random mechanical failure, all the availability states (except the zero power row) are multiplied by q (the array forced outage probability). The old entries are replaced by the new ones. The result obtained by summing all the probabilities and subtracting from one is the probability of zero output. When this is complete, the probability



(a) Two State Representation



(b) Multistate Representation

Figure 9: Forced Outage Capacity Probability Density Function

distribution of the array output includes the effects of wind and forced outages.

3.3.2 The Effective Load Curve

Random failure of generating units can be interpreted as random loads presented to the generating units, whose probability density functions are the outage capacity density functions of the units. Thus a 100% reliable generating unit sees an affective load comprising its forced outage rate and the random demand. The effective load curve is also referred to as the equivalent load duration curve (ELDC) [13].

The effective load is defined by:

$$Le = L + \sum_{Loi} Loi \qquad (3.10)$$

where Loi is the random outage load for the ith unit. Addition of these two independent random variables is achieved by a convolution process either with the method of moments or cummulants [20] or with the commonly used recursive technique [26]. The method of moments is described in the Appendix while some aspects of the recursive technique are given below. To further illustrate this method, consider the curves of Fig.10.

If unit A fails, all other units will drop to fill the vacancy caused by the loss of unit A. The same effect on units B - K can be demonstrated by raising the load curve by the capacity of unit A for the period unit A failed. This

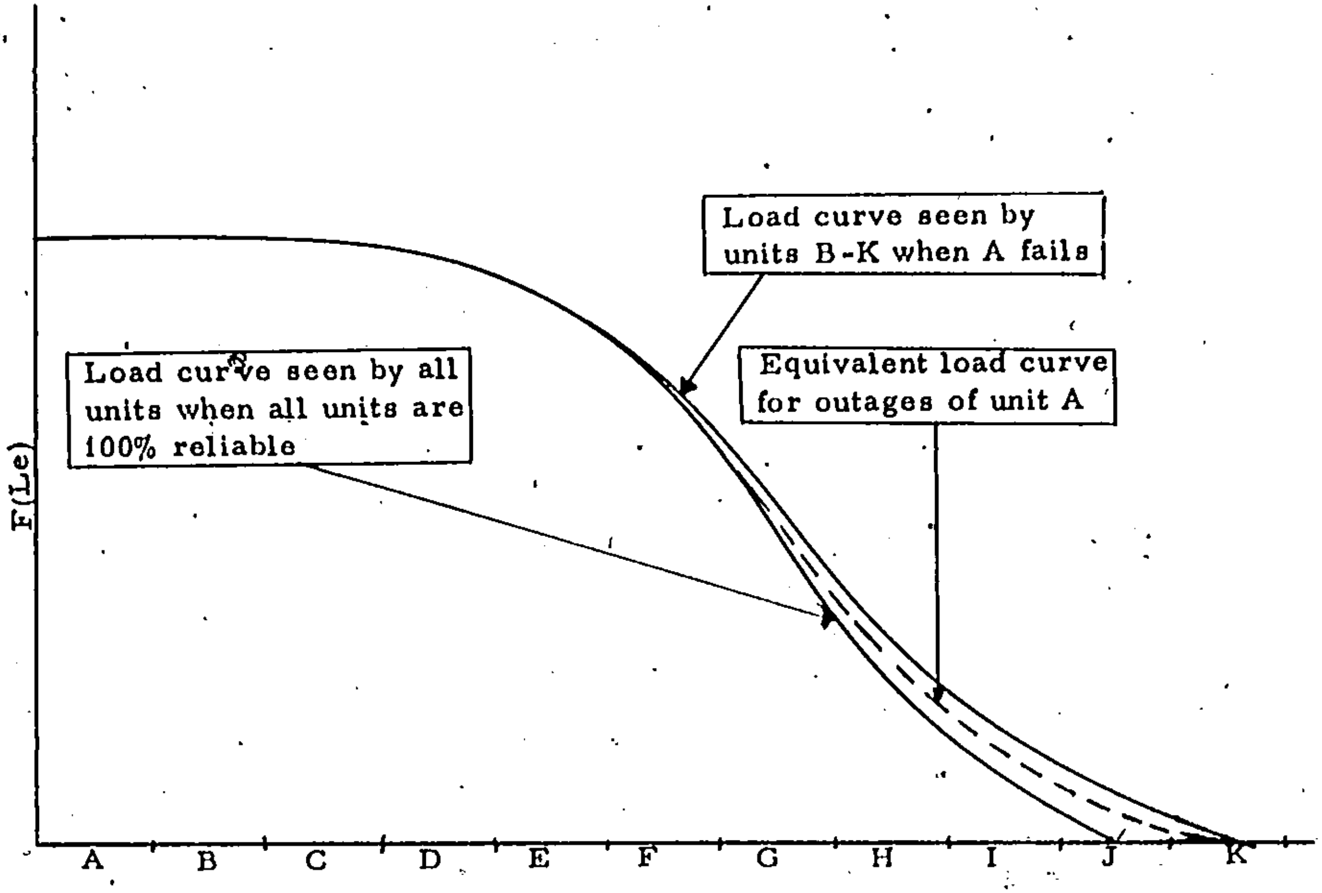


Fig. 10 Change in Effective Load Curve With Failure of Unit A

is shown in Fig.10. Since p and q are the availability and forced outage rate respectively, the system has a probability p of operating on the lower curve and a probability q of operating on the upper curve. The effective load curve for units B - K as a result of the original load and outages of unit A could be taken as a weighted average of the two curves based on p and q for unit A. This process will produce a curve like the dashed curve which is the effective load for units B - K. To deal with unit B, the process is repeated using the equivalent load curve for unit A as a basis. Each convolution will extend the peak of the curve upward by the capacity of the unit considered. Fig. 11 shows the ELDC characteristics with all units convolved. The curves are not as smooth as exagerated in Figs. 10 and 11.

It could be further shown mathematically that the ELDC makes the LDC look larger by the following arguments:

Assuming that $F_L(L) = F(L)$, $F^i_{Le}(Le) = F^i(Le)$,

Let $F^0(Le) =$ $F(L)$ = load probability distribution function,

$F^i(Le)$ = the equivalent load probability distribution function,

C_i = capacity of unit i,

$f_{oi}(Loi)$= density function of the random outage load,

then

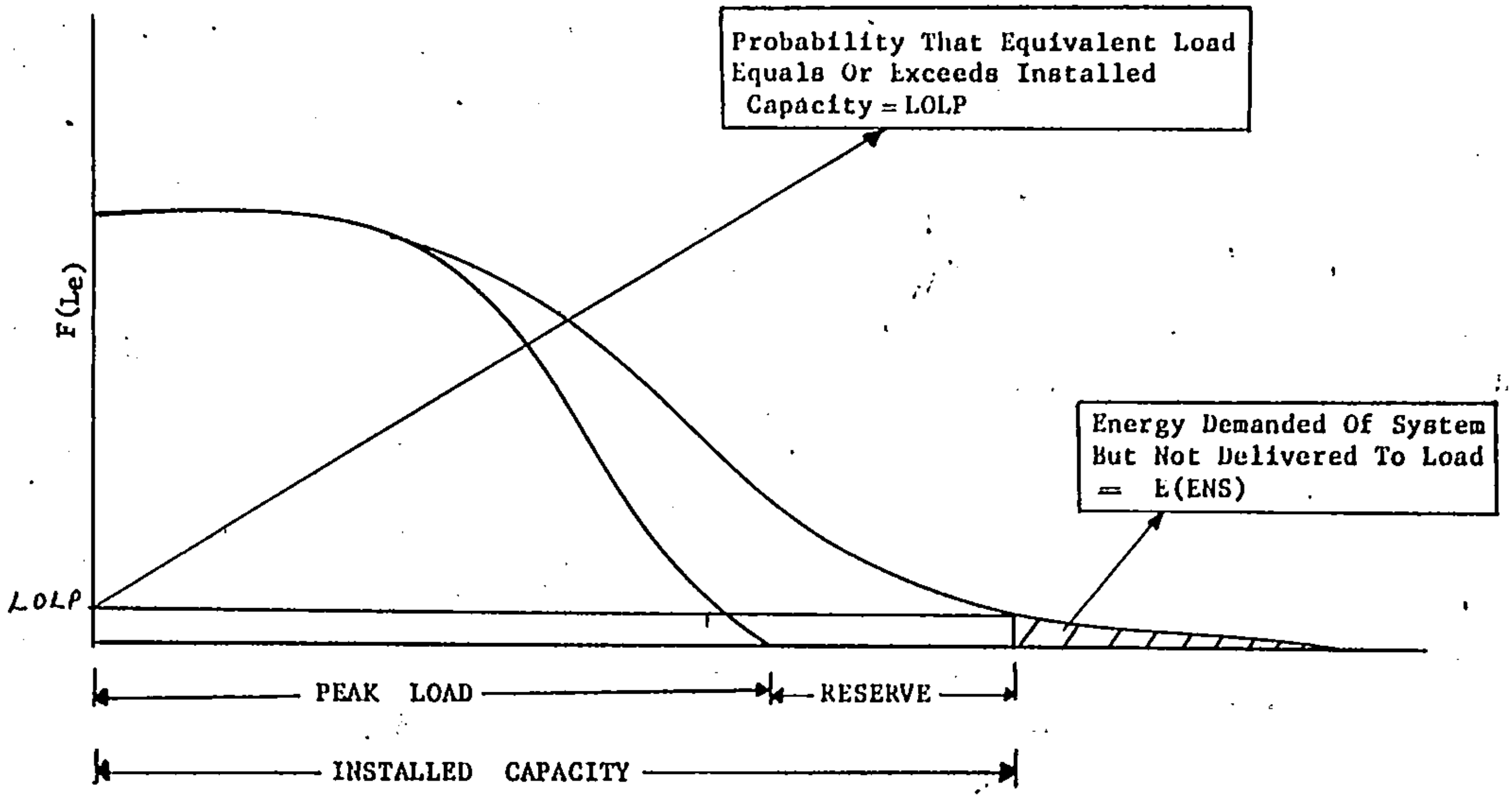


Figure 11. ELDC Characteristics With All Units Convolved.

$$F^{i}(Le) = \int_{Loi} F^{i-1}(Le-Loi) f_{oi}(Loi) dLoi \tag{3.11}$$

where $F^{i}(Le)$ is the effective load probability distribution with the outage capacity of the first i units convolved. Since f_{oi} is a dicrete density function, then

$$f_{oi}(Loi) = p_i \delta(Loi) + \sum_{k=1}^{n} q_{ik} \delta(Loi-C_{ik}) \tag{3.12}$$

$$\therefore F^{i}(Le) = \sum_{Loi} F^{i-1}(Le-Loi) f_{oi}(Loi) \tag{3.13}$$

but

$f_{oi}(Loi = 0) = p_i$

$f_{oi}(Loi = C_{ik}) = q_{ik}$

where i represents the unit number convolved and k represents the capacity state of i.

Using the recursive technique, (3.13) reduces to

$$F^{i}(Le) = F^{i-1}(Le) p_i + \sum_{k=1}^{n} F^{i-1}(Le-C_{ik}) q_{ik} \tag{3.14}$$

If a two state model is considered, (3.14) reduces further to

$$F^{i}(Le) = F^{i-1}(Le)p_i + F^{i-1}(Le-C_i)q_i \qquad (3.15)$$

To show that equation (3.16) is true.

$$F^{i-1}(Le)p_i + F^{i-1}(Le-C_i)q_i \geq F^{i-1}(Le) \qquad (3.16)$$

We note that,

$$F^{i-1}(Le-C_i)q_i \geq (1-p_i)F^{i-1}(Le) \qquad (3.17)$$

$$F^{i-1}(Le-C_i) \geq F^{i-1}(Le) \qquad (3.18)$$

(3.18) is true since a backward cummulative distribution never increases. Therefore (3.16) holds.

3.3.3 LOLP and E(ENS)

For the calculation of the LOLP and the E(ENS), all that is needed is the ELDC with all units convolved. Since each unit convolved adds its capacity to the peak of the previous curve, the final ELDC extends to a point equal to the sum of the forecast peak load plus the installed capacity.

The abscissa value of the ELDC at the installed capacity is the percent of time the equivalent load will exceed the installed capacity. This is the LOLP.

The area above the installed capacity of the ELDC represents energy demanded of the system but not delivered to load because of failure of all the generating units in the system. This is the E(ENS).

3.3.4 Equivalent Capacity

The equivalent capacity is conceptually similar to the effective load carrying capability (ELCC) of a generating unit. The ELCC was extensively investigated by Garver [33] and used by Marsh [2] in his studies. The ELCC is the allowable increase in utility system annual peak load that can be accommodated, while maintaining a fixed level of system reliability, by installing a new generating unit. This concept is illustrated in Fig.12. Therefore, what the ELCC gives is the proportion of the unit's capacity that will serve the demand taking into account that the unit has a finite probability of failure.

In contrast, the equivalent capacity assumes a fixed load with varying installed capacity whereas the ELCC varies the system load and capacity. Thus the equivalent capacity of a

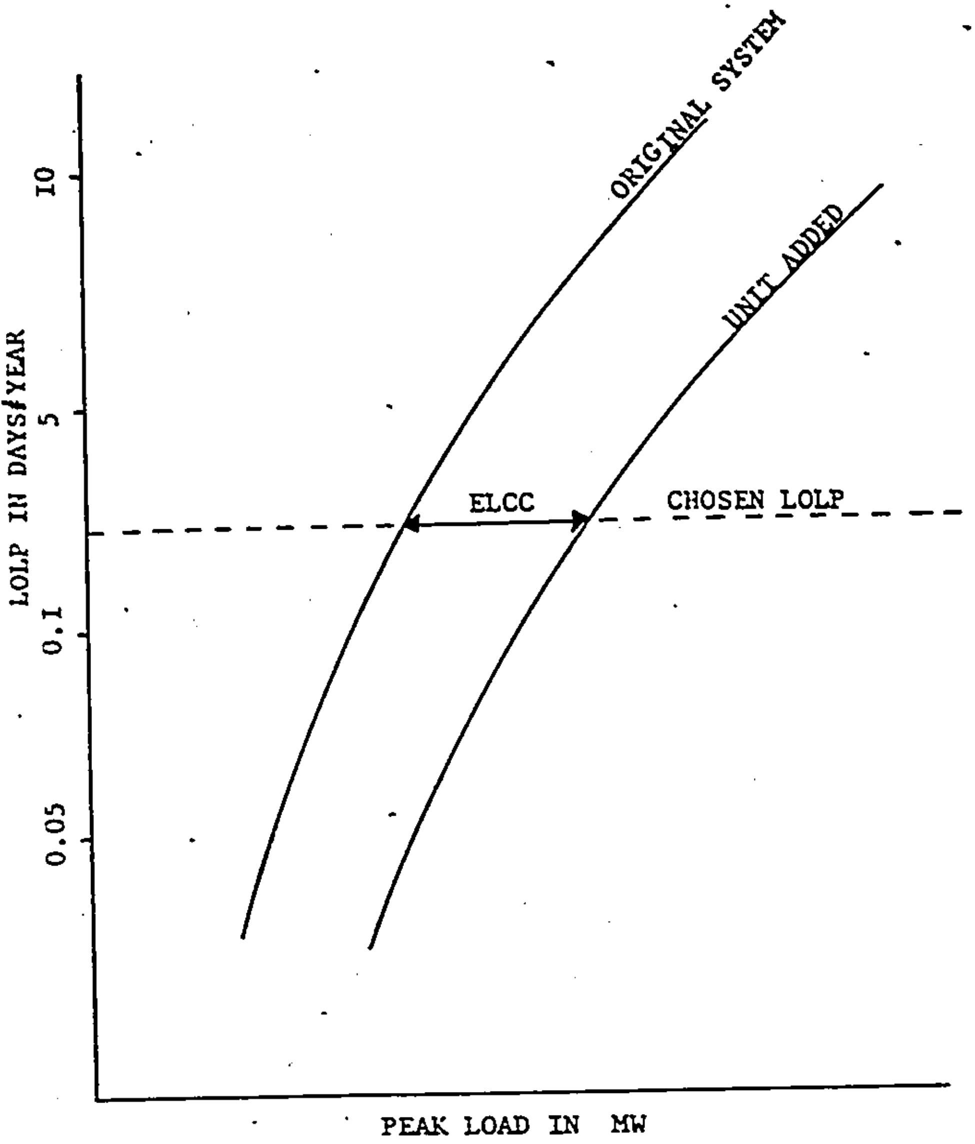


Figure 12. ELCC Of Unit Addition

WTG array is that capacity of the conventional unit of interest that can be replaced by the WTG array without change in LOLP.

The equivalent capacity is used in this study to evaluate the wind capacity credit. By noting the base case LOLP, the conventional capacity that could be added or subtracted from the system to yield the same LOLP after wind addition is determined.

3.4 PRODUCTION COSTS

Booth [26], Wilson et al. [12] and others have shown that the expected energy generated by a unit is the area the unit occupies under the ELDC. So, unlike reliability calculations, the order in which the units are convolved with the LDC is important. This order is described below under the subsection "Thermal Units".

Production cost is made up of fuel, operation and maintenance costs.

3.4.1 Expected Energy Generated by a Unit

As was mentioned in the calculation of the LOLP, forced outages of generating units also affect the expected energy. This must also be incorporated in calculating the expected energy and subsequently the production costs in order to increase the accuracy of the results. Consider Fig.13, Let Fig.13a describe a LDC of the system along with the merit order of loading.

Assuming that $F_L(L) = F(L)$, $F^i_{Le}(Le) = F^i(Le)$,

Let E_1 = the energy generated by unit 1,

E_2 = the energy generated by unit 2,

p_1 and p_2 = the availabilities of units 1 and 2 respectively,

q_1 and q_2 = the forced outage rates of units 1 and 2 respectively,

T = period for which the LDC is obtained,

C_i = capacity of unit i,

$F^i(Le)$ = equivalent load probability distribution function,

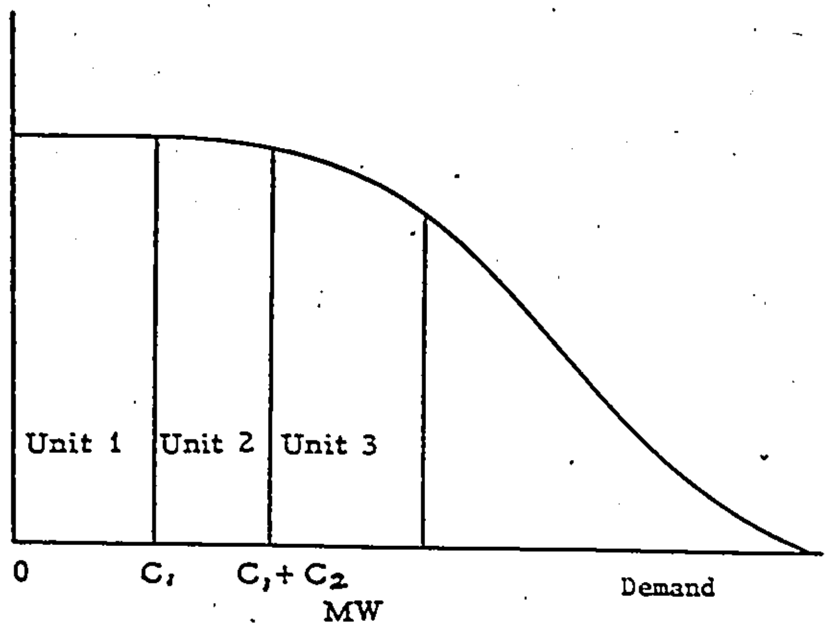
$F^0(Le) = F(L)$ = load probability distribution function,

$F^1(Le)$ = the equivalent load distribution function after adding the effect of the random outage of the first unit.

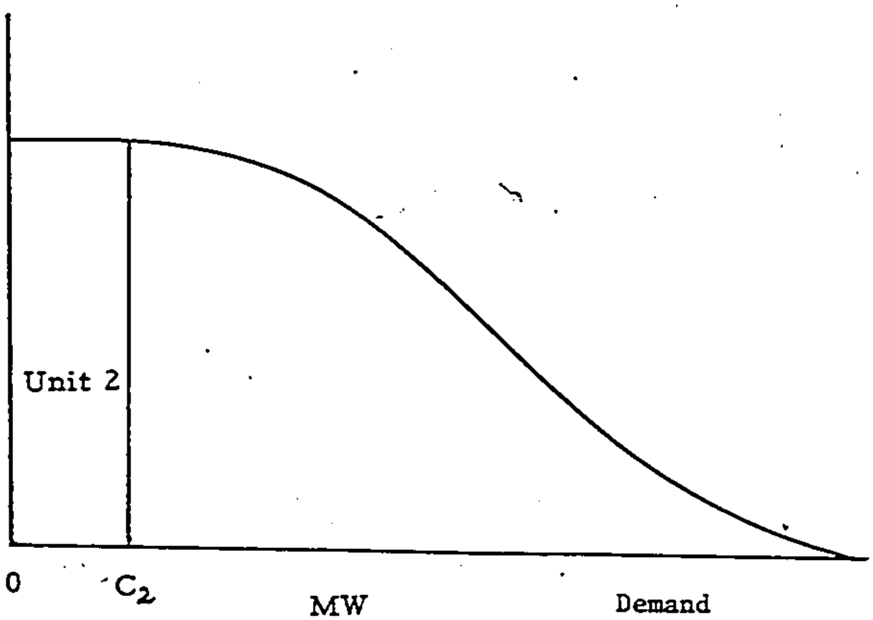
$F^{n-1}(Le)$ = the equivalent load distribution function after adding the effect of the random outage of (n-1) units.

then, ignoring maintenance requirements, the expected energy delivered by unit 1 is given by:

$$E_1 = p_1 T \int_0^{C_1} F(L)\,dL \qquad (3.19)$$



(a) Unit 1 Available with Probability p



(b) Unit 1 Unavailable with Probability q

Figure 13. Energy Generation By Units

In calculating the energy delivered by the second unit in the merit order, two components must be considered. When unit 1 is available, with probability p_1, unit 2 will be loaded to generation between loads C_1 and $C_1 + C_2$; however when unit 1 is out of service because of forced outage, with probability q_1, unit 2 will occupy the first position in the merit order and will be loaded to generation between the loads 0 and C_2, as shown in Fig.13b. The expected energy delivered by unit 2 is therefore:

$$E_2 = p_1 p_2 T \int_{C_1}^{C_1+C_2} F(L)dL + q_1 p_2 T \int_{0}^{C_2} F(L)dL \tag{3.20}$$

$$= p_2 T \left\{ p_1 \int_{C_1}^{C_1+C_2} F(L)dL + q_1 \int_{0}^{C_2} F(L)dL \right\} \tag{3.21}$$

$$= p_2 T \left\{ p_1 \int_{C_1}^{C_1+C_2} F(L)dL + q_1 \int_{C_1}^{C_1+C_2} F(L-C_1)dL \right\} \tag{3.22}$$

$$= p_2 T \left\{ \int_{C_1}^{C_1+C_2} [p_1 F(L) + q_1 F(L-C_1)]dL \right\} \tag{3.23}$$

$$E_2 = p_2 T \int_{C_1}^{C_1+C_2} F^1(Le)dLe \tag{3.24}$$

continuing in this way, it can be shown that for the nth unit:

$$E_n = p_n T \int_{\sum_{i=1}^{n-1} C_i}^{\sum_{i=1}^{n} C_i} F^{n-1}(Le)\,dLe \qquad (3.25)$$

3.4.2 Generating Unit Characteristics

The individual characteristics of generating units determine to a great extent how they are committed to meet the load plus reserve requirements.

3.4.2.1 Hydro

In hydro - thermal systems, the scheduling and dispatch problem requires the allocation of available hydraulic and thermal resources of the system in such a way as to minimize the system production cost. Economic dispatch of hydro thermal systems involves complex optimization which is not within the scope of this study. As is the standard practice [17], to make the most efficient use of the 'free'(zero fuel cost) hydro energy, the hydro units are loaded to displace the units highest in the loading order. The hydro units are fitted iteratively in the loading order so that the available hydro energy is discharged, at the specified hydro capacity, within a specified tolerance.

3.4.2.2 WTG As a Multistate Unit

In this model, a WTG is regarded as just another conventional unit. But the two state forced outage capacity density function used for conventional units is not valid for WTGs. A multistate representation as shown in Fig.9 must be used to reflect the variability of available WTG power output with time.

Convolving this multistate density function with the load probability distribution can be accomplished using the recursive equation of (3.14). But as have been shown by Schenk et al. [20], the method of moments as given in the Appendix is more efficient than the recursive technique especially where multistate representation of units is involved.

The dispatch strategy used with this model is to load the WTGs right after the nuclear units. This assumes that WTGs are must run units. The accuracy of this assumption lies on how good the forecast of wind availability is. Before this strategy was adopted, a preliminary result obtained by varying the loading order was examined. The WTG array was divided into three blocks and loaded at the base, midrange and peaking areas of the LDC respectively. Table 5 shows the results obtained.

TABLE 5

Variation In WTG Loading

	Single Block Loading	3 Block Loading
Penetration (%)	2.2	2.2
LOLP	0.00029	0.00029
Fuel Cost (M$)	13.5100	13.6400

Table 5 shows that in so far as there is confidence in the forecasted expected WTG energy, it is more appropriate to load WTGs in such a way as to minimize fuel costs.

3.4.2.3 WTG As a Negative Demand

This approach was used by Marsh [2] and Vankuiken et al. [7]. It consists of subtracting the hourly expected WTG output power from the hourly demand and convolving conventional units to meet residual demand after load modification. The way the WTG array power output modifies the LDC in the second model is shown in Fig.14.

This method gives a clear picture of how WTGs contribute by reducing the system load.

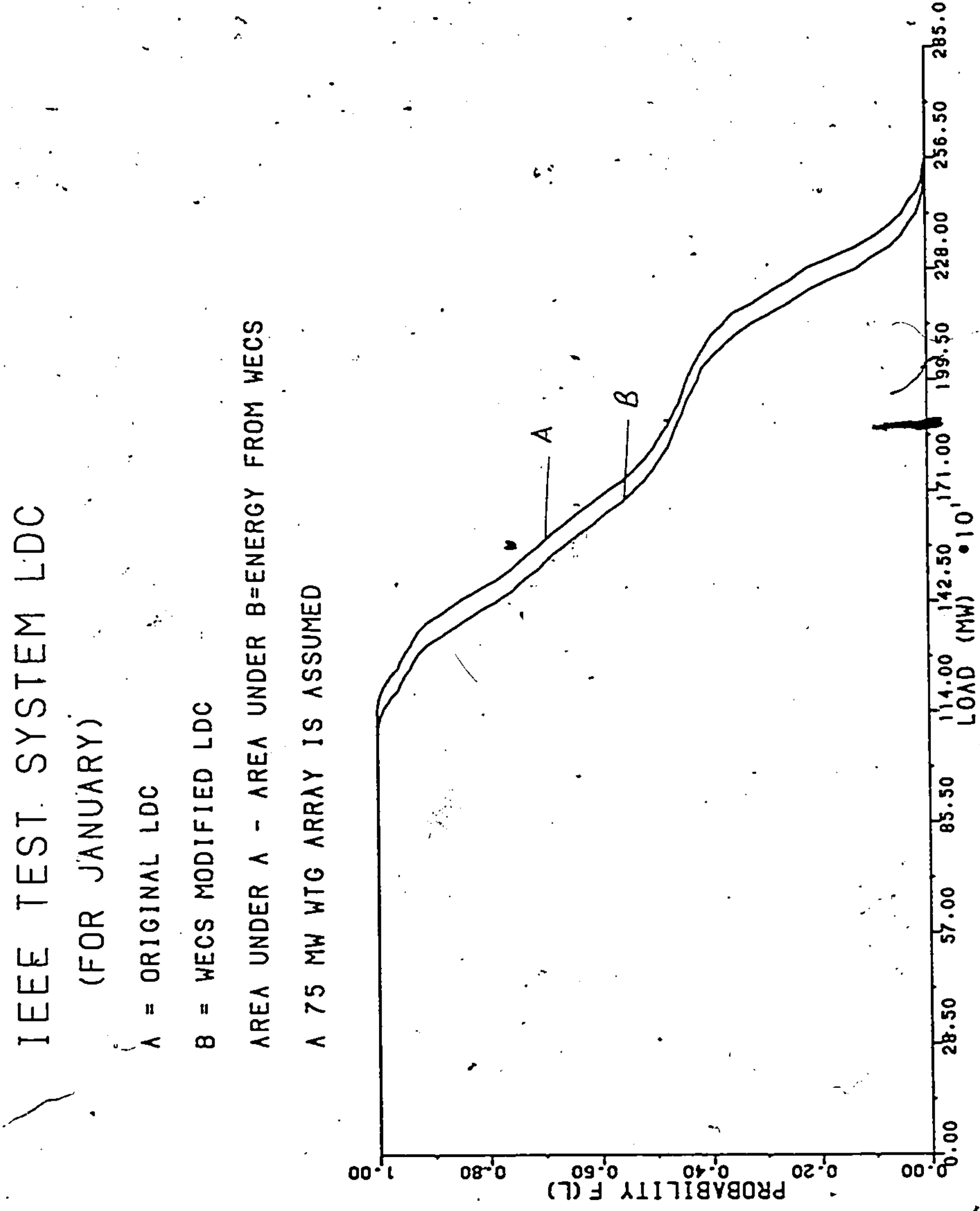


Figure 14. WECS - Modified LDC (Base Year)

Addition or subtraction of the cumulants of the random variables of independent distributions is equivalent to convolving or deconvolving the distributions [20]. Assuming the energy from wind, represented by the PODC, is independent of the load represented by the LDC, the cumulants of the random variables describing the PODC can be subtracted from those of the LDC. The remainder should represent the cumulants of the modified LDC akin to treating WTG energy as a negative demand. The method of moments can be used to great advantage here in that the step that calculates the WTG power output from the PODC is circumvented. Preliminary results shown in Table 6 points out the limitation of this method.

TABLE 6

Preliminary Results on Subtraction of Cumulants Method

	Multi-state Rep.	Subtraction of Cum.	Multi-state Rep.	Subtraction of Cum.
Penetration (%)	2.2	2.2	15.0	15.0
LOLP	0.00029	0.00033	0.00001	0.000013
Fuel Cost (M$)	13.5100	13.6600	7.73200	7.732400

The reason for the discrepancy at the 2.2% level could be seen by examining the values of the cumulants being subtracted (only five cumulants shown).

TABLE 7

Value of Cumulants For 2.2% Penetration

ORDER	LDC Cumulants	PODC Cumulants	LDC - PODC Cumulants
1	0.3807E 00	0.1094E-01	0.36970E 00
2	0.5555E-01	0.4101E-04	0.55510E-01
3	0.3866E-02	0.7625E-08	0.38650E-02
4	-0.2617E-02	-0.1791E-08	-0.26169E-02
5	-0.9307E-03	-0.3998E-11	-0.93070E-03

Table 7 clearly points out the limitation of this method. For small WTG penetration, the PODC is small, consequently the cumulants are small compared with the cumulants of the LDC and the subtraction makes little or no difference. For higher penetrations, however, the accuracy improves.

3.4.2.4 Thermal Units

Thermal units have peculiar characteristics and in committing units to achieve the smallest production cost, the economic strategy is to first commit least expensive units. The economics of these units are governed by performance parameters such as the heat input and the price of fuel used by the units. Units are segmented into blocks because it is rarely economical to commit one unit completaly before calling on another. The dispatching function in the production costing program loads the units committed in a manner which serves the demand at minimum fuel cost. The dipatch technique is the equal incremental cost approach used by many utilities [35].

Segmented commitment or blocking of units is used because of the shape of the heat rate curves. This curve gives the heat rate for each MWh (Energy) produced. A typical heat rate curve is shown in Fig.15.

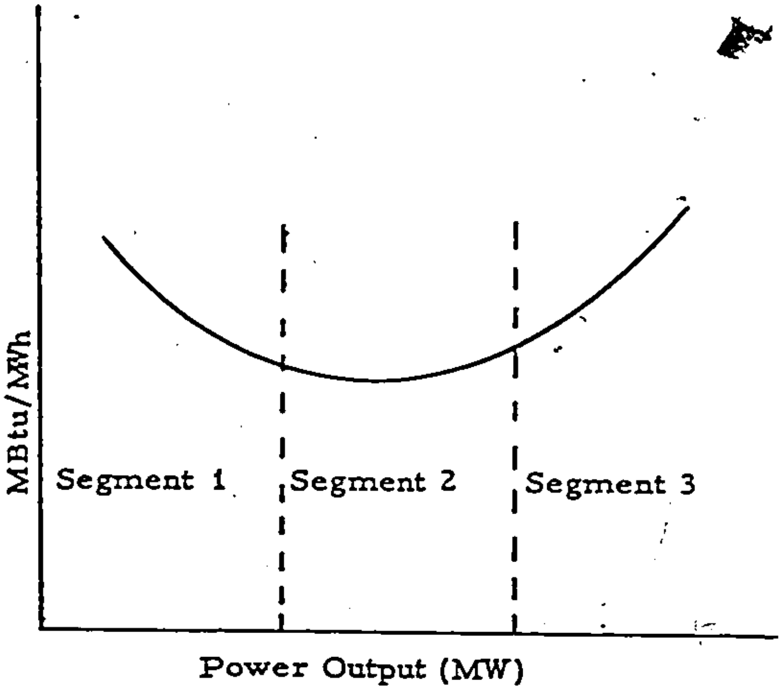


Figure 15: Typical Heat Rate Curve

The input-output curves of a thermal plant are important in describing the plant's efficiency. Such a curve is a plot of fuel input (MBtu/hr) vs. electrical power output as shown in Fig.16.

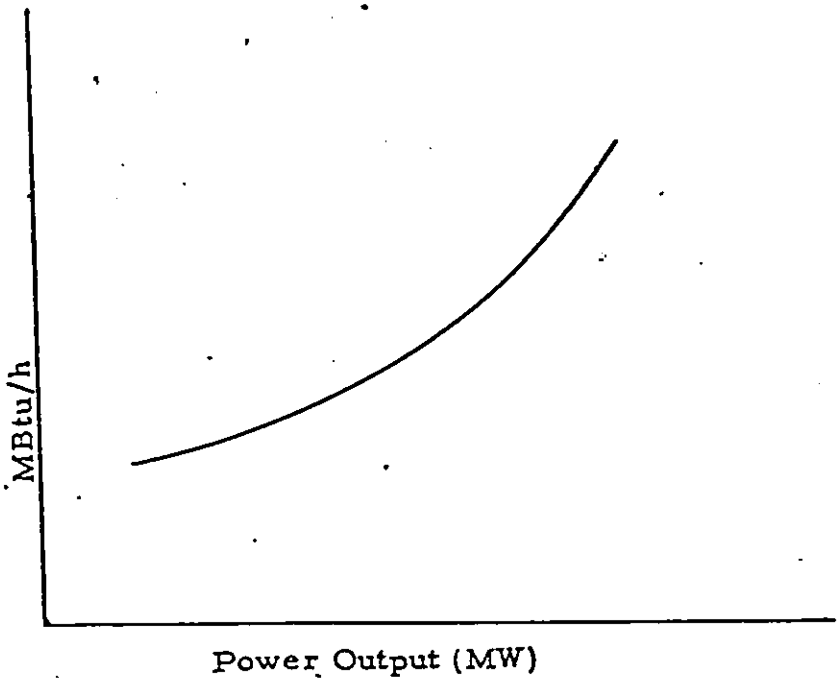


Figure 16:- Typical Input-Output Curve

The incremental heat rate curve (if the heat is expressed in $) is a measure of how costly it will be to produce the next increment of power and is a plot of the slope of the input-output curve vs. output. Thus:

$$IHR_i = \frac{d(I/O)}{dP_i} \qquad (3.26)$$

where

IHR_i is the incremental heat rate,

$\frac{d(I/O)}{dP_i}$ is the differential of the input-output curve with respect to power output, P.

In the special case where the heat rate curve is assumed constant, the incremental heat rate equals the heat rate, that is

$$IHR_i = HR_i$$

A typical incremental heat rate curve is shown in Fig.17

Once the incremental heat rate is obtained, the incremental fuel cost (IFC), which is an important component of the fuel cost, is calculated by:

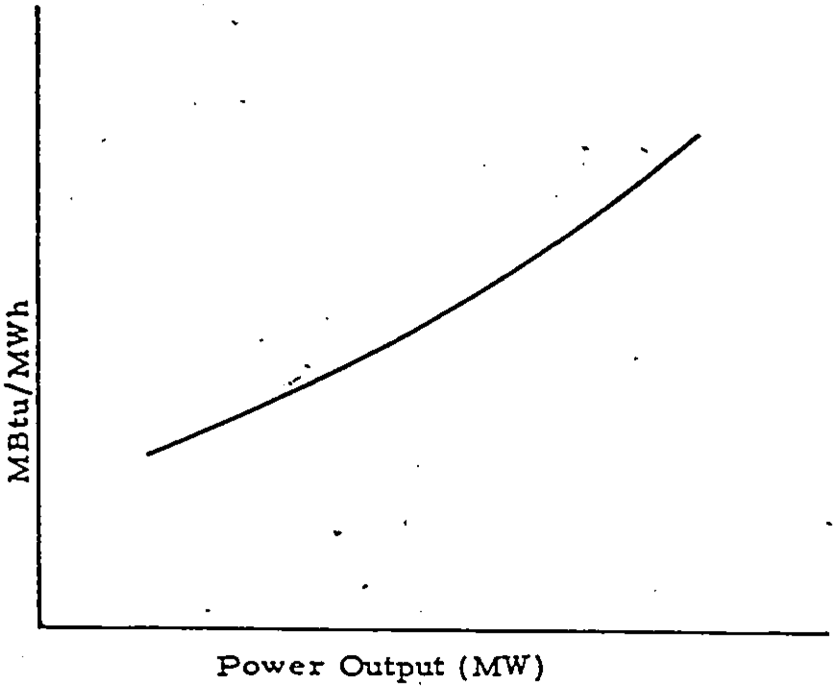


Figure 17: Typical Incremental Heat Rate Curve

$$IFC_i = \frac{IHR_i \times \text{UNIT FUEL COST}}{\text{HEAT VALUE}} \quad \$/\text{MWh} \tag{3.27}$$

The fuel cost of unit i is given by the product of the expected energy and the incremental fuel cost. The total cost of energy generated by unit i is:

$EC_i = FC_i + OM_i$

where

EC_i = production or energy cost

FC_i = fuel cost

OM_i = operation and maintenance cost

The equal incremental loading procedure results in minimum operating cost for a power system [29]. This concept can best be demonstrated by considering the curves of Fig.18.

Assume generators A, B, C, and D are to be operated together in the most economic manner. The basic criteria for such an operation is that each unit operate at the same value of incremental fuel cost (λ). A unit with an entire range of incremental fuel costs less than that of other units (curve C) is fully loaded before the other units are brought above their minimum load level. Similarly, unit D, with a higher range of incremental fuel costs, might be used as reserve. Stated mathematically, optimal allocation of power to n individual running units within a power system for a given total load P, can be formulated as the minimization of

$$f = \sum_{i=1}^{n} K_i(P_i) \qquad (3.28)$$

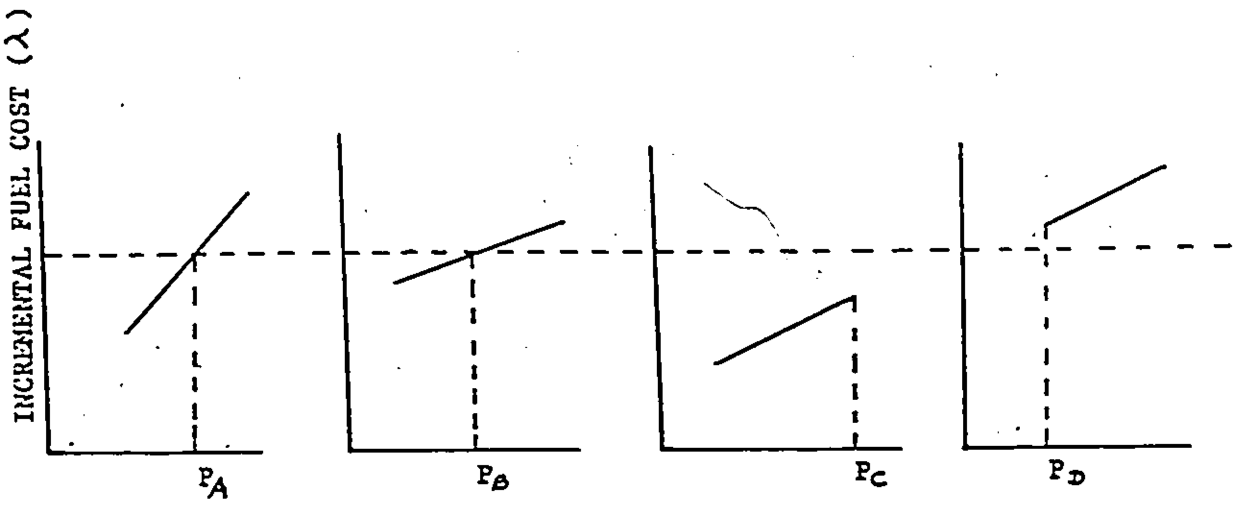


Figure 18: Incremental Loading

subject to the constraint

$$P_T + P_{LOSS} - \sum_{i-1}^{n} P_i = 0$$

where

P_i = power output of unit i (i = 1,2,----n)
$K_i(P_i)$ = cost of producing P
P_T = total power to be supplied by power plant
P_{LOSS} = transmission losses.

The solution of this problem is simply

$$\frac{dK_A}{dP_A} = \frac{dK_B}{dP_B} = \frac{dK_C}{dP_C} = \ldots \frac{dK_n}{dP_n} = \lambda \qquad (3.30)$$

Therefore to achieve minimum operating cost, units are committed in the order of their marginal incremental fuel cost, with the least expensive units first (unit commitment), allocation of output to committed units must follow the equal incremental cost approach (economic dispatch). With multiblock units, cognizance must be taken of the fact that a higher block must not be loaded before its lower block irrespective of their relative marginal costs. This is because sometimes λ is not non - decreasing, so that the lower blocks could have higher average incremental fuel cost than the upper blocks.

An example of single block and multiblock representation and their associated incremental fuel costs are given in Table 8, their fuel cost and type in Table 9.

TABLE 8

Generating Unit data

Unit Size (MW)	No. of Units	Type	FOR	Marginal Costs ($/MWh) Single Block Repres.	Three Block Repres. Lower	Middle	Upper
400	2	Nuclear	.12	5.592	---	---	5.592
300	1	Coal	.08	11.400	10.368	10.880	11.400
197	3	#6 Oil	.05	19.971	19.757	22.563	19.872
155	4	Coal	.04	11.160	10.272	10.680	11.160
100	3	#6 Oil	.04	22.080	19.780	20.700	22.080
76	4	Coal	.02	14.880	13.220	12.280	14.880
50	6	Hydro	.01	0.000	---	---	---
20	4	#2 Oil	.10	37.500	---	---	37.500
12	5	#6 Oil	.02	28.520	---	---	28.520

TABLE 9

Fuel Type and Costs

Type	Cost $/MBtu
#6 Oil	2.30
#2 Oil	3.00
Coal	1.20
Nuclear	0.60

Chapter IV

CRITERIA TO ASSESS THE VALUE OF A WECS

4.1 INTRODUCTION

Economic appraisal methods command a greater confidence when used for selecting or ranking on a common basis the different options available.

Conventionally, when a new plant is operated in the system, some other plants having higher operating costs are relieved of duty. There is a saving associated with this which must be assessed over the lifetime of the new plant. If the saving is mostly fuel, the value of the new plant is evaluated using the marginal rather than the average cost of fuel. The cost of supplying the energy associated with different alternatives to meet demand is evaluated. These costs and benefits are assessed over the lifetime of each competing plant option and present valued to a fixed date using the chosen interest and discount rates.

As new generating concepts become substantially different operationally and economically from the conventional generating units, the established utility assessment and evaluation methodologies may become inadequate. In particular, guesses have to be made about the future behaviour of some quantities such as interest rate on capital, inflation rate on fuel prices, the useful life of the proposed plant and sometimes the conversion efficiancy which can be achieved.

Although the combination of so many elements of uncertainty detracts from the credibility of the final economic assessment, this study chose a set of criteria whereby the conclusions made from results will almost always be realized. This certainty has been enhanced by many sensitivity analyses carried out. The extent of realization is still a function of the assumptions made by individual utilities.

4.2 TOTAL UTILITY SYSTEM COST

4.2.1 Revenue Requirements

Revenue requirements are defined as the revenues which must be obtained in order to cover all expenses incurred, associated with and including the company's Minimum Acceptable Returns (MAR) on investors committed capital [31]. The plan with the minimum present worth of revenue requirements is identified as the most economic.

The economic criteria using detailed minimum revenue requirements consists of capital and operating cost components for each year of the study period [23]. These components are shown in Table 10.

TABLE 10

Revenue Requirements Components

Capital Associated Revenue Requirements

- Minimum Acceptable Return on Capital
- Depreciation
- Income Taxes on MAR on Capital
- Other Taxes
- Insurance

Operating Revenue Requirements

- Fuel Costs
- Variable (function of use) O&M
- Fixed (function of time) O&M

These criteria using different variables for every year of the study period tend to be too complex and costly especially in a study where the aim is to establish and assess some effects. This brings the question of whether other simpler methods cannot be successfully usad without loss of generality. The levelized present worth equivalent cost approach is one such method. This will be taken up in the next section.

4.2.2 Levelized Present Worth Equivalent Cost

Levelization is a process by which a series of non-uniform future payments is converted to a uniform (level) series of payments whose present worth is equal to that of the original non-uniform series. In this approach, the projected cost under investigation is converted to a level annual annuity covering the plants' life and the present worth taken. In this way, the impact of escalation on fuel, interest rate on capital and O&M costs are included. If a full scale study is required, the analysis is repeated for each year of the study period. This levelization approach is shown pictorially in Fig. 19.

Present worth arithmetic is commonly used by planners. The ending value of an amount P at an annual compound interest rate of i for n years is given by

$$V_n = P(1+i)^n \tag{4.1}$$

The present value of an amount F, due in n years, given i as the time value of money is

$$PV = F(1+i)^{-n} \tag{4.2}$$

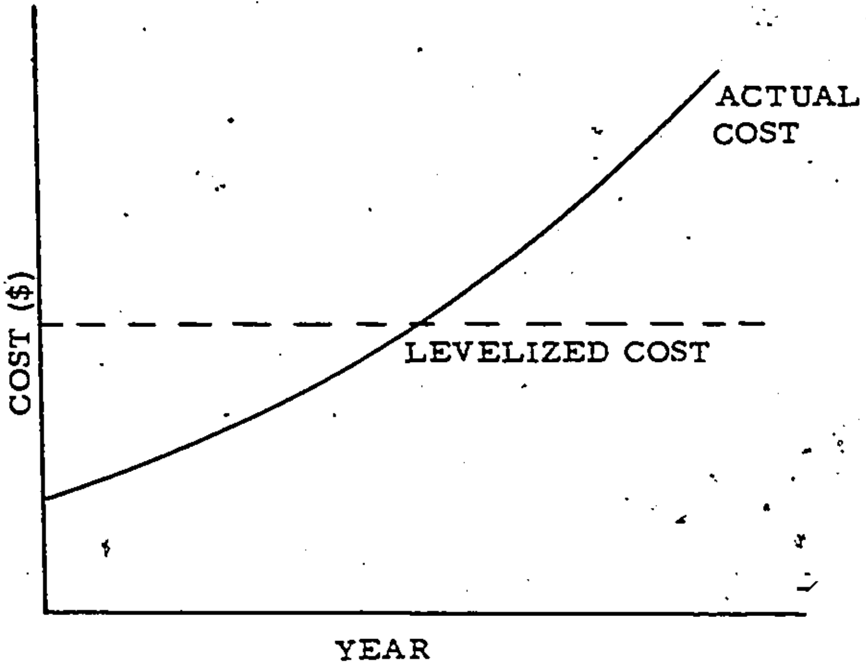


Figure 19: Levelized Equivalent Cost

The present value of a series of payments to be received at the end of each of the next n years is given by

$$PV = F[(1+i)^{-1} + (1+i)^{-2} + \dots (1+i)^{-n}] \qquad (4.3)$$

Multiplying equation (4.3) by (1 + i) gives

$$PV(1+i) = F[(1+(1+i)^{-1} + \ldots (1+i)^{-n+1}] \qquad (4.4)$$

Subtracting equation (4.3) from equation (4.4) yields

$$PV = F[\frac{1-(1+i)^{-n}}{i}] \qquad (4.5)$$

Suppose the amount F is an outlay such as production costs or O&M costs, which inflates at a rate of a% annually, the series of equation (4.3) becomes

$$PV = F[\frac{1}{(1+i)} + \frac{1+a}{(1+i)^2} + \frac{(1+a)^2}{(1+i)^3} + \ldots \frac{(1+a)^{n-1}}{(1+i)^n}] \qquad (4.6)$$

$$= F[\frac{1-(\frac{1+a}{1+i})^n}{i-a}] \qquad (4.7)$$

where

F = first year, end of year, cost
a = Annual inflation rate in per unit
i = present worth interest rate in per unit
n = number of years

The term in the bracket of equation (4.7) is the present worth factor putting into consideration the present worth interest rate and the annual inflation rate. The equivalent cost, X , for n years which produces the same present value can be written as:

X * a = present value

where

a = annuity factor given by:

$$a = \frac{(1+i)^n - 1}{i(1+i)^n} \qquad (4.9)$$

Therefore:

X = 1/a * Present value

1/a is the capital recovery factor [30]. From (4.7), (4.8) and (4.9), the levelized present worth equivalent factor is:

$$L = \frac{1 - (\frac{1+a}{1+i})^n}{i-a} \times \frac{i(1+i)^n}{(1+i)^n - 1} \qquad (4.10)$$

The total utility system cost was therefore taken as the levelized production costs + fixed charges on WTGs + levelized WTGs O&M costs - fixed charges on any conventional unit displaced.

4.3 ECONOMIC ASSUMPTIONS

Most of the Economic assumptions used were obtained from [2] and [7]. These assumptions are given in Table 11.

TABLE 11

Economic Assumptions

Factor	Value
WTG Lifetime	30 years
Present Worth Rate	10%
Escalation	6%
WTG Rating	1500 kw
WTG Capital Cost	590 $/kw
WTG O&M Cost (Fixed cost Equivalent)	10.70 $/kw

4.4 FUEL (ENERGY) DISPLACEMENT

Energy displacement is the amount of electric energy that need not be generated by installed conventional generation because of the energy produced by installed wind machines. When no conventional capacity is dropped as a result of the wind machine introduced, some other more expensive generating units will generate less energy and as such fuel is saved. What value this savings in fuel has to the utility can be evaluated in terms of costs of fuel displaced. These fuel savings may be more significant since the cost of fuel escalates over the life of the wind turbine plant.

The production cost result was used to determine the cost of fuel saved.

Let

P_B = Base case production cost
P_W = Wind case production cost
L = Levelizing factor given by equation (4.10)

then cost saved on fuel is:

$$CS = L(P_B - P_W)$$

4.5 CAPACITY DISPLACEMENT

Capacity displacement is the amount of conventional generating capacity, if any, that might be omitted from a utility's planned future requirements because of the planned addition of wind machines.

Obtaining the equivalent capacity for each change case as was earlier explained gave the capacity displaced.

Decisions could be made on units to be displaced based on some underlying assumptions. Firstly, the utility does not want to displace nuclear capacity since these are base loaded units and thus the most economic units to operate. Secondly, the fast starting peaking units would not be displaced because of needed fast pick up in case of unprecedented lack of wind to operate the wind turbines. Therefore, the remaining coal and oil fired units were displaced in turn. The displacement with lowest system cost was the economic choice. This choice of displacement by alternate substitution guarantees optimum generation mix.

Capacity displacement results are given here as equivalent capacity in percent of the installed wind capacity.

4.6 SENSITIVITY ANALYSIS

4.6.1 Change in Generation Mix

In the fuel displacement study, it was assumed that the base case generating units' mix will remain constant throughout the study period. Most utilities change their mix through time, replacing oil with coal or nuclear or vice versa depending on the policy in vogue. In order to assess the effects of this change, all oil fired units were changed to coal half way in the study period while maintaining the installed capacity constant.

4.6.2 Change in WTGs Forced Outage Rate

Planned and forced outages of plants contribute extensively to their viability. Since the forced outage rates of WTGs are not very well known at the moment, it was accounted for by derating the probability density functions by 3%. Planned outages of WTGs can conveniently be scheduled during periods of low wind. As a way of examining the effect of this assumption on results, the deration multiplier was increased in steps of 5% up to 25%.

4.6.3 Change in Oil and O&M costs

The extensive lack of experience with WTGs warranted the study of a variation on the assumed O&M costs. Future oil cost is also highly unpredictable. The present oil price was not envisaged 10 years ago. To consider this, the escalation rate of fuel was varied and effects assessed.

Chapter V

NUMERICAL EVALUATIONS AND RESULTS

5.1 INTRODUCTION

This chapter gives the results obtained from the steps as described in previous chapters. Likely reasons why such results were obtained are discussed.

Whatever assessment made of a WECS in an electrical utility context, the primary concern of the utility is to be able to measure the viability of a WECS in terms of both reliability and economic considerations. As such, all results and conclusion are aimed towards achieving this objective by making costs and value the predominant quantity.

5.2 ENERGY DISPLACEMENT

Most utilities may first apply WECSs in this mode as it guarantees no loss of load due to unexpected low wind periods since no planned conventional capacity was dropped. Energy displacement was determined via the production costing program. The fuel costs for the base case and for each wind addition was obtained by:

$$L(FC_B - FC_W) \tag{5.1}$$

where

FC_B = Base case fuel cost
FC_W = Wind case fuel cost
L = Levelizing factor given by equation (4.10)

The results are summarized in Table 12.

TABLE 12

Total Annual Fuel Costs

(A) Penetration %	(B) Levelized Fuel Costs M$	(C) ~~Funds~~ Available M$	(D) % Increase In Funds Available
0.0	225.43	0.00	0.0
2.2	218.23	7.20	3.2
4.2	207.63	17.80	4.7
6.2	197.13	28.30	4.7
8.1	186.52	38.91	4.7
11.6	168.13	57.30	8.2
15.0	150.42	75.01	7.9
18.0	142.91	82.52	3.3
21.0	140.75	84.68	1.0

An examination of column (B) of Table 12 shows that although there is a continuous decrease in fuel cost with increase in penetration, these costs tend to saturate at higher penetrations. To make this clearer, column (C) gives the funds available as a result of the zero fuel cost for

WTGs (base case - change case). Column (D) is the % increase in available funds per penetration level with respect to the base case. This column clearly shows the saturation effect. The highest payback would be somewhere between 4% and 8% for this system. The jump at 11.6% is as a result of the doubling of the capacity of WTGs from an increment of 75 MW to 150 MW per level of penetration.

The reason for this saturation effect is that each additional increment of a WECS displaces lower cost energy from conventional units. The system is simply following the law of diminishing returns. A picture of this effect is seen better in Fig.20 where wind power is considered as a negative demand.

A plot of column (D) versus column (A) of Table 12 is shown in Fig. 21. This clearly shows diminishing returns with increase in penetration.

In this energy displacement mode, it might be safer for utilities to simply look at the funds available column and compare this with all expected expenses to be incurred on the purchase, installation and operation of the WECS.

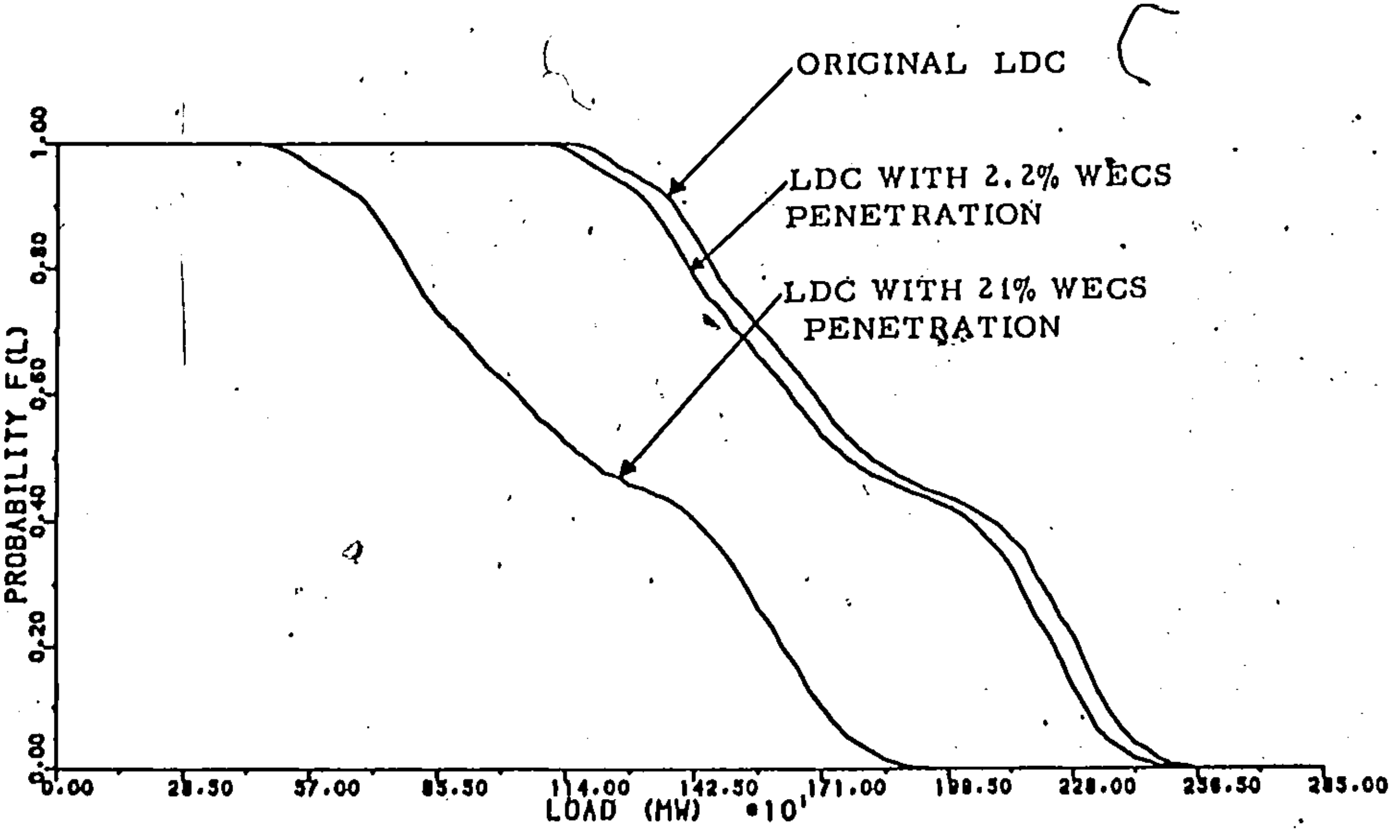


Figure 20. Change In LDC With WECS Penetration

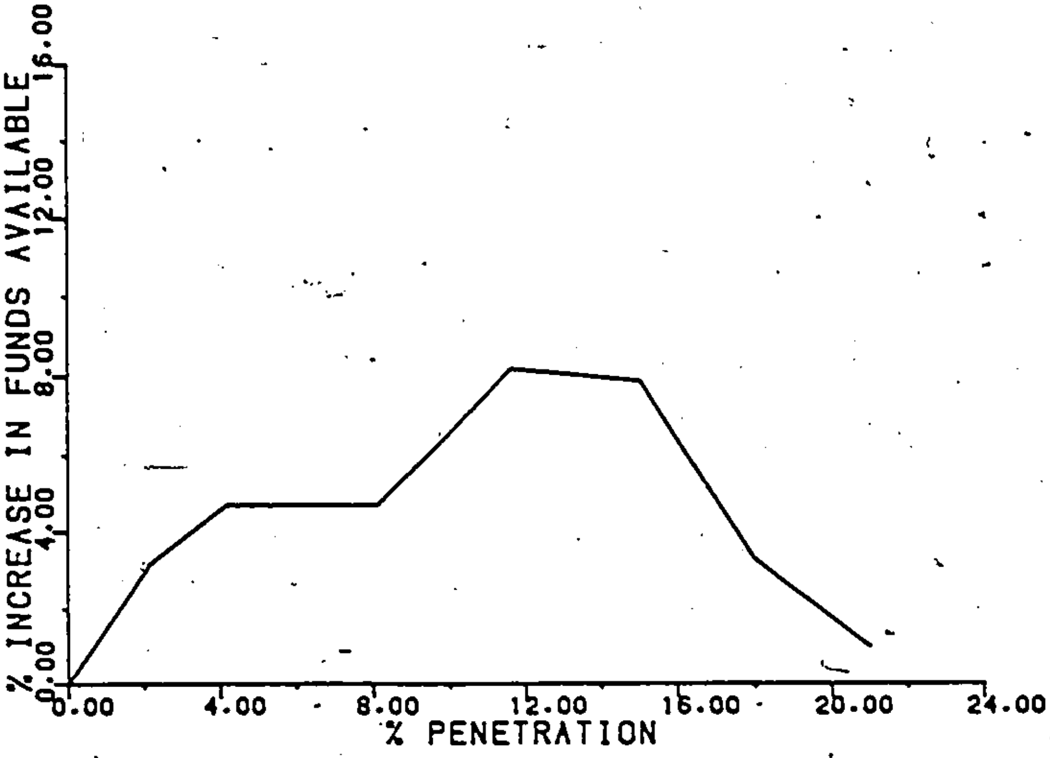


Figure 21: % Increase In Funds vs WECS Penetration

5.2.1 Value of Energy Displaced

There could be several ways of looking at the benefits or value of the energy displaced. It would be worthless if the available funds recovered as a result of savings in fuel cannot purchase and maintain the WTGs responsible for the savings. One way of assessing this benefit is by comparing the total utility system cost with and without a WECS. Assuming the assumptions of Table 11 hold, Table 13 gives the benefits using the total utility system cost.

TABLE 13

Energy Displacement Value of WECS

Penetration %	WTG Base Year Capital Cost M$	WTG Levelized O&M Costs M$	Levelized Fuel Cost M$	Total Cost M$	Gain (Loss) M$
0.0	0.0	0.0	225.43	225.43	0.0
2.2	1.47	1.43	218.23	221.13	4.30
4.2	2.95	2.86	207.63	213.44	11.99
6.2	4.43	4.28	197.13	205.84	19.59
8.1	5.90	5.71	186.52	198.13	27.30
11.6	8.85	8.57	168.13	185.55	39.88
15.0	11.80	11.42	150.42	173.64	51.79
18.0	14.75	14.28	142.91	171.94	53.49
21.0	17.70	17.13	140.75	175.58	49.85

The gains from each level of penetration could be compared with available wind resources with a view to establishing which penetration level will benefit the utility more. Figure 22 gives a graph of the gain or savings versus penetration. This also shows that the savings is not continuosly increasing with increase in a WECS penetration.

Another way of looking at the value of a WECS is by making no assumption for the capital and O&M costs. By calculating how many dollars would be saved due to the addition of WTGs as given in column (C) of Table 12 (funds available), the amount that could be profitably spent on each WTG could be established. This approach will yield a breakeven cost that the utility can afford to spend on each

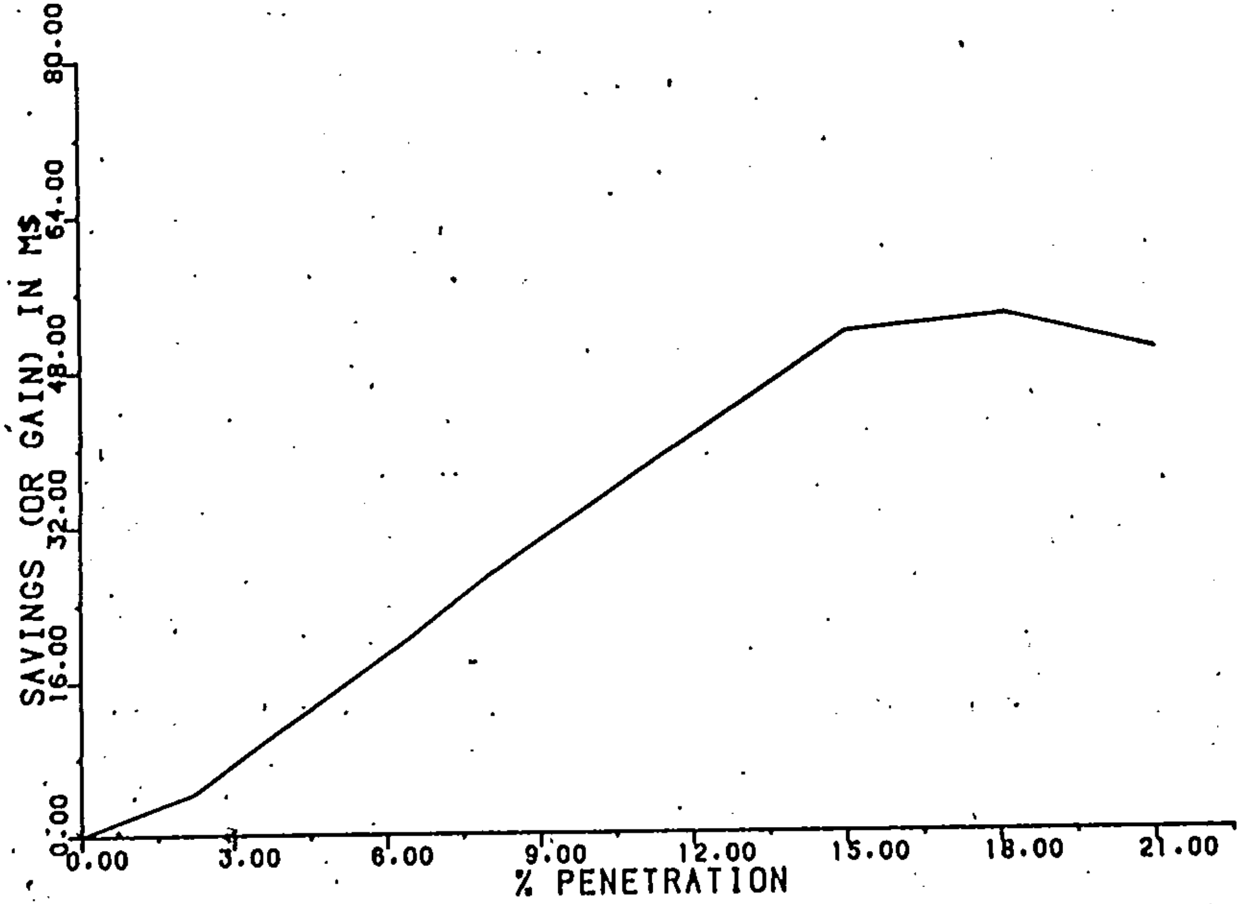


Figure 22. Savings Vs Penetration.

WTG and at the same time suggest the cost goals manufacturers must meet if they wish utilities to buy their WTGs. For a breakeven, equation (5.2) must hold.

$$FA(X) = TWA(X) \qquad (5.2)$$

Where

FA(X) = Funds available for penetration level X
TWA(X) = Total WECS costs for penetration level X

TWA(X) may consist of WTG capital cost, WTG O&M costs, land costs, interface costs, capital investment, stock earnings, interest price on bonds, etc. All except WTG capital and O&M costs could be accurately estimated. Equation (5.2) can be further broken down into:

$$FA(X) = WUC(X) + WKC(X) \qquad (5.3)$$

Where

FA(X) = Funds available for penetration level X
WUC(X) = WECS unknown costs for penetration level X
WKC(X) = WECS known costs for penetration level X

Equation (5.3) can then be solved for the WTG capital and O&M costs for the penetration level of interest.

5.3 RELIABILITY

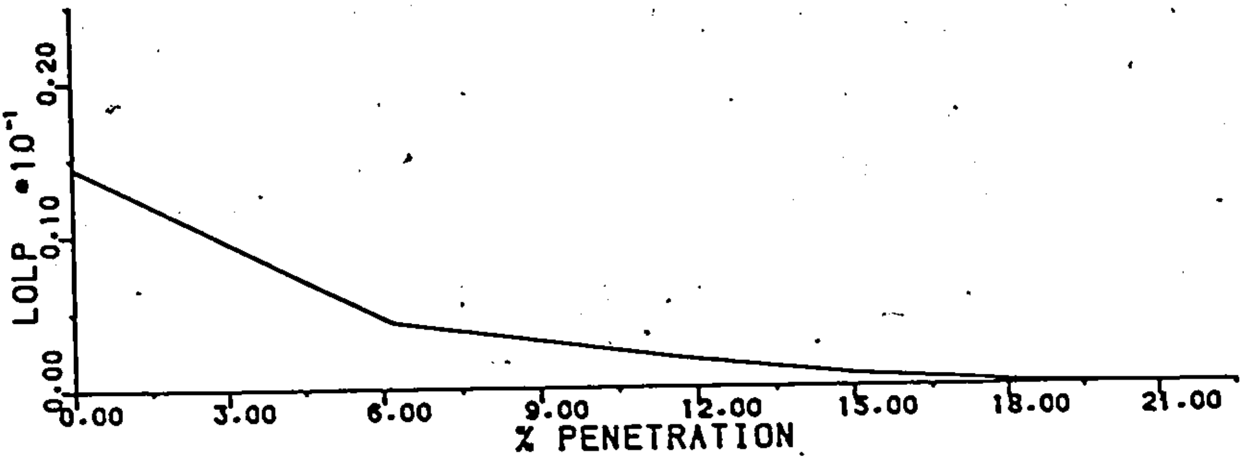
The reliability considered is that of the generation system. The LOLP and E(ENS) indices were used. The variation of LOLP and E(ENS) with penetration level is shown in Table 14. To express the LOLP in days/year, the probability values are multiplied by the number of days in the year.

TABLE 14

LOLP & E(ENS) With Different Penetration

Penetration %	LOLP	E(ENS) GWh
0.0	0.013390	1.231852
2.2	0.010899	0.971175
6.2	0.004402	0.370446
11.6	0.002016	0.159944
15.0	0.000882	0.066143
18.0	0.000359	0.025056
21.0	0.000149	0.009626

Fig.23 shows the values of these indices with a WECS penetration. This result is obvious since increase in penetration adds more generating units to the system serving the same peak load which would have otherwise been served reliably without the WECS. The fact that these curves saturate implies that saturation is also expected in the capacity displacement mode since the LOLP is used as a criteria for determining the capacity displacement.



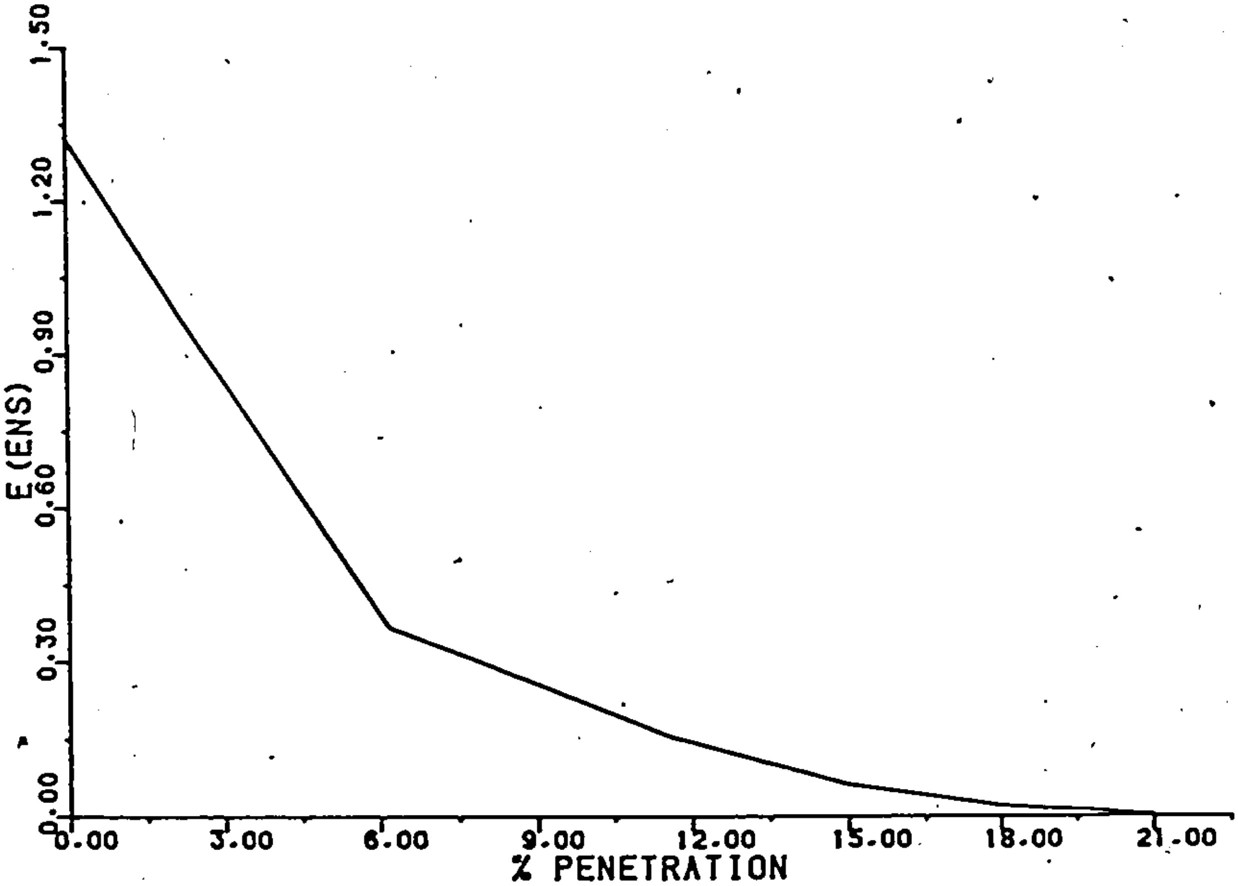


Figure 23: LOLP & E(ENS) vs Penetration

5.4 CAPACITY DISPLACEMENT

Unlike energy displacement, when a WTG is added, conventional capacity is removed in such a way as to maintain a constant LOLP, in this case, the base case LOLP. Capacity displacement is mainly a function of the demand, generating units' forced outages and capacities. The order in which the generating units are convolved with the load probability distribution is not sensitive to capacity displacement. But in this study, production cost results were used to determine optimum generation mix for each capacity dropped by making sure that the displaced capacity for each WTG addition presented the lowest production costs when compared with other displaceable units. So the same production cost program and the same commitment strategy was employed in determining the capacity displaced by each addition of WTGs. The results obtained are presented in Table 15.

TABLE 15

Equivalent Capacity.

(A) Penetration %	(B) WTG Capacity (MW)	(C) Conventional Capacity Displaced (MW)	(D) Type of Unit Displaced	(E) $\frac{(C)}{(B)}$ x 100
2.2	75	36	COAL	0.48
6.2	225	103.5	COAL	0.46
11.6	450	168.6	COAL	0.37
15.0	600	221.0	COAL	0.36
18.0	750	264.5	COAL+OIL	0.35
21.0	900	315.8	COAL+OIL	0.35

The last column of Table 15 shows the saturation at higher penetrations mentioned earlier. This column is the equivalent capacity in percent of installed WTG capacity. The value to the utility of the capacity displaced would be the investment cost associated with the conventional generating units displaced as a result of a WECS addition. Fig. 24 shows a graph of equivalent capacity in percent of WTG capacity plotted against penetrations.

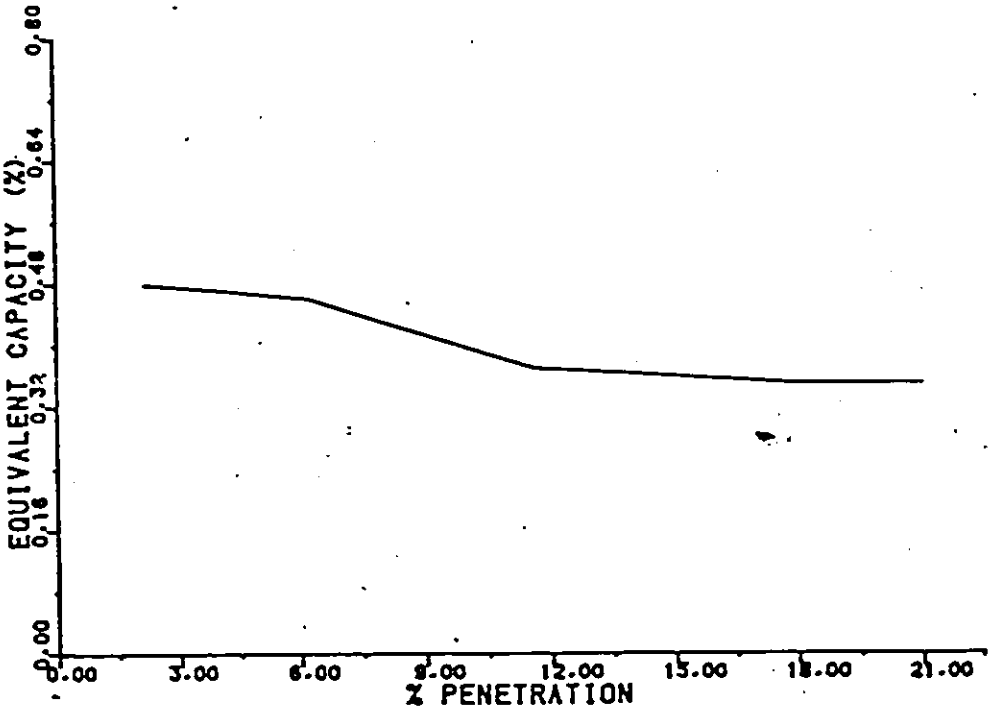


Figure 24: WTG Equivalent Capacity vs. Penetration

5.5 SENSITIVITY ANALYSIS

5.5.1 Variation In WTG Forced Outage Rate

Table 16 describes the affect of variation in FOR, fuel cost as well as LOLP.

TABLE 16

Effect of Forced Outage Rate (FOR) of WTGs

FOR %	Fuel Cost M$	LOLP
3	13.670	0.00473
5	13.747	0.00490
10	13.766	0.00496
15	13.783	0.00500
20	13.805	0.00509
25	13.829	0.00518

These results clearly show that increase or decrease in the duration multiplier to account for WTG random mechanical failure has some effect on the viability of WTGs. There is a consistent increase in cost and LOLP with increase in forced outage rate. So a WTG design with lower forced outage rate can enhance benefits where results for viability are marginal.

5.5.2 Variation In Fuel and O&M Costs

For the baseline analysis, a 6% per year escalation rate was used. In this section, the effects of an increase in fuel cost escalation rate by 50% while that of the O&M cost remained constant and an increase and decrease in the O&M cost escalation rate by 50% while that of fuel cost remained constant was assessed. Table 17 shows the effect of an increase in the escalation rate of fuel cost by 50%.

TABLE 17

Energy Displacement Value, Fuel Cost Escalated 9%/yr.

Penetration %	WTG Base Year Capital Cost M$	WTG Levelized O&M Costs M$	Levelized Fuel Cost M$	Total Cost M$	Gain (Loss) M$
0.0	0.0	0.0	322.14	322.14	0.0
2.2	1.47	1.43	311.85	314.75	7.39
4.2	2.95	2.86	296.72	302.53	19.61
6.2	4.43	4.28	281.69	290.40	31.74
8.1	5.90	5.71	266.54	278.15	43.99
11.6	8.85	8.57	240.28	257.70	64.44
15.0	11.80	11.42	214.96	238.18	83.96
18.0	14.75	14.28	204.23	233.26	88.88
21.0	17.70	17.13	201.13	235.96	86.18

Table 18 shows the effect of an increase in the escalation rate of O&M cost by 50%.

Table 19 shows the effect of a decrease in the escalation of O&M cost by 50%. An examination of the Gain(Loss) column of Tables 17, 18 and 19 shows that an increase or decrease in the escalation rate of the O&M costs, although has some effect on the viability of WECSs when compared with the

TABLE 18

Energy Displacement Value, O&M Cost Escalated 9%/yr.

Penetration %	WTG Base Year Capital Cost M$	WTG Levelized O&M Costs M$	Levelized Fuel Cost M$	Total Cost M$	Gain (Loss) M$
0.0	0.0	0.0	225.43	225.43	0.0
2.2	1.47	2.04	218.23	221.74	3.69
4.2	2.95	4.08	207.63	214.66	10.77
6.2	4.43	6.12	197.13	207.68	17.75
8.1	5.90	8.16	186.52	200.58	24.85
11.6	8.85	12.24	168.13	189.22	36.21
15.0	11.80	16.32	150.42	178.54	46.89
18.0	14.75	20.40	142.91	178.06	47.37
21.0	17.70	24.48	140.75	182.93	42.50

TABLE 19

Energy Displacement Value, O&M Cost Escalated 3%/yr.

Penetration %	WTG Base Year Capital Cost M$	WTG Levelized O&M Costs M$	Levelized Fuel Cost M$	Total Cost M$	Gain (Loss) M$
0.0	0.0	0.0	225.43	225.43	0.0
2.2	1.47	1.05	218.23	220.75	4.68
4.2	2.95	2.10	207.63	212.68	12.75
6.2	4[illegible]3	3.14	197.13	204.70	20.73
8.1	5.90	4.20	186.52	196.62	28.81
11.6	8.85	6.28	168.13	183.26	42.17
15.0	11.80	8.38	150.42	170.60	54.88
18.0	14.75	10.47	142.91	168.13	57.30
21.0	17.70	12.56	140.75	171.01	54.42

baseline rate of 6% shown in Table 13, increase in fuel cost escalation rate by 50% almost doubled the gains from a WECS. This is an eloquent testimony of the fact that the benefits from a WECS will increase substantially if the cost of fuel rises. This is clearly shown in Fig. 25.

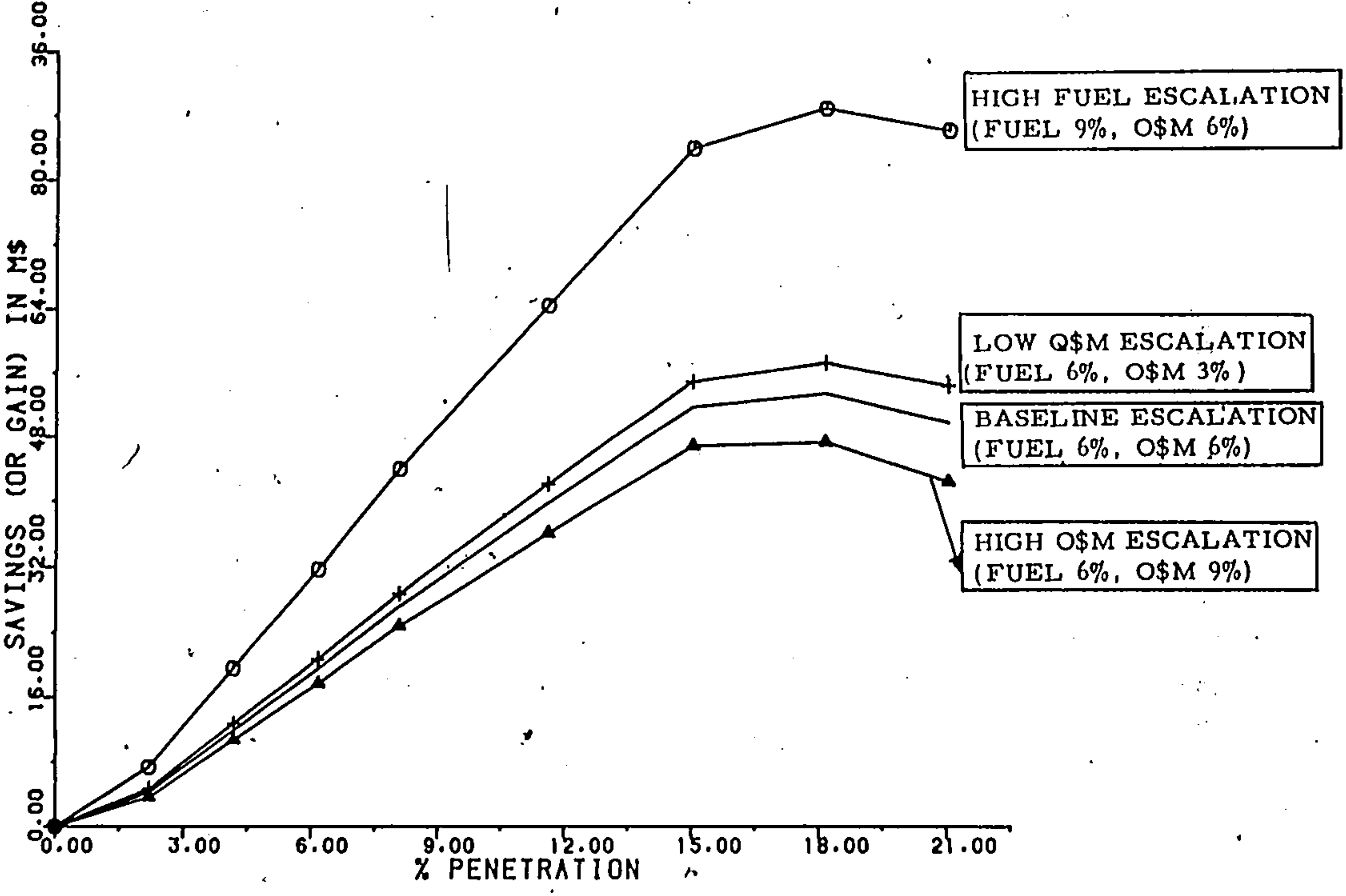


Figure 25. Savings For Different Escalation Rates vs Penetration

5.5.3 Change In Generation Mix.

All the results so far have been based on constant generation mix. The results below compares the benefits obtained with a constant generation mix to that obtained with a change in mix through time. Assuming the base year to be 1981, a constant mix was used for the 30 years ending 2010. This was compared with converting all the oil fired units to coal by 1995 while maintaining the same installed capacity that should serve the load growth through time. Tables 20 and 21 show results obtained from this comparison. No assumption was made as regards capital and O&M costs.

TABLE 20

Constant Generation Mix

Penetration %	Levelized Fuel Cost M$	Funds Available M$
0.0	25.44	0.0
2.2	24.32	1.12
6.2	22.27	3.17
11.6	20.03	5.41
15.0	18.35	7.09
18.0	16.57	8.87
21.0	14.96	10.48

Tables 20 and 21 show that among other things, the type of generation mix greatly affects the benefits from a WECS. If the mix is dominated by coal or nuclear units, the benefits are low. On the other hand, if there are many oil

TABLE 21

Change In Generation Mix

Penetration %	Levelized Fuel Cost M$	Funds Available M$
0.0	24.81	0.0
2.2	23.77	1.04
6.2	21.90	2.91
11.6	19.86	4.95
15.0	18.24	6.57
18.0	16.50	8.31
21.0	14.92	9.89

fired units, then the expected benefits should be high. Fig. 26 shows how the funds available vary with the two types of mixes considered.

The dashed line could be taken as the effect of a gradual change from oil to coal. It is all tantamount to the former inference drawn that higher benefits are realized when there are more oil fired units in the system.

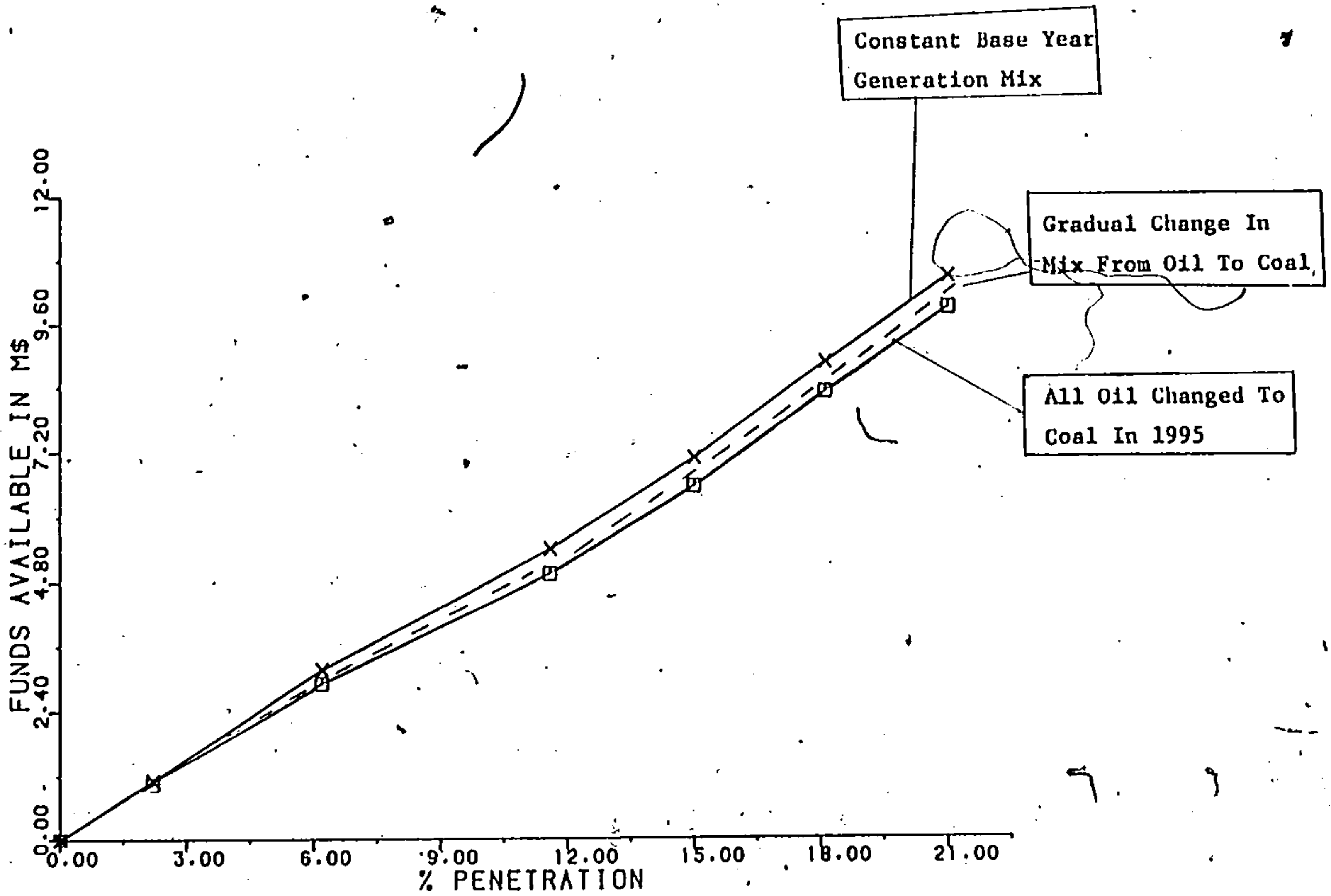


Figure 26. Effects Of Change In Generation Mix For 30 Year Study Period.

Chapter VI

CONLUSION

The objective of this thesis is to assess the impact a WECS has on electrical utility planning. This objective has been achieved by finding out how a WECS effects the two planning goals - cost and reliability.

The WECS has been modelled in two ways:

1. As a multistate unit
2. As a load modifier

These models were incorporated in a production costing and reliability program from where results based on parametric variations were assessed. The main conclusions that can be drawn from this study for the wind data and utility assumed are:

1. A WECS can contribute to overall system reliability. Since reliability is the main criteria used in planning, then a WECS can displace conventional unit capacity.

2. There is an optimum value for the level of penetration to be used after which each additional WTG has less expensive fuel to displace and as such less value to the utility.

3. The value of a WECS to the utility is sensitive to generation mix.

4. A WECS will be much more competitive if oil price increases.

5. The benefit from a WECS is utility specific.

The last point emphasizes that the incorporation of a WECS into an electric utility should not be based on results obtained by other utilities because results are not generic. Individual utilities should verify how a WECS affects them by the application of the models described. All results point towards a WECS being a viable venture. No negative results discouraging the application of a WECS has so far been envisaged.

The reliability and production cost module is the core of an electric utility optimal generation expansion planning computer program such as the WIEN Automatic System Planning Package (WASP). Utilities wishing to exploit wind energy and having the knowledge of the effects of a WECS and how it is assessed, can evaluate how it impacts their specific system by simply making the required changes in the reliabilty and production cost module of their planning package as was described in this thesis.

As Grumman Energy Systems President, Ronald B. Peterson pointed out in Wind Energy Report, May 1980, "One hundred thousand small wind systems would save some five million barrels of oil consumption annually". This optimism has been expressed severally in many places but like any other new technology, WTGs are still fraught with market uncertainties.

6.1 FURTHER RESEARCH

A WECS being a new area offers limitless possibilities for future research.

6.1.1 Coincidence of Wind and Load

By intuition, wind power that peaks during summer would be more valuable to a utility with summer peaking loads than a utility with winter peaking loads. A study done by Marsh [2] showed that for the Southwestern Kansas, the wind monthly energy output peaks in March while the peak load energy occurs in July and August. This somehow contradicts the 'coincidence hypothesis'. There is therefore the need for proper research with several sites to verify this hypothesis. If on the long run the coincidence phenomenon is nullified, then simulation of systems with a WECS will be greatly simplified as this will validate the use of quarterly load curves instead of monthly or hourly load curves.

6.1.2 Wind Data

It has been shown that better wind profiles give better WECS value. Therefore if wrong wind statistics are used, erroneous results would be obtained. There should be very good means of recording wind speeds minute by minute at appropriate heights without relying on wind data meant for other purposes and the associated correction factors which make the results error prone.

Appendix A

DESCRIPTION OF THE METHOD OF MOMENTS

This method was introduced by Schenk and Rau [14], [15]. The statistical moments and cumulants of the normalized LDC and the probability density function for the generating units' forced outage capacities are calculated. To convolve a unit with the LDC, the cumulants of the unit are added to the cumulants of the LDC. Deconvolution is simply achieved by subtraction of cumulants. The resultant cumulants after the convolution of all units are the cumulants representing the random variables of the ELDC. The Gram - Charlier expansion is used to obtain the areas under the ELDC. This simple manipulation of cumulants to achieve convolution and deconvolution is based on probability theory results which show that the cumulants of the sum of independent random variables are equal to the sum of the cumulants of the individual random variables, and the moments of the product of independent random variables are equal to the product of the moments of each variable.

To obtain the area under the ELDC between two values Z_1 and Z_2 one gets

$$\text{Area} = \int_{Z_1}^{\infty} f(Z)dZ - \int_{Z_2}^{\infty} f(Z)dZ \qquad (A1)$$

in which f(Z) is the ELDC and Z_i are standardized RVs defined as

$$Z_i = (X_i - \mu_i)/\sigma_i \qquad (A2)$$

In equation (A2), μ_i and σ_i are the mean and standard deviations of the ELDC, described by the RV X_i. The integral in equation (A1) is obtained in terms of the normal probability density function and its derivatives as follows

$$\int_{Z_i}^{\infty} f(Z)dZ = \int_{Z_i}^{\infty} N(Z)dZ + K(Z_i) \qquad (A3)$$

in which N(Z) is the standard normal probability density function given by

$$N(Z) = \frac{1}{\sqrt{2\pi}} \exp\left[-\frac{Z^2}{2}\right] \qquad (A4)$$

and the factor $K(Z_i)$ are given in terms of the Gram - Charlier expansion as follows

$$\begin{aligned} K(Z_i) &= \frac{G_1}{3!} N^{(2)}(Z_i) - \frac{G_2}{4!} N^{(3)}(Z_i) \\ &+ \frac{G_3}{5!} N^{(4)}(Z_i) - \frac{(G_4 + 10G_1^2)}{6!} N^{(5)}(Z_i) \\ &+ \frac{(G_5 + 35G_1G_3)}{7!} N^{(6)}(Z_i) \end{aligned}$$

$$- \frac{(G_6 + 56G_1G_3 + 35G_2^2)}{8!} N^{(7)}(Z_i) \qquad \text{(A5)}$$

This series can be chosen in such a way as to give the best approximation to the curve. In equation (A5) the derivatives of the normal probability density function, $N^{(r)}(Z_i)$, of order r, may be expressed in terms of polynomials $H_r(Z_i)$ as follows

$$N^{(r)}(Z_i) = (-1)^r H_r(Z_i) N(Z_i) \qquad \text{(A6)}$$

The factors G_ν, $\nu = 1,2,\ldots\ldots\ldots$, are obtained in terms of the cumulants K_ν as follows

$$G_\nu = K_{\nu+2}/\sigma^{\nu+2} \qquad \text{(A7)}$$

Cumulants are known polynomial function of moments and vice versa. Essentially, the cumulants of a distribution are defined in terms of the first moment about the origin or the mean and the higher moments about the mean. Higher order cumulants of a distribution with probability density function f(x) measure the departure of f(x) from the normal distribution. Therefore the first two moments completely describe a normal distribution. This implies that for a normal curve, the third and higher order cumulants are zero. Since the LDC or ELDC are not normal, the use of higher order cumulants becomes essential. The cumulants K_i are obtained from the moments μ' from the relationship [14] (only four are shown).

$$K_1 = \mu_1'$$

$$K_2 = \mu_2' - \mu_1'^2$$

$$K_3 = \mu_3' - 3\mu_2'\mu_1' + 2\mu_1'^3$$

$$K_4 = \mu_4' - 4\mu_3'\mu_1' - 3\mu_2'^2 + 12\mu_2'\mu_1'^2 - 6\mu_1'^4$$

The moments are given by

$$\mu_1' = C_{ai}q_{ai} + C_{bi}q_{bi} + \cdots$$

$$\mu_2' = C_{ai}^2q_{ai} + C_{bi}^2q_{bi} + \cdots$$

$$\mu_3' = C_{ai}^3q_{ai} + C_{bi}^3q_{bi} + \cdots$$

and so on, where q_{ai} is the unavailability corresponding to a partial capacity outage C_{ai} MW, etc.

As was earlier stated, the area each unit occupies under the ELDC as given by (A1) is a prelude to calculating the cost of energy production. In contrast to numerical integration used in obtaining the ELDC area in the recursive technique, areas in the method of moments are obtained by calculating the normal probability P($C_1 \leq Z_i \leq C_2$).

where C_1 and C_2 are the capacity states before and after unit convolution. Note that the energy generated by a particular unit is obtained as a difference between their unserved energies.

Appendix B

IEEE RELIABILITY TEST SYSTEM LOAD DATA

Tables 22, 23 and 24 give the weekly load in percent of annual peak, daily peak load in percent of weekly peak and hourly peak load in percent of daily peak respectively. The annual peak load is 2850.0 MW.

TABLE 22

Weekly Peak Load in Percent of Annual Peak

Week	Peak Load	Week	Peak Load
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.1	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0

22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.22

TABLE 23

Daily Peak Load in Percent of Weekly Peak

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

TABLE 24

Hourly Peak in Percent of Daily Peak

	Winter Weeks 1-8 & 44-52		Summer Weeks 18-30		Spring/Fall Weeks 9-17 & 31-43	
Hour	Wkdy	Wknd	Wkdy	Wknd	Wkdy	Wknd
12-1am	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
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Appendix C

WIND DATA FOR MULTISTATE REPRESENTATION OF WTGS

TABLE 25

Wind Data

CAPACITY (MW)	AVAILABILITY	
	FEB	MAR
75.000	0.49305	0.50731
73.125	0.06599	0.06790
69.375	0.09141	0.09405
65.625	0.02156	0.02219
61.875	0.01897	0.01952
58.125	0.01265	0.01301
54.375	0.01261	0.01297
50.626	0.01257	0.01294
46.875	0.01142	0.01176
43.125	0.00754	0.00776
39.375	0.01008	0.01038
35.675	0.00633	0.00651
31.875	0.00499	0.00514
28.125	0.00377	0.00388
24.375	0.00377	0.00388
20.625	0.04356	0.04482
16.875	0.00754	0.00776
13.125	0.00125	0.00129
9.375	0.00125	0.00129
5.625	0.01518	0.01562
1.875	0.06028	0.06203
0.000	0.09416	0.06794

TABLE 26

Wind Data

CAPACITY (MW)	AVAILABILITY	
	APR	MAY
75.000	0.50731	0.44567
73.125	0.06790	0.05965
69.375	0.09405	0.08262
65.625	0.02219	0.01949
61.875	0.01952	0.01714
58.125	0.01301	0.01143
54.375	0.01297	0.01139
50.625	0.01294	0.01137
46.875	0.01176	0.01033
43.125	0.00776	0.00681
39.375	0.01038	0.00911
35.675	0.00651	0.00572
31.875	0.00514	0.00451
28.125	0.00388	0.00341
24.375	0.00388	0.00341
20.625	0.04482	0.03938
16.875	0.00776	0.00682
13.125	0.00129	0.00113
9.375	0.00129	0.00113
5.625	0.01562	0.01372
1.875	0.06203	0.05449
0.000	0.06794	0.18121

TABLE 27

Wind Data

CAPACITY (MW)	AVAILABILITY	
	JUN	JUL
75.000	0.39823	0.35557
73.125	0.05330	0.04759
69.375	0.07382	0.06592
65.625	0.01742	0.01555
61.875	0.01532	0.01368
58.125	0.01021	0.00912
54.375	0.01018	0.00909
50.625	0.01015	0.00907
46.875	0.00923	0.00824
43.125	0.00609	0.00544
39.375	0.00815	0.00728
35.675	0.00511	0.00456
31.875	0.00403	0.00360
28.125	0.00305	0.00272
24.375	0.00305	0.00272
20.625	0.03518	0.03142
16.875	0.00609	0.00544
13.125	0.00101	0.00090
9.375	0.00101	0.00090
5.625	0.01226	0.01094
1.875	0.04869	0.04347
0.000	0.26835	0.34674

TABLE 28

Wind Data

CAPACITY (MW)	AVAILABILITY	
	AUG	SEP
75.000	0.34608	0.38403
73.125	0.04632	0.05140
69.375	0.06416	0.07119
65.625	0.01514	0.01679
61.875	0.01332	0.01478
58.125	0.00880	0.00985
54.375	0.00885	0.00982
50.625	0.00883	0.00979
46.875	0.00802	0.00890
43.125	0.00529	0.00587
39.375	0.00708	0.00786
35.675	0.00444	0.00493
31.875	0.00351	0.00389
28.125	0.00265	0.00294
24.375	0.00265	0.00294
20.625	0.03058	0.03393
16.875	0.00529	0.00587
13.125	0.00088	0.00098
9.375	0.00088	0.00098
5.625	0.01066	0.01182
1.875	0.04232	0.04695
0.000	0.36417	0.29445

TABLE 29

Wind Data

CAPACITY (MW)	AVAILABILITY	
	OCT	NOV
75.000	0.45516	0.41721
73.125	0.06092	0.05584
69.375	0.08438	0.07735
65.625	0.01991	0.01825
61.875	0.01751	0.01605
58.125	0.01168	0.01071
54.375	0.01164	0.01067
50.625	0.01161	0.01064
46.875	0.01055	0.00967
43.125	0.00696	0.00638
39.375	0.00931	0.00854
35.675	0.00584	0.00535
31.875	0.00461	0.00423
28.125	0.00348	0.00319
24.375	0.00348	0.00319
20.625	0.04022	0.03687
16.875	0.00696	0.00638
13.125	0.00116	0.00106
9.375	0.00116	0.00106
5.625	0.01401	0.01285
1.875	0.05565	0.05101
0.000	0.16378	0.23350

TABLE 30

Wind Data

CAPACITY (MW)	AVAILABILITY
	DEC
75.000	0.45987
73.125	0.06155
69.375	0.08525
65.625	0.02011
61.875	0.01769
58.125	0.01179
54.375	0.01176
50.625	0.01173
46.875	0.01066
43.125	0.00703
39.375	0.00941
35.675	0.00590
31.875	0.00466
28.125	0.00352
24.375	0.00352
20.625	0.04063
16.875	0.00703
13.125	0.00117
9.375	0.00117
5.625	0.01416
1.875	0.05623
0.000	0.15511

```
C
C                 PROGRAM  DESCRIPTION
C                 --------------------
C
C         THIS PROGRAM CALCULATES FUEL COSTS, LOSS OF LOAD
C         PROBABILITY AND EXPECTED ENERGY NOT SERVED FOR
C         GENERATING UNITS DERATED N TIMES TO ACCOUNT FOR
C         WECS UNAVAILABILITY OR CONVENTIONAL UNITS
C         PARTIAL OUTAGES USING THE METHOD OF MOMENTS(CUMULANTS)
C
C
C       EACH INPUT VARIABLE IS DESCRIBED BEFORE USE
C
C
C
        REAL*8 TS,AB/0.0D0/,BB/0.0D0/,PUBASE,ENG,XLIM,SNAM(100)
        REAL TOTAL/0.0/,TCOST/0.0/,INSTLC
        COMMON /CUMMC/ CAREA,CMEAN,CUM2,CUM3,CUM4,CUM5,CUM6,CUM7,CUM8
        COMMON /MMCGEN/ CMGEN1(100),CMGEN2(100),CMGEN3(100),
       &CMGEN4(100),CMGEN5(100),CMGEN6(100),CMGEN7(100),CMGEN8(100)
        DIMENSION C(100),P(100),CD(100),UNS(100),IFC(100),
       &BC(70,6),AA(70,6),PP(70,6),CC(70,6),AP(100),
       &IAP(100),FC(70,6)
        REAL*4 FMT(18),FMT1(18),FMT2(18)
        LOGICAL * 1 LINE(119)/119 * '*' /
        REAL N,IFC
C
C       INPUT THE BASE LOAD, PEAK LOAD, TIME
C       AND NO. OF POINTS IN THE LDC
C
        READ(5,555) FMT
        READ(5,FMT) BASE,PKMW,TIME,NU
C
C       INPUT THE WECS PENETRATION
C
        PEN = 2.2
C
C
C       PUBASE IS THE BASE LOAD CAPACITY EXPRESSED
C       IN PER UNIT OF TOTAL LOAD
C
C
        PUBASE=BASE/PKMW
        CALL MLDC(NU,BASE,PKMW)
        CALL MCGEN(C,P,NBLK,PKMW,SNAM,CD,UNS,IFC,AP,INSTLC)
        DO 35 I=1,NBLK
        JAP=AP(I)
        DIFR=AP(I)-JAP
        JDIFR=DIFR*10.0+0.1
        AA(JAP,JDIFR)=I
        FC(JAP,JDIFR)=IFC(I)
        CC(JAP,JDIFR)=C(I)
        PP(JAP,JDIFR)=P(I)
        BC(JAP,JDIFR)=CD(I)
   35   CONTINUE
```

```
      PRINT 11
      PRINT 22
      WRITE(6,777) LINE
      DO 150 I=1,NBLK
      IAP(I)=AP(I)
      DIF=(AP(I)-IAP(I))*10.0+0.1
      IU=IAP(I)
      IB=DIF
C
C
C     IF A HIGHER BLOCK, THE PREVIOUS BLOCK IS REMOVED
C
C
      IF(IB-1)7,7,68
68    IF(IB-2)7,67,69
67    IBM=IB-1
      GO TO 9
69    IF(IB.GT.3)GO TO 7
      IBM=IB+3
9     CONTINUE
      CMEAN=CMEAN-CMGEN1(AA(IU,IBM))
      CUM2=CUM2-CMGEN2(AA(IU,IBM))
      CUM3=CUM3-CMGEN3(AA(IU,IBM))
      CUM4=CUM4-CMGEN4(AA(IU,IBM))
      CUM5=CUM5-CMGEN5(AA(IU,IBM))
      CUM6=CUM6-CMGEN6(AA(IU,IBM))
      CUM7=CUM7-CMGEN7(AA(IU,IBM))
      CUM8=CUM8-CMGEN8(AA(IU,IBM))
7     CONTINUE
      IF(BC(IU,IB)-1)15,5,5
5     CONTINUE
      BB=BB+CC(IU,IB)/PKMW
C
C     CALCULATE EXPECTED ENERGY AND COST.
C
      CALL CALENG(ENG,BB,AB,PUBASE)
      ENERGY=PP(IU,IB)*TIME*ENG*PKMW/1000.
      COST=ENERGY*FC(IU,IB)*1000.
      TCOST=TCOST+COST
      TOTAL=TOTAL+ENERGY
      WRITE(6,200)SNAM(I),IAP(I),IB,UNS(I),C(I),IFC(I),ENERGY,COST
      IF(BC(IU,IB)-1)15,15,3
15    CALL CONV(I)
3     AB=BB
150   CONTINUE
C
C     CALCULATE LOLP AND ENERGY UNDER LDC.
C
      TS=AB+10.0D-2/PKMW
      CALL CALENG(ENG,TS,AB,PUBASE)
      SLOLP=ENG*1.0D6
      DCEN = PKMW * TIME * CAREA/1000.0
```

```
C
C     CALCULATE EXPECTED ENERGY NOT SERVED.
C
      XLIM=AB+1.0
      CALL CALENG(ENG,XLIM,AB,PUBASE)
      ENGY=ENG*PKMW*TIME/1000.
C
C     OUTPUT RESULTS
C
      WRITE(6,111) DCEN
      WRITE(6,105) INSTLC
      WRITE(6,104)PEN
      WRITE(6,55)SLOLP
      WRITE(6,66)TOTAL
      WRITE(6,77)TCOST
      WRITE(6,30)ENGY
      WRITE(6,101)PKMW
      WRITE(6,102)BASE
      WRITE(6,103)TIME
C
C     FORMAT STATEMENTS
C
30    FORMAT(//,5X,'ENERGY NOT SERVED=',E18.6,'GWH')
11    FORMAT(/,2X,'STATION',5X,'UNIT',6X,'BLOCK',6X,'UNIT SIZE',8X,
     &'BLOCK SIZE',9X,'I F C',13X,'EXPECTED ENERGY',8X,'FUEL COST')
22    FORMAT(3X,'NAME',8X,'NO.',7X,'NO.',10X,'(MW)',14X,'(MW)',11X,
     &'$/MWH',17X,'(GWH)',16X,'($)'/)
55    FORMAT(//,5X,'THE SYSTEM LOLP IS',2X,E18.7)
66    FORMAT(//,5X,'THE TOTAL EXPECTED ENERGY IS',2X,E18.7,2X,'GWH')
111   FORMAT(//,5X,'ENERGY UNDER LDC =',1X,F9.3,2X,'GWH')
77    FORMAT(//,5X,'THE TOTAL FUEL COST IS',F14.4,1X,'$')
200   FORMAT(/,1X,A8,3X,I5,5X,I5,3X,F12.2,5X,F12.2,5X,F15.6,5X,F15.4,
     &9X,F13.2)
101   FORMAT(/,5X,'PEAK LOAD=',1X,F10.3,1X,'MW')
102   FORMAT(/,5X,'BASE LOAD=',1X,F10.3,1X,'MW')
103   FORMAT(/,5X,'TIME=',1X,F8.1,1X,'HOURS')
104   FORMAT(//,5X,'W E C S PENETRATION IS',F7.3,1X,'%')
105   FORMAT(//,5X,'INSTALLED CAPCITY =',1X,F10.3,1X,'MW')
555   FORMAT(18A4)
777   FORMAT(1X,119A1)
      WRITE(6,777) LINE
      STOP
      END
```

```
      SUBROUTINE MLDC(NU,BASE,PKMW)
C
C
C     THIS SUBROUTINE CALCULATES THE MOMENTS AND
C     CUMULANTS OF THE LDC
C
C
      COMMON /CUMMC/ CAREA,CMEAN,CUM2,CUM3,CUM4,CUM5,
     &CUM6,CUM7,CUM8
      COMMON /MM/ CM1,CM2,CM3,CM4,CM5,CM6,CM7,CM8
      DIMENSION RMOM(10),F(110),AS(12),XVEC(110),XVC(12),
     &XVB(12)
      REAL M1,M2,M3,M4,M5,M6,M7,M8
C
C
C     INPUT THE HORIZONTAL AND VERTICAL AXES DATA OF THE LDC
C
C
      READ(5,60)(XVEC(I),I=1,NU)
      READ(5,65)(F(I),I=1,NU)
C
C
      PUBASE=BASE/PKMW
      DO 10 K=1,8
      RMOM(K)=PUBASE**(K+1)/(K+1.0)
   10 CONTINUE
      PAREA=PUBASE
      DO 11 I=1,NU
      XVEC(I)=XVEC(I)/PKMW
   11 CONTINUE
      AS(1)=10.0
      DO 12 J=2,11
      AS(J)=AS(J-1)*10.0
   12 CONTINUE
      F(NU+1)=0.
      XVEC(NU+1)=2.0*XVEC(NU)-XVEC(NU-1)
      NU=NU-1
      DO 20 I=1,NU
      BO=F(I)
      B1=(F(I)-F(I+1))/(XVEC(I)-XVEC(I+1))
      B12=(F(I+1)-F(I+2))/(XVEC(I+1)-XVEC(I+2))
      B2=(B1-B12)/(XVEC(I)-XVEC(I+2))
      AB1=BO-B1*XVEC(I)+B2*XVEC(I)*XVEC(I+1)
      AB2=B1-B2*(XVEC(I)+XVEC(I+1))
      AB3=B2
      XVC(1)=XVEC(I+1)/10.0
      XVB(1)=XVEC(I)/10.0
      DO 13 J=2,11
      XVC(J)=XVC(J-1)*XVC(1)
      XVB(J)=XVB(J-1)*XVB(1)
   13 CONTINUE
```

```
      PAREA=PAREA+AB1*(XVC(1)-XVB(1))*AS(1)+AB2*
     &(XVC(2)-XVB(2))*AS(2)/2.0+AB3*(XVC(3)-XVB(3))*
     &AS(3)/3.0
      DO 14 K=1,8
      RMOM(K)=RMOM(K)+AB1*(XVC(K+1)-XVB(K+1))*AS(K+1)/(K+1.0)
     &+AB2*(XVC(K+2)-XVB(K+2))*AS(K+2)/(K+2.0)+AB3*
     &(XVC(K+3)-XVB(K+3))*AS(K+3)/(K+3.0)
14    CONTINUE
20    CONTINUE
      M1=RMOM(1)/PAREA
      M2=RMOM(2)/PAREA
      M3=RMOM(3)/PAREA
      M4=RMOM(4)/PAREA
      M5=RMOM(5)/PAREA
      M6=RMOM(6)/PAREA
      M7=RMOM(7)/PAREA
      M8=RMOM(8)/PAREA
      CALL MMC(M1,M2,M3,M4,M5,M6,M7,M8)
      CAREA=PAREA
      CMEAN=CM1
      CUM2=CM2
      CUM3=CM3
      CUM4=CM4
      CUM5=CM5
      CUM6=CM6
      CUM7=CM7
      CUM8=CM8
60    FORMAT(8F8.2)
65    FORMAT(8F9.6)
      RETURN
      END
```

```
      SUBROUTINE MCGEN(C,P,NP,PKMW,SNAM,CD,UNS,IFC,AP,INSTLC)
C
C
C     SUBROUTINE MCGEN CALCULATES THE MOMENTS AND CUMULANTS
C     OF GENERATING UNITS
C
C
      COMMON /MMCGEN/ CMGEN1(100),CMGEN2(100),CMGEN3(100),
     &CMGEN4(100),CMGEN5(100),CMGEN6(100),CMGEN7(100),CMGEN8(100)
      REAL Q(100)/100*0.0/, C(100), P(100),INSTLC
      REAL MM1(25),MM2(25),MM3(25),MM4(25),MM5(25),MM6(25),MM7(25),
     &MM8(25),M1(100)/100*0.0/,M2(100)/100*0.0/,M3(100)/100*0.0/
     &,M4(100)/100*0.0/,M5(100)/100*0.0/,M6(100)/100*0.0/,
     &M7(100)/100*0.0/,M8(100)/100*0.0/,M,CC(25),QQ(25)
      DIMENSION CM1(100),CM2(100),CM3(100),CM4(100),CM5(100),
     &CM6(100),CM7(100),CM8(100),CU3(100),CU4(100),CU5(100),
     &CU6(100),CU7(100),CU8(100)
      REAL CD(100),IFC(100),UNS(100),AP(100),INSTLC
      REAL * 8 SNAM(100)
      REAL*4 FMT(18),FMT1(18),FMT2(18)
      NO = 1
      INSTLC = 0.0
      DO 50 I=1,100
      C(I) = 0.0
50    CONTINUE
C
C
C     INPUT SNAM = NAME OF UNIT
C
C            CD = CODE THAT INDICATES WHETHER BLOCK IS TO
C                 BE CONVOLVED OR DECONVOLVED AND FOR THE
C                 CONVOLVED BLOCK, WHETHER ENERGY IS TO BE
C                 CALCULATED OR NOT
C
C           UNS = UNIT SIZE
C
C           IFC = INCREMENTAL FUEL COST
C
C            AP = UNIT AND BLOCK NO.
C
C            NS = NO. OF DERATED CAPACITY STATES
C
C
C
      READ(5,555) FMT
      READ(5,555) FMT1
      READ(5,555) FMT2
55    READ(5,FMT,END = 100)SNAM(NO),CD(NO),UNS(NO),IFC(NO),AP(NO),NS
```

```
C
C     INPUT THE DERATED CAPACITIES
C
      READ(5,FMT1)(CC(N),N=1,NS)
C
C     INPUT THEIR CORRESPONDING UNAVAILABILITIES
C
      READ(5,FMT2)(QQ(N),N=1,NS)
C
C
      DO 10 N=1,NS
      CC(N)=CC(N)/PKMW
      Q(NO)=Q(NO)+QQ(N)
      MM1(N)=CC(N)*QQ(N)
      M1(NO)=M1(NO)+MM1(N)
      MM2(N)=MM1(N)*CC(N)
      M2(NO)=M2(NO)+MM2(N)
      MM3(N)=MM2(N)*CC(N)
      M3(NO)=M3(NO)+MM3(N)
      MM4(N)=MM3(N)*CC(N)
      M4(NO)=M4(NO)+MM4(N)
      MM5(N)=MM4(N)*CC(N)
      M5(NO)=M5(NO)+MM5(N)
      MM6(N)=MM5(N)*CC(N)
      M6(NO)=M6(NO)+MM6(N)
      MM7(N)=MM6(N)*CC(N)
      M7(NO)=M7(NO)+MM7(N)
      MM8(N)=MM7(N)*CC(N)
      M8(NO)=M8(NO)+MM8(N)
10    CONTINUE
      P(NO)=1.-Q(NO)
      C(NO)=C(NO)+CC(NS)*PKMW
      IF(CD(NO) .EQ. 0.) GO TO 11
      INSTLC = INSTLC + C(NO)
11    CONTINUE
C
C
C     CALCULATE THE CENTRAL MOMENTS
C
C
      CM2(NO)=M2(NO)-M1(NO)**2
      CM3(NO)=M3(NO)-3.*M1(NO)*M2(NO)+2.*M1(NO)**3
      CM4(NO)=M4(NO)-4.*M1(NO)*M3(NO)+6.*M1(NO)**2*M2(NO)-3.
     &*M1(NO)**4
      CM5(NO)=M5(NO)-5.*M1(NO)*M4(NO)+10.*M1(NO)**2*M3(NO)
     &-10.*M1(NO)**3*M2(NO)+4.*M1(NO)**5
      CM6(NO)=M6(NO)-6.*M1(NO)*M5(NO)+15.*M1(NO)**2*M4(NO)-20.
     &*M1(NO)**3*M3(NO)+15.*M1(NO)**4*M2(NO)-5.*M1(NO)**6
      CM7(NO)=M7(NO)-7.*M1(NO)*M6(NO)+21.*M1(NO)**2*M5(NO)
     &-35.*M1(NO)**3*M4(NO)+35.*M1(NO)**4*M3(NO)-21.*M1(NO)
     &**5*M2(NO)+6*M1(NO)**7
      CM8(NO)=M8(NO)-8.*M1(NO)*M7(NO)+28.*M1(NO)**2*M6(NO)
     &-56.*M1(NO)**3*M5(NO)+70.*M1(NO)**4*M4(NO)-56.*M1(NO)
     &**5*M3(NO)+28.*M1(NO)**6*M2(NO)-7.*M1(NO)**8
```

```
      &+210.*CM3(NO)*CM2(NO)**2
       CU8(NO)=CM8(NO)-28.*CM6(NO)*CM2(NO)-56.*CM5(NO)*CM3(NO)
      &-35.*CM4(NO)**2+420.*CM4(NO)*CM2(NO)**2+560.*CM3(NO)
      &**2*CM2(NO)-630.*CM2(NO)**4
       CMGEN1(NO)=M1(NO)
       CMGEN2(NO)=CM2(NO)
       CMGEN3(NO)=CU3(NO)
       CMGEN4(NO)=CU4(NO)
       CMGEN5(NO)=CU5(NO)
       CMGEN6(NO)=CU6(NO)
       CMGEN7(NO)=CU7(NO)
       CMGEN8(NO)=CU8(NO)
       NO = NO + 1
       GO TO 55
100    CONTINUE
       NP = NO - 1
       RETURN
555    FORMAT(18A4)
       END
C
C
C
C
C
C
C
C
       SUBROUTINE MMC(VM1,VM2,VM3,VM4,VM5,VM6,VM7,VM8)
C
C      SUBROUTINE MMC CALCULATES THE MOMENTS ABOUT THE
C      MEAN AND CUMULANTS
C
       COMMON /MM/ CM1,CM2,CU3,CU4,CU5,CU6,CU7,CU8
       REAL M
       CM1=VM1
       CM2=VM2-VM1**2
       CM3=VM3-3.*VM1*VM2+2.*VM1**3
       CM4=VM4-4.*VM1*VM3+6.*VM1**2*VM2-3.*VM1**4
       CM5=VM5-5.*VM1*VM4+10.*VM1**2*VM3-10.*VM1**3
      &*VM2+4.*VM1**5
```

```
      CM6=VM6-6.*VM1*VM5+15.*VM1**2*VM4-20.*VM1**3
     &*VM3+15.*VM1**4*VM2-5.*VM1**6
      CM7=VM7-7.*VM1*VM6+21.*VM1**2*VM5-35.*VM1**3
     &*VM4+35.*VM1**4*VM3-21.*VM1**5*VM2+6.*VM1**7
      CM8=VM8-8.*VM1*VM7+28.*VM1**2*VM6-56.*VM1**3*VM5
     &+70.*VM1**4*VM4-56.*VM1**5*VM3+28.*VM1**6
     &*VM2-7.*VM1**8
      CU3=CM3
      CU4=CM4-3.*CM2**2
      CU5=CM5-10.*CM3*CM2
      CU6=CM6-15.*CM4*CM2-10.*CM3**2+30.*CM2**3
      CU7=CM7-21.*CM5*CM2-35.*CM4*CM3+210.*CM3*CM2**2
      CU8=CM8-28.*CM6*CM2-56.*CM5*CM3-35.*CM4**2+420.
     &*CM4*CM2**2+560.*CM3**2*CM2-630.*CM2**4
      RETURN
      END
C
C
C
C
C
C
C
C
C
      SUBROUTINE CALENG(ENG,XT,YT,PUBASE)
C
C     THIS SUBROUTINE CALCULATES THE EXPECTED ENERGY.
C     XT=UPPER LIMIT,YT=LOWER LIMIT,PUBASE=P.U.DISTANCE
C     OCCUPIED BY THE BASE LOAD.
C
      REAL*8 ENG,XT,YT,PUBASE
      IF(YT.LT.PUBASE)GO TO 5
      ENG=AELDC(XT,YT)
      RETURN
5     IF(XT.LE.PUBASE)GO TO 10
      ENG=(PUBASE-YT)+AELDC(XT,PUBASE)
      RETURN
10    ENG=XT-YT
      RETURN
      END
```

```
      SUBROUTINE CONV(I)
C
C     SUBROUTINE CONV ADDS THE CUMMULANTS OF PLANT(I)
C     TO THE CUMULANTS OF THE LDC TO OBTAIN THE CONVOLUTION
C     OF UNITS WITH THE LDC.
C
      COMMON /MMCGEN/ CMGEN1(100),CMGEN2(100),CMGEN3(100),
     &CMGEN4(100),CMGEN5(100),CMGEN6(100),CMGEN7(100),CMGEN8(100)
      COMMON /CUMMC/ CAREA,CMEAN,CUM2,CUM3,CUM4,CUM5,CUM6,
     &CUM7,CUM8
      CMEAN=CMEAN+CMGEN1(I)
      CUM2=CUM2+CMGEN2(I)
      CUM3=CUM3+CMGEN3(I)
      CUM4=CUM4+CMGEN4(I)
      CUM5=CUM5+CMGEN5(I)
      CUM6=CUM6+CMGEN6(I)
      CUM7=CUM7+CMGEN7(I)
      CUM8=CUM8+CMGEN8(I)
      RETURN
      END
C
C
C
C
C
C
C
C
      FUNCTION AREA(Z)
C
C     THIS SUBROUTINE CALCULATES THE AREA UNDER A
C     NORMAL CURVE.
C
      REAL*8 P,B1,B2,B3,B4,B5,T,Z,ZX
      P=0.2316419D0
      B1=0.31938153D0
      B2=-0.356563782D0
      B3=1.781477937D0
      B4=-1.821255978D0
      B5=1.330274429D0
      T=1./(1.+P*Z)
      ZX=DEXP(-(Z*Z/2.))*0.3989422804D0
      AREA=ZX*(B1*T+B2*T**2+B3*T**3+B4*T**4+B5*T**5)+7.0D-8
      RETURN
      END
```

```
      FUNCTION AELDC(XU,XL)
      IMPLICIT REAL*8 (G-H,M-O,P-V,X-Z)
C
C
C     THIS SUBROUTINE CALCULATES THE AREA UNDER THE EQUIV. LOAD
C     DURATION CURVE (ELDC)
C
C
      COMMON /CUMMC/ CAREA,CMEAN,CUM2,CUM3,CUM4,CUM5,CUM6,
     &CUM7,CUM8
      DIMENSION SK(2),Z(2),MD(2)
      VAR=DSQRT(DBLE(CUM2))
C
C     CALCULATE THE GRAM CHARLIER SERIES G(I) FACTORS
C
      G1=CUM3/VAR**3
      G2=CUM4/VAR**4
      G3=CUM5/VAR**5
      G4=CUM6/VAR**6+10.0*G1*G1
      G4B=10.*G1**2
      G5=CUM7/VAR**7+35.*G1*G2
      G6=CUM8/VAR**8+56.*G1*G3+35.*G2**2
C
C
C     CALCULATE THE DERIVATIVES OF THE NORMAL PDF, N(Z)
C     FROM HERMITE POLYNOMIALS H(Z), AND HENCE THE
C     PROBABILITY F(Z)
C
C
      IJ=1
      X=XU
      GO TO 97
98    X=XL
97    Z(1)=(X-DBLE(CMEAN))/VAR
      Z(2)=(X+DBLE(CMEAN))/VAR
      DO 30 I=1,2
      ZZ=Z(I)
      NZ=DEXP(-(ZZ**2/2.))/2.506628275
      H1=ZZ
      H2=ZZ*H1-1
      H3=ZZ*H2-2.*H1
      H4=ZZ*H3-3.*H2
      H5=ZZ*H4-4.*H3
      H6=ZZ*H5-5.*H4
      H7=ZZ*H6-6.*H5
      H8=ZZ*H7-7.*H6
      H9=ZZ*H8-8.*H7
```

```
      N2=H2*NZ
      N3=-H3*NZ
      N4=H4*NZ
      N5=-H5*NZ
      N6=H6*NZ
      N7=-H7*NZ
      MD(I)=G4B*N5/720.0D0
      SK(I)=AREA(ZZ)+G1*N2/6.-G2*N3/24.+G3*N4/120.-G4*N5/720.
     &+G5*N6/5040.-G6*N7/40320.
30    CONTINUE
      IF(SK(1).LT.0.0)SK(1)=0.0
      IF(SK(2).LT.0.0)SK(2)=0.0
      PROB=SK(1)+SK(2)
      IF(IJ.EQ.1)PTEST=PROB
      IF(PTEST.LE.8.0D-4)PROB=PROB+MD(1)*6.0D-1
      IF(IJ.EQ.1)PROB1=PROB
      IF(IJ.EQ.2)PROB2=PROB
      IJ=IJ+1
      IF(IJ.LE.2)GO TO 98
      AELDC=CAREA*(DABS(PROB1-PROB2))
      RETURN
      END
//GO.SYSIN  DD  *
(3F8.2,2I3)
 1140.00 2565.00  744.00 51
 1140.00 1168.50 1197.00 1225.50 1254.00 1282.50 1311.00 1339.50
 1368.00 1396.50 1425.00 1453.50 1482.00 1510.50 1539.00 1567.50
 1596.00 1624.50 1653.00 1681.50 1710.00 1738.50 1767.00 1795.50
 1824.00 1852.50 1881.00 1909.50 1938.00 1966.50 1995.00 2023.50
 2052.00 2080.50 2109.00 2137.50 2166.00 2194.50 2223.00 2251.50
 2280.00 2308.50 2337.00 2365.50 2394.00 2422.50 2451.00 2479.50
 2508.00 2536.50 2565.00
 1.000000 0.997312 0.990591 0.978495 0.962366 0.952957 0.939516 0.928763
 0.911290 0.879032 0.850806 0.815860 0.779570 0.752688 0.731183 0.705645
 0.685484 0.659946 0.637097 0.610215 0.583333 0.553763 0.533602 0.514785
 0.498656 0.486559 0.473118 0.463710 0.452957 0.446237 0.439516 0.430107
 0.419355 0.407258 0.395161 0.373656 0.356183 0.314516 0.283602 0.245968
 0.219086 0.172043 0.125000 0.090054 0.063172 0.041667 0.030914 0.014785
 0.006720 0.004032 0.000000
```

```
(A8,F3.0,F5.0,F7.3,F5.1,I3)
(7F7.3)
(7F7.6)
NUCLEAR  1. 400.  5.592  1.1  1
 400.00
 0.12
NUCLEAR  1. 400.  5.592  2.1  1
 400.00
 0.12
W E C S  1.  75.  0.000 28.1 21
  1.875  5.625  9.375 13.125 16.875 20.625 24.375
 28.125 31.875 35.625 39.375 43.125 46.875 50.625
 54.375 58.125 61.875 65.625 69.375 73.125 75.000
 .06473 .08966 .02115 .01861 .01241 .01237 .01233
 .01121 .00739 .00989 .00621 .00489 .00369 .00369
 .04273 .00739 .00123 .00123 .01490 .05913 .11150
COAL ->B 1. 155. 10.476  7.1  1
 77.5
 0.04
   -
   -
   -
   -
   -
   -
#6 OIL-C 1.  12. 28.520 27.1  1
 12.0
 0.02
#2 OIL   1.  20. 37.500 19.1  1
 20.0
 0.1
#2 OIL   1.  20. 37.500 20.1  1
 20.0
 0.1
#2 OIL   1.  20. 37.500 21.1  1
 20.0
 0.1
#2 OIL   1.  20. 37.500 22.1  1
 20.0
 0.1
/*
```

SAMPLE OUTPUT

```
 STATION    UNIT     BLOCK     UNIT SIZE        BLOCK SIZE         I F C            EXPECTED ENERGY      FUEL COST
 NAME       NO.      NO.        (MW)             (MW)              $/MWH              (GWH)               ($)
**************************************************************************************************************
NUCLEAR       1        1        400.00           400.00            5.591999          261.8877          1464475.00
NUCLEAR       2        1        400.00           400.00            5.591999          261.8877          1464475.00
W E C S      28        1         75.00            75.00            0.0                26.9883                0.0
COAL ->B      7        1        155.00            77.50           10.476000           55.3536           579884.00
              -        -          -                 -                -                  -                  -
              -        -          -                 -                -                  -                  -
              -        -          -                 -                -                  -                  -
              -        -          -                 -                -                  -                  -
              -        -          -                 -                -                  -                  -
              -        -          -                 -                -                  -                  -
#6 OIL-C     27        1         12.00            12.00           28.519989            0.0250             712.90
#2 OIL       19        1         20.00            20.00           37.500000            0.0346            1296.25
#2 OIL       20        1         20.00            20.00           37.500000            0.0308            1154.13
#2 OIL       21        1         20.00            20.00           37.500000            0.0274            1027.17
#2 OIL       22        1         20.00            20.00           37.500000            0.0244             913.74

   ENERGY UNDER LDC =  1393.229  GWH

   INSTALLED CAPCITY =   3479.990 MW

   W E C S PENETRATION IS  2.200 %

   THE SYSTEM LOLP IS       0.6734324E-01

   THE TOTAL EXPECTED ENERGY IS       0.1393097E 04  GWH

   THE TOTAL FUEL COST IS 10796953.0000 $

   ENERGY NOT SERVED=      0.117890E 00GWH
   PEAK LOAD=   2565.000 MW
   BASE LOAD=   1140.000 MW
   TIME=    744.0 HOURS
**************************************************************************************************************
```

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