Q. Please confirm (or explain to the extent you do not confirm) that prior to 1977, Newfoundland and Labrador Hydro had adopted this "*one event in ten years*" reliability criterion.

A. Prior to 1977, Hydro had not adopted this "*one event in ten years*" reliability criterion. As noted below, prior to 1977, Hydro did not have an approved long-term reliability criterion to use in establishing the reserve capacity which should be installed on the system. From page 2 of *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions – System Planning Department – Newfoundland and Labrador Hydro – May 16, 1977* (see PUB-NLH-118 Attachment 1):

> Introduction
> At present there is no approved long term reliability criterion which can be used by System Planning in establishing the reserve MWs which must be installed on the power system. On a short term basis (to 1979), the following reserve criterion has been approved by Management:
>
> > *"The Island shall have installed sufficient generating capacity to supply ninety-five percent (95%) of the Island's coincident peak demand with the largest generating unit out of service. The largest generating unit shall be taken as one 150 MW unit (142 MW net) at the Newfoundland and Labrador Hydro Holyrood Generating Station."*

NEWFOUNDLAND AND LABRADOR HYDRO

RECOMMENDED LOSS OF LOAD PROBABILITY (LOLP) INDEX FOR ESTABLISHING GENERATION RESERVE ADDITIONS

System Planning Department

May 16, 1977

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Introduction

At present there is no approved long term reliability criterion which can be used by System Planning in establishing the reserve MWs which must be installed on the power system. On a short term basis (to 1979), the following reserve criterion has been approved by Management:

> "The Island shall have installed sufficient generating capacity to supply ninety-five percent (95%) of the Island's coincident peak demand with the largest generating unit out of service. The largest generating unit shall be taken as one 150 MW unit (142 MW net) at the Newfoundland and Labrador Hydro Holyrood Generating Station".

In order to compare generation expansion alternatives, it is necessary to have a reserve criterion that can be used for the full extent of any comparison (i.e. to 1990 or beyond). System Planning therefore adopted the following criterion, that the generation reserve, beginning in 1980, would be fifteen percent (15%) of the total Island load or the largest generating unit on the system plus five percent (5%), whichever is greater.

This method of percent reserve however is not sensitive to some system conditions (i.e. type of unit plus history of generation outages, etc.). A new method, proposed by G. Calabrese in 1947, which uses probability mathematics, is sensitive to the above parameters. This new method has become known as the Loss of Load Probability (LOLP) technique. The LOLP technique describes the generation reserve requirements in terms of "the expected

Introduction (Cont'd)

number of days per year that generation will not be sufficient to meet the peak daily load"[1]. It is this technique and the effect which it has on our generation expansion that will be outlined in the following report.

[1] Basic Probability and Statistics for Reliability Analysis by Paul F. Albrecht.

Merits of LOLP Technique

The purpose of using the LOLP technique is basically the same as that for using a percent reserve criterion. It allows the planner to plan the amounts of extra generation which he must add to the power system each year to assure some degree of reliability to the customer.

It should be noted that neither of these methods are used for determining the addition of energy sources, they are only used for determining the amount of reserve capacity and that transmission reliability is not accounted for in either method.

The advantages of using the LOLP technique are that it takes into account:

a) the type of generation that is being added, i.e. different types of generating facilities are more reliable than others whereas the percent reserve criterion assumes that a set amount of generation has the same reliability regardless of type, i.e. hydro or thermal,

b) each of the three hundred sixty-five (365) daily load peaks, whereas the percent reserve criterion assumes only the peak load for the year.

c) the maintenance of units, whereas the percent reserve criterion does not take this into account.

As noted by the definition of LOLP in the Introduction, this technique provides the planners of the power system with an index which is tangeable to the ordinary individual i.e. a LOLP of .1 days/year or 1 day/10 years as opposed to saying there

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Merits of LOLP Technique (Cont'd)

is a 20% reserve carried on the system. Although the reliability is now stated as say 1 day in 10 years, this still does not mean that load will not be interrupted due to outages of generation, it only means that the probability of not having sufficient generation available to put into service is within this limit. The fact that we can still lose load due to generation outages is because we do not have any spinning reserve generation. This point is another major policy decision and will not be dealt with here.

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Methodology

In order to appreciate the results and conclusions of our work, it is necessary to understand the basis of the method used.

The input parameters which are necessary to calculate the LOLP are as follows:

a) a description of each generating unit which is to be included in the study;

i) size in MWs,

ii) forced outage rate (F.O.R.) - this is defined as;

$$\text{F.O.R.} = \frac{\text{Forced Outage Hours}}{\text{Operating Hours + Forced Outage Hours}}$$

This data is obtained from actual operating experience or from typical values which can be obtained from "CEA Forced Outage Reports"

iii) maintenance schedule - this can be obtained from operating personnel.

b) description of the peak load for each day of the year.

i) in order to do this a yearly peak load in MWs is given for each year to be studied. The year is then divided into 26 intervals each of which contains 14 days. The interval peak is given as a p.u. of the yearly peak and the daily peak is given as a p.u. of the interval peak. A detailed description of the load model for the Island system is contained in Appendix A of this report.

A sample calculation will now be done to illustrate how this input information is used to arrive at a LOLP index.

Methodology (Cont'd)

A sample system as shown below, will be assumed:

Rating of Units MW	Forced Outage Rate
100	.01
150	.02
200	.03

A capacity outage table is now developed using the following formula:

New entry at X MW = (1 - F.O.R.) • (old entry at X MW) + F.O.R.•(old entry at X-C MW)

The detailed calculation can be found in attached Appendix B.

CAPACITY OUTAGE TABLE

450 MW CAPACITY SYSTEM

Outage MW	Probability of Outage or Greater
0	1.000000
50	.058906
100	.058906
150	.049400
200	.030194
250	.001088
300	.000894
350	.000600
400	.000006
450	.000006
500	0.0

This table relates to the planner the probability of having a specified amount of generation in MWs or greater not available

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Methodology (Cont'd)

for service, i.e. from the table the probability of having 200 MW of generation or greater not available for service is equal to .030194 days/day. This now means that if we can calculate the amount of reserve which exists on our example system, we can by using the above table, calculate the daily LOLP.

Let us assume that for our example the forecasted load for the year to be studied and the assumed load model are as follows:

Forecasted load = 400 MW

Interval*	Peak P.U.
1	.74
2	.62

Days	Interval 1	Interval 2
1	1.0000	1.0000
2	.96	.96
3	.93	.94
4	.90	.90
5	.84	.80
6	.80	.76
7	.78	.72
8	.76	.68
9	.72	.64
10	.70	.60
11	.67	.57
12	.62	.53
13	.58	.48
14	.50	.40

* Only two intervals shown here in order to simplify the example. As shown in Appendix A there are 26 intervals to describe the year.

Methodology (Cont'd)

The following steps are now taken to find the daily LOLP:

Step 1 - Calculate the peak for day 1 in interval 1

peak (MW) = 400 x .74 x 1.0
= 296 MW

Step 2 - The daily peak load must now be rounded upwards so that it is equal to one of the outage MW steps in the capacity outage table.

∴ The peak (MW) now goes from 296 MW to 300 MW.

Step 3 - Calculate the reserve on the system.

Reserve = Available MWs - Peak Load in MWs. As there is no maintenance being carried out in this interval then the available MWs are equal to the installed MWs.

∴ Reserve = 450 - 300
= 150 MW

Step 4 - Find the probability of losing the reserve MWs or greater. To do this we go to our capacity outage table and find the probability that corresponds to 150 MW.

∴ LOLP for Day 1 = .049400 Days/Day

Step 5 - The above four steps are carried out for each of the 14 days and the resultant arithmetic sum of the daily LOLPs is the LOLP for the interval.

∴ LOLP for interval 1 = .382922 Days/Interval

The detailed calculation for each day can be found in Appendix B.

Step 6 - The same procedure is now followed for Interval 2. Assume in this interval that maintenance will be performed on the 100 MW unit. A new capacity outage table must now be calculated to reflect the decrease in available capacity.

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Methodology (Cont'd)

CAPACITY OUTAGE

TABLE FOR MAINTENANCE

Outage MW	Probability of Outage or Greater
0	1.000000
50	.049400
100	.049400
150	.049400
200	.030000
250	.000600
300	.000600
350	.000600
400	0.0
450	0.0
500	0.0

The detailed calculations for this table are found in Appendix B.

Peak (MW) for Day 1 in Interval 2

= 400 x .62 x 1.0
= 248 MW

The peak is now rounded upwards to the nearest outage step size

= 250 MW

The reserve = available MWs - peak load

= (450 - 100) - 250

= 100 MW

∴ LOLP for day 1 = .049400 days/day

This is now done for each day in interval 2 to arrive at the:

LOLP for interval 2 = .565200 days/interval.

Methodology (Cont'd)

The detailed calculations for interval 2 are contained in Appendix B.

Step 7 - The above steps are followed for each interval (i.e. creating a revised capacity outage table when needed for maintenance or the addition of a new unit).

When all the intervals are calculated the values are summed to provide the yearly LOLP.

$$LOLP = \sum_{i=1}^{n} LOLPi$$

LOLP - yearly LOLP

LOLPi - interval LOLP

n - number of intervals

i - interval

The above example has illustrated the basic method of calculation that is used in analyzing our system.

LOLP Specifics

Some points of special interest which should be noted are as follows:

a) the load model as developed by the System Planning Department runs from April 1 to March 30 of the following year and includes 364 days (i.e. 26 intervals at 14 days/interval) as opposed to neglecting Saturdays and Sundays as adopted by some utilities.

There are two basic reasons for developing our load model as noted above:

1) due to the fact that our yearly winter peak occurs in January or February of the subsequent year, a year was specified to run from April 1 to March 30 in order to include this peak,

2) it was felt best to include all Saturdays and Sundays because of the nature of our major industrial customers (i.e. 24 hour shift work (7 days/week)).

b) all generation on the Island is included in this study. For a detailed breakdown of this generation please refer to Appendix C.

Method for Cost Evaluation

In order to evaluate the cost of planning a system to meet a required LOLP, the following method of approach was used:

a) a capacity outage table was developed using the Island system up to and including Holyrood No. 3, In addition to the units previously described in Appendix C, this would also include:

Unit Description	Size MW	F.O.R. @ Year 1	2	3	4	5
Price 1	10.0	.0005	.0005	.0005	.0005	.0005
Price 2	10.0	.0005	.0005	.0005	.0005	.0005
Bay D'Espoir	150.0	.0514	.0257	.0257	.0257	.0257
Holyrood No. 3	140.0	.1200	.1000	.0900	.0800	.0700

b) the study was run to the year 1990 using the August 1976 load forecast.

Year	Peak MW
1980	1395.0
1981	1449.0
1982	1568.0
1983	1658.0
1984	1752.0
1985	1856.0
1986	2060.0
1987	2069.0
1988	2229.0
1989	2354.0
1990	2490.0

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Method for Cost Evaluation (Cont'd)

c) the following energy sources were added to all cases:

Unit Description	MW Size	1	2	3	4	5	I/S Date
Hinds Lake	80.0	.0178	.0089	.0089	.0089	.0089	1980
Cat Arm 1	60.0	.0181	.0092	.0092	.0092	.0092	1981
Cat Arm 2	50.0	.0181	.0092	.0092	.0092	.0092	1981
Upper Salm 1	40.0	.0178	.0089	.0089	.0089	.0089	1982
Upper Salm 2	40.0	.0178	.0089	.0089	.0089	.0089	1982
Upper Terra Nova	120.0	.0514	.0257	.0257	.0257	.0257	1982
Thermal 1	290.0	.1200	.1000	.0900	.0800	.0800	1984
Thermal 2	280.0	.1200	.1000	.0900	.0800	.0800	1987

These units were added in or near the fourteenth interval of each year.

d) maintenance is scheduled and performed on major plants only (eg. Holyrood and Bay D'Espoir) including plant which is installed during the study period (i.e. after 1980). No maintenance is carried out on gas turbine units. The maintenance schedule for existing units and the proposed schedule for future units was obtained from our operating personnel.

e) in order to regulate the LOLP from year to year, 50 MW G.T. units with a F.O.R. of 15% were added where necessary to regulate the LOLP to the required level.

In order to subject a system of our size to a LOLP analysis, it was necessary to develop a computer program. This has been done by the System Planning Department and it was used to produce the following results.

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Results and Analysis

In order to compare the increased costs of maintaining a higher generation reliability, it was decided to choose an existing expansion schedule to use for comparison purposes. The generation expansion sequence as recommended in the report to Management dated November 23, 1976 and titled "Recommended Island Generation Additions 1978 to 1990 (No Labrador Infeed Prior to 1990)" was chosen for the above purpose and will be referred to as the "base" case. The detailed generation expansion for this base case in included in Appendix D as Table I. The reserve MWs for this case were calculated solely on the percent reserve criterion as defined in the Introduction.

For comparison purposes it was decided to subject our expansion alternative for the following LOLPs, 1 day/year, .75 days/year, .5 days/year, .4 days/year, .3 days/year, .2 days/year, .1 days/year. As previously stated, only the energy sources were added to each case and the LOLP was adjusted by adding gas turbines in 50 MW sizes. It should be noted that the LOLP was held to the above figures or less than in each particular case.

The results showing the amounts of gas turbine which must be added for each LOLP can be found in Appendix D in Tables II through VIII.

The resultant present worth dollars for each alternative are given in Appendix D as Table IX.

Figures 1 - 4 which are contained in Appendix D present the data from Tables I - VIII in a graphic form.

Results and Analysis (Cont'd)

Figure 1 shows the gas turbine installed as a percent of the total installed MWs on the system on a year to year basis. Only four (4) cases were plotted on this graph due to the closeness of the results. It can be seen however that there is a significant increase in the percent gas turbine when a LOLP $\leq$ .1 days/year is chosen.

Figure 2 presents the percent reserve (i.e. installed MW ÷ peak load MW) on a year to year basis. These results, once again, illustrate the jump in results when a LOLP of $\leq$ .1 days/year is chosen.

Figure 3 shows the steady increase in the average percent reserve as we go from a percent reserve criteria to an LOLP of $\leq$ .1 days/year.

Figure 4 presents the total present worth dollars which must be spent to increase the generation reliability on the system. For example, to increase the reliability from a percent reserve criteria to an LOLP of $\leq$ .1 days/year, an additional 61.5 million present worth dollars (January 1976) must be spent.

Upon analyzing the results, it was felt that a large part of the dollar increase necessary to maintain a specified LOLP or better was due to the heavy expenditures in gas turbines in the year 1980 (see Table VIII, Appendix D).

It was now felt that we should evaluate our system when holding a specified LOLP from 1981 onwards. We therefore returned to our original system and added Hinds Lake as well as 100 MW of

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Results and Analysis (Cont'd)

gas turbine (i.e. two 50 MW units) in the year 1980. Although the original expansion report required 78 MW of gas turbine to be added to meet the percent reserve criteria in 1980, it was felt that in order to compare our previous work (maintaining a specified LOLP from 1980 onwards) with this latest step, it would be best to use some multiple of the 50 MW gas turbines which we were using to maintain the LOLP.

We then ran the case from 1981 to 1990 for LOLPs of 1 day/year, .5 days/year, .2 days/year and .1 days/year. The results are shown in Tables I - V and Figures 1 - 4 contained in Appendix E.

It can be seen by investigating the present worth dollars that at the higher LOLPs (i.e. 1 day/year) there is no substantial savings. However for an LOLP of $\leq$ .1 days/year, the incremental cost over the base case now becomes 50 million dollars instead of 61.5 million as was previously calculated.

Table VI in Appendix E outlines the actual LOLPs which occurred year by year for the various cases which were run. This table shows that if we wish to hold an LOLP $\leq$ .1 days/year, for example from 1980 onwards, we are well below this mark of .1 for the subsequent years after installing a large amount of gas turbines in 1980. If however we wait until 1981 and add only 100 MW of gas turbine in 1980 then we can see that we are closer to our limit of .1 days/year and that both cases, i.e. 1980 and 1981, become equal after 1986 for LOLP $\leq$ .1 days/year.

Table VII of Appendix E is tabulated to show the expenditure of capital dollars necessary to maintain a specified LOLP for both cases (i.e. commencing in 1980 and 1981). If we consider the case

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Results and Analysis (Cont'd)

of an LOLP index of $\leq$ .1 days/year, it will be noted that in the 1980 case the capital dollar expenditure is quite large in the first year 1980 while for the 1981 case the capital experditure is distributed over the years from 1979 to 1986. However more total capital dollars are spent in this time frame for the 1981 case.

Table VIII presents in summary fashion, the difference which exists between the alternatives when specifying the LOLP in 1981.

Table IX describes the system from 1977 to 1979 in terms which are applicable to this report. It will be noted that the LOLPs are relatively high compared to those that have been presented in this report and that the reserves are very low when compared to those which we require to maintain an LOLP of $\leq$ .1 days/year.

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Conclusions and Recommendations

The attached Appendix F contains a copy of a paper that was presented at the Spring meeting of the CEA (Canadian Electrical Association). This paper presents the approach which utilities are taking in the area of generation reliability.

Probably the most important point which is contained in the above paper is found on page 3 as a reply to question 2. As noted, the standard risk level which is used (i.e. LOLP level) is one (1) day in ten (10) years or .1 days per year except for one utility which uses .2 days per year. This value of LOLP should be qualified by a statement which is taken from the above paper "any discussion of a standard risk index such as .1 days/year should also include a detailed statement of the factors used in arriving at this figure".

In comparing the factors which we have used in studying the LOLP technique to those used by other utilities, we feel assured that our results will be as meaningful as theirs.

From the above results and analysis, we conclude that:

a) the present method of establishing generation reserve is inadequate,
b) the reserve of the largest unit +5% or 15% of the load does not take into account the generation mix on our system.

We therefore recommend that:

a) the different reliability of various types of generation sources should be taken into account by adopting a LOLP criterion,

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Conclusions and Recommendations (Cont'd)

b) the LOLP index to be adopted depends upon the availability of capital. System Planning feels that .1 days/year is not realistic and would suggest .2 days/year as an optimum value to aim for,

c) the value of LOLP which is chosen will have to be decided by Management, depending upon the capital dollars available and the level of service the customers should receive.

SUMMARY

Loss-of-load probability (LOLP) studies are used to determine power system reliability and for planning generation capacity additions. An essential component of LOLP calculations is an accurate load shape model for the system being studied. A model for the Newfoundland and Labrador Hydro system is developed in this report.

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INTRODUCTION

In 1947 a new method of measuring power system reliability using probability mathematics was proposed by G. Calabrese. This method was more sensitive to system conditions than per cent reserve and other measures in use at the time. A number, known as the loss-of-load probability (LOLP), is obtained which represents the reliability of a system in days of capacity shortage per year. Since only a shortage of generation capacity is considered as a loss of load, the LOLP gives an indication of the need for more reserve. It is also referred to as a system's risk index.

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Loss-of-Load Probability Program

The Corporate Planning Department of Newfoundland and Labrador Hydro is developing a computer program for loss-of-load probability calculations. This program aids in maintenance schedule planning and in the selection of generation capacity additions as well as in the study of system reliability. The input data consists basically of the load model including forecasted peak loads for each year, a description of the original generation system and maintenance schedule, and proposed generation additions.

The first step in the program is to develop a capacity outage table from knowledge of the installed system capacity and the maintenance schedule planned for that capacity. The table consists of a list of generation capacity outages in steps of 10 MW and the probability of the existance of each in days per year. If a maintenance outage is scheduled or a new generating unit is added during the period of study, the table is revised.

Loss-of-load probabilities are now calculated for the twenty-six maintenance intervals into which each year is divided. The expected daily peak load is found using the load model which is derived later. Subtracting the daily peak from the available megawatts gives the reserve which is then rounded

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Loss-of-Load Probability Program (Cont'd)

to the nearest 10 MW and located in the capacity outage table. The corresponding value of outage probability is the loss-of-load probability for that day. The LOLP for an interval is found by adding the values for each day in the interval. The yearly LOLP is simply the total of all the interval values.

As indicated above the loss-of-load probability is directly related to the system load model. It is thus essential to obtain an accurate model if the results are to be meaningful. The model consists of a forecasted peak load for each year in the study period and an average annual load shape which is determined from historical records. The load shape for the Newfoundland and Labrador Hydro system is obtained in the following section.

Derivation of Load Shape

The data used to derive the load shape is taken from the system hourly readings recorded at Bay D'Espoir. The peak value of "Total Island Generation" for each day is utilized. This includes the power generated by Newfoundland and Labrador Hydro, Newfoundland Light and Power, Bowater Power Company and Price (Nfld.) Pulp and Paper Company. The values are given in the nearest whole megawatt.

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Derivation of Load Shape (Cont'd)

The starting point for the one year interval is taken as April 1 to ensure that the annual winter peak, which must be planned for, occurs within the interval. This peak usually occurs between January and March. Values for February 29 and March 31 are excluded to allow the division of the year into twenty-six equal, fourteen day maintenance intervals. The time period included in these intervals are as follows:

Interval	Period	Interval	Period
1	Apr. 1 - Apr. 14	14	Sept. 30 - Oct. 13
2	Apr. 15 - Apr. 28	15	Oct. 14 - Oct. 27
3	Apr. 29 - May 12	16	Oct. 28 - Nov. 10
4	May 13 - May 26	17	Nov. 11 - Nov. 24
5	May 27 - June 9	18	Nov. 25 - Dec. 8
6	June 10 - June 23	19	Dec. 9 - Dec. 22
7	June 24 - July 7	20	Dec. 23 - Jan. 5
8	July 8 - July 21	21	Jan. 6 - Jan. 19
9	July 22 - Aug. 4	22	Jan. 20 - Feb. 2
10	Aug. 5 - Aug. 18	23	Feb. 3 - Feb. 16
11	Aug. 19 - Sept. 1	24	Feb. 17 - Mar. 2
12	Sept. 2 - Sept.15	25	Mar. 3 - Mar. 16
13	Sept.16 - Sept.29	26	Mar. 17 - Mar. 30

The available data covers a period of two years and eight months:

Year 1 - April 1, 1974 to March 30, 1975,

Year 2 - April 1, 1975 to March 30, 1976,

Year 3 - April 1, 1976 to November 30, 1976.

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Derivation of Load Shape (Cont'd)

This data is listed in Tables 1, 2 and 3 respectively. The model may be improved as more data becomes available.

The load shape consists of twenty-six interval peak loads expressed as a per unit of the annual peak and fourteen daily peak loads per interval expressed as a per unit of the respective interval peak. That is:

$$\text{Interval Peak (p.u.)} = \frac{\text{Interval Peak (MW)}}{\text{Annual Peak (MW)}} \quad \text{--- (1)}$$

$$\text{Daily Peak (p.u.)} = \frac{\text{Daily Peak (MW)}}{\text{Interval Peak (MW)}} \quad \text{--- (2)}$$

Using these values in conjunction with the forecasted annual peaks, the expected peak loads for any future day can be calculated as follows:

$$\begin{aligned}\text{Daily Peak (MW)} = {} & \text{Forecasted Annual Peak (MW)} \\ & \times \text{ Interval Peak (p.u.)} \\ & \times \text{ Daily Peak (p.u.)}\end{aligned}$$

It is noted that the interval peak is merely the highest daily peak in each fourteen day interval and the annual peak is the highest interval peak.

Per Unit Interval Peak Loads

Since the annual peak is required for this calculation only the complete years of data can be used. The annual

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Derivation of Load Shape (Cont'd)

Per Unit Interval Peak Loads (Cont'd)

peak for Year 1 is 723 MW, occurring in intervals 22 and 23, and that for Year 2 is 763 MW, occurring in intervals 24 and 25. The interval peaks for both years are listed in Table 4. Using equation 1 the per unit interval peaks are calculated (see Table 4) and plotted in Graph 1.

As can be seen from the graph, there is not a close correlation between the two years. This is assumed to be mainly due to the unpredictable operation of an industrial customer. The adjusted values of per unit interval peaks with this customer excluded show a closer correlation. The values are listed in Table 5 and plotted in Graph 2.

It was decided that an overall average of the adjusted and original values would be used. However, from Table 5 it is seen that the one per unit value is lost in this averaging. The values are normalized by adding 0.0202 to each. The twenty-six normalized per unit peak loads which will be used for LOLP calculations are listed in Table 5 and plotted in Graph 3.

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Derivation of Load Shape (Cont'd)

Per Unit Daily Peak Loads

For this calculation each of the daily peaks in Tables 1, 2 and 3 is divided by its respective interval peak (equation 2). The values for each interval are arranged in decreasing order for comparison and averaging of corresponding intervals (see Tables 6, 7 and 8). The fact that the days are not in order of occurrence within the interval is not important since only the total LOLP for the interval is recorded. It can be seen that except for intervals 3, 10, 11 and 12 the values compare very well. The differences in these intervals are mainly due to several unusually high or low readings.

The set of per unit daily peak loads to be used for calculating loss-of-load probabilities is obtained by averaging the values for the three years. The results are recorded in Table 9 and plotted in Graph 5.

References

(1) Generation Reserve Planning, presented by General Electric, Electric Utility Engineering Seminars, 1970

(2) S.P. Chu, Effective Load Carrying Capability User's Manual, August, 1975

Interval	DAILY PEAK LOADS (MW)													
1	474	565	558	491	552	512	530	538	527	559	527	518	489	473
2	485	521	563	553	592	600	554	583	587	574	582	610	583	528
3	582	568	575	597	608	582	589	540	529	565	571	574	560	523
4	548	529	536	530	526	520	513	562	573	595	566	569	533	536
5	543	590	577	585	585	540	542	548	535	513	521	594	568	514
6	540	449	488	497	532	496	501	499	447	452	447	446	427	418
7	456	440	500	539	549	526	513	430	452	532	514	565	563	523
8	531	548	573	536	479	477	433	447	454	435	462	458	464	453
9	476	467	438	412	422	385	373	411	408	419	390	404	369	388
10	389	389	380	416	411	370	382	420	392	368	401	415	393	384
11	402	381	394	458	436	424	403	432	436	410	416	466	392	392
12	274	338	417	438	461	441	461	481	499	521	550	482	433	428
13	512	520	527	496	475	472	464	473	449	469	495	486	446	465
14	493	499	502	583	552	560	562	584	503	561	579	592	531	495
15	538	505	525	569	541	530	516	571	559	546	582	584	553	580
16	684	601	603	649	614	638	604	604	644	614	647	642	638	625
17	633	640	611	647	588	600	578	650	665	683	655	668	651	561
18	570	581	539	549	613	542	597	650	606	648	641	627	646	558
19	618	510	579	620	676	624	676	703	643	599	641	597	647	636
20	679	586	452	584	634	622	598	646	559	489	606	612	588	547
21	621	569	602	613	589	599	572	639	635	652	664	645	687	631
22	666	707	668	668	697	701	668	680	704	720	710	723	675	651
23	669	707	720	675	680	657	638	710	723	695	660	676	666	655
24	676	653	619	603	633	693	650	697	640	609	628	636	631	641
25	639	630	615	625	629	655	558	668	604	634	602	611	572	596
26	583	560	521	507	544	547	529	639	607	610	578	538	493	526

TABLE 1 - DAILY PEAK LOADS - YEAR 1 (APRIL 1, 1974 TO MARCH 30, 1975)

Interval	DAILY PEAK LOADS (MW)													
1	490	508	525	543	520	469	501	507	484	462	492	495	510	588
2	581	556	578	554	539	562	621	579	584	557	570	577	499	532
3	527	544	579	598	493	494	501	518	490	484	494	476	446	515
4	427	443	469	454	498	535	461	491	433	431	413	438	454	479
5	532	446	470	466	448	425	449	410	384	420	449	424	430	445
6	457	443	413	409	434	375	378	370	386	397	382	358	353	376
7	368	362	355	329	313	307	282	361	368	378	349	302	288	348
8	347	337	331	341	310	303	361	374	376	400	380	369	371	373
9	388	404	409	420	400	318	355	562	346	351	347	337	352	361
10	329	314	316	327	304	285	336	339	345	339	354	349	389	425
11	428	420	441	425	440	443	442	438	437	435	448	419	430	291
12	435	454	467	469	429	441	479	452	438	469	474	440	436	484
13	461	457	500	506	457	451	487	500	591	505	468	482	495	512
14	504	493	486	507	528	540	532	512	574	612	574	513	482	487
15	468	533	517	511	479	520	509	530	512	531	539	508	504	522
16	564	569	593	615	631	573	612	572	608	649	606	558	515	640
17	614	597	568	542	527	505	594	564	609	628	613	533	529	593
18	572	587	566	633	581	474	548	502	499	536	552	513	474	543
19	555	574	516	519	573	551	556	520	589	594	575	580	556	600
20	494	536	561	557	587	503	621	625	568	499	578	610	578	654
21	634	609	573	600	616	609	664	640	668	634	678	618	516	621
22	634	590	583	581	620	568	598	563	544	570	572	600	580	604
23	639	601	671	659	654	612	617	611	652	675	653	687	734	733
24	719	714	727	725	741	689	678	721	686	712	698	709	692	763
25	695	684	662	638	671	708	719	714	702	763	729	682	652	711
26	744	755	722	666	677	610	678	666	617	620	655	596	600	635

TABLE 2 - DAILY PEAK LOADS - YEAR 2 (APRIL 1, 1975 - MARCH 30, 1976)

Interval	DAILY PEAK LOADS (MW)													
1	601	551	573	591	602	583	577	574	607	654	638	664	680	666
2	652	554	635	597	593	585	641	588	556	591	559	564	552	544
3	568	538	499	486	521	515	559	552	581	572	533	563	556	539
4	527	527	559	585	590	547	508	524	592	531	562	560	627	606
5	603	609	571	541	542	558	547	531	501	499	474	538	581	558
6	501	521	596	591	562	547	519	515	504	479	469	461	494	539
7	507	513	505	468	488	486	505	506	513	448	452	417	404	471
8	464	440	425	428	456	486	506	489	478	460	466	475	484	433
9	493	491	456	464	501	436	441	454	415	404	413	490	498	448
10	467	487	468	460	401	431	419	406	421	481	434	509	496	497
11	496	482	453	472	486	499	526	496	524	452	452	457	486	501
12	471	515	475	423	345	471	421	492	517	480	501	504	525	491
13	507	525	483	492	538	492	489	485	526	492	504	507	547	569
14	538	559	523	518	600	586	534	492	552	568	576	563	622	614
15	576	588	571	588	652	669	618	587	551	564	570	603	619	572
16	615	621	547	559	559	602	623	596	587	597	606	605	676	689
17	667	685	649	643	673	677	726	700	723	648	654	707	710	714
18	671	747	708	653	745	769								

TABLE 3 - DAILY PEAK LOADS - YEAR 3 (APRIL 1, 1976 - NOVEMBER 30, 1976)

Interval	Interval Peak (MW)		Interval Peak (p.u.)	
	Year 1	Year 2	Year 1	Year 2
1	565	588	0.7815	0.7706
2	610	621	0.8437	0.8139
3	608	598	0.8409	0.7837
4	595	535	0.8230	0.7012
5	594	470	0.8216	0.6160
6	540	457	0.7469	0.5990
7	565	378	0.7815	0.4954
8	573	400	0.7925	0.5242
9	476	420	0.6584	0.5505
10	420	425	0.5809	0.5570
11	466	448	0.6445	0.5872
12	550	484	0.7607	0.6343
13	527	512	0.7289	0.6710
14	592	612	0.8188	0.8021
15	584	539	0.8077	0.7064
16	684	649	0.9461	0.8506
17	683	628	0.9447	0.8231
18	650	633	0.8990	0.8296
19	703	600	0.9723	0.7864
20	679	654	0.9391	0.8571
21	687	678	0.9502	0.8886
22	723	634	1.0000	0.8309
23	723	734	1.0000	0.9620
24	697	763	0.9640	1.0000
25	668	763	0.9239	1.0000
26	639	755	0.8838	0.9895

TABLE 4 - INTERVAL PEAK LOADS

Interval	Adjusted Interval Peak (p.u.) Year 1	Adjusted Interval Peak (p.u.) Year 2	Overall Average (p.u.)	Normalized Average (p.u.)
1	0.6732	0.7593	0.7462	0.7664
2	0.7413	0.8148	0.8034	0.8236
3	0.7368	0.8490	0.8026	0.8228
4	0.7171	0.7507	0.7480	0.7682
5	0.7201	0.6667	0.7061	0.7263
6	0.6384	0.6496	0.6585	0.6787
7	0.6657	0.5370	0.6199	0.6401
8	0.6778	0.5684	0.6407	0.6609
9	0.6248	0.5969	0.6077	0.6279
10	0.5401	0.6040	0.5705	0.5907
11	0.6097	0.6368	0.6196	0.6398
12	0.6596	0.6880	0.6857	0.7059
13	0.6248	0.7279	0.6882	0.7084
14	0.7125	0.8704	0.8010	0.8212
15	0.7005	0.7664	0.7453	0.7655
16	0.8608	0.9231	0.8952	0.9154
17	0.8593	0.8932	0.8801	0.9003
18	0.8911	0.9003	0.8800	0.9002
19	0.9713	0.8533	0.8958	0.9160
20	0.9319	0.8604	0.8980	0.9182
21	0.9440	0.9017	0.9211	0.9413
22	0.9985	0.8447	0.9472	0.9674
23	1.0000	0.9573	0.9798	1.0000
24	0.9607	0.9943	0.9798	1.0000
25	0.9168	1.0000	0.9602	0.9804
26	0.8729	0.9843	0.9326	0.9528

TABLE 5 - ADJUSTED INTERVAL PEAK LOADS

Interval	DAILY PEAKS/INTERVAL PEAK													
1	1.0000	0.9894	0.9876	0.9770	0.9522	0.9381	0.9327	0.9327	0.9168	0.9062	0.8690	0.8655	0.8389	0.8372
2	1.0000	0.9836	0.9705	0.9623	0.9557	0.9557	0.9541	0.9410	0.9230	0.9080	0.9066	0.8656	0.8541	0.7951
3	1.0000	0.8919	0.9688	0.9572	0.9572	0.9457	0.9441	0.9391	0.9342	0.9293	0.9211	0.8882	0.8701	0.8602
4	1.0000	0.9630	0.9563	0.9513	0.9445	0.9210	0.9008	0.9008	0.8958	0.8908	0.8891	0.8840	0.8739	0.8622
5	1.0000	0.9933	0.9848	0.9848	0.9714	0.9562	0.9226	0.9141	0.9125	0.9091	0.9007	0.8771	0.8653	0.8636
6	1.0000	0.9852	0.9278	0.9241	0.9204	0.9185	0.9037	0.8370	0.8315	0.8278	0.8278	0.8259	0.7907	0.7741
7	1.0000	0.9965	0.9717	0.9540	0.9416	0.9310	0.9257	0.9097	0.9080	0.8850	0.8071	0.8000	0.7788	0.7611
8	1.0000	0.9564	0.9354	0.9267	0.8360	0.8325	0.8098	0.8063	0.7993	0.7923	0.7906	0.7593	0.7592	0.7557
9	1.0000	0.9811	0.9202	0.8866	0.8803	0.8655	0.8634	0.8571	0.8487	0.8193	0.8151	0.8088	0.7836	0.7752
10	1.0000	0.9905	0.9881	0.9786	0.9548	0.9357	0.9333	0.9262	0.9262	0.9143	0.9095	0.9048	0.8810	0.8762
11	1.0000	0.9828	0.9356	0.9356	0.9270	0.9099	0.8927	0.8798	0.8648	0.8627	0.8455	0.8412	0.8412	0.8176
12	1.0000	0.9473	0.9073	0.9764	0.8745	0.8382	0.8382	0.8018	0.7964	0.7873	0.7782	0.7582	0.6145	0.4982
13	1.0000	0.9867	0.9715	0.9412	0.9393	0.9222	0.9012	0.8975	0.8956	0.8899	0.8824	0.8805	0.8520	0.8463
14	1.0000	0.9865	0.9848	0.9780	0.9493	0.9476	0.9459	0.9324	0.8970	0.8497	0.8480	0.8429	0.8361	0.8328
15	1.0000	0.9966	0.9932	0.9777	0.9743	0.9572	0.9469	0.9349	0.9264	0.9212	0.9075	0.8990	0.8836	0.8647
16	1.0000	0.9488	0.9459	0.9415	0.9386	0.9327	0.9327	0.9137	0.8977	0.8830	0.8830	0.8830	0.8816	0.8787
17	1.0000	0.9780	0.9736	0.9590	0.9531	0.9517	0.9473	0.9370	0.9268	0.8946	0.8785	0.8609	0.8643	0.8241
18	1.0000	0.9969	0.9938	0.9877	0.9862	0.9646	0.9431	0.9323	0.9185	0.9138	0.8938	0.8769	0.8585	0.8292
19	1.0000	0.9616	0.9616	0.9203	0.9147	0.9047	0.8876	0.8819	0.8791	0.8734	0.8521	0.8492	0.8236	0.7255
20	1.0000	0.9514	0.9337	0.9161	0.9013	0.8925	0.8807	0.8660	0.8630	0.8601	0.8233	0.8056	0.7202	0.6657
21	1.0000	0.9665	0.9592	0.9389	0.9301	0.9243	0.9185	0.9039	0.8923	0.8763	0.8719	0.8574	0.8326	0.8282
22	1.0000	0.9959	0.9820	0.9779	0.9737	0.9696	0.9640	0.9405	0.9336	0.9239	0.9239	0.9239	0.9212	0.9004
23	1.0000	0.9959	0.9820	0.9770	0.9613	0.9405	0.9350	0.9336	0.9253	0.9212	0.9129	0.9087	0.9059	0.8824
24	1.0000	0.9943	0.9699	0.9369	0.9326	0.9197	0.9182	0.9125	0.9053	0.9010	0.8881	0.8737	0.8651	0.8651
25	1.0000	0.9805	0.9566	0.9491	0.9431	0.9416	0.9356	0.9207	0.9147	0.9042	0.9012	0.8922	0.8563	0.8353
26	1.0000	0.9546	0.9499	0.9124	0.9045	0.8764	0.8560	0.8513	0.8419	0.8279	0.8232	0.8153	0.7934	0.7715

TABLE 6 - PER UNIT DAILY PEAK LOADS - YEAR 1

Interval	DAILY PEAKS/INTERVAL PEAK													
1	1.0000	0.9235	0.8929	0.8844	0.8673	0.8639	0.8622	0.8520	0.8418	0.8367	0.8333	0.8231	0.7976	0.7857
2	1.0000	0.9404	0.9356	0.9324	0.9308	0.9291	0.9179	0.9050	0.8969	0.8953	0.8921	0.8680	0.8567	0.8035
3	1.0000	0.9682	0.9097	0.8813	0.8662	0.8612	0.8378	0.8261	0.8261	0.8244	0.8194	0.8094	0.7943	0.7458
4	1.0000	0.9308	0.9178	0.8953	0.8766	0.8617	0.8486	0.8486	0.8280	0.8187	0.8093	0.9056	0.7981	0.7720
5	1.0000	0.9915	0.9553	0.9553	0.9532	0.9489	0.9468	0.9191	0.9149	0.9043	0.9021	0.8936	0.8723	0.8170
6	1.0000	0.9694	0.9037	0.8950	0.8687	0.8446	0.8359	0.8271	0.8228	0.8206	0.8096	0.7834	0.7724	0.7502
7	1.0000	0.9735	0.9735	0.9577	0.9550	0.9392	0.9233	0.9206	0.8704	0.8280	0.8122	0.7989	0.7619	0.7460
8	1.0000	0.9500	0.9400	0.9350	0.9325	0.9275	0.9225	0.9025	0.8675	0.8525	0.8425	0.8275	0.7750	0.7575
9	1.0000	0.9738	0.9619	0.9524	0.9238	0.8619	0.8595	0.9452	0.8381	0.8357	0.8262	0.8238	0.8024	0.7571
10	1.0000	0.8329	0.8212	0.8118	0.7976	0.7976	0.7906	0.7741	0.7694	0.7435	0.7388	0.7153	0.6800	0.6706
11	1.0000	0.9888	0.9866	0.9844	0.9821	0.9777	0.9754	0.9710	0.9598	0.9554	0.9487	0.9375	0.9353	0.6496
12	1.0000	0.9897	0.9793	0.9690	0.9690	0.9649	0.9380	0.9337	0.9112	0.9091	0.9050	0.9008	0.8988	0.8864
13	1.0000	0.9883	0.9863	0.9766	0.9766	0.9668	0.9590	0.9512	0.9414	0.9141	0.9004	0.8926	0.8926	0.8809
14	1.0000	0.9380	0.9380	0.8823	0.8692	0.8627	0.8383	0.8366	0.8284	0.8236	0.8056	0.7958	0.7941	0.7875
15	1.0000	0.9889	0.9852	0.9833	0.9685	0.9647	0.9592	0.9499	0.9481	0.8443	0.9425	0.9351	0.8887	0.8683
16	1.0000	0.9861	0.9723	0.9476	0.9430	0.9368	0.9337	0.9137	0.8829	0.8814	0.8767	0.8690	0.8598	0.7935
17	1.0000	0.9777	0.9761	0.9697	0.9506	0.9459	0.9443	0.9045	0.8981	0.8631	0.8487	0.8424	0.8392	0.8041
18	1.0000	0.9273	0.9179	0.9036	0.8942	0.8720	0.8657	0.8578	0.8468	0.8104	0.7930	0.7883	0.7488	0.7488
19	1.0000	0.9900	0.9817	0.9667	0.9583	0.9567	0.9550	0.9267	0.9267	0.9250	0.9183	0.8667	0.8650	0.8600
20	1.0000	0.9557	0.9495	0.9327	0.8976	0.8838	0.8838	0.8685	0.8578	0.8517	0.8196	0.7691	0.7630	0.7554
21	1.0000	0.9853	0.9794	0.9440	0.9351	0.9351	0.9159	0.9115	0.9086	0.8982	0.8982	0.8850	0.8451	0.7611
22	1.0000	0.9779	0.9527	0.9464	0.9432	0.9306	0.9106	0.9164	0.9148	0.9022	0.8991	0.8959	0.8880	0.8580
23	1.0000	0.9986	0.9360	0.9305	0.9196	0.9142	0.8978	0.8910	0.8883	0.8706	0.8406	0.8337	0.8324	0.8188
24	1.0000	0.9712	0.9528	0.9502	0.9450	0.9423	0.9358	0.9332	0.9292	0.9148	0.9069	0.9030	0.8991	0.8886
25	1.0000	0.9554	0.9423	0.9358	0.9279	0.9201	0.9109	0.8965	0.8938	0.8794	0.8676	0.8545	0.8545	0.8362
26	1.0000	0.9854	0.9563	0.8980	0.8821	0.8821	0.8675	0.8411	0.8212	0.8172	0.8079	0.7947	0.7894	0.7642

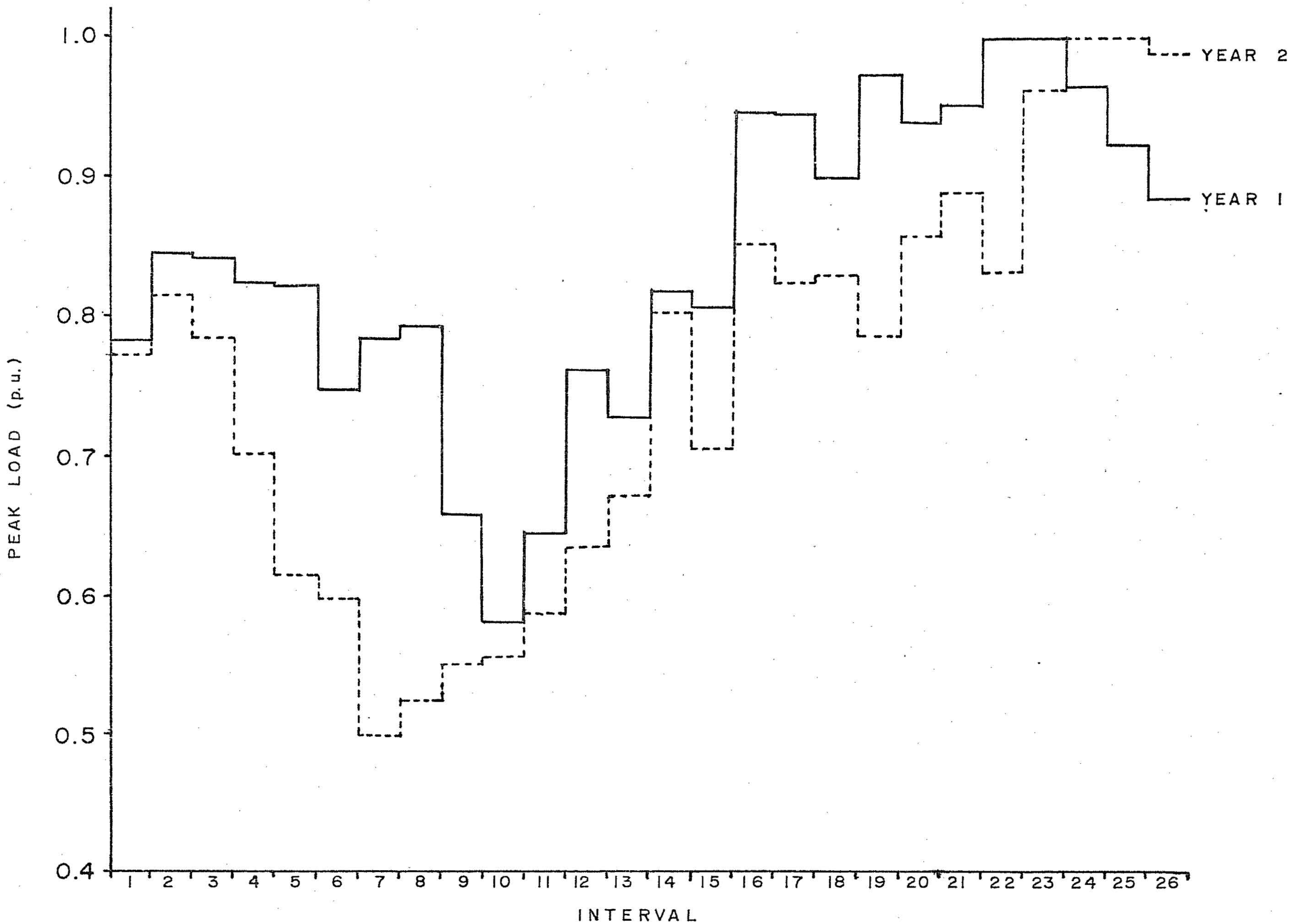
TABLE 7 - PER UNIT DAILY PEAK LOADS - YEAR 2

Interval	DAILY PEAKS/INTERVAL PEAK													
1	1.0000	0.9794	0.9765	0.9618	0.9382	0.8926	0.8853	0.8838	0.8691	0.8574	0.8485	0.8441	0.8426	0.8103
2	1.0000	0.9831	0.9739	0.9156	0.9095	0.9064	0.9018	0.8972	0.8650	0.8574	0.8528	0.8497	0.9466	0.9344
3	1.0000	0.9845	0.9776	0.9690	0.9621	0.9570	0.9505	0.9277	0.9260	0.9174	0.8967	0.8864	0.8589	0.8365
4	1.0000	0.9665	0.9442	0.9410	0.9330	0.8963	0.8931	0.8915	0.8724	0.8469	0.8405	0.8405	0.8357	0.8102
5	1.0000	0.9901	0.9540	0.9376	0.9163	0.9163	0.8982	0.8900	0.8883	0.8834	0.8719	0.8227	0.8194	0.7783
6	1.0000	0.9916	0.9430	0.9178	0.9044	0.8742	0.8708	0.8641	0.8456	0.8406	0.8289	0.8037	0.7869	0.7735
7	1.0000	1.0000	0.9883	0.9864	0.9844	0.9844	0.9513	0.9474	0.9181	0.9123	0.8811	0.8733	0.8129	0.7934
8	1.0000	0.9664	0.9605	0.9565	0.9447	0.9387	0.9209	0.9170	0.9091	0.9012	0.8696	0.8557	0.8459	0.8399
9	1.0000	0.9940	0.9840	0.9800	0.9780	0.9261	0.9102	0.9062	0.8942	0.8802	0.8703	0.8283	0.8244	0.8064
10	1.0000	0.9764	0.9745	0.9568	0.9450	0.9194	0.9194	0.9175	0.9037	0.8527	0.8468	0.8271	0.8232	0.7878
11	1.0000	0.9962	0.9525	0.9487	0.9430	0.9430	0.9240	0.9240	0.9163	0.8973	0.8688	0.8612	0.8593	0.8593
12	1.0000	0.9848	0.9810	0.9600	0.9543	0.9371	0.9352	0.9143	0.9048	0.8971	0.8971	0.8057	0.8019	0.6571
13	1.0000	0.9613	0.9455	0.9244	0.9227	0.8910	0.8910	0.8858	0.8647	0.8647	0.8647	0.8594	0.8524	0.8489
14	1.0000	0.9871	0.9646	0.9421	0.9260	0.9132	0.9051	0.8987	0.8875	0.8650	0.8585	0.8408	0.8328	0.7910
15	1.0000	0.9746	0.9253	0.9238	0.9013	0.8789	0.8789	0.8774	0.8610	0.8550	0.8535	0.8520	0.8430	0.8236
16	1.0000	0.9811	0.9042	0.9013	0.8926	0.8795	0.8781	0.8737	0.8665	0.8650	0.8520	0.8113	0.8113	0.7939
17	1.0000	0.9959	0.9835	0.9780	0.9738	0.9642	0.9435	0.9325	0.9270	0.9187	0.9008	0.8939	0.8926	0.8857

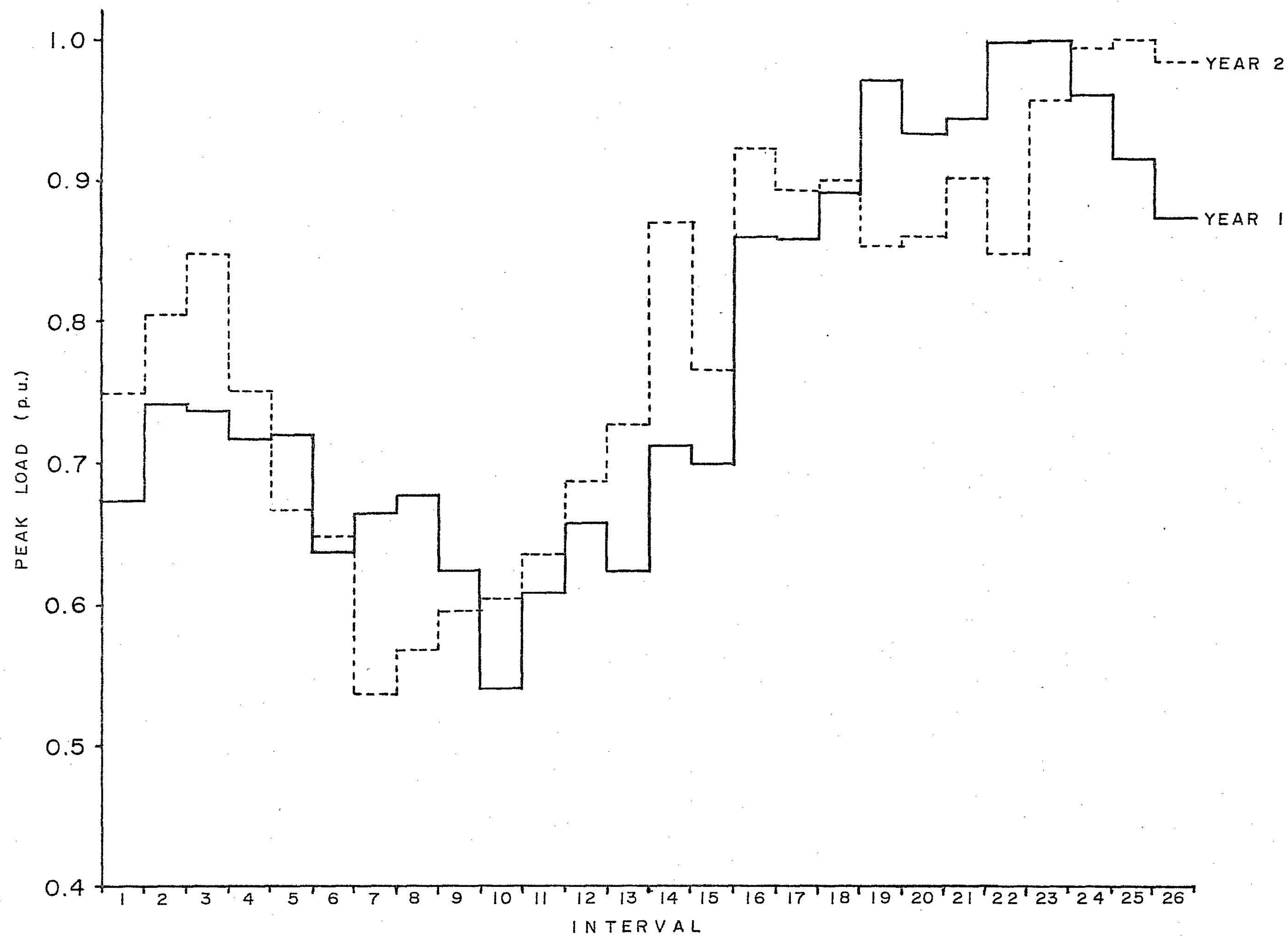
TABLE 8 - PER UNIT DAILY PEAK LOADS - YEAR 3

Interval	DAILY PEAKS/INTERVAL PEAK													
1	1.0000	0.9641	0.9523	0.9411	0.9192	0.8989	0.8934	0.8895	0.8759	0.8668	0.8503	0.8442	0.8264	0.8111
2	1.0000	0.9690	0.9600	0.9368	0.9320	0.9304	0.9246	0.9144	0.8950	0.8870	0.8838	0.8611	0.8525	0.8110
3	1.0000	0.9782	0.9520	0.9358	0.9285	0.9213	0.9108	0.8976	0.8954	0.8904	0.8791	0.8613	0.8411	0.8142
4	1.0000	0.9534	0.9394	0.9292	0.9180	0.8930	0.8808	0.8803	0.8654	0.8521	0.8463	0.8434	0.8359	0.8148
5	1.0000	0.9916	0.9647	0.9592	0.9470	0.9405	0.9225	0.9077	0.9052	0.8989	0.8916	0.8645	0.8523	0.8196
6	1.0000	0.9821	0.9248	0.9123	0.8978	0.8798	0.8701	0.8427	0.8333	0.8297	0.8221	0.8043	0.7833	0.7660
7	1.0000	0.9900	0.9778	0.9660	0.9603	0.9515	0.9334	0.9259	0.8988	0.8715	0.8335	0.8241	0.7845	0.7668
8	1.0000	0.9576	0.9453	0.9394	0.9044	0.8996	0.8844	0.8753	0.8586	0.8487	0.8342	0.8142	0.7934	0.7844
9	1.0000	0.9830	0.9554	0.9397	0.9274	0.8845	0.8777	0.8695	0.8603	0.8451	0.8372	0.8203	0.8035	0.7796
10	1.0000	0.9333	0.9279	0.9157	0.8891	0.8842	0.8811	0.8726	0.8664	0.8368	0.8317	0.8157	0.7947	0.7782
11	1.0000	0.9893	0.9582	0.9562	0.9507	0.9435	0.9307	0.9249	0.9136	0.9051	0.8877	0.8800	0.8786	0.7755
12	1.0000	0.9739	0.9559	0.9351	0.9326	0.9134	0.9038	0.8833	0.8708	0.8645	0.8601	0.8216	0.7717	0.6806
13	1.0000	0.9788	0.9678	0.9474	0.9462	0.9267	0.9171	0.9115	0.9006	0.8896	0.8825	0.8775	0.8657	0.8580
14	1.0000	0.9705	0.9625	0.9341	0.9148	0.9078	0.8964	0.8892	0.8710	0.8461	0.8374	0.8265	0.8210	0.8038
15	1.0000	0.9865	0.9679	0.9616	0.9480	0.9336	0.9283	0.9207	0.9118	0.9068	0.9012	0.8954	0.8718	0.8522
16	1.0000	0.9720	0.9408	0.9301	0.9247	0.9163	0.9148	0.9004	0.8824	0.8765	0.8706	0.8544	0.8509	0.8220
17	1.0000	0.9839	0.9777	0.9689	0.9592	0.9539	0.9450	0.9247	0.9173	0.8921	0.8760	0.8657	0.8594	0.8371
18	1.0000	0.9621	0.9559	0.9457	0.9402	0.9183	0.9044	0.8951	0.8827	0.8621	0.8434	0.8326	0.8037	0.7890
19	1.0000	0.9758	0.9717	0.9435	0.9365	0.9307	0.9213	0.9043	0.9029	0.8992	0.8852	0.8580	0.8443	0.7928
20	1.0000	0.9536	0.9416	0.9244	0.8995	0.8882	0.8823	0.8673	0.8604	0.8559	0.8215	0.7874	0.7416	0.7106
21	1.0000	0.9759	0.9693	0.9415	0.9326	0.9297	0.9172	0.9077	0.9005	0.8873	0.8851	0.8712	0.8389	0.7947
22	1.0000	0.9869	0.9674	0.9622	0.9568	0.9501	0.9418	0.9285	0.9242	0.9131	0.9115	0.9099	0.9046	0.8792
23	1.0000	0.9973	0.9590	0.9542	0.9405	0.9273	0.9164	0.9123	0.9068	0.8959	0.8768	0.8712	0.8692	0.8506
24	1.0000	0.9828	0.9614	0.9466	0.9388	0.9310	0.9270	0.9229	0.9173	0.9079	0.8975	0.8884	0.8821	0.8769
25	1.0000	0.9680	0.9495	0.9425	0.9355	0.9309	0.9233	0.9086	0.9043	0.8918	0.8844	0.8734	0.8554	0.8358
26	1.0000	0.9700	0.9531	0.9052	0.8933	0.8793	0.8618	0.8462	0.8316	0.8226	0.8156	0.8050	0.7914	0.7679

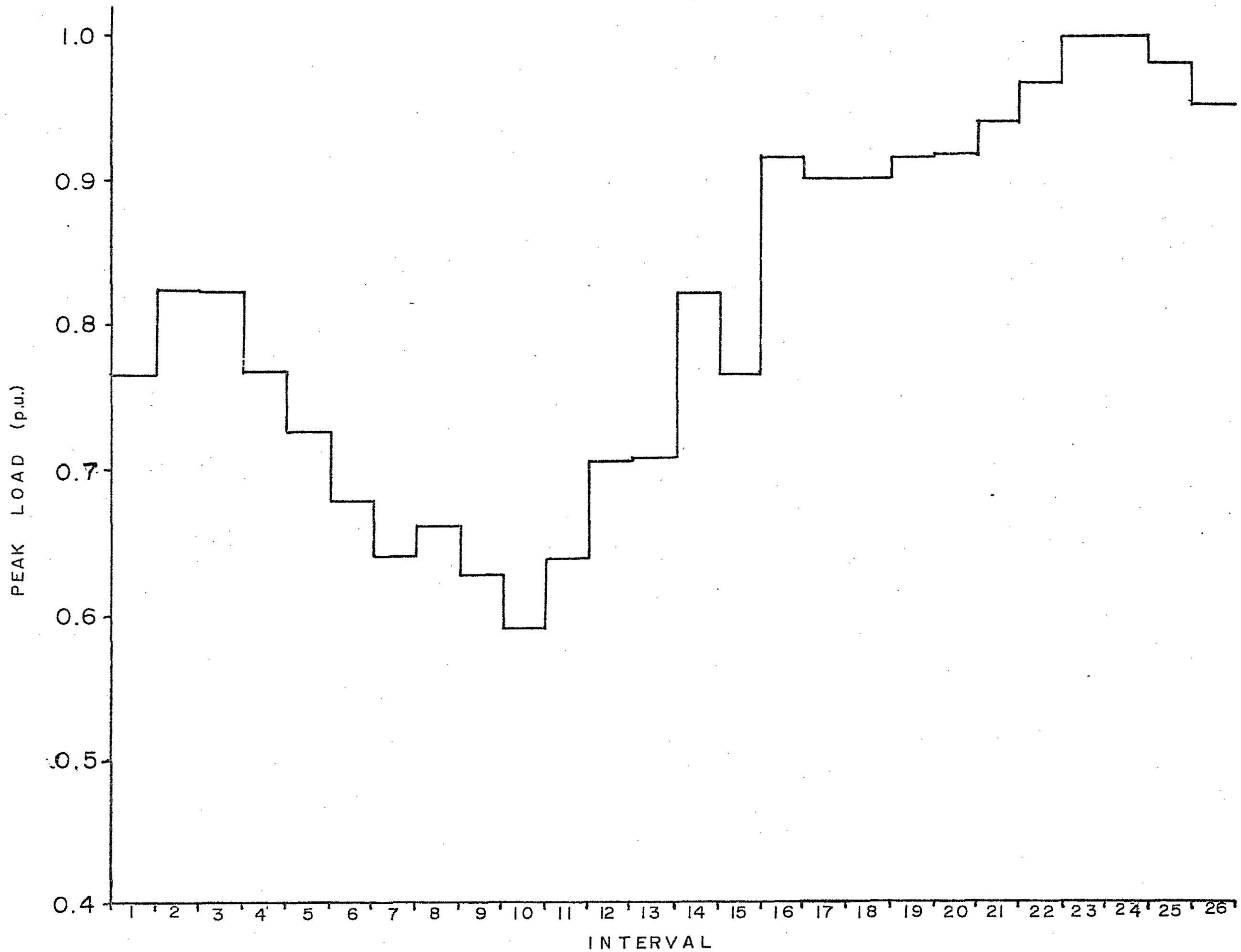
TABLE 9 - PER UNIT DAILY PEAK LOADS - AVERAGE



GRAPH 1 - Per Unit Interval Peak Loads



GRAPH 2 - Adjusted Per Unit Interval Peak Loads



GRAPH 3 - Normalized Per Unit Interval Peak Loads

GRAPH 4 - Per Unit Daily Peak Loads

(i) Intervals 1 to 7

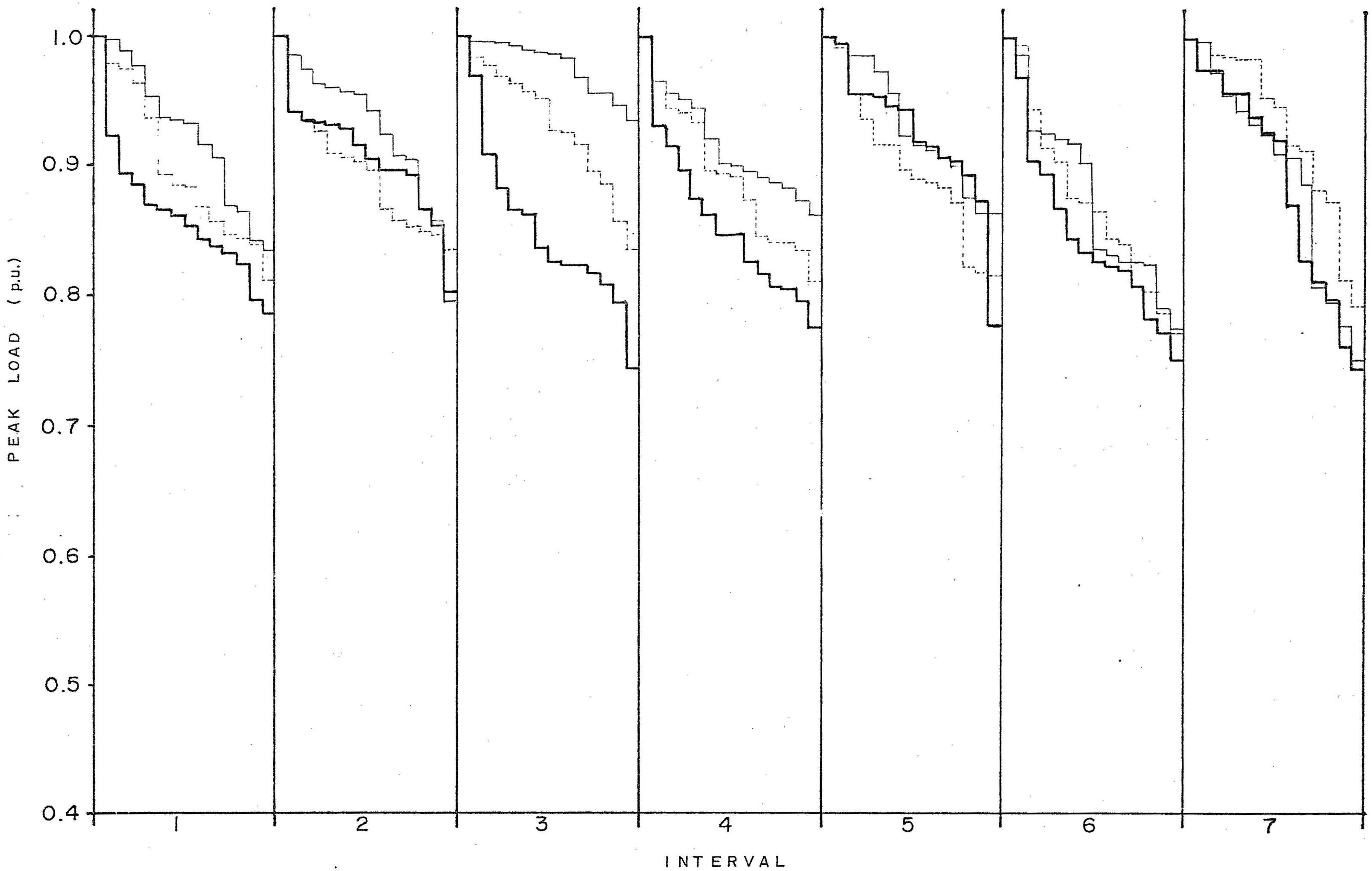
(ii) Intervals 8 to 14

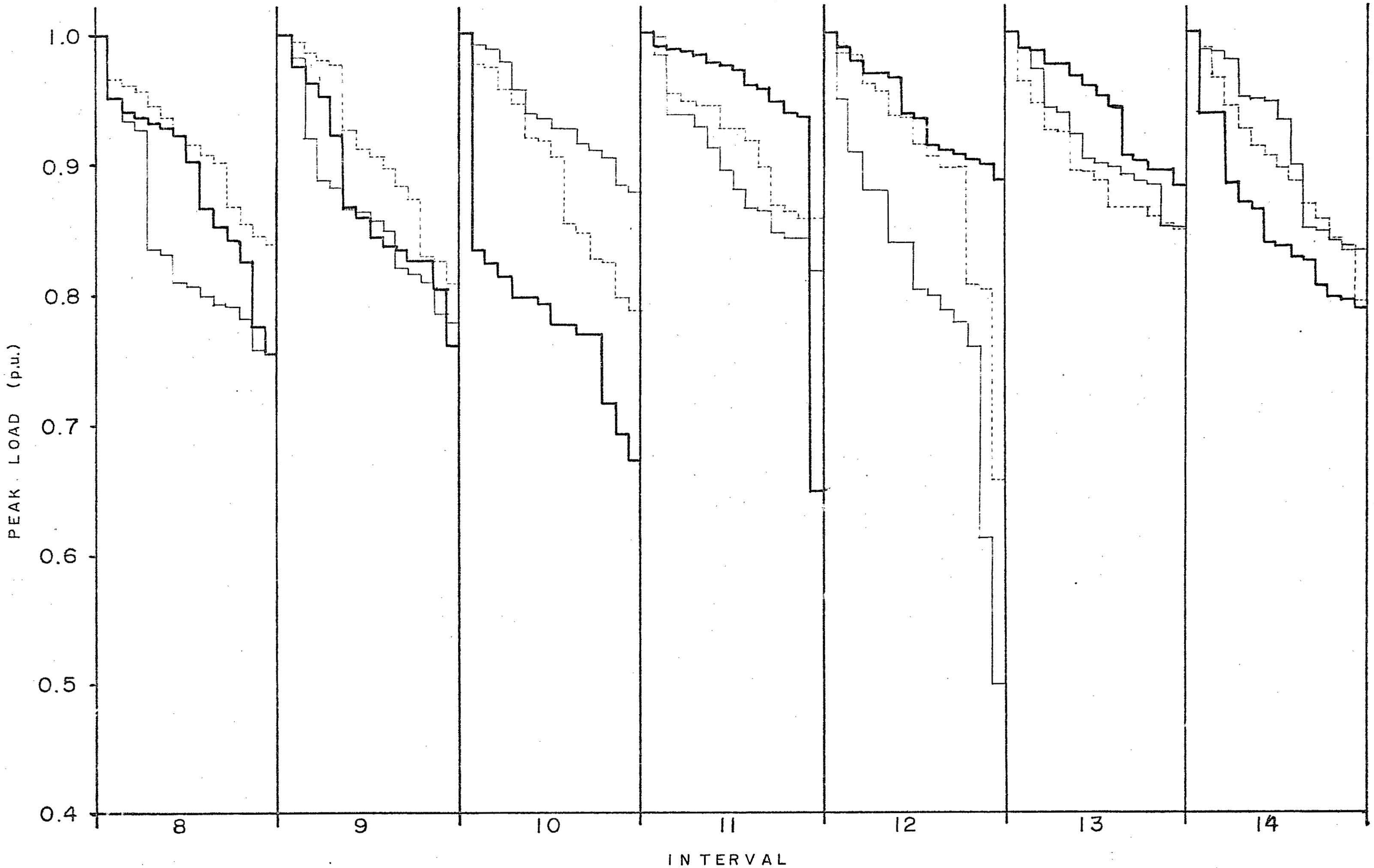
(iii) Intervals 15 to 21

(iv) Intervals 22 to 26

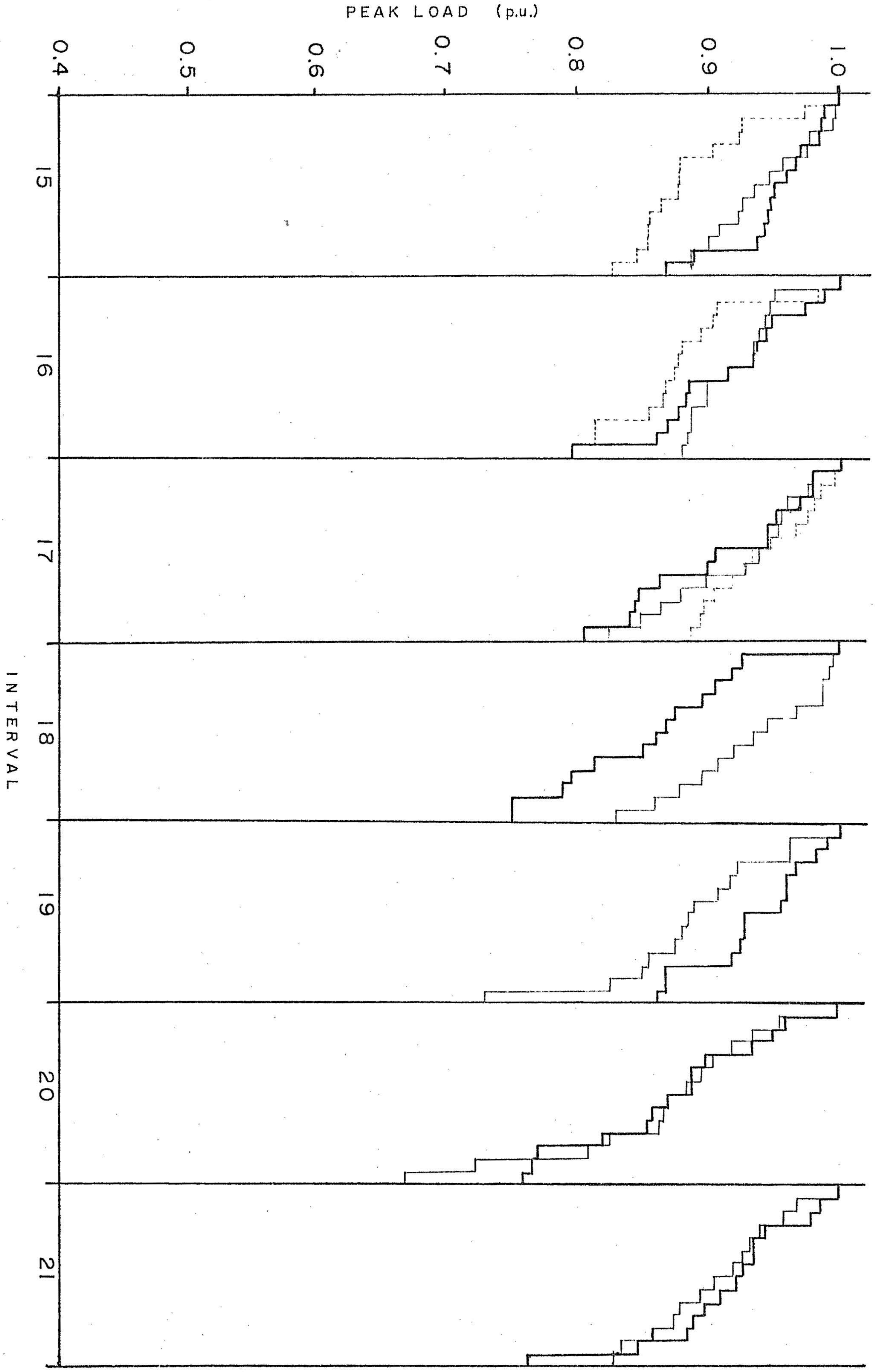
NOTE :

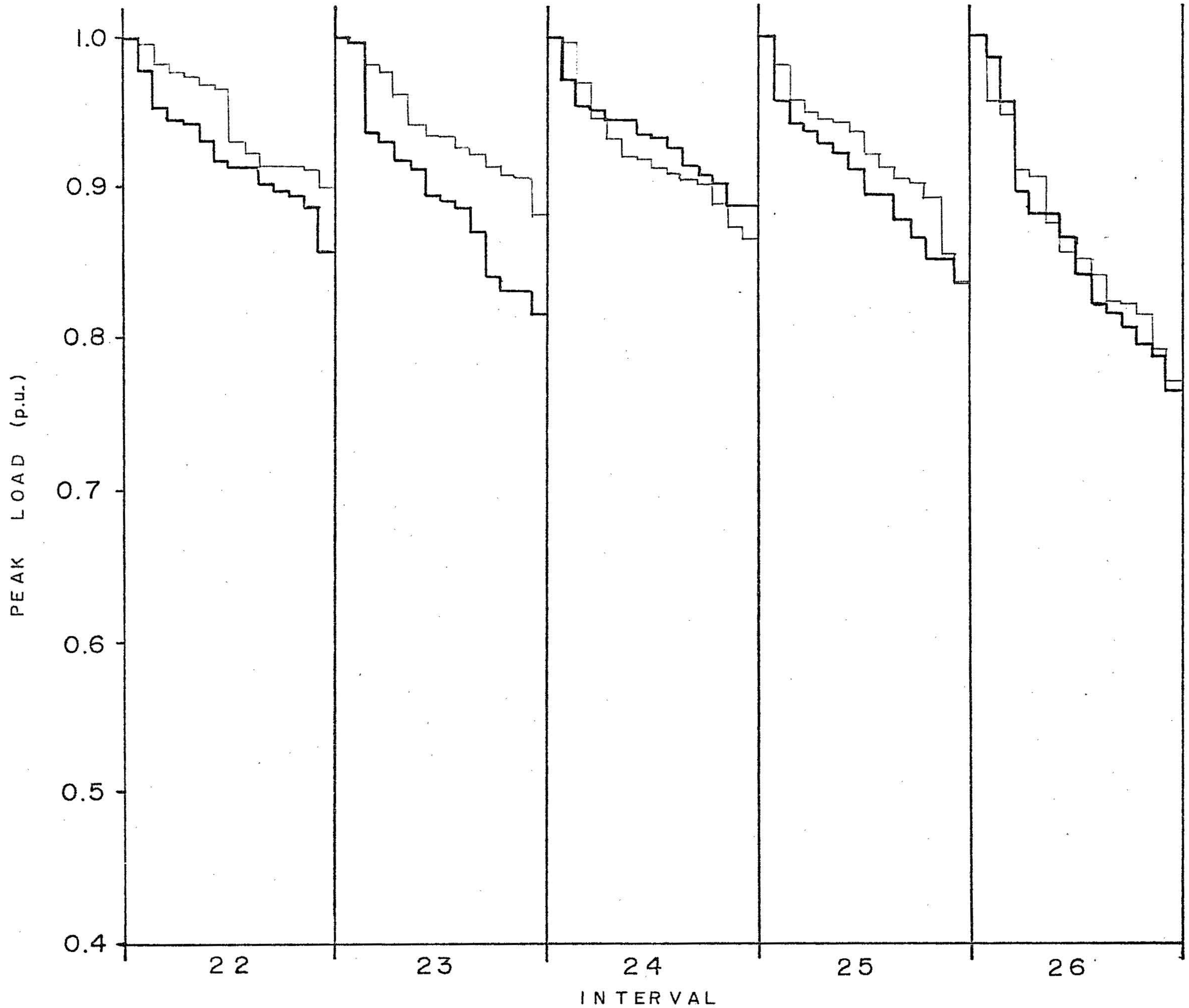
——— (thick)	YEAR 1
———	YEAR 2
---------	YEAR 3


PEAK LOAD (p.u.)
1.0
0.9
0.8
0.7
0.6
0.5
0.4
1
2
3
4
5
6
7
INTERVAL



(i)


PEAK LOAD (p.u.)
0.4
0.5
0.6
0.7
0.8
0.9
1.0
15
16
17
18
19
20
21
INTERVAL
(ii)



(iv)

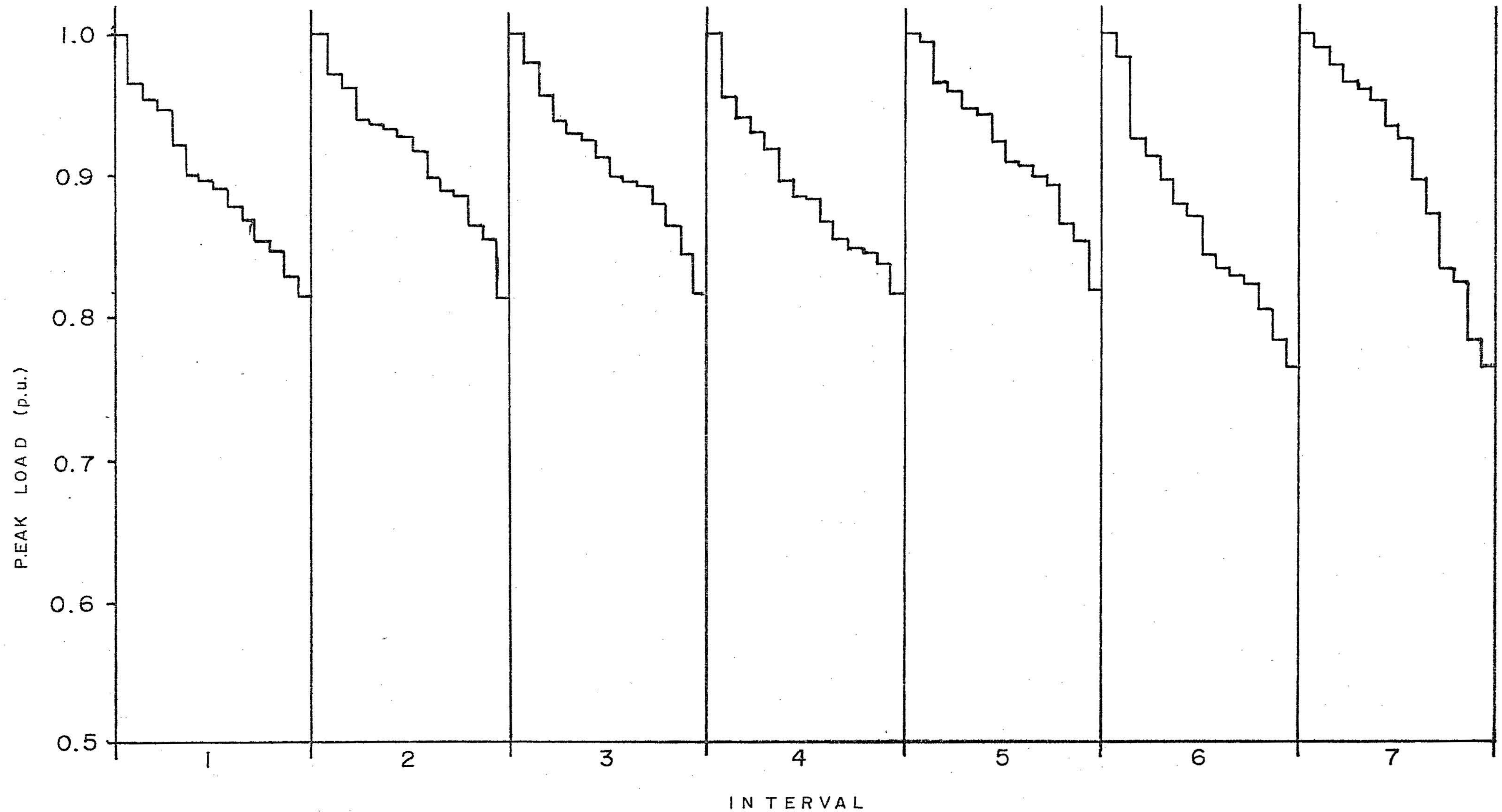
GRAPH 5 - Average Per Unit Daily Peak Loads

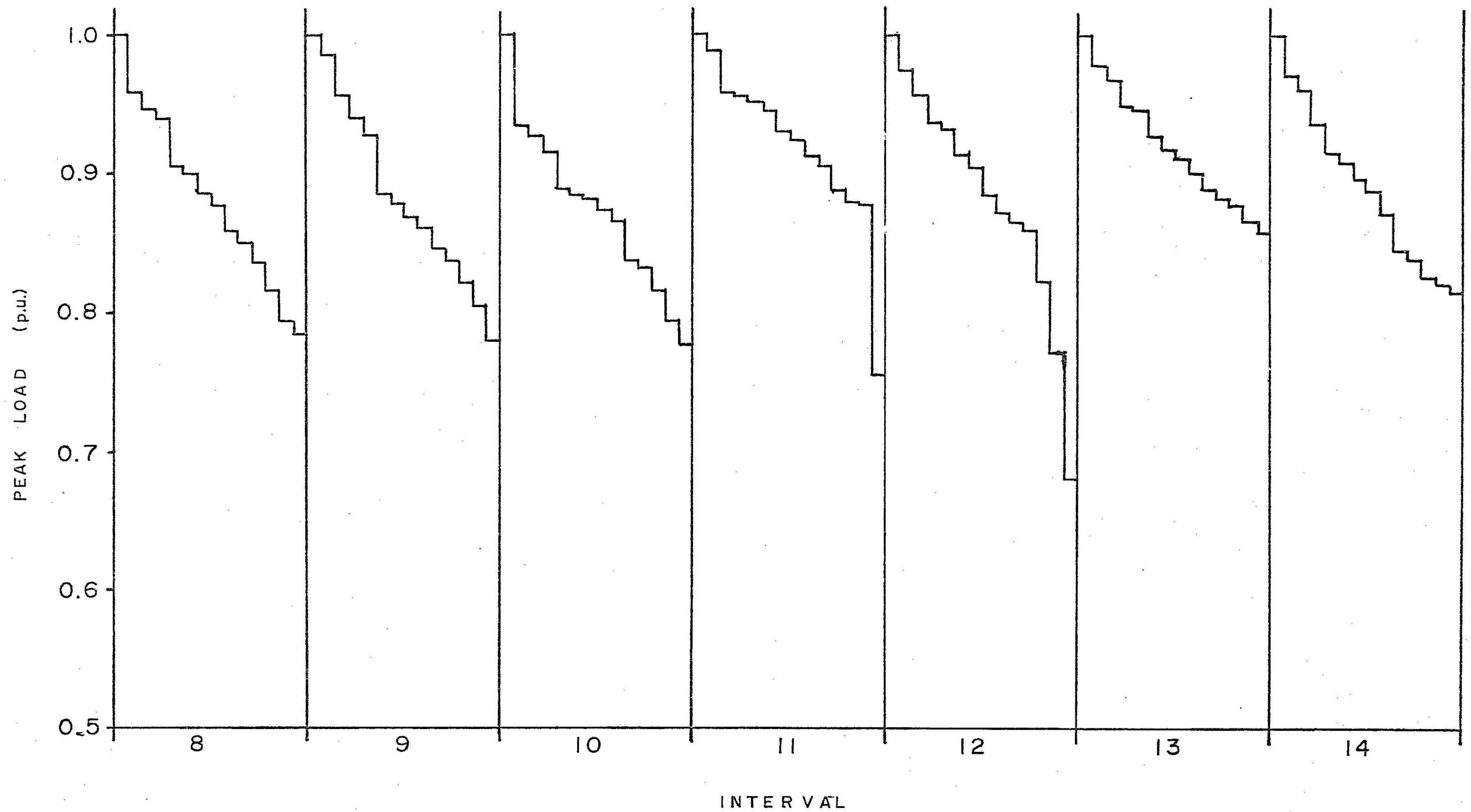
(i) Intervals 1 to 7

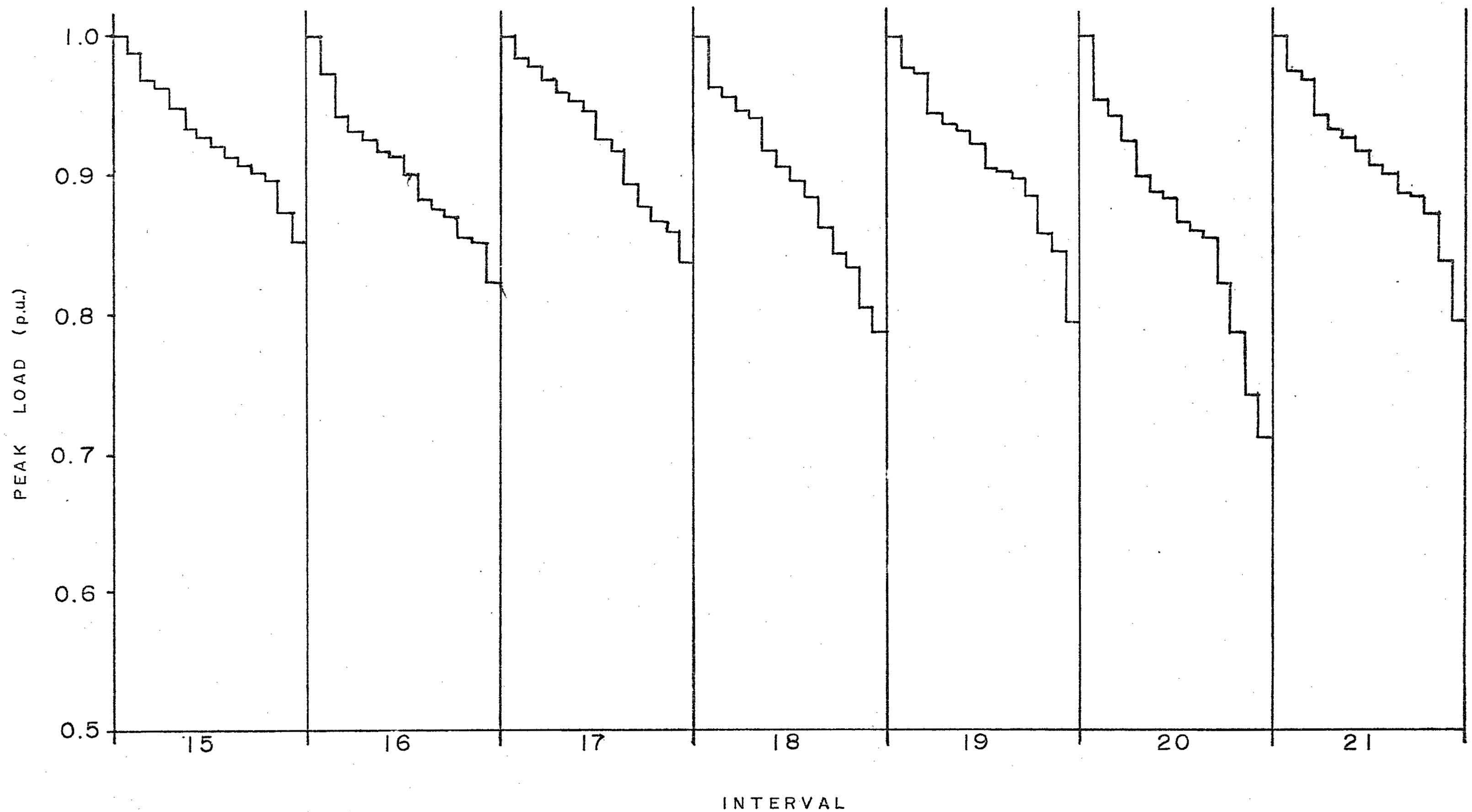
(ii) Intervals 8 to 14

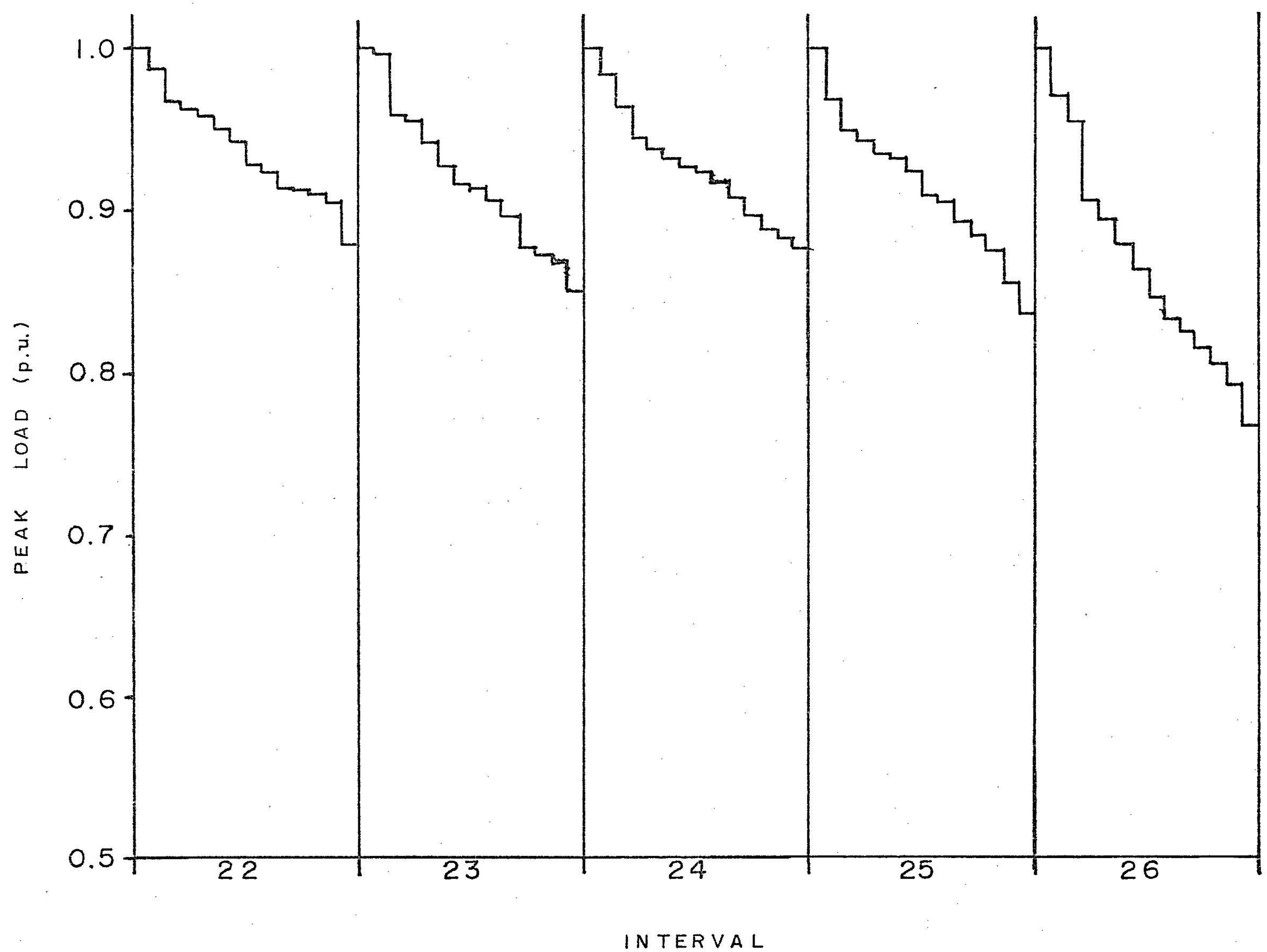
(iii) Intervals 15 to 21

(iv) Intervals 22 to 26


1.0
0.9
0.8
0.7
0.6
0.5
PEAK LOAD (p.u.)
1
2
3
4
5
6
7
INTERVAL


1.0
0.9
0.8
0.7
0.6
0.5
PEAK LOAD (p.u.)
8
9
10
11
12
13
14
INTERVAL


1.0
0.9
0.8
0.7
0.6
0.5
PEAK LOAD (p.u.)
15
16
17
18
19
20
21
INTERVAL


1.0
0.9
0.8
0.7
0.6
0.5
PEAK LOAD (p.u.)
22
23
24
25
26
INTERVAL

APPENDIX B

The detailed calculation as to how the capacity outage table is set up will now be shown.

As given in the text, the original system and the probability formula* are as follows:

Rating MW	Forced Outage Rate
100	.01
150	.02
200	.03

New entry at X MW = (1 - F.O.R.) • (Old entry at X MW)
+ (F.O.R.) • (Old entry at X-C MW)

Step 1 - A capacity outage table is set up for a zero (0) MW system and the probabilities are initialized as follows:

Outage* MW	Probability of Outage or Greater
0	1.0
50	0.0
100	0.0
150	0.0
200	0.0
250	0.0
300	0.0
350	0.0
400	0.0
450	0.0
500	0.0

*The difference between entries under this heading is called the step size. This step size should be chosen so that the unit sizes, which must be expressed as some even multiple of this step size, are as close to their rated capacity as possible.

... /2

Step 2 - To the initial capacity outage table we now add the first 100 MW unit. Entries into the new table are found by solving the above equation.

Outage MW	0 MW System Probability of Outage or Greater (Old)	100 MW System* Probability of Outage or Greater (New)
0	1.0	1.00
50	0.0	.01
100	0.0	.01
150	0.0	0.0
200	0.0	0.0
250	0.0	0.0
300	0.0	0.0
350	0.0	0.0
400	0.0	0.0
450	0.0	0.0
500	0.0	0.0

* The first three entries will now be calculated:

New entry at 0 MW = (1-F.O.R.) . (Old entry at 0 MW)
+ (F.O.R.) . (Old entry at - 100 MW[+])
.99 + .01
= (1 - .01) . (1.0) + (.01) . (1.0)
= 1.0

[+] X-C = 0 - 100 = -100 whenever this value is a negative or zero then the probability is entered as 1.0

New entry at 50 MW = (1 - F.O.R.) . (Old entry at 50 MW)
+ (F.O.R.) . (Old entry at -50 MW)
= (1.01 - .01) . (0.0) + (.01) . (1.0)
= .01

New entry at 100 MW = (1-F.O.R.) . (Old entry at 100 MW)
+ (F.O.R.) . (Old entry at 0 MW)
= (1.0 - .01) . (0.0) + (.01) . (1.0)
= .01

The above procedure is continued until the entire outage table is completed. Subsequent units are added in a similar manner until all the units on the system have been included.

Outage MW	0 MW System	100 MW System Unit = 100 MW F.O.R. = .01	250 MW System Unit = 150 MW F.O.R. = .02	450 MW System+ Unit = 200 MW F.O.R. = .03
0	1.0	1.00	1.00	1.00
50	0.0	.01	.0298	.058906
100	0.0	.01	.0298	.058906
150	0.0	0.0	.02	.04940
200	0.0	0.0	.0002	.030194
250	0.0	0.0	.0002	.001088
300	0.0	0.0	0.0	.000894
350	0.0	0.0	0.0	.0006
400	0.0	0.0	0.0	.000006
450	0.0	0.0	0.0	.000006
500	0.0	0.0	0.0	0.0

+ This capacity outage table now represents the outage nature of the system in a probabilistic manner.

The following table illustrates the method of calculating the daily LOLPs.

Interval 1 Peak = .74 x 400 = 296 MW

Day	Peak MW	Peak Rounded Upwards to Nearest Step Size	Available MWs	Reserve	Daily LOLP
1	1.0 x 296 = 296	300	450	150	.049400
2	.96 x 296 = 284	300	450	150	.049400
3	.93 x 296 = 275	300	450	150	.049400
4	.90 x 296 = 266	300	450	150	.049900
5	.84 x 296 = 249	250	450	200	.030194
6	.80 x 296 = 237	250	450	200	.030194
7	.78 x 296 = 231	250	450	200	.030194
8	.76 x 296 = 225	250	450	200	.030194
9	.72 x 296 = 213	250	450	200	.030194
10	.70 x 296 = 207	250	450	200	.030194
11	.67 x 296 = 198	200	450	250	.001088
12	.62 x 296 = 184	200	450	250	.001088
13	.58 x 296 = 172	200	450	250	.001088
14	.50 x 296 = 148	150	450	300	.000894

Figure 1 of this appendix represents graphically the above procedure. The interval LOLP is now equal to the sum of the daily LOLPs.

LOLP (interval 1) = .382922 days/interval

It is necessary to remove a unit from service in interval 2. In order to calculate the proper LOLP for this interval it is necessary to develop a revised capacity outage table. This is done by using the existing outage table and the following formula to arrive at a new outage table which describes the revised system.

Revised entry at <u>X</u> MW = ((existing entry at X MW) - (F.O.R.) · (revised entry at X-C MW))/(1 - F.O.R.)

Outage MW	450 MW System Probability of Outage or Greater	350 MW System* Removal of 100 MW for Maintenance F.O.R. = .01
0	1.000000	1.000000
50	.058906	.049400
100	.058906	.049400
150	.049400	.049400
200	.030194	.030000
250	.001088	.000600
300	.000894	.000600
350	.000600	.000600
400	.000006	0.0
450	.000006	0.0
500	0.0	0.0

* The first two entries will now be calculated.

Revised entry at 0 MW = $\frac{((\text{Existing entry at } 0 \text{ MW}) - (\text{F.O.R.}) \cdot (\text{Revised entry at } -100 \text{ MW}))}{(1 - \text{F.O.R.})}$

$= \frac{1.00 - (.01)\ (1.0)}{(1.0 - .01)}$

$= 1.00$ Days/Day

Revised entry at 50 MW = $\frac{((\text{Existing entry at } 50 \text{ MW}) - (\text{F.O.R.}) \cdot (\text{Revised entry at } -100 \text{ MW}))}{(1 - \text{F.O.R.})}$

$= \frac{(.058906) - (.01)\ (1.0)}{(1 - .01)}$

$= .049400$ Days/Day

... /6

The remainder of the table is filled in the same manner.

This table now becomes representative of the system in this interval.

The table below gives the daily LOLPs which can be calculated for interval 2.

Interval 2 Peak = .62 x 400 = 248 MW

Day	Peak MW	Peak Rounded Upwards to Nearest Step Size	Available MWs	Reserve	Daily LOLP
1	1.0 x 248 = 248	250	450-100 = 350	100	.049400
2	.96 x 248 = 238	250	350	100	.049400
3	.94 x 248 = 233	250	350	100	.049400
4	.90 x 248 - 223	250	350	100	.049400
5	.80 x 248 = 198	200	350	150	.049400
6	.76 x 248 = 188	200	350	150	.049400
7	.72 x 248 = 179	200	350	150	.049400
8	.68 x 248 = 169	200	350	150	.049400
9	.64 x 248 = 159	200	350	150	.049400
10	.60 x 248 = 149	150	350	200	.030000
11	.57 x 248 = 141	150	350	200	.030000
12	.53 x 248 = 131	150	350	200	.030000
13	.48 x 248 = 119	150	350	200	.030000
14	.40 x 248 = 99	100	350	250	.000600

∴ LOLP interval 2 = .565200 Days/Interval.

46 0702

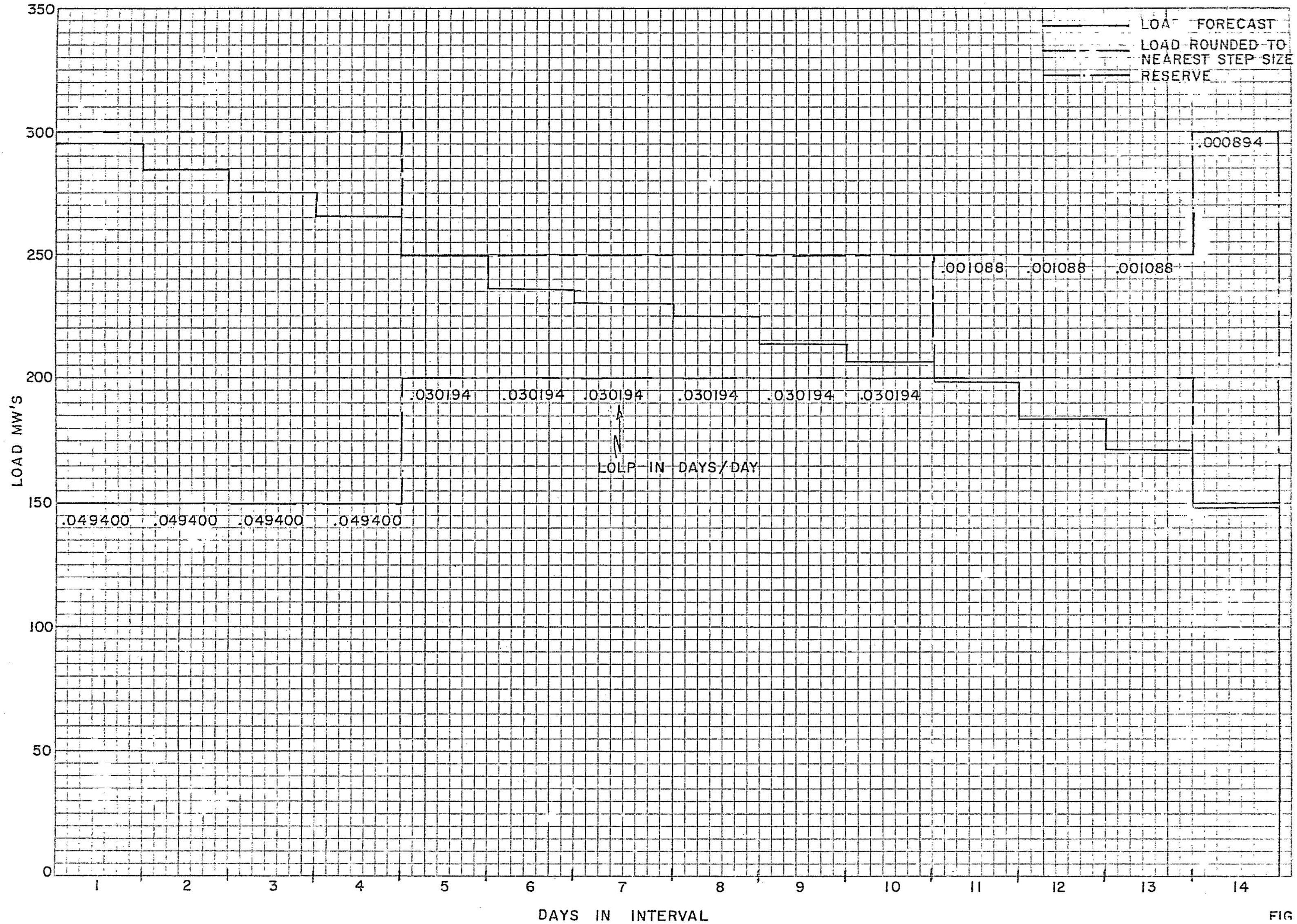

LOAD FORECAST
LOAD ROUNDED TO NEAREST STEP SIZE
RESERVE
LOAD MW'S
350
300
250
200
150
100
50
0
.000894
.001088
.001088
.001088
.030194
.030194
.030194
.030194
.030194
.030194
LOLP IN DAYS/DAY
.049400
.049400
.049400
.049400
1
2
3
4
5
6
7
8
9
10
11
12
13
14
DAYS IN INTERVAL

FIG. I

APPENDIX C

This appendix will give a detailed description of the Island generation.

1 - Existing generation
(Newfoundland and Labrador Hydro)

Description	Actual MW Rating	Adjusted MW Rating	Forced Outage Rate
Holyrood No. 1	142	140	.07
Holyrood No. 2	142	140	.07
Bay D'Espoir No. 1	71	70	.002
Bay D'Espoir No. 2	71	70	.002
Bay D'Espoir No. 3	71	70	.002
Bay D'Espoir No. 4	71	70	.002
Bay D'Espoir No. 5	71	70	.005
Bay D'Espoir No. 6	71	70	.006
Holyrood GT	13	10	.1500
Stephenville GT	50	50	.1500
Hardwoods GT	50	50	.1500
Total	823	810	

As noted in Appendix B, it is necessary to choose a particular step size to use in the LOLP calculations. The more accurate step size would of course be 1, however the accuracy gained by using such a small step size is offset by the increased time in computation. It was therefore decided that a reasonable step size would be chosen at 10 MW (i.e. this has been reflected in the adjusted MW rating above). The system as shown above, adjusted MW values and the F.O.R. was used as the Newfoundland and Labrador Hydro portion of the Island generation. The F.O.R. for the different plants were obtained as follows:

... /2

a) Holyrood - actual operating data was available but it was felt that due to the nature of operations at the Holyrood plant, this data did not represent a true picture. It was therefore decided to use representation data from C.E.A. statistics for units of the size which are found at Holyrood.

b) Bay D'Espoir - the values were obtained from actual operating data which was supplied by our operations people.

c) Gas Turbines - a value of F.O.R.s for gas turbines is not an easy number to obtain. Depending on operating considerations the value can vary widely. Based on our own considerations and the report entitled "Generation Planning Processes" by Ontario Hydro, it was decided to use 15%.

2) Newfoundland Light and Power Company:

Description	No. of Units	Actual MW Rating
South Side 1	1	10.00
South Side 2	1	20.00
Petty Harbour	2	1.60
	1	1.80
Pierre's Brook	1	3.20
Mobile	1	9.35
Tors Cove	2	2.00
	1	2.50
Rocky Pond	1	3.20
Horsechops	1	7.60

... /3

Description	No. of Units	Actual MW Rating
Cape Broyle	1	6.00
Topsail	1	1.00
Seal Cove	1	0.80
	1	2.40
Victoria	1	0.40
Heart's Content	1	2.40
New Chelsea	1	4.00
Pitmans Pond	1	0.85
Fall Pond	1	0.30
West Brook	1	0.70
Lawn	2	0.16
Lockston	1	1.60
	1	1.60
Port Union	1	.30
	1	.30
Rattling Brook	2	5.40
Sandy Brook	1	5.70
Lookout Brook	2	1.30
	1	2.40
Salt Pond GT	1	13.00
Greenhill GT	1	25.00

Due to the variation in the size of the units and the fact that a step size of 10 MWs had been chosen, it was decided that an equivalent would be obtained for the NewLight system, for all units excluding the South Side plant and the gas turbines. These latter units would be considered individually.

... /4

It was felt that the best criteria for equivalence in this case would be if two systems had similar capacity outage probability tables. The first step was then to establish the outage table which best described the existing system. A step size of 1 MW was chosen and the following F.O.R.s were applied:

Unit No.	Description	Rating MW	Outage Rate
1	Petty Harbour B1	2.00	.0172
2	Petty Harbour B2	2.00	.0172
3	Petty Harbour B3	2.00	.0172
4	Pierre's Brook	3.00	.0172
5	Mobile	9.00	.0128
6	Tors Cove 1	2.00	.0172
7	Tors Cove 2	2.00	.0172
8	Tors Cove 3	3.00	.0172
9	Rocky Pond	3.00	.0172
10	Horsechops	8.00	.0128
11	Cape Broyle	4.00	.0128
12	Topsail	1.00	.0172
13	Seal Cove 1	1.00	.0172
14	Seal Cove 2	2.00	.0172
15	Victoria	1.00	.0172
16	Heart's Content	2.00	.0172
17	New Chelse	4.00	.0172
18	Pitmans Pond	1.00	.0172
19	Fall Pond	1.00	.0172
20	West Brook	1.00	.0172
21	Lockston 1	2.00	.0172
22	Lockston 2	2.00	.0172
23	Rattling 1	5.00	.0128
24	Rattling 2	5.00	.0128
25	Sandy Brook	6.00	.0128
26	Lookout Brook 1	1.00	.0172
27	Lookout Brook 2	1.00	.0172
28	Lookout Brook 3	2.00	.0172

The F.O.R.s were obtained from C.E.A. statistics.

This system produced the following capacity outage table:

CAPACITY OUTAGE TABLE
80.0 MW CAPACITY
SYSTEM

Outage MW	Probability of Outage or Greater
0.0	1.000000
1.0	.36807621
2.0	.27960169
3.0	.16358936
4.0	.11473811
5.0	.08937162
6.0	.06409281
7.0	.04149587
8.0	.03469005
9.0	.02178257
10.0	.01034387
11.0	.00665205
12.0	.00372951
13.0	.00243652
14.0	.00162748
15.0	.00093397
16.0	.00052024
17.0	.00035565
18.0	.00013510
19.0	.00009477
20.0	.00005026
21.0	.00002705
22.0	.00001633
23.0	.00000907
24.0	.00000387
25.0	.00000210
26.0	.00000100

... /6

Outage MW	Probability of Outage or Greater
27.0	.00000050
28.0	.00000028
29.0	.00000012
30.0	.00000005
31.0	.00000002
80.0	0.0

As the step size has been chosen at 10 MW for the overall system, it was felt that an equivalent system should consist of 8 x 10 MW units with F.O.R.s necessary to give an equivalent system applied. This system was run for a number of F.O.R.s until the equivalent capacity outage table was similar to the original.

The equivalent system which was derived is as follows:

Unit No.	Description	Rating MW	Outage Rate
1	NewLight 1	10.00	.0013
2	NewLight 2	10.00	.0013
3	NewLight 3	10.00	.0013
4	NewLight 4	10.00	.0013
5	NewLight 5	10.00	.0013
6	NewLight 6	10.00	.0013
7	NewLight 7	10.00	.0013
8	NewLight 8	10.00	.0013

The capacity outage table is as follows:

... /7

Outage MW	Probability of Outage or Greater
0	1.00000000
10.0	.01035279
20.0	.00004707
30.0	.00000012

On comparison with the original NewLight system capacity outage table, it was felt that the equivalent system which had been developed was acceptable.

The South Side plant and the gas turbines were inputed as follows:

Description	Unit Size	F.O.R.
South Side 1	10.0	.07
South Side 2	20.0	.07
Salt Pond GT	10.0	.15
Greenhill GT	30.0	.15

The F.O.R.s were obtained in the same manner as described for the Holyrood thermal plant and gas turbine.

3. Price (Nfld.) Pulp and Paper

In order to obtain an equivalent system for Price, the same procedure as described for Newfoundland Light and Power was followed.

The original Price (Nfld.) system for which an equivalent was obtained is as follows:

... /8

No. of Units	Description	Rating MW
3	Grand Falls	1.50
1	Grand Falls	24.50
7	Bishop's Falls	2.00
2	Bishop's Falls	1.50
4	Grand Falls	4.00

The equivalent system obtained is:

No. of Units	Description	Rating MW	Outage Rate
1	Price 1	10.0	.0005
2	Price 2	10.0	.0005
3	Price 3	20.0	.0068
4*	Price 4	10.0	.0005
5*	Price 5	10.0	.0005

4. Bowater Nfld. Limited

Again the same procedure as before was used to determine an equivalent system for Bowaters.

No. of Units	Description	Rating MW	Outage Rate
1	Deer Lake 1	10.0	.0055
2	Deer Lake 2	10.0	.0055
3	Deer Lake 3	10.0	.0055
4	Deer Lake 4	10.0	.0055
5	Deer Lake 5	10.0	.0055
6	Deer Lake 6	10.0	.0055
7	Deer Lake 7	10.0	.0055
8	Watson Brook 1	10.0	.0055
9	Watson Brook 2	10.0	.0055
10	Bowater Power Ther.	10.0	.0055
11	Deer Lake 8	20.0	.0068
12	Deer Lake 9	20.0	.0068

* These two units represent the additional generation from Price (Nfld.) which will be in service in 1977.

... /9

The original Bowaters system is as follows:

No. of Units	Description	Rating MW
7	Deer Lake	11.30
2	Deer Lake	22.80
2	Watson's Brook	4.60
1	Bowater Thermal	6.60

The above equivalent systems have only one F.O.R. applied to each unit as it is felt that these units have reached the maturity levels.

Any units which were added subsequent to this were considered to have variable F.O.R.s for the first five years of service. Thereafter, they would maintain a constant F.O.R.

The values which were used for these F.O.R.s are as follows:

Year/ Type	1	2	3	4	5
Hydro 50 MW	.0178	.0089	.0089	.0089	.0089
100 - 150 MW	.0514	.0257	.0257	.0257	.0257
Thermal					
150 MW	.12	.10	.09	.08	.07
300 MW	.12	.10	.09	.08	.08

TABLE I

LOSS OF LOAD PROBABILITY

BASE CASE

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	15	1607	14	76 MW Hinds Lake 78 MW GT
1981	1449	19	1721	13	114 MW Cat Arm
1982	1568	23	1924	12	203 MW Upper Salmon and Upper Terra Nova
1983	1658	16	1924	12	
1984	1752	26	2209	10	285 MW Thermal
1985	1856	20	2234	11	25 MW GT
1986	1960	20	2343	15	109 MW GT
1987	2069	27	2628	14	285 MW Thermal
1988	2229	18	2628	14	
1989	2354	17	2757	18	129 MW GT
1990	2490	16	2900	22	143 MW GT

TABLE II

LOSS OF LOAD PROBABILITY

LOLP MAINTAINED

$\leq$1.0 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	17	1629	15	76 MW Hinds Lake 100 MW GT
1981	1449	20	1743	14	114 MW Cat Arm
1982	1568	24	1946	13	203 MW Upper Salmon and Upper Terra Nova
1983	1658	17	1946	13	
1984	1752	27	2231	11	285 MW Thermal
1985	1856	20	2231	11	
1986	1960	19	2331	15	100 MW GT
1987	2069	26	2616	13	285 MW Thermal
1988	2229	20	2666	15	50 MW GT
1989	2354	20	2816	19	150 MW GT
1990	2490	19	2966	24	150 MW GT

TABLE III

LOSS OF LOAD PROBABILITY

LOLP MAINTAINED

≤.75 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	20	1679	18	76 MW Hinds Lake 150 MW GT
1981	1449	24	1793	17	114 MW Cat Arm
1982	1568	27	1996	15	203 MW Upper Salmon and Upper Terra Nova
1983	1658	20	1996	15	
1984	1752	30	2281	13	285 MW Thermal
1985	1856	23	2281	13	
1986	1960	19	2331	15	50 MW GT
1987	2069	26	2616	13	285 MW Thermal
1988	2229	22	2716	16	100 MW GT
1989	2354	22	2866	21	150 MW GT
1990	2490	21	3016	25	150 MW GT

TABLE IV

LOSS OF LOAD PROBABILITY

LOLP MAINTAINED

$\leq$.50 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	20	1679	18	76 MW Hinds Lake 150 MW GT
1981	1449	24	1793	17	114 MW Cat Arm
1982	1568	27	1996	15	203 MW Upper Salmon and Upper Terra Nova
1983	1658	20	1996	15	
1984	1752	30	2281	13	285 MW Thermal
1985	1856	23	2281	13	
1986	1960	21	2381	17	100 MW GT
1987	2069	29	2666	15	285 MW Thermal
1988	2229	24	2766	18	100 MW GT
1989	2354	22	2866	21	100 MW GT
1990	2490	21	3016	25	150 MW GT

TABLE V

LOSS OF LOAD PROBABILITY

LOLP MAINTAINED

≤.40 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	24	1729	20	76 MW Hinds Lake 200 MW GT
1981	1449	27	1843	19	114 MW Cat Arm
1982	1568	30	2046	17	203 MW Upper Salmon and Upper Terra Nova
1983	1658	23	2046	17	
1984	1752	33	2331	15	285 MW Thermal
1985	1856	26	2331	15	
1986	1960	27	2381	17	50 MW GT
1987	2069	29	2666	15	285 MW Thermal
1988	2229	24	2766	18	100 MW GT
1989	2354	24	2916	22	150 MW GT
1990	2490	23	3066	26	150 MW GT

TABLE VI

LOSS OF LOAD PROBABILITY

LOLP MAINTAINED

≤.30 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	24	1729	20	76 MW Hinds Lake 200 MW GT
1981	1449	27	1843	19	114 MW Cat Arm
1982	1568	30	2046	17	203 MW Upper Salmon and Upper Terra Nova
1983	1658	23	2046	17	
1984	1752	33	2331	15	285 MW Thermal
1985	1856	26	2331	15	
1986	1960	24	2431	18	100 MW GT
1987	2069	31	2716	16	285 MW Thermal
1988	2229	26	2816	19	100 MW GT
1989	2354	26	2966	24	150 MW GT
1990	2490	25	3116	27	150 MW GT

TABLE VII

LOSS OF LOAD PROBABILITY

LOLP MAINTAINED

≤.20 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	28	1779	22	76 MW Hinds Lake 250 MW GT
1981	1449	31	1893	21	114 MW Cat Arm
1982	1568	34	2096	19	203 MW Upper Salmon and Upper Terra Nova
1983	1658	26	2096	19	
1984	1752	36	2381	17	285 MW Thermal
1985	1856	28	2381	17	
1986	1960	27	2481	20	100 MW GT
1987	2069	34	2766	18	285 MW Thermal
1988	2229	29	2866	21	100 MW GT
1989	2354	26	2966	24	100 MW GT
1990	2490	25	3116	27	150 MW GT

TABLE VIII

LOSS OF LOAD PROBABILITY

LOLP MAINTAINED

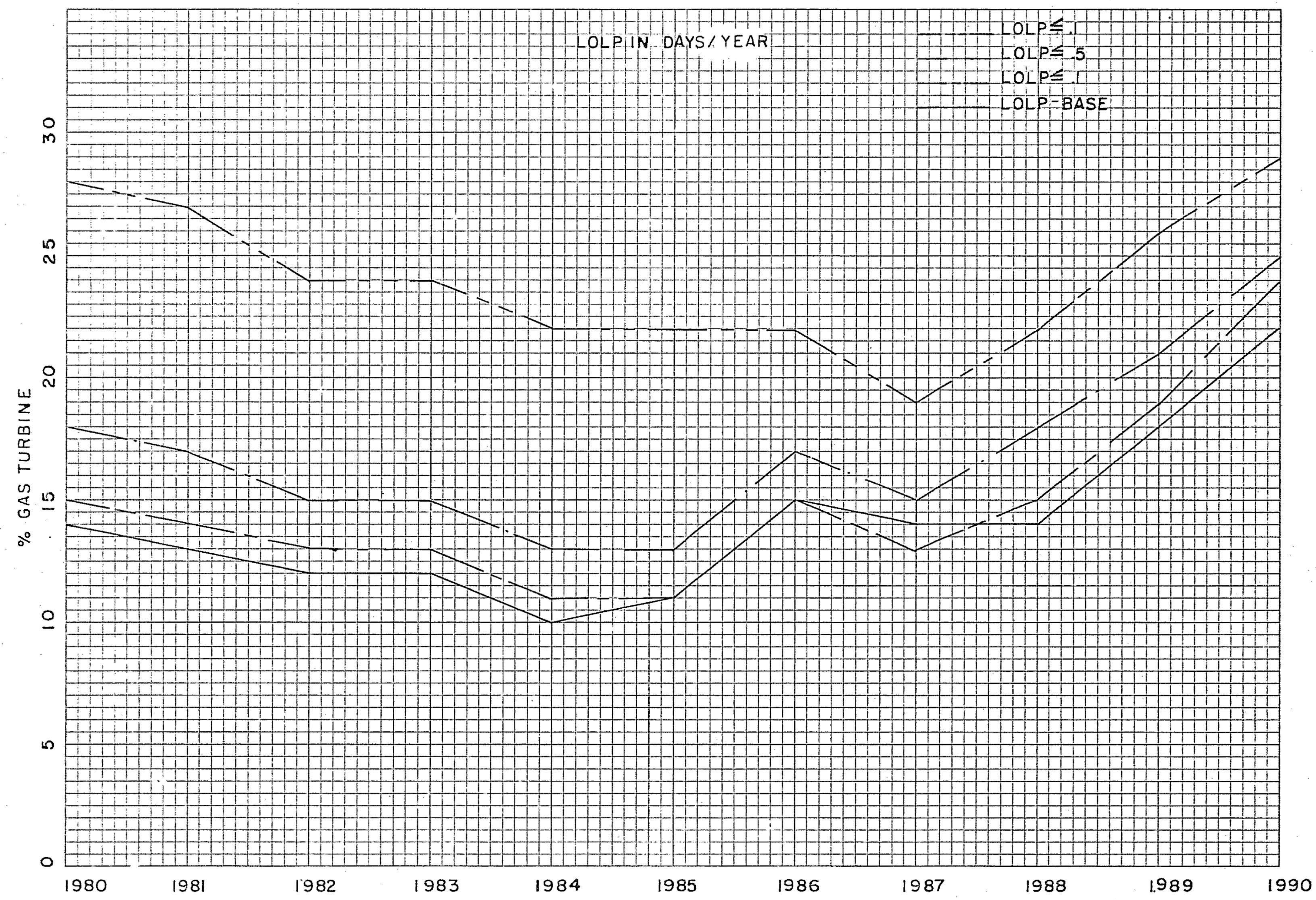
≤.10 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	38	1939	28	76 MW Hinds Lake 400 MW GT
1981	1449	41	2043	27	114 MW Cat Arm
1982	1568	43	2246	24	203 MW Upper Salmon and Upper Terra Nova
1983	1658	36	2246	24	
1984	1752	45	2531	22	285 MW Thermal
1985	1856	36	2531	22	
1986	1960	29	2531	22	
1987	2069	36	2816	19	285 MW Thermal
1988	2229	31	2916	22	100 MW GT
1989	2354	30	3066	26	150 MW GT
1990	2490	29	3216	29	150 MW GT

TABLE IX

TABULATION OF PW VALUES
FOR VARYING LOLPs
Discount Rate - 11%
$ x 1000

LOLP/ Description	Base	1	.75	.5	.4	.3	.2	.1
Simulation								
PW Capital less GT	475,862	475,862	475,862	475,862	475,862	475,862	475,862	475,862
PW Capital GT	44,718	50,775	56,637	57,253	62,919	67,684	69,817	83,282
PW Total	520,580	526,637	532,499	533,115	538,781	543,546	545,679	559,144
PW Fuel	570,152	570,152	570,152	570,152	570,152	570,152	570,152	570,152
PW O & M less GT	28,901	28,901	28,901	28,901	28,901	28,901	28,901	28,901
PW O & M GT	2,682	3,033	3,826	4,087	4,791	5,135	6,022	8,316
Total	31,583	31,934	32,727	32,988	33,700	34,036	34,923	37,217
Sub Total	1,122,315	1,128,723	1,135,378	1,136,255	1,142,633	1,147,734	1,150,754	1,166,513
Evaluation								
PW Capital less GT	39,113	39,113	39,113	39,113	39,113	39,113	39,113	39,113
PW Capital GT	11,061	12,559	14,009	14,162	15,563	16,742	17,270	20,600
PW Total	50,174	51,672	53,122	53,275	54,676	55,855	56,383	59,713
PW Fuel	1,624,932	1,624,932	1,624,932	1,624,932	1,624,932	1,624,932	1,624,932	1,624,932
PW O & M less GT	56,761	56,761	56,761	56,761	56,761	56,761	56,761	56,761
PW O & M GT	8,852	10,428	11,702	11,670	12,955	14,256	14,177	16,669
Total	65,613	67,189	68,463	68,431	69,716	71,017	70,938	73,430
GRAND TOTAL	2,863,033	2,872,516	2,881,895	2,882,893	2,891,957	2,899,538	2,903,007	2,924,588
Incremental Dollars Above Base Case	--	9,483	18,862	19,860	28,924	36,505	39,974	61,555
Incremental Dollars Above Preceeding Case	--	9,483	9,379	998	9,064	7,581	3,469	21,581


LOLP IN DAYS/YEAR
LOLP≤.1
LOLP≤.5
LOLP≤.1
LOLP-BASE
% GAS TURBINE
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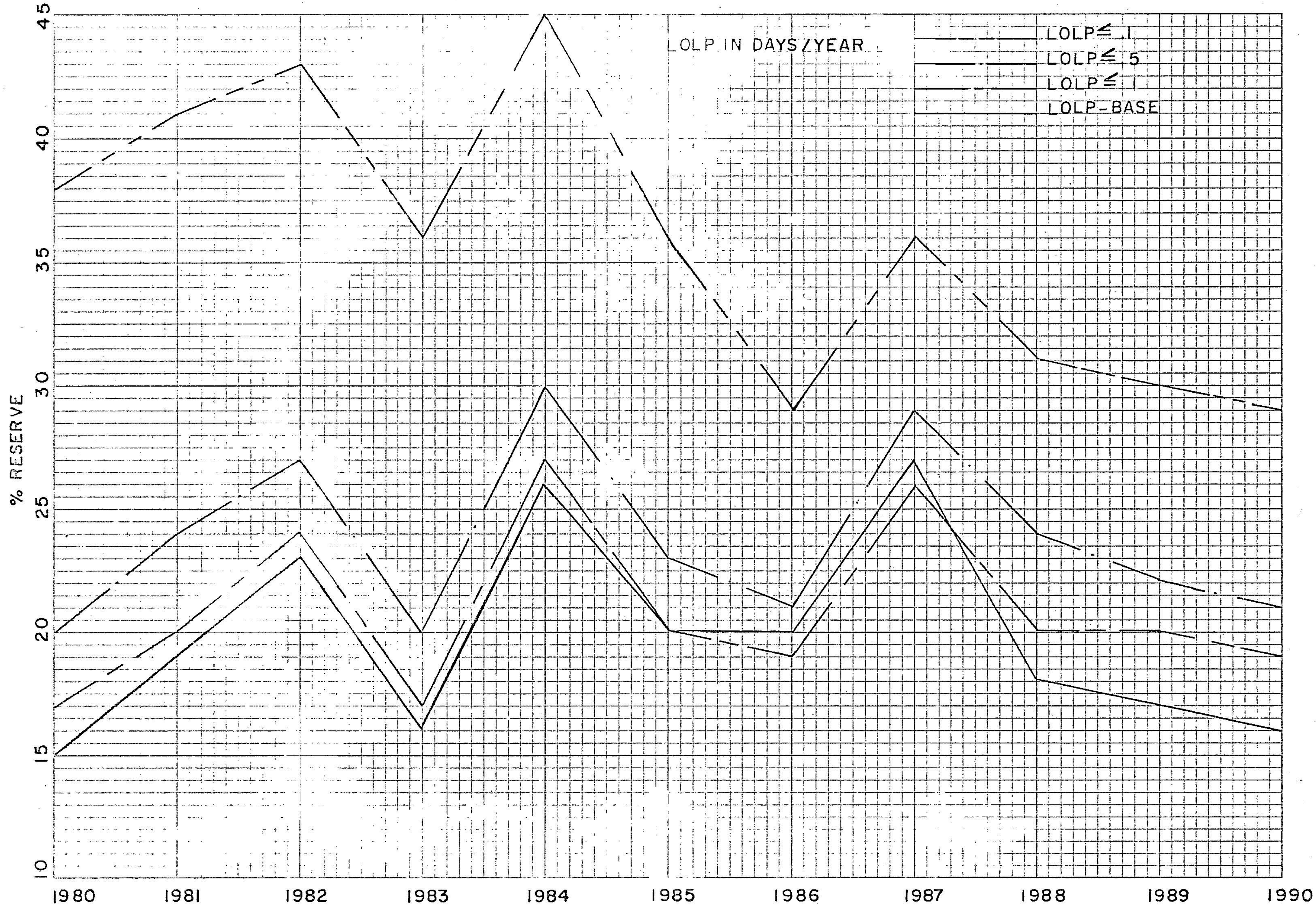
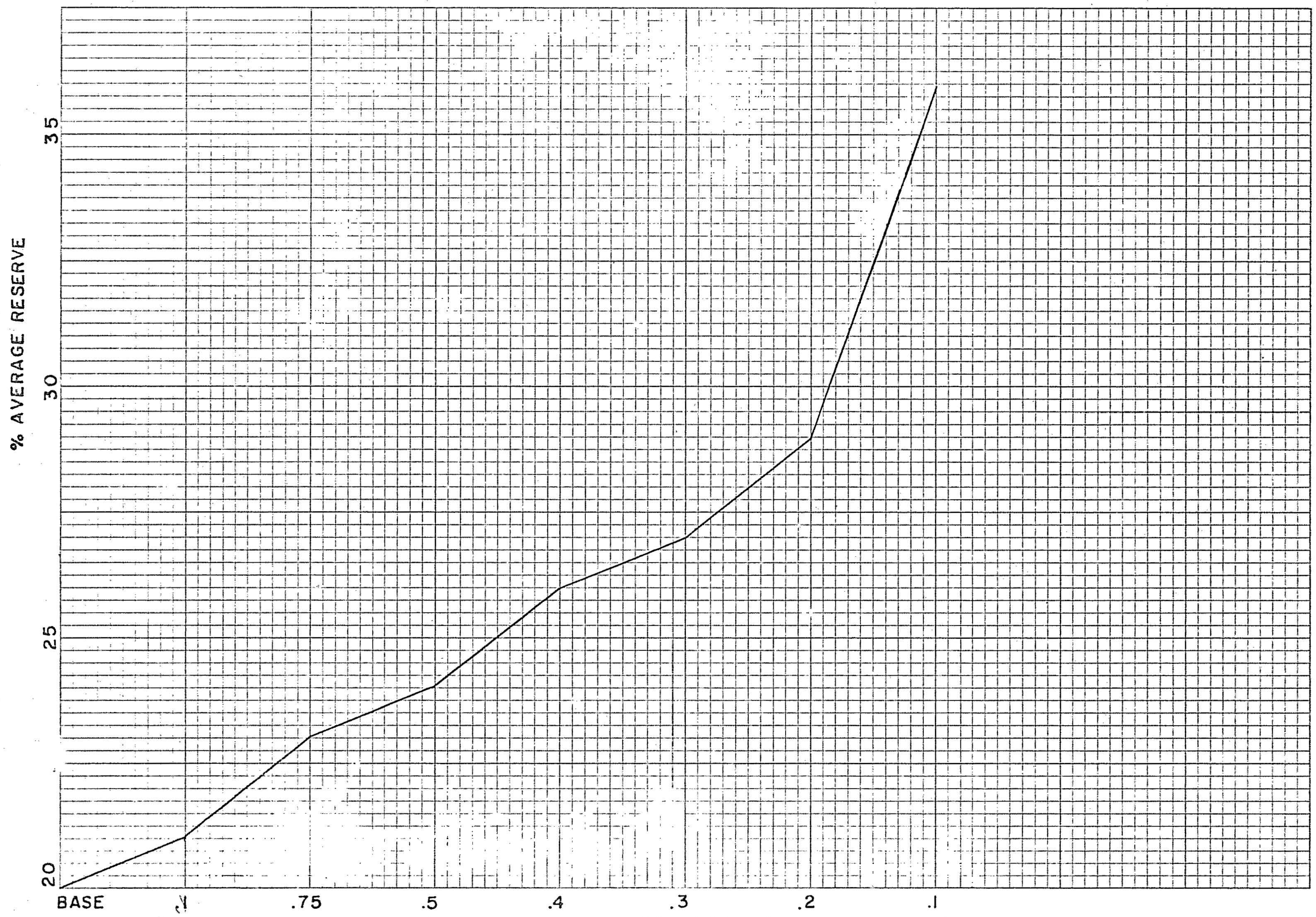
5
10
15
20
25
30
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990


LOLP IN DAYS/YEAR
LOLP≤ .1
LOLP≤ .5
LOLP≤ 1
LOLP-BASE
% RESERVE
45
40
35
30
25
20
15
10
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990


% AVERAGE RESERVE
35
30
25
20
BASE
1
.75
.5
.4
.3
.2
.1

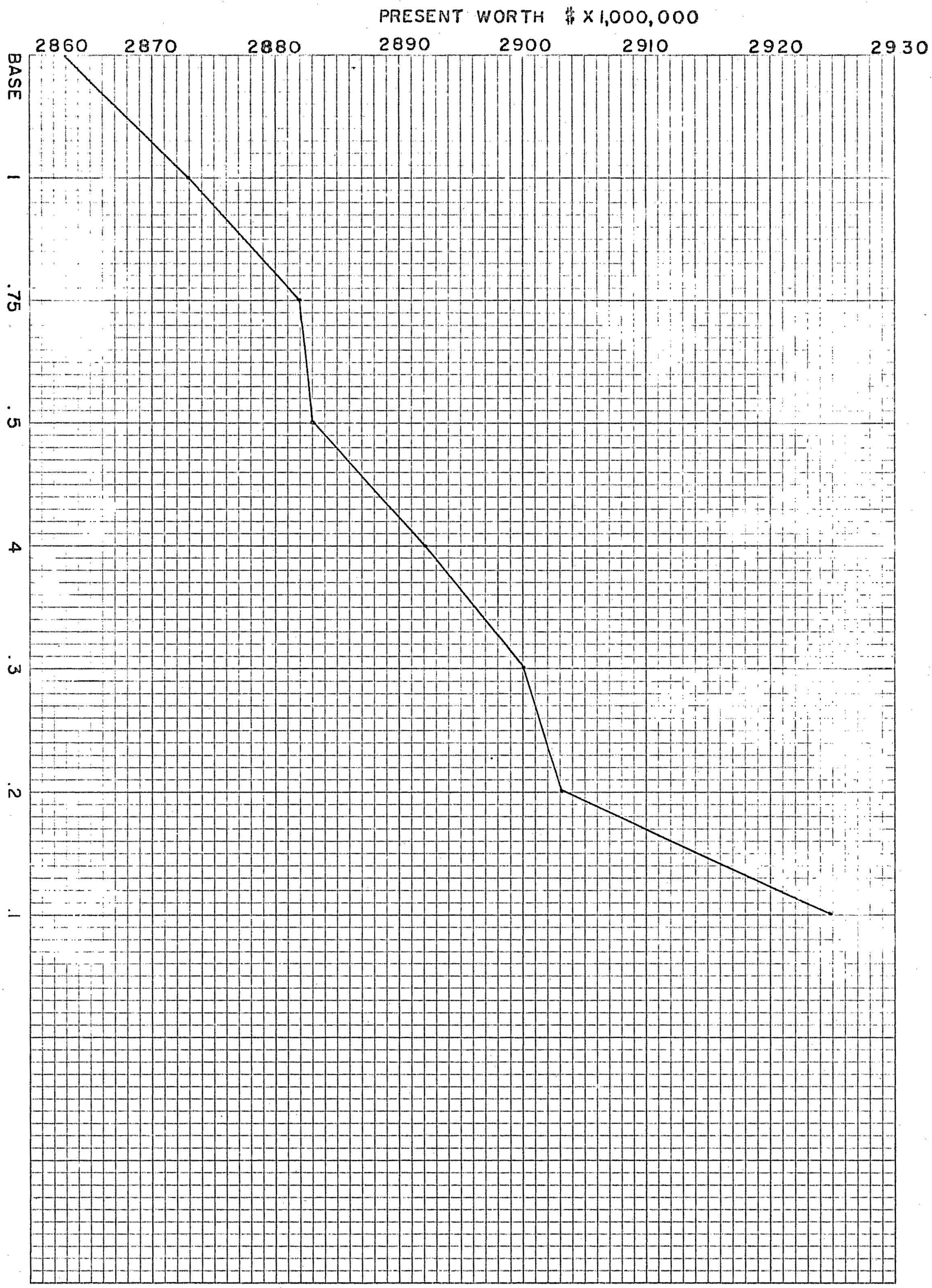

PRESENT WORTH $ X 1,000,000
2860
2870
2880
2890
2900
2910
2920
2930
BASE
1
.75
.5
4
.3
.2
.1

TABLE I

LOSS OF LOAD PROBABILITY

LOLP* Maintained

1.00 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	17	1629	15	76 MW Hinds Lake 100 MW GT
1981	1449	20	1743	14	114 MW Cat Arm
1982	1568	24	1946	13	203 MW Upper Salmon and Upper Terra Nova
1983	1658	17	1946	13	
1984	1752	27	2231	11	285 MW thermal
1985	1856	20	2231	11	
1986	1960	19	2331	15	100 MW GT
1987	2069	26	2616	13	285 MW thermal
1988	2229	20	2666	15	50 MW GT
1989	2354	20	2816	19	150 MW GT
1990	2490	19	2966	24	150 MW GT

* From 1981 onwards.

TABLE II

LOSS OF LOAD PROBABILITY

LOLP* MAINTAINED

.50 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	17	1629	15	76 MW Hinds Lake 100 MW GT
1981	1449	20	1743	14	114 MW Cat Arm
1982	1568	24	1946	13	203 MW Upper Salmon and Upper Terra Nova
1983	1658	17	1946	13	
1984	1752	27	2231	11	285 MW thermal
1985	1856	23	2281	13	50 MW GT
1986	1960	21	2381	17	100 MW GT
1987	2069	29	2666	15	285 MW thermal
1988	2229	24	2766	18	100 MW GT
1989	2354	22	2866	21	100 MW GT
1990	2490	21	3016	25	150 MW GT

* From 1981 onwards.

TABLE III

LOSS OF LOAD PROBABILITY

LOLP* MAINTAINED

.2 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	17	1629	15	76 MW Hinds Lake 100 MW GT
1981	1449	24	1793	17	114 MW Cat Arm 50 MW GT
1982	1568	27	1996	15	203 MW Upper Salmon and Upper Terra Nova
1983	1658	20	1996	15	
1984	1752	30	2281	13	285 MW Thermal
1985	1856	26	2331	15	50 MW GT
1986	1960	27	2481	20	150 MW GT
1987	2069	34	2766	18	285 MW Thermal
1988	2229	29	2866	21	100 MW GT
1989	2354	26	2966	24	100 MW GT
1990	2490	25	3116	27	150 MW GT

* From 1981 onwards.

TABLE IV

LOSS OF LOAD PROBABILITY

LOLP* MAINTAINED

.10 Days/Year

Year	Coincident Peak MW	Reserve %	MW Installed	% Gas Turbine	Additions To System
1980	1395	17	1629	15	76 MW Hinds Lake 100 MW GT
1981	1449	27	1843	19	114 MW Cat Arm 100 MW GT
1982	1568	30	2046	17	203 MW Upper Salmon and Upper Terra Nova
1983	1658	23	2046	17	
1984	1752	33	2331	15	285 MW thermal
1985	1856	28	2381	17	50 MW GT
1986	1960	29	2531	22	150 MW GT
1987	2069	36	2816	19	285 MW thermal
1988	2229	31	2916	22	100 MW GT
1989	2354	30	3066	26	150 MW GT
1990	2490	29	3216	29	150 MW GT

* From 1981 onwards.

TABLE V

CALCULATION OF PW VALUES

FOR VARYING LOLPs

Discount Rate - 11%

$ x 1000

LOLP in Days/Year Description	Base	1	.5	.2	.1
Simulation					
PW Capital less GT	475,862	475,862	475,862	475,862	475,862
PW Capital GT	44,718	50,775	55,961	64,883	76,872
PW Total	520,580	526,637	531,823	540,745	552,734
PW Fuel	570,152	570,152	570,152	570,152	570,152
PW O & M less GT	28,901	28,901	28,901	28,901	28,901
PW O & M GT	2,682	3,033	3,558	4,783	5,653
Total	31,583	31,934	32,459	33,684	34,554
Sub Total	1,122,315	1,128,723	1,134,434	1,144,581	1,157,440
Evaluation					
PW Capital less GT	39,113	39,113	39,113	39,113	39,113
PW Capital GT	11,061	12,559	13,842	16,505	17,781
PW Total	50,174	51,672	52,955	55,618	56,894
PW Fuel	1,624,932	1,624,932	1,624,932	1,624,932	1,624,932
PW O & M less GT	56,761	56,761	56,761	56,761	56,761
PW O & M GT	8,852	10,428	11,708	14,286	16,897
Total	65,613	67,189	68,469	71,047	73,658
GRAND TOTAL	2,863,033	2,872,516	2,880,790	2,896,178	2,912,924
Incremental Dollars Above Base Case	--	9,483	17,757	33,145	49,891
Incremental Dollars Above Preceeding Case	--	9,483	8,274	15,388	16,746

TABLE VI

TABULATION OF LOSS OF LOAD PROBABILITY

In Days/Year

Year/ LOLP	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Base	1.2325	.3773	.0905	.3638	.2107	.5549	.6423	.2809	1.2462	1.4129	1.6410
1.0	.8801	.2466	.0581	.2450	.1602	.6012	.6971	.3042	.8991	.7819	.7752
.75	.4694	.1095	.0248	.1135	.0775	.3393	.6940	.3042	.5774	.4993	.4971
.50	.4694	.1095	.0248	.1135	.0775	.3393	.3966	.1849	.3632	.4959	.4971
.40	.2665	.0465	.0103	.0498	.0370	.1826	.3953	.1849	.3632	.3145	.3143
.30	.2665	.0465	.0103	.0498	.0370	.1826	.2192	.1082	.2253	.1952	.1959
.20	.1691	.0191	.0042	.0211	.0173	.0933	.1161	.0618	.1364	.1942	.1959
.10	.0982	.0011	.0002	.0014	.0014	.0106	.0593	.0345	.0804	.0706	.0720
*1.0	.8801	.2466	.0581	.2450	.1602	.6012	.6971	.3042	.8991	.7819	.7752
* .50	.8801	.2466	.0581	.2450	.1602	.3398	.3966	.1849	.3632	.4959	.4971
* .10	.8801	.0516	.0103	.0495	.0370	.0934	.0596	.0345	.0804	.0706	.0720
* .20	.8801	.1131	.0248	.1135	.0775	.1829	.1166	.0618	.1364	.1942	.1959

* LOLP is regulated from 1981 onwards.

TABLE VII

TABULATION OF CAPITAL COST OF GAS TURBINES ESCALATION 6% $ x 1000

LOLP in Days/Year

Year/ LOLP	Base	1	.75	.5	.4	.3	.2	.1	1*	.5*	.2*	.1*
1979	4,609	5,908	8,862	8,862	11,816	11,816	14,770	23,632	5,908	5,908	5,908	5,908
1980	11,398	14,614	21,921	21,921	29,228	29,228	36,535	58,456	14,614	14,614	17,745	20,876
1981											7,745	15,490
1982												
1983												
1984	1,977									3,954	3,954	3,954
1985	14,024	8,382	4,919	8,382	4,191	8,382	8,382		8,382	18,160	22,351	22,351
1986	22,595	20,730	10,365	20,730	10,365	20,730	20,730		20,730	20,730	31,095	31,095
1987		4,709	9,418	9,418	9,418	9,418	9,418	9,418	4,709	9,418	9,418	9,418
1988	12,877	26,619	38,265	33,274	38,265	38,265	33,274	38,265	26,619	33,274	33,274	38,265
1989	46,979	52,908	52,908	40,563	52,908	52,908	40,563	52,908	52,908	40,563	40,563	52,908
1990	37,423	39,255	39,255	39,255	39,255	39,255	39,255	39,255	39,255	39,255	39,255	39,255
TOTAL	151,882	173,125	185,185	182,405	195,446	210,002	202,927	221,934	173,125	185,876	211,308	239,520

* A 100 MW gas turbine is installed in 1980 and the LOLP is maintained at the specified value from 1981 onwards.

TABLE VIII

TABULATION OF COSTS

IN PRESENT WORTH $ x 1000

FOR VARYING LOLPs

Discount Rate - 11%

LOLP in Days/Year	Base	1ø	.5ø	.2ø	.1ø
Description					
Present Worth of Capital	520,580	6,057	11,243	20,165	32,154
Present Worth of Adjustments*	2,342,453	3,426	6,514	12,980	17,737
TOTAL	2,863,033	9,483	17,757	33,145	49,891
Total Installed GT MWs from 1980 - 1990	484	550	600	700	800
Average Percent Reserve	20	21	23	27	30

* Includes such things as fuel, O & M, etc.

ø Shows only the incremental dollars above the base case.

TABLE IX

TABULATION OF LOLP FOR YEARS FROM 1977 - 1979

Year	Peak MW	Reserve %	Installed MW	Gas Turbine %	Addition To System	LOLP Days/Year
1977	1139	15	1311	11	50 MW Hardwoods 16 MW Price 154 MW Bay D'Espoir No. 7	2.0956
1978	1229	7	1311	11		5.4115
1979	1310	11	1453	10	142 MW Holyrood No. 3	3.7753

46 0702

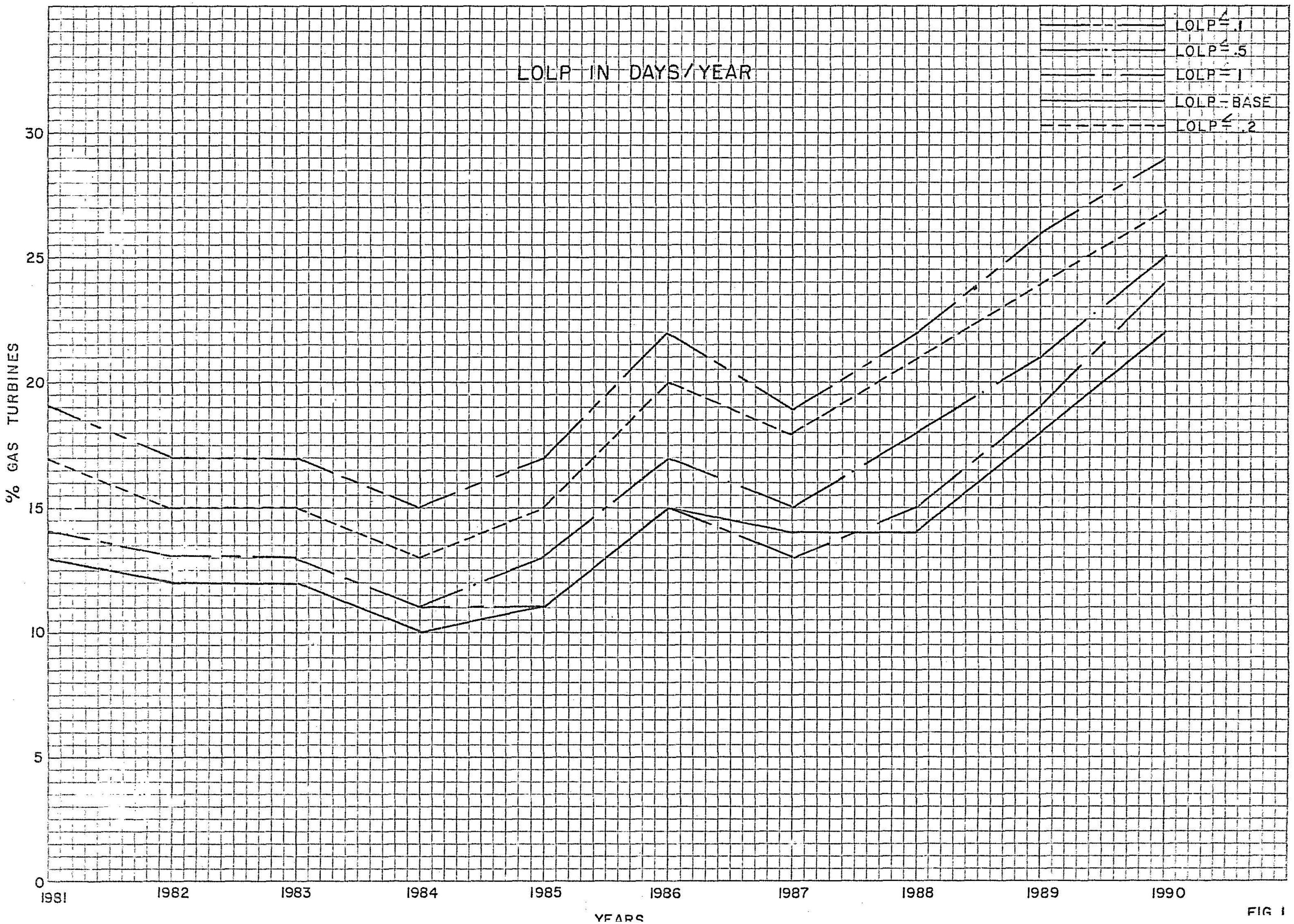

LOLP IN DAYS/YEAR
LOLP ≤ .1
LOLP ≤ .5
LOLP = 1
LOLP - BASE
LOLP ≤ .2
% GAS TURBINES
0
5
10
15
20
25
30
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
YEARS

FIG. I

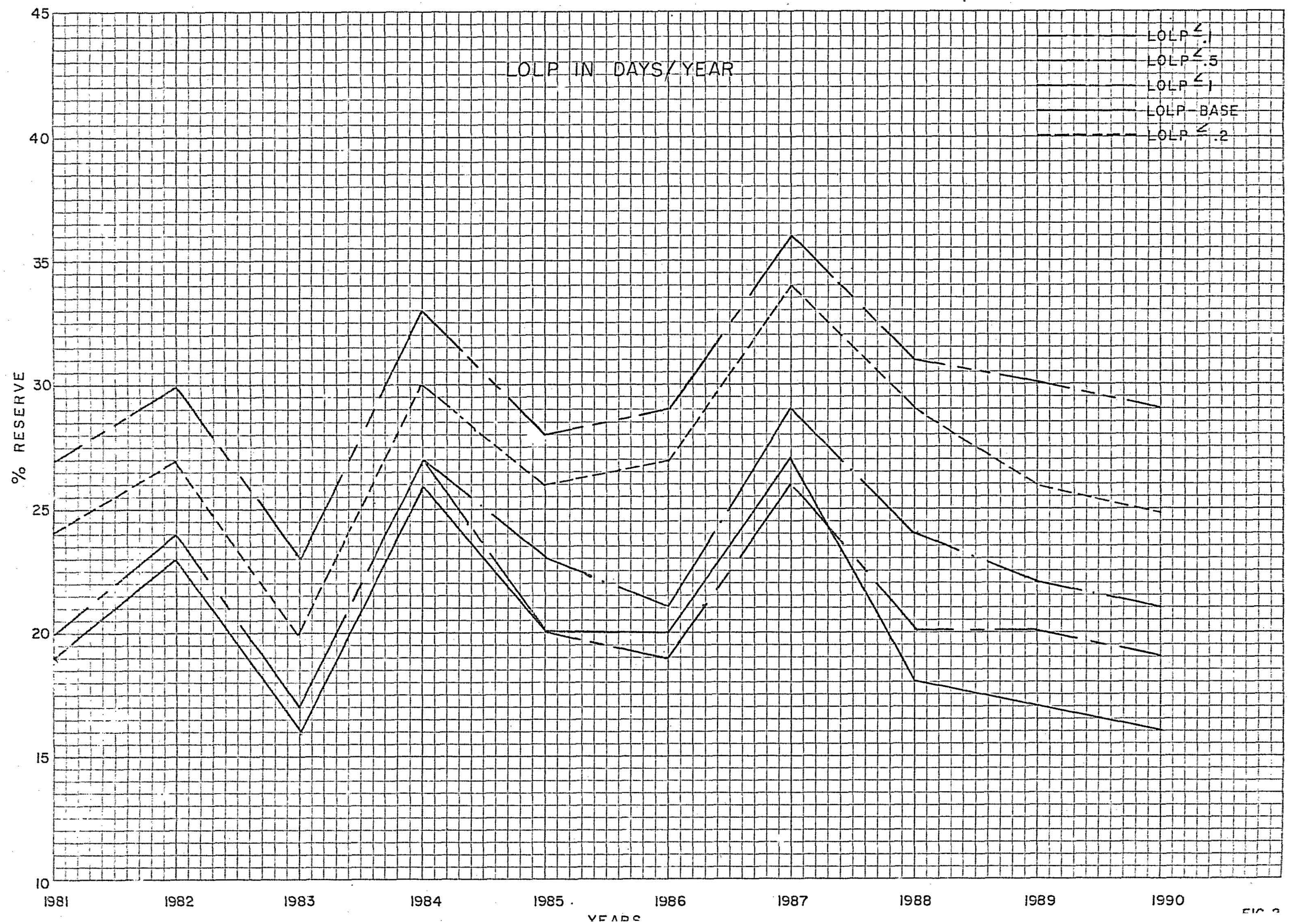

K+E 10 X 10 TO THE INCH • 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.
LOLP IN DAYS/YEAR
LOLP ≤ .1
LOLP ≤ .5
LOLP ≤ 1
LOLP - BASE
LOLP ≤ .2
% RESERVE
45
40
35
30
25
20
15
10
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
YEARS

FIG. 3

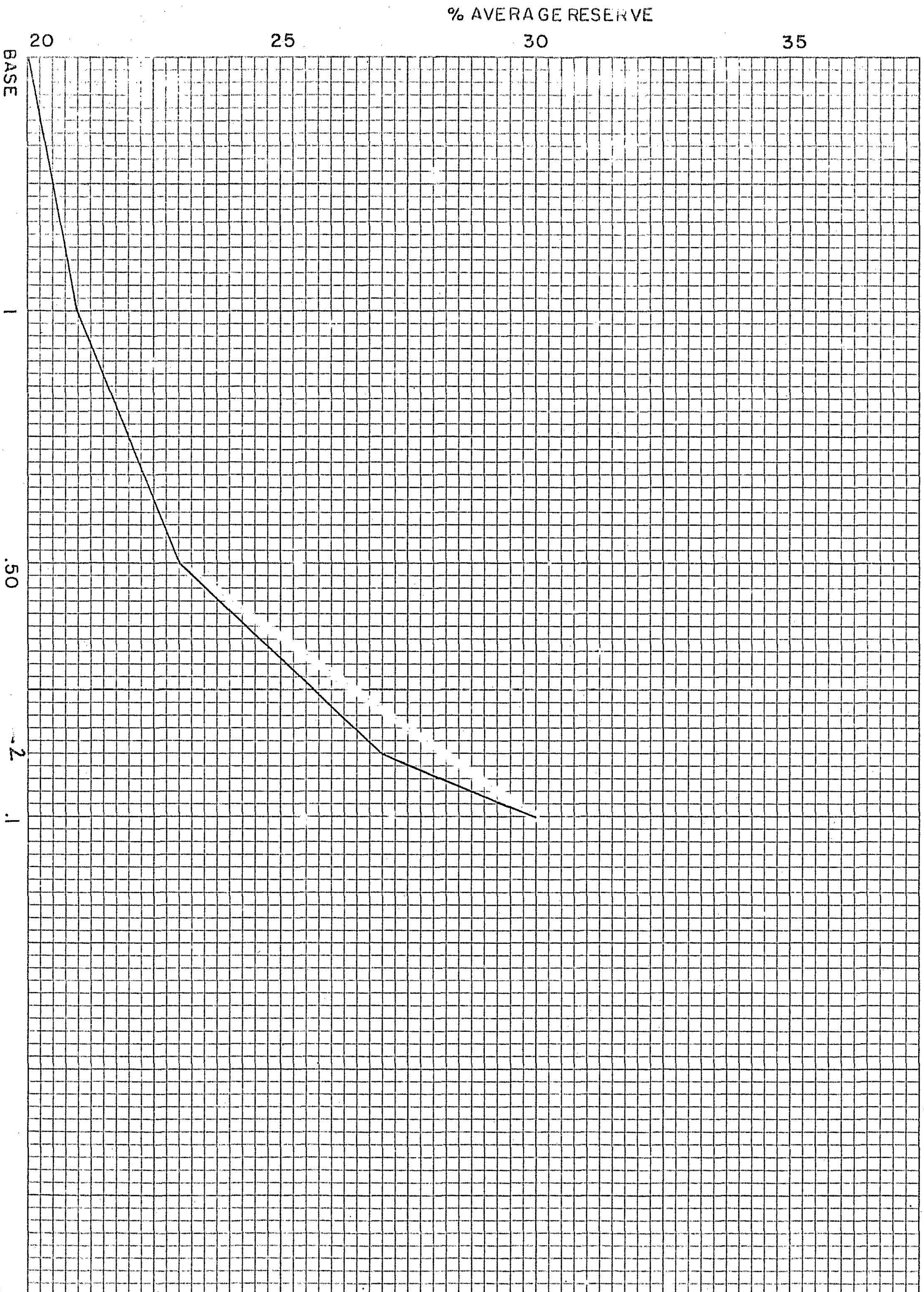
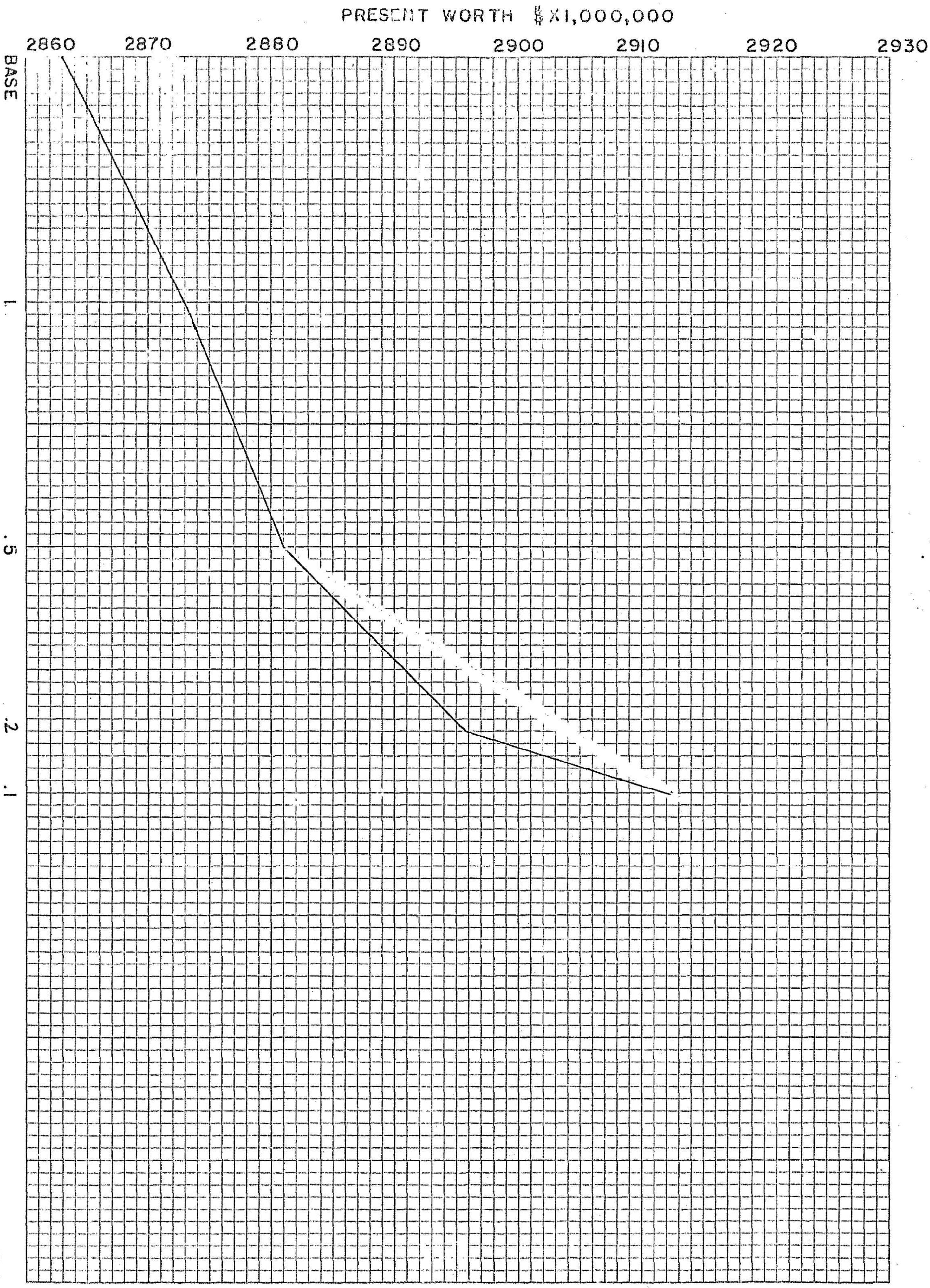


FIG 3


PRESENT WORTH $X1,000,000
2860
2870
2880
2890
2900
2910
2920
2930
BASE
1
.5
.2
.1

CANADIAN ELECTRICAL ASSOCIATION

Power System Planning and Operating Section

Power System Reliability Subsection

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RELIABILITY CRITERIA USED BY CANADIAN UTILITIES IN GENERATING CAPACITY PLANNING AND OPERATION

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Reliability Subsection

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RELIABILITY CRITERIA USED BY CANADIAN UTILITIES IN GENERATING CAPACITY PLANNING AND OPERATION

INTRODUCTION

The Canadian Electrical Association has long been concerned with reliability evaluation and appraisal in all phases of utility systems design, planning and operation. This concern led to the development within the Power System Planning and Operating Section of the Power System Reliability Subsection. In addition to other functions, the terms of reference of the Subsection include the responsibility of reviewing the criteria used by Canadian utilities in the relibility evaluation of generation and transmission systems.

The first questionnaire on this subject dealt with System Generating Capacity Planning and Operation and was circulated in 1964. It was subsequently updated in 1969 and again in 1974. Questionnaires on the Reliability Aspects of Major Transmission Planning and of Terminal Station Planning were circulated in 1971 and 1973. The Major Transmission Planning Questionnaire was repeated in 1975 and an updated report on Terminal Station Planning is expected in 1977.

The thirteen utilities listed in the Appendix provided data for the 1974 Report On The Questionnaire On System Generating Capacity Planning. The range in size of those utilities is indicated in Table 1.

TABLE 1. Companies By Installed Capacity

Range in MW	No. of Companies
0 - 200	1
200 - 1000	4
1000 - 2000	4
2000 - 3000	1
3000 - 5000	1
Above - 5000	2
	13

Table II shows the extent to which these utilities are interconnected.

TABLE II. Interconnection Capacity As A Percentage of the System Installed Capacity

Percentage	No. of Companies	Companies in Which Interconnection Affects the Reserve Criteria
0	2	-
0 - 15	4	1
15 - 25	2	0
Above 25	2	1
	10	2

Three utilities indicated that their interconnection capacities are "indeterminate" as they have multi-interconnections with each other. In this case their capacity planning is done on a three systems integrated basis. The two utilities which indicated in Table II that interconnections do affect their reserve criterion are connected together and "share installed reserves across the interconnection". All the reporting utilities indicated that the reliability of internal transmission does not affect their criteria. One utility did indicate that in future studies, the transmission associated with remote generation facilities would be included in their analysis.

The criteria used in the planning of generating capacity reserve margins is shown in Table III.

TABLE III. Criteria Used In Reserve Generating Capacity Planning

Criteria	No. of Companies
(1) Percent Margin	2
(2) Loss of the Largest Unit	1
(3) Combination of (1) and (2)	6
(4) Probability Methods	4
	13

Criterion (1)

One utility did not state its percent margin, the second gave a figure of 15% but indicated that this figure is "based on loss of load probability analysis which is carried out from time to time".

Criterion (2)

The utility using this criterion indicated that the largest unit is 19.5% of the installed capacity. There are two units of this size, with the next size one half the capacity of the largest unit.

Criterion (3)

One utility indicated that the system generation is sized such that 90% of the peak could be carried with the largest unit out of service. The three utilities previously noted as being heavily interconnected use a 15% reserve at peak unless the capacity of the largest unit exceeds 15% of the combined peak in the three interconnected systems. These three utilities form the Alberta Electric Utility Planning Council and are now using probability methods to assess alternate sequences of new generation additions beyond the late 1970's. One utility indicated that it used an 11% reserve or the capacity of the largest unit with the largest contingency taking preference. They also indicated that probability methods are also used in further examination. One utility used the following margin "2% of load plus 5% of required hydro plus 7% of required thermal to meet the forecast load".

Criterion (4)

Four utilities indicated that they used a quantitative reliability technique to assess the adequacy of the present and proposed generating capacity systems. All these utilities used some form of the Loss of Load Probability (LOLP) or Expectation (LOLE) Technique. It was obvious, however, that the approach used in each case contained different elements and that the simple description given by the name LOLP or LOLE is not sufficient to appreciate the difference in the approaches without a more detailed investiagation. It was therefore decided to survey those utilities utilizing probability techniques and attempt to determine the basic elements used in each case and the fundamental differences between the various approaches.

These utilities are shown below in Table IV together with their total installed capacities as of January 1, 1976.

TABLE IV. Utilities Using Probability Techniques

Nova Scotia Power Corporation	N.S.P.C.	1,164 MW
Hydro Quebec	H.Q.	15,897
Ontario Hydro	O.H.	18,667
Manitoba Hydro	M.H.	2,986
Alberta Electric Utility Planning Council	A.E.U.P.C.	3,423

UTILITY ASSESSMENT METHODOLOGY

The following section contains the questions asked of each utility and their replies in each case.

Question 1.

Indicate the basic technique used in assessing reserve capacity.

Replies

1. N.S.P.C.

Loss of load probability studies are carried out from time to time to evaluate the percent reserve required at time of winter peak.

2. H.Q.

Loss of load probability calculated on a monthly basis.

3. O.H.

Loss of load probability method (multi-state technique)

4. M.H.

Loss of load probability method.

5. A.E.U.P.C.

For new projects being planned for 1980 and beyond, the basic loss-of-load probability analysis is applied to the interconnected system.

Question 2.

Indicate the standard risk level used.

Replies

1. N.S.P.C.

1 day in 10 years

2. H.Q.

A probability of 1/3650 (i.e. 1 day in 10 years)

3. O.H.

A probability of 1/2400 (approximately 1 day in 10 years)

4. M.H.

Two risk level criteria must be satisfied: 0.1 days per year without considering out of province interconnections (Internal Reliability) and .003 days per year considering provincial interconnections (Interconnected Reliability).

5. A.E.U.P.C.

An annual risk index of 0.2 is used.

Question 3.

Indicate the basic factors used in establishing the generation model. This should include information on the ranges of forced outage rates for each unit classification, unit derating levels if considered, multiple station models, any incorporated transmission restrictions and an indication of how generating unit maintenance schedules are considered in establishing the basic model.

Replies

1. N.S.P.C.

The following forced outage rates were used in our most recent Loss of Load Probability Study:

MEGAWATT SIZE OF PLANT	NUMBER OF YEARS	PERCENT FORCED OUTAGE RATE
Present Fossil Fired Generators		
0 - 49 MW	Remaining Life	4%
50 - 150 MW	Remaining Life	5%
Hydro Generation		
All Sizes	Remaining Life	1%
New Thermal (oil fired) Units		
150 MW	1st Year	6%
	Remaining Life	5%
300 MW	1st Year	6.5%
	Remaining Life	6%
500 MW	1st Year	6.5%
	Remaining Life	6%
New Thermal (coal fired) Units		
150 MW	Life	6%
300 MW	Life	6.5%
Nuclear (CANDU)		
600 MW	1st Year	12.8%
	2nd Year	10.6%
	3rd Year	9.4%
	4th Year	8.6%
	5th Year	8.0%
Gas Turbines		
30 MW	Life	9.0%
50 MW	Life	11.0%

Occasionally some of the smaller units are lumped with an assumed slight reduction in forced outage rate. No transmission restrictions are considered within the Province. Generation maintenance is automatically scheduled by levelizing the risk of loss of load.

2. H.Q.

Hydraulic Units <400MW	Hydraulic Units >400MW	Gas Turbines	Nuclear and Thermal Units 0-300MW	Nuclear and Thermal Units 301-500MW	Nuclear and Thermal Units 501-800MW
1st Year					
3.6%	4%	9.5%	11.5%	15%	20%
2nd Year					
3.6%	4%	9.5%	11%	12%	18%
3rd Year					
3.6%	4%	9.5%	10%	11%	16%
4th Year					
1.2%	2%	9.5%	9%	10%	14%
5th Year					
1.2%	2%	9.5%	8%	10%	13%
6th Year					
1.2%	2%	9.5%	8%	10%	10%

Transmission restrictions or energy limitations are not included in the analysis. Unit maintenance is not considered as all maintenance is assumed to be scheduled during the off-peak periods.

3. O.H.

The following is a table that displays the ranges of forced outage rates for each classification of generating units currently used in our loss of load studies:

Nominal Capacity, MW	Fuel Used	Adjusted For**, %
100	coal	6 - 8
200	gas, coal	9
300	coal	13 - 14
500	coal	6 - 20*
200	nuclear	20
500	nuclear	9 - 17
500	oil	8 - 15*
750	nuclear	10 - 24
750	fossil	10 - 17
1200	nuclear	12 - 22

NOTE: *A partial derating of about 50 MW from a unit's dependable peak capacity is modelled by a multi-state representation and given an outage rate of 50%.

**The higher adjusted FOR apply normally to immature units.

The adjusted forced outage rate includes allowances for forced deratings and forced extensions to scheduled outages. There are no transmission restrictions incorporated into our model. A maintenance schedule which is arrived at manually is incorporated into monthly LOLP computations by removing the unit if it is on maintenance. We do not make any special allowance for multi-unit station representation.

4. M.H.

The generation model is based on the generators in the system having the following forced outage probabilities:

Hydro Units	<90 MW	0.005
Hydro Units	>90 MW	0.010
Thermal Units		0.030

Generating unit maintenance is not considered. Probability of loss of load is calculated at the time of the annual system peak and it is assumed that if the reliability is adequate at this time, it will also be adequate during the other months even with units on maintenance. The only internal transmission restrictions are as indicated in (8).

5. A.E.U.P.C.

All units are individually simulated except for two small hydro electric plants where the size of the units are less than 5 Mw each and the plant is simplistically simulated as a single unit. Unit characteristics are selected and revised annually on the basis of the unit's previous five years of operating experience. In the event of there being less than five years of experience, the general experience of similar units in the province is used in the selection together with the judgement of the committee members. For units new to the provincial system or being planned, the EEI data is used.

During the first four years of operation the outage rate of a new thermal unit is increased by the following factors against its assumed long term outage rate.

1st year	1.8
2nd year	1.5

The transmission system is assumed to have no limitations and the outage rates of all units are assumed to be independent.

All thermal units are assumed to be taken out on planned maintenance for the same length of time each year. Hydro units are not assumed to have a planned outage. Planned outages for units 150Mw and above are assumed to be between 28 and 35 days and smaller units between 7 and 21 days. Selection is made on the basis of provincial experience.

Question 4.

Indicate the basic factors used in establishing the load model. This should include information on the data used to create the model, the time period of application and any modifications used in predicting future models. Also indicate if load forecast uncertainty and/or interruptible loads are incorporated in the calculation of the risk index.

Replies

1. N.S.P.C.

The Reliability Program most recently used was G.E.'s Time Shared Computer Program, "PRODS". Typical daily loads were input for 13 intervals of 20 days each, 4 peak days and 16 average days, for each year. To date, load forecast uncertainty has not been taken into consideration. Interruptible loads are not included in the forecast load used for reliability evaluation.

2. H.Q.

The monthly load duration curve is used. Load forecast uncertainty is represented by a normal distribution. Interruptible loads are not considered in the calculation procedure.

3. O.H.

Our load model is based on ten years of working day peak loads for each month. These peaks are arranged in decreasing order to yield what we call "a peak load distribution curve". In the computation the load forecast for a future year is applied to the peak point on the curve and all other loads are derived from this.

No modification is made to allow for future change in load shape. No adjustments are made for load forecast uncertainty. Interruptible loads are excluded from the LOLP calculation, only LOLP for the firm load is calculated.

4. M.H.

The load model is based on the January weekday peak demands. The probability of loss of load is multiplied by 365 to give a risk index expressed in days per year. The forecast peak demand is assumed to by the mean of a normal distribution with a standard deviation of 4%. From studies of previous loads and forecasts, the 4% figure was determined to be reasonable. Interruptible loads are not considered

5. A.E.U.P.C.

The peak hour of each and every day of calendar month is divided by the monthly peak and the resulting normalized values ordered. This is repeated for the five preceding years and the ordered curves averaged. Twelve monthly normalized "peak hour duration curves" are projected for the simulation of the future.

A sophisticated analysis of the energy capability of the provincial system is also made using monthly load duration curves prepared in a similar manner. Some adjustment of the relationships between monthly peaks is made to account for changing annual load factors and these adjustments are reflected in the static capacity evaluation.

Load forecast uncertainty is not formally taken into account and interruptible loads are deducted specifically from the monthly loads. Interruptible loads are contractual interruptible loads and do not include a recognition of the provincial load shedding policy.

Question 5.

Indicate how interconnections are incorporated in the analysis.

Replies

1. N.S.P.C.

To date interconnections have not been included in the generation reserve analysis. Generation reserve has been established by combining the New Brunswick and the Nova Scotia systems in a single area loss of load probability program, thus assuming the tie capability between the Provinces is infinite.

2. H.Q.

Interconnections are not considered.

3. O.H.

Interconnection with neighbouring power systems is not incorporated into our loss of load computation. (Program in use is so-called single-area). Firm capacity purchases, however, are represented as generating units either with a zero or non-zero forced outage depending on the purchases being modelled. Random assistance from neighbouring system is not considered.

4. M.H.

For the Interconnected Reliability Study, the generators in the neighbouring systems are modelled in the same manner as Manitoba's. After their peak demands are supplied, any remaining capacity is assumed available for assistance to Manitoba, limited by the outage probability table of the neighbouring system's reserves and the tie lines which are assigned appropriate forced outage rates. (230 kV transmission lines are assumed to have one outage per 100 miles per year, with an average duration of 1/2 hour). Firm capacity purchases (or sales) are added to (or subtracted from) the Manitoba capacity model with zero forced outage and the capabilities of the interconnections and the other system's loads are adjusted appropriately.

5. A.E.U.P.C.

At present, no significant interconnections to utilities external to the province exist. New proposed interconnections are included specifically using a simplified two area LOLP analysis in which the probability of assistance together with the availability of the tie is included. However, as no new interconnections have yet been definitely planned, the inclusion of adjacent utilities via a tie has only been made for specific years during studies of such proposals.

Question 6.

Indicate how intra-system transmission considerations are incorporated in the probabilistic assessment.

Replies

1. N.S.P.C.

Intra-system transmission considerations are not incorporated in a probabilistic assessment.

2. H.Q.

Intra-systems transmission considerations are not incorporated in the analysis.

3. O.H.

Intra-system transmission considerations are not incorporated into the probabilistic assessment.

4. M.H.

The only intra-system transmission considered is Manitoba's HVDC facilities. These are incorporated as follows: A number of derated DC transmisssion capability states caused by valve group, pole or bipole failures are determined, each with a probability of occurrence. The Manitoba system is divided into north and south and, after the northern peak demand is supplied, the remaining capacity is available to the south, limited by the outage probability table for the generators in the north (incorporating the northern peak demand), the HVDC facilities, and a 230 kV AC tie. No forced outage rate is applied to this 230 kV line.

5. A.E.U.P.C.

Intra-system interconnection limitations are not considered.

Question 7.

Indicate how generation unit maintenance is considered in the calculation procedure.

Replies

1. N.S.P.C.

The planned length of maintenance for each unit is input into the program. The program then takes this information and assigns a maintenance schedule which levelizes the probability of loss of load. The annual risk is calculated by summing the individual period risks throught the year.

2. H.Q.

Maintenance can be considered by adding this capacity to the monthly load model. This is an approximate technique. In some cases a more exact approach is used in which the unit capacity is removed from the system capacity model.

3. O.H.

Generating unit maintenance is considered in the monthly LOLP computation by simply removing the unit prior to that computation. The maintenance program used for planning purposes is arrived at by manually balancing margins and capacities on maintenance outage to achieve as uniform a risk profile as possible. This is done on a month by month basis for each future year for which LOLP computations are required. The Ontario Hydro uses a monthly criterion and therefore the required reserves are set by the worst month which is usually December.

4. M.H.

Generation unit maintenance is not considered.

5. A.E.U.P.C.

The annual risk index is calculated as the sum of individual daily probabilities of losing load for 365 days per year. The computer program includes an automatic planned maintenance scheduling routine which is used to optimize the percent reserve each month. Techniques to equalize monthly risk were not found to be any better than the technique now used. Whenever the combination of units change due to planned maintenance, the probability-capacity table is corrected to reflect the change. Planned maintenance is specified in days.

Question 8.

Indicate any other factors which are used in calculating the annual risk index and describe any modifications which are being considered for future use.

Replies

1. N.S.P.C.

The New Brunswick Electric Power Commission and the Nova Scotia Power Corporation are presently working with System Control Inc. to develop a generation reliability program. It will be based on probabilistic theory developed by R.R. Booth, State Electricity Commission of Victoria, Australia. The program will have the capability of analyzing hourly loads, taking into consideration uncertainty of forecasted peak. The maintenance schedule will be input either as data or the program will calculate it by levelizing risk throughout the year. River hydro with limited storage will be analyzed by a reserve equivalent which will take into consideration stream flow probabilities. The program output will include both probability of loss of load and probability of loss of energy. It will be used to examine the reserves required for New Brunswick and Nova Scotia combined, and to determine how these reserves should be distributed between the Provinces.

2. H.Q.

3. O.H.

A future consideration in our loss of load probability studies is to acquire more complete data on partial outages and deratings of large generating units in our system to enable a better representation to be made of the capacity on outage. Because of an increasing concern with the effects of changing load shapes on generation reliability we intend to increasingly employ frequency and duration, and loss of energy techniques in planning future generation additions to the system.

4. M.H.

The only modification that is being considered for the future is a relaxing in the satisfactory Internal reliability risk level as the Interconnected Reliability improves with the addition of new interconnections.

5. A.E.U.P.C.

Application of the LOLP technique to generation system planning is dynamic and all aspects of the application are under continuous review. Of primary concern is the selection of the best data for the existing system of generating units and for those planned in the future. A review is underway of the possible extension of reliability analysis into transmission planning.

CRITERIA USED IN PLANNING SPINNING CAPACITY

The 1974 Questionnaire on Generating Capacity Reliability Evaluation also asked a series of questions on operating capacity assessment. The criteria used are shown in Table V. In addition to the replies in Table V, the three interconnected utilities noted earlier stated that there is no formal spinning capacity planning in the interconnected system. One other utility indicated that no spinning reserve is carried and reliance is placed on under-frequency load shedding for the loss of the largest unit. The remaining utility provided no usable data.

TABLE V. Operating Capacity Assessment

	Criterion	No. of Companies
1.	Loss of the Largest Unit	6
2.	Percent Margin	0
3.	Fixed Margin	1
4.	Combination of 1 and 3	1
5.	Constant Risk	0
		8

Under Criterion (1), three utilities used the loss of the largest unit, while two utilities considered the largest single contingency. The remaining utility used a criterion of 60% of 1.1 times the largest single contingency.

Five of the eight utilities reported that interconnections provide a portion of their scheduled spinning reserve.

Two of the eight utilities indicated that under-frequency relaying or load shedding techniques were used in setting their spinning reserve criterion.

Seven of the eight utilities defined "spinning capacity" as the difference between the load and the capacity synchronized to the system which can be loaded immediately. One utility defined spinning capacity as the operating reserve for the first contingency, which must be available in five minutes. Two thirds of this reserve must be synchronized capacity. One third may be shut-down hydro, combustion turbine units or interruptible contract loads.

CONCLUSION

The first questionnaire on generating capacity reliability evaluation circulated in 1964 indicated that only one utility in Canada used probability techniques in static capacity reliability evaluation. This paper illustrates the changes in this regard, which have occurred over the last decade. The Loss of Load Probability or Expectation Technique is the most popular approach but each utility appears to utilize different elements in their appraisal. Any discussion of a standard risk index such as 0.1 days/year should also include a detailed statement of the factors used in arriving at this figure.

No Canadian utility at the present time utilizes probability techniques in the evaluation of operating capacity reserve margins. All the utilities which reported used some form of fixed contingency analysis.

ACKNOWLEDGEMENT

The Power System Reliability Subsection would like to thank all the utilities listed in the Appendix who provided data for this study and particularly the Nova Scotia Power Corporation, Hydro Quebec, Ontario Hydro, Manitoba Hydro and the Alberta Electric Utility Planning Council who also provided data on their probabilistic approach.

APPENDIX

The following utilities provided the data for the 1974 Report On The Questionnaire On System Generating Capacity Planning: British Columbia Hydro and Power Authority, West Kootenay Power and Light Company, Alberta Power Ltd., Calgary Power Ltd., Edmonton Power, Saskatchewan Power Corporation, Manitoba Hydro, Ontario Hydro, Hydro Quebec, New Brunswick Electric Power Commission, Nova Scotia Power Corporation, Maritime Electric Co. Ltd. and Newfoundland and Labrador Power Corporation.