ELECTRIC UTILITY ANALYSIS PACKAGE

Submitted to the

Public Utilities Commission of Ohio

Principal Investigators

S. Nakamura (Editor)
M. S. Gerber
D. W. Miller
K. A. Kelly

Graduate Research Associates

R. W. Baker
J. A. Brown
B. R. Hampton
B. A. Maki
D. J. Pasz
C. Poseidon
J. N. Storch
S. Tzemos

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Executive Summary

This report is a summary of essentially all the work† performed at The Ohio State University (OSU) for The Public Utilities Commission of Ohio (PUCO) under the name of Corporate Finance Model Development. The package of computer programs decribed in this report is designated as the Electric Utility Analysis Package. This report describes both the programs and the results of analyses which were required either to prepare the basic data for the package or to demonstrate the usefulness of the package.

The objective of this project is to develop an integrated package of computer programs which will assist the PUCO staff in analyzing electric utilities' corporate operations. These analyses include the engineering and economic analyses which are necessary for such activities as rate cases, rate design studies, approval of new plant construction, load control studies productivity evaluation, studies of the impacts of alternative policies, and sensitivity analyses for economic parameters.

The package therefore includes both engineering, economics and accounting oriented programs. The engineering programs are FRED, MARC-3A & B, WASP, LOLP, PPP and CONTROL programs. FRED deals with hourly electric load for the electric utility systems and provides necessary load data for other programs. MARC-3A & B calculate production costs of an electric generation system for a specified period. WASP decides the optimal expansion schedule for generation systems by using the dynamic programming principle. LOLP evaluates the reliability of a generating system. PPP analyzes the load data and determines the range of hours of a day in which the daily peak is likely to occur. CONTROL simulates the effect

† As one exception, the result of the nuclear fuel cost study is reported separately: C. Poseidon, K.A. Grant, S. Nakamura and F. A. O'Hara, "Nuclear Fuel Cost", submitted to PUCO, December, 1976.

of radio control of water heaters. The economics oriented programs include the TIME-OF-DAY PRICING program, COST ALLOCATION program and MARGINALCOST program. The FINANCIAL ANALYSIS program and RESIDENTIAL BILL FREQUENCY program are oriented towards accounting analyses.

Among these programs, eight (FRED, MARC, LOLP, CONTROL, TIME-OF-DAY PRICING, ALLOCATION, BILL FREQUENCY, and PPP) were developed at The Ohio State University; while three programs, (WASP, FINANCIAL ANALYSIS, MARGINALCOST) are the programs developed elsewhere (TVA, TBA and University of Wisconsin, respectively) and adopted in this package. All the programs are available on the IBM 370/168 at The Ohio State University, Instruction and Research Computer Center. The programs are available on the batch execution basis and/or the TSO (Time Sharing Option) basis.

The Electric Utility Analysis Package can be used for the following purposes among others:

<u>Rate Design</u>

Rate design can be anything from a minor reform of current rate structure to the design of a drastically different rate structure under marginal cost pricing. The present model is useful in any such study, from the simplest to the most complex. The revenue requirement for future years is calculated by the FINANCIAL ANALYSIS program. The BILL FREQUENCY program is suitable for analyzing the current rate structure. The MARC program calculates short run marginal costs which must be known for marginal cost pricing or time-of-day pricing. The MARGINALCOST program calculates long run marginal costs including the transmission and distribution costs. The ALLOCATION code can be used to allocate the total utility cost among different user groups. The effect of time-of-day pricing on utility revenue may be analyzed with the PPP and TIME-OF-DAY PRICING programs.

Performance Evaluation

Regulatory agencies are continually forced to judge the performance of an electric utility. Average forced outage rate of plants varies substantially from a well maintained system to a poorly maintained system. Improvement of the average forced outage rate of a utility means an increased system reliability as well as a small capacity expansion requirement. The MARC and WASP programs are suitable for this analysis. The FINANCIAL ANALYSIS program may be used to analyze various aspects of the historic data of performance. For example, the relationship between the inflation-adjusted cost of generating boiler maintenance and the total capacity of boilers may be determined. Further, it can be determined whether this relationship suggests improving or deteriorating performance.

Plant Construction Approval

The decisions made by regulatory agencies in approving construction of major electric plants have a great impact on present and future consumers. The Electric Utility Analysis Package can be used to evaluate and verify the system expansion schedule submitted by a utility. The WASP, MARC and LOLP programs are suitable for this purpose. These programs may also be used to evaluate the effects of load control, economic growth grate, and change of operating cost on the amount and type of construction required in the future. FINANCIAL ANALYSIS can be used to study the impact of plant construction on the revenue requirement. By using these programs, the evaluation for construction approval can be made more thoroughly in a short period, and thus regulatory lag in authorization of new plants can be decreased.

Policy Analysis for Conservation and Load Control

Regulatory agencies are interested in evaluating various means of encouraging consumers to conserve electricity. These include time-of-day pricing, radio control of water heaters, voltage control and increased insulation of buildings. All of these efforts have the effect of reducing the energy requirement and/or the capacity requirement. An analysis of the cost vs. benefit relationship is important in choosing a conservation policy. LOAD CONTROL, MARC, WASP, TIME-OF-DAY PRICING programs are useful for this type of analysis.

Evaluation of Generation System Reliability

Two aspects of generating system reliability are relevant to regulatory agencies as well as consumers: (1) the generating system reliability associated with the utility's own construction schedule, (2) the effects of reliability constraints on the future cost of electricity. MARC, WASP and LOLP programs along with FINANCIAL ANALYSIS program are suitable for this analysis.

Rate Cases

The analyses required for rate cases involve all the types of analysis described in the preceding paragraphs, though not all are used at once. The advantages of using the present package for rate cases are, first, analysis of past history and projections of future utility operation can be made much more quickly than is possible without computer programs, and secondly, much wider analyses become possible especially where staff resources are limited. As a consequence, PUCO can not only reduce regulatory lag in rate cases but also perform in-depth studies in a limited time period. Another effect of using the computer model is that the rate case analysis may be easily standardized, and accordingly, adversary testimony on analysis methodology can be avoided once the model is accepted.

PREFACE

This report is a summary of essentially all the work performed at The Ohio State University for the Public Utilities Commission of Ohio (PUCO) under the name of Corporate Finance Model Development. The report also outlines the computer programs that were developed elsewhere but adopted in the package. The computer programs included in this report will be designated as Electric Utility Analysis Model, because all the materials reported here are concerned with analysis of electric utilities while "Corporate Finance Model" indicates a much wider area of interest. In other words, the Electric Utility Analysis Model is a package of computer programs for analyzing the effect of policy alternatives and changes in economic parameters on the financial operation of electric utilities in the future.

Most of the work described in this report has been reported to PUCO as interim reports, user's manuals, memos or letters. However, the degree of detail varies substantially among those materials. Some programs have been changed since interim reports were submitted. Some new works are yet to be reported. For these reasons it is necessary to summarize and describe all of the works performed in a consistent manner. This final report is intended to serve this purpose.

Among nine programs included, six programs were developed at The Ohio State University while three were developed elsewhere but adopted in the model. Each is independent and can be used separately. Nevertheless, one program provides input to another and all of them are more or less interrelated. Therefore, the user of the model must understand the relationships among them. Chapters 12 through 16 describes the results of analyses that are either necessary to provide basic data for the programs, or performed by using the programs.

All the work described in this report has been supported by the PUCO. The authors are grateful to the Commissioners of PUCO for their substantial financial support. The Corporate Finance Model Devlopment, mentioned earlier, was proposed, initiated and supervised by the PUCO staff, especially, Messrs. E. Skipton, R. Wayland and S. Enkara. This study would have been impossible without the effort of Messrs. Wayland and Enkara. We also thank Mr. A. Thilke, Dr. Lazare, Mr. J. Winter and many other PUCO staffers who assisted in developing and utilizing the model. It should also be mentioned that this project for PUCO was carried out in conjunction with another of our projects supported by the Ohio Power Siting Commission. Because both projects had similar aspects, information and techniques could be shared. We acknowledge the support and assistance of Messrs. J. Kennedy and J. Mulcahey of the Ohio Power Siting Commission. Finally, we wish to thank the electric companies who provided us with the necessary information to complete this work.

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CHAPTER 1

INTRODUCTION

1.1 Purpose of the Electric Utility Analysis Package

The objective of this project is to develop an integrated package of computer programs which will assist the PUCO staff in analyzing the electric utilities' corporate operations. Such analyses include those engineering and economic analyses which are necessary for such activities as rate cases, rate design studies, approval of new plant construction, load control study, productivity evaluation, studies of the impacts of alternative policies and sensitivity analyses for econo-nomic parameters.

The package therefore includes both engineering and economics and accounting oriented programs. The engineering programs are FRED, MARC-3A & B, WASP, LOLP, PPP and CONTROL programs. FRED deals with hourly electric load for the electric utility systems and provides necessary load data for other programs. MARC-3A & B calculate production costs of an electric generation system for a specified period. WASP decides the optimal expansion schedule for generation systems by using the dynamic programming principle. LOLP evaluates the reliability of a generating system. PPP analyzes the load data and determines the range of hours of a day in which the daily peak is likely to occur. CONTROL simulates the effect of radio control of water heaters. The economics oriented programs include the TIME-OF-DAY PRICING program, COST ALLOCATION program and MARGINAL COST program. The FINANCIAL ANALYSIS program and RESIDENTIAL BILL FREQUENCY program are oriented towards accounting analyses.

Among these programs, eight (FRED, MARC, LOLP, CONTROL, TIME-OF-DAY PRICING, ALLOCATION, BILL FREQUENCY, and PPP) were developed at The Ohio State University; while three programs, (WASP, FINANCIAL ANALYSIS, MARGINALCOST) are the programs developed elsewhere (TVA, TBS and Univsity of Wisconsin, respectively) and adopted in this package. All the programs are available on the IBM 370/168 at The Ohio State University, Instruction and Research Computer Center. The programs are available on the batch execution basis and/or the TSO (Time Sharing Option) basis.

Chapters 2 through 11 of this report outline the programs and give the users' information where it is appropriate. Chapters 12 through 16 describe the results of the studies which are necessary either to provide input data for the programs or to demonstrate the validity and usefulness of the programs. The CONTROL program is described in the appendix of Chapter 16, while each of the other programs is described in an independent chapter.

1.2 Suggested Utilization of the Programs

This section explains the kinds of analyses that can be made using the programs in this package.

Rate Design

Rate design can be anything from a minor reform of current rate structure to the design of a drastically different rate structure like marginal cost pricing. The present model is useful in any such study, from the simplest to the most complex. The revenue requirement for future years is calculated by the FINANCIAL ANALYSIS program. The BILL FREQUENCY program is suitable for analyzing the current rate structure. The MARC program calculates short run marginal costs which must be known for marginal cost pricing or time-of-day pricing. The MARGINALCOST program calculates long run marginal cost including the transmission and distribution costs. The ALLOCATION code can be used to allocate the total utility cost among different user groups. The effect of time-of-day pricing on utility revenue may be analyzed with the PPP and TIME-OF-DAY PRICING programs.

Performance Evaluation

Regulatory agencies are continuously forced to judge the performance of an electric utility. Average forced outage of plants varies substantially from a well maintained system to a poorly maintained system. Improvement of the average forced outage of a utility means an increased system reliability as well as a smaller capacity expansion requirement. The MARC and WASP programs are suitable for this analysis. The FINANCIAL ANALYSIS program may be used to analyze various aspects of the historic data of performance. For example, the relationship between the inflation-adjusted cost of generating boiler maintenance and the total capacity of boilers may be determined. Further, it can be determined whether this relationship suggests improving or deteriorating performance.

Plant Construction Approval

The decisions made by regulatory agencies in approving construction of major electric plants have a great impact on present and future consumers. The Electric Utility Analysis Package can be used to evaluate and verify the system expansion schedule submitted by a utility. The WASP, MARC and LOLP programs are suitable for this purpose. These programs may also be used to evaluate the effects of load control, economic growth rate, and change of operating cost on the amount and type of construction required in the future. FINANCIAL ANALYSIS can be used to study the impact of plant constructions on the revenue requirement in the near future. By using these programs, the evaluation for the construction approval can be made more thoroughly in a short period, and thus a regulatory lag in authorization of new plants can be avoided.

Policy Analysis for Conservation and Load Control

Regulatory agencies are interested in evaluating various means of encouraging consumers to conserve electricity. These include time-of-day pricing, radio control of water heaters, voltage control and increased insulation of buildings. All of these efforts have the effect of reducing the energy requirement and/or the capacity requirement. An analysis of the cost vs. benefit relations is important in choosing a conservation policy. LOAD CONTROL, MARC, WASP, TIME OF DAY PRICING programs are useful for this type of analysis. Chapter 15 illustrates the results of such a study.

Evaluation of Generation System Reliability

Two aspects of generating system reliability are relevant to regulatory agencies as well as consumers: (1) the generating system reliability associated with the utility's own construction schedule, (2) the affects of reliability constraints on the future cost of electricity. MARC, WASP and LOLP programs along with FINANCIAL

ANALYSIS program are suitable for this analysis. Chapters 14 and 15 describe the result of analysis of the system reliability.

Rate Cases

The analyses required for rate cases involve all the types of analysis described in the preceding paragraphs, though not all are used at once. The advantages of using the present package for rate cases are, first, analysis of past history and projections of future utility operation can be made much more quickly than is possible without computer programs, and secondly, much wider analyses become possible especially where staff resources are limited. As a consequence, PUCO can not only reduce regulatory lag in rate cases but also perform in-depth study in a limited time period. Another effect of using the computer model is that the rate case analysis may be easily standardized, and accordingly, adversary testimony on analysis methodology can be avoided once the model is accepted.

1.3 Relations Among the Programs

Although each program in this package is indepedently used, many analyses would require a combination of programs. Therefore, it is important that the user understand the relations among these programs. Fig. 1 and 2 illustrate a conceptual relation among them. Fig. 1 should not be taken to mean that all programs in the figure must be used in this sequence, rather, it is intended to show generally when which program is used. Depending on the analysis, only a part of this flow chart may be used. It is also possible to start or stop in the middle. In some cases, a feedback loop may be necessary. The CONTROL, MARC, WASP, PPP, and LOLP programs need the system load data in the form of either load duration curve or hourly load data. The FRED program provides such load data, based on EEI load data for the past years. The FINANCIAL ANALYSIS program needs the estimates of the operating cost as well as construction cost in the future. This information may be directly provided by the utility, or estimated by using MARC and WASP under various alternative assumptions. The MARGINALCOST program needs the estimates for the marginal operating cost and construction costs.

The construction cost estimates may be provided directly by the utility or may be estimated by WASP. The MARC program can provide suitable estimates of the marginal production cost. The marginal cost data required by the TIME-OF-DAY PRICING program is also provided by the MARC program. The BILL FREQUENCY and ALLOCATION programs are independent of other programs.

Almost all the source information for preparing inputs for the programs is available through the annual reports of the utility.

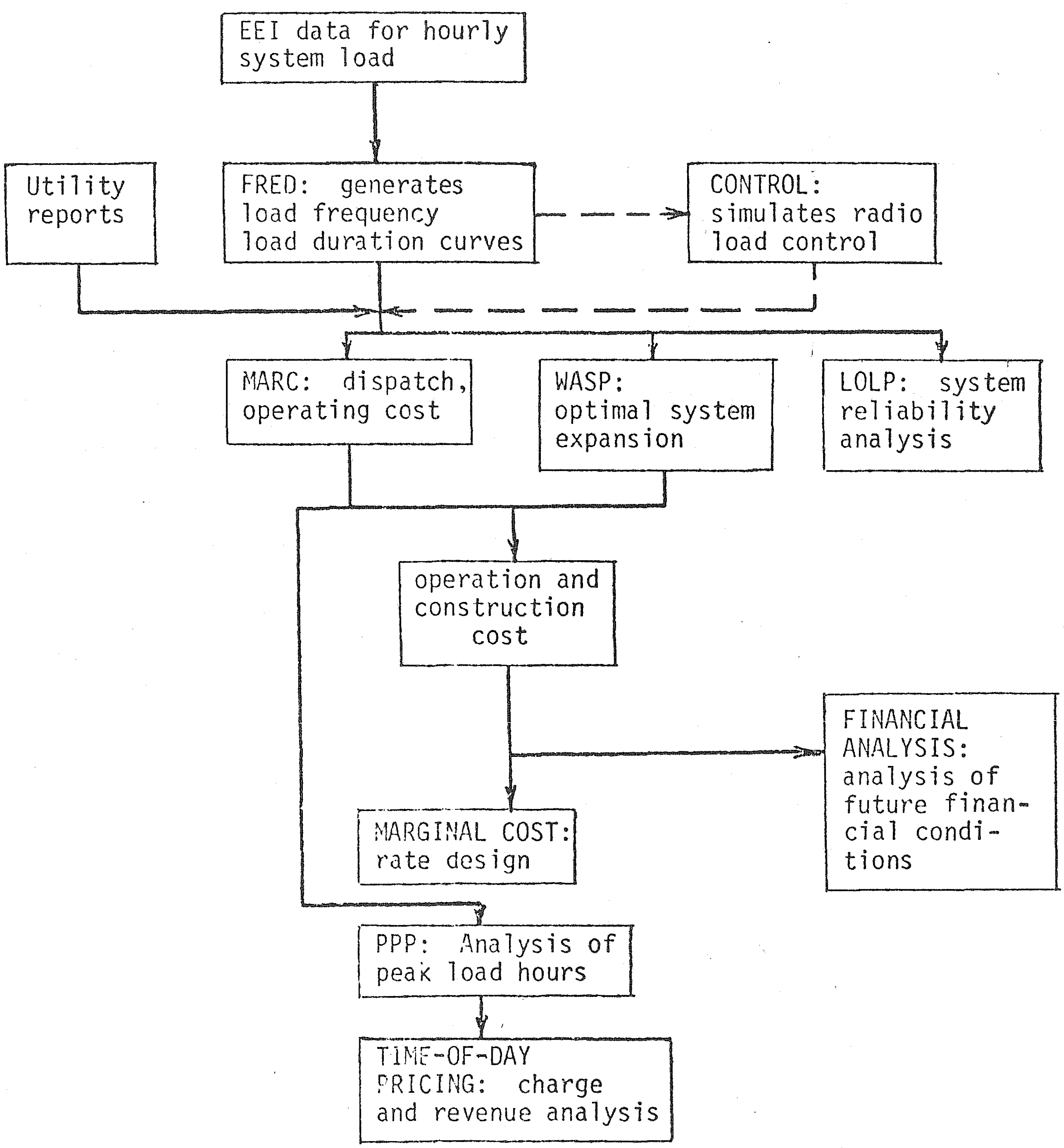


Figure 1. Relations among the programs

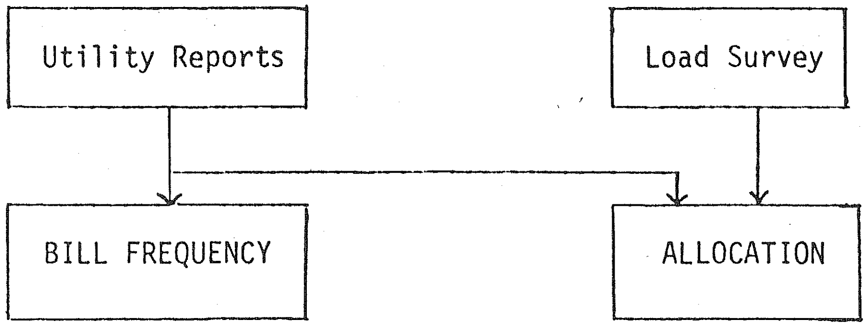


Figure 2. Relations among the programs

CHAPTER 2

LOAD DATA ANALYSIS PROGRAM: FRED

2.1 Description of the FRED Code

The FRED code[1] described in this chapter was developed at the Ohio State University to calculate and plot the load frequency and load duration curves for specified periods of an electric utility operation. The hourly load data for the system in the EEI format is the basic source of input. The FRED code provides the means of analyzing the characteristics of the electric load and also provides inputs for other programs including MARC-3A, MARC-3B, WASP, and LOAD CONTROL programs, which are described in the later chapters. This program is placed in disk storage for use at the time sharing option (TSO) terminals of IBM 370 system at Ohio State.

The input to the FRED code consists of daily hourly load data (in megawatt-hours) of Ohio electric utilities. This data is stored in disk memory by company and year. The names of the hourly load data sets stored in the disc space are printed during the execution of the program. The user of the code has the option of using data from one hour of any day to one full year. The load frequency and load duration curves are calculated by arranging the data in order of load magnitude. In other words, the data is ordered from the lowest hourly usage to the peak hourly usage regardless of the time of day which the usage occured.

The load frequency curve shows megawatt-hours on the x-axis, ranging from just below the minimum hourly load to just above the peak hourly usage. On the y-axis the number of hours for which the system load was greater than or equal to the x-axis load value but less than the next x-axis load value are given. The load duration curve shows on the x-axis the number of hours which the system exceeded the value on the y-axis.

The code can be used to calculate and display the following:

1. For the given period. determine the peak system demand and the month, day, and hour it occurred, the load factor for the period, and the megawatt-hours generated for the period.

2. List the hourly load data for a given period.

3. Calculate and plot the load frequency curve for a given period.

4. Calculate and plot the load duration curve for a given period.

5. Calculate and plot the load probability curve for a given period.

6. Calculate, list and plot the average hourly load for each day of the week for a given period.

7. Calculate, list and plot the peak hourly load for each day of the week for a given period.

The user has the option of selecting any combinations of outputs 2 through 7, while output 1 is always given.

In specifying the period of interest the user has many options. These include:

1. Specifying the starting month and day of the period of interest and the ending month and day (these are inclusive days).

2. Within that period specifying the individual days of the week to be used in the calculations.

3. Specifying the range of hours within each day to be used in the calculations. (These are conclusive hours.)

4. Specifying a range of hours, within those hours specified in Item 3, not to be used in the calculation. (These are inclusive hours.)

Using these four options the user could, for example, analyze the hourly load data for the period May 15 through August 10, for week days only (excluding holidays) for the hours starting at 10:00 a.m. and ending at 7:00 p.m. excluding the hours of 12 noon and 1:00 p.m.

In summary, the output options and the options in specifying the period of interest are many. This gives FRED much versatility.

2.2 Operation of the Program

The program FRED is stored on disks at the OSU IRCC Computer Center and is accessible from a TSO terminal through the normal "logon" procedure. This procedure is shown in Figure 1 with the allocation and run commands for FRED. Once the user has established contact with the computer by using the data phone, he enters "logon". The computer will then ask a review of questions by which the computer identifies the user and the type of programming the user is going to use. As shown in Figure 1, the questions include:

1.	USER ID?	This is a six character number assigned to the user by the OSU IRCC Customer Service group.
2.	PASSWORD?	This is a six character word assigned when the USER ID is assigned.
3.	TERMINAL ID?	This is a number on the terminal being used.
4.	UNIVERSITY ID?	This is a nine character number which is generally the user social security number.
5.	PROCEDURE NAME?	For all the programs in this report, the response is "fortuser". This identifies the user to the computer as a FORTRAN language user.

The computer will check this information against its account data files if it is correct the computer will respond with the word "READY". Before the user runs this program he should check the listing of data sets available. This is accomplished using the command:

```
listds 'puco.data' mem
```

As shown in Figure 1, the computer will respond with a list of the member names of the partitioned data set PUCO.DATA. This data set contains the hourly load data for electric utilities.

Once a current listing of data sets has been checked, the user, as shown in Figure 1, enters the following statements:

```
alloc da('puco.data') f(ft10f001)
```

The computer responds with READY. The user enters:

```
run 'puco.fredl.fort'
```

The program will compile and operate.

An example of the program operations is given in Figure 2. For this example, Dayton Power and Light 1976 load data for weekdays during the period May 15 through August 10 was analyzed for the hours of the day starting with 10:00 a.m., ending 11:00 a.m. and starting again at

2:00 p.m. and ending at 7:00 p.m. For this example all output options were selected. The hourly load data for 10:00 a.m. to 7:00 p.m. is shown in Figure 3. Figures through 4-6 show respectively the load frequency curve, the load duration curve, and the load probability curve. A listing of the average hourly load and the peak hourly load for every day in the period is shown in Table 1. Figure 7 shows the plots of the information in Table 1.

Figure 1 Logon Procedure, Request for Data Set Names, and the Alloc and Run Commands

```
OW+43929P US¢UH  YQAQS
IKJ53020A ENTER  LOGON
logon
USERID? ts0287
PASSWORD? [redacted]
TERMINAL ID? r124
UNIVERSITY ID? [redacted]
PROCEDURE NAME? fortuser
TS0287 LOGON IN PROGRESS AT 14:10:44 ON JANUARY 10, 1977
READY
listds 'puco.data' mem
PUCO.DATA
--RECFM-LRECL-BLKSIZE-DSORG
  FB    80    3120     PO
--VOLUMES--
  IRCC71
--MEMBERS--
  CC073L
  CC074L
  CEI73L
  CEI74L
  CGE73L
  CGE74L
  CGE75L
  CSO74L
  CSO75L
  DPL73L
  DPL74L
  DPL75L
  DPL76L
  DUQ73L
  DUQ74L
  OED73L
  OED74L
  OED75L
  TED73L
  TED74L
  TED75L
READY
alloc da('puco.data') f(ft10f001)
READY
run 'puco.fred1.fort'
```

Figure 2 Operations of FRED with Option 1 Output

```
LOAD FREQUENCY, LOAD DURATION, LOAD PROBABILITY
PEAK DAY, AND AVERAGE DAY CODE, SEPT., 1976
          THE OHIO STATE UNIVERSITY
          NUCLEAR ENGINEERING DEPARTMENT
          COLUMBUS, OHIO 43210

IMPORTANT--TO ELIMINATE DATA ENTRY ERRORS DATA ENTERED
BY YOU WILL BE ECHOED FOR ACCURACY.  IF THE ENTRY IS CORRECT
PRESS THE RETURN KEY. IF NOT TYPE NO THEN RETURN THEN ENTER
THE CORRECTED INPUT.
TO SELECT DATA TYPE THE SIX CHARACTER DATA SET NAME.
dpl76l
DPL76L

IEC225I 00,TS0287,LOGON1,FT10F001,431,IRCC71,PUCO.DATA
THE INCLUSIVE TIME PERIOD OF INTEREST IS SPECIFIED BY TYPING THE
STARTING MONTH AND DAY AND THE ENDING MONTH AND DAY IN THE FORMAT
--/--/--/--.FOR EXAMPLE, TO SPECIFY JUNE 1 THROUGH OCTOBER 15 TYPE
06/01/10/15 THEN PRESS RETURN.
05/15/08/10
 5/15/ 8/10

DO YOU WISH TO SPECIFY THE DAYS OF THE WEEK FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
yes
IN SPECIFYING THE DAYS OF THE WEEK THE FOLLOWING
OPTIONS ARE AVAILABLE:
          1.   WEEKDAYS WITHOUT HOLIDAYS
          2.   WEEKENDS WITH HOLIDAYS
          3.   INDIVIDUAL DAYS OF THE WEEK

TO SPECIFY THE DESIRED OPTION, TYPE THAT NUMBER, THEN RETURN
3
TO SPECIFY INDIVIDUAL DAYS, TYPE THE STANDARD ABBREVIATION
FOR A GIVEN DAY THEN PRESS RETURN. REPEAT THIS FOR EACH DAY
OF INTEREST. WHEN ALL DAYS OF INTEREST HAVE BEEN SPECIFIED
TYPE THE WORD END THEN PRESS RETURN.  HOLIDAYS ARE INCLUDED IN THE
CALCULATION BY TYPING HOLI THEN PRESS RETURN
mon
tues
wed
thur
fri
end
```

Figure 2 (Continued)

```
DO YOU WISH TO SPECIFY THE HOURS OF THE DAY FOR WHICH
THE CALCULATIONS ARE TO BE MADE?
yes
TO SPECIFY THE PERIOD OF THE DAY YOU ARE INTERESTED IN TYPE
THE STARTING HOUR AND THE ENDING HOUR USING MILITARY
NOTATION IN THE FORMAT
--/--  FOR EXAMPLE, TO SPECIFY 11AM THROUGH 4PM TYPE
11/16 THEN PRESS RETURN
10/19
10/19

DO YOU WISH TO SPECIFY A RANGE OF HOURS DURING THE DAY
WHICH ARE NOT USED IN THE CALCULATION?
yes
TYPE THE RANGE OF HOURS NOT TO BE USED IN THE
CALCULATION IN THE FORMAT
--/--    THEN PRESS RETURN
12/13
12/13

DO YOU WISH TO SEE THE SELECTED DATA?
yes
DO YOU WISH TO SEE THE LOAD FREQUENCY PLOT?
yes
DO YOU WISH TO SEE THE LOAD DURATION CURVE?
yes
DO YOU WISH TO SEE THE LOAD PROBABILITY CURVE?
yes
DO YOU WISH TO HAVE AN AVERAGE AND PEAK DAY CALCULATED
FOR EACH DAY OF THE WEEK?
yes
OUTPUT FOR THE AVERAGE AND PEAK DAY
CALCULATION IS AVAILABLE IN
  1  SUMMARY TABLE OF THE AVERAGE LOAD PER HOUR
     PER DAY AND THE PEAK LOAD PER HOUR PER DAY.
  2  A DAY BY DAY PLOT OF THE SUMMARY DATA
  3  BOTH OF THE ABOVE

TYPE THE NUMBER OF THE OUTPUT OPTION
3
THIS PROGRAM WILL NOW GENERATE OUTPUT FOR ABOUT 20 MINS
TAKE A COFFEE BREAK

                PEAK MW          MO/DA/HR
                 1793.            7/15/16

                 THE LOAD FACTOR IS 76.4%

                 THE TOTAL MEGAWATTHOUR SALES ARE     835218.
```

Figure 3 Hourly Load Data

MO/DA		D	10 (AM/PM)	11	12	13	14	15	16	17	18	19
5	15	6	1002	1076	1074	1077	1047	1015	1000	1004	1006	981
5	16	7	759	795	840	867	849	828	815	828	837	849
5	17	1	1252	1326	1314	1313	1311	1283	1262	1269	1252	1225
5	18	2	1315	1308	1299	1288	1276	1252	1224	1226	1192	1140
5	19	3	1258	1284	1236	1238	1226	1211	1193	1194	1154	1109
5	20	4	1236	1270	1260	1257	1267	1262	1258	1248	1228	1180
5	21	5	1262	1302	1299	1308	1313	1302	1281	1275	1237	1201
5	22	6	988	1032	1040	1025	998	957	962	976	985	981
5	23	7	783	809	841	853	841	810	799	811	826	815
5	24	1	1255	1304	1285	1283	1267	1242	1205	1225	1193	1141
5	25	2	1222	1249	1235	1246	1237	1213	1201	1208	1174	1128
5	26	3	1224	1253	1231	1243	1246	1229	1205	1214	1179	1138
5	27	4	1233	1261	1249	1248	1257	1248	1244	1234	1211	1164
5	28	5	1243	1274	1260	1248	1249	1247	1210	1210	1145	1116
5	29	6	895	936	944	936	900	912	887	896	913	899
5	30	7	715	750	780	803	780	764	762	772	776	774
5	31	8	760	837	889	886	867	844	839	839	850	867

MO/DA		D	10 (AM/PM)	11	12	13	14	15	16	17	18	19
6	1	2	1261	1330	1331	1339	1335	1300	1286	1259	1235	1191
6	2	3	1251	1291	1279	1288	1284	1270	1249	1265	1212	1159
6	3	4	1269	1312	1284	1290	1291	1267	1254	1249	1212	1172
6	4	5	1271	1315	1301	1307	1319	1285	1298	1278	1241	1183
6	5	6	991	1049	1058	1047	1015	999	977	994	1005	990
6	6	7	777	824	858	884	875	862	864	876	891	892
6	7	1	1303	1395	1394	1406	1413	1413	1392	1403	1384	1348
6	8	2	1321	1396	1398	1428	1453	1463	1463	1472	1442	1400
6	9	3	1308	1390	1438	1511	1506	1505	1535	1535	1506	1469
6	10	4	1368	1458	1489	1530	1557	1539	1528	1534	1489	1449
6	11	5	1357	1411	1462	1504	1527	1552	1556	1557	1532	1495
6	12	6	1140	1247	1294	1323	1337	1344	1358	1380	1383	1368
6	13	7	938	1028	1090	1161	1179	1178	1173	1162	1143	1148
6	14	1	1476	1594	1616	1670	1695	1689	1693	1688	1652	1605
6	15	2	1463	1561	1558	1602	1633	1634	1620	1617	1566	1514
6	16	3	1342	1391	1380	1382	1373	1340	1321	1301	1262	1203
6	17	4	1254	1330	1353	1360	1391	1385	1390	1405	1371	1333
6	18	5	1301	1372	1417	1466	1487	1506	1498	1486	1483	1397
6	19	6	1055	1144	1172	1173	1177	1172	1137	1119	1099	1066
6	20	7	791	848	877	896	891	876	853	865	861	850
6	21	1	1226	1300	1312	1311	1315	1298	1275	1267	1247	1183
6	22	2	1237	1317	1326	1337	1341	1340	1321	1316	1278	1228
6	23	3	1233	1314	1329	1364	1381	1377	1376	1363	1324	1271
6	24	4	1269	1335	1343	1374	1368	1353	1338	1331	1287	1254
6	25	5	1347	1419	1416	1420	1415	1368	1332	1301	1244	1195
6	26	6	1009	1095	1114	1120	1120	1119	1130	1154	1175	1167
6	27	7	851	929	977	1025	1053	1065	1119	1120	1146	1146
6	28	1	1325	1396	1383	1397	1418	1415	1429	1420	1382	1342
6	29	2	1366	1446	1503	1517	1541	1557	1536	1535	1511	1452
6	30	3	1235	1301	1310	1323	1334	1316	1304	1283	1218	1164

Figure 3 (Continued)

MO/DA		D	AM/PM 10	11	12	13	14	15	16	17	18	19
7	1	4	1189	1250	1269	1266	1284	1261	1261	1256	1221	1185
7	2	5	1203	1264	1287	1296	1305	1308	1282	1250	1204	1145
7	3	6	897	960	993	1000	995	989	983	998	997	978
7	4	8	744	783	836	851	822	810	802	807	819	814
7	5	1	772	863	919	943	928	920	912	932	918	924
7	6	2	1258	1355	1384	1432	1449	1447	1403	1363	1334	1280
7	7	3	1262	1331	1344	1390	1425	1405	1445	1428	1404	1342
7	8	4	1305	1378	1439	1453	1476	1466	1475	1487	1442	1420
7	9	5	1302	1386	1402	1439	1473	1486	1479	1469	1432	1386
7	10	6	1087	1190	1275	1293	1286	1315	1303	1323	1312	1310
7	11	7	992	1113	1178	1251	1265	1271	1291	1305	1320	1299
7	12	1	1419	1472	1486	1489	1493	1474	1474	1465	1423	1369
7	13	2	1219	1237	1303	1345	1350	1362	1354	1377	1349	1313
7	14	3	1286	1374	1443	1501	1573	1608	1653	1674	1655	1642
7	15	4	1562	1672	1702	1767	1790	1789	1793	1786	1664	1422
7	16	5	1334	1389	1404	1416	1454	1444	1416	1393	1344	1285
7	17	6	979	1046	1062	1068	1040	1042	1026	1027	1047	1036
7	18	7	770	825	867	909	912	917	920	943	957	968
7	19	1	1279	1363	1400	1445	1476	1473	1482	1487	1461	1412
7	20	2	1280	1356	1362	1399	1445	1469	1457	1493	1457	1422
7	21	3	1375	1465	1504	1558	1612	1636	1585	1543	1512	1475
7	22	4	1408	1488	1531	1572	1572	1597	1594	1606	1567	1518
7	23	5	1506	1604	1655	1712	1730	1751	1742	1737	1702	1673
7	24	6	1249	1357	1418	1440	1447	1434	1422	1429	1398	1368
7	25	7	841	903	962	1016	1048	1062	1085	1102	1136	1126
7	26	1	1316	1404	1445	1493	1526	1544	1535	1547	1539	1497
7	27	2	1293	1375	1413	1481	1536	1582	1537	1585	1509	1455
7	28	3	1382	1491	1518	1586	1617	1632	1620	1615	1590	1541
7	29	4	1345	1413	1417	1451	1502	1511	1521	1524	1495	1457
7	30	5	1331	1390	1429	1446	1489	1489	1485	1473	1445	1405
7	31	6	1033	1144	1204	1233	1263	1259	1261	1273	1266	1234

MO/DA		D	AM/PM 10	11	12	13	14	15	16	17	18	19
8	1	7	776	840	867	921	903	890	887	899	910	903
8	2	1	1211	1301	1318	1331	1356	1351	1333	1315	1287	1232
8	3	2	1174	1236	1269	1276	1308	1320	1305	1300	1272	1230
8	4	3	1194	1280	1277	1324	1342	1344	1358	1365	1329	1291
8	5	4	1262	1328	1354	1396	1426	1434	1435	1440	1391	1360
8	6	5	1301	1377	1369	1379	1384	1341	1295	1270	1242	1189
8	7	6	945	1012	1027	1025	1007	973	955	950	957	939
8	8	7	756	797	826	865	849	834	828	845	870	859
8	9	1	1206	1302	1317	1341	1368	1344	1341	1340	1310	1260
8	10	2	1233	1302	1326	1361	1394	1397	1416	1444	1421	1372

Figure 4

```
LOAD FREQUENCY CURVE FOR THE PERIOD  5/15/10- 8/10/19.

  LOAD   FREQ
   MW     HR   *****************************************************
  772.0    1.0 +                                                   *
  807.2    0.0 +                                                   *
  842.4    0.0 +                                                   *
  877.6    1.0 +                                                   *
  912.8    5.0 +---+                                               *
  948.0    1.0 +                                                   *
  983.2    0.0 +                                                   *
 1018.4    0.0 +                                                   *
 1053.7    0.0 +                                                   *
 1088.9    0.0 +                                                   *
 1124.1    6.0 +----+                                              *
 1159.3    9.0 +------+                                            *
 1194.5   30.1 +-----------------------+                           *
 1229.7   39.1 +-------------------------------+                   *
 1264.9   60.9 +-------------------------------------------------+ *
 1300.1   56.0 +--------------------------------------------+      *
 1335.3   43.0 +----------------------------------+                *
 1370.5   39.0 +-------------------------------+                   *
 1405.7   42.0 +---------------------------------+                 *
 1440.9   27.1 +---------------------+                             *
 1476.1   38.0 +------------------------------+                    *
 1511.3   21.0 +----------------+                                  *
 1546.5   22.0 +-----------------+                                 *
 1581.8   12.0 +---------+                                         *
 1617.0   13.0 +----------+                                        *
 1652.2    6.0 +----+                                              *
 1687.4    8.0 +-----+                                             *
 1722.6    2.0 ++                                                  *
 1757.8    2.0 ++                                                  *
 1793.0    4.0 +--+                                                *
               +++++++++++++++++++++++++++++++++++++++++++++++++++++
```

Figure 5

```
 LOAD DURATION CURVE FOR THE PERIOD  5/15/10- 8/10/19.

  TIME     LOAD
  HRS       MW     *BASE LOAD**********************************************
    3.0   1793.0  *--/  /--------------------------------------------+   *
   19.7   1649.9  *--/  /---------------------------------------+        *
   36.4   1602.8  *--/  /-------------------------------------+          *
   53.2   1557.5  *--/  /-----------------------------------+            *
   69.9   1533.3  *--/  /----------------------------------+             *
   86.6   1503.4  *--/  /---------------------------------+              *
  103.3   1486.3  *--/  /--------------------------------+               *
  120.1   1474.3  *--/  /-------------------------------+                *
  136.8   1454.0  *--/  /-------------------------------+                *
  153.5   1431.2  *--/  /------------------------------+                 *
  170.2   1415.1  *--/  /-----------------------------+                  *
  187.0   1400.3  *--/  /----------------------------+                   *
  203.7   1386.6  *--/  /----------------------------+                   *
  220.4   1372.4  *--/  /---------------------------+                    *
  237.1   1356.1  *--/  /---------------------------+                    *
  253.9   1341.2  *--/  /--------------------------+                     *
  270.6   1331.3  *--/  /--------------------------+                     *
  287.3   1319.1  *--/  /-------------------------+                      *
  304.0   1307.0  *--/  /-------------------------+                      *
  320.8   1298.2  *--/  /------------------------+                       *
  337.5   1285.7  *--/  /------------------------+                       *
  354.2   1273.2  *--/  /-----------------------+                        *
  370.9   1265.5  *--/  /-----------------------+                        *
  387.7   1256.4  *--/  /----------------------+                         *
  404.4   1246.2  *--/  /----------------------+                         *
  421.1   1233.7  *--/  /---------------------+                          *
  437.8   1217.8  *--/  /---------------------+                          *
  454.5   1200.2  *--/  /--------------------+                           *
  471.3   1161.7  *--/  /-------------------+                            *
  488.0    772.0  *--/  /---+                                            *
                   *BASE LOAD**********************************************
```

Figure 6

```
LOAD PROBABILITY CURVE FOR THE PERIOD  5/15/10- 8/10/19.

  LOAD     PROB
   MW          **********************************************************
 772.0 1.00000 *------------------------------------------------------+ *
 807.2 0.99795 *-----------------------------------------------------+  *
 842.4 0.99795 *-----------------------------------------------------+  *
 877.6 0.99795 *-----------------------------------------------------+  *
 912.8 0.99594 *-----------------------------------------------------+  *
 948.0 0.98561 *-----------------------------------------------------+  *
 983.2 0.98360 *-----------------------------------------------------+  *
1018.4 0.98360 *-----------------------------------------------------+  *
1053.7 0.98360 *-----------------------------------------------------+  *
1088.9 0.98360 *-----------------------------------------------------+  *
1124.1 0.98360 *-----------------------------------------------------+  *
1159.3 0.97126 *----------------------------------------------------+   *
1194.5 0.95279 *---------------------------------------------------+    *
1229.7 0.89114 *------------------------------------------------+       *
1264.9 0.81110 *--------------------------------------------+           *
1300.1 0.68632 *------------------------------------+                   *
1335.3 0.57153 *------------------------------+                         *
1370.5 0.48344 *--------------------------+                             *
1405.7 0.40357 *---------------------+                                  *
1440.9 0.31754 *----------------+                                       *
1476.1 0.26212 *-------------+                                          *
1511.3 0.18422 *---------+                                              *
1546.5 0.14124 *-------+                                                *
1581.8 0.09624 *-----+                                                  *
1617.0 0.07165 *--+                                                     *
1652.2 0.04502 *-+                                                      *
1687.4 0.03274 *+                                                       *
1722.6 0.01637 *+                                                       *
1757.8 0.01225 *+                                                       *
1793.0 0.00818 *+                                                       *
               **********************************************************
```

Table 1 Average and Peak Load Data

THE FOLLOWING ARE AVERAGE LOAD DAYS FOR THE PERIOD 5/15 TO 8/10.

HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WKED
1	822.	896.	917.	944.	941.	904.	906.	814.	702.	850.
2	770.	829.	855.	872.	868.	839.	822.	747.	638.	775.
3	737.	790.	807.	827.	824.	797.	771.	701.	613.	728.
4	727.	772.	791.	803.	796.	778.	742.	674.	591.	701.
5	730.	768.	788.	803.	794.	776.	730.	663.	581.	689.
6	766.	804.	816.	844.	827.	811.	732.	656.	582.	687.
7	853.	902.	917.	929.	921.	904.	749.	647.	572.	691.
8	1022.	1077.	1078.	1105.	1092.	1075.	816.	680.	598.	740.
9	1161.	1197.	1206.	1229.	1226.	1204.	916.	747.	673.	823.
10	1253.	1280.	1279.	1308.	1313.	1287.	1021.	812.	752.	908.
11	1335.	1344.	1347.	1375.	1375.	1355.	1099.	872.	810.	977.
12	1349.	1362.	1357.	1391.	1392.	1370.	1129.	914.	863.	1013.
13	1369.	1389.	1392.	1414.	1412.	1395.	1135.	954.	869.	1035.
14	1381.	1408.	1410.	1432.	1429.	1412.	1126.	954.	845.	1029.
15	1371.	1410.	1406.	1426.	1423.	1407.	1118.	946.	827.	1020.
16	1361.	1398.	1404.	1424.	1406.	1399.	1108.	950.	821.	1016.
17	1363.	1400.	1398.	1425.	1392.	1396.	1118.	961.	823.	1026.
18	1337.	1365.	1362.	1382.	1354.	1360.	1119.	973.	835.	1033.
19	1295.	1317.	1317.	1326.	1306.	1312.	1101.	969.	841.	1023.
20	1244.	1265.	1265.	1270.	1248.	1259.	1066.	956.	818.	999.
21	1221.	1236.	1243.	1249.	1212.	1232.	1032.	960.	805.	983.
22	1242.	1258.	1273.	1271.	1212.	1251.	1050.	1013.	854.	1019.
23	1177.	1189.	1207.	1209.	1149.	1180.	1009.	997.	843.	991.
24	1042.	1059.	1070.	1082.	1033.	1057.	914.	911.	786.	903.

THE FOLLOWING ARE PEAK LOAD DAYS FOR THE PERIOD 5/15 TO 8/10.

HR	MON	TUES	WED	THUR	FRI	WKDA	SAT	SUN	HOLI	WKED
1	1066.	1122.	1076.	1201.	1068.	1201.	1138.	1017.	733.	1138.
2	989.	1030.	985.	1106.	985.	1106.	1041.	931.	656.	1041.
3	932.	964.	939.	1032.	919.	1032.	962.	875.	644.	962.
4	909.	930.	912.	977.	896.	977.	929.	827.	603.	929.
5	900.	913.	905.	986.	889.	986.	901.	816.	600.	901.
6	932.	950.	932.	991.	921.	991.	896.	795.	598.	896.
7	991.	1028.	1029.	1052.	1010.	1052.	901.	782.	573.	901.
8	1163.	1217.	1172.	1248.	1188.	1248.	957.	840.	606.	957.
9	1348.	1350.	1268.	1425.	1374.	1425.	1098.	901.	675.	1098.
10	1476.	1463.	1382.	1562.	1506.	1562.	1249.	992.	780.	1249.
11	1594.	1561.	1491.	1672.	1604.	1672.	1357.	1113.	837.	1357.
12	1616.	1558.	1518.	1702.	1655.	1702.	1418.	1178.	889.	1418.
13	1670.	1602.	1580.	1767.	1712.	1767.	1440.	1251.	886.	1440.
14	1695.	1633.	1617.	1790.	1730.	1790.	1447.	1265.	867.	1447.
15	1689.	1634.	1636.	1789.	1751.	1789.	1434.	1271.	844.	1434.
16	1693.	1620.	1653.	1793.	1742.	1793.	1422.	1291.	839.	1422.
17	1688.	1617.	1674.	1786.	1737.	1786.	1429.	1305.	839.	1429.
18	1652.	1566.	1655.	1664.	1702.	1702.	1398.	1326.	850.	1398.
19	1605.	1514.	1642.	1518.	1673.	1673.	1368.	1299.	867.	1368.
20	1546.	1438.	1582.	1467.	1569.	1582.	1324.	1281.	823.	1324.
21	1482.	1402.	1538.	1436.	1485.	1538.	1275.	1266.	837.	1275.
22	1504.	1423.	1561.	1437.	1484.	1561.	1269.	1312.	921.	1312.
23	1453.	1351.	1506.	1357.	1411.	1506.	1227.	1280.	904.	1280.
24	1286.	1213.	1373.	1221.	1291.	1373.	1113.	1179.	808.	1179.

Figure 7 Plots of Average and Peak Load Data

AVERAGE AND PEAK LOADS FOR MONDAYS

HR	AVE	PEAK
1	822.	1066.
2	770.	989.
3	737.	932.
4	727.	909.
5	730.	900.
6	766.	932.
7	853.	991.
8	1022.	1163.
9	1161.	1348.
10	1253.	1476.
11	1335.	1594.
12	1349.	1616.
13	1369.	1679.
14	1381.	1695.
15	1371.	1689.
16	1361.	1693.
17	1363.	1688.
18	1337.	1652.
19	1295.	1605.
20	1244.	1546.
21	1221.	1482.
22	1242.	1504.
23	1177.	1453.
24	1042.	1286.

THERE ARE 12 MONDAYS
IN THE PERIOD 5/15/- 8/10/.

AVERAGE AND PEAK LOADS FOR TUESDAYS

HR	AVE	PEAK
1	896.	1122.
2	829.	1030.
3	790.	964.
4	772.	930.
5	768.	913.
6	804.	950.
7	902.	1028.
8	1077.	1217.
9	1197.	1350.
10	1280.	1463.
11	1344.	1561.
12	1362.	1558.
13	1389.	1602.
14	1408.	1633.
15	1410.	1634.
16	1398.	1620.
17	1400.	1617.
18	1365.	1566.
19	1317.	1514.
20	1265.	1438.
21	1236.	1402.
22	1258.	1423.
23	1189.	1351.
24	1059.	1213.

THERE ARE 13 TUESDAYS
IN THE PERIOD 5/15/- 8/10/.

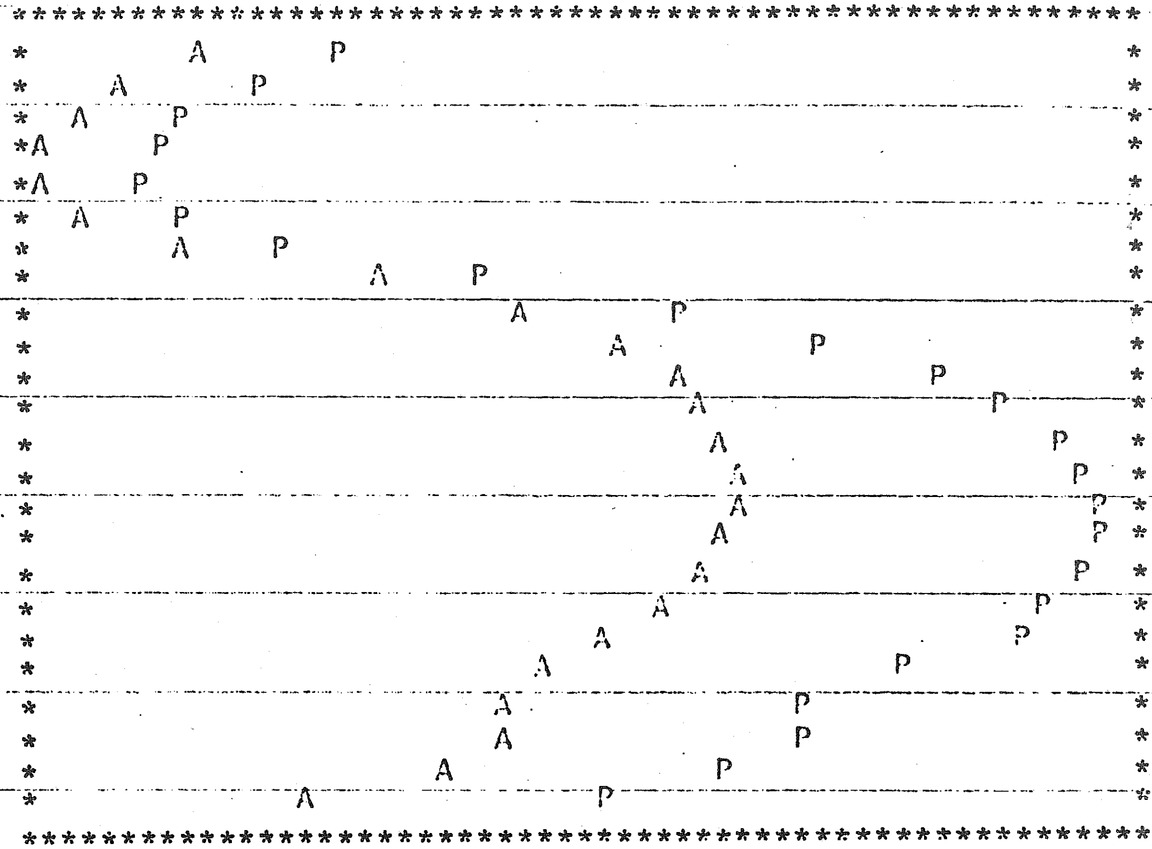
```
                AVERAGE AND PEAK LOADS FOR WEDNESDAYS
HR  AVE   PEAK **********************************************************
 1  917. 1076. *        A        P                                      *
 2  855.  985. *    A       P                                           *
 3  807.  939. * A       P                                              *
 4  791.  912. *A      P                                                *
 5  788.  905. *A      P                                                *
 6  816.  932. *  A      P                                              *
 7  917. 1029. *        A      P                                        *
 8 1078. 1172. *                 A     P                                *
 9 1206. 1268. *                         A    P                         *
10 1279. 1382. *                             A       P                  *
11 1347. 1491. *                                  A        P            *
12 1357. 1518. *                                   A         P          *
13 1392. 1586. *                                     A           P      *
14 1410. 1617. *                                      A            P    *
15 1406. 1636. *                                      A             P   *
16 1404. 1653. *                                      A              P  *
17 1398. 1674. *                                      A               P *
18 1362. 1655. *                                   A                 P  *
19 1317. 1642. *                                 A                  P   *
20 1265. 1582. *                              A                 P       *
21 1243. 1538. *                            A                 P         *
22 1273. 1561. *                              A                P        *
23 1207. 1506. *                          A                 P           *
24 1070. 1373. *                  A                 P                   *
               **********************************************************

                 THERE ARE 12 WEDNESDAYS
                 IN THE PERIOD  5/15/- 8/10/.

                AVERAGE AND PEAK LOADS FOR THURSDAYS
HR  AVE   PEAK **********************************************************
 1  944. 1201. *        A            P                                  *
 2  872. 1106. *    A           P                                       *
 3  827. 1032. * A          P                                           *
 4  803.  977. *A        P                                              *
 5  803.  980. *A         P                                             *
 6  844.  991. *  A       P                                             *
 7  929. 1052. *       A     P                                          *
 8 1105. 1248. *                A       P                               *
 9 1229. 1425. *                       A          P                     *
10 1308. 1562. *                            A             P             *
11 1375. 1672. *                                A               P       *
12 1391. 1702. *                                A                P      *
13 1414. 1767. *                                  A                  P  *
14 1432. 1790. *                                   A                  P *
15 1426. 1789. *                                  A                   P *
16 1424. 1793. *                                  A                   P *
17 1425. 1786. *                                  A                   P *
18 1382. 1664. *                                A              P        *
19 1326. 1518. *                             A         P                *
20 1270. 1467. *                          A          P                  *
21 1249. 1436. *                         A         P                    *
22 1271. 1437. *                          A        P                    *
23 1209. 1357. *                       A       P                        *
24 1082. 1221. *                A      P                                *
               **********************************************************

                 THERE ARE 12 THURSDAYS
                 IN THE PERIOD  5/15/- 8/10/.
```

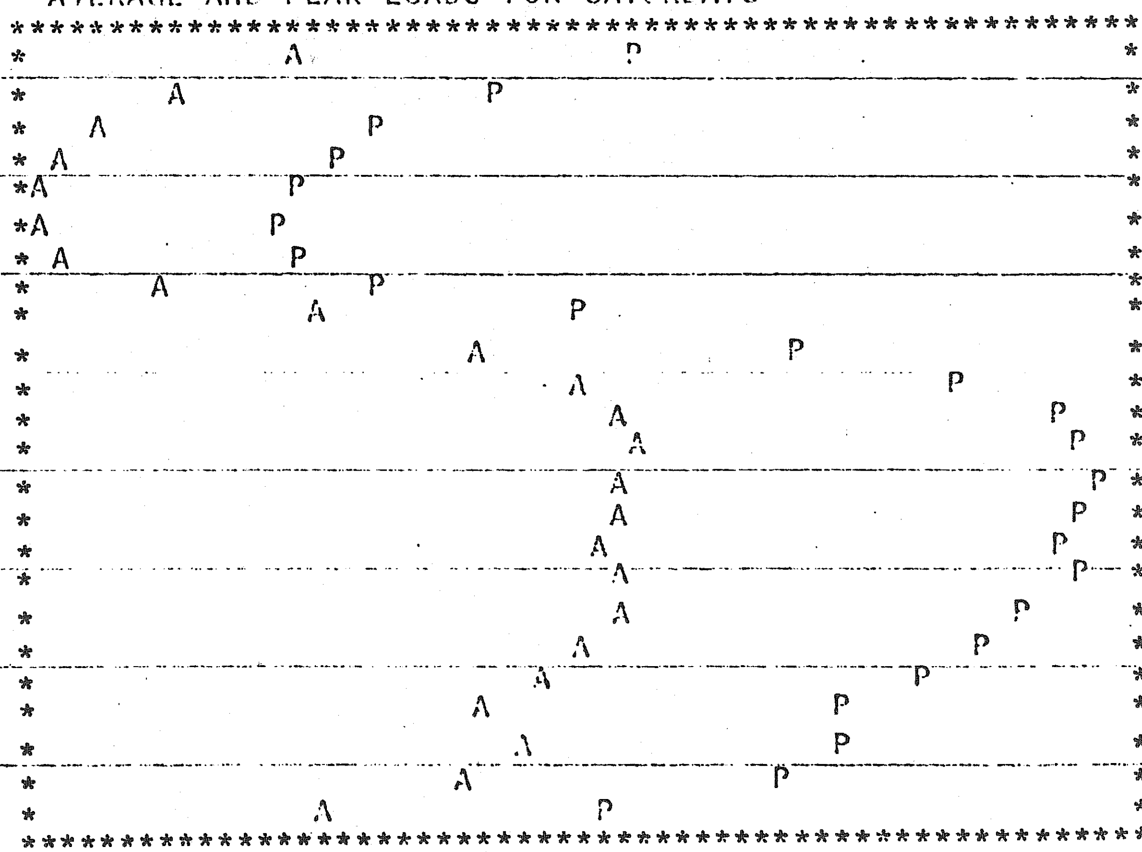
AVERAGE AND PEAK LOADS FOR FRIDAYS



HR	AVE	PEAK
1	941.	1068.
2	868.	985.
3	824.	919.
4	796.	896.
5	794.	889.
6	827.	921.
7	921.	1010.
8	1092.	1188.
9	1226.	1374.
10	1313.	1506.
11	1375.	1604.
12	1392.	1655.
13	1412.	1712.
14	1429.	1730.
15	1423.	1751.
16	1406.	1742.
17	1392.	1737.
18	1354.	1702.
19	1306.	1673.
20	1248.	1569.
21	1212.	1485.
22	1212.	1484.
23	1149.	1411.
24	1033.	1291.

THERE ARE 12 FRIDAYS
IN THE PERIOD 5/15/- 8/10/.

AVERAGE AND PEAK LOADS FOR SATURDAYS



HR	AVE	PEAK
1	906.	1138.
2	822.	1041.
3	771.	962.
4	742.	929.
5	730.	901.
6	732.	896.
7	749.	901.
8	816.	957.
9	916.	1098.
10	1021.	1249.
11	1099.	1357.
12	1129.	1418.
13	1135.	1440.
14	1120.	1447.
15	1118.	1434.
16	1108.	1422.
17	1118.	1429.
18	1119.	1398.
19	1101.	1368.
20	1066.	1324.
21	1032.	1275.
22	1050.	1269.
23	1009.	1227.
24	914.	1113.

THERE ARE 13 SATURDAYS
IN THE PERIOD 5/15/- 8/10/.

AVERAGE AND PEAK LOADS FOR SUNDAYS

HR	AVE	PEAK	
1	814.	1017.	A P
2	747.	931.	A P
3	701.	875.	A P
4	674.	827.	A P
5	663.	816.	A P
6	656.	795.	A P
7	647.	782.	A P
8	680.	840.	A P
9	747.	901.	A P
10	812.	992.	A P
11	872.	1113.	A P
12	914.	1178.	A P
13	954.	1251.	A P
14	954.	1265.	A P
15	946.	1271.	A P
16	950.	1291.	A P
17	961.	1305.	A P
18	973.	1326.	A P
19	969.	1299.	A P
20	956.	1281.	A P
21	960.	1266.	A P
22	1013.	1312.	A P
23	997.	1280.	A P
24	911.	1179.	A P

THERE ARE 12 SUNDAYS
IN THE PERIOD 5/15/- 8/10/.

AVERAGE AND PEAK LOADS FOR HOLIDAYS

HR	AVE	PEAK	
1	702.	733.	A P
2	638.	656.	A P
3	613.	644.	A P
4	591.	603.	A P
5	581.	600.	A P
6	582.	590.	AP
7	572.	573.	B
8	598.	606.	AP
9	673.	675.	AP
10	752.	760.	A P
11	810.	837.	A P
12	863.	889.	A P
13	869.	886.	A P
14	845.	867.	A P
15	827.	844.	A P
16	821.	839.	A P
17	823.	839.	A P
18	835.	850.	A P
19	841.	867.	A P
20	818.	823.	AP
21	805.	837.	A P
22	854.	921.	A P
23	843.	904.	A P
24	786.	808.	A P

THERE ARE 2 HOLIDAYS
IN THE PERIOD 5/15/- 8/10/.

```
                 AVERAGE AND PEAK LOADS FOR WEEKDAYS
HR  AVE  PEAK  **************************************************************
 1  904. 1201. *        A               P                                   *
 2  839. 1106. *   A               P                                        *
 3  797. 1032. * A            P                                             *
 4  778.  977. *A          P                                                *
 5  776.  986. *A           P                                               *
 6  811.  991. *  A         P                                               *
 7  904. 1052. *        A      P                                            *
 8 1075. 1248. *                  A        P                                *
 9 1204. 1425. *                        A            P                      *
10 1287. 1562. *                             A               P              *
11 1355. 1672. *                                 A                 P        *
12 1370. 1702. *                                  A                 P       *
13 1395. 1767. *                                   A                    P   *
14 1412. 1790. *                                    A                     P *
15 1407. 1789. *                                    A                     P *
16 1399. 1793. *                                   A                      P *
17 1396. 1786. *                                   A                      P *
18 1360. 1702. *                                 A                  P       *
19 1312. 1673. *                               A                   P        *
20 1259. 1582. *                           A                  P             *
21 1232. 1538. *                          A                 P               *
22 1251. 1561. *                           A                 P              *
23 1186. 1506. *                       A                  P                 *
24 1057. 1373. *                A                 P                         *
               **************************************************************

                   THERE ARE 61 WEEKDAYS
                   IN THE PERIOD  5/15/- 8/10/.
```

```
                   AVERAGE AND PEAK LOADS FOR WEEKEND DAYS
HR  AVE  PEAK  **************************************************************
 1  850. 1138. *            A                    P                          *
 2  775. 1041. *      A                    P                                *
 3  728.  962. *   A                 P                                      *
 4  701.  929. * A                P                                         *
 5  689.  901. *A               P                                           *
 6  687.  896. *A               P                                           *
 7  691.  901. *A               P                                           *
 8  740.  957. *    A                P                                      *
 9  823. 1098. *          A                    P                            *
10  908. 1249. *                A                         P                 *
11  977. 1357. *                      A                            P        *
12 1013. 1418. *                         A                             P    *
13 1035. 1440. *                          A                               P *
14 1029. 1447. *                          A                               P *
15 1020. 1434. *                         A                               P  *
16 1016. 1422. *                         A                             P    *
17 1026. 1429. *                          A                              P  *
18 1033. 1398. *                          A                            P    *
19 1023. 1368. *                         A                         P        *
20  999. 1324. *                        A                       P           *
21  983. 1275. *                       A                     P              *
22 1019. 1312. *                         A                      P           *
23  991. 1280. *                       A                     P              *
24  903. 1179. *                A                    P                      *
               **************************************************************

                   THERE ARE 27 WEEKEND DAYS
                   IN THE PERIOD  5/15/- 8/10/.
```

References

(1) R. Baker, M. S. Gerber, B. Maki and S. Nakamura, "Manual for the Load Data Analysis Code (FRED)," prepared for The Public Utilities commission of Ohio, The Ohio State University, Department of Mechanical Engineering (1976).

CHAPTER 3

MARGINAL OPERATING COST PROGRAMS: MARC-3A and MARC-3B

3.1 Objectives

This chapter describes the MARC-3A and MARC-3B programs (FORTRAN IV) developed at The Ohio State University. These programs are designed to calculate the production cost of electricity generation for a specified period. Their ability to calculate marginal operating cost for production as a function of demand level is particularly important. These programs can be used for various analyses such as:

1. analysis of the effects of some types of fuel cost on the annual production cost,

2. effect of load control techniques on the production cost as well as on reliability of the system,

3. effect of load control techniques on the production cost as well as on reliability of the system,

4. calculation of marginal cost as a function of demand level, and

5. effect of delay or advance of a new plant construction schedule on reliability and production cost.

The programs are written in FORTRAN-IV and can be easily modified by the user to suit the demands of his application. In fact, several versions of the program have been utilized at PUCO already. Thus, only the basic versions of the programs are reported here.

The MARC-3A and -3B programs are developed as extentions of the previous program, MARC-2. The major difference between MARC-3A and MARC-2 is that the effect of forced outage is more accurately taken into consideration in the former than the latter. In MARC-2, the effect of forced outages was treated by derating capacities, which was found to underestimate the use of peaking units.

Although MARC-3A and MARC-3B use almost the same input and can be used interchangedly, the algorithms of the two programs are somewhat different. The MARC-3A program simulates the load dispatch of an electric utility on an hourly basis, assuming the hourly load is given. The times when forced outages occur to each generating unit are determined by using random numbers: this is a Monte Carlo approach. A detailed schedule of maintenance outages is specified by the user.

MARC-3B simulates the load dispatch on a monthly basis by using a probabilistic simulation method. The load for a month is represented by a load duration curve for that month, which may be obtained from the same hourly load data for MARC-3A. In this program, the forced outage rate and the maintenance outage rate for each month are combined and incorporated into the equivalent load duration curve as explained in Appendix 3A. MARC-3B also calculates the LOLP (loss-of-load probability). The algorithm of this program is essentially the same as that part of the WASP program (Chapter 4) which calcualtes the production cost for each subinterval of the whole study period, except MARC-3B uses the piecewise linear functions[7] rather than the Fourier series to express equivalent load duration curves.

The remainder of this chapter describes the algorithms of the programs, input requirements and the procedure for operations. Appendix 3-B summarizes the load data available, Appendix 3Cand 3Dillustrate the output of MARC-3A and 3B, respectively.

3.2 The MARC-3A Program

3.2.4 Incremental Production Cost

The marginal cost (or incremental cost), $RMARG_i(L_i)$, for unit i at load L_i MW may be written as

$$RMARG_i(L_i) = FC_i(L_i) + OP_i(L_i) + COSTNM_i(L_i)$$

where

$FC_i(L_i)$: the marginal fuel cost in $/MWH at the load level L_i

$OP_i(L_i)$: the marginal operating (non fuel) cost in $/MWH at the load level L_i

$COSTMN_i(L_i)$: the marginal maintenance cost in $/MWH at the load level L_i

The marginal operating and maintenance costs are relatively small compared to the marginal fuel cost. Although it is desirable that the operating and maintenance costs be broken into a fixed and a variable part, this is almost impossible under the present accounting system of utilities. It is therefore assumed that the marginal operating and maintenance costs are equal to the average operating and maintenance cost for each unit.

The marginal fuel cost for unit i, in ¢/kwh, is defined as follows:

$$RFC_i = \text{Fuel Cost}\left(\frac{¢}{10^6\ \text{Btu}}\right) \times \text{Incremental Heat Rate}\left(\frac{\text{Btu}}{\text{kwh}}\right) \times 10^{-6}$$

The fuel cost varies from unit to unit depending on the type of fuel used, time of the year, and location of the unit. The incremental heat rate, on the other hand, depends on the load at which a unit is operated and the temperature of the condenser intake water. The fuel cost and incremental heat rate of each unit are specified for each month during the study period.

The average marginal cost of production by a unit is defined as

$$RMARG_i = \langle Ht.Rt_i \rangle_{av} * \text{Fuel Cost}\left(\frac{¢}{10^6 \text{Btu}}\right) *10^{-6} + \langle OP_i \rangle_{av} + \langle COSTMN_i \rangle_{av}$$

where RMARG is the average marginal cost of production by unit i, and $\langle Ht.Rt_i \rangle_{av}$ is the average incremental heat rate of unit i. Use of the average marginal cost causes some error in simulating dispatch and estimating the production cost for a unit if the study period is short. However, if the entire simulation is for more than a few weeks, the error is believed to be small.

3.2.2 Loading Order

In determining the loading order of generating units, the units are grouped into three types: 1) base load units, 2) cycling (or shoulder) units, and 3) peaking units. All the base units are assumed to have minimum loading levels under which they cannot be operated because of flame-out. Therefore, the generating system is assumed to be generating at least the sum of the minimum loading levels of the units available. (The units on maintenance or forced outage are excluded.) As the system demand increases, the loading level of the base units is increased in the order of increasing incremental generation cost.

Loading of cycling units starts when the system demand exceeds the total capacity of the base units excluding the maintenanced base units. Cycling units are loaded in the order of increasing incremental generating cost. Peaking units are loaded in the order of increasing incremental generating cost, but not loaded until all the cycling units are loaded to their full capacity. The loading order (priority) is illustrated in Table 1.

In both MARC-3A and MARC-3B, the peak block of a base unit is fully loaded before the peak block of the base unit in the next loading order (except at a rapid transient in MARC-3A). Similarly, one cycling unit or peaking unit is fully loaded before the cycling unit or peaking unit in the next loading order (again excepting a rapid transient in MARC-3A).

3.2.3 Transient Load Response

Each generating unit has a certain limit on the rate of load increase. If the units which are partially loaded cannot follow the load increase, then the units at the next loading order must follow the increasing load. If the total of the base units and cycling units cannot follow a rapid increase of demand, peaking units must be used even if the total demand is low. One Ohio utility pointed out that the cost of using peaking units in this way is rather substantial, although the quantity of electricity thus generated is not investigated.

The MARC-3A program takes account of the effect of load following limit by allowing the user to specify the maximum load following rate for each unit. Suppose the system demand changes from α MW to β MW in one hour, and the unit i is loaded to its intermediate capacity level. As described before, this program assumes that the power is increased by only one unit at a time under normal conditions.

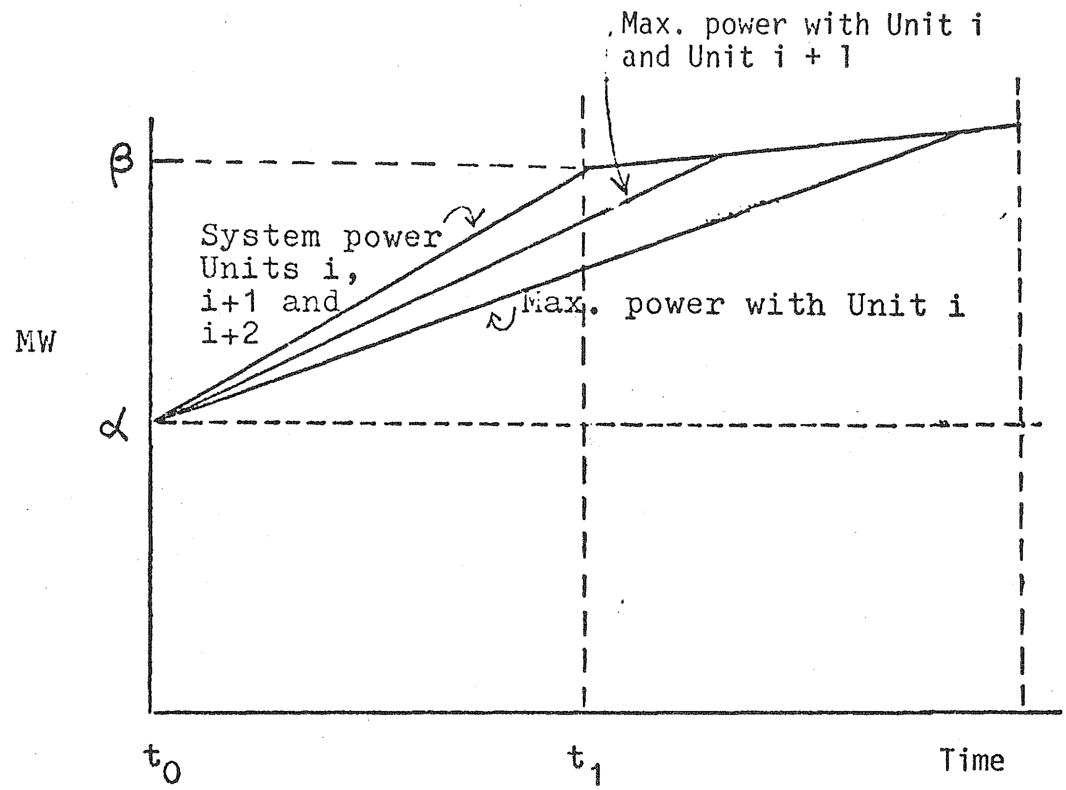


Figure 1 Transient Power Dispatch

Table 1 Illustration of the Loading Order

	Unit No.	Loading Priority	With Marginal Operating Cost
Base Block	6	6	7.203
	3	5	7.192
	4	4	7.192
	5	3	7.192
	1	2	5.182
	2	1	4.906
Shoulder Block	10	10	21.126
	17	9	15.753
	11	8	12.598
	12	7	11.667
	13	6	11.667
	14	5	11.667
	15	4	11.667
	16	3	11.667
	9	2	10.866
	8	1	10.113
Peaking Block	30	14	30.000
	27	13	23.394
	7	12	23.392
	26	11	23.231
	25	10	23.230
	21	9	17.376
	22	8	17.376
	23	7	17.376
	24	6	17.376
	18	5	17.376
	19	4	17.376
	20	3	17.376
	29	2	13.300
	28	1	6.950

Referring to Figure 1, for example, only unit i is at an intermediate loading level when time is $t=t_0$. If the rate of the demand exceeds the maximum rate of load increase of unti i as in Figure 1, then the hatched portion of the demand has to be covered by the units at higher loading orders. Therefore, the unit at the next loading order is brought on line and its load is increased. If the demand increase is not met even with the maximum load increase of the two units, then the third unit is loaded and increased in load. Thus, as many units are brought on line as are necessary to follow the demand. As the units at the earlier loading order catch up with the demand, the units at the later loading order are taken off line.

3.2.4 Unit Outages

Two types of outages are considered by the MARC-3A: maintenance (scheduled) outages and forced outages. In the hourly version, MARC-3A, the maintenance schedule of all the units (the days and hours of starting and ending the maintenance outages of every unit) is specified by input. The generating units are omitted from the loading table for the duration of the outage thus specified. The forced outage rate for individual units is also specified by input. It is desirable to obtain the outage rate from the past record for each plant. If this is not possible, the statistics of a regional reliability council of electric utilities or EEI may be used as an estimate. Average duration of a forced outage for each unit is specified by input. The average duration published by EEI is shown in Figure 2. In the MARC-3A code, the time of forced outage is determined as follows. First, the duration of outages is assumed equal to the average duration. Second, the number of outages during the study period is calculated with the forced outage rate and the duration. Then, the time when each forced outage starts is determined by using random numbers.

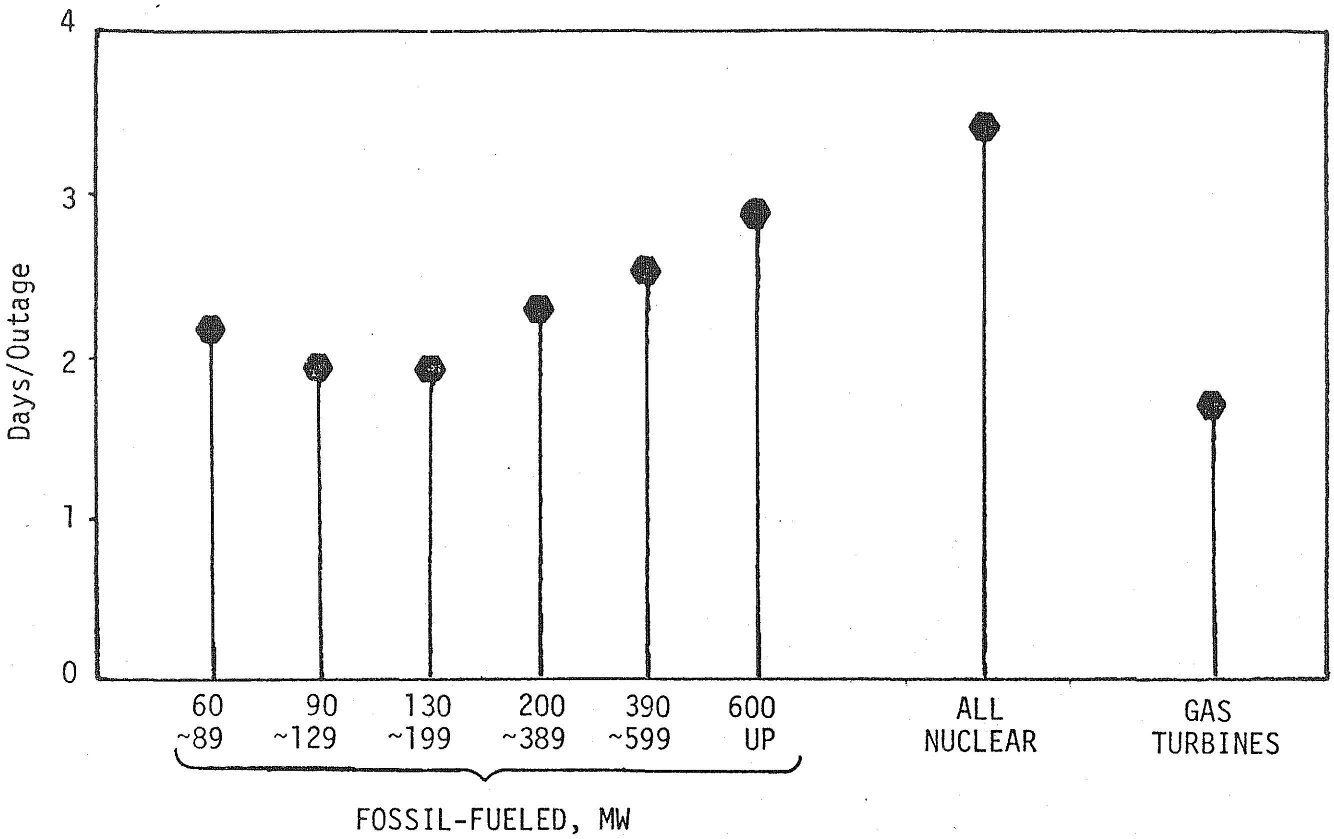


Figure 2 Forced Outage Duration

Source: EEI[8]

3.2.5 Contract and Purchase Power

Contract and purchase power can be handled in the MARC-3A code in the following way. For each firm purchase or emergency power contracts, a dummy plant is defined. These dummy plants are specified in the input by using 4 for the NTYPE parameter (see Section 3.4). The heat cost for these dummy plants is set to the total cost of the purchased power in $/MWH, and the average heat rate is set at 1.0×10^5, thus making the marginal cost equal to the total cost of the purchased power. The maximum power output, P3, should be defined as the maximum amount of power available according to the purchase agreement. All the contracts are considered to be in the peaking block of the dispatching table. The percent ownership, PER(I), of these plants should be considered to be 100% since 100% of the power P3 is available to the company under simulation. The planned maintenance outage days should all be zero. No forced outage times are generated for these dummy plants since it is assumed that this power is always available to the contractee.

3.2.6 Flow of Calculations

The general logic flow in the MARC-3A code can be seen in Figure 3. The program essentially consists of three main DO-loops. The outer loop runs through the months, beginning at the first month and ending at the last month selected by the operator. The load data, the plant heat rates, and the heat costs are read inside this loop month-by-month. This eliminates the need for large storage areas for the load data. Each month a new marginal cost is calculated based on the monthly heat rate and fuel costs. The system dispatching table is then reformed based on these new marginal costs. Subroutine FORCE is called to generate a new set of outage times for the current month. The outage times are arranged in chronological order using subroutine CONSEC.

Of the two inner loops, the first runs through the days of the month while the second advances through the hours of the day. For each hour, a test is made to see if the current hour is an outage hour for the unit I by comparing the current hours with the maintenance outage table and the forced outage times determined by random numbers. Subroutine DSPTCH is then called to load the units of the system. This subroutine increases the effective demand so as to take into account the outages. In this scheme, the units of the system are loaded so as to meet the effective demand. At each hour the load increase on each unit is checked to see if the maximum allowed rate of load increase has been exceeded. If so, the effective demand is further increased and higher cost units are loaded to meet the new demand level.

For each hour, the month, day, hour, system output, system cost, marginal cost, and unit outages can be printed out if desired. If only a partial outage occurs, a minus sign appears before the unit number.

After each month, a monthly summary appears which includes a unit-by-unit summary of the MMBTU and MWH produced during that month, the fuel, operating, maintenance and startup costs, the number of start-ups, and the total unit cost for that month. In addition, the system MMBTU and MWH production and the fuel, operating, maintenance, startup, average generation, and total system costs are printed out. A similar summary also appears for the total period simulated by the code.

2.3 The MARC-3B Program

2.3.1 Outline of MARC-3B

The MARC-3B program performs almost the same types of analyses as MARC-3A except a different algorithm is adopted. MARC-3B is, however, designed to perform the calculations more economically than the other program. The major difference between MARC-3B and MARC-3A is that in the former the generation cost is calculated by using the load duration curves for subintervals of the study period. In the particular version of MARC-3B reported here, the subintervals are assumed to be one month each.[†]

The energy generated by each unit is calculated by the probabilistic simulation method, which is essentially the same as that used in the WASP program (Chapter 4) except that the load curves are expressed by piecewise polynomials rather than Fourier series. The principle of the probabilistic simulation is summarized in Appendix 3A. This method takes the effects of forced outage and maintenance outages into account in the form of an availability factor for each subinterval. Because of the gross nature of the algorithm, MARC-3B does not consider the effect of load following characteristics of the units. The startup cost is calculated in MARC-3B based on the expected number of start-ups after forced outage shutdowns in a month.

[†]The over-all computational time is roughly proportional to the number of subintervals in a year. The length of subintervals can be changed with a minor change to the program. If the gross annual cost of production is to be simulated, the use of four subintervals per year is thought to provide enough accuracy.

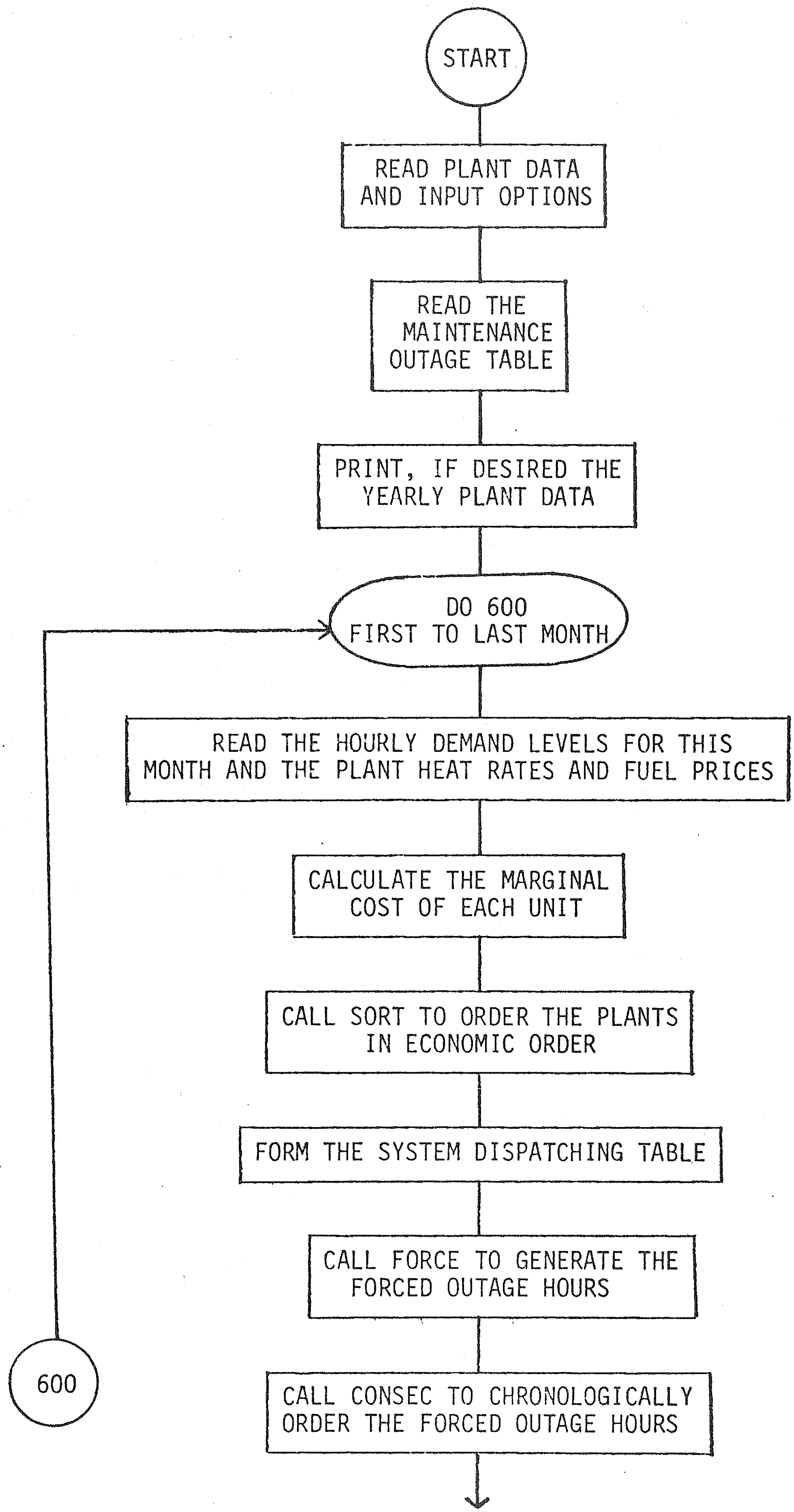
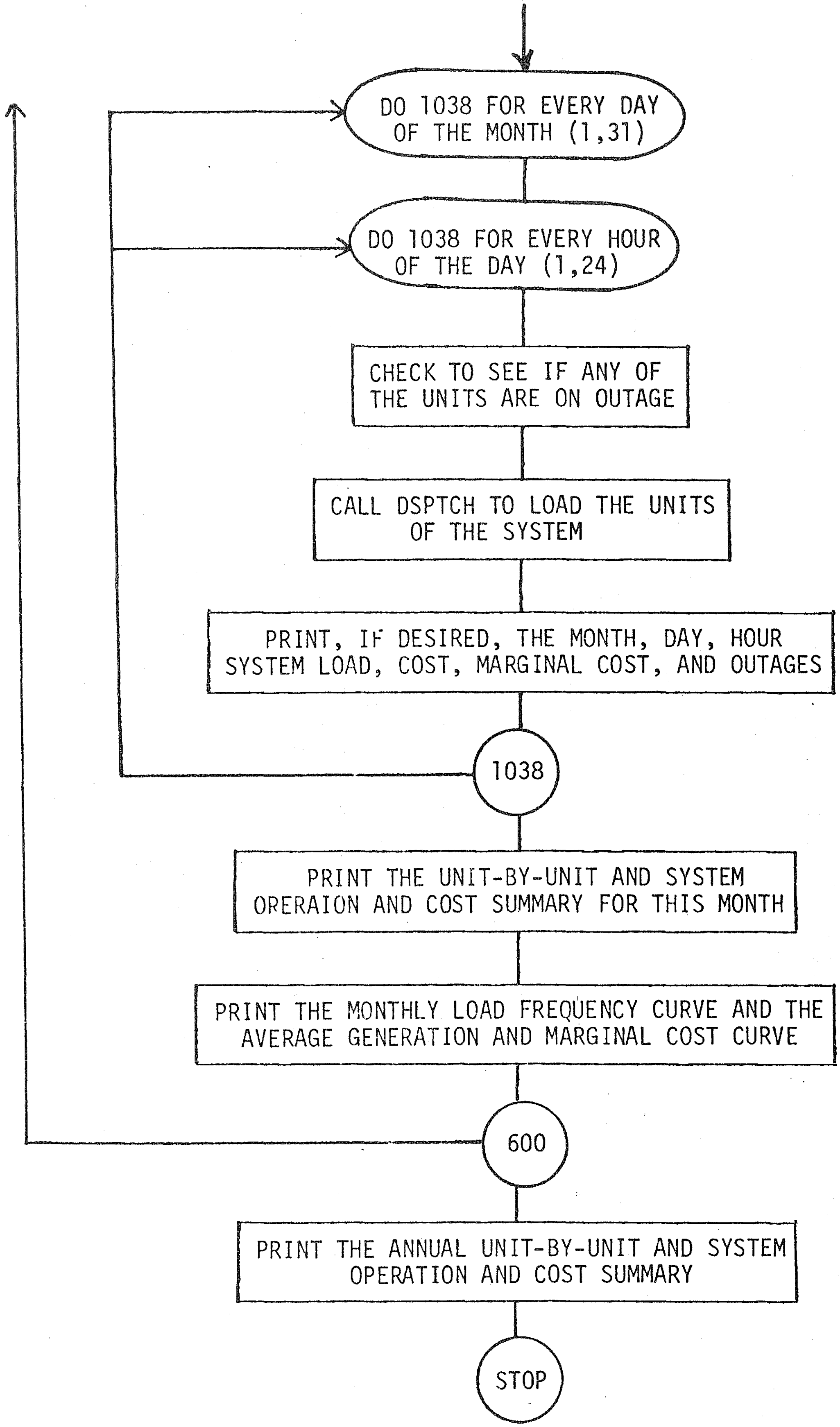


Figure 3 General Logic Flow Diagram for the MARC III-A Program



(Figure 3 continued)

MARC-3B uses almost the same input data as MARC-3A. The availability factor for each unit is calculated by using the maintenance and forced outage rates for that month, and then used in the probabilistic simulation. The load duration curves for subintervals are obtained directly from the hourly load data in the file, if the analysis for base year is performed. Once the compelte set of input for a base year is prepared, MARC-3B can be run for a future test year by giving the escalation rate and the expected annual peak demand for that future year. The escalation factor is used as a multiplier to adjust all the cost data. The expected peak is used to normalize the monthly load duration curves for the entire year so that the annual peak becomes equal to the specified expected peak.

3.3.2 FLow of Calculations

The flow diagram for the MARC-3B program is shown in Figure 4, As can be seen, the program is, for the most part, the same as the MARC-3A with subroutine EQUILD replacing the two inner loops of the hourly versions. Subroutine EQUILD employs the probabilistic scheme to find the equivalent load curves and to calculate the expected generation for each unit. The generating system reliability is also calculated in this subroutine. Also, the subroutine LDPB is used to form the normalized inverted load duration curve from the load frequency curve and the anticipated system peak load for the period of the simulations. The summary outputs of the MARC-3B program are exactly the same as those of the MARC-3A program except that an estimate for the loss-of-load probability appears in the former.

3.4 Input Preparation

There are two data files to be prepared for the MARC-3 programs; the yearly plant files, and the yearly load data. Each file is for existing data and is stored on disks as a partitioned data set and is easily accessed by using the subroutine PDSIN(N,COMPYR,IRET) where N is the number of the logical reading unit, COMPRR is the partition name, and IRET is an error code. The hourly load data set has been named "PUCO.DATA" with partition

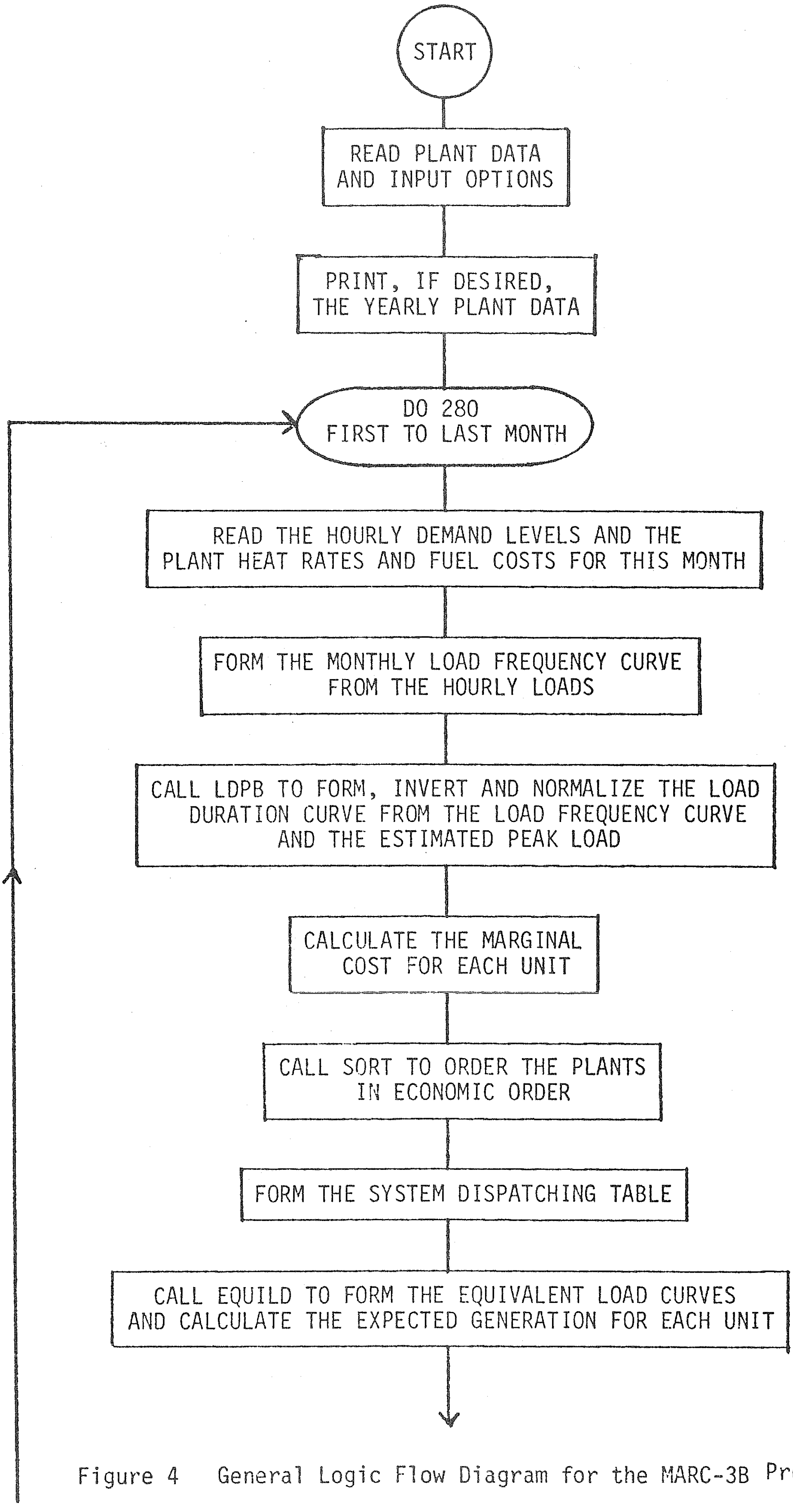
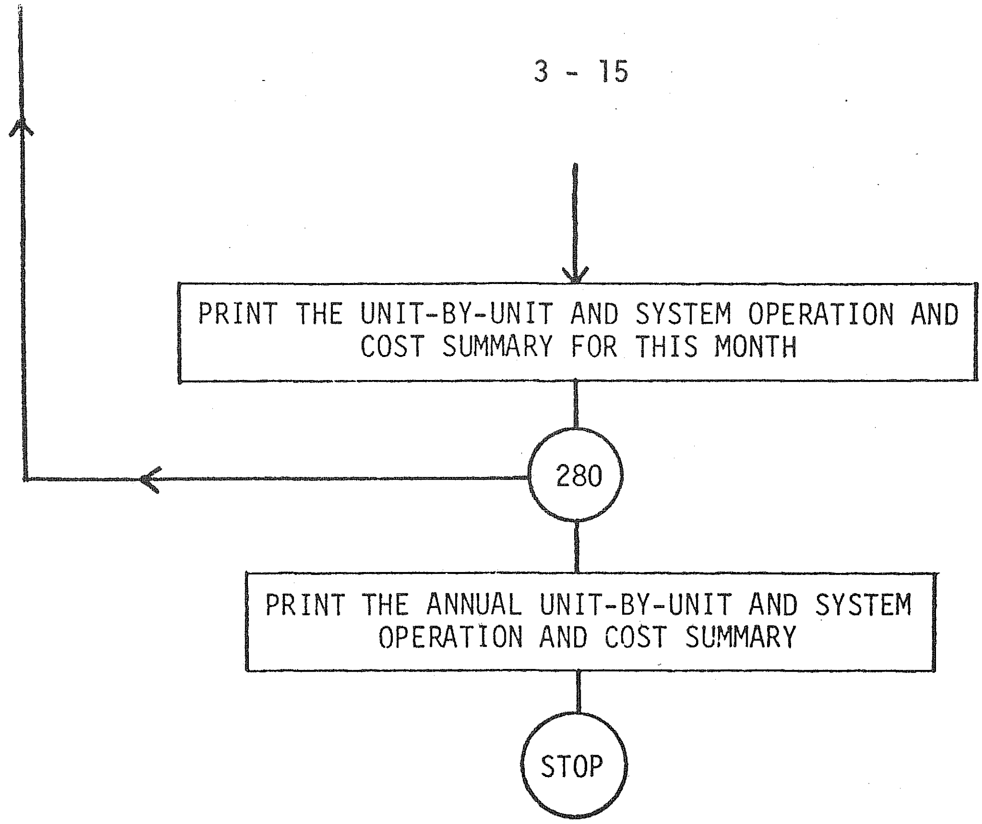


Figure 4 General Logic Flow Diagram for the MARC-3B Program



(Figure 4 Continued)

names DPL76L, OED74L, etc.. (See Appendix 3B for a complete listing of the load data available and their respective partition names.) In MARC 3A and 3B this data set has been assigned to Unit 10. The yearly plant data set has been named "PUCO.MARCDATA" with partition names corresponding to those of the load data. The plant data set has been assigned to Unit 15. Each data set can be accessed from TSO by the commands:

```
ALLOC da('PUCO.DATA')f(ft10f001)
ALLOC da('PUCO.MARCDATA')f(ft15f001)
```

If the program is to be run in batch, the commands used are:

```
//GO.FT10F001 DD DSN=PUCO.DATA,DISP=SHR,LABEL=(,,,IN)
//GO.FT15F001 DD DSN=PUCO.MARCDATA,DISP=SHR,LABEL=(,,,IN)
```

The hourly load data is stored in disks as if the year consisted of twelve months of thirty-one days each. The dummy days, for instance February 31, list zero for each hourly load. Each day's hourly load data is on two cards (see Figure 5) each having twelve load values each. The first six columns of each card consist of the month, day, and the year of load data in a 3I2 format. The seventh column designates a.m. (=1; first card) or p.m. (=2; second card). The next thirteen columns consist of other data not used by the MARC code. The hourly load data begins in Column 21 on each card and is listed in a 12I5 format. Each year's data should contain 744 cards or records, whichever the case.

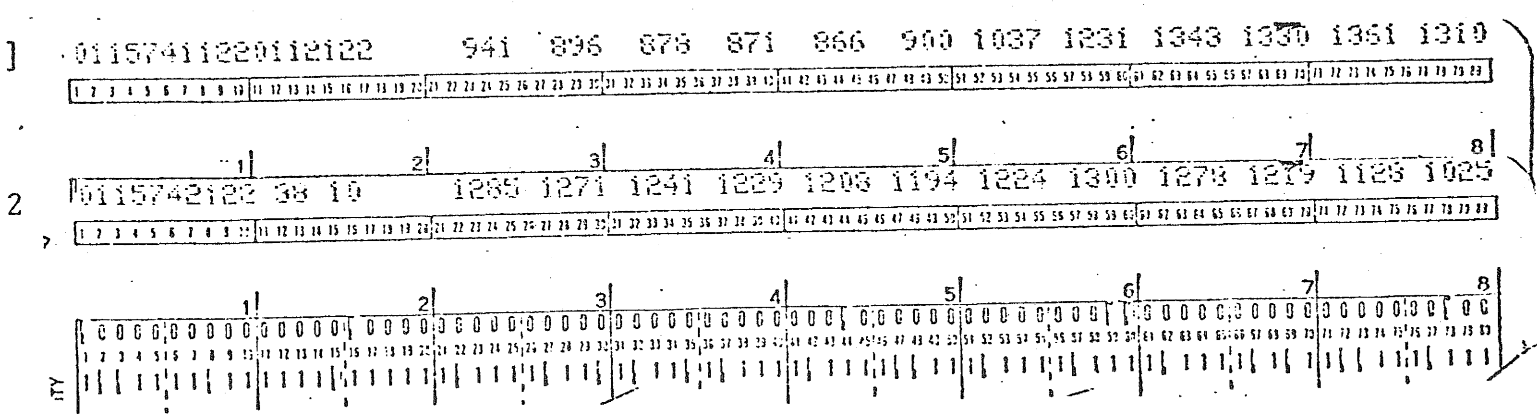


Figure 5

The yearly plant data consists of two parts (see Figure 6). Presented here is the listing of the cards required:

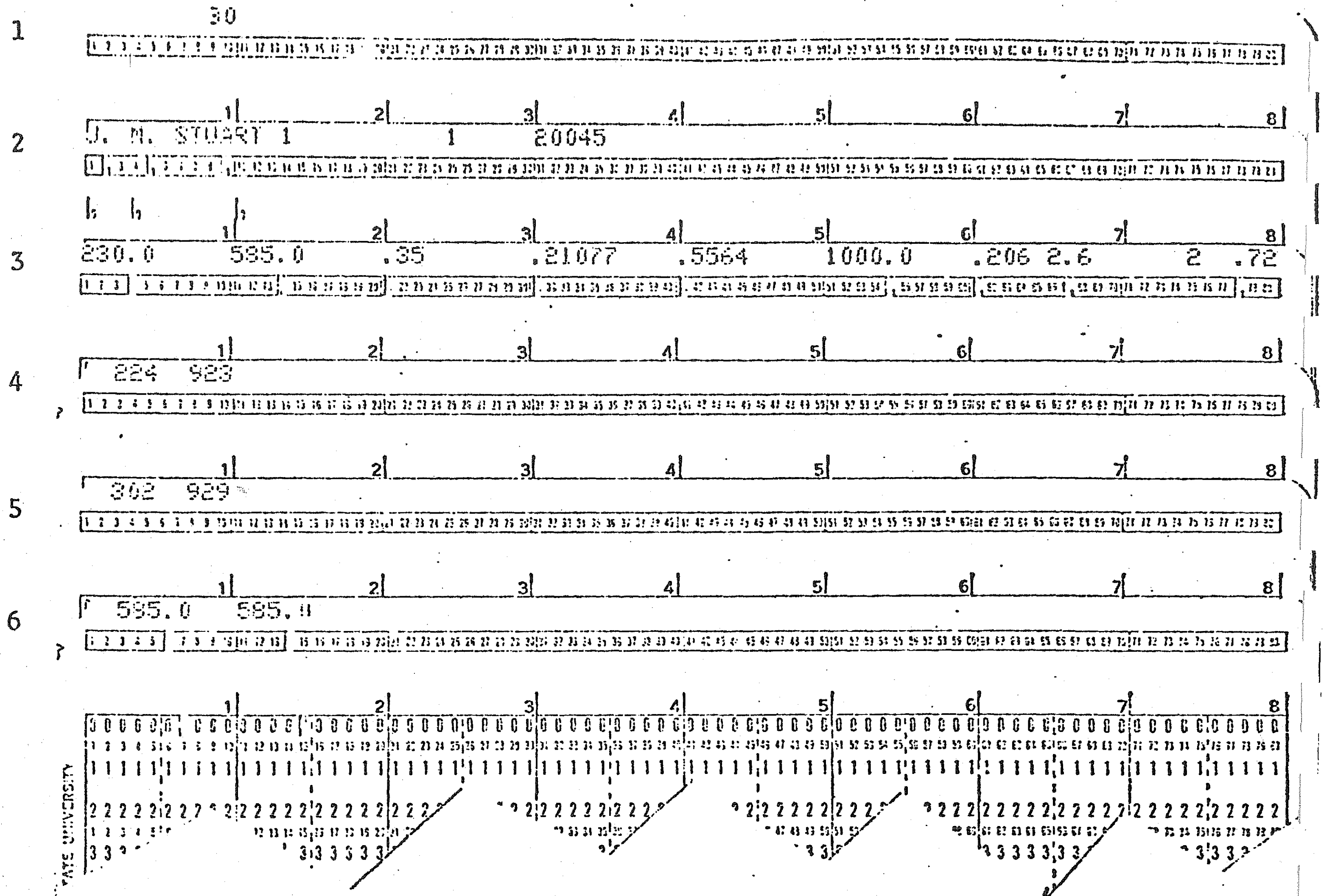
Card 1: Contains in I10 format the total number of units in the system for the year being considered.

Card 2: First 20 columns contain the alphanumeric name of the unit. Beginning in 21, in an I5 format, is a number from 1 to 4 specifying the loading type of the unit: (1 = base loaded unit, 2 = shoulder plant, 3 = peaking unit, 4 = contract, emergency, or purchase powers.) Columns 26-35 show the five digit PUCO number identifying the plant to which the unit belongs in an I10 format.

Card 3: Listed on this card according to the format (6F10.0, 2F5.0, I5,F5.0) are (a) the power output in MW at the flameout loading; (b) the capacity of the unit in MW; (c) the fractional ownership of the unit by the company being considered (1.0 = total ownership); (d) the marginal operating cost for that year in $/MWH; (e) the marginal maintenance for that year in $/MWH; (f) the cost per startup of the unit in $; (g) the fractional historic forced outage rate of the unit; (h) the average length of a forced outage in days; (i) the number of separate planned outages for the unit in that year (up to five allowed); (j) the maximum allowable rate of load change in MW/hour divided by the units maximum capacity. This value defaults to 1.0 if a zero is entered or these columns are left blank.

Cards 4-6: These cards are omitted if (i) of card 3 is 0. Otherwise there must be three cards. On card 5, in I5 formats, is the data that the unit is taken off-line for each outage listed in chronological order. This is expressed as an integer by combining the month and the day into one number. For instance, if an outage occurs on January 9, card 4 would have for its first entry beginning in column 3 the number 109. Card 5 contains, in I5 formats, the data that the unit comes on line from the planned outage, again expressed as a single number. Card 6 contains, in F10.0 formats, the amount of the derate in MW of the units capacity during the planned outage. If the unit is to be completely down during outage, then this is simply set to the capacity of the unit. Each of the entries of cards 4-6 should correspond. In other words, the first entry of cards 4,5 and 6 specifies the first outage, the second entry of cards 4,5 and 6 specifies the second outage and so-on.

Analogous cards 2-6 are compiled for each unit in the system and placed after card 6 in the manner stated above. The ordering of the plants in the data deck is arbitrary. Following these cards are the



Place other plant decks here with cards corresponding to those above.

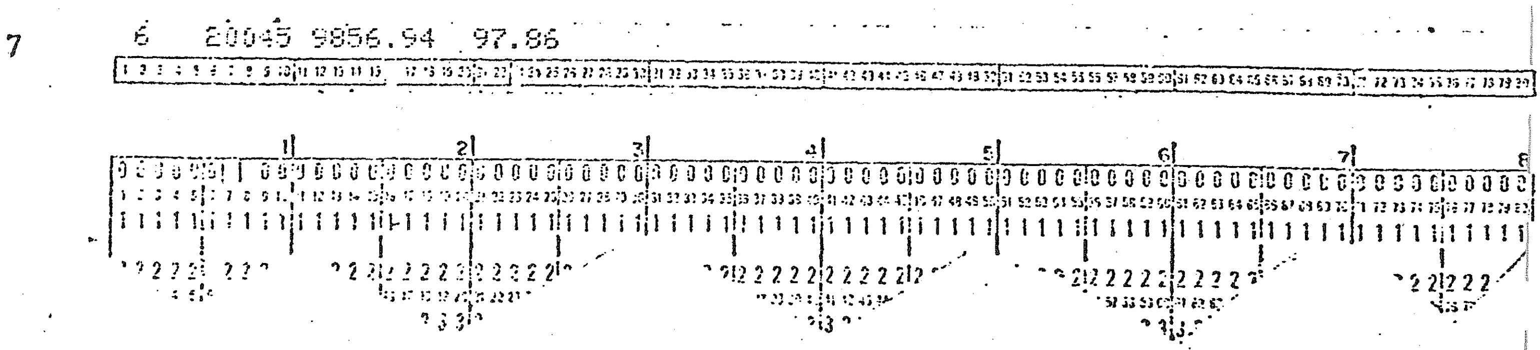


Figure 6

monthly heat rates and marginal fuel costs. In card 7, columns 1-2, in I2 format, contain the month of the data. Columns 6-10 contain the PUCO plant number. Columns 11-20 contain the monthly average heat rate in Btu/kWh. Columns 21-30 contain the monthly average heat cost in ¢/MMBtu. For each month there is one of these cards for each unit in the system. These cards are ordered to match the ordering of the plants on the previous cards. The monthly decks are placed in chronological order with the same plant ordering within each month's deck.

3.5 Operation of the Programs on TSO

The MARC-3A and MARC-3B programs are stored on TSO under the names MARCHRLD and MARCROB, respectively. Once the program is loaded, the operation proceeds in an interrogative manner between the computer and the user. The output of the two programs for sample problems is illustrated in Appendies 3B and 3C so that the reader can refer to them in following the remainder of this section.

The procedure to call for these programs on TSO is explained below. After LOGON to the TSO has been completed, type the following on separate lines:

```
ALLOC da('PUCO.DATA')f(f10f001)
ALLOC da('PUCO.MARCDATA')f(f15f001)
```

These statements allow the program access to the data files which are stored on disks. MARC 3-A is now accessed by typing the statement:

```
RUN'PUCO.MARCHRLD,FORT'
```

or MARC 3-B by the similar statement:

```
RUN'PUCO.MARCPROB.FORT'
```

The probram is now loaded into and compiled by the G1 compiler. Execution begins with the printing of the program name and certain preliminary comments indicating the purpose and usage of the program. Questions requiring operator response immediately follow this. The answers to these questions define the calculational periods, options, and the output editing. After each question a series of "-" are printed out to indicate the format field. It is important when responding to these questions that the number be typed right-justified under this field.

			SYS.LOAD	SYS.CST	INC.CST	OUTAGES
6	1	1	971.00	9933.	10.413	1
6	1	2	904.00	9235.	10.413	1
6	1	3	901.00	9204.	10.413	1
6	1	4	888.00	9068.	10.413	1
6	1	5	900.00	9193.	10.413	1
6	1	6	958.00	9797.	10.413	1
6	1	7	1094.00	11214.	10.413	1
6	1	8	1310.00	13972.	13.825	1
6	1	9	1402.00	15244.	13.825	1
6	1	10	1437.00	15728.	13.825	1
6	1	11	1448.00	15880.	13.825	1
6	1	12	1403.00	15258.	13.825	1
6	1	13	1405.00	15285.	13.825	1
6	1	14	1416.00	16181.	14.486	1 7
6	1	15	1386.00	15721.	13.825	1 7
6	1	16	1378.00	15611.	13.825	1 7
6	1	17	1395.00	15851.	14.486	1 7
6	1	18	1402.00	15953.	14.486	1 7
6	1	19	1410.00	17172.	14.486	1 2 7
6	1	20	1427.00	17418.	14.486	1 2 7
6	1	21	1409.00	17158.	14.486	1 2 7
6	1	22	1324.00	15926.	14.486	1 2 7
6	1	23	1203.00	14174.	14.486	1 2 7
6	1	24	1109.00	12850.	13.825	1 2 7
6	2	1	1008.00	11453.	13.825	1 2 7
6	2	2	962.00	10817.	13.825	1 2 7
6	2	3	930.00	10375.	13.825	1 2 7
6	2	4	920.00	10936.	14.486	1 2 6 7
6	2	5	923.00	10977.	13.825	1 2 6 7
6	2	6	983.00	11821.	14.486	1 2 6 7
6	2	7	1114.00	13718.	14.486	1 2 6 7
6	2	8	1289.00	16253.	14.486	1 2 6 7
6	2	9	1351.00	17148.	7.990	1 2 6 7
6	2	10	1355.00	17180.	7.990	1 2 6 7
6	2	11	1358.00	16814.	7.990	1 2 6 7 13
6	2	12	1331.00	16599.	7.990	1 2 6 7 13
6	2	13	1314.00	16463.	7.990	1 2 6 7 13
6	2	14	1295.00	16311.	7.990	1 2 6 7 13
6	2	15	1244.00	15601.	14.486	1 2 6 7 13
6	2	16	1197.00	14921.	14.486	1 2 6 7 13
6	2	17	1173.00	14573.	14.486	1 2 6 7 13
6	2	18	1135.00	14022.	14.486	1 2 6 7 13
6	2	19	1128.00	13921.	14.486	1 2 6 7 13 26
6	2	20	1194.00	14877.	14.486	1 2 6 7 13 26
6	2	21	1203.00	15007.	14.486	1 2 6 7 13 26
6	2	22	1148.00	14211.	14.486	1 2 6 7 13 26
6	2	23	1058.00	12993.	14.486	1 2 6 7 10 13 26
6	2	24	977.00	11820.	14.486	1 2 6 7 10 13 26
6	3	1	882.00	10443.	14.486	1 2 6 7 10 13 26
6	3	2	834.00	9743.	14.486	1 2 6 7 10 13 26
6	3	3	815.00	9484.	13.825	1 2 6 7 10 13 26
6	3	4	805.00	9345.	13.825	1 2 6 7 10 13 26
6	3	5	803.00	9318.	13.825	1 2 6 7 10 13 26
6	3	6	822.00	9580.	13.825	1 2 6 7 10 13 26
6	3	7	848.00	9951.	14.486	1 2 6 7 10 13 26
6	3	8	904.00	10762.	14.486	1 2 6 7 10 13 26
6	3	9	985.00	11935.	14.486	1 2 6 7 10 13 26
6	3	10	1041.00	12747.	14.486	1 2 6 7 10 13 26

Figure 7 Illustration of MARC-3A Print-out

This means that the last digit of the number must be entered directly under the last "-" of the format field.

MARC-3A has an option that permits an ideal system operation without outages. It can also include only planned outages in the simulation. In this way the user may choose to control outages for his test study. MARC-3A prints out the plant data for each month, the monthly summary of operating costs and the annual summary of operating costs. In addition to the monthly summary, the system load frequency curve is printed out with the system average generation cost and the average marginal cost given for each load level. Output of MARC-3A may include an hour-by-hour listing of the system load, total production cost, marginal cost and unit outages as shown in Figure 7. The outages appear as unit numbers. A minus sign before a unit outage number, if any, indicates that the unit is partially derated rather than completely off-line. The derated amount of capacity is found by looking at an output of the maintenance outage table.

It is time consuming and uneconomical to print out the hourly results on TSO. It is recommended that the user omit this output option unless the code is applied for a short study period. The output of the plant data, the system dispatch table, and the system maintenance table can be omitted by typing appropriate responses at the TSO terminal.

The data files to be prepared for MARC-3B are the same as for MARC-3A. The input data different from MARC-3A are given through the TSO terminal by a typewriter, as can be seen in Appendix 3C. As for such input, MARC-3B requires the system peak load and the price escalation factor. The system peak load is used to renormalize the load data of the base year. The escalation factor is used to adjust all the costs in the future. MARC-3B prints out the monthly and annual summaries of operating costs. In addition, the monthly loss-of-load probability is printed out, which is translated in terms of days per year if multiplied by 1/365.

APPENDIX 3A PROBABILISTIC SIMULATION METHOD

This appendix outlines the probabilistic simulation of the generating system with which MARC - 3B calculates the amount of electricity generated by each generating unit during a specified period of time. This method was originally proposed by Booth and then adopted in the WASP program[6] described in Chapter 4.

Let us consider a time period, T, for which the system operation is to be simulated. The load profile during this period may be represented by a load duration curve. The abscissa of a load duration curve is time, and the ordinate is the load. The meaning of a point on the load duration curve is that the total time that the load exceeds the ordinate (laod) is given by the abscissa (time). The probabilistic simulation uses the inversed load duration curve, in which the abscissa and the ordinate of the load duration curve is exchanged. The curve L (D) in Fig.3A-1 illustrates an inversed load duration curve. In later descriptions, however, the word "inversed" is omitted for simplicity.

Suppose that the generating system under consideration has eight units, which are load in order of their unit numbers. We define the availability of a unit as

$$p = 1 - \frac{T_f + T_m}{T}$$

where p is the availability, T_f is the expected total period of forced outage, T_m is the expected total period of maintenance outage and T is the total length of the time period considered.

If the availability of each unit is 1.0 during the period considered, the energy output of a unit is represented by the area for that unit under the inversed load duration curve, L_0, as illustrated in Fig.3A-1.

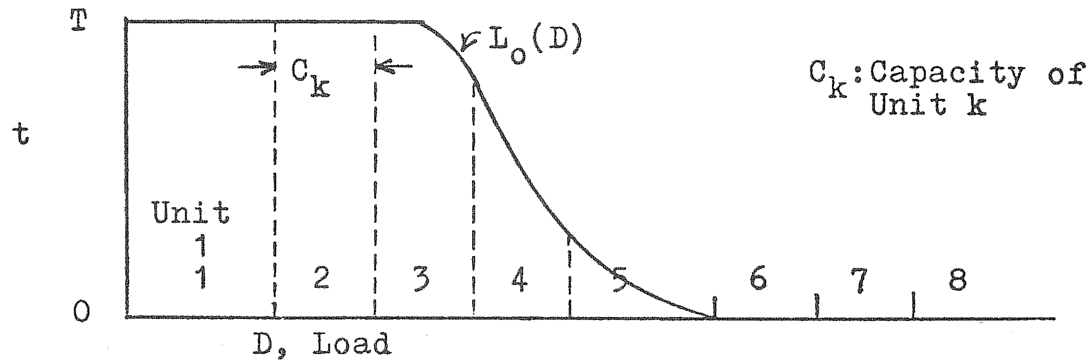


Fig. 3A-1 Generation by units without any outage.

If the availability of unit 1 is zero, but that of all the other units is 1.0, then the energy output of any unit except unit 1 is represented by the area for the unit under the curve, L_o, as shown in Fig. 3A-2.

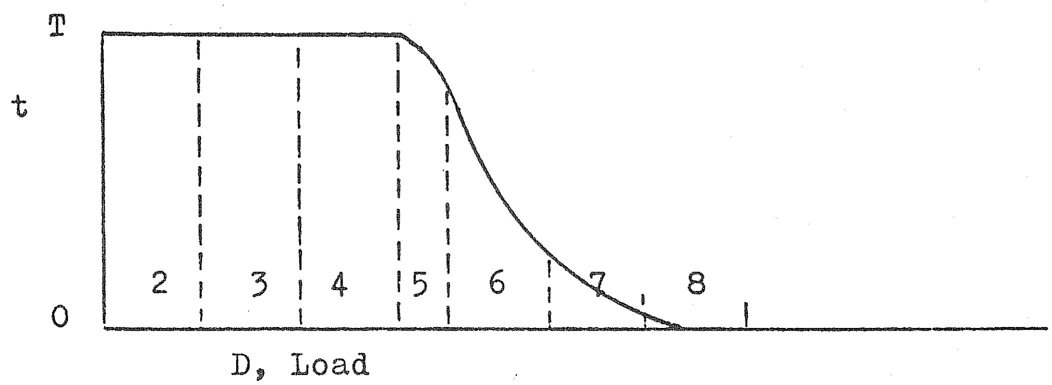


Fig. 3A-2 Generation by units when unit 1 is in outage during the entire period, but no outage to other units

The energy output for units 2 through 8 can be equivalently calculated by shifting the curve, L_o, in Fig. 3A-1 to the right by the capacity of unit 1, namely, C_1, as illustrated in Fig. 3A-3.

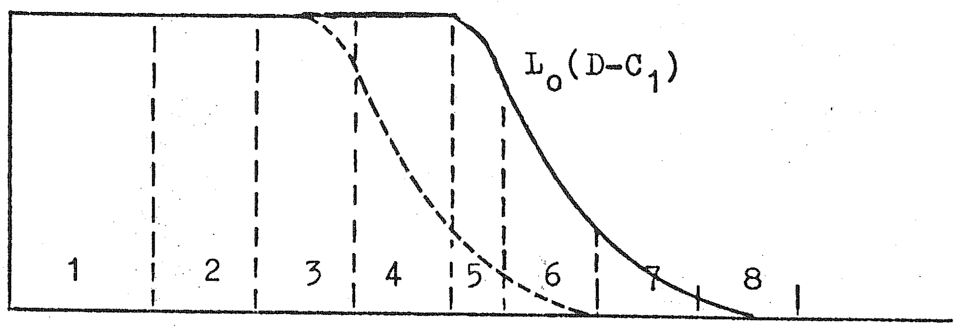


Fig. 3A-1 An equivalent calculation of energy generation by Unit 2 through Unit 8.

(The energy calculation with the above curve is valid only for Units 2 through 8, assuming zero availability of Unit 1.)

If the actual availability of unit 1 is $0<p_1<1$ rather than 0 or 1, the equivalent load duration curve is defined by

$$L_1(D) = p_1 L_o(D) + (1-p_1)\, L_o\,(D - C_1)$$

Assuming the availability of all other units is 1.0, the energy output of Units 2 through 8 may be calculated by integrating L_1.

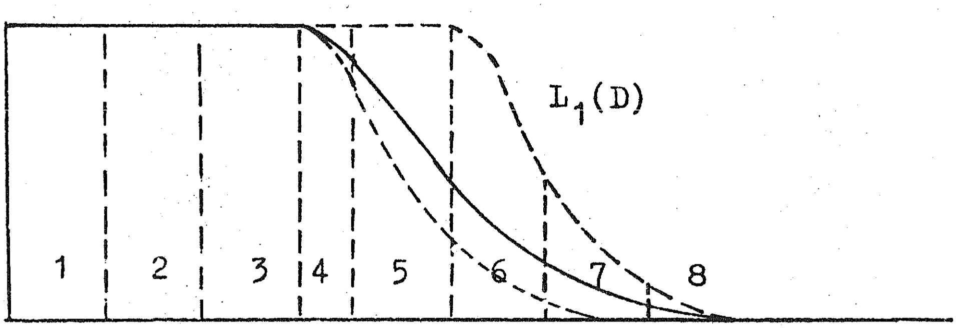


Fig. 3A-4 Equivalent load duration curve, L_1

The actual energy output of Unit 1 is p_1 times the area under L_o for Unit 1 in Fig. 3A-1. If the availability of Unit 2 is p_2, then the actual energy output of Unit 2 is p_2 times the area under L_1 for Unit 2 in Fig. 3A-1.

Starting with L_1, the next equivalent load duration curve L_2, that takes the availability of Unit 2, namely p_2, into consideration, is calculated as

$$L_2(d) = p_2 L_1(D) + (1-P_2)\, L_1\, (D - C_2)$$

It is obvious now that the k-th equivalent load curve is given by

$$L_k(D) = P_k L_{k-1}(D) + (1-P_k)\, L_{k-1}\, (D - C_k)$$

The energy generated by the k-th unit is P_k times the area under the curve L_{k-1} for the k-th unit as illustrated in Fig. 3A-5.

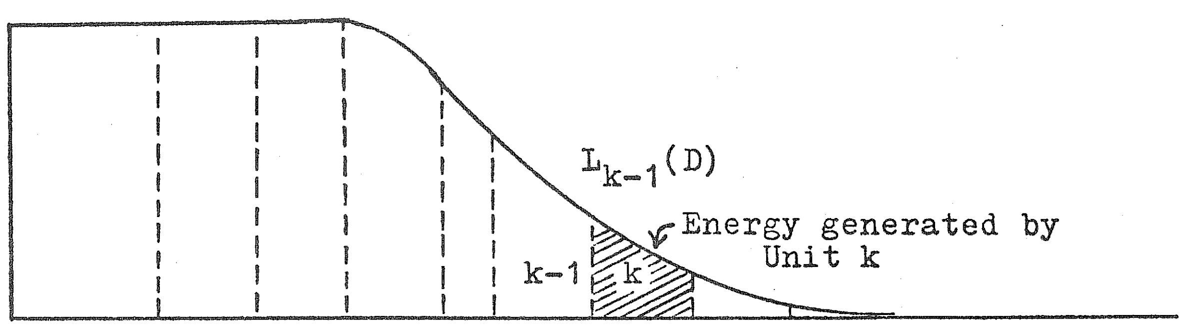


Fig. 3A-5 Calculation of Energy Generated by Unit k.

When the last equivalent load curve (the eighth curve in the present example) is calculated, the unserved energy and the loss-of load probability (LOLP) are found as shown in Fig. 3A-6. The area under L_{max} at the abscissa is equal to the system capacity.

The computational cost and accuracy of the probabilistic simulation is significantly affected[7] by the mathematical method to express the equivalent load curves. MARC-3B uses a piecewise linear approximation while WASP uses a Fourier series expansion.

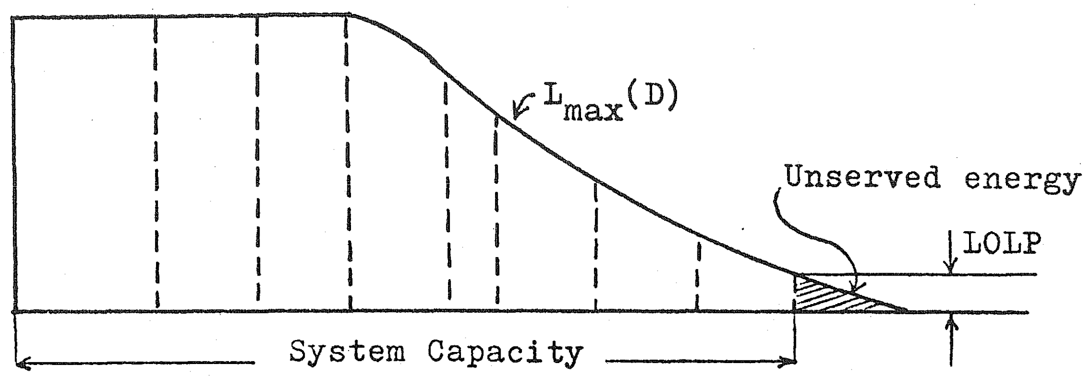


Fig. 3A-6 Unserved energy and LOLP

APPENDIX 3B
LOAD DATA AVAILABLE ON DISK

Partition Name	Company Name	Year
CC073L	CAPCO GROUP	1973
CC074L		1974
CGE73L	Cincinnati Gas and Electric	1973
CGE74L		1974
CGE75L		1975
CEI73L	Cleveland Electric Illuminating	1973
CEI74L		1974
CS)74L	Columbus & Southern Electric	1974
CSO75L		1975
DPL73L	Dayton Power & Light	1973
DPL74L		1974
DPL75L		1975
DPL76L		1976 (thru Aug.)
DUQ73L	Duquesne	1973
DUQ74L		1974
OED73L	Ohio Edison	1973
OED74L		1974
OED75L		1975
TLE73L	Toledo Edison	1973
TLE74L		1974
TLE75L		1975

APPENDIX 3C

SAMPLE OUTPUT OF MARC 3-A

```
logon
USERID? ts0287/gerber
TERMINAL ID? r125
UNIVERSITY ID? [redacted]
PROCEDURE NAME? fortuser
TS0287 LOGON IN PROGRESS AT 10:44:14 ON JANUARY 3, 1977
allocREADY
alloc da('puco.data') f(ft10f001)
READY
alloc da('puco.marcdata') f(ft15f001)
READY
run 'puco.marchrid.fort'
G1 COMPILER ENTERED
SOURCE ANALYZED
PROGRAM NAME = MAIN
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = SORT
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = MAX
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = FORCE
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = CONSEC
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = DMAX
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = DSPTCH
*  NO DIAGNOSTICS GENERATED
     *STATISTICS*  NO DIAGNOSTICS THIS STEP r
```

```
$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$
$                                 3 - 29                                     $
$                              M A R C   I I I-A                             $
$                                                                            $
$                        ELECTRIC UTILITY SIMULATION                         $
$                                                                            $
$                         THE OHIO STATE UNIVERSITY                          $
$                      NUCLEAR ENGINEERING DEPARTMENT                        $
$                           COLUMBUS, OHIO 1976                              $
$                                                                            $
$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$

THE PURPOSE OF THIS CODE IS TO CALCULATE THE MARGINAL FUEL COST
OF AN ELECTRIC UTILITY BY A REAL-TIME SIMULATION OF THE SYSTEM ON
AN HOUR TO HOUR BASIS. THE OUTPUT EDITING AND COMPUTATIONAL OPTIONS
ARE TO BE ENTERED BELOW BY THE CODE OPERATOR.

DATA ENTRY PROCEDURE:
    1 AFTER EACH ENTRY PRESS THE RETURN KEY
    2 WHEN ENTERING DATA FOLLOW THE FORMAT CODE BY ENTERING
      THE DATA DIRECTLY BELOW THE FORMAT CODE.

TYPE THE THREE CHARACTER NAME OF THE COMPANY DESIRED
---
dpl

TYPE IN THE SIX CHARACTER NAME OF THE COMPANY AND YEAR OF LOAD DATA
DESIRED.
------
dpl761

TYPE IN THE FIRST AND LAST MONTH OF THE CALCULATIONAL PERIOD
--/--
07/07

DO YOU WISH THAT THE EFFECTS OF OUTAGES BE INCLUDED IN THE CALCULATION?
(Y OR N)
-
y

DO YOU WISH THAT THE EFFECTS OF FORCED OUTAGES BE INCLUDED IN THE
CALCULATION? (Y OR N)
-
y

DO YOU WISH TO SEE THE OUTPUT DATA ON AN HOUR-BY-HOUR BASIS? (Y OR N)
-
y

DO YOU WISH A LISTING OF THE PLANT DATA, THE SYTEM DISPATCHING TABLE,
AND THE SYSTEM MAINTENANCE TABLE? (Y OR N)
-
y

ON WHAT BASIS SHALL THE INCREMENTAL COST BE COMPUTED?
    1 FUEL COSTS ONLY
    2 FUEL PLUS MAINTENANCE COSTS
    3 FUEL PLUS OPERATION COSTS
    4 FUEL PLUS OPERATION PLUS MAINTENANCE COSTS
TYPE IN THE NUMBER FROM THE ABOVE LIST OF THE OPTION DESIRED
-
4
```

~~OPERATING PARAMETERS FOR EACH UNIT~~

#	PUCO#	UNIT NAME	%OWN	CAPACITY	L.TYPE
~~1~~	~~20040~~	~~MIAMI FORT 7~~	~~36.00~~	~~500.00~~	~~1~~
2	20041	BECKFORD 6	50.00	440.00	1
3	20015	CONESVILLE 4	16.50	800.00	1
~~4~~	~~20045~~	~~J. M. STUART 1~~	~~35.00~~	~~585.00~~	~~1~~
5	20045	J. M. STUART 2	35.00	585.00	1
6	20045	J. M. STUART 3	35.00	585.00	1
~~7~~	~~20045~~	~~J. M. STUART 4~~	~~35.00~~	~~585.00~~	~~1~~
8	21114	STUART DIESELS	36.36	11.00	3
9	20043	TAIT 4	100.00	140.00	2
~~10~~	~~20043~~	~~TAIT 5~~	~~100.00~~	~~130.00~~	~~2~~
11	20043	TAIT TOPPING	100.00	150.00	2
12	20044	HUTCHINGS 1	100.00	61.00	2
~~13~~	~~20044~~	~~HUTCHINGS 2~~	~~100.00~~	~~60.00~~	~~2~~
14	20044	HUTCHINGS 3	100.00	67.00	2
15	20044	HUTCHINGS 4	100.00	67.00	2
~~16~~	~~20044~~	~~HUTCHINGS 5~~	~~100.00~~	~~67.00~~	~~2~~
17	20044	HUTCHINGS 6	100.00	67.00	2
18	21110	HUTCHINGS G. T.	100.00	32.00	3
~~19~~	~~20046~~	~~YANKEE 1~~	~~100.00~~	~~21.00~~	~~3~~
20	20046	YANKEE 2	100.00	21.00	3
21	20046	YANKEE 3	100.00	21.00	3
~~22~~	~~20046~~	~~YANKEE 4~~	~~100.00~~	~~18.00~~	~~3~~
23	20046	YANKEE 5	100.00	18.00	3
24	20046	YANKEE 6	100.00	18.00	3
~~25~~	~~20046~~	~~YANKEE 7~~	~~100.00~~	~~18.00~~	~~3~~
26	21115	TAIT DIESELS	100.00	11.00	3
27	21100	MONUMENT DIESELS	100.00	14.00	3
~~28~~	~~21101~~	~~SIDNEY DIESEL~~	~~100.00~~	~~14.00~~	~~3~~
29	20009	OHIO POWER CONTRACT	100.00	150.00	3
30	21043	OVEC CONTRACT	100.00	100.00	3

MAINTENANCE OUTAGE TABLE

UNIT	FOR (%)	RLCHG (MW/HR)	DATE DOWN MMDD	DATE UP MMDD	DERATE (MW)
1	10.5	350.00	425	623	500.00
2	33.1	316.80	405	420	440.00
3	14.0	576.00	105	405	800.00
4	20.6	583.00	224	302	585.00
			923	929	585.00
5	22.3	421.20	428	504	585.00
			928	1031	585.00
6	20.3	421.20	101	213	585.00
			216	224	585.00
			912	923	585.00
7	17.1	421.20	316	329	585.00
			1101	1109	585.00
8	10.0	11.00			
9	16.9	100.80			
10	15.5	93.60			
11	16.0	108.00			
12	4.9	43.92			
13	6.7	43.20			
14	8.3	48.24			
15	7.6	48.24			
16	4.9	48.24			
17	5.0	48.24			
18	6.8	32.00			
19	13.3	21.00			
20	9.2	21.00			
21	10.8	21.00			
22	6.6	18.00			
23	4.8	18.00			
24	6.5	18.00			
25	7.0	18.00			
26	16.0	11.00			
27	25.8	14.00			
28	21.4	14.00			
29	0.0	150.00			
30	0.0	100.00			

LIST OF SYMBOLS:

%OWN =PERCENT OWNERSHIP OF THE UNIT BY THE UTILITY CURRENTLY BEING CONSIDERED

L.TYPE =LOADING TYPE: 1=BASE
2=SHOULDER
3=PEAKING

FOR =THE FORCED OUTAGE RATE IN PERCENT

RLCHG =THE MAXIMUM RATE OF LOAD INCREASE IN MW/HR FOR THE UNIT

AV.HT.RT=THE NET HEAT RATE FOR THE CURRENT MONTH IN BTU/KWH

F.CST =THE FUEL COST FOR THE CURRENT MONTH IN $/MMBTU

OP.CST =THE AVERAGE OPERATING COST IN $/MWH

MN.CST =THE AVERAGE MAINTENANCE COST IN $/MWH

MARG.CST=THE TOTAL INCREMENTAL COST IN $/MWH COMPUTED ON THE BASIS OF THE SELECTED OPTION

S.CST =THE AVERAGE COST IN $ PER STARTUP OF THE UNIT

```
**************************************************************************
**********************BEGIN MARGINAL CALCULATION**************************
**************************************************************************

$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$
$$$$$$$$$   MONTH= 7   $$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$
$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$
```

INCREMENTAL HEAT AND COST DATA

#	AV.HT.RT	F.CST	OP.CST	MN.CST	MARG.CST	S.CST
1	9907.95	86.24	0.370	0.423	9.338	1000.
2	10262.30	85.27	0.359	0.847	9.957	1000.
3	10359.43	91.18	0.320	0.775	10.540	1000.
4	9708.44	95.90	0.211	0.556	10.078	1000.
5	9708.44	95.90	0.211	0.556	10.078	1000.
6	9708.44	95.90	0.211	0.556	10.078	1000.
7	9708.44	95.90	0.211	0.556	10.078	1000.
8	11297.83	253.90	0.0	11.280	39.965	0.
9	11000.87	104.13	1.170	1.629	14.254	500.
10	11000.87	104.13	1.170	1.629	14.254	500.
11	11000.87	104.13	1.170	1.629	14.254	500.
12	11026.37	110.45	1.116	1.149	14.444	500.
13	11026.37	110.45	1.116	1.149	14.444	500.
14	11026.37	110.45	1.116	1.149	14.444	500.
15	11026.37	110.45	1.116	1.149	14.444	500.
16	11026.37	110.45	1.116	1.149	14.444	500.
17	11026.37	110.45	1.116	1.149	14.444	500.
18	16641.09	245.90	0.188	2.049	43.157	0.
19	13262.89	241.83	0.511	5.521	38.105	0.
20	13262.89	241.83	0.511	5.521	38.105	0.
21	13262.89	241.83	0.511	5.521	38.105	0.
22	13262.89	241.83	0.511	5.521	38.105	0.
23	13262.89	241.83	0.511	5.521	38.105	0.
24	13262.89	241.83	0.511	5.521	38.105	0.
25	13262.89	241.83	0.511	5.521	38.105	0.
26	10236.79	239.02	1.439	1.741	27.648	0.
27	10610.45	236.81	1.086	4.584	30.797	0.
28	10802.54	238.36	1.458	9.840	37.047	0.
29	100000.00	16.46	0.0	0.0	16.460	0.
30	100000.00	8.02	0.0	0.0	8.020	0.

******************SYTEM DISPATCHING TABLE******************

UNIT	UNIT OUTPUT (MW)	MARG.CST ($/MW)	SYSTEM OUTPUT (MWH)	SYSTEM CST. ($)
BASE LOADED PLANTS (MIN)				
1	72.00	9.338	72.00	672.
2	75.00	9.957	147.00	1419.
7	80.50	10.078	227.50	2230.
6	80.50	10.078	308.00	3042.
5	80.50	10.078	388.50	3853.
4	80.50	10.078	469.00	4664.
3	59.99	10.540	528.99	5296.
BASE LOADED PLANTS (MAX)				
1	180.00	9.338	636.99	6305.
2	220.00	9.957	781.99	7749.
7	204.75	10.078	906.24	9001.
6	204.75	10.078	1030.49	10253.
5	204.75	10.078	1154.74	11505.
4	204.75	10.078	1278.99	12757.
3	132.00	10.540	1351.00	13516.
SHOULDER PLANTS (MAX)				
11	150.00	14.254	1501.00	15654.
10	130.00	14.254	1631.00	17507.
9	140.00	14.254	1771.00	19503.
17	67.00	14.444	1838.00	20471.
16	67.00	14.444	1905.00	21438.
15	67.00	14.444	1972.00	22406.
14	67.00	14.444	2039.00	23374.
13	60.00	14.444	2099.00	24241.
12	61.00	14.444	2160.00	25122.
PEAKING PLANTS (MAX)				
30	100.00	8.020	2260.00	25924.
29	150.00	16.460	2410.00	28393.
26	11.00	27.648	2421.00	28697.
27	14.00	30.797	2435.00	29128.
28	14.00	37.047	2449.00	29647.
25	18.00	38.105	2467.00	30332.
24	18.00	38.105	2485.00	31018.
23	18.00	38.105	2503.00	31704.
22	18.00	38.105	2521.00	32370.
21	21.00	38.105	2542.00	33190.
20	21.00	38.105	2563.00	33990.
19	21.00	38.105	2584.00	34791.
8	4.00	39.965	2588.00	34951.
18	32.00	43.157	2620.00	36332.

	SYS.LOAD	SYS.CST	INC.CST	OUTAGES
7 1 1	845.00	8384.	10.078	0
7 1 2	780.00	7729.	9.957	0
7 1 3	745.00	7380.	9.957	0
7 1 4	724.00	7171.	9.957	0
7 1 5	731.00	7241.	9.957	0
7 1 6	758.00	7510.	9.957	0
7 1 7	836.00	8293.	10.078	0
7 1 8	997.00	9916.	10.078	0
7 1 9	1119.00	11145.	10.078	0
7 110	1189.00	11850.	10.078	0
7 111	1250.00	12465.	10.078	0
7 112	1269.00	12657.	10.078	0
7 113	1266.00	12626.	10.078	0
7 114	1284.00	12810.	10.540	0
7 115	1261.00	12576.	10.078	0
7 116	1261.00	12576.	10.078	0
7 117	1256.00	12526.	10.078	0
7 118	1221.00	12173.	10.078	0
7 119	1185.00	11810.	10.078	17
7 120	1134.00	11324.	10.540	6 17
7 121	1103.00	10997.	10.540	6 17
7 122	1125.00	11229.	10.540	6 17
7 123	1114.00	11113.	10.540	6 17
7 124	983.00	9774.	10.078	6 17
7 2 1	847.00	8404.	10.078	6 17
7 2 2	769.00	7618.	10.078	6 17
7 2 3	746.00	7386.	10.078	6 17
7 2 4	721.00	7134.	10.078	6 17
7 2 5	715.00	7074.	10.078	6 17
7 2 6	751.00	7436.	10.078	6 17
7 2 7	820.00	8132.	10.078	6 17
7 2 8	986.00	9805.	10.078	6 17
7 2 9	1103.00	10997.	10.540	6 17
7 210	1203.00	12262.	14.254	6 17
7 211	1264.00	13131.	14.254	6 17
7 212	1287.00	13459.	14.254	6 17
7 213	1296.00	13587.	14.254	6 17
7 214	1305.00	13716.	14.254	6 17
7 215	1308.00	13759.	14.254	6 17
7 216	1282.00	13388.	14.254	6 17
7 217	1250.00	12932.	14.254	6 17
7 218	1204.00	12276.	14.254	6 17
7 219	1145.00	11440.	10.540	6 17
7 220	1098.00	10944.	10.540	6 17
7 221	1072.00	10671.	10.078	6 17
7 222	1079.00	10744.	10.540	6 17
7 223	1016.00	10107.	10.078	6 17
7 224	915.00	9089.	10.078	6 17
7 3 1	798.00	7910.	10.078	5 6 17
7 3 2	731.00	7235.	10.078	5 6 17
7 3 3	[illegible]	[illegible]	10.078	5 6 17

```
720 3    824.00     8172.  10.078      6 11 12 28
720 4    803.00     7960.  10.078      6 11 12 28
720 5    790.00     7829.  10.078      6 11 12 28
720 6    821.00     8142.  10.078      6 11 12 28
720 7    910.00     9039.  10.078      6 11 12 28
720 8   1059.00    10540.  10.078      6 11 12 21 28
720 9   1209.00    13216.  14.444      6  7 11 12 21 28
72010   1280.00    14228.  14.444      6  7 11 12 21 28
72011   1356.00    15325.  14.444      6  7 11 12 21 28
72012   1362.00    15412.  14.444      6  7 11 12 21 28
72013   1399.00    15946.  14.444      6  7 11 12 21 28
72014   1445.00    16611.  14.444      6  7 11 12 21 28
72015   1469.00    16957.  14.444      6  7 11 12 21 28
72016   1457.00    16784.  14.444      6  7 11 12 21 28
72017   1493.00    17304.  14.444      6  7 11 12 21 28
72018   1457.00    16784.  14.444      6  7 11 12 21 28
72019   1422.00    16279.  14.444      6  7 11 12 21 28
72020   1371.00    15542.  14.444      6  7 11 12 21 28
72021   1327.00    14906.  14.444      6  7 11 12 21 28
72022   1348.00    15210.  14.444      6  7 11 12 21 28
72023   1291.00    14386.  14.444      6  7 11 12 21 28
72024   1169.00    12632.  14.254      6  7 11 12 21 28
721 1    991.00    10095.  14.254      6  7 11 12 21 28
721 2    934.00     9310.  10.540      6  7 11 12 21 28
721 3    876.00     8699.  10.540      6  7 11 12 21 28
721 4    857.00     8505.  10.078      6  7 11 12 21 28
721 5    840.00     8333.  10.078      6  7 11 12 21 28
721 6    869.00     9211.  14.254      4  6  7 11 12 21 28
721 7    964.00    10565.  14.254      4  6  7 11 12 21 28
721 8   1125.00    12883.  14.444      4  6  7 11 12 21 28
721 9   1268.00    14948.  14.444      4  6  7 11 12 21 28
72110   1375.00    16204.   8.020      4  6  7 11 12 21 28
72111   1465.00    17212.  16.460      4  6  7 11 12 21 28
72112   1504.00    22082.  39.965      2  4  6  7 11 12 21 28
72113   1558.00****SYSTEM CAPACITY HAS BEEN EXCEEDED****
                           43.157      2  4  6  7 11 12 21 28
72114   1612.00****SYSTEM CAPACITY HAS BEEN EXCEEDED****
                           43.157      2  4  6  7 11 12 21 28
72115   1636.00****SYSTEM CAPACITY HAS BEEN EXCEEDED****
                           43.157      2  4  6  7 11 12 21 28
72116   1585.00****SYSTEM CAPACITY HAS BEEN EXCEEDED****
                           43.157      2  4  6  7 11 12 21 28
72117   1543.00****SYSTEM CAPACITY HAS BEEN EXCEEDED****
                           43.157      2  4  6  7 11 12 21 28
72118   1512.00    22415.  43.157      2  4  6  7 11 12 21 28
72119   1475.00    18594.  27.648      2  4  6  7 12 21 28
72120   1428.00    17703.  16.460      2  4  6  7 12 21 28
72121   1402.00    17275.  16.460      2  4  6  7 12 21 28
72122   1404.00    17308.  16.460      2  4  6  7 12 21 28
72123   1360.00    16624.   8.020      2  4  6  7 12 21 28
72124   1189.00    14766.  14.444      2  4  6  7 12 21 28
[illegible]
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OPERATING AND COST SUMMARY FOR THE MONTH 7

#	MMBTU	MWH	FUEL	OP	MAINT	ST	ST.CST	TOT.CST
1	1213600.	122495.	1046669.	45322.	51864.	1	1000.	1144854.
2	1229424.	119806.	1048385.	43058.	101524.	3	3000.	1195966.
3	691640.	66764.	630632.	21344.	51722.	0	0.	703698.
4	903266.	93042.	866253.	19610.	51768.	2	2000.	939631.
5	1027578.	105846.	985471.	22309.	58893.	18	18000.	1084673.
6	1064876.	109689.	1021246.	23119.	61031.	2	2000.	1107395.
7	1141115.	117545.	1094386.	24775.	65402.	2	2000.	1186561.
8	274.	24.	696.	0.	274.	1	0.	969.
9	177275.	16115.	184600.	18855.	26251.	15	7500.	237206.
10	265841.	24166.	276828.	28274.	39367.	22	11000.	355469.
11	411801.	37434.	428812.	43798.	60980.	23	11500.	545089.
12	11809.	1071.	13043.	1195.	1231.	3	1500.	16969.
13	24709.	2241.	27292.	2501.	2575.	10	5000.	37367.
14	43506.	3946.	48052.	4403.	4533.	9	4500.	61489.
15	52229.	4737.	57687.	5286.	5443.	8	4000.	72416.
16	58803.	5333.	64948.	5952.	6128.	10	5000.	82028.
17	86552.	7850.	95597.	8760.	9019.	12	6000.	119376.
18	2733.	164.	6721.	31.	337.	1	0.	7089.
19	1950.	147.	4715.	75.	812.	1	0.	5601.
20	1950.	147.	4715.	75.	812.	1	0.	5601.
21	0.	0.	0.	0.	0.	0	0.	0.
22	1671.	126.	4041.	64.	696.	1	0.	4801.
23	1671.	126.	4041.	64.	696.	1	0.	4801.
24	1671.	126.	4041.	64.	696.	1	0.	4801.
25	1671.	126.	4041.	64.	696.	1	0.	4801.
26	811.	79.	1939.	114.	138.	1	0.	2191.
27	1040.	98.	2462.	106.	449.	1	0.	3018.
28	0.	0.	0.	0.	0.	0	0.	0.
29	162350.	1624.	26723.	0.	0.	2	0.	26723.
30	229653.	2297.	18418.	0.	0.	3	0.	18418.

TOTAL HEAT OUTPUT IN MMBTU	8811459.
TOTAL SYSTEM GENERATION IN MWH	843161.
TOTAL FUEL COST IN $	7972443.
TOTAL OPERATING COST IN $	319220.
TOTAL MAINTENANCE COST IN $	603332.
TOTAL STARTUP COSTS IN $	84000.
TOTAL SYSTEM COSTS IN $	8978993.
AVERAGE GENERATION COST IN $/MWH	10.649

****

SYSTEM AVERAGE AND MARGINAL COST CURVE

LOAD (MW)	HRS.AT LOAD	AV.GEN.CST ($/MWH)	AV.MARG.CST ($/MWH)
573	4.	9.871	9.957
597	7.	9.869	9.957
622	4.	9.902	9.493
647	7.	9.882	10.043
672	5.	9.887	10.005
697	11.	9.905	10.001
722	14.	9.902	10.026
747	15.	9.901	10.022
772	25.	9.941	10.058
797	22.	9.943	10.078
821	22.	9.921	10.078
846	22.	9.930	10.078
871	26.	10.109	10.613
896	23.	9.958	10.259
921	31.	10.087	10.496
946	18.	9.947	10.335
971	23.	10.124	11.357
996	23.	10.143	11.902
1021	12.	10.018	10.774
1046	12.	10.191	10.789
1070	17.	10.104	11.207
1095	16.	10.005	10.628
1120	12.	10.163	11.059
1145	13.	10.197	12.433
1170	11.	10.458	12.753
1195	17.	10.356	12.311
1220	13.	10.385	12.998
1245	20.	10.359	13.637
1270	31.	10.345	12.847
1295	25.	10.625	13.416
1319	20.	10.484	13.168
1344	21.	10.737	13.778
1369	23.	10.734	13.745
1394	22.	10.823	14.506
1419	21.	11.085	14.458
1444	25.	10.855	14.330
1469	25.	11.103	14.962
1494	23.	11.200	15.446
1519	9.	11.466	16.857
1544	8.	11.123	17.867
1568	8.	12.069	15.829
1593	11.	11.530	15.199
1618	5.	11.600	20.073
1643	6.	11.682	19.134
1668	4.	11.591	14.948
1693	2.	11.872	15.452
1718	2.	11.809	8.020
1743	3.	11.760	8.020
1768	1.	11.563	14.444
1792	4.	11.599	14.444

****

ANNUAL OPERATING COST SUMMARY

#	MMBTU	MWH	FUEL	OP	MAINT	ST	ST.CST	TOT.CST
1	1213600.	122495.	1046669.	45322.	51864.	1	1000.	1144854.
2	1229424.	119806.	1048385.	43058.	101524.	3	3000.	1195966.
3	691640.	66764.	630632.	21344.	51722.	0	0.	703698.
4	903266.	93042.	868253.	19610.	51768.	2	2000.	939631.
5	1027578.	105846.	985471.	22309.	58893.	18	18000.	1084673.
6	1064876.	109689.	1021246.	23119.	61031.	2	2000.	1107395.
7	1141115.	117543.	1094388.	24775.	65402.	2	2000.	1186561.
8	274.	24.	696.	0.	274.	1	0.	969.
9	177275.	16115.	184600.	18855.	26251.	15	7500.	237206.
10	265841.	24166.	278828.	28274.	39367.	22	11000.	355469.
11	411801.	37434.	428812.	43798.	60980.	23	11500.	545089.
12	11809.	1071.	13043.	1195.	1231.	3	1500.	16969.
13	24709.	2241.	27292.	2501.	2575.	10	5000.	37367.
14	43506.	3946.	48052.	4403.	4533.	9	4500.	61489.
15	52229.	4737.	57687.	5286.	5443.	8	4000.	72416.
16	58803.	5333.	64948.	5952.	6128.	10	5000.	82028.
17	86552.	7850.	95597.	8760.	9019.	12	6000.	119376.
18	2733.	164.	6721.	31.	337.	1	0.	7089.
19	1950.	147.	4715.	75.	812.	1	0.	5601.
20	1950.	147.	4715.	75.	812.	1	0.	5601.
21	0.	0.	0.	0.	0.	0	0.	0.
22	1671.	126.	4041.	64.	696.	1	0.	4801.
23	1671.	126.	4041.	64.	696.	1	0.	4801.
24	1671.	126.	4041.	64.	696.	1	0.	4801.
25	1671.	126.	4041.	64.	696.	1	0.	4801.
26	811.	79.	1939.	114.	138.	1	0.	2191.
27	1040.	98.	2462.	106.	449.	1	0.	3018.
28	0.	0.	0.	0.	0.	0	0.	0.
29	162350.	1624.	26723.	0.	0.	2	0.	26723.
30	229653.	2297.	18418.	0.	0.	3	0.	18418.

TOTAL HEAT OUTPUT IN MMBTU	8311459.
TOTAL SYSTEM GENERATION IN MWH	843161.
TOTAL FUEL COST IN $	7972443.
TOTAL OPERATING COST IN $	319220.
TOTAL MAINTENANCE COST IN $	603332.
TOTAL STARTUP COSTS IN $	84000.
TOTAL SYSTEM COSTS IN $	8978993.
AVERAGE GENERATION COST IN $/MWH	10.649

****

```
READY
logoff
OEF201I CSU=  3  CPU=00:00:10.24  DSK=  202  CNCT=00:38  CHGS=  $5.96  B
AL=  $266.62
TS0287 LOGGED OFF TSO AT 11:21:36 ON JANUARY 3, 1977+
```

APPENDIX 3D

SAMPLE OUTPUT OF MARC III-B

```
logon
USERID? ts0287/gerber
TERMINAL ID? r125
UNIVERSITY ID? [redacted]
PROCEDURE NAME? fortuser
TS0287 LOGON IN PROGRESS AT 10:12:49 ON JANUARY 3, 1977
READY
alloc da('puco.data') f(ft10f001)
READY
alloc da('puco.marcdata') f(ft15f001)
READY
run 'puco.marcprob.fort'
G1 COMPILER ENTERED
SOURCE ANALYZED
PROGRAM NAME = MAIN
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = SORT
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = MAX
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = LDPB
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = EQUILD
*  NO DIAGNOSTICS GENERATED
    *STATISTICS*  NO DIAGNOSTICS THIS STEP r
```

```
$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$
$                                                                      $
$                         M A R C    I I I-B                           $
$                                                                      $
$                    ELECTRIC UTILITY SIMULATION                       $
$                                                                      $
$                     THE OHIO STATE UNIVERSITY                        $
$                  NUCLEAR ENGINEERING DEPARTMENT                      $
$                       COLUMBUS, OHIO 1976                            $
$                                                                      $
$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$

THE PURPOSE OF THIS CODE IS TO CALCULATE THE MARGINAL COST
OF AN ELECTRIC UTILITY BY APPLYING A PROBABILISTIC LOADING SCHEME TO
THE PROJECTED LOAD DURATION CURVE. LOAD DURATION CURVES ARE PROJECTED
ON THE BASIS OF THE SYSTEM PEAK LOAD FORECAST WHICH MAY BE OBTAINED
FROM THE UTILITY'S TEN YEAR FORECAST. ALL COSTS ARE ESCALATED BY A
CONSTANT FACTOR WHICH IS ENTERED BELOW BY THE CODE OPERATOR.

TYPE THE THREE CHARACTER NAME OF THE COMPANY DESIRED
---
dp1

TYPE IN THE SIX CHARACTER NAME OF THE COMPANY AND BASE YEAR OF LOAD
DATA DESIRED

dp1761

TYPE IN THE FIRST AND LAST MONTH OF THE CALCULATIONAL PERIOD
--/--
06/06

TYPE IN THE PROJECTED SYSTEM PEAK LOAD
----
2105

TYPE IN THE ESCALATION FACTOR FOR THE PROJECTED FUEL COSTS. (INCLUDE
DECIMAL POINT.)
----------
1.0

DO YOU WISH A LISTING OF THE PLANT DATA, THE SYTEM DISPATCHING TABLE,
AND THE SYSTEM MAINTENANCE TABLE? (Y OR N)
-
y

ON WHAT BASIS SHALL THE INCREMENTAL COST BE COMPUTED?
   1 FUEL COSTS ONLY
   2 FUEL PLUS MAINTENANCE COSTS
   3 FUEL PLUS OPERATION COSTS
   4 FUEL PLUS OPERATION PLUS MAINTENANCE COSTS
TYPE IN THE NUMBER FROM THE ABOVE LIST OF THE OPTION DESIRED

4
```

OPERATING PARAMETERS FOR EACH UNIT

#	PUCO#	UNIT NAME	%OWN	CAPACITY	L.TYPE
1	20040	MIAMI FORT 7	36.00	500.00	1
2	20041	BECKFORD 6	50.00	440.00	1
~~3~~	~~20015~~	~~CONESVILLE 4~~	~~16.50~~	~~800.00~~	~~1~~
4	20045	J. M. STUART 1	35.00	585.00	1
5	20045	J. M. STUART 2	35.00	585.00	1
~~6~~	~~20045~~	~~J. M. STUART 3~~	~~35.00~~	~~585.00~~	~~1~~
7	20045	J. M. STUART 4	35.00	585.00	1
8	21114	STUART DIESELS	36.35	11.00	3
~~9~~	~~20043~~	~~TAIT 4~~	~~100.00~~	~~140.00~~	~~2~~
10	20043	TAIT 5	100.00	130.00	2
11	20043	TAIT TOPPING	100.00	150.00	2
~~12~~	~~20044~~	~~HUTCHINGS 1~~	~~100.00~~	~~61.00~~	~~2~~
13	20044	HUTCHINGS 2	100.00	60.00	2
14	20044	HUTCHINGS 3	100.00	67.00	2
~~15~~	~~20044~~	~~HUTCHINGS 4~~	~~100.00~~	~~67.00~~	~~2~~
16	20044	HUTCHINGS 5	100.00	67.00	2
17	20044	HUTCHINGS 6	100.00	67.00	2
~~18~~	~~21110~~	~~HUTCHINGS G. T.~~	~~100.00~~	~~32.00~~	~~3~~
19	20046	YANKEE 1	100.00	21.00	3
20	20046	YANKEE 2	100.00	21.00	3
~~21~~	~~20046~~	~~YANKEE 3~~	~~100.00~~	~~21.00~~	~~3~~
22	20046	YANKEE 4	100.00	18.00	3
23	20046	YANKEE 5	100.00	18.00	3
~~24~~	~~20046~~	~~YANKEE 6~~	~~100.00~~	~~18.00~~	~~3~~
25	20046	YANKEE 7	100.00	18.00	3
26	21115	TAIT DIESELS	100.00	11.00	3
~~27~~	~~21100~~	~~MONUMENT DIESELS~~	~~100.00~~	~~14.00~~	~~3~~
28	21101	SIDNEY DIESEL	100.00	14.00	3
29	20009	OHIO POWER CONTRACT	100.00	150.00	3
~~30~~	~~21043~~	~~OVEC CONTRACT~~	~~100.00~~	~~100.00~~	~~3~~

MAINTENANCE OUTAGE TABLE

UNIT	FOR (%)	RLCHG (MW/HR)	DATE DOWN MMDD	DATE UP MMDD	DERATE (MW)
1	10.5	360.00	425	623	500.00
~~2~~	~~33.1~~	~~316.80~~	~~405~~	~~420~~	~~440.00~~
3	14.0	576.00	105	405	800.00
4	20.6	421.20	224	302	585.00
			923	929	585.00
5	22.3	421.20	428	504	585.00
			928	1031	585.00
6	20.3	421.20	101	213	585.00
			216	224	585.00
			~~912~~	~~925~~	~~585.00~~
7	17.1	421.20	316	329	585.00
			~~1101~~	~~1109~~	~~585.00~~
8	10.0	7.92			
~~9~~	~~16.9~~	~~100.80~~			
10	15.5	93.60			
11	16.0	108.00			
~~12~~	~~4.9~~	~~43.92~~			
13	6.7	43.20			
14	8.3	48.24			
~~15~~	~~7.6~~	~~48.24~~			
16	4.9	48.24			
17	5.0	48.24			
~~18~~	~~6.8~~	~~23.04~~			
19	13.3	15.12			
20	9.2	15.12			
~~21~~	~~10.8~~	~~15.12~~			
22	6.6	12.96			
23	4.8	12.96			
~~24~~	~~6.5~~	~~12.96~~			
25	7.0	12.96			
26	16.0	7.92			
~~27~~	~~25.8~~	~~10.08~~			
28	21.4	10.08			
29	0.0	108.00			
~~30~~	~~0.0~~	~~72.00~~			

LIST OF SYMBOLS:


```
~~%OWN      =PERCENT OWNERSHIP OF THE UNIT BY THE UTILITY CURRENTLY BEING~~
             CONSIDERED
L.TYPE    =LOADING TYPE:      1=BASE
                              2=SHOULDER
                              3=PEAKING
FOR       =THE FORCED OUTAGE RATE IN PERCENT
RLGNG     =THE MAXIMUM RATE OF LOAD INCREASE IN MW/HR FOR THE UNIT
AV.HT.RT=THE NET HEAT RATE FOR THE CURRENT MONTH IN BTU/KWH
F.CST     =THE FUEL COST FOR THE CURRENT MONTH IN $/MMBTU
~~OP.CST    =THE AVERAGE OPERATING COST IN $/MWH~~
MN.CST    =THE AVERAGE MAINTENANCE COST IN $/MWH
MARG.CST=THE TOTAL INCREMENTAL COST IN $/MWH COMPUTED ON THE BASIS
~~           OF THE SELECTED OPTION~~
S.CST     =THE AVERAGE COST IN $ PER STARTUP OF THE UNIT
```

```
~~**************************************************************************~~
********************BEGIN MARGINAL CALCULATION*************************
**************************************************************************
```

```
~~$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$~~
$$$$$$$$$   MONTH= 6   $$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$
$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$$
```

~~INCREMENTAL HEAT AND COST DATA~~

#	AV.HT.RT	F.CST	OP.CST	MN.CST	MARG.CST	S.CST
~~1~~	~~9683.67~~	~~84.69~~	~~0.370~~	~~0.423~~	~~8.994~~	~~1000.~~
2	9762.88	84.64	0.359	0.847	9.470	1000.
3	10800.82	90.76	0.320	0.775	10.897	1000.
~~4~~	~~9856.94~~	~~97.86~~	~~0.211~~	~~0.556~~	~~10.413~~	~~1000.~~
5	9856.94	97.86	0.211	0.556	10.413	1000.
6	9856.94	97.86	0.211	0.556	10.413	1000.
~~7~~	~~9856.94~~	~~97.86~~	~~0.211~~	~~0.556~~	~~10.413~~	~~1000.~~
8	11286.50	250.44	0.0	11.280	39.546	0.
9	10494.80	105.06	1.170	1.629	13.825	500.
~~10~~	~~10494.80~~	~~105.06~~	~~1.170~~	~~1.629~~	~~13.825~~	~~500.~~
11	10494.80	105.06	1.170	1.629	13.825	500.
12	11181.25	109.30	1.116	1.149	14.486	500.
~~13~~	~~11181.25~~	~~109.30~~	~~1.116~~	~~1.149~~	~~14.486~~	~~500.~~
14	11181.25	109.30	1.116	1.149	14.486	500.
15	11181.25	109.30	1.116	1.149	14.486	500.
~~16~~	~~11181.25~~	~~109.30~~	~~1.116~~	~~1.149~~	~~14.486~~	~~500.~~
17	11181.25	109.30	1.116	1.149	14.486	500.
18	19562.02	246.00	0.188	2.049	50.359	0.
~~19~~	~~14091.07~~	~~238.57~~	~~0.511~~	~~5.521~~	~~39.649~~	~~0.~~
20	14091.07	238.57	0.511	5.521	39.649	0.
21	14091.07	238.57	0.511	5.521	39.649	0.
22	14091.07	238.57	0.511	5.521	39.649	0.
23	14091.07	238.57	0.511	5.521	39.649	0.
24	14091.07	238.57	0.511	5.521	39.649	0.
~~25~~	~~14091.07~~	~~238.57~~	~~0.511~~	~~5.521~~	~~39.649~~	~~0.~~
26	10425.35	235.09	1.439	1.741	27.689	0.
27	9915.64	233.00	1.096	4.584	28.773	0.
~~28~~	~~10531.32~~	~~231.71~~	~~1.458~~	~~9.340~~	~~35.700~~	~~0.~~
29	100000.00	14.71	0.0	0.0	14.710	0.
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.

******************SYTEM DISPATCHING TABLE******************

UNIT	UNIT OUTPUT (MW)	MARG.CST ($/MW)	SYSTEM OUTPUT (MWH)	SYSTEM CST. ($)
BASE LOADED PLANTS (MIN)				
1	72.00	8.994	72.00	648.
2	75.00	9.470	147.00	1358.
7	80.50	10.413	227.50	2196.
6	80.50	10.413	308.00	3034.
5	80.50	10.413	388.50	3873.
4	80.50	10.413	469.00	4711.
3	59.99	10.897	528.99	5365.
BASE LOADED PLANTS (MAX)				
1	180.00	8.994	636.99	6336.
2	220.00	9.470	781.99	7709.
7	204.75	10.413	906.24	9003.
6	204.75	10.413	1030.49	10297.
5	204.75	10.413	1154.74	11591.
4	204.75	10.413	1278.99	12885.
3	132.00	10.897	1351.00	13669.
SHOULDER PLANTS (MAX)				
11	150.00	13.825	1501.00	15743.
10	130.00	13.825	1631.00	17540.
9	140.00	13.825	1771.00	19476.
17	67.00	14.486	1838.00	20446.
16	67.00	14.486	1905.00	21417.
15	67.00	14.486	1972.00	22387.
14	67.00	14.486	2039.00	23358.
13	60.00	14.486	2099.00	24227.
12	61.00	14.486	2160.00	25111.
PEAKING PLANTS (MAX)				
30	100.00	7.990	2260.00	25910.
29	150.00	14.719	2410.00	28116.
26	11.00	27.689	2421.00	28421.
27	14.00	28.773	2435.00	28824.
28	14.00	35.700	2449.00	29323.
8	4.00	39.546	2453.00	29482.
25	18.00	39.649	2471.00	30195.
24	18.00	39.649	2489.00	30909.
23	18.00	39.649	2507.00	31623.
22	18.00	39.649	2525.00	32336.
21	21.00	39.649	2546.00	33169.
20	21.00	39.649	2567.00	34002.
19	21.00	39.649	2588.00	34834.
18	32.00	50.359	2620.00	36446.

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OPERATING AND COST SUMMARY FOR THE MONTH 6

~~#~~	~~MMBTU~~	~~MWH~~	~~FUEL~~	~~OP~~	~~MAINT~~	~~ST~~	~~ST.CST~~	~~TOT.CST~~
1	299527.	30931.	253670.	11444.	13096.	9	9000.	287210.
~~2~~	~~1069051.~~	~~109502.~~	~~904845.~~	~~39355.~~	~~92792.~~	~~4~~	~~4000.~~	~~1040992.~~
3	858319.	79468.	779010.	25406.	61564.	1	1000.	866980.
4	1147177.	116383.	1122628.	24530.	64755.	2	2000.	1213912.
~~5~~	~~1151394.~~	~~116811.~~	~~1126754.~~	~~24620.~~	~~64993.~~	~~2~~	~~2000.~~	~~1218367.~~
6	1193646.	121097.	1168102.	25524.	67378.	2	2000.	1263003.
7	1244539.	126260.	1217905.	26612.	70251.	2	2000.	1316767.
~~8~~	~~1861.~~	~~165.~~	~~4660.~~	~~0.~~	~~1859.~~	~~1~~	~~0.~~	~~6519.~~
9	563799.	53722.	592327.	62854.	87513.	2	1000.	743694.
10	615564.	58654.	646711.	68625.	95548.	2	1000.	811884.
~~11~~	~~900946.~~	~~76309.~~	~~841368.~~	~~89281.~~	~~124307.~~	~~2~~	~~1000.~~	~~1055956.~~
12	127502.	11403.	139360.	12726.	13102.	0	0.	165188.
13	147322.	13176.	161022.	14704.	15139.	0	0.	190866.
~~14~~	~~190064.~~	~~16998.~~	~~207740.~~	~~18970.~~	~~19531.~~	~~1~~	~~500.~~	~~246741.~~
15	222300.	19882.	242974.	22188.	22844.	1	500.	288505.
16	260843.	23329.	285101.	26035.	26805.	0	0.	337941.
~~17~~	~~291449.~~	~~26066.~~	~~318553.~~	~~29089.~~	~~29950.~~	~~0~~	~~0.~~	~~377592.~~
18	10319.	527.	25384.	99.	1081.	1	0.	26564.
19	5389.	382.	12856.	195.	2111.	2	0.	15162.
~~20~~	~~6467.~~	~~459.~~	~~15427.~~	~~234.~~	~~2534.~~	~~1~~	~~0.~~	~~18195.~~
21	7229.	513.	17246.	262.	2832.	1	0.	20340.
22	7336.	521.	17501.	266.	2874.	1	0.	20642.
~~23~~	~~8375.~~	~~594.~~	~~19981.~~	~~303.~~	~~3202.~~	~~0~~	~~0.~~	~~23566.~~
24	9166.	650.	21867.	332.	3591.	1	0.	25791.
25	10114.	718.	24129.	366.	3963.	1	0.	28459.
~~26~~	~~5172.~~	~~496.~~	~~12160.~~	~~714.~~	~~864.~~	~~2~~	~~0.~~	~~13738.~~
27	5193.	524.	12099.	569.	2401.	4	0.	15069.
28	5495.	522.	12734.	761.	5135.	3	0.	18629.
~~29~~	~~1270715.~~	~~12707.~~	~~106922.~~	~~0.~~	~~0.~~	~~0~~	~~0.~~	~~106922.~~
30	1478779.	14788.	118154.	0.	0.	0	0.	118154.

~~TOTAL HEAT OUTPUT IN MMBTU~~	~~13014941.~~
TOTAL SYSTEM GENERATION IN MWH	1033555.
TOTAL FUEL COST IN $	10509182.
TOTAL OPERATING COST IN $	526065.
TOTAL MAINTENANCE COST IN $	902094.
TOTAL STARTUP COSTS IN $	26000.
~~TOTAL SYSTEM COSTS IN $~~	~~11963338.~~
AVERAGE GENERATION COST IN $/MWH	11.575

~~*** SYSTEM LOSS OF LOAD PROBABILITY IS 0.02142 ***~~

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ANNUAL OPERATING COST SUMMARY

#	MMBTU	MWH	FUEL	OP	MAINT	ST	ST.CST	TOT.CST
1	299527.	30931.	253670.	11444.	13096.	9	9000.	287210.
2	1069051.	109502.	904845.	39355.	92792.	4	4000.	1040992.
3	858319.	79468.	779010.	25406.	61564.	1	1000.	866980.
4	1147177.	116383.	1122629.	24559.	64755.	2	2000.	1213912.
5	1151394.	116811.	1126754.	24620.	64993.	2	2000.	1218367.
6	1193646.	121097.	1168102.	25524.	67378.	2	2000.	1263003.
7	1244539.	126260.	1217905.	26612.	70251.	2	2000.	1316767.
8	1861.	165.	4660.	0.	1859.	1	0.	6519.
9	563799.	53722.	592327.	62854.	87513.	2	1000.	743694.
10	615564.	58654.	646711.	68625.	95548.	2	1000.	811884.
11	800846.	76309.	841368.	89281.	124307.	2	1000.	1055956.
12	127502.	11403.	139360.	12726.	13102.	0	0.	165188.
13	147322.	13176.	161022.	14704.	15139.	0	0.	190866.
14	190064.	16998.	207740.	18970.	19531.	1	500.	246741.
15	222300.	19882.	242974.	22188.	22844.	1	500.	288505.
16	260843.	23329.	285101.	26035.	26805.	0	0.	337941.
17	291448.	26066.	318553.	29089.	29950.	0	0.	377592.
18	10319.	527.	25384.	99.	1081.	1	0.	26564.
19	5309.	382.	12856.	195.	2111.	2	0.	15162.
20	6467.	459.	15427.	234.	2534.	1	0.	18195.
21	7229.	513.	17246.	262.	2832.	1	0.	20340.
22	7536.	531.	17501.	266.	2874.	1	0.	20642.
23	8375.	594.	19981.	303.	3282.	0	0.	23566.
24	9166.	650.	21867.	332.	3591.	1	0.	25791.
25	10114.	718.	24129.	366.	3963.	1	0.	28459.
26	5172.	496.	12160.	714.	864.	2	0.	13738.
27	5193.	524.	12099.	569.	2401.	4	0.	15069.
28	5495.	522.	12734.	761.	5135.	3	0.	18629.
29	1270715.	12707.	186922.	0.	0.	0	0.	186922.
30	1478779.	14788.	118154.	0.	0.	0	0.	118154.

TOTAL HEAT OUTPUT IN MMBTU	13014941.
TOTAL SYSTEM GENERATION IN MWH	1033555.
TOTAL FUEL COST IN $	10509182.
TOTAL OPERATING COST IN $	526065.
TOTAL MAINTENANCE COST IN $	902094.
TOTAL STARTUP COSTS IN $	26000.
TOTAL SYSTEM COSTS IN $	11963339.
AVERAGE GENERATION COST IN $/MWH	11.575

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READY

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AL= $276.14

TS0287 LOGGED OFF TSO AT 10:28:59 ON JANUARY 3, 1977!

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CHAPTER 4

LONG TERM ELECTRIC GENERATION SYSTEM EXPANSION ANALYSIS PROGRAM: WASP

4.1 Introduction

A computer program that estimates the future configuration of utility generating capacity has become increasingly important for regulatory agencies for the following reasons:

1. It provides an independent estimate of the future need for generating capacity and of operating cost of an electric utility;

2. It provides a basis to project the future financial status of an electric utility; and

3. It provides regulatory agencies with a means of studying the effects of their proposed policies and economic factors on system expansion.

WASP[1-4] (Wien Automatic System Planning Package) developed by the Tennessee Valley Authority (TVA), is a modular program for analyzing electric power generating systems. It is designed to find the economically optimal generation expansion pattern for an electric utility with various constraints. Although other computer programs for finding the optimal expansion schedule of power generating systems have been developed, they are not available to the public. Even through a contract arrangement with those who offer such services, only limited information about the program is released. The WASP program evolved from the SAGE program of TVA that was originally designed for use in the International Atomic Energy market survey for nulcear power in developing countries. From its beginning, the SAGE program's development has attracted much interest among electric companies and regulatory agencies in the United States since it provides a unique means of studying the optimal generating system expansion schedule. In the project reported here the WASP program was adapted for various applications and is used for the following studies:

1. evaluation of the utilities' own expansion schedules;
2. sensitivity study for various parameters including construction cost, consumption growth assumptions, interest and escalation rates;[5-6]
3. evaluation of the effect of system reliability criteria on the capital cost; and
4. providing the input data for the Regulatory Analysis Model described in Chapter 6.

4.2 Overview of WASP

The program uses probabilistic simulation for power production cost calculations as well as for system reliability evaluation in terms of loss of load probability. The optimal generation mix in every year during the study period is found by forward dynamic programming. The criterion for optimization is minimization of the total escalated operating and expansion related capital costs which are discounted to a specific base year.

WASP is able to consider:

1. 100 existing and committed multi-unit plants of the following types:
   a. different kinds of thermal units including base, intermediate and peaking units;
   b. hydro units;
   c. pumped storage; and
   d. emergency hydro power.

   Each hydro, pumped storage and emergency power sources is treated as a single composite plant.

2. Twenty expansion candidate plant-types. Among these plant types, hydro, pumped storage and emergency power are treated as a single plant type, each consisting of a maximum of 20 units.

3. Thirty years in the study period.

4. Two hundred alternative system configurations in any one year with a limit of 2000 configurations in the study period.

The WASP program consists of six modules. Each module generates a separate report, so the user can analyze the output at completion of each step. This maximizes the advantage of man-machine interactions and makes possible the correction of data errors without loss of effort and computing cost. The six modules are:

1. LOADSY: describes present and forecasted system load characteristics on which the capacity expansion and power generation requirements are based. This module is assisted by a curve-fit routine to calculate a low order polynomial fit for the periodical load duration curves.

2. FIXSYS: describes the existing power system plant characteristics and firmly scheduled additions to and retirements from the system.

3. VARSYS: describes all alternate plants which can be used as expansion candidates to the system.

4. CONGEN: generates alternative system configurations for capacity additions within specified reliability and added unit number constraints.

5. MERSIM: uses probabilistic simulation to calculate the periodical operating costs and reliability factors for each configuration allowed in CONGEN. The module also keeps track of all previously simulated configurations.

6. DYNPRO: determines the optimum expansion schedule with respect to timing, type and number of units to be added.

The first three modules create data files which are used in the three remaining ones. Additional files are created by the fourth and fifth modules and used in the sixth. A brief flow diagram of WASP is presented in Figure 1.

4.3 More Details about the Six Modules

4.3.1 Fix System Module

The FIXSYS module generates a data file which describes: (1) the existing generating system, (2) all prescheduled plant additions and (3) retirements. A minimum of 100 fixed multi-unit plants can be defined (normal hydro, emergency hyro and pumped storage are treated as single composite plants). A maximum of 999 single units can be defined

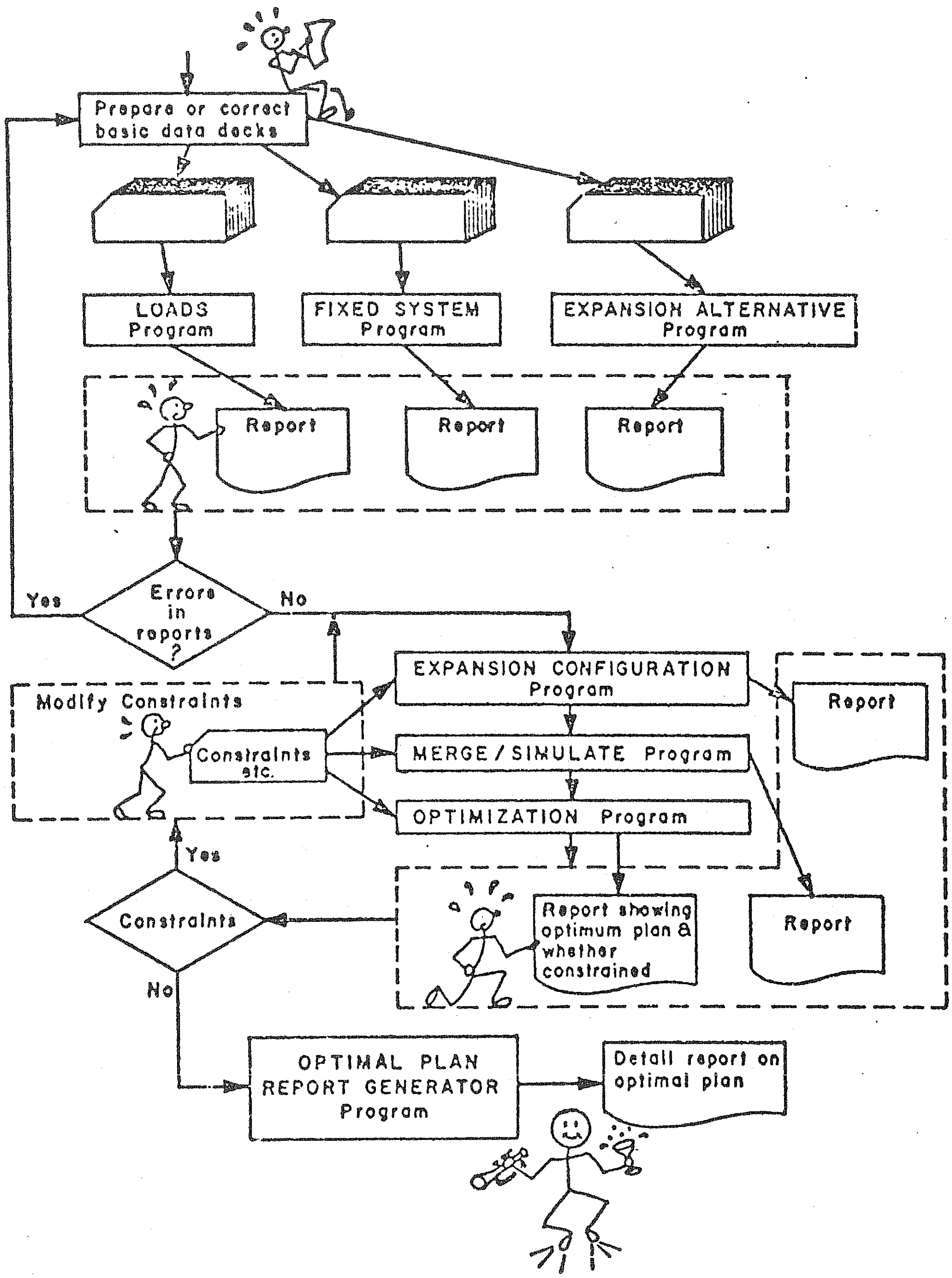

Fig. 1 Flow of WASP Calculations

within each multi-unit thermal plant. A maximum of five different types of plant fuel can be defined for discounting and escalating purposes.

The treatments for each thermal, hydro and pumped storage plant are described next.

Thermal Plants

Thermal plants include nuclear, oil, coal and others. A thermal plant can be defined as either an individual generating unit or a composite plant of multiple units. Since the computing time rapidly increases with the increase in the number of plants, thermal plants of similar type, fuel and operating characteristics can be merged into a single equivalent plant. The units belonging to a composite plant are assumed to have the same capacity and characteristics. Each plant is specified by the following input data:

Number of Units (<999)

Operating Blocks: i) Minimum operating level (MW) for a unit
ii) Maximum operating level (MW)

Heat Rate: i) Minimum load heat rate for the base block
ii) Average incremental heat rate for the peak block.

Fuel Cost in ¢/MBTU: A separate fuel cost is defined for each plant in the system. In principle, a maximum of 100 separate fuel costs can be defined. Different types of fuel such as nuclear, oil and coal are identified by different fuel costs.

Plant Type: The number of different thermal plant types is limited to 100 because of the number of fuel costs. However, each plant is assigned a numeral type code to factor in optional, separate escalation and discount rates for fuel and non-fuel costs. The total number of codes for thermal units is limited to 5.

Forced Outage: A forced outage rate is assigned to each plant.

Maintenance: i) Average number of days per year that the plant is to be shut down for maintenance.
ii) Maintenance class expressed in MW.

Operation and Maintenance Cost:
i) Fixed O&M cost including staffing, insurance and other items independent of energy generation
ii) Variable O&M costs that are dependent on energy generated.

Hydro Plants

The hydro plants considered fall into two types, namely, normal hydro and emergency hydro. Normal hydro represents the every-day hydro capacity. Emergency hydro represents any hydro capacity that can be used only as a reserve in excess of normal hydro capacity. It is used only to maintain system reliability in case of major forced outages. If it is used, the theoretical future availability of hydro energy is reduced and must be replaced by fossil generation. This is reflected by assigning a fossil plant cost-related penalty to emergency hydro energy instead of reducing the availability of normal hydro energy during the following period. Each type of hydro capacity is characterized by the input listed in Table 1.

4.3.2 VARSYS

The VARSYS module generates a data file for the candidate plants and requires inputs similar to FIXSYS. A maximum of 20 different types of expansion candidate plants can be considered. Hydro and pumped storage plants count each as one expansion candidate, but within both plant types, a maximum of 20 individual expansion projects can be specified. The number of allowable thermal plant candidates is reduced to 18 if hydro and pumped storage projects are included in the expansion. A maximum of five fuel type groups can be defined for thermal plants (same as for FIXSYS). The input required for thermal plant candidates is similar to that for FIXSYS.

4.3.3 LOADSY

LOADSY creates a data file of load data used by CONGEN, MERSIM and DYNPRO modules. The expansion schedule is found by DYNPRO on the annual basis. However, the maintenance schedule and energy cost calculations (for each division of a year) are done by MERSIM. A year is divided into a maximum of 12 periods. In the WASP code the load variation is treated by the load duration curves. Therefore, subdividing a year into some number of periods is important for taking into account the effect of seasonal load variations on the maintenance schedule. Otherwise, the operation cost and reliability estimate will be seriously erroneous.

Table 1 Input for Hydro Plants

Normal and Emergency Hydro		
Number of Units	:	always 1 for normal and emergency hydro.
Operating levels	:	Minimum operating level (run-of-river capacity) and maximum operating level (sum of base and peak block capacities).
Forced outage rate (normal hydro only)	:	assumed to be zero.
Maintenance outage rate (normal hydro only)	:	set to zero but implicitly taken into consideration by periodical factors.
Expected annual total energy (GWH/year)		
O & M costs		
Periodical factors	:	periodical variation in the generating capabilities.
Hydrological conditions	:	capacity and energy multipliers to consider variation in hydrological conditions.
Heat rate (emergency hydro only)	:	hypothetical heat rate
Fuel cost (emergency hydro only)	:	hypothetical fuel cost
Pumped Storage		
Number of Units	:	actual total number of individual units.
Operating mode level	:	pumping load (MW) and generating capacity.
Maximum Energy (GWd/period)		
Efficiency	:	pumping efficiency and generator efficiency

The LOADSY module requires, as input, (1) unnormalized load duration curves for each period in the form of a polynomial (up to fifth order) or pointwise data, and (2) forecast peak load for each period. The load duration curves given by input are normalized with the peak load and then expanded into the Fourier series. This module prints out, as output, (1) load factor, (2) maximum and minimum load for each period, and (3) the Fourier coefficients. The Fourier coefficients are written in the data file and passed to CONGEN, MERSIM and DYNPRO.

4.3.4 CONGEN Module

The CONGEN module generates a set of all acceptable system configurations for each study year and creates a file to be used by MERSIM and DYNPRO. Theoretically, for each year there are many possible system configurations consisting of fixed system and candidate plants. However, practical constraints limit the acceptable number of configurations.

There are three such constraints as follows:

1. minimum and maximum values of installed reserve capacity;
2. maximum permissible value of loss-of-load probability; and
3. minimum and maximum number of units (or projects in the case of hydro or pumped storage) for each year: this constraint is called an expansion "tunnel".

The loss-of-load probability of each system configuration, which is necessary for the test of the second criterion above, is calculated in the module by using the probabilistic simulation method that is described in Appendix 3A. The probabilistic simulation is applied for each subinterval of a year. It should be pointed out here, however, that only the effect of forced outages is considered in the probabilistic simulation of this module; the effect of maintenance outage is neglected.

The third constraint is a computational device for reducing the computing time (and accordingly, cost), without restricting the optimal configuration. If the number of units (or projects) is touching the ceiling or bottom of the tunnel, the tunnel is altered and the calculation from CONGEN through DYNPRO is reiterated.

The input for CONGEN consists of the user's direct input and the data files from LOADSY, FIXSYS and VARSIS. The user's direct input includes the specification of the tunnel, the maximum and minimun permissible reserve margin, the indicator for optional loss-of-load calculation and the printout options.

4.3.5 MERSIM

The MERSIM module uses the files of data created by the four preceeding modules and calculates energy generation and the corresponding operation cost (for every acceptable configuration for every period) on a plant basis. The energy generation by unit and the loss-of-load probability are calculated with the equivalent-load-duration curves that are recursively calculated. The effect of maintenance outage is taken into consideration in MERSIM. Therefore, the major calculations in MERSIM generate multiple equivalent load duration curves that are all expressed by Fourier expansion coefficients. In generating the equivalent load duration, the following new information is necessary:

1. loading order of units;
2. maintenance outage rate for each unit during each period; and
3. forced outage rate.

In discussing the loading order, the difference in the treatments for thermal plants, normal hydro and pumped storage should be first mentioned. Thermal plants are treated as having either one or two blocks of capacity. Typically, the base block of a unit represents the minimum operating capacity of the unit and the peak block equals the remainder of the capacity. A normal hydro composite plant has two blocks of capacity. The first block represents a run-of-river capacity that is always loaded first, and the second block is the peaking hydro capacity. The pumped storage and emergency hydro are treated as single blocks of composite capacity. The loading order of normal and emergency hydro capacity is automatically handled. The base block of hydro has the dirst loading priority while its peak block is used to share the peak load.

The loading order of thermal units and pumped storage plants can be fixed in any desired order though the base block of a thermal unit is always loaded before the peak block. Figure 2 illustrated the principle of loading the pumped storage capacity to share the peak of a

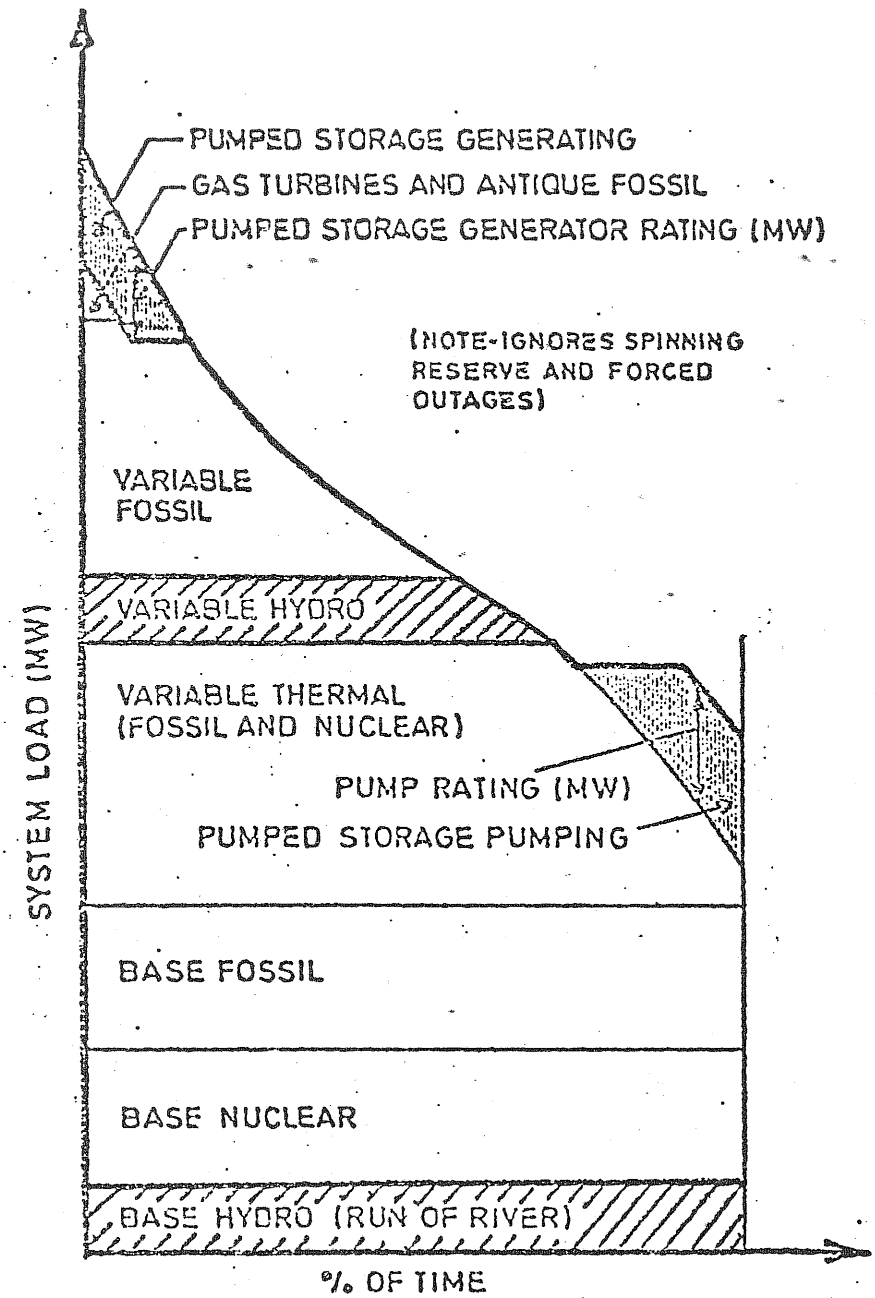

Fig. 2 Illustration of Loading Order

a load duration curve and the impact of corresponding pumping requirements on the low load end of the curve.

The maintenance outage rate of a unit is specified by the input. Generally, maintenance of large units is done in the period that has the greatest space for maintenance. The thermal units can be divided into a maximum of seven maintenance classes. Scheduling is always started from the largest unit and period of largest available maintenance space. Once the maintenance outage rate for each period is decided the maintenance of a single unit is randomly distributed over the period and is combined with its forced outage rate. The combined outage rate is used to generate the equivalent load duration curves.

The major part of input comes from the preceeding modules as the data file. However, the user has to provide a few input parameters such as (1) loading order for thermal and pumped storage plants, (2) number of hydrological conditions and (3) some cost parameters for pumped storage operations.

The output of the MERSIM module is printed out for each configuration and period considered and includes installed capacity, total generation, generation cost, energy balance, loss-of-load probability and energy not served. In addition, as an option, the following results are printed on a plant-by-plant basis: base and peak block operating hours, energy generation and operating cost, capacity factors. This module also creates a data file to be passed to the last module, DYNPRO.

4.3.6 DYNPRO

This module performs the economic evaluation of the alternative expansion plans provided by the CONGEN module, and then determines the base expansion policy for the system. The forward dynamic programming method is used to find the expansion plan that gives the minimum discounted cash flow of compounded capital and operating expenditures over the study period. The value of the objective function, which is to be minimized through dynamic programming, is calculated for each system configuration in each study year. Each system configuration is designated as "state" and each year is designated as "stage". In conjunction with the dynamic programming optimization, two aspects, namely how to calculate the objective function and what constraints are imposed, are outlined in the next two paragraphs.

The objective function is defined as the sum of all operating costs and capital costs for construction minus the salvage value of the plants, both of which are discounted to a specified base year. Separate or common discount and escalation rates can be applied to each cost component. Discount rates can be varied within the study period. The salvage value considered in the objective function represents the credit given for the unused portion of the unit life. In other words, it is equivalent to the depreciated value of the plant. The salvage value is calculated by either the straight-line depreciation schedule or the sinking fund depreciation schedule.

The major constraints on optimization are: (1) critical value of LOLP, (2) upper and lower reserve limits and (3) the tunnels to limit the possible number of units added in each year. With the first constraint, the configuration with a LOLP higher than the value specified by the user are not included in the final expansion pattern. The LOLP values used here are either from CONGEN or MERSIM, depending on the option selected by the user. The LOLP from CONGEN does not include the effect of the maintenance schedule, while the LOLP from MERSIM does. The second constraint is applied at CONGEN rather than in the DYNPRO module, so all of the configuration passed from CONGEN to DYNPRO already satisfies this constraint. The same applies to the third constraint.

As explained in Section 4.3.4 the tunnel is an artificial constraint to reduce the amount of calculation for each run of the module. If the number of one type of unit at a stage is on either the upper or lower side of the tunnel, it indicates that the true optimal may be outside of the tunnel. Therefore, the run of the three modules, CONGEN through DYNPRO, must be reiterated with an altered tunnel until all the numbers of units are within the tunnels. The wider the width of tunnels, the fewer the number of iterations; but computing time of each iteration is substantially increased.

The DYNPRO module uses the five data files generated by the preceeding modules and some additional input. The input consists of the economic parameters for calculating the objective function, the number of years for optimization, selection of alternative options available

Reference 7 points out that, even though the "look ahead" optimization which results in capital intensive expansion is cheaper in a very long run, the utility manager must be willing to lose money for six to eight years. The length of period for losing money depends on how far into the future one looks. In the WASP case, this means how long the study period is.

If the construction cost for the future plant is passed on to present customers, the present customers are sacrificing by constructing large nuclear units for the benefit of the customers of six to eight years later. (This length of time would be much longer if the length of time of construction of large nuclear units is taken into account.) On the other hand, if only less capital intensive plants are built for the benefit of present customers, the customers in the future will be burnened with a higher cost of electricity. If we consider the value of our children's future, as well as our own, then paying higher prices for constructing future plants would be justified, and accordingly WASP should be used rather than OGP.

There is no unique way from the engineering view point to determine how long the period should be for which the total cost is minimized. The present gap between OGP and WASP offers a fundamental problem that the regulators would have to investigate and solve.

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CHAPTER 5

THE LOSS-OF-LOAD PROBABILITY PROGRAM

5.1 Objectives

As the cost of generation becomes higher, regulatory agencies focus more attention on the following questions:

1. Is the current reliability level of the generation system really necessary?
2. What is the effect of reliability criteria on the cost of electric generation?
3. How effective is load control in maintaining a high reliability with minimal addition of new capacity?
4. Are all the plants scheduled by a utility really necessary to maintain the current reliability standard?

In order to provide a means of answering those questions, the LOLP program has been developed. The loss-of-load probability [1,2] is the concept most commonly used by the electric utility industry to measure the reliability level of a generating system. The method of calculating the annual LOLP adopted in this program is to sum up the LOLP for all the hours in a year. The LOLP program consists of two parts, (1) maintenance scheduling and (2) LOLP calculation, which are explained in detail in the remainder of this chapter. The Dayton Power & Light System (DPL) as shown in Table 1 will serve as a model to illustrate the result. However, the results of calculation in the illustration should not be considered to represent the real DP&L system, since several simplifications and assumptions have been made.

5.2 Maintenance Schedule Algorithm

The maintenance schedule determined by this program is based on (1) the estimated peak load by month and (2) the net system capacity by month. The difference between the estimated peak load and the net system capacity for each month provides the maintenance space and will be denoted in this chapter as the operation reserve before maintenance (ORBM). The ORBM for DP&L is illustrated in Figure 1. The number of

Table 1. Dayton Power & Light Company
Generating Stations

Plant Number	Plant Name	Maximum Net Capacity (MW)	DP&L Ownership (%)	Effective DP&L Capacity (MW)	Effective Forced Outage Rate (%)
1	Beckjord 6	434	50	215	11.6
2	Conesville 4	800	16.5	130	22.9
3	J. M. Stuart 1	585	35	205	11.6
4	J. M. Stuart 2	585	35	205	11.6
5	J. M. Stuart 3	585	35	205	11.6
6	J. M. Stuart 4	570	35	200	11.6
7*	Miami Fort 7	500	36	180	11.6
8	Stuart Diesels (4)	11	35	5	10.0
9	Tait 4	139	100	140	5.1
10	Tait 5	139	100	140	5.1
11	Tait Topping	148	100	150	5.1
12	Hutchings 1	61	100	60	3.2
13	Hutchings 2	60	100	60	3.2
14	Hutchings 3	67	100	65	3.2
15	Hutchings 4	67	100	65	3.2
16	Hutchings 5	67	100	65	3.2
17	Hutchings 6	67	100	65	3.2
18	Hutchings G.T.	28	100	30	10.0
19	Yankee 1	21	100	20	10.0
20	Yankee 2	21	100	20	10.0
21	Yankee 3	21	100	20	10.0
22	Yankee 4	18	100	20	10.0
23	Yankee 5	18	100	20	10.0
24	Yankee 6	18	100	20	10.0
25	Yankee 7	18	100	20	10.0
26	Tait Diesels (4)	11	100	10	10.0
27	Monument Diesels (5)	14	100	15	10.0
28	Sidney Diesels (5)	14	100	15	10.0

*On line as of 1975.
System capacity = 2,365 MW.

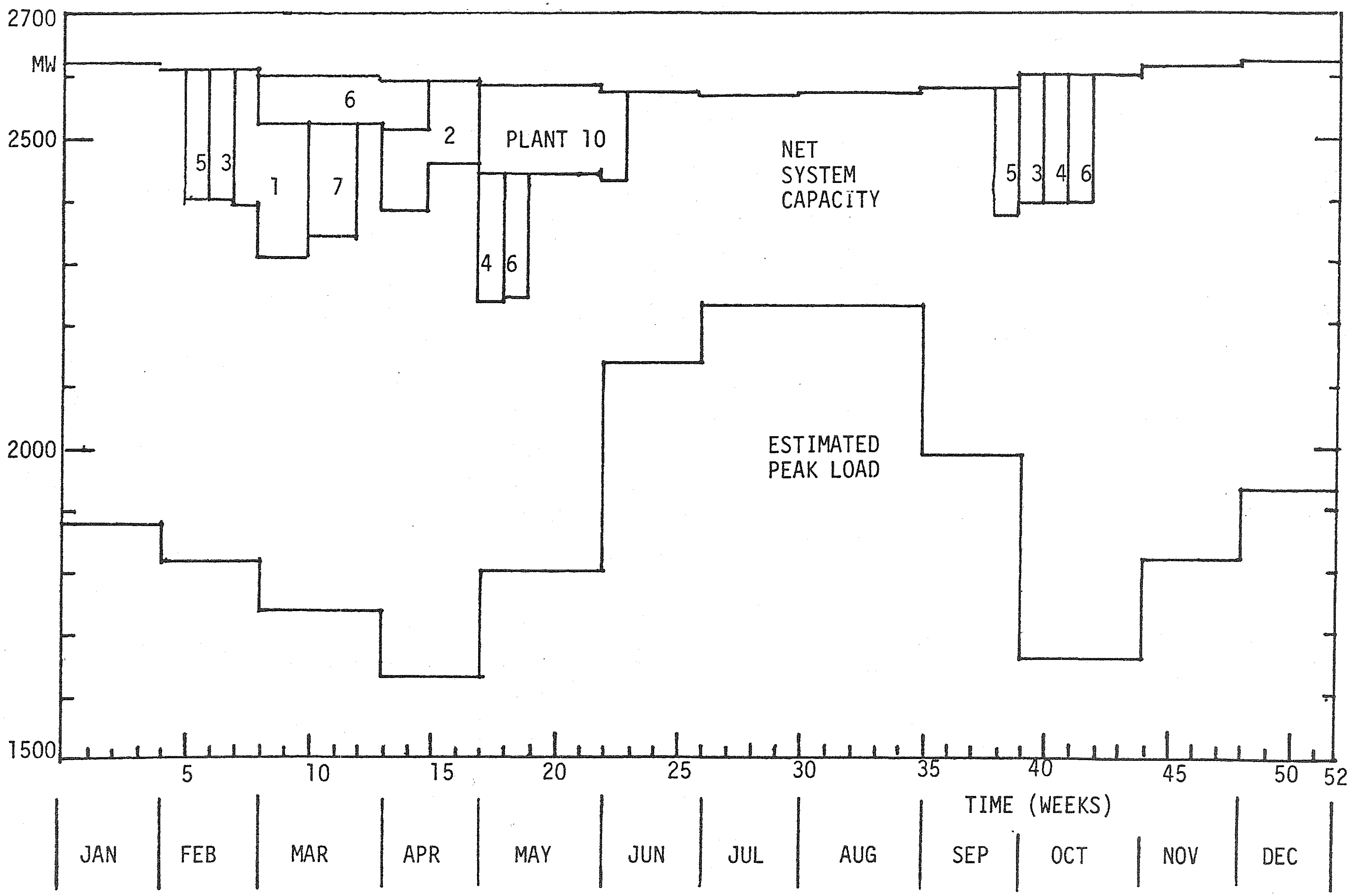

Fig. 1 1977 Maintenance Schedule
Planned by DPL

days required for maintenance of each unit is given by input. The number of days times the capacity of a unit is defined as maintenance space for the unit. The total maintenance space is calculated by summing up the maintenance space for all the units.

The first step of maintenance scheduling in this program is to allocate the total maintenance space to the twelve months in the year considered. The criterion in planning a maintenance schedule is to minimize the annual loss-of-load probability. In this program, the maintenance space is first allocated so that the operating reserve after maintenance becomes a constant for each month except for the months in which the ORBM is too small to allow any maintenance. At this stage it is assumed that the maintenance space can be distributed in any way. The maintenance schedule thus determined is referred to as thd ideal maintenance schedule and is illustrated in Figure 2.

The maintenance schedule for each unit is determined in the decreasing order of unit capacity as follows:

1) The largest capacity unit is considered first. The maintenance schedule is determined if this can be done within the ideal maintenance schedule . If it does not fit in the ideal maintenance schedule, then the program uses the schedule by which the deviation from the ideal maintenance schedule is a minimum.

2) The second largest unit is considered next. The same procedure as (1) is performed for the remaining part of the ideal maintenance schedule.

3) The same procedure is repeated for all the units to be maintenanced in order of decreasing capacity.

The maintenance schedule thus determined for the DP&L system is shown in Figure 3 compared with the DPL's own schedule, Figure 1. The effect of the difference in those two maintenance schedules on the reliability is discussed in Section 5.4.

5.3 Loss-of-Load Probability

The annual loss-of-load probability is calculated by totaling the loss-of-load for each hour of the year studied. The capacity outage probability table is constructed for this purpose. It describes the probability of more than X MW on outage, where X is a multiple of an increment

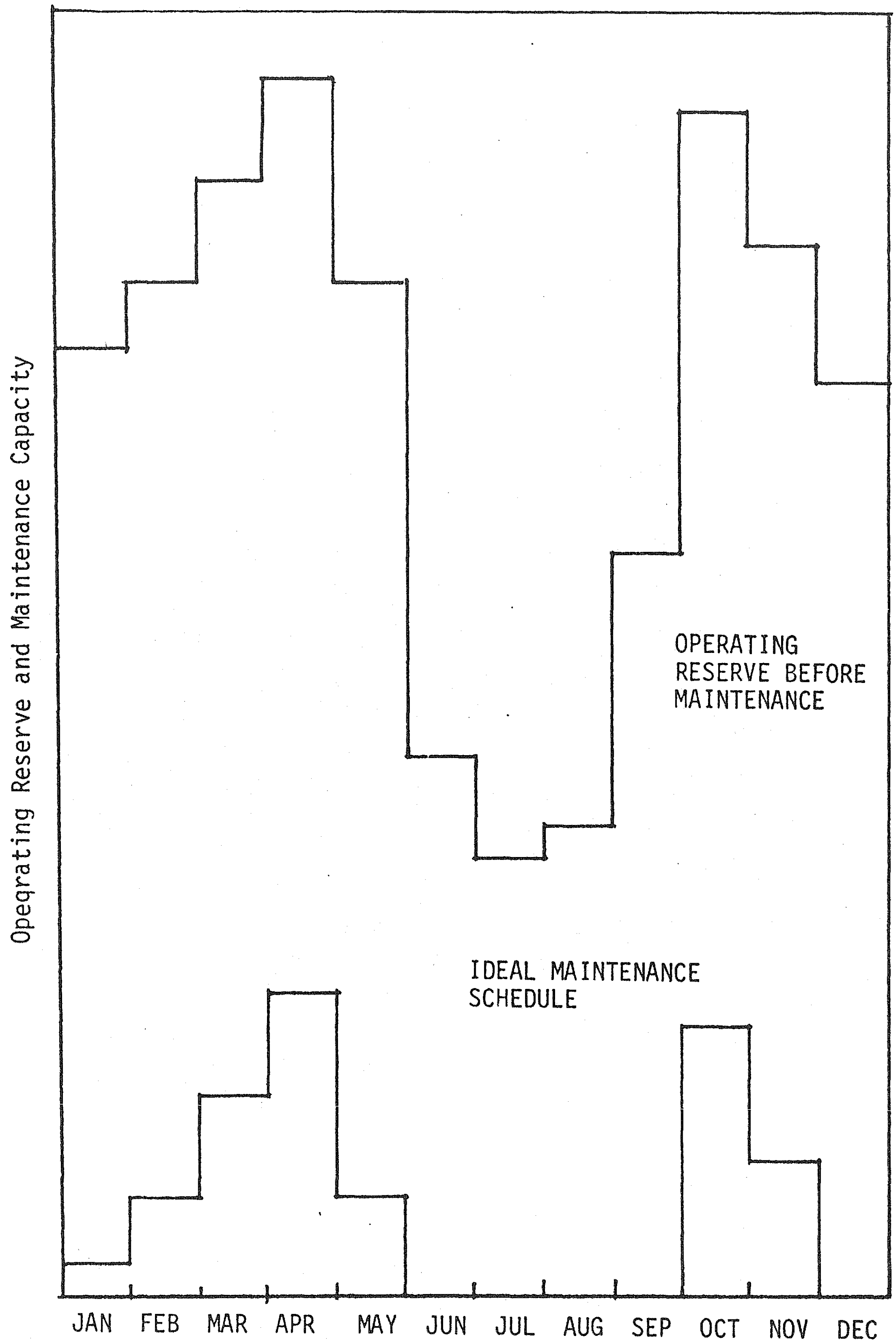

Fig. 2 Ideal Maintenence Schedule

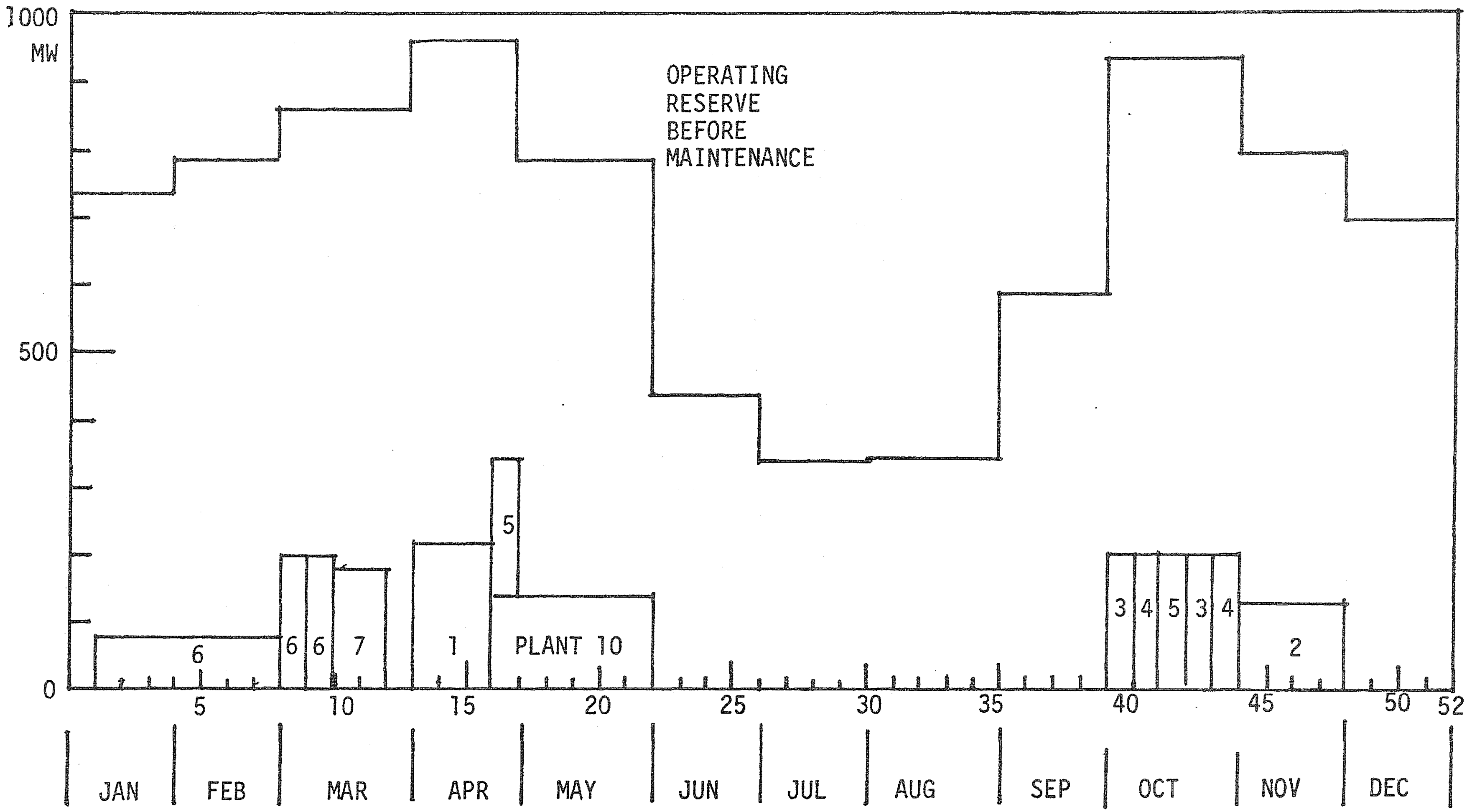

Fig. 3 Theoretically Planned Maintenance Schedule

of 5 MW. The capacity of units is rounded to the nearest multiple of 5 MW. This discretization makes the whole calculation and tabulation of the result easy.

By using the capacity outage table, one can easily find the loss-of-load probability for a period in which the electric load can be assumed to remain constant. Suppose one hour during which the system load can be assumed to be a constant, say L MW, and that the system reserve during this hour is R MW. Capacity outage that is equal to or less than R MW produces no loss-of-load. On the other hand a capacity outage greater than R yields loss-of-load. Therefore, the value of the capacity outage table at X = R, say P, gives the probability that loss-of-load continues during this hour. Statistically, this is equivalent to saying that the estimated loss-of-load during this hour is P. The total hour of loss-of-load for a year can be obtained by totaling this loss-of-load hour for all the hours in a year, and then can be converted into units of days/year.

The capacity outage table is first constructed on the assumption that there is no maintenance outage. In order to take account of the units off line for maintenance, the capacity outage table is altered for any particular combination of the maintenanced units. This can be done with a small amount of computing time, as will be described later.

The next two examples show how the capacity outage table is constructed.

EXAMPLE 1 Construction of Capacity Outage Probability Table

In this example a system consisting of only two units is considered:

Unit #1 215 MWe; $P_f = 0.116$

Unit #2 130 MWe; $P_f = 0.229$

where P_f is the forced outage probability. The capacity outage probabilities are calculated as follows:

Capacity on Outage X (MW)	Probability of X MW on Outage
0	(1-0.116)(1-0.229) = 0.6816
130	(1-0.116)(0.229) = 0.2024
215	(0.116)(1-0.229) = 0.0894
215+130 = 345	(0.116)(0.229) = 0.0266

EXAMPLE 2

Suppose another unit is added to the system of Example 1:

Unit #2   205 MWe; $P_f = 11.6$

Then the probability of X on outage is calculated as follows:

For the case where Unit #3 is available, probabilities are calculated as:

X MW on Outage	Probability of X MW on Outage
0+0 = 0	(0.6816)(1-0.116) = 0.6025
130+0 = 130	(0.2024)(1-0.116) = 0.1789
215+0 = 215	(0.0894)(1-0.116) = 0.0791
345+0 = 345	(0.0266)(1-0.116) = 0.0235

For the case where Unit #3 is not available, we have:

X MW on Outage	Probability of X MW on Outage
0+205 = 205	(0.6816)(0.116) = 0.0791
130+205 = 335	(0.2024)(0.116) = 0.0235
215+205 = 420	(0.0894)(0.116) = 0.0103
345+205 = 550	(0.0266)(0.116) = 0.0031

Rearranging X in the above two tables in the increasing order of X, the capacity outage table for the system of three units is obtained as follows:

X MW	Probability	Cumulative Probability*,P
0	0.6025	1.0000
130	0.1789	0.3975
205	0.0791	0.2186
215	0.0791	0.1395
335	0.0235	0.0604
345	0.0235	0.0369
420	0.0103	0.0134
550	0.0031	0.0031

* P is the probability that X or more MW is on outage.

For a system with a larger number of units the procedure shown in the above examples is continued until all the units are included. The capacity of each unit is rounded to the nearest multiple of 5 MW (or 10 MW depending on the selection of discrete increment of X). As the number of units increases, X of almost every multiple of 5 MW in the range of interest appear in the table. If some multiple of 5 MW is missing in the table, the cumulative probability for that X can be found by interpolation. The capacity outage table thus obtained for DP&L is illustrated in Table 2 and also plotted in Figure 4.

The table thus constructed does not take the maintenance outage into consideration. In order to incorporate the effect of maintenance outage accurately, the table for all combinations of forced outage would have to be constructed. However, there is a convenient method[1] for removing a unit from the capacity outage table. To explain this approach let us first generalize the procedure to add a unit to the table. If the cumulative probability for a system consisting of N units is given by $P_N(X)$, then the cumulative probability for the same system with one additional unit is given by

$$P_{N+1}(X) = P_N(X)(1-r) + P_N(X-C).r$$

where P_{N+1} is the cumulative probability for the N+1 units, C is the capacity of the (N+1)-st unit, and r is the forced outage probability of the (N+1)-st unit, and

$$P_N(X) = 1.0 \text{ for } X \leq 0$$

In Equation 1, C is also rounded to the nearest multiple of 5 MW. The calculation for $P_{N+1}(X)$ starts for the lowest multiple of 5 MW for X and proceeds by increasing X by 5 MW.

Removing any unit from the table is just the reverse of Equation 5-1. Assuming a unit of D MW with a forced outage probability r' is removed from the system of the N+1 units, we replace C and r' in Equation (1) by D and r, respectively, and solve for $P_N(X)$. Thus we have

$$P_N(X) = \left[P_N(X-b').r' - P_{N+1}(X)\right]/r'$$

Table 2 Capacity Outage Probability Table

MW ON OUT-AGE	PROBABIL-ITY OF X MW ON OUTAGE	PROBABIL-ITY OF X OR MORE MW ON OUTAGE	MW ON OUT-AGE	PROBABIL-ITY OF X MW ON OUTAGE	PROBABIL-ITY OF X OR MORE MW ON OUTAGE
0	0.827E-01	0.100E+01	5	0.918E-02	0.917E+00
10	0.918E-02	0.908E+00	15	0.194E-01	0.899E+00
20	0.663E-01	0.880E+00	25	0.918E-02	0.813E+00
30	0.176E-01	0.804E+00	35	0.162E-01	0.786E+00
40	0.242E-01	0.770E+00	45	0.614E-02	0.746E+00
50	0.107E-01	0.740E+00	55	0.614E-02	0.729E+00
60	0.110E-01	0.723E+00	65	0.142E-01	0.712E+00
70	0.516E-02	0.698E+00	75	0.390E-02	0.693E+00
80	0.789E-02	0.689E+00	85	0.101E-01	0.681E+00
90	0.299E-02	0.671E+00	95	0.361E-02	0.669E+00
100	0.387E-02	0.664E+00	105	0.372E-02	0.660E+00
110	0.159E-02	0.657E+00	115	0.185E-02	0.655E+00
120	0.128E-02	0.653E+00	125	0.165E-02	0.652E+00
130	0.258E-01	0.650E+00	135	0.343E-02	0.625E+00
140	0.122E-01	0.621E+00	145	0.764E-02	0.609E+00
150	0.258E-01	0.601E+00	155	0.563E-02	0.576E+00
160	0.132E-01	0.570E+00	165	0.719E-02	0.557E+00
170	0.129E-01	0.550E+00	175	0.421E-02	0.537E+00
180	0.686E-02	0.532E+00	185	0.346E-02	0.526E+00
190	0.581E-02	0.522E+00	195	0.527E-02	0.516E+00
200	0.142E-01	0.511E+00	205	0.368E-01	0.497E+00
210	0.835E-02	0.460E+00	215	0.212E-01	0.452E+00
220	0.196E-01	0.431E+00	225	0.309E-01	0.411E+00
230	0.104E-01	0.380E+00	235	0.198E-01	0.370E+00
240	0.118E-01	0.350E+00	245	0.138E-01	0.338E+00
250	0.671E-02	0.324E+00	255	0.909E-02	0.319E+00
260	0.525E-02	0.308E+00	265	0.808E-02	0.303E+00
270	0.101E-01	0.295E+00	275	0.471E-02	0.285E+00
280	0.661E-02	0.280E+00	285	0.613E-02	0.274E+00
290	0.784E-02	0.268E+00	295	0.359E-02	0.260E+00
300	0.526E-02	0.256E+00	305	0.331E-02	0.251E+00
310	0.372E-02	0.248E+00	315	0.200E-02	0.244E+00
320	0.234E-02	0.242E+00	325	0.137E-02	0.240E+00
330	0.500E-02	0.238E+00	335	0.114E-01	0.233E+00
340	0.362E-02	0.222E+00	345	0.961E-02	0.218E+00
350	0.727E-02	0.209E+00	355	0.130E-01	0.201E+00
360	0.523E-02	0.188E+00	365	0.985E-02	0.183E+00
370	0.549E-02	0.173E+00	375	0.760E-02	0.168E+00
380	0.365E-02	0.160E+00	385	0.500E-02	0.157E+00
390	0.277E-02	0.152E+00	395	0.399E-02	0.149E+00
400	0.304E-02	0.145E+00	405	0.681E-02	0.142E+00
410	0.722E-02	0.135E+00	415	0.481E-02	0.128E+00
420	0.842E-02	0.123E+00	425	0.670E-02	0.114E+00
430	0.656E-02	0.108E+00	435	0.488E-02	0.101E+00
440	0.673E-02	0.963E-01	445	0.373E-02	0.896E-01
450	0.364E-02	0.859E-01	455	0.272E-02	0.822E-01
460	0.286E-02	0.795E-01	465	0.180E-02	0.767E-01
470	0.270E-02	0.749E-01	475	0.289E-02	0.722E-01
480	0.194E-02	0.693E-01	485	0.285E-02	0.673E-01
490	0.217E-02	0.645E-01	495	0.260E-02	0.623E-01
500	0.169E-02	0.597E-01	505	0.228E-02	0.580E-01
510	0.130E-02	0.557E-01	515	0.150E-02	0.544E-01
520	0.939E-03	0.529E-01	525	0.103E-02	0.520E-01
530	0.622E-03	0.510E-01	535	0.203E-02	0.503E-01
540	0.197E-02	0.483E-01	545	0.167E-02	0.463E-01
550	0.273E-02	0.447E-01	555	0.241E-02	0.419E-01
560	0.268E-02	0.395E-01	565	0.202E-02	0.369E-01
570	0.271E-02	0.348E-01	575	0.172E-02	0.321E-01
580	0.185E-02	0.304E-01	585	0.127E-02	0.286E-01
590	0.138E-02	0.273E-01	595	0.887E-03	0.259E-01
600	0.106E-02	0.250E-01	605	0.774E-03	0.240E-01

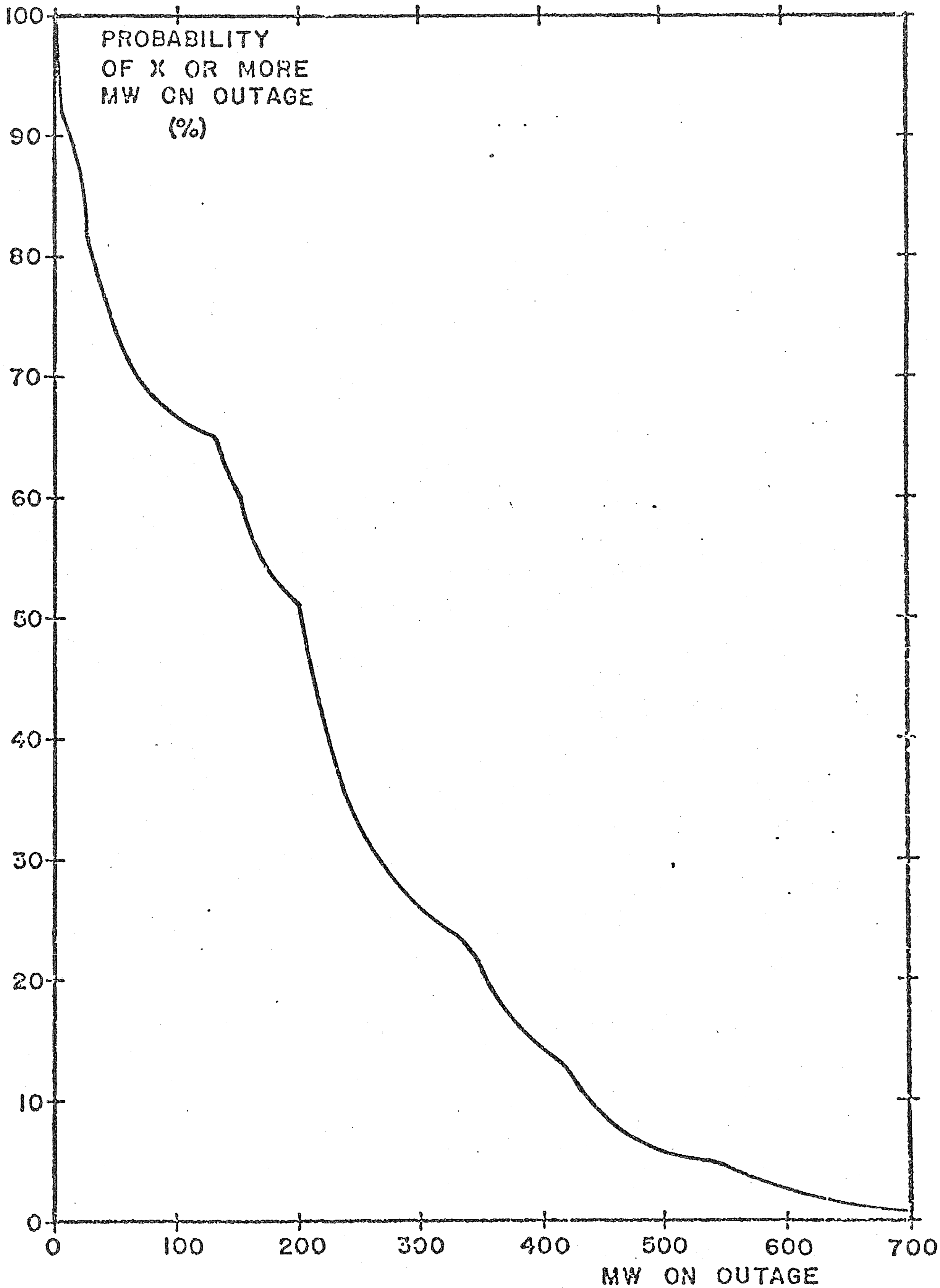

Figure 4 Capacity Outage Probability

Table 2 (Continued)

MW ON OUT-AGE	PROBABIL-ITY OF X MW ON OUTAGE	PROBABIL-ITY OF X OR MORE MW ON OUTAGE	MW ON OUT-AGE	PROBABIL-ITY OF X MW ON OUTAGE	PROBABIL-ITY OF X OR MORE MW ON OUTAGE
610	0.134E-02	0.232E-01	615	0.984E-03	0.218E-01
620	0.133E-02	0.209E-01	625	0.141E-02	0.195E-01
630	0.115E-02	0.181E-01	635	0.958E-03	0.170E-01
640	0.113E-02	0.160E-01	645	0.106E-02	0.149E-01
650	0.666E-03	0.138E-01	655	0.601E-03	0.132E-01
660	0.551E-03	0.126E-01	665	0.456E-03	0.120E-01
670	0.332E-03	0.116E-01	675	0.497E-03	0.112E-01
680	0.431E-03	0.107E-01	685	0.455E-03	0.103E-01
690	0.544E-03	0.984E-02	695	0.442E-03	0.920E-02
700	0.466E-03	0.886E-02	705	0.420E-03	0.839E-02
710	0.455E-03	0.797E-02	715	0.295E-03	0.752E-02
720	0.311E-03	0.722E-02	725	0.229E-03	0.691E-02
730	0.219E-03	0.668E-02	735	0.150E-03	0.646E-02
740	0.330E-03	0.631E-02	745	0.195E-03	0.595E-02
750	0.373E-03	0.579E-02	755	0.364E-03	0.541E-02
760	0.378E-03	0.505E-02	765	0.304E-03	0.467E-02
770	0.392E-03	0.437E-02	775	0.353E-03	0.398E-02
780	0.278E-03	0.362E-02	785	0.239E-03	0.335E-02
790	0.224E-03	0.311E-02	795	0.184E-03	0.289E-02
800	0.144E-03	0.270E-02	805	0.139E-03	0.255E-02
810	0.112E-03	0.242E-02	815	0.145E-03	0.220E-02
820	0.106E-03	0.216E-02	825	0.175E-03	0.205E-02
830	0.127E-03	0.188E-02	835	0.119E-03	0.175E-02
840	0.104E-03	0.163E-02	845	0.135E-03	0.153E-02
850	0.907E-04	0.139E-02	855	0.747E-04	0.130E-02
860	0.648E-04	0.123E-02	865	0.613E-04	0.116E-02
870	0.423E-04	0.110E-02	875	0.368E-04	0.106E-02
880	0.511E-04	0.102E-02	885	0.367E-04	0.972E-03
890	0.624E-04	0.935E-03	895	0.527E-04	0.873E-03
900	0.540E-04	0.820E-03	905	0.474E-04	0.766E-03
910	0.585E-04	0.719E-03	915	0.466E-04	0.660E-03
920	0.400E-04	0.613E-03	925	0.348E-04	0.573E-03
930	0.313E-04	0.539E-03	935	0.244E-04	0.507E-03
940	0.203E-04	0.483E-03	945	0.257E-04	0.462E-03
950	0.160E-04	0.437E-03	955	0.409E-04	0.421E-03
960	0.247E-04	0.380E-03	965	0.305E-04	0.355E-03
970	0.216E-04	0.325E-03	975	0.386E-04	0.303E-03
980	0.229E-04	0.265E-03	985	0.240E-04	0.242E-03
990	0.173E-04	0.218E-03	995	0.205E-04	0.200E-03
1000	0.126E-04	0.180E-03	1005	0.123E-04	0.167E-03
1010	0.929E-05	0.155E-03	1015	0.933E-05	0.146E-03
1020	0.966E-05	0.136E-03	1025	0.728E-05	0.127E-03
1030	0.109E-04	0.119E-03	1035	0.717E-05	0.108E-03
1040	0.851E-05	0.101E-03	1045	0.686E-05	0.928E-04
1050	0.832E-05	0.859E-04	1055	0.498E-05	0.776E-04
1060	0.550E-05	0.726E-04	1065	0.422E-05	0.671E-04
1070	0.388E-05	0.629E-04	1075	0.253E-05	0.590E-04
1080	0.260E-05	0.565E-04	1085	0.276E-05	0.539E-04
1090	0.191E-05	0.511E-04	1095	0.472E-05	0.492E-04
1100	0.261E-05	0.445E-04	1105	0.375E-05	0.419E-04
1110	0.264E-05	0.381E-04	1115	0.438E-05	0.355E-04
1120	0.244E-05	0.311E-04	1125	0.303E-05	0.287E-04
1130	0.204E-05	0.256E-04	1135	0.232E-05	0.236E-04
1140	0.140E-05	0.213E-04	1145	0.149E-05	0.199E-04
1150	0.104E-05	0.184E-04	1155	0.108E-05	0.173E-04
1160	0.200E-05	0.163E-04	1165	0.925E-06	0.143E-04
1170	0.124E-05	0.133E-04	1175	0.954E-06	0.121E-04
1180	0.173E-05	0.112E-04	1185	0.755E-06	0.942E-05
1190	0.103E-05	0.866E-05	1195	0.670E-06	0.764E-05
1200	0.887E-06	0.697E-05	1205	0.440E-06	0.608E-05
1210	0.508E-06	0.564E-05	1215	0.310E-06	0.513E-05

This calculation is started from the lowest X and proceeds by increasing X by 5 MW.

By repeating this procedure, any number of units on maintenance outage can be removed from the table. However, since the number of units on maintenance at one time is much smaller than the number of units on line, this procedure is much faster than reconstructing the whole capacity outage table for the units on line.

5.4 Sample Calculations

The result of three applications of the LOLP program is presented in this section.

In the first application, the annual LOLP for DP&L is calculated using the hourly load data in 1974. The two different maintenance schedules as discussed in Section 1, namely the schedule determined by this program and the 1977 schedule determined by DP&L, are considered. The LOLP for both schedules are compared in Table 3.

Table 3 LOLP* of DP&L

No Maintenance**	Maintenance Schedule of this Program	Maintenance Schedule of DPL
0.315	0.528	0.557

* (1) 1974 hourly Load Data
  (2) Any Interconnection is Neglected

** No Maintenance is Assumed

In the second application the amount of guaranteed reserve is considered as a parameter.

A guaranteed reserve may be provided by a firm contract which supplies power whenever necessary up to the contracted amount. In the calculation of LOLP, the effect of such guaranteed reserve can be equivalently taken into consideration by decreasing the load by that amount throughout the study period. The relation between LOLP and the amount of guaranteed reserve thus calculated on an hourly basis is shown in Table 4. An alternative way to provide a guaranteed reserve is to install peaking units. Then, referring to Table 4, the cost of reducing LOLP form 0.315 day/year to 0.02 day/year may be equal to the cost of installing and maintaining 200 MW equivalent peaking units.

Table 4 Effect of Guaranteed Reserve Margin on LOLP

Guaranteed Reserve,MW	LOLP* Day/Year
0	0.315
50	0.175
100	0.095
150	0.051
200	0.027
250	0.013
300	0.007
350	0.003
400	0.001

* Maintenance outage effect is neglected.

In the third application the LOLP calculated by this code is compared with the LOLP calculated by the WASP program on the same data basis. The WASP reliability calculation is performed by the convolution method using Fourier expansion for the equivalent load duration curves. Therefore, the LOLP program was modified so that a load duration curve is used as input. No maintenance schedule is considered for simplicity in this comparison. The annual LOLP's during 1976 and 1986, for an assumed load forcast and system expansion of DPL, calculated by the two methods are compared in Table 5.

Table 5 Comparison of LOLP (days/year)

Year	WASP	LOLP Program
1976	0.658	0.425
1977	1.803	1.499
1978	1.792	1.567
1979	1.624	1.365
1980	1.227	1.028
1981	0.988	0.805
1982	0.846	0.689
1983	0.733	0.585
1984	0.511	0.418
1985	1.483	1.330
1986	1.261	1.128

The LOLP calculated by WASP is consistently higher (an average of 22%) than that by the LOLP program. It is not clear at this time which program is responsible for this discrepancy. Although this amount of discrepancy is not serious in a crude analysis of reliability, a further investigation to improve the numerical accuracy or prove the validity of the programs is necessary.

References

(1) R. Billington, Power System Reliability Evaluation, Gordon and Breach, N.Y. (1970).

(2) R. W. Baker, "The Effect of Electric Generating System Reliability on Power System Economics," Master's Thesis, The Ohio State University, Nuclear Engineering (1977).

CHAPTER 6

REGULATORY ANALYSIS MODEL

6.1 Description of the Program

The Regulatory Analysis Model[1] is a package of computer programs to project the financial status of a utility operations by using a set of input assumptions about demand, capital expenditures, operating costs, and financial and regulatory policies. This program was developed by Temple, Barker and Sloane, Inc., in Boston, Massachusetts, under the contract with the Federal Energy Administration and tailored for the Public Utilities Commission of Ohio (PUCO). The program is currently available on the IBM-370/168 at The Ohio State University, and can be accessed by PUCO through the TSO system.

All the details of the model including the input preparation and operational procedure is described in Reference 1. The purpose of this chapter is, however, to introduce an outline of the Regulatory Analysis Model so that the reader can understand the role of this model in the entire computer package described in this report. Should any agency other than PUCO adopt this model it should consult with Temple, Barker and Sloan, Inc., for transfer of the model.

The Regulatory Analysis Model consists of five major modules:* (a) Plant Module, (b) Performance Module, (c) Fixed Obligation Module, (d) Finance Module, and (e) Report Writing Module. Interactions among the five modules are shown in Figure 1. The mathematical equations for each calculation are contained in Reference 1. In the remainder of this chapter the functions of each module are described.

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* In the original report on this program prepared by TBS, the whole program is called "RAm(finance)" while the same name is used for one module of the program. This is somewhat confusing to the reader; so we call the entire program as Regulatory Analysis Module and each subprogram as follows:

Original Name	In This Report
RAm (finance)	Regulatory Analysis Model
RAm (finance) Module	Finance Module
RAm (performance) Module	Performance Module
RAm (fixed obligation) Module	Fixed-Obligation Module
Plant Module	Plant Module
Report Writing Module	Report Writing Module

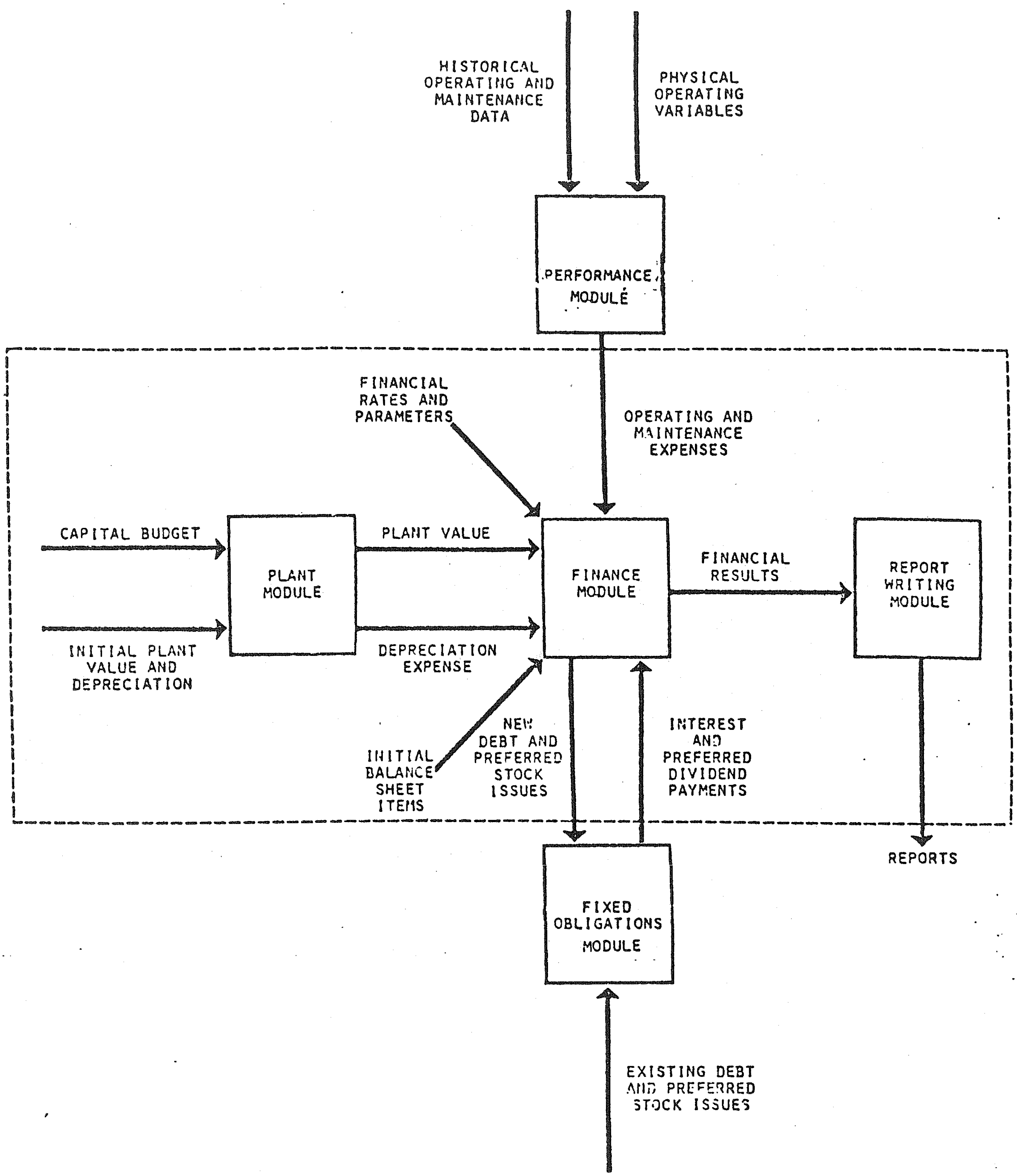


Figure 1 Regulatory Analysis Model Structure

6.2 Description of the Modules

6.2.1 Plant Module

The plant module performs the following five types of calculations:

1. Construction Work in Progress (CWIP)
2. Allowance for Funds Used During Construction (AFDC)
3. Amount of AFDC associated with each category of plant in service. (The model allows from one to ten categories of future plant, such as transmission, distribution, nuclear production, etc.)
4. Amount of depreciation, both tax and book, for each plant category.
5. Net and gross plant value.

To perform these tasks, the plant module needs two types of information. The first type is historic, and consists of the latest available ending balances of CWIP, gross and net plant value, and accumulated tax and book depreciation. These are used as a starting point for the projections. The other type of information required is a projection of annual capital expenditures (actual excluding AFDC), retirements, and plant in service additions, for each plant category. (The four plant categories most commonly used are production, transmission, distribution, and other.) These data are obtained from the companies being studied and public sources, such as annual reports or prospectuses.

(i) Construction Work In Progress

CWIP is calculated by taking the previous year's CWIP figure, adding to it all actual expenditures, and subtracting all increases in plant in service (before retirements). The AFDC component of CWIP is kept separate. This implies that all capital expenditures must be accounted for in either CWIP or plant in service. Therefore, the increase (or decrease) in CWIP is equal to capital expenditures less the amount transferred to plant in service.

(ii) Allowance for Funds Used During Construction

The amount of AFDC shown as income in each year is calculated by multiplying the average CWIP balance by the AFDC rate. While the calculation of AFDC is simple, its accounting is more complex. The amount of AFDC in the CWIP account and the AFDC portion of each plant in service category must be kept separate because of the special nature of AFDC. When calculating the current year's AFDC amount, the AFDC portion of CWIP cannot be included. When depreciating the plant accounts for income tax purposes, only the non-AFDC portion of plant cost can be depreciated. For book purposes, however, the AFDC portion evaluated in plant cost must be depreciated.

To properly account for AFDC, a second calculation is made. The second calculation determines how much AFDC is associated with the plant going into service in a particular year. This amount is subtracted from the accumulated AFDC in the CWIP balance, and added to the accumulated AFDC in the plant in service balance. In effect, AFDC accounting parallels that of cash expenditures, with each plant and CWIP account having a corresponding AFDC account.

The second AFDC calculation is based on an estimate of the portion of expenditures which occurs in each year prior to completion for each type of construction project, the total cost of that project, and the AFDC rate. From this information, the amount of AFDC which would be accrued during the construction of the project is calculated and transferred from accumulated AFDC in CWIP to accumulated AFDC in plant in service when the project is completed.

(iii) Depreciation

The annual depreciation charges are determined separately for plant existing at the beginning of the analysis and plant which is added over the period of the run. In addition, several depreciation figures are calculated: book depreciation of plant, book depreciation of AFDC component of plant, and tax (accelerated) depreciation of plant.

The main difference between the calculations for existing plant and new plant is the level of detail. Depreciation for existing plant can be computed by FPC plant account while the new plant is subdivided between one to ten categories (or general accounts).

Book depreciation is calculated on a straight-line basis by multiplying the gross value of each plant account and category by a depreciation factor. For existing plant, these factors for each account are available from the FPC Form 1, as are the net and gross values of each plant account. The depreciation factor is determined by the utility for each plant account based on studies of the average expected life of equipment in each account. For new plant, the factor is equivalent to the inverse of the number of years of expected life. The AFDC component of new plant is also depreciated on a straight-line basis for book purposes, using the same depreciation factor as the corresponding plant in service account.

Tax depreciation is calculated exclusive of AFDC. Since it is difficult to identify the gross and net plant values used for tax purposes, the net plant value (tax) of existing plant is estimated based on the ratio of tax depreciation to book depreciation, asset life, and gross plant value (book). Tax depreciation is calculated on a double declining balance basis, That is, tax depreciation is equal to the net plant value (tax) times twice the inverse of the life.

(iv) Gross Plant Value (Book)

The gross plant value is determined by summing the gross value of each FPC plant account for existing plant, adding the gross value of all new plant, and subtracting any retirements.

6.2.2 Performance Module

Performance module provides projections of operations and maintenance (O&M) to the Finance Module for each FPC account and sub-account for the entire forecast horizon.

To perform this function, Performance Module uses four types of input data:

1. FPC O&M account and sub-account data for the past five to ten years.
2. kWh sales, peak load demand, number of customers for the historic time span the same as the historic O&M values,
3. Projections of the above exogenous variables, covering the time span over which the user wishes to project the O&M values,
4. Projection of fuel usage by generation type of station with projected heat rates. (These data will greatly improve the accuracy of future cost projections, though this level of detail is not necessary.)

The first step in projecting the O&M values is adjusting the historic data for inflation and abnormal expenses. This adjustment can be done in two different ways. The first is a multiplicative ajdustment which will multiply (or divide) each historic value in a given O&M account or sub-account by a factor. This adjustment is frequently used to adjust historic costs to constant dollars. With such an adjustment, analysis of historic data reflects basic relationships, not trends in inflation. The second type of adjustment is additive, and to adjust the O&M values for a specific year or number of years in a specific account or sub-account to reflect abnormal charges or charges that a regulatory commission will not allow. For example, high maintenance expenses resulting from a bad storm might be normalized by reducing the expense in the year of occurrence and adding appropriate amounts to other years so as not to exert undue influence on projected values.

After the adjustments, it proceeds to project future values for each O&M account or sub-account. For each FPC account and sub-account, the user must specify the following:

1. Method of calculation
2. Exogenous variables.

The user has the option of specifying one of six existing calculation methods or adding new ones. The six methods employ three separate equations, which project O&M expenses using trend, linear, or multiplicative relationships. In general, each equation requires a projection of one or more exogenous variables, and coefficients that show the historic relationship ofeach variable and the O&M account value. In three of the six calculation options, performance module will calculate those variable using a standard statistical approach, least-squares regression. In the other three calculation options, the user can specify the coefficients. This gives the user the freedom to exercise judgment over the accuracy of the projections and to adjust them to reflect actual experiences or changing circumstances.

After Performance Module has made projections for each FPC account or sub-account, the projected values are transferred to Finance Module, where they are aggregated and used to develop the financial projections.

6.2.3 Fixed Obligations Module

Fixed Obligations Module performs calculations regarding a utility's outstanding long-term debt and preferred stock issues (fixed obligations). In addition, it can measure the effect on interest and dividend payments and embedded interest rates of any new issue. In conjunction with Finance Module, Fixed Obligations Module performs two functions:

1. it allows the user to create a long-term debt file and a preferred stock file which contain information pertaining to each debt and stock issue outstanding as of the model base year; and

2. it calculates the annual interest charges and dividend payments on outstanding debt and preferred stock for each year of the forecast period.

The debt file and preferred stock file created with the Fixed Oblications Module contains a description of each issue, the year and date of issue, the year of retirement (if any), the interest or dividend rate, the original amount of issue, the current amount outstanding, and the annual sinking fund payment (if any). Finance Module uses this file to make preliminary estimates of interest payments, calculates the amount of new debt and stock issues, and adds them to debt and stock files. Fixed Obligations Module then uses the file to calculate the exact amount of long-term debt interest payments and preferred stock dividends. The informaion is then passed on to Finance Module for use in the financial calculations. The amount of interest or dividends to be paid each year on each issue is assumed to be paid on the date of original issue, and is prorated if the issue has not been outstanding for a full year.

6.2.4 Finance Module

Finance Module is the heart of this program. It calculates required revenues and all the relevant financial parameters necessary to develop an income statement, a balance sheet, a sources and uses of funds statement, and other financial indicators such as interest coverage ratios. In particular, Finance Module calculates for each year of the forecast period:

1. Required revenues

2. Net income and return on equity for a given rate of return on the rate base

the savings realized by the utility is amortized over a period of years (usually equal to the life of the asset which generates the tax deferral). The accounting for investment tax credits is handled on a normalized basis whichever accounting method is selected. This was done to reflect the federal law governing ITC's at the time this model was developed, requiring the normalization of ITC's if the full 10% rate was to be used.

The basis for the financial calculations in the finance module is the attainment of a net income derived from the user-specified rate of return on net plant investment or common equity. The finance module calculates the information necessary to develop an income statement from the bottom up. That is, net income is calculated first, then income taxes, interest, other income, operating income, operating expenses, and finally, operating revenues. The following formula shows a simple income statement which will be useful for reference in the following discussion.

Operating Revneues

- Operating Expense (fuel, operating, maintenance, purchased power, etc.)
- Other expenses (depreciation, other taxes, etc.)

Operating Income

+ Other Income (equity earnings in subsidiaries)

Earnings Before Interest and Taxes (EBIT)

- Interest (long-term debt, short-term debt)

Earnings Before Taxes (EBT)

- Income Taxes (including the effect of tax deferrals)

+ ITC

Net Income

- Preferred Dividends
- Common Dividends

Retained Earnings

The calculations are, for the most part, straight-forward and simple. After subtracting preferred dividends calculated by Fixed Obligations module from net income, the remaining income is allocated between retained earnings and common dividends, using a user-specified ratio. Working up the income statement, income taxes are calculated using the prevailing federal and state income tax rate and the after tax net income (less any non-taxable income, such as AFDC). This cal- cualtion is somewhat complicated because the effects of the various non-taxable items, tax deferral items, and ITC's must be accounted for. The amount of investment tax credit is calculated as a percentage of the cash capital expenditures for the year, less a portion assumed to be ineligible for ITC (e.g., buildings, land, etc.). By adding net income and taxes paid and subtracting ITC, earnings before taxes (EBT) is determined. Adding in the long-term debt interest calculated by Fixed Obligations Module and the interest on short-term debt interest calcualted by the Finance Module (a given interest rate times the average short-term debt for the year), to EBT gives earnings before interest and taxes (EBIT). Subtracting other income (AFDC, calculated by the Plant Module, and any user-specified equity earnings in subsidiary companies) from EBIT yields operating income. To determine operating revenues, the various expenses must be added to the operating oncome. The O&M expenses (fuel, operations, maintenance, purchased power, etc.) are provided by the Performance Module. Depreciation charges are cal- culated by Plant Module. The remaining expense, other taxes, is cal- culated by the Finance Module as a percent of gross plant (property tax) and of operating revenues (franchise and payroll, and miscellaneous taxes).

As Finance Module calculations work their way up the income state- ment, the calculations necessary to develop the other two basic financial statements, the balance sheet and sources and uses of funds, are performed in the process. The capital expenditures and AFDC computed in Plant Module require financing from internal sources (retained earnings, tax deferrals) and external sources (long- and short-term debt, preferred and common stock). Funds required in excess of internally generated funds are financed first through the issuance of short-term debt to a predetermined limit, then through the issuance of a user-specified mix of long-term debt, common stock and preferred stock. If there exists internally generated funds in excess of expenditures, short-term debt will be reduced to a user-specified minimum and any remaining funds will be put into the net working capital account.

6.2.5 Report Writing Module

The report writer receives all the information calculated by Finance Module, Fixed Obligations Module and the Performance Module and displays these data in various user-specified reports. At present, the user has the option of printing income statements, balance sheets, sources and uses of funds statements, and O&M expense projections. The Report Writer allows the user to print these reprots for any year or years over the forecast period. The user also has the option of specifying which lines of each report are to be printed.

The reports now available to the user are those which will be of the most use to regulatory commissions and utilities. The income statement (Table 1) is formatted in the same manner as in the FPC Form 1, the Uniform Statistical Report, and most utilities' annual reprots. The income statement shows the various operating expenses, capital expenses, and taxes, and the revenues that are required to meet those expenses and still yield a given net income or return on common equity.

Table 2 shows the sources and uses of funds statement that is useful in determining the cash flow of a utility. The various sources of cash (e.g., retained earnings, external financing, depreciation, etc.) are shown along with the uses of funds (capital expenditures, etc.), allowing the user to see explicitly how a utility can be expected to meet its future financial obligations.

The balance sheet shown in Table 3 is a summary of all the financial transactions shown on the sources and uses of funds statement. From it the user can track the changes in capitalization and asset value of a utility.

The O&M expense report in Table 4 shows the future values of each O&M account and the method and coefficients used to calculate the O&M values. Both the projected values and the historic values on which the projection was based are shown. In addition to the O&M expense

Table 1

DAYTON POWER AND LIGHT
INCOME STATEMENT
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
OPERATING REVENUES	258.73	289.04	333.54	385.66	463.93	543.33	628.05	722.43	826.47	951.26
-FUEL	86.29	100.95	117.59	128.02	155.15	183.18	212.89	245.33	282.84	326.22
-PURCHASED POWER	10.33	8.48	8.14	8.02	6.69	5.51	5.12	5.03	6.42	-.25
-OPERATION	32.30	35.41	38.67	42.07	45.66	49.46	53.59	58.00	62.80	67.64
-MAINTENANCE	14.22	15.88	17.76	19.91	22.60	25.45	28.34	31.37	34.76	38.44
-DEPRECIATION	23.63	24.52	26.68	31.80	38.74	45.24	52.00	58.86	67.13	79.64
TOTAL OPERATING EXPENSES	166.77	185.23	208.83	229.82	268.85	308.84	351.94	398.59	453.95	511.69
-OTHER TAX	18.08	19.37	21.58	25.19	30.26	35.20	40.42	45.97	52.28	61.09
-INCOME TAX PAID	6.73	16.32	21.97	29.03	38.78	46.16	55.27	73.43	86.69	105.37
-DEFERRED INCOME TAX	0	0	0	0	0	0	0	0	0	0
-DEF INVEST TAX CREDIT	7.52	3.50	4.08	5.03	5.67	7.06	7.75	4.43	4.90	6.26
TOTAL EXPENSES	199.09	224.42	256.47	289.08	343.56	397.26	455.38	522.42	598.03	684.40
OPERATING INCOME	59.64	64.62	77.07	96.58	120.37	146.07	172.68	200.01	228.44	266.86
+OTHER INCOME	0	0	0	0	0	0	0	0	0	0
+AFDC	13.35	20.26	26.31	28.39	28.95	33.61	40.92	44.86	42.70	33.05
INCOME BEFORE INTEREST	72.99	84.88	103.38	124.97	149.32	179.68	213.60	244.87	271.15	299.91
-INTEREST-LTD	26.55	30.17	38.06	47.08	57.35	70.82	84.77	98.35	109.76	122.17
-INTEREST STD	3.33	4.06	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
-MISC AMORT.	0	0	0	0	0	0	0	0	0	0
NET INCOME	43.11	50.65	63.45	76.02	90.09	106.99	126.96	144.64	159.51	175.86
-PREFERRED DIVIDENDS	7.56	9.35	12.60	15.61	18.86	22.76	27.37	31.45	34.87	38.65
EARNINGS AVAIL COMM	35.55	41.30	50.85	60.41	71.24	84.23	99.59	113.20	124.63	137.21
-COMMON DIVIDENDS	26.31	30.56	37.63	44.70	52.72	62.33	73.70	83.77	92.23	101.54
RETAINED EARNINGS	9.24	10.74	13.22	15.71	18.52	21.90	25.89	29.43	32.40	35.67

Table 2

DAYTON POWER AND LIGHT
SOURCES AND USES OF FUNDS
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
SOURCES										
INTERNAL										
NET INCOME	43.11	50.65	63.45	76.02	90.09	106.99	126.96	144.64	159.51	175.86
DEPRECIATION	23.63	24.52	26.68	31.80	38.74	45.24	52.00	58.86	67.13	79.64
DEFERRED INCOME TAXES	0	0	0	0	0	0	0	0	0	0
DEF INVEST TAX CREDIT	7.52	3.50	4.08	5.03	5.67	7.06	7.75	4.43	4.90	6.26
TOTAL INTERNAL	74.26	78.67	94.21	112.85	134.50	159.29	186.70	207.94	231.54	261.76
EXTERNAL										
COMMON STOCK	0	62.22	50.20	57.44	63.04	82.21	89.36	49.72	51.83	59.75
PREFERRED STOCK	0	33.92	28.06	29.26	32.62	41.65	46.10	31.66	33.69	38.17
LONG TERM DEBT	0	68.76	86.17	92.65	103.31	171.93	159.34	100.25	120.17	120.87
SHORT TERM DEBT	77.72	-58.27	0	0	0	0	0	0	0	0
TOTAL EXTERNAL	77.72	106.64	164.42	179.34	198.97	295.78	294.79	181.63	205.70	218.80
TOTAL SOURCES	151.98	185.31	258.63	292.19	333.47	455.07	481.50	389.57	437.24	480.56
USES										
GR PLANT ADDITIONS +AFDC	27.96	35.98	106.88	217.05	218.99	188.01	238.18	197.57	314.67	479.31
CWIP INCREMENT	84.02	108.59	65.73	-7.68	16.55	102.34	88.74	33.93	-65.74	-191.56
TOTAL CONST EXPENDITURES	111.99	144.57	172.60	209.37	235.54	290.34	326.92	231.51	248.92	287.75
PREFERRED DIVIDENDS	7.56	9.35	12.60	15.61	18.86	22.76	27.37	31.45	34.87	38.65
COMMON DIVIDENDS	26.31	30.56	37.63	44.70	52.72	62.33	73.70	83.77	92.23	101.54
DEBT RETIREMENT	0	0	20.47	0	0	40.05	13.35	0	13.48	0
PREF RETIREMENT	0	0	0	0	0	0	0	0	0	0
NET INCR WORKING CAPITAL	6.12	.83	15.33	22.50	26.36	39.59	40.16	42.85	47.73	52.62
TOTAL USES	151.98	185.31	258.63	292.19	333.47	455.07	481.50	389.57	437.24	480.56

Table 3

DAYTON POWER AND LIGHT
BALANCE SHEET
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
ASSETS										
GR ELEC PLANT	688.68	716.65	752.63	859.50	1076.55	1295.54	1483.55	1721.73	1919.30	2233.97
-ACCUM DEPREC	203.23	226.86	251.38	278.06	309.87	348.60	393.85	445.84	504.70	571.83
NET ELEC PLANT	485.45	489.79	501.25	581.44	766.68	946.94	1089.71	1275.89	1414.60	1662.14
+CWIP	120.95	204.97	313.56	379.28	371.61	388.16	490.49	579.24	613.17	547.43
NET ELEC UTIL PLANT	606.40	694.76	814.80	960.72	1138.29	1335.10	1580.20	1855.13	2027.77	2209.57
NET WORKING CAPITAL	123.91	130.03	130.86	146.18	168.69	195.05	234.64	274.79	317.64	365.37
TOTAL ASSETS	730.31	824.79	945.66	1106.91	1306.98	1530.15	1814.84	2129.92	2345.41	2574.94
LIABILITIES										
COMMON STOCK	154.35	154.35	216.57	266.77	324.21	387.24	469.46	558.82	608.53	660.36
RETAINED EARNINGS	94.94	104.18	114.92	128.14	143.85	162.37	184.27	210.16	239.59	272.00
TOTAL COMMON EQUITY	249.29	258.53	331.49	394.91	468.05	549.61	653.73	768.98	848.12	932.36
PREFERRED STOCK	95.99	95.99	129.91	157.96	187.22	219.85	261.49	307.59	339.25	372.94
LONG TERM DEBT	365.76	365.76	434.52	500.22	592.87	696.18	828.05	974.04	1074.29	1180.99
TOTAL CAPITAL	711.04	720.28	895.92	1053.09	1248.14	1465.63	1743.27	2050.61	2261.66	2486.29
SHORT TERM DEBT	5.55	83.27	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
DEFERRED INCOME TAXES	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44
DEF INVEST TAX CREDIT	4.28	11.80	15.30	19.38	24.40	30.08	37.13	44.88	49.31	54.22
TOTAL LIABILITIES	730.31	824.80	945.67	1106.91	1306.99	1530.15	1814.84	2129.93	2345.42	2574.95

Table 4

LEGEND

* = ACCOUNT- 502 FILE- LDPL71
COMPANY- DPL DATE- 07/21/76

STEAM - OPERATION - STEAM EXPENSE

MULTIVARIATE LINEAR REGRESSION
N = 700.238 + .114359E-03*<1002>
R-SQUARED = .9494 BASED ON 10 POINTS

DATA

ACCOUNT	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
502	603.15	618.79	640.35	729.77	792.93	993.63	1106.30	1236.21	1387.96	1459.55	1604.15	1864.44	2050.40	2254.8

ACCOUNT	1979	1980	1981	1982	1983	1984	1985	1986
502	2484.01	2768.27	3063.70	3356.81	3661.64	3996.99	4366.17	4790.01

WHICH REPORT?

report, the user can have the historic and projected O&M values graphed in current or constant (uninflated) dollars (Figure 2). Up to five O&M expense accounts can be plotted on the same graph for comparison purposes. This allows a visual comparison of O&M accounts within a utility or between utilities.

Table 5 is an example of the Master Data File report. This report is intended only as an aid to the user in tracking down input errors. The report displays all the items contained in the main output data file of Financial Module, including all the items which make up the other reports shown in the preceeding exhibits. In this report, as with the others, the user can specify whether the whole report is to be printed, or just certain lines and/or years.

The report writer is not limited to just printing reports from data from the Master Data File. The report writer can access and output file and use its data as the basis for a report.

6.3 Execution of the Program

To use the Regulatory Analysis Model, the user must:

1. collect the data necessary for input,
2. put the data in the proper form,
3. load the data into the model input files,
4. run the model,
5. print reports, and
6. analyze the results.

A brief description of each step follows.

Collect the Data

The majority of the data required to run Financial Module and the other modules are available from public sources, such as the FPC Form 1, the Uniform Statistical Report (USF; filed by each utility annually with the Edison Electric Institute), the annual reports to stockholders, and utility's most recent stock or bond prospectus. The data obtained from these sources include:

1. Historic operations and maintenance account data
2. Heat rates of plants
3. Interest rates

Table 5 (cont'd)

DAYTON POWER AND LIGHT
MASTER DATA FILE
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
FEDERAL INCOME TAXES	0	6.73	16.32	21.97	29.03	38.78	46.16	55.27	73.43	86.89
OTHER TAXES	0	18.08	19.37	21.58	25.19	30.26	35.20	40.42	45.97	52.28
OTHER INCOME	0	0	0	0	0	0	0	0	0	0
ALLOW FUNDS DURING CONST	0	13.35	20.26	26.31	28.39	28.95	33.61	40.92	44.86	42.70
INT EXP LONG TERM DEBT	0	26.55	30.17	38.06	47.08	57.35	70.82	84.77	98.35	109.76
INT RATE LTD AVERAGE	0	7.31	7.58	8.15	8.65	8.93	9.20	9.49	9.62	9.74
INT RATE LTD END OF PER	0	7.31	7.82	8.48	8.80	9.05	9.30	9.58	9.67	9.83
DIVIDEND EXP PREF STOCK	7.50	7.56	9.35	12.60	15.61	18.86	22.76	27.37	31.45	34.87
INT RATE PREF STK AVERAGE	0	7.88	8.27	8.75	9.04	9.26	9.45	9.62	9.72	9.79
INT RATE PREF STK END PER	0	7.88	8.56	8.91	9.16	9.36	9.54	9.68	9.76	9.83
INT EXP SHORT TERM DEBT	0	3.33	4.06	1.88	1.88	1.88	1.88	1.88	1.88	1.88
MISC AMORT DEBT DISC,EXP	0	0	0	0	0	0	0	0	0	0
COMMON DIVIDENDS	0	26.31	30.56	37.63	44.70	52.72	62.33	73.70	83.77	92.23
UNUSED	0.	0	0	0	0	0	0	0	0	0
UNUSED	0	0	0	0	0	0	0	0	0	0
UNUSED	0	0	0	0	0	0	0	0	0	0
NET INCOME	0	43.11	50.65	63.45	76.02	90.09	106.99	126.96	144.64	159.51
INVESTMENT TAX CREDIT	0	7.89	3.98	4.68	5.79	6.61	8.22	9.15	5.97	6.60
INVEST TAX CREDIT AMORT	0	.37	.48	.61	.76	.94	1.16	1.40	1.54	1.69
CAPITAL EXPENDITURE PLANT	0	26.49	33.83	94.34	184.08	190.30	163.27	207.54	172.43	271.17
SINKG FUND PAY THIS PER	0	0	0	0	0	0	0	0	0	0
CONSTRUCT EXPEND PLANT	0	98.64	124.31	146.29	180.98	206.59	256.73	286.00	186.65	206.22
NET WORK CAPITAL THIS PER	0	6.12	.83	15.33	22.50	26.36	39.59	40.16	42.85	47.73
DEPRECIATION AFDC - CUM	2.32	4.67	7.06	9.68	13.04	17.40	22.63	28.75	35.78	43.93
INVEST TAX CREDIT CUMUL	4.28	11.80	15.30	19.38	24.40	30.08	37.13	44.88	49.31	54.22
TAX CREDIT	0	7.52	3.50	4.08	5.03	5.67	7.06	7.75	4.43	4.90
A F D C - CUM IN CWIP	0	11.87	29.98	43.76	39.18	39.43	48.31	58.59	78.31	77.51
DEPREC AFDC - THIS PER	2.32	2.34	2.39	2.62	3.36	4.36	5.23	6.13	7.03	8.15

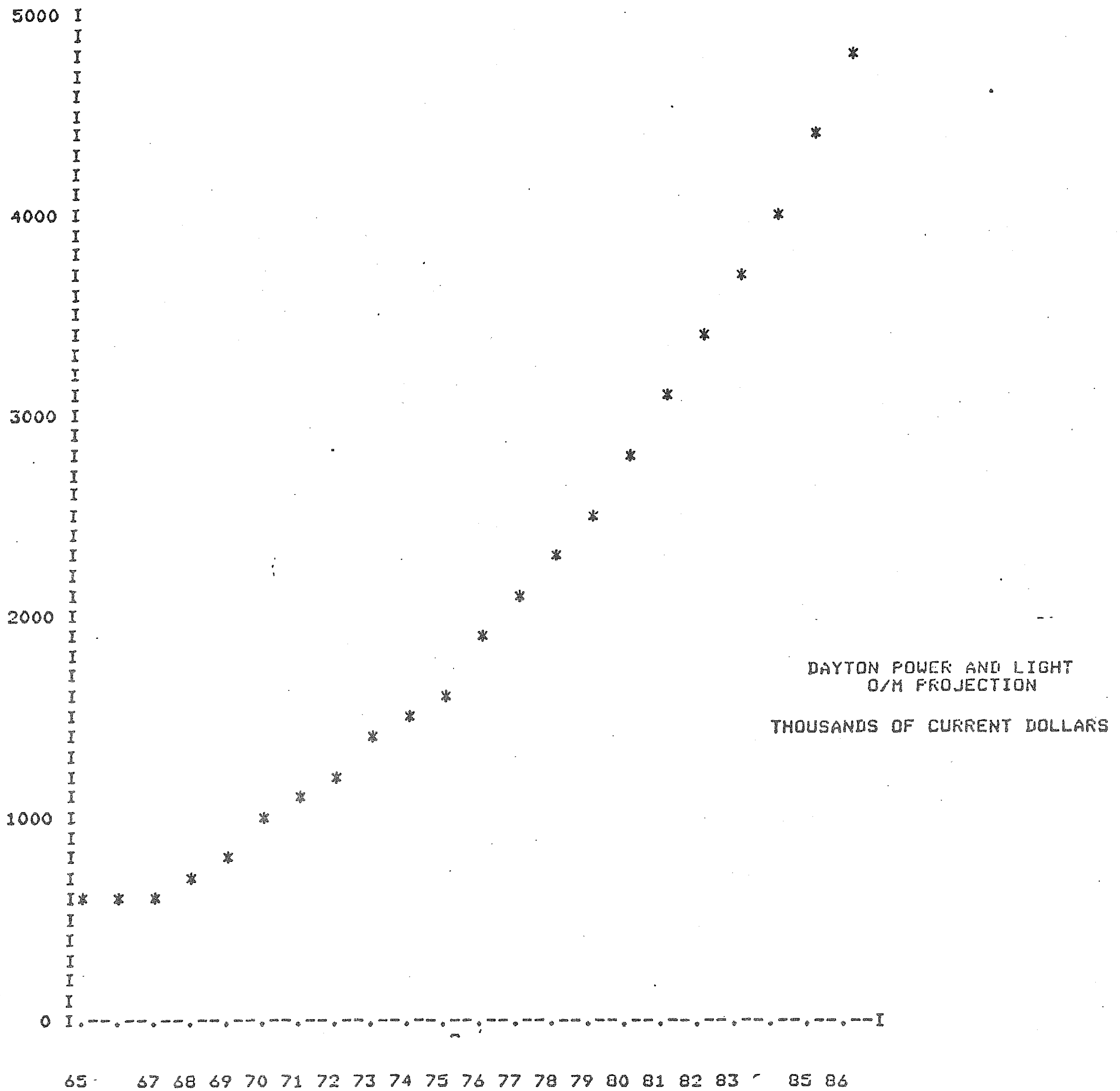
Table 5

DAYTON POWER AND LIGHT
MASTER DATA FILE
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
FILE NUM, DATE, COM CODE	52	07/15/76	DPL							
UNUSED FIELD	0	0	0	0	0	0	0	0	0	0
GNP DEFLATOR	1.00	.93	.88	.83	.79	.75	.72	.69	.66	.63
ELECTRIC PLANT(GROSS,INS)	688.68	715.17	749.00	843.34	1027.42	1217.72	1380.99	1588.53	1760.96	2032.13
CONST WORK IN PROGRESS	120.95	193.10	283.58	335.53	332.43	348.72	442.18	520.65	534.86	469.92
ACCUM DEPRECIATION	200.91	222.19	244.32	268.38	296.83	331.21	371.22	417.09	468.92	527.90
DEPREC THIS PER (ACCEL)	36.58	32.89	30.64	30.95	36.35	44.68	52.04	59.50	66.83	76.13
NET WORKING CAPITAL CUM	123.91	130.03	130.86	146.18	168.69	195.05	234.64	274.79	317.64	365.37
CUM COMMON STK ISSUED	154.35	154.35	216.57	266.77	324.21	387.24	469.46	558.82	608.53	660.36
COM STK ISSUED THIS PER	0	0	62.22	50.20	57.44	63.04	82.21	89.36	49.72	51.83
CUM RET EARNINGS GENER	94.94	104.18	114.92	128.14	143.85	162.37	184.27	210.16	239.59	272.00
RET EARNINGS GEN THIS PER	0	9.24	10.74	13.22	15.71	18.52	21.90	25.89	29.43	32.40
CUM PREF STK ISSUED	95.99	95.99	129.91	157.96	187.22	219.85	261.49	307.59	339.25	372.94
PREF STK ISSUED THIS PER	0	0	33.92	28.06	29.26	32.62	41.65	46.10	31.66	33.69
CUM LONG TERM DEBT	365.76	365.76	434.52	500.22	592.87	696.18	828.05	974.04	1074.29	1180.99
LNG TRM DBT ISS THIS PER	0	0	68.76	86.17	92.65	103.31	171.93	159.34	100.25	120.17
LNG TRM DBT REF THIS PER	0	0	0	20.47	0	0	40.05	13.35	0	13.48
CUM SHORT TERM DEBT	5.55	83.27	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
SHT TRM DBT ISS THIS PER	0	77.72	-58.27	0	0	0	0	0	0	0
CUM INC TAX DEFERRALS	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44
INC TAX DEF THIS PER	0	0	0	0	0	0	0	0	0	0
CUM AFDC CAPITALIZED	0	1.48	3.63	16.16	49.13	77.82	102.56	133.20	158.34	201.84
AFDC CAPITALIZED THIS PER	0	1.48	2.15	12.53	32.97	28.69	24.74	30.64	25.14	43.50
OPERATING REVENUES	257.10	258.73	289.04	333.54	385.66	463.93	543.33	628.05	722.43	826.47
FUEL EXPENSE	89.75	86.29	100.95	117.59	128.02	155.15	183.18	212.89	245.33	282.84
PURCHASED POWER EXPENSE	10.98	10.33	8.48	8.14	8.02	6.69	5.51	5.12	5.03	6.42
OPERATION EXPENSE	28.36	32.30	35.41	38.67	42.07	45.66	49.46	53.59	58.00	62.80
MAINTENANCE EXPENSE	13.82	14.22	15.88	17.76	19.91	22.60	25.45	28.34	31.37	34.76
DEPREC EXPENSE (STR LIN)	20.90	21.28	22.13	24.06	28.44	34.38	40.01	45.87	51.84	58.98
STATE INCOME TAXES	0	0	0	0	0	0	0	0	0	0

Figure 2



~ SIGNIFIES BEGINNING OF FORECASTED DATA

4. Assets and liabilities
5. Depreciation rates
6. Capacity additions
7. Capacity factors
8. Rate used for allowance for funds used during construction (AFDC)
9. Effective tax rates
10. Dividend payout ratio

In addition, the model requires some data from the utility, such as:

1. proposed capital budget for the forecast period,
2. energy supply and demand forecasts,
3. expected fuel prices,
4. purchased power agreements and costs,
5. plant retirements, and
6. expected capital structure.

Load the Data Into the Model Input Files

This step consists of keypunching (and verifying, if desired) all the input data into the various input files. Printed copies of each file should be kept for each model run so that the calculation can be repeated later if necessary.

Run the Model

After the input data have been entered, the files must be converted to a machine-readable form. Then the model is executed, module by module. Every module need not be run every time. For example, if the user decides to change the tax rate or an interest rate, the O&M calculation program and the plant program do not have to be re-run.

Print Reports

After one or more model runs have been completed, the Report Writer is used to print the desired reports.

Analyze the Results

When the user is confident the results are correct, the results can be analyzed with regard to what they imply. This is the main purpose of the Regulatory Analysis Model--to provide the user with the information necessary to determine the effect and implications of various policies and regulatory strategies. Proper utilization of this program requires the user not only to run the model, but also to think about and analyze the results. A wealth of information can be obtained by comparing the financial statements of a utility under two alternative sets of assumptions. As the user becomes more familiar with the model, additional reports can be added to provide bases for specific financial and operational comparisons of a single utility or group of utilities.

References

(1) "Regulatory Analysis Model, RAM, Descriptions Documentation," Temple, Baker & Sloane, Inc., Wellesley Hills, Massachusetts 02181 (1977).

CHAPTER 7

RESIDENTIAL BILL FREQUENCY PROGRAM

7.1 Description of the Program

The residential billing frequency program[1] was developed at The Ohio State University. It calculates the expected revenues for a given electric power utility and customer group with a rate structure given as input. A maximum of four rate structures and time periods in any one year may be specified in one execution of the program. Billing frequency data for recent years and certain utilities has been stored on disk in a partitioned data set. Each file of the data set contains data for a particular customer group of a particular utility for a certain year. The name of each file (e.g., CEI741) identifies the information contained therein as follows: the first three characters are the utility code; the next two are the last two digits of the appropriate year, and the last character is the customer group code. A listing of the available data files and a description of each can be obtained during execution of the program as shown in Section 7.4.

The expected revenue information may be printed out for each consumption block, each month, and rate structure or in a summary form for the entire time period.

7.2 Algorithm

In the discussion that follows, characters in parentheses denote variable names of quantities used in the program.

After all necessary input information has been furnished, the average energy consumption (AKWHIB) for each block of billing frequency data is calculated by dividing the total number of kWh's consumed in each block by the total number of customers in that block. The number of kWh's included in the service charge is subtracted from AKWHIB to yield the number of kWh's the energy charge is applied to(ECKWH). This value is compared to each rate block endpoint (BLKENP(I,J)) in the rate structure until the first rate block endpoint (BLKENP(I,L)) which is larger than

ECKWH is found. The energy and fuel adjustment revenues are calculated by multiplying the number of kWh's covered in each of the first L-1 rate blocks by the appropriate charges and the difference ECKWH-BLKENP(I,L) by the appropriate charges. The revenues thus obtained are summed to yield the average energy and fuel bills for that consumption block. Multiplying the average bills by the total number of customers in that block results in the total expected energy and fuel revenues for that block. The total revenue for each block is found by adding the energy and fuel revenues to the product of the service charge and the total number of customers in the block.

Monthly totals of kWh usage, number of customers, energy and fuel revenues and total revenues are calculated and outputted. The summary table presents the totals of the same quantities for the entire period of interest based on the monthly totals.

7.3 Execution of the Program

The first step in execution of the program is to gain TSO access. The procedure is shown in the sample. Lower case characters are user inputs and upper case characters indicate computer responses (upper and lower case characters are identical on the TSO). After the computer types "ENTER.LOGON" the user responds by entering:

```
logon
```

and pressing the "RETURN" key.

The computer then prompts the user for information by asking for his user ID number, a password, terminal ID number, university ID number and procedure name. Authorized users will be supplied with the necessary information. The "RETURN" key is pressed after every user input. If the user makes a typographical error and the error is found before the "RETURN" key is pressed, the user may backspace as far as desired and re-enter the information; characters backspaced over are erased.†

Once the user has gained TSO access and the "READY" response has been obtained, the following command is entered:

```
alløc da('pucø.bilfreq')f(ft01f001)
```

and the "RETURN" key is pressed. Upon obtaining the "READY" response again, the following is entered:

```
run'pucø.blkrev.ført'
```

and "RETURN" is pressed again.

† Note this procedure may vary for different terminals.

A series of questions are asked of the user which are necessary to specify the time period(s) and rate structure(s) of interest. These are illustrated in the sample. The allowable input fields are also shown. At the end of execution the user has the option of applying another rate structure to the same data, executing the program with different data or terminating execution.

7.4 Illustration

This section demonstrates the execution of the program. A representative rate schedule is shown in Table 1. This schedule was used in the sample program execution shown in Figure 1. The data set selected was OHE751. The data echoing technique along with the backspace capability allows the user ample opportunity to catch typographical errors.

Only the summary table was requested in this run. If a detailed output was requested, a revenue table for each month and for each rate schedule of the time period would have been printed. A representative monthly revenue is shown in Figure 2. Referring to the summary table of Figure 1, the columns of each row proceeding left to right may be described as follows: the rate structure number, the month number, the total number of kWh's consumed in the month, the total number of customers in the month, the average consumption for the month (kWh/customer), the total monthly revenue due to the energy charge excluding the minimum monthly charge, the total monthly revenue due to the fuel adjustment charge and the total monthly revenue including the minimum monthly charge. The information contained in the monthly revenue table in Table 2 is similar to that contained in the summary table.

Table 1 Sample Rate Schedule

Energy Charge:

$1.50 for the first 25 kWh or less per month

	Summer*	Winter
For the next 75 kWh per month, per kWh	4.4¢	4.4¢
For the next 200 kWh per month, per kWh	3.9¢	3.5¢
For all over 300 kWh per month, per kWh	2.7¢	2.4¢

* June through October - Winter rates apply to all other months.

Fuel Adjustment Rate: 0.10¢/kWh for all blocks.

SAMPLE RATE SCHEDULE

Energy Charge:

$1.50 for the first 25 kWh or less per month

	Summer*	Winter
For the next 75 kWh per month, per kWh	4.4¢	4.4¢
For the next 200 kWh per month, per kWh	3.9¢	3.5¢
For all over 300 kWh per month, per kWh	2.7¢	2.4¢

* June through October - Winter rates apply to all other months.

Fuel Adjustment Rate:

0.10¢/kWh for all blocks.

Fig. 2

```
logon
USERID? ts0287
PASSWORD? [redacted]
TERMINAL ID? r125
UNIVERSITY ID? [redacted]
PROCEDURE NAME? fortuser
TS0287 LOGON IN PROGRESS AT 13:22:29 ON OCTOBER 26, 1976
READY
alloc da('puco.bilfreq') f(ft01f001)
READY
run 'puco.blkrev.fort'
G1 COMPILER ENTERED
SOURCE ANALYZED
PROGRAM NAME = MAIN
*  NO DIAGNOSTICS GENERATED
SOURCE ANALYZED
PROGRAM NAME = REVBLK
*  NO DIAGNOSTICS GENERATED
    *STATISTICS*  NO DIAGNOSTICS THIS STEP r


          REVENUE CODE FOR BLOCK RATE STRUCTURES
                THE OHIO STATE UNIVERSITY
                NUCLEAR ENGINEERING DEPARTMENT
                COLUMBUS, OHIO 43210


        GENERAL OPERATING INSTRUCTIONS
THE PURPOSE OF THIS CODE IS TO CALCULATE THE EXPECTED
REVENUES FROM OPERATOR ENTERED BLOCK RATE STRUCTURES
USING HISTORICAL BILLFREQUENCY DATA. THE OUTPUT IS
AVAILABLE IN SUMMARY FORM FOR EACH MONTH OR BY USAGE
BLOCK FOR EACH MONTH.
UP TO FOUR DIFFERENT RATE STRUCTURES CAN BE SPECIFIED.

DATA ENTRY PROCEDURE
    1. AFTER EACH ENTRY PRESS THE RETURN KEY
    2. RESPOND TO QUESTIONS BY TYPING YES OR NO
    3. WHEN ENTERING DATA FOLLOW THE FORMATTING EXAMPLE
        AND USE A DECIMAL POINT WHEN CALLED FOR
    4. ALL DATA WITH BE ECHOED FOR ACCURACY. IF THE ENTRY
       IS CORRECT, PRESS THE RETURN KEY. IF NOT, TYPE NO.
       PRESS RETURN, THEN ENTER THE CORRECT DATA AND PRESS
       RETURN.


DO YOU NEED TO SEE THE LISTING OF DATA SETS?
```

Fig. 1   Sample Program Execution

```
yes
 DATA SET
   NAME         DESCRIPTION

  CLEVELAND ELECTRIC ILLUMINATING
   CEI741       GRC
   CEI742       GRC WITH ESH
   CEI743       GRC WITH EWH
   CEI744       ALL-ELECTRIC APARTMENT SUITES

  CINCINNATI GAS AND ELECTRIC
   CGE741       GRC
   CGE742       GRC WITH EWH
   CGE743       GRC WITH ESH
   CGE744       GRC WITH ESH AND EWH
   CGE745       APARTMENTS WITH ESH
   CGE746       APARTMENTS WITH ESH AND EWH

  OHIO EDISON
   OHE751       GRC
   OHE752       GRC WITH EWH
   OHE753       GRC WITH EWH AND ESH

  OHIO POWER
   OHP741       GRC
   OHP742       GRC WITH EWH
   OHP743       GRC WITH EWH AND ESH

  TOLEDO EDISON
   TLE751       GRC - UNICORPORATED AREA
   TLE752       GRC WITH EWH
   TLE753       GRC - ORDINANCE RATES
   TLE754       GRC WITH ESH AND EWH

  DAYTON POWER AND LIGHT
   DPL751       CITY CONSUMERS WITHOUT EWH
   DPL752       SUBURBAN AND UNINCORPORATED CONSUMERS WITHOUT EWH
   DPL753       CITY CONSUMERS WITH UNCONTROLLED EWH
   DPL754       SUBURBAN AND UNINCORPORATED CONSUMERS WITH CONTROLLED EWH

         * GRC = GENERAL RESIDENTIAL CONSUMERS
           ESH = ELECTRIC SPACE HEATING
           EWH = ELECTRIC WATER HEATING


TO SELECT THE DATA OF INTEREST, TYPE
THE SIX CHARACTER DATA SET NAME.
ohe751
OHE751
yes
ENTER, UP TO 4, THE NUMBER OF RATE PERIODS.
```

(Fig. 1 continued)

```
3
3
yes
ENTER THE STARTING MONTH AND THE ENDING MONTH
FOR WHICH THE FIRST   RATE STRUCTURE APPLIES.
**/**
01/05
 1/ 5
yes
ENTER THE MINIMUM MONTHLY CHARGE OR SERVICE CHARGE.
***.**
  1.50
  1.50
yes
ENTER THE NUMBER OF KILOWATT HOURS PAID FOR UNDER
THE MONTHLY CHARGE.
***.
 25.
 25.
yes
ENTER THE BLOCK RATE STRUCTURE BY TYPING IN THE END
POINT IN KWH OF EACH BLOCK, FOLLOWED BY THE COST PER KWH IN
DOLLARS, FOLLOWED BY THE FUEL ADJUSTMENT RATE IN DOLLARS.
ENTER 99999. AS THE KWH END POINT OF THE LAST BLOCK AND
IF THE FUEL ADJUSTMENT RATE IS THE SAME FOR ALL BLOCKS ENTER
IT ONLY IN THE FIRST BLOCK. UP TO 20 BLOCKS MAY BE ENTERED
ALL ENTERIES WILL BE ECHOED CHECKED.
BLOCK    $      FUEL
 KWH    COST    COST
 END    PER     PER
POINT   KHW     KHW
*****. *.**** *.******
  100. 0.0440 0.0010
  100. 0.0440 0.0010
yes
  300. 0.0350
  300. 0.0350
yes
99999. 0.0240
99999. 0.0240
yes
ENTER THE STARTING MONTH AND THE ENDING MONTH
FOR WHICH THE SECOND  RATE STRUCTURE APPLIES.
**/**
06/10
 6/10
yes
ENTER THE MINIMUM MONTHLY CHARGE OR SERVICE CHARGE.
***.**
  1.50
  1.50
```

(Fig. 1 continued)

```
yes
ENTER THE NUMBER OF KILOWATT HOURS PAID FOR UNDER
THE MONTHLY CHARGE.
***.
 25.
 25.
yes
ENTER THE BLOCK RATE STRUCTURE BY TYPING IN THE END
POINT IN KWH OF EACH BLOCK, FOLLOWED BY THE COST PER KWH IN
DOLLARS, FOLLOWED BY THE FUEL ADJUSTMENT RATE IN DOLLARS.
ENTER 99999. AS THE KWH END POINT OF THE LAST BLOCK AND
IF THE FUEL ADJUSTMENT RATE IS THE SAME FOR ALL BLOCKS ENTER
IT ONLY IN THE FIRST BLOCK. UP TO 20 BLOCKS MAY BE ENTERED
ALL ENTERIES WILL BE ECHOED CHECKED.
BLOCK     $      FUEL
 KWH     COST    COST
 END     PER     PER
POINT    KHW     KHW
*****. *.**** *.******
  100. 0.0440 0.0010
  100. 0.0440 0.0010
yes
  300. 0.0390
  300. 0.0390
yes
99999. 0.0270
99999. 0.0270
yes
ENTER THE STARTING MONTH AND THE ENDING MONTH
FOR WHICH THE THIRD   RATE STRUCTURE APPLIES.
**/**
11/12
11/12
yes
ENTER THE MINIMUM MONTHLY CHARGE OR SERVICE CHARGE.
***.**
  1.50
  1.50
yes
ENTER THE NUMBER OF KILOWATT HOURS PAID FOR UNDER
THE MONTHLY CHARGE.
***.
 25.
 25.
yes
ENTER THE BLOCK RATE STRUCTURE BY TYPING IN THE END
POINT IN KWH OF EACH BLOCK, FOLLOWED BY THE COST PER KWH IN
DOLLARS, FOLLOWED BY THE FUEL ADJUSTMENT RATE IN DOLLARS.
ENTER 99999. AS THE KWH END POINT OF THE LAST BLOCK AND
IF THE FUEL ADJUSTMENT RATE IS THE SAME FOR ALL BLOCKS ENTER
IT ONLY IN THE FIRST BLOCK. UP TO 20 BLOCKS MAY BE ENTERED
```

(Fig. 1 continued)

```
ALL ENTERIES WILL BE ECHOED CHECKED.
BLOCK      $       FUEL
 KWH     COST     COST
 END      PER      PER
POINT     KHW      KHW
*****. *.**** *.*****
   100. 0.0440 0.0010
   100. 0.0440 0.0010
yes
   300. 0.0350
   300. 0.0350
yes
99999. 0.0240
99999. 0.0240
yes
DO YOU WISH ONLY THE SUMMARY TABLE AS OUTPUT?
yes
OUTPUT WILL NOW BE GENERATED FOR 5-20 MINS.
FOR THE PERIOD  1/ 5 THE FOLLOWING RATE STRUCTURE IS APPLIED
WHERE THE SERVICE CHARGE IS $ 1.50 WHICH INCLUDES  25. KWHS OF ENERGY.

           ENERGY    FUEL
    KWH     COST     COST
   BLOCK    PER      PER
    END     KWH      KWH
  POINTS     $        $
    100.  0.0440   0.0010
    300.  0.0350   0.0010
  99999.  0.0240   0.0010
FOR THE PERIOD  6/10 THE FOLLOWING RATE STRUCTURE IS APPLIED
WHERE THE SERVICE CHARGE IS $ 1.50 WHICH INCLUDES  25. KWHS OF ENERGY.

           ENERGY    FUEL
    KWH     COST     COST
   BLOCK    PER      PER
    END     KWH      KWH
  POINTS     $        $
    100.  0.0440   0.0010
    300.  0.0390   0.0010
  99999.  0.0270   0.0010
FOR THE PERIOD 11/12 THE FOLLOWING RATE STRUCTURE IS APPLIED
WHERE THE SERVICE C ARGE IS $ 1.50 WHICH INCLUDES  25. KWHS OF ENERGY.

           ENERGY    FUEL
    KWH     COST     COST
   BLOCK    PER      PER
    END     KWH      KWH
  POINTS     $        $
    100.  0.0440   0.0010
    300.  0.0350   0.0010
  99999.  0.0240   0.0010
```

(Fig. 1 continued)

SUMMARY TABLE FOR ALL RATE STRUCTURES

					********* REVENUES **********		
R	MO	TOTAL KWH	TOTAL CUSTUMERS	AVERAGE USE	TOTAL ENERGY REVENUES	TOTAL FUEL REVENUES	TOTAL REVENUES
1	1	482756112.	675467.	714.7	13773916.19	465869.24	15252985.93
1	2	450945106.	678741.	664.4	12995702.02	433976.41	14447789.93
1	3	348100168.	572277.	608.3	10162471.64	333793.09	11354680.23
1	4	413928248.	680776.	608.0	12081165.39	396908.67	13499238.05
1	5	351970986.	681561.	516.4	10532358.73	334931.81	11889632.04
2	6	356157331.	679613.	524.1	11573818.85	339146.94	12932405.19
2	7	405561361.	679409.	596.9	12944846.44	388575.94	14352535.88
2	8	420782572.	680033.	618.8	13372048.30	403781.59	14795879.39
2	9	408380866.	679774.	600.8	13034976.96	391386.35	14444024.30
2	10	355773360.	680569.	522.8	11575031.97	338758.98	12934644.45
3	11	358339051.	683909.	524.0	10715588.82	341241.18	12082693.50
3	12	428372092.	687021.	623.5	12469202.74	411196.39	13910930.63
TOTALS		4781067253.	8059150.	593.2	145231128.05	4579586.49	161899439.53

```
DO YOU WANT TO APPLY ANOTHER RATE STRUCTURE TO
THE SAME DATA BASE?
no
DO YOU WISH TO USE A DIFFERENT DATA BASE?
no
IEC225I 00,TS0287,LOGON1,FT01F001,331,IRCC81,PUCO.BILFREQ
READY
logoff
OEF201I CSU=  2  CPU=00:00:03.32  DSK=  143  CNCT=00:14  CHGS=  $2.84  R
AL=  $484.74
TS0287 LOGGED OFF TSO AT 13:36:29 ON OCTOBER 26, 1976+
```

(Fig. 1 continued)

REVENUE TABLE FOR RATE STRUCTURE I FOR JAN

******* BILL FREQUENCY DATA ******** ******** REVENUE DATA ********

KWH BLOCK END POINTS	TOTAL KWH PER BLOCK	TOTAL CUSTUMERS PER BLOCK	AVERAGE USE PER BLOCK	ENERGY REVENUE PER BLOCK	FUEL REVENUE PER BLOCK	TOTAL REVENUE PER BLOCK
50.	1187585.	30424.	39.0	18787.33	426.98	64850.31
100.	0.	0.	0.0	0.0	0.0	0.0
200.	6438018.	41558.	154.9	226369.54	5399.07	294105.60
300.	14995718.	59264.	253.0	526331.64	13514.11	628741.75
400.	25132994.	71381.	352.1	860163.05	23348.45	990582.99
600.	79346614.	158581.	500.4	2475209.80	75382.05	2788463.35
800.	87852512.	126590.	694.0	2564183.93	84687.73	2838756.66
1000.	66887454.	75113.	890.5	1875705.51	65009.61	2053384.62
1200.	43837733.	40176.	1091.1	1196738.78	42833.32	1299836.10
1400.	29389323.	22761.	1291.2	787283.24	28820.29	850245.03
1600.	20215705.	13553.	1491.6	533967.51	19876.87	574173.88
1800.	13818572.	8168.	1691.8	361050.42	13614.36	386916.79
2000.	9506082.	5021.	1893.3	246221.56	9380.55	263133.61
2500.	14765935.	6661.	2216.8	378361.93	14599.41	402952.84
3000.	9449891.	3456.	2734.3	239238.95	9363.49	253786.44
3500.	8540958.	2630.	3247.5	214450.96	8475.21	226871.17
4000.	8988458.	2400.	3745.2	224362.95	8928.46	236891.41
4500.	8567796.	2020.	4241.5	212898.97	8517.29	224446.26
5000.	7841214.	1655.	4737.9	194146.99	7799.83	204429.33
99999.	25993550.	4055.	6410.2	638443.12	25892.17	670417.79
TOTALS	482756112.	675467.	714.7	13773916.19	465869.24	15252985.93

Table 2 Monthly Revenue Table

References

(1) M. S. Gerber, R. W. Baker, and S. Nakamura, "Operations Manual: Residential Billing Frequency Program," Mechanical Engineering Department, The Ohio State University (1976).

CHAPTER 8

TIME-OF-DAY PRICING PROGRAM

8.1 Description of the Program

This program is to estimate the monthly charge to an electric user group based on time-of-day pricing. The pricing scheme here consists of three periods, namely, peak, shoulder (cycling) and base periods. By using this program, the increase or decrease in revenue of a utility due to time-of-day pricing can be analyzed. The basic inputs are:

1) hourly system load data for a year (unnormalized),
2) annual consumption of the customer group in kWh,
3) time-of-day pricing scheme, and
4) load adjustment factors.

An example of a time-of-day pricing schedule is illustrated in Table 1.

Table 1 Sample Rate Schedule

Peak Periods:

November 15 - February 15, Mon.-Fri.
(1:00 p.m. - 7:00 p.m.)

June 15 - September 15, Mon.-Fri.
(12:00 a.m. - 6:00 p.m.)

Shoulder Periods:

February 16 - June 14, Mon.-Fri.
(1:00 p.m. - 6:00 p.m.)

September 16 - November 14, Mon.-Fri.
(12:00 a.m. - 6:00 p.m.)

Base Periods:

All other hours.

Rates	
Peak	$.10/kWh
Shoulder	$.04/kWh
Base	$.013/kWh

(Holidays are considered base hours.)

It is desirable to perform the calculation by using the customer's hourly load data. Unfortunately, such data is not available especially for residential groups. Therefore, it is assumed that a group's load is proportional to the system load. However, the difference between the system load and the group load in each of peak, shoulder and base load periods can be corrected by using adjusting parameters. The adjusting parameters for the three periods may be interpreted as the averaged fraction of the user's load relative to the system load in each period. They may be found from a load survey study. Since the group load is normalized with the annual kWh consumption input, only the ratio among the three factors are important.

The major outputs of the program consist of:

1) monthly total of the kWh consumption for the three periods,
2) monthly charge and its breakdown for the three periods, and
3) annual summary of kWh and customer charge.

The program is on IBM 370/168 TSO system. The input requirement and output format are self-explanatory once the program is executed on TSO.

8.2 Algorithm

After all necessary information has been input, the program sums the hourly loads (LODA) for each month. This yields the total system MWH's produced for each month. The program then sums the hourly loads over each designated peak period and shoulder period. In doing so it applies load adjustment factors (PKFACT and SHFACT) to each hour to arrive at the total MWH's sold on the peak and shoulder (PKKWH and SHKWH) each month. These values are subtracted from the total monthly consumption (BSKWH). The total modified monthly consumption (MOLODW) is then calculated by adding PKKWH, SHKWH, and BSKWH. These monthly consumptions are totaled to give the modified yearly consumption (YRLOAD), and then the percentage of monthly consumption (MOPCT) is calculated. The customer monthly kWh consumption (MOKWH) is calculated by multiplying the group annual kWh times MOPCT/100.

The customer's monthly consumption is then broken into peak consumption, shoulder consumption, and base consumption by applying the percentage of system monthly peak and shoulder consumption to total monthly consumption (PKKWH/MOLODW and SHKWH/MOLODW). This yields the customer's monthly peak, shoulder, and base consumption (CPKKWH, CSHKWH, CBSKWH). The appropriate rates (PKRATE, SHRATE, BSRATE) are then applied to these usages to yield monthly and yearly bills.

8.3 Execution of the Program

The first step in execution of the program is to gain TSO access. The procedure is shown in the sample. Lower case characters are user inputs and upper case characters indicate computer responses (upper and lower case characters are identical on the TSO terminal). After the computer types "ENTER LOGON" the user responds by entering:

logon

and pressing the "RETURN" key. The computer then prompts the user for information by asking for his user ID number, a passwork, terminal ID number, university ID number and procedure name. Authorized users will be supplied with the necessary information. The "RETURN" key is pressed after every user input. If the user makes a typographical error and the error is found before the "RETURN" key is pressed, the user may backspace as far as desired and re-enter the information; characters backspaced over are erased.†

Once the user has gained TSO access and the "READY" response has been obtained, the following commands are entered:

```
alloc da('puco.data')f(ft10f001)
"RETURN" (then wait for READY response)
READY
run 'puco.tofda.fort'
"RETURN"
```

Once the program is compiled it will execute and proceed to prompt input from the user through the use of questions and commands. These are illustrated in the example in Figure 1. It is important to enter the data within the field provided and to use a decimal point when called for.

---

† Note this procedure may vary for different terminals.

8.4 Illustration

Figure 1 illustrates the results of a demonstration run with the rate schedule shown in Table 1. The 1974 system load data of Dayton Power and Light is arbitrarily selected for demonstration purposes. The output of the sample rate structure is shown in Figure 2. Customer consumptions of 6,000 kWh and 12,000 kWh are arbitrarily selected,

FIGURE 1

SAMPLE EXECUTION

```
Elogon
USERID? ts0287
PASSWORD? XXXXXX
TERMINAL ID? r125
UNIVERSITY ID? XXXXXXXXX
PROCEDURE NAME? fortuser
TS0287 LOGON IN PROGRESS AT 10:27:51 ON NOVEMBER 23, 1976
READY
alloc da('puco.data') f(ft10f001)
READY
run 'puco.tofda.fort'
G1 COMPILER ENTERED
SOURCE ANALYZED
PROGRAM NAME = MAIN
*  NO DIAGNOSTICS GENERATED


                RESIDENTIAL PEAK LOAD PRICING CODE
                    THE OHIO STATE UNIVERSITY
                    NUCLEAR ENGINEERING DEPARTMENT
                    COLUMBUS, OHIO 43210


        GENERAL OPERATING INSTRUCTIONS
THE PURPOSE OF THIS CODE IS TO ALLOW THE USER TO STUDY
THE EFFECTS ON THE BILL OF A RESIDENTIAL CLASS OF CUSTOMERS
DUE TO THE INITIATION OF A TIME OF DAY(AND TIME OF YEAR)
PRICING SCHEME.  THE USER MUST ENTER THE RATE STRUCTURE, THE
ANNUAL KWH USAGE OF THE CUSTOMER CLASS IN QUESTION, AND
THE APPROPRIATE LOAD FACTORS FOR EACH PERIOD OF TIME.  THE
OUTPUT GIVES THE CUSTOMERS MONTHLY AND ANNUAL BILL, BROKEN
DOWN INTO PEAK, SHOULDER, AND BASE CHARGES.

DATA ENTRY PROCEDURES

    1.  WHEN ENTERING DATA FOLLOW THE FORMATTING EXAMPLE
        AND USE A DECIMAL POINT WHEN CALLED FOR
    2.  AFTER EACH ENTRY PRESS THE RETURN KEY
    3.  RESPOND TO QUESTIONS BY TYPING YES OR NO


ENTER THE UTILITY AND YEAR WHICH IS TO BE USED IN THE ANALYSIS.  FOR
EXAMPLE, DPL74L TELLS THE PROGRAM TO USE DAYTON POWER AND LIGHT LOAD
DATA FROM 1974.
********
dpl74l
IEC225I 00,TS0287,LOGON1,FT10F001,431,IRCC71,PUCO.DATA
ENTER THE ANNUAL KWH USAGE OF THE CUSTOMER CLASS TO BE ANALYZED.  BE
SURE TO INCLUDE A DECIMAL POINT.
**********
6000.
```

ENTER THE PEAK RATE, SHOULDER RATE, BASE RATE, AND MINIMUM CHARGE IF ONE EXISTS. THESE RATES SHOULD BE ENTERED IN THE ORDER IN WHICH THEY ARE LISTED, AND RATES SHOULD BE IN DOLLARS PER KWH. IF THERE IS NO SHOULDER PERIOD, LEAVE THE SHOULDER RATE BLOCK BLANK.

.***,**.*****,**.*****,**.*****

00:10   0:04   0:13   6:00

ENTER THE TOTAL NUMBER OF PEAK PERIODS WITHIN THE YEAR. FOR EXAMPLE, IF JUNE TO SEPTEMBER AND DECEMBER TO FEBRUARY ARE CONSIDERED PEAK PERIODS, THE NUMBER OF PEAK PERIODS WOULD BE 2. (MAX OF 5)

*

3

ENTER THE BEGINNING MONTH AND DAY, AND THE ENDING MONTH AND DAY FOR PEAK PERIOD 1. FOR EXAMPLE, 0615-0930 INDICATES THAT THE INTERVAL OF THIS PERIOD IS FROM JUNE 15 TO SEPTEMBER 30.

****-****

0101 0215

ENTER THE INCLUSIVE HOURS IN THE DAY FOR PEAK PERIOD 1. FOR EXAMPLE, 11-19 INDICATES THAT THE PEAK PERIOD IS ONLY IN EFFECT FROM 11:00 AM TO 7:00 PM.

-

13 19

ENTER THE BEGINNING MONTH AND DAY, AND THE ENDING MONTH AND DAY FOR PEAK PERIOD 2. FOR EXAMPLE, 0615-0930 INDICATES THAT THE INTERVAL OF THIS PERIOD IS FROM JUNE 15 TO SEPTEMBER 30.

****-****

0615 0915

ENTER THE INCLUSIVE HOURS IN THE DAY FOR PEAK PERIOD 2. FOR EXAMPLE, 11-19 INDICATES THAT THE PEAK PERIOD IS ONLY IN EFFECT FROM 11:00 AM TO 7:00 PM.

-

12 18

ENTER THE BEGINNING MONTH AND DAY, AND THE ENDING MONTH AND DAY FOR PEAK PERIOD 3. FOR EXAMPLE, 0615-0930 INDICATES THAT THE INTERVAL OF THIS PERIOD IS FROM JUNE 15 TO SEPTEMBER 30.

****-****

1115 1231

ENTER THE INCLUSIVE HOURS IN THE DAY FOR PEAK PERIOD 3. FOR EXAMPLE, 11-19 INDICATES THAT THE PEAK PERIOD IS ONLY IN EFFECT FROM 11:00 AM TO 7:00 PM.

-

13 19

ENTER THE TOTAL NUMBER OF SHOULDER PERIODS WITHIN THE YEAR. FOR EXAMPLE, IF MARCH TO MAY IS CONSIDERED THE ONLY SHOULDER PERIOD IN THE YEAR, THE NUMBER OF SHOULDER PERIODS WOULD BE 1. (MAX OF 5)

*

2

ENTER THE BEGINNING MONTH AND DAY,AND THE ENDING MONTH AND DAY FOR SHOULDER PERIOD 1. FOR EXAMPLE, 0301-0515 INDICATES THAT THE INTERVAL OF THIS PERIOD IS FROM MARCH 1 TO MAY 15.

****-****

0216 0614

ENTER THE INCLUSIVE HOURS IN THE DAY FOR SHOULDER PERIOD 1. FOR EXAMPLE, 07-10 INDICATES THAT THE SHOULDER PERIOD IS ONLY IN EFFECT FROM 7:00AM TO 10:00AM.

-

13 19

```
ENTER THE LOAD ADJUSTMENT FACTOR FOR THE 3 PEAK PERIODS TO BE STUDIED.
IF IT IS ASSUMED THAT THE CUSTOMER USAGE EXACTLY FOLLOWS THE SYSTEM
LOAD, ENTER 1.0 FOR EACH PEAK PERIOD.
*.***,*.***,*.***,*.***,*.***
0.500 0.500 0.500
ENTER THE LOAD ADJUSTMENT FACTOR FOR THE 2 SHOULDER PERIODS TO BE
STUDIED.  IF IT IS ASSUMED THAT THE CUSTOMER USAGE EXACTLY FOLLOWS
THE SYSTEM LOAD, ENTER 1.0 FOR EACH SHOULDER PERIOD.
*.***,*.***,*.***,*.***,*.***
0.500 0.500
ENTER THE LOAD ADJUSTMENT FACTOR FOR THE BASE PERIOD.
*.***
0.500
```

CUSTOMER CONSUMPTION= 12000.00KWH

MONTH	PCT OF YEARLY CONSUMPTION	KWH
1	8.93	1071.44
2	8.13	975.20
3	8.25	989.51
4	7.52	902.45
5	7.71	925.05
6	7.71	924.72
7	9.10	1091.87
8	8.96	1074.89
9	7.74	928.81
10	8.38	1005.54
11	8.54	1024.82
12	9.05	1085.71

MONTH	PEAK KWH	PEAK CHRG	SHOULDER KWH	SHOULDER CHRG	BASE KWH	BASE CHRG	TOTAL CHRG
1	224.	22.44	0.	0.0	847.	110.11	138.55
2	111.	11.09	89.	3.55	776.	100.83	121.47
3	0.	0.0	198.	7.91	792.	102.94	116.85
4	0.	0.0	199.	7.97	703.	91.43	105.39
5	0.	0.0	208.	8.32	717.	93.20	107.53
6	98.	9.84	101.	4.04	725.	94.31	114.18
7	261.	26.08	0.	0.0	831.	108.04	140.12
8	253.	25.29	0.	0.0	822.	106.86	138.15
9	90.	8.99	107.	4.27	732.	95.19	114.45
10	0.	0.0	220.	8.80	786.	102.13	116.92
11	88.	8.79	111.	4.44	826.	107.38	126.60
12	203.	20.28	0.	0.0	883.	114.77	141.06
TOTAL	1328.	132.80	1232.	49.28	9440.	1227.19	1481.27

FIGURE A.3

SAMPLE OUTPUT

```
                    CUSTOMER CONSUMPTION=    6000.00KWH
         PCT OF YEARLY
 MONTH    CONSUMPTION         KWH

    1         8.93           535.72
    2         8.13           487.60
    3         8.25           494.75
    4         7.52           451.22
    5         7.71           462.52
    6         7.71           462.36
    7         9.10           545.93
    8         8.96           537.44
    9         7.74           464.40
   10         8.38           502.77
   11         8.54           512.41
   12         9.05           542.85
         PEAK    PEAK   SHOULDER   SHOULDER   BASE    BASE    TOTAL
 MONTH   KWH     CHRG   KWH          CHRG     KWH     CHRG    CHRG

    1    112.    11.22     0.         0.0     424.    55.06   72.28
    2     55.     5.55    44.         1.77    388.    50.42   63.74
    3      0.     0.0     99.         3.95    396.    51.47   61.42
    4      0.     0.0    100.         3.98    352.    45.71   55.70
    5      0.     0.0    104.         4.16    358.    46.60   56.76
    6     49.     4.92    50.         2.02    363.    47.15   60.09
    7    130.    13.04     0.         0.0     416.    54.02   73.06
    8    126.    12.64     0.         0.0     411.    53.43   72.07
    9     45.     4.50    53.         2.13    366.    47.59   60.22
   10      0.     0.0    110.         4.40    393.    51.06   61.46
   11     44.     4.39    55.         2.22    413.    53.69   66.30
   12    101.    10.14     0.         0.0     441.    57.39   73.53

 TOTAL   654.    66.40   616.        24.64   4720.   613.59  776.63


DO YOU WISH TO LOOK AT ANOTHER CUSTOMER CLASS USING THE EXISTING RATE
STRUCTURE?  (ANSWER YES OR NO)
***
yes
ENTER THE ANNUAL KWH USAGE FOR THE NEXT CUSTOMER CLASS TO BE STUDIED.
**********
12000.
DO YOU WISH TO USE DIFFERENT LOAD FACTORS THAN PREVIOUSLY ENTERED?
***
yes
```

```
ENTER THE BEGINNING MONTH AND DAY,AND THE ENDING MONTH AND DAY FOR
SHOULDER PERIOD 2.  FOR EXAMPLE, 0301-0515 INDICATES THAT THE INTERVAL
OF THIS PERIOD IS FROM MARCH 1 TO MAY 15.
****-****
0916 1114
ENTER THE INCLUSIVE HOURS IN THE DAY FOR SHOULDER PERIOD 2.  FOR
EXAMPLE, 07-10 INDICATES THAT THE SHOULDER PERIOD IS ONLY IN EFFECT
FROM 7:00AM TO 10:00AM.
**-**
12 18
ENTER THE LOAD ADJUSTMENT FACTOR FOR THE 3 PEAK PERIODS TO BE STUDIED.
IF IT IS ASSUMED THAT THE CUSTOMER USAGE EXACTLY FOLLOWS THE SYSTEM
LOAD, ENTER 1.0 FOR EACH PEAK PERIOD.
*.***,*.***,*.***,*.***,*.***
1.000 1.000 1.000
ENTER THE LOAD ADJUSTMENT FACTOR FOR THE 2 SHOULDER PERIODS TO BE
STUDIED.  IF IT IS ASSUMED THAT THE CUSTOMER USAGE EXACTLY FOLLOWS
THE SYSTEM LOAD, ENTER 1.0 FOR EACH SHOULDER PERIOD.
*.***,*.***,*.***,*.***,*.***
1.000 1.000 1.000
ENTER THE LOAD ADJUSTMENT FACTOR FOR THE BASE PERIOD.
*.***
1.000
```

CHAPTER 9

COST ALLOCATION PROGRAM

9.1 Introduction

This chapter describes the detail of the Electric Cost Allocation program developed at The Ohio State University (OSU) under a contract with the Public Utilities Commission of Ohio (PUCO). The code consists of two independent modules. The first module, designated as ALLODEC, allocates the total annual cost of an electric utility into the demand, energy, and customer components based on the input data available from the FPC Form 1 Annual Report. The second module, designated as ALLOCUS, uses the output from the first module as well as load survey data for the customer groups as input, and allocates the three components to the customer groups.

The remainder of this report includes descriptions of ALLODEC and ALLOCUS in Section 9.2 and 9.3, respectively. Section 9.4 describes how to execute both modules. The appendix of Reference 1 includes the following:

Appendix A Input Data Format
B Listing of Fortran and Data
C Flow Chart
D Sample Output
E Job Control Language
F Code for Hourly Load Normalization

9.2 ALLODEC Module

The ALLODEC module allocates the total annual cost of an electric utility to the following five categories:

1. production (i = 1)
2. transmission (i = 2)
3. distribution (i = 3)
4. customer cost (i = 4)
5. administrative, general and others (i = 5)

where i is the index to identify each category. Then the total for each category is reallocated to demand, energy, and customer related costs.

9.3 Input Requirement

All the input data required for this module (except some parameters which must be specified by the user) are available from the FPC Form 1 report.

The following input data are necessary:

a) Values of electric plants in service for each of FPC Account No. 300-399 (page 401-403). The five categories each of the above accounts belongs to must be found from the FPC Form 1 and specified by the input.

b) Electric plant operation and maintenance expenses for FPC Account No. 500-599 and 900-932 (page 417-419). Distribution of each account in the three components (demand, energy and customer) must be judged and specified by the user in fractions for each account.

c) Depreciation for each of FPC account numbers that appeared in (a).

d) Jurisdictional allocation factors for the major expense accounts as follows:

   Operation and Maintenance (fuel)

   Operation and Maintenance (purchased power)

   Provision for Depreciation

   Amortization and Acquisition

   Taxes Other than Income Taxes

   Federal Income Taxes

   The jurisdictional allocations must be prepared by the user.

e) Distribution of salaries and wages (page 355-356). The distribution of salaries and wages in the five categories is directly available from FPC Form 1, and must be given as input.

f) Tax distribution by major expense accounts. The total amount and jurisdictional allocation factor for the following taxes are necessary as input:

   Federal Income Tax

   Other Federal Taxes

   Property Tax

   Ohio Excise Tax

   Other State Taxes

   Federal Payroll Taxes

State Payroll Taxes

Other Tax 1

Other Tax 2

Other Tax 3

The designations "Other Taxes" 1-3 may be used for any taxes that are not included in the previous tax categories. The total amount of each tax is found on page 114 of FPC Form 1. The jurisdictional factors must be prepared by the user.

g) Demand and energy costs of purchased power (FPC Form 1, Account No. 555, pages 422-423). Only the ratio of those two numbers is meaningful, as explained in (2) of Section 2.3.

h) Total values for construction work in progress (CWIP) (FPC Form 1, page 406). In this program, only the total value for CWIP is necessary.

i) Accumulated depreciation for the five categories (FPC Form 1, page 408).

j) The total value of amortization and acquisition (FPC Form 1, page 407).

The allocation of costs in this module consists of two stages as follows. The result of each stage is printed out as Schedule 1 (Table 1) and Schedule 2 (Table 2), respectively.

9.4 Allocation to the Five Categories (Stage 1)

The first stage is to allocate the following cost items into the five categories denoted by $i = 1 \sim 5$:

1) Total Non-Fuel Operating Expenses*
2) Total Maintenance Expenses*
3) Total Depreciation Expenses
4) Total Taxes other than Ohio Excise Taxes
5) Total Amortization and Acquisition Expenses
6) Total Operating Income
7) Total Ohio Excuse Tax

The breakdown of the first two cost items (*) to the five categories is given by input.

The remaining five items are allocated in the following manner:

Allocation of (3)

Depreciation is allocated in proportion to Net Electric Plant in Service.

Allocation of (4)

i) Federal Income Tax and Property Taxes are allocated in proportion to the Net Electric Plant in Service in each category.

ii) Payroll taxes are allocated in proportion to the salaries and wages in the five categories.

iii) Other taxes are assumed to belong to the category "administrative and general and other."

Allocation of (5)

Amortization and acquisition are allocated in proportion to the net electric plant values in each category.

Allocation of (6)

The net operating income represents the dividends to be paid to the stockholders of the utility, which should be considered by the utility as an expense item. The distribution of the net operating income is allocated in proportion to the net electric plant in each category.

Allocation of (7)

The Ohio excise tax is allocated in proportion to the total of all expenses excluding the Ohio Excise Tax in each category.

In each allocation for (4), (5), (6), and (7), the values of net electric plant in service for the five categories are necessary. Those are calculated by:

$$GEP_i = EPV_i + CWIP_i$$

$$NEP_i = GEP_i - AD_i$$

where the subscript i represents the i-th item in the five categories as mentioned earlier, GEP_i is the gross electric plant value, EPV_i is the value of the electric plant in service, $CWIP_i$ is the value of the construction work in progress and AD_i is the accumulated depreciation. EPV_i is calculated by using the input that was explained under (a). $CWIP_i$ is calculated by allocating the total CWIP given by input in proportion to EPV_i. AD_i is given by input for each i as mentioned under (j).

The result of the first stage is printed as "Schedule 1" (Table 1). the distribution of the net electric plant in service in the five categories is printed on the first line in Schedule 1. Lines 2 through 7 are the straight results of allocation. Line 8 is the total of lines 2 through 7. The Ohio Excise Tax in line 9 is allocated in proportion to the subtotal in line 8. The sum of lines 8 and 9 is the total cost in each category (line 10).

9.3 Allocation to the Three Components (Stage 2)

In this stage, all the expense accounts given by input are reallocated to the three components:

1. Demand-Related Cost,
2. Energy-Related Cost; and,
3. Customer-Related Cost.

Then, the three components are correlated to the five categories calculated in Stage 1.

Allocation to the three components proceeds as follows;

1) Each of non-fuel operating and maintenance expenses (FPC Account No. 500-599 and 900-932), except for Account No. 555, 920, and 926, is allocated according to the allocation factor specified by the input for each account.

2) The total Purchased Power Expenses (Account No. 555) is allocated in two alternative ways. The first approach is to use the allocation factors defined for Account No. 555. The second approach is to allocate in proportion to the demand and energy cost for the purchased power specified by the user separately from the non-fuel operating cost, Account No. 555. If the allocation factors for Account No. 555 are zero, the second approach is automatically chosen. There is no customer component in the purchased power cost. The demand and energy costs defined by the user for the second approach are used only to calculate the allocation factors, but their absolute values are neglected.

3) Before Account No. 902 (employees' salaries) and 926 (pension) are allocated, the total demand-, energy- and customer costs

Table 1 Illustration of Schedule 1

SCHEDULE 1

FUNCTIONALIZATION OF TOTAL SYSTEM COSTS, 1975
(PER BOOK OF ACCOUNTS, IN THOUSANDS OF DOLLARS)

	TOTAL ALL FUNCTIONS	PRODUC-TION	TRANS-MISSION	DISTRI-BUTION	CUSTOMER COSTS	A&G AND OTHER
1. NET EL. PLANT IN SERVICE	697218.	332136.	108637.	186869.	44757.	24820.
2. NON-FUEL OPERATING EXPENSES	37385.	15352.	954.	5792.	4799.	10489.
3. MAINTENANCE EXPENSES	13110.	6918.	592.	5237.	0.	364.
4. DEPRECIATION	21872.	11296.	2710.	5993.	1408.	466.
5. TAXES OTHER THAN OHIO EXCISE TAX	29180.	14408.	4297.	7391.	1770.	1314.
6. AMORTIZATION AND ACQUISITION	49.	23.	8.	13.	3.	2.
7. OPERATING INCOME	58816.	28018.	9164.	15764.	3776.	2094.
8. TOTAL EXPENSES EXCEPT OHIO EXCISE TAX	160412.	76015.	17724.	40190.	11755.	14728.
9. OHIO EXCISE TAX	8206.	3889.	907.	2056.	601.	753.
10. TOTAL COST OF SERVICE SUM OF LINES 8 AND 9	168618.	79904.	18631.	42246.	12357.	15482.

of non-fuel operating expense and maintenance are calculated, excluding Account No. 920 and 926. Then, Account No. 920 and 926 are allocated in proportion to the subtotal thus calculated.

4) Depreciation, property taxes, payroll taxes, other taxes, amortization and acquisition, and operating income are all allocated to the demand-related cost.

5) The preceeding three rules cover all the costs except for Federal Income Tax and Ohio Excise Tax. Before those two costs are allocated, the demand-, energy-, and customer-related portion for each of the five categories is calculated, excluding those two costs. Then, the portion of Federal Income Tax and Ohio Excise Tax in each of the five categories is allocated in proportion to the three components thus calculated for each category.

The results of the allocation in this stage is printed out as Schedule 2 (see Table 2).

9.3 ALLOCUS Module

This module allocates each of the demand-, energy- and customer-related costs ot the customer classes. Although a maximum of seven classes can be considered by this module, only three customer groups (residential group, general service group, and large power users group) are considered here.

The costs are allocated to the three customer groups according to the following rules:

1) Energy-related cost is allocated in proportion to the energy consumed by each customer group.

2) Customer related cost is allocated in proportion to the number of customers in each group.

3) Demand related cost is allocated in proportion to the demand responsibility factor defined by:

$$DR_k = W_1 * PR_k + W_2 * SR_k + W_3 * WR_k$$

$$k = 1, 2, 3$$

where k denotes a customer group, DR is the demand responsibility factor, PR is the peak responsibility factor, SR is the summer high energy responsibility factor, WR is the winter high responsibility factor and $W_1 \sim W_3$ are weighting factors specified by the user.

Table 2 Illustration of Schedule 2

SCHEDULE 2

ALLOCATION OF FUNCTIONAL CATEGORIES
(THOUSANDS OF DOLLARS)

FUNCTIONAL CATEGORY	TOTAL	DEMAND	ENERGY	CUSTOMERS
1. PRODUCTION	79904.	69643.	10261.	0.
2. TRANSMISSION	18631.	18307.	324.	0.
3. DISTRIBUTION	42246.	35558.	905.	5783.
4. CUSTOMERS	12357.	0.	0.	12357.
5. A&G AND OTHERS	15482.	7468.	1894.	6120.
TOTAL	168618.	130975.	13384.	24259.

READY

The remainder of this section describes how to calculate PR, SR, and WR. In order to calculate the three responsibility factors, the hourly load data throughout a year for Residential Group, Large Power Users Group and the system hourly load data are necessary. At present the hourly load data for the General Service Group is more difficult to estimate. It is obtained by subtracting the sum of the load of the two other customer groups from the system load.

From the system hourly load data, the N peak hours (N hours of highest load throughout a year) are found, and the day and time for each peak hour are recorded, where N is an integer specified by the user. The load at the n-th system peak hour is denoted by P_n. The load by group at each of the N peak hours is found from the customer load data. The peak responsibility for the j-th group at the n-th peak hour is defined as:

$$PR_{j,n} = L_{j,n}/P_n$$

where $PR_{j,n}$ is the peak responsibility for the j-th group at the n-th peak hours, $L_{j,n}$ is the group load of the j-th group at the n-th peak hours. The peak responsibility throughout the year is defined as the average of $PR_{j,n}$, namely,

$$PR_j = \left(\sum_{n=1}^{N} PR_{j,n}\right)/N$$

where PR_j is the peak responsibility for the j-th group.

In order to calculate summer high energy responsibility factor (SR), the threshold load for the system (STRESH) is first calculated by:

$$\text{STHRES} = (1-f)(\text{Summer peak load})$$

where f is a parameter specified by the user by which the incremental cost becomes considerably higher for the loads exceeding STHRES. Then, the loads and hours when the load exceeds STHRES are recorded and indexed by m. The customer group load coincident with those hours is found from the customer group load data and denoted by $SL_{j,m}$ for the j-th group.

The SR is then given by:

$$SR_j = \sum_{m=1}^{M} SL_{j,m} / \sum_{m=1}^{M} SP_m$$

where M is the total number of hours by which the system load exceeds STHRES.

Summer, in this program, is defined as June, July, August and September. The winter high energy responsibility factor (WR) is calculated in the same manner as SR and is given by

$$WR_j = \sum_{q=1}^{Q} WL_{j,n} / \sum_{q=1}^{Q} WP_q$$

where Q is the total number of hours that the system load exceeds the threshold load for the winter WTHRES. The winter is defined as December, January, February and March.

The results of the ALLOCUS module are printed out as Schedules 3,4- and 5 as illustrated in Tables 3 through 5.

9.4 Execution of the Program

The two modules are independently executed on a time sharing terminal. The required core space for the whole package is less than 150,000 bites. The two modules are stored in each file of the disc space. Each module requires two different files of input. Reference 1 explains how to prepare the total of four files. The JCL (Job Control Language) necessary to load the files on the IBM 370/Model 168 at OSU are shown in Reference 1.

The ALLODEC module is stored under the file name "ALLODEC.FORT" and the ALLOCUS module is stored under the file name "ALLOCUS.FORT". The names of the four data files and the logical units to be assigned are:

1. ALLODEC.FPC.DATA	Unit 8
2. ALLODEC.CFM.DATA	Unit 9
3. ALLOCUS.DATA	Unit 10
4. ALLOCUS.HRLOAD.DATA	Unit 11

Table 3 Illustration of Schedule 3

DAYTON POWER & LIGHT JUNE 1977

SCHEDULE 3

SYSTEM CHARACTERISTICS *

CHARACTERISTIC	DEF	TOTAL SYSTEM	CUSTOMER CATEGORIES						
			RESI- DENTIAL	GENERAL SERVICE	LARGE POWER	OTHER I	OTHER II	OTHER III	OTHER IV
TOTAL ENERGY	(1)	5313466.	1796692.	1612353.	1904421.	0.	0.	0.	0
SUMMER HIGH-ENERGY	(2)	80724.	26788.	29189.	24747.	0.	0.	0.	0
WINTER HIGH-ENERGY	(3)	70695.	24589.	22065.	24041.	0.	0.	0.	0
PEAK DEMAND	(4)	1729.	608.	611.	510.	0.	0.	0.	0
AVERAGE PEAK	(5)	1729.	572.	633.	524.	0.	0.	0.	0
NUMBER OF CUSTOMERS		395443	353694	41474	275	0	0	0	

DEFINITIONS:
(1) KWH ENERGY
(2) KWH ENERGY CONSUMED DURING THOSE SUMMER PERIODS (TOTAL<900 HOURS) DURING WHICH DEMAND EXCEEDED 90.0% OF THE SUMMER PEAK
(3) KWH ENERGY CONSUMED DURING THOSE WINTER PERIODS (TOTAL<900 HOURS) DURING WHICH DEMAND EXCEEDED 90.0% OF THE WINTER PEAK
(4) KW COINCIDENT DEMAND DURING SYSTEM PEAK
(5) KW COINCIDENT DEMAND AVERAGED OVER THE 30 HIGHEST SYSTEM PEAKS

Table 4 Illustration of Schedule 4

SCHEDULE 4

FACTORS FOR COST ALLOCATION TO CUSTOMER CATEGORIES *

EXPENSE FUNCTION	TOTAL SYSTEM	CUSTOMER CATEGORIES RESI-DENTIAL	GENERAL SERVICE	LARGE POWER	OTHER I	OTHER II	OTHER III	OTHER IV
1. TOTAL DEMAND	72.49%							
1.1 PEAK RESPONSIBILITY	100.00%	33.10%	36.61%	30.29%	0.0 %	0.0 %	0.0 %	0.0 %
1.2 SUMMER HI-ENERGY RESP	0.0 %	33.18%	36.16%	30.66%	0.0 %	0.0 %	0.0 %	0.0 %
1.3 WINTER HI-ENERGY RESP	0.0 %	34.78%	31.21%	34.01%	0.0 %	0.0 %	0.0 %	0.0 %
2. ENERGY	12.98%	33.81%	30.34%	35.84%	0.0 %	0.0 %	0.0 %	0.0 %
3. CUSTOMERS	14.53%	89.44%	10.49%	0.07%	0.0 %	0.0 %	0.0 %	0.0 %
TOTAL COST OF SERVICE	100.00%	41.38%	32.00%	26.62%	0.0 %	0.0 %	0.0 %	0.0 %

Table 5 Illustration of Schedule 5

SCHEDULE 5

COST ALLOCATION TO CUSTOMER CATEGORIES *
(THOUSANDS OF DOLLARS)

EXPENSE FUNCTION	DEF	TOTAL SYSTEM	CUSTOMER CATEGORIES RESI-DENTIAL	GENERAL SERVICE	LARGE POWER	OTHER I	OTHER II	OTHER III	OTHER IV
1. TOTAL DEMAND		122228. (72.49%)	40454.	44752.	37022.	0.	0.	0.	0.
1.1 PEAK	(1)	122228. (100.00%)	40454.	44752.	37022.	0.	0.	0.	0.
1.2 SUMMER HIGH-ENERGY	(2)	0. (0.0 %)	0.	0.	0.	0.	0.	0.	0.
1.3 WINTER HIGH-ENERGY	(3)	0. (0.0 %)	0.	0.	0.	0.	0.	0.	0.
2. ENERGY		21889. (12.98%)	7402.	6642.	7845.	0.	0.	0.	0.
3. CUSTOMERS		24502. (14.53%)	21915.	2570.	17.	0.	0.	0.	0.
TOTAL COST OF SERVICE		168619. (100.00%)	69771. (41.38%)	53964. (32.00%)	44884. (26.62%)	0. (0.0 %)	0. (0.0 %)	0. (0.0 %)	0. (0.0 %)

DEFINITIONS:

(1) RESPONSIBILITY (PORTION OF TOTAL DEMAND) ALLOCATED PROPORTIONATE TO USAGE DURING THE 30 HIGHEST PEAKS

(2) RESPONSIBILITY (PORTION OF TOTAL DEMAND) ALLOCATED PROPORTIONATE TO USAGE DURING THOSE SUMMER PERIODS DURING WHICH DEMAND EXCEEDED 90.00% OF THE SUMMER PEAK

(3) RESPONSIBILITY (PORTION OF TOTAL DEMAND) ALLOCATED PROPORTIONATE TO USAGE DURING THOSE WINTER PERIODS DURING WHICH DEMAND EXCEEDED 90.00% OF THE WINTER PEAK

The first two files are used by the ALLODEC module and the last two by the ALLOCUS module. The second file is necessary only when the operating and maintenance data from the Regulatory Analysis Model is used.

The whole program is executed in the following sequence:

STEP 1 - Set the program and data files.

STEP 2 - Allocate the data files to the proper I/O units by using the following commands:

"alloc da (allodec.fpc.data)f(ft08f001)"

"allod da (allodec.cfm.data)f(ft09001)"

"alloc da (allocus.data)f(ft10f001)"

"alloc da (allocus.hrload.data)f(ft11f001)"

After each command the computer answers "READY",

STEP 3 - (Execution of ALLODEC) Type "run allodec.fort". The computer replies by asking, "WILL YOU HAVE ANY INPUT LISTED?" If you type "YES", the computer will ask which file number you want to be listed (see the file numbers and its content). A part or all of the listed input data are listed depending upon what file numbers the user selects. If the answer for the previous question is "no", the computer asks "WILL YOU CHANGE TEMPORARILY ANY FPC ACCT DATA?" If the user's answer is "YES", a part or all of the FPC account data can be changed by following the computer's instruction. If the user's answer is "NO", then the computer proceeds to print Schedule 1 and Schedule 2 as the output. Output of sample runs is shown in Tables 1 and 2.

STEP 4 - Add the result of ALLODEC, namely the demand, energy and customer costs from Schedule 2, to the ALLOCUS.DATA file.

STEP 5 - (Execution of ALLOCUS) In order to execute the ALLOCUS module, the user should type "run allocus.fort". Then, the computer asks "READ WEIGHT FACTORS APPLIED TO PEAK RESPONSIBILITY, SUMMER HIGH ENERGY, AND WINTER HIGH ENERGY." The user must enter the three numbers in the decimal system, Each number must be between 0.0 and 10., and separated by blanks. The total of the three numbers must be unity. The computer asks next:

"ENTER: THE NUMBER OF PEAKS (INTEGER<31) THE % OF LOAD DEFINED AS "HIGH" (REAL), THE NUMBER OF GROUPS CONSIDERED (INTEGER>8).LEAVE ONE BLANK BETWEEN NUMBERS."

To answer this, the user types, for example, "10 20. 3". Following this, Schedules 3,4, and 5 are printed as illustrated in Tables 3, 4, and 5, respectively.

References

(1) S. Tzemos and S. Nakamura, "User's Manual for Electric Cost Allocation Program, A Computer Program to Allocate the Total Electric Utility Cost Among Customer Groups" Submitted to Public Utilities Commission of Ohio by The Ohio State University, Mechanical Engineering Department (1977).

CHAPTER 10

AN OVERVIEW OF THE OPERATION OF THE MARGINALCOST PROGRAM

10.1 Introduction

A computer program to compute the long run marginal cost of electricity has been developed by Professor Charles J. Cicchetti of The University of Wisconsin. At the request of the Public Utilities Commission of Ohio (PUCO), the program, called MARGINALCOST, was obtained from Professor Cicchetti and adapted for use on an interactive programming terminal called time sharing option (TSO). In addition, a number of modifications to the MARGINALCOST program were made for the PUCO's use;[1,2] these included:

1. changes which improved the method for computing marginal cost of generation,
2. addition of description comments and printout of the input data,
3. addition of a section for computing a linear regression coefficient for measuring the correlation of historical transmission and distribution facility capacity to historical peak load,
4. the correction to an apparent error in a section of the program which allows changes to be made in the data input; and
5. alteration of the section of the program for reading in data so as to allow a set of data for a utility to be stored for use on TSO.

The alternations listed above have made it necessary to prepare a user's manual of the Cicchetti program for the PUCO. This chapter serves as an amendment to an earlier reference manual written by Professor Cicchetti, William J. Gillen, and Paul Smolensky[3] for the National Science Foundation in June 1976. This package contains material taken from that manual.

10.2 An Overview of the Program

The MARGINALCOST program uses the forecasted generation, transmission, distribution, running cost, and load data on a utility along with optional historic data to estimate for selected peak and off-peak periods the (long-run) marginal costs of:

1. Generation Capacity (in \$/KW);
2. Transmission and Distribution Capacity (in \$/KW); and
3. Energy (related to the running costs of variable operaiton and maintenance as well as fuel consumption, in ¢/kWh;

After these components of the marginal cost are determined, they are combined to give the total marginal cost as follows:

Peak Periods

1. The capacity costs of generation, transmission, and distribution are combined. This total \$/KW cost is then spread over the annual total hours on peak to give a total capacity cost in ¢/kWh.
2. The marginal capacity cost is then combined with the marginal energy cost for the period to yield the total marginal cost.

Off-Peak Periods

1. The marginal capacity costs are taken to be zero, based on the assumption that additional capacity does not have to be built to provide service for these times.
2. Because there are no capacity costs in the off-peak periods, the marginal energy cost for a given period is taken to be the total marginal cost.

The marginal cost computed in the Cicchetti program cannot be directly implemented into a tariff because it does not include additional costs covering return on investment, administrative expenses, taxes, metering, and billing. Nevertheless, it does provide some indication of the cost differential between peak and off-peak times as well as voltage levels of service.

10.3 Refinement of Marginal Costs According to Voltage Level

The components of marginal cost relating to generation, transmission, and distribution are adjusted in the Cicchetti program to account for power and energy-related losses incurred down to the voltage level at which service is provided. Separate marginal costs may be determined for a maximum of five voltage levels using factors called loss multipliers. These escalate the costs slightly for each voltage level of service to reflect the fact that in order to provide one kWh of service, more than one kWh must be produced at the generating plant to overcome losses incurred through the transmission and distribution system.

10.4 Computation of the Marginal Cost of Generation

The procedure used in the Cicchetti program to calculate the marginal cost of generation is based on an approach developed by British economist Ralph Turvey.[1] His method assumes that an increase in demand is met by moving the future plants of an expansion plan toward the present by one year.

For each power plant that is brought forward, a series of sequential calculations is performed:

1. The capital cost of each plant J, CGP(J), is annualized using the interest rate on borrowed capital, IR, and the lifetime of the plant, NYA(J). The annualized cost, ACC, is given as:

$$ACC = CGP(J) * \frac{IR}{1 - (1 + IR)^{-NYA(J)}} \qquad (1)$$

   The term in parentheses is the capital recovery factor which equals 0.1061 for an interest rate of 10% and a plant lifetime of 30 years.

2. An annualized cost covering the increase in generation capacity, CIGC, is then found by combining the annualized capital cost with the annual fixed operation and maintenance cost of each plant, AFOM(J), and then subtracting off the total fuel savings, PVFS, to be credited from having brought a newer, more efficient plant on line one year earlier:

$$CIGC = ACC + AFOM(J) - PVFS \qquad (2)$$

   The fuel savings can be obtained from estimates of system dispatchers or from a computer simulation of the generation system. The MARC-3A program (see Chapter 3) can be used in the latter instance. Running a simulation of the generation system twice for the year the new plant is to come on line, once with and once without the new plant in the mix, provides an estimate of the fuel savings as is shown in Table 10-1. This procedure, however, assumes only one year of such a savings when in fact the fuel savings may extend over the lifetime of the plant. The MARGINALCOST program provides for several years of fuel savings by discounting each yearly fuel savings of a plant to the first year the plant comes on line. Then it sums these "present" costs over all years to get a total fuel savings, PVFS, for the plant J:

$$PVFS = \sum_{I=1}^{NY(J)} \frac{FS\ (J,I)}{(1 + IR)^{I-1}} \qquad (3)$$

Table 1 Sample Calculation of Fuel Savings for One Plant by the MARC 3A Code

Simulation Year 1978	Generated System Output (MWh)	Total System Costs* ($)
Without New Plant	12,701,164	147,388,330
With New Plant	12,701,164	142,897,568
	Difference	$ 4,490,762

* Covering only fuel, variable operation, and maintenance costs.

Estimated Fuel Savings for Plant:

Difference = $4,490,762

3. Since the costs used in Equation (2) may be in either "present" or future dollars for the year a new plant is due to come on line, two options are available for adjusting the cost of increased generation capacity to a present cost.

   A) If the costs of the new plant are in future dollars for the year the new plant is to come on line, then they are discounted back to the present by modifying Equation (2),

$$CIGC = \frac{ACC \quad AFOM(J) - PVFS}{(1 + IR)^{FY(Plant) - FY(1)}} \tag{4}$$

   The terms FY(Plant) and FY(1) of the discounting factor in the denominator are respectively the years a particular plant and the first plant of an expansion plan are to come on line.

   B) If the costs of the new plant are in present dollars, then the FY's in Equation (3) are taken to be zero and Equation (2) can be used.

After Steps 1,2, and 3 have been exercised for each plant, the total annual cost of increased generation capacity is then determined for the expansion plan on a per kilowatt basis. This is achieved by summing the costs of increased capacity over all plants and dividing this result by the total service capacity of all the plants adjusted for a margin of available reserve, RM. The result for the annual cost of increasing generation capacity per kilowatt, AGCKW, is expressed as:

$$AGCKW = \frac{\text{(Sum of CGIC over all new plants) (1 + RM)}}{\text{(Sum of KW capacity over all new plants)}} \quad (5)$$

A maximum of five plants may be considered in this calculation.

The expression in Equation (5) would be the marginal cost of generation were it not for losses over the transmission and distribution system. To account for these, the annual cost per KW of increased generation capacity is refined by the demand-related cumulative loss multipliers to give the marginal cost of generation for each voltage level of service J:

$$MKWGC(J) = AGCKW * CALDP(J). \quad (6)$$

Table 2 Calculation of the Demand Loss Multipliers Case Where Loss/Load Ratios Are Exactly Known

Voltage Level	Loss / Load	Simple Loss Multiplier for Peak Demand	Cummulative Loss Multiplier for Peak Demand
J	LOLP(J)	ALMDP(J)	CALDP(J)
1	.0259	1.0266	1.0266
2	.0398	1.0415	1.0692 (1.0415 x 1.0266)
3	.0520	1.0548	1.1278 (1.0548 x 1.0415 x 1.0266)

Marginal Cost of Generation for 1977 for DP&L is calculated based on the cost data in Table 3 as:

$$\frac{\$14{,}784{,}000 + \$19{,}640{,}000}{800{,}000 \text{ KW} + 800{,}000 \text{ KW}} (1 + .15) = \$24.742/\text{KW}.$$

For low voltage users this cost can be refined by using the cumulative loss multiplier for low voltage service determined in Table 2.

For this case the marginal cost of generation for low voltage users is found to be:

$$\$24.742/KW \times 1.1278$$

or:

$$\$27.904/KW.$$

Table 3 Calculation of the Marginal Cost of Generation for Two Plants Brought Forward for the Case Where the Input Generation Costs are in Present (1977) Dollars*

Item	Coal Plant (On Line in 1977)	Nuclear Plant (On Line in 1980)
1) Capital Cost	$240,000,000	$400,000,000
2) Capacity	800,000 KW	800,000 KW
3) Annual Capital Cost **	$ 25,464,000	$ 42,440,000
4) Annual Fixed Operation and Maintenance Cost	$ 1,320,000	$ 1,200,000
5) Fuel Savings	$ 12,000,000	$ 24,000,000
6) Cost of Increased Generation Capacity = (3) + (4) - (5)	$ 14,784,000	$ 19,640,000
7) Reserve Margin	15%	15%

* Costs listed are rounded-off figures taken from a variety of sources.

** Determined from an annuity factor (.1061) based on 3-year life and a 10% interest rate

10.5 Computation of the Marginal Cost of Transmission and Distribution

The Turvey approach is again applied in the program for the case of transmission and distribution. For each voltage level of service, planned facilities are assumed to be brought forward in time to serve an increased demand. The program allows a maximum of five facilities per voltage level to be used. A sample of transmission and distribution facilities is illustrated in Table 4.

Table 4 Sample Transmission and Distribution Facilities for Some Major Voltage Levels of Service

Voltage Stage	Voltage Level	Transmission - Distribution Facilities Providing Service	Unit Of Facility Capacity
Power Supply	345 KV	345 KV Transmission Lines 345 - 138 KV Substations	Line Mile KVA*
High	69 KV	The Above, Plus 138 KV Transmission Lines 69 KV Transmission Lines Transmission Substations	 Line Mile Line Mile KVA
Primary	13 KV	The Above, Plus 13 KV Distribution Lines Distribution Substations Line Capacitors	 Line Mile KVA KW
Low	220/120v	The Above, Plus Line Transformers	 KVA

* KVA = Kilovolt-ampere

The methodology used to determine the marginal cost of transmission and distribution may be summarized in five major steps:

1. The annualized cost of providing an additional unit of facility capacity (e.g. line mile of cable wire of KVA of substation capacity) is found:

$$\frac{\$}{\text{Unit of Facility Capacity}} .$$

2. For a particular transmission and distribution facility at a given voltage level, the additional capacity of that facility necessary to service one additional kilowatt for use is found. It is assumed that the expansion of each transmission and distribution facility varies directly with the increase in the total load that it serves during the peak period, namely,

$$\frac{\text{Increase in Facility Capacity}}{\text{1 KW of Additional Demand}} = \text{Constant.}$$

3. From the results above, the annual cost of providing enough capacity for a given facility to serve 1 KW of demand is determined as:

$$\frac{\text{Increase in Facility Capacity}}{\text{1 KW of Additional Demand}} \times \frac{\$}{\text{Unit of Facility Capacity}}$$

$$= \frac{\$}{\text{KW}} .$$

4. For each voltage level of service, Steps 1 to 3 are performed for each facility. These incremental costs are then summed over all facilities at each voltage stage to get a total incremental cost for the facilities at that level.

5. Finally, the marginal cost for a particular voltage level is determined by adding the total incremental cost covering all facilities at that level with the corresponding total incremental facility cost (adjusted for power line losses) of all those voltage levels which are higher.

It should be noted that the procedure outlined above assumes a hierarchical structure of the transmission and distribution system whereby an increase in facility capacity at the low voltage stage requires an increase in facility capacity at higher voltage states. As a first approximation, such an assumption may be justified. However, such a model is not exactly correct because expensive segments of the higher voltage network cannot be fairly allocated to any one particular group of customers. Moreover, such portions of the network may not be in the direct lineage between low voltage customers and the generating plant.

A sample calculation of the marginal transmission and distribution is illustrated in Tables 5 through 7.

10.6 Computation of the Number of Hours in the Pricing Periods and the Marginal Cost of Energy (Running Costs)

Marginal energy or running costs are associated with the cost of running existing plants more to provide additional energy (kWh). Such costs are independent of capacity costs and include mostly fuel costs along with some variable operation and maintenance expenses. To some degree, they depend on the length of the pricing periods, namely, peak and off-peak.

The number of pricing periods, each being designated as "peak" or "off-peak", must be defined as illustrated in Table 8. Such a description for each period allows the MARGINALCOST program to group the hours of the year, taking particular account of holiday hours. A maximum of six pricing periods can be considered. Choices may be made according to season as well as time of day. Possible references for use in identifying the peak periods include load curves over selected periods, plant maintenance schedule, and historical data of seasonal, monthly, weekly, or daily peaks.

For each pricing period, incremental costs must be specified for determining the marginal cost of energy, or marginal running cost. These costs are called "incremental fuel costs" but in fact are meant to include a small portion of variable operation and maintenance expenses.

The MARGINALCOST program does not provide any way to determine these incremental costs for the marginal cost of energy. Like the fuel savings, they can be either estimated by system dispatchers or determined from a computer program simulation of the system. The latter can be done by a slight modification of the MARC-3A prgram described in Chapter 3. Using periodic system load data, the planned maintenance schedule and loading order or plants, and the incremental costs of each plant covering fuel, operation, and maintenance expenses, the MARC-3A program determines the system generated output and incremental cost for each hour of the year.

Table 5 Facility Costs Used to Determine the Marginal Cost of Transmissin and Distribution*

Voltage Level I	Number Of Types Of Facilities (Table 1-15) NF(I)	Capital Cost Per Unit of Facility Capacity ($/Unit) CCUF(I,J),J=1,NF(I)	Annualized Capital Cost Of Facility** ($/Unit) CCUF(I,J)*CRF	Annual Fixed Operation and Maintenance Cost Per Unit Of Facility Capacity ($/Unit) AOMCF(I,J)	Total Annual Cost Per Unit Of Facility Capacity ($/Unit) ACUF(I,J)
69 KV	3	80,000.00	8,486.34	250.00	8,736.34
(1)		50,000.00	5,303.96	350.00	5,653.96
		14.00	1.49	0.35	1.84
12.5 KV	3	10,000.00	1,043.14	300.00	1,343.14
(2)		16.00	1.70	0.50	2.20
		2.00	.21	0.01	0.22
220/ 120 V (3)	1	30.00	3.18	0.25	3.43

* Based on a variety of sources including Reference 1 and 3.

** Determined from a capital recovery factor based on a 30-year life and a 10% interest rate.

Table 6 Computation of the Costs of Increasing Transmission and Distribution Capacity With the Use of Historical Data

Voltage Level I	Total Annual Cost Per Unit Of Facility Capacity ($/Unit) ACUF(I,J)	Facility Capacity Increase Per KW of Demand (from Historical Data) (Units/KW)* EUFKW(I,J)	Cost of Increasing Facility Capacity Per KW of Demand ($/KW) ACUF(I,J)*EUFKW(I,J)
1	8,736.34	1.2392×10^{-4}	1.083
(3 Facilities)	5,653.96	1.1859×10^{-4}	.671
	1.84	2.4830	4.569
Total Cost of Increasing Capacity of Facilities at 69 KV Level			6.323
2	1,343.14	2.5216×10^{-3}	3.387
(3 Facilities)	2.20	6.7730	14.901
	0.22	0.2790	.061
Total Cost of Increasing Capacity of Facilities at 12.5 KV Level			18.349
3	3.43	5.2874	18.136
Total Cost of Increasing Capacity of Facilities at Low Voltage Level			18.136

* Based on the slope of the line best fitting historical customer load and facility capacity data.

Table 7 Computation of the Marginal Cost of Transmission and Distribution Using the Results of Table 6

Voltage Level	Total Cost Of Increasing Capacity of Voltage Level Facilities ($/KW)	Simple Loss Multipliers (from Table 1-2)	Marginal Cost ($/KW)
I	CKWTD(I)	ALMDP(I)	MKWTD(I)
1 (69KV)	6.323	1.0266	6.323*
2 (12.5KV)	18.349	1.0415	24.934**
3 (220/120v)	18.136	1.0548	44.437***

* MKWTD(1) = CKWTD(1)

** MKWTD(2) = MKWTD(1) * ALMDP(2) + CKWTD(2)

*** MKWTD(3) = MKWTD(2) * ALMDP(3) + CKWTD(3)

Table 9 Marginal Cost of Energy According to Voltage Level and Period of Service

Period Description (P) = On Peak (O) = Off Peak	Voltage Level	Incremental Running Cost From MARC 3A Code (¢/kWh)	Cumulative Marginal Loss Multiplier (Table 1-5)	Marginal Cost Of Energy (¢/kWh)
(1)	(2)	(3)	(4)	(3) x (4)
Nov. 15 to Mar. 14 (P)	High	1.268	1.0546	1.337
Monday thru Friday (Excluding Holidays)	Primary	1.268	1.1558	1.466
10 a.m. to 6 p.m.	Low	1.268	1.2900	1.636
All Hours of	High	0.994	1.0293	1.023
Weekends and	Primary	0.994	1.0764	1.070
Holidays (O)	Low	0.994	1.1417	1.135

Table 8 Incremental Costs Associated with Fuel Variable Operation and Maintenance Expenses Computed by the MARC 3A Code for Selected Periods Using Data from Dayton Power and Light

Period Description (P) = On Peak (O) = Off Peak	Incremental Cost ($/kWH)
Nov. 15 to Mar. 14 (P) Monday thru Friday* 10 a.m. to 6 p.m.	1.268
May 15 to Sept. 14 (P) Monday thru Friday* 10 a.m. to 6 p.m.	1.268
Nov. 15 to Mar. 14 (O) Monday thru Friday* 6 p.m. to 10 a.m.	1.112
May 15 to Sept. 14 (O) Monday thru Friday* 6 p.m. to 10 a.m.	1.066
Mar. 15 to May 14 (O) Sept. 15 to Nov. 14 (O) All Hours. Mon. thru Fri.*	1.102
All Hours of Weekends and Holidays (O)	0.994

* Excluding Holidays

Marginal loss multipliers are used to refine the incremental fuel costs of the MARC-3A program to determine the marginal cost of energy. Because such loss factors are energy-related and are determined separately for peak and off-peak periods, they enable a marginal energy cost to be determined for each pricing period and voltage level of service. In the MARGINALCOST program this is determined in the following way.

For each voltage level, I (I - 1,NVL), and pricing period, J (J = 1,NPER), the marginal cost of energy per kWh, MEKWH(I,J), is found for peak periods by:

$$MEKWH(I,J) = (CKWH(J) * CMLEP(I), \tag{7}$$

and for off-peak periods by:

$$MEKWH(I,J) = ICKWH(J) * CMLEO(I). \tag{8}$$

In each of these equations ICKWH(J) is the incremental fuel cost per kWh for the period J and CMLEP(I) and CMLEO(I) are the respective cumumative marginal loss multipliers on and off peak for voltage level I.

Using sample results of incremental fuel costs from the MARC-3A program along with the cumulative marginal loss multipliers of Table 2. the marginal cost of energy is computed for a peak winter period and an annual off-peak period in Table 9.

10.7 Computation of the Total Marginal Cost

The MARGINALCOST program determines the total marginal cost of producing an extra kWh for service by combining the marginal capacity costs for each period with the marginal energy cost.

For each peak period and voltage level of service, I (I = 1,NVL), the capacity costs are first spread over the total annual peak hours, HRSPK, and converted to a cost per kWh. The marginal cost in ¢/kWh for peak generation, MKWHG(I), is determined from the $/KW cost by:

$$MKWHG(I) = \frac{100 * MKWGC(I)}{HRSPK} \tag{9}$$

and the marginal cost in ¢/kWh for peak transmission and distribution, MKWHT(I), is determined from the $/KW cost by:

$$\mathrm{MKWHT(I)} = \frac{100 * \mathrm{MKWTD(I)}}{\mathrm{HRSPK}} \quad . \qquad (10)$$

These results are then combined with the marginal energy cost of a particular peak period and voltage level to give the total marginal cost, TOTMC(I).

For off-peak times, the MARGINALCOST program assumed no capacity costs and takes the marginal energy costs for these times to be the total marginal cost. In summary, the total marginal costs for peak and off-peak periods are calculated for each voltage level I(= 1,NVL) as follows:

For peak periods:

TOTMC(I) = MKWHG(I) (generation)
(Total) +
MKWHT(I) (transmission & distribution)
+
MEKWH(I,peak period)
(energy) (11)

For off-peak periods:

TOTMC(I) = MEKWH(I, off-peak period)
(Total) (energy) (12)

A sample calculation of the total marginal cost using the steps described above is provided in Table 10. Results are given only for low voltage users using the sample marginal capacity and energy costs calculated throughout this chapter.

Table 10 Calculation of the Total Marginal Cost for Low Voltage Users

1. For Peak Periods		
Marginal Capacity Costs:		
A. Generation (Table 1-11):	$27.904/KW	
B. Transmission and Distribution (Table 1-21): (for Historical Data)	44.437/KW	
Total Marginal Capacity Cost:	$72.341/KW	(1)
Annual Number of Peak Hours (for the winter period days and summer period days specified in Table 1-25):	(664 + 688) = 1352 hrs.	(2)
Spreading Capacity Costs Over the Annual Peak Hours, (1) ÷ (2):	5.351 ¢/kWh	(3)
Marginal Energy Cost (e.g., for winter day period of Table 1-26):	1.636 ¢/kWh	(4)
Total Marginal Cost (for winter day period), (3) + (4):	6.987 ¢/kWh	
2. For Off-Peak Periods		
Marginal Capacity Costs:	NONE	
Marginal Energy Cost (e.g., for the off-peak winter night periods, from Tables 1-5 and 1-25):	1.270 ¢/kWh	
Total Marginal Cost (for the off-peak winter night period):	1.270 ¢/kWh	

References

(1) D. Z. Czamanski, J. S. Henderson, and K. A, Kelly, Electricity Pricing Policies For Ohio, prepared for the PUCO by The Ohio State University, October, 1977.

(2) S. H. Storch, A Method For Computing The Long-Run Marginal Cost of Electricity, Master's Thesis, The Ohio State University, June, 1977.

(3) C. J. Cicchetti, W. J. Gillen and P. Smolinsky, The Marginal Cost and Pricing of Electricity, An Applied Approach, National Science Foundation (1976).

CHAPTER 11
PEAK PROBABILITY PROGRAM

11.1 Introduction

The purpose of the Peak Probability Program (PPP)[1] is to analyze the hourly system load data of an electric utility to determine on a monthly basis the range of hours during the day in which the daily peak is most likely to occur. This chapter explains the operation and use of the program.

Section 11.2 describes the methodology of the calculation. Section 11.3 deals with the required input data and its format. The third section discusses the operation of the program in batch and TSO mode. A flow chart of the program is listed in Appendix 11A. A listing of the program with output provided in Reference 1.

11.2 Program Methodology

In general the program keeps track of the number of times the hourly system load is greater than a user supplied load level by the time-of-day and day of the week. From this tabulation, the probability that the system load is greater than a user determined base is calculated for each hour of each day (Mon-Fri) for each month of the year. These probabilities are then used to calculate the cumulative probability that they system load will be above a given level during any span of hour for weekdays.

A sample output from these calculations is shown in Figure 1. The first table lists the number of times the system load exceeded, in this case, 1450 MW for each hour of each Monday-Sunday in July 1974, and the total number of times for each hour for the five weekdays. The second table is, for weekdays only, the ratio of the number of times the system load was above 1450 MW in a given hour to the total number of times it was above 1450 MW. The last table is the cumulative probability for weekdays. This table aids the program user in determining, for a given confidence level, the range of hours for which the load exceeded 1450 MW. For example, if the user wants to determine the range of hours for which he would be 95% confident that the system load would exceed 1450 MW, he would consult the table looking for the value 0.95 to

JULY 1976 DPL76L PEAK LOAD- 1793 MWS ON THUR THE 15 AT 16 HOURS.

THE PROBABILITY THAT THE LOAD WAS GREATER THAN 1650MWS DURING THE MONTH IS .162
BASED ON A PERIOD OF 117 HOURS.

THE LOAD EXCEEDED 1650MWS FOR 19 WEEKDAY HOURS DURING JULY 1976

THE NUMBER OF HOURS THE LOAD EXCEEDED 1650MWS DURING EACH HOUR OF THE DAY

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
MON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TUES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0
THUR	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0
FRI	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0
SAT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
M--F	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	3	3	3	1	0	0	0	0	0

THE PROBABILITY THAT THE LOAD WAS GREATER THAN 1650MWS BASED ON A PERIOD OF 19 HOURS

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
MON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TUES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.05	0.05	0.05	0.0	0.0	0.0	0.0	0.0	0.0
THUR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.0	0.0	0.0	0.0	0.0	0.0
FRI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.0	0.0	0.0	0.0	0.0
M--F	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.05	0.11	0.11	0.11	0.11	0.16	0.16	0.16	0.05	0.0	0.0	0.0	0.0	0.0

CUMULATIVE PROBABILITY THAT FOR ANY RANGE OF WEEKDAY HOURS THE LOAD EXCEEDED 1650MWS

HR/HR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0.0																							
2	0.0	0.0																						
3	0.0	0.0	0.0																					
4	0.0	0.0	0.0	0.0																				
5	0.0	0.0	0.0	0.0	0.0																			
6	0.0	0.0	0.0	0.0	0.0	0.0																		
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0																	
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0																
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0															
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0														
11	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05													
12	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.11												
13	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.21	0.11											
14	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.32	0.21	0.11										
15	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.42	0.32	0.21	0.11									
16	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.58	0.47	0.37	0.26	0.16								
17	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.74	0.63	0.53	0.42	0.32	0.16							
18	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.89	0.79	0.68	0.58	0.47	0.32	0.16						
19	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.84	0.74	0.63	0.53	0.37	0.21	0.05					
20	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.84	0.74	0.63	0.53	0.37	0.21	0.05	0.0				
21	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.84	0.74	0.63	0.53	0.37	0.21	0.05	0.0	0.0			
22	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.84	0.74	0.63	0.53	0.37	0.21	0.05	0.0	0.0	0.0		
23	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.84	0.74	0.63	0.53	0.37	0.21	0.05	0.0	0.0	0.0	0.0	
24	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.84	0.74	0.63	0.53	0.37	0.21	0.05	0.0	0.0	0.0	0.0	0.0

RERUN?

Figure 1

find the range of hours. In this case, one range would be from the hour ending at 10:00 a.m. to the hour ending at 8:00 p.m.

The program operation starts by reading in the hourly load data, supplied by the user in the Edison Electric Institute format (see Section 11.3), as well as a code indicating which day of the week the load data is for (1 = Monday, 7 = Sunday, 8 = Holiday). This load data is stored in the array LOAD indexed by month, day, and hour. The day of the week information is stored in the array DAY indexed by month and day. The LOAD array is then searched to find the peak load for each month. The peak load, and the hour and day on which that load occurs are stored respectively in arrays PEAK, PKHR, and PKDA for later use.

The user now enters the load level for which the program calculates the probability that the system load will exceed that level. This number can be supplied in two forms. If the user inputs a value greater than 100, the program treats that as a load level. If the number is less than 100, the program treats that as a percentage of the monthly peak. This value is stored in the program as PCPEAK and is later defined as LEVEL.

At this point the code initializes cumulative variables and then searches each month for load levels above LEVEL. If the load exceeds LEVEL that information is stored in array HOUR by month, day of week, and hour. The total for each week, day and hour is also maintained in array HOUR.

The probability of the system load exceeding LEVEL for each week-day hour is calculated by dividing the appropriate array element of HOUR by HRLEV, the total number of hours the sytem load exceeds LEVEL. This information is stored in the array PROB indexed by month, day of week, and hour. The total hourly probability is also stored in PROB.

The cumulative probability that the system load will exceed LEVEL over a given range of hours is calculated by summing the probability of the system load exceeding LEVEL for weekdays over the desired range of hours. Mathematically, to find the probability that the system load exceeded LEVEL during the period beginning with the ith hour and ending at the jth hour, calculate

$$\mathrm{CUMLA}(i,j) = \sum_{k=i+1}^{j} \mathrm{PROB}(\mathrm{MO},8,k).$$

11.3 Data Requirements

The non-load data which are used in the program are listed in Table 1.

Table 1 Input Data Requirements

Variable Name	Description	Format
YEAR	Year of Study	A4
COMPNA	The Name of the Company or the load data set name if the PDSIN subroutine is used	A8
PCPEAK	If ≥100, the level to compare the system load data to. If <100, the percentage of the monthly peak to compare the load data to.	F6.0

The variables YEAR and COMPNA are entered at the beginning of the program. They are used for information in the output table. The variable year is entered as a four digit number but read by the program as an alphabetic character. The variable COMPNA can be up to eight characters in length, left justified in the field. The variable PCPEAK is entered at least once but can be entered at the end of each run so that analysis at numerous load levels can be accomplished. It is entered as a floating point number with decimal point. If the percentage feature is used the program divides the entered number by 100 to obtain the fractional value of the peak used to determine the value for LEVEL.

The load data is supplied in the reporting format determined by the Edison Electric Institute (EEI). This format, as shown in Table 2, consists of two cards per day which contain the load information as well as time zone, temperature, and day of week information.

Table 2 Organization of EEI Load Cards

Column Number(s)	Description of Parameter	Reading Format
CARD 1		
1-2	Month	I2
3-4	Day	I2
5-6	Year	I2
7	#1 for A.M.	I1
8-15	EEI Code Number for Utility	I8
16	Day of Week 0=Dummy Day; 1=Monday; 7=Sunday; 8=Holiday	I9
17	Time Zone 1=EST; 2=EDT	I1
18-20	Blank	3X
21-80	Hourly Load in Terms of MWH/HR. for the hours ending at 1:00 a.m. through 12 noon. Each load is given five columns and is right justified.	12I5 or 12F5.0
CARD 2		
1-6	Same as Card 1	3I2
7	#2 for P.M.	I1
8-10	First three digits of EEI utility ID number	I3
11-13	Average temperature for the day	I3
14-16	Departure from normal average for that day	I3
17-20	Blank	4X
21-80	Same as Card 1 for the hour ending 1:00 p.m. through 12 midnight	12I5 or 12F5.0

This program utilizes the load data and the day of week information for the EEI load cards.

11.4 Program Operation

The program is designed to operate in batch mode on an IBM System 370/165 computer using the FORTRAN complier. For operation at The Ohio State University computer center the program uses a library subroutine called PDSIN. Since the load data is stored in disk space as part of a partitioned data set, the PDSIN subroutine is used to correctly address the requested partition. If this subroutine is not required, the statement which calls it should be removed.†

As described in the previous section, there are three input variable values supplied by the user as well as the load data. The program uses logical unit 5 (the normal card reader) as the input device for reading variables YEAR, COMPNA, and PCPEAK. Logical unit 10 is used for reading the load data and day information.

The job control language (JCL) for running the code is shown in Figure 11-2.

```
//EXEC PROC=FORTRUN
//CMP.SYSIN DD*
        :
Program Cards
        :
/*
                      DSN = PUCO.DATA,DISP = SHR, LABEL = (,,,IN)
//GO.FT10F001 DD    {       used with partitioned data set
                           *is used when card reader is desired
//GO.SYSIN DD*
        :             YEAR
Data Cards          { COMPNA
        :             PCPEAK
/*
//
```

Figure11-2 JCL for Peak Probability Program

This program is also available throught the time sharing option of the OSU IBM 370/165 computer. Using the time sharing option allows for easy access to the program,but because of the slow speed of the printer

† When a program which uses a special subroutine such as PDSIN is supplied to other agencies, these options are replaced with techniques with known universal application. In most cases the use of disk storage will be replaced with a card reader.

more time is required to achieve the amount of output data batch processing yields. For this reason the program has been modified to be more specific in the choice of output. The user can specify which month he wishes to have output for and which tables.

Once the user has completed the "logic" procedure the following command sequence is required for program operation:[††]

```
term   line size ('130')
READY
alloc da('puco.data')  f(ft10f001)
READY
loadgo 'puco.peakprob.obj'
```

The program will then ask for input data by variable name as shown in Figure 3 with example response. It will also ask for the output required. As shown in Figure 11-3, these output questions consist of asking for the number of tables (NO. TABLES?). The first entry is the number of tables; the following entries are the table numbers.

```
YEAR?
1976
Company name (COMPNA)
dpl/61
NO. TABLES?
2 - number of table numbers to follow - to specify all
    tables enter 3
1 - for Table 1
3 - for Table 3
Number of months?
4 - number of month(s) - to specifiy all months enter 12
6
7
8
12
PCPEAK?
1650
:
output
:
RERUN?
/*   Ends Program
number>1.0 is used as PCPEAK and the previously defined
  output format is used
number≤1.0 the program asks for the output format.
```

Figure 3 Data Entry from TSO Terminal

[††] Small case letters are operator entered, large case are computer responses.

If all the tables are required enter the number 3. The computer will respond with the next question. If the number 0 is entered the output will be the non-table information.

After the table information has been entered the computer will ask for the number of months for which the output information is required (NO.MONTHS?). This number is entered followed by the number corresponding to the months desired.

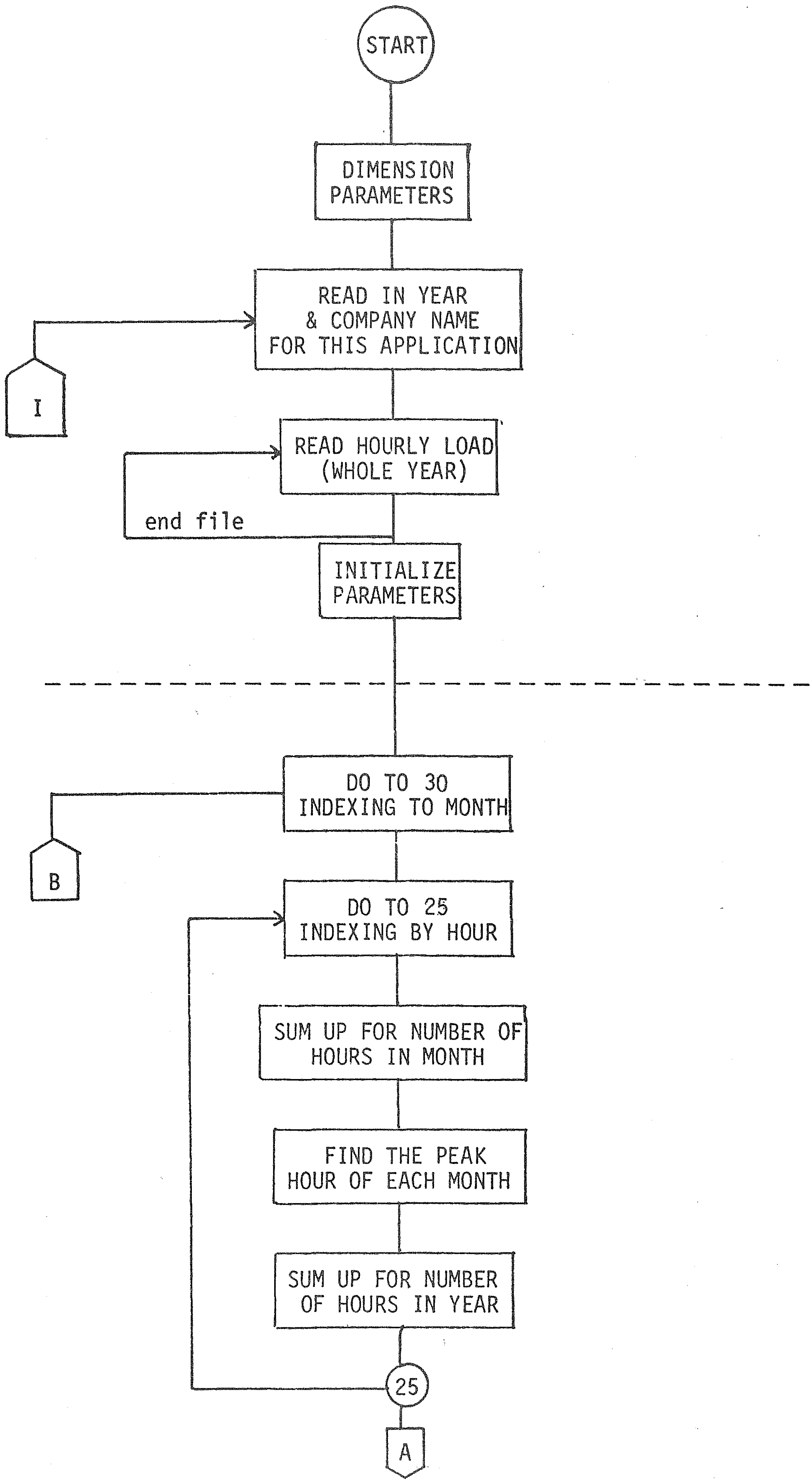
The last input variable required before the output is printed is PCPEAK. At the conclusion of printing the output the computer asks the question "RERUN?"; three possible responses to this are:

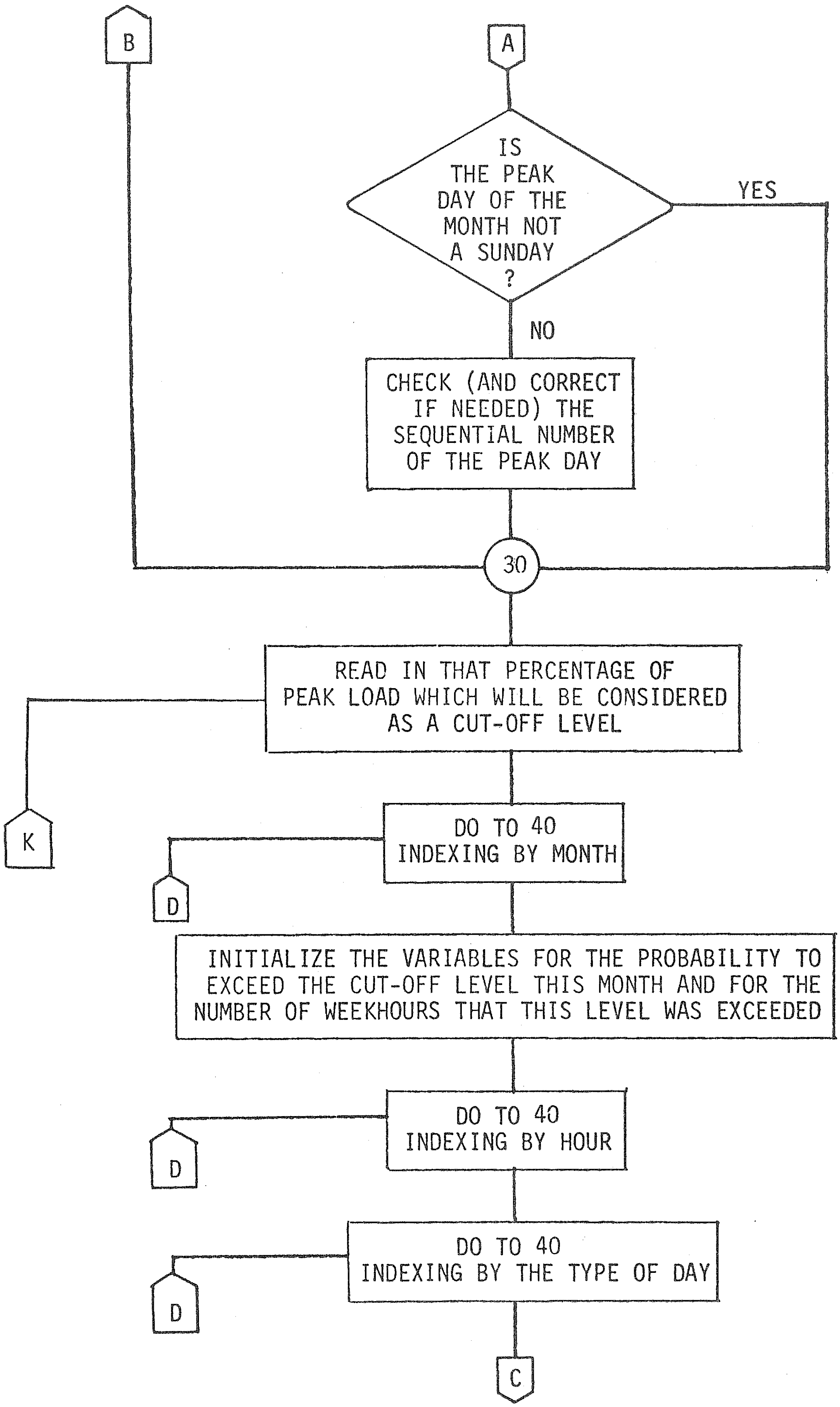
1. type * to end the program
2. enter a number, with decimal point, that is greater than 1.0; the program will act as if the variable PCPEAK had been entered. The output will be in the same format as previously requested.
3. enter 1.0.; the program will then ask for new output format information and the value for PCPEAK.

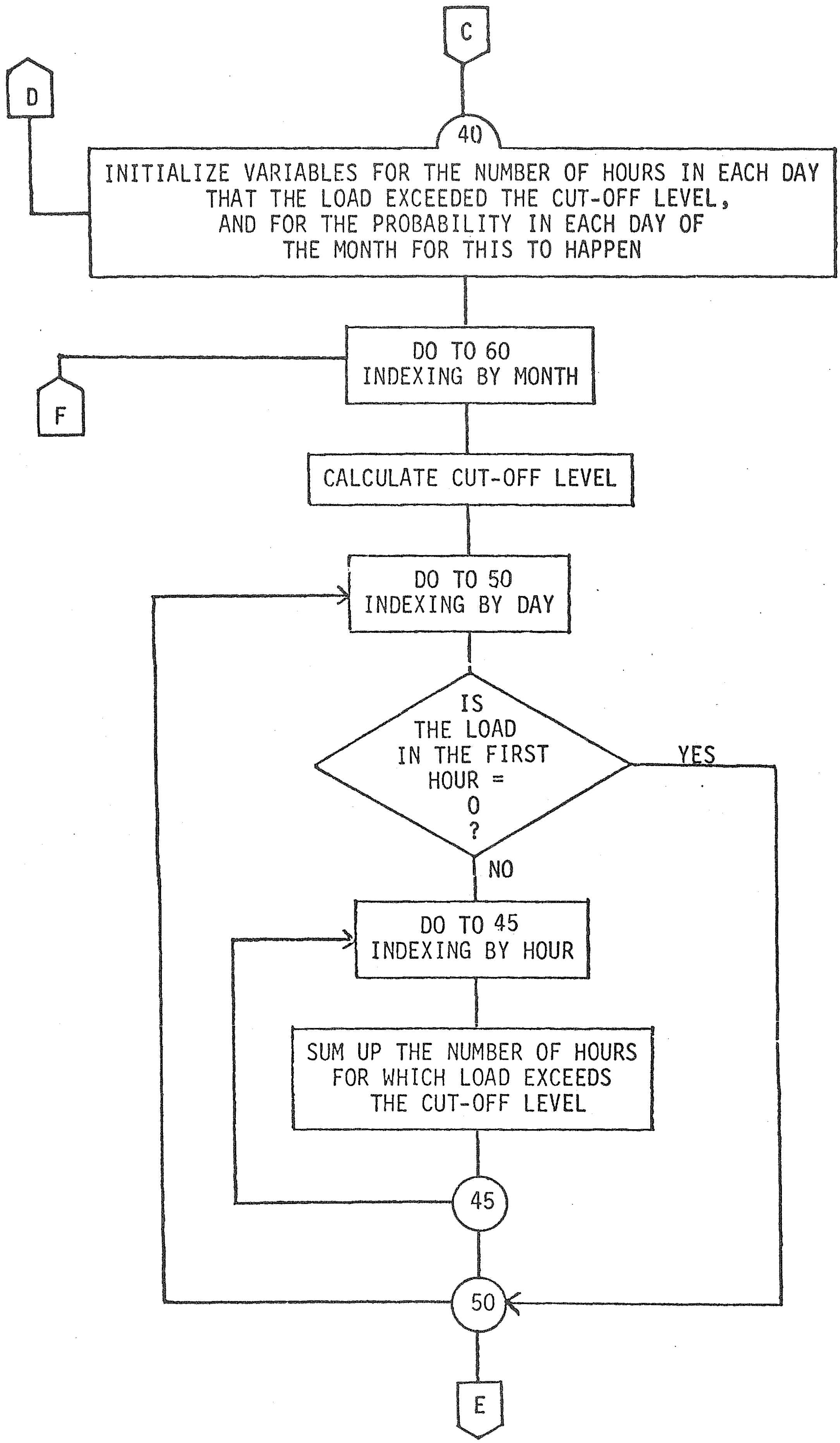
With these instructions and the following appendix the user of this program should have minimal problems.

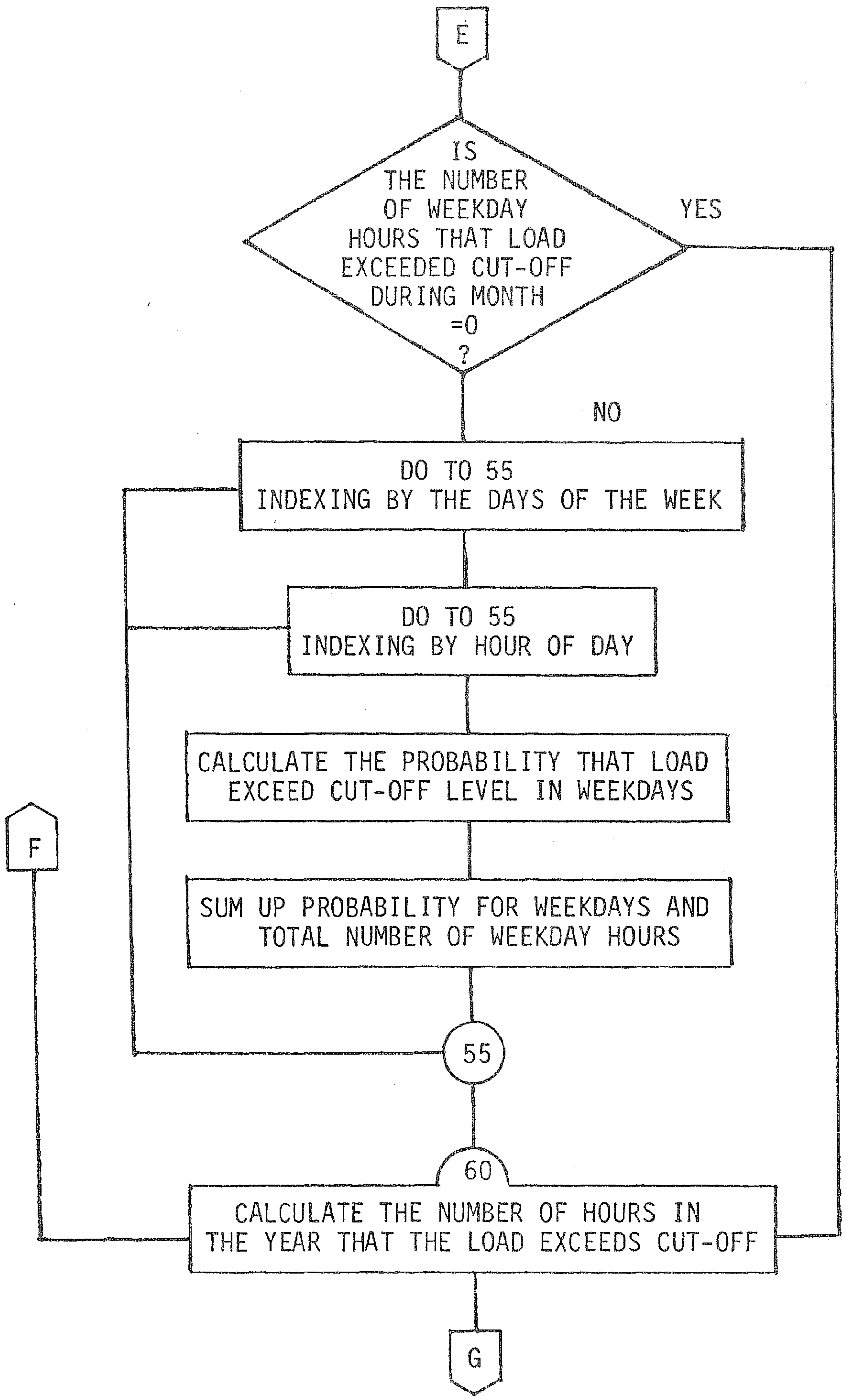
APPENDIX 11A

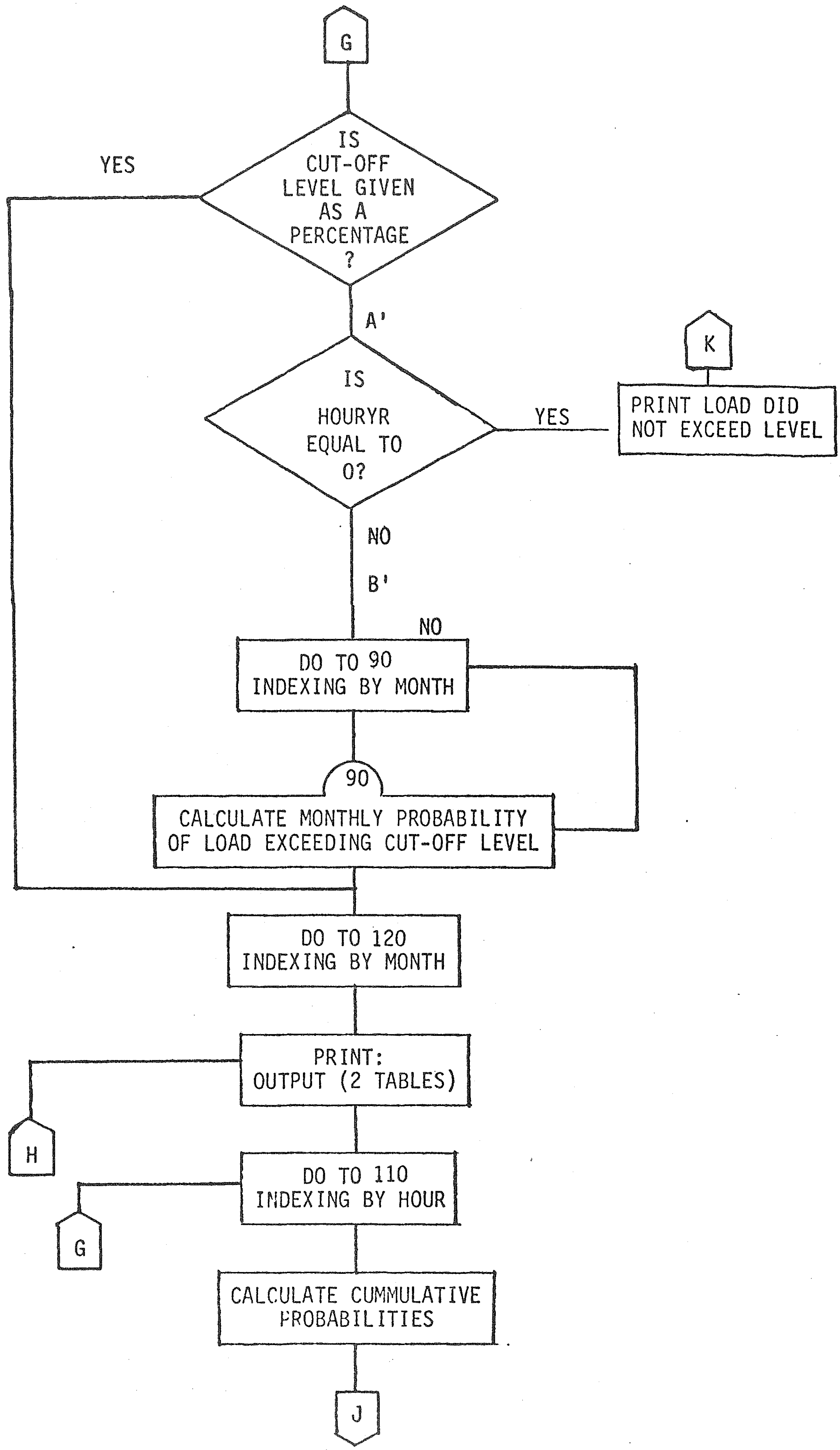
Flow Chart of the Peak Probability Program

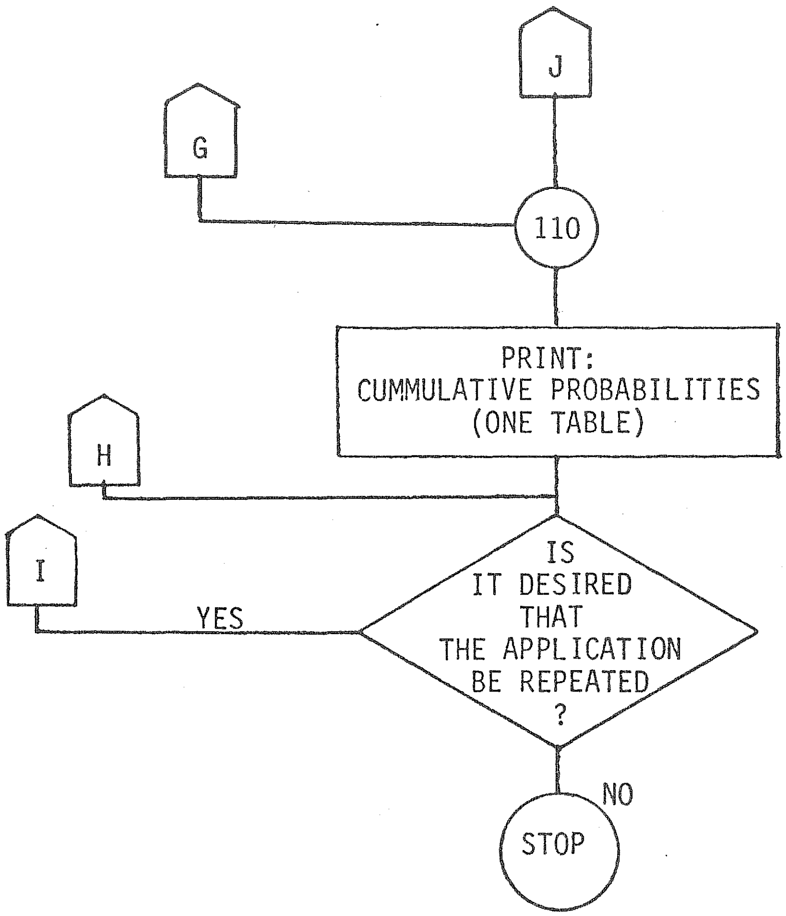

START
DIMENSION PARAMETERS
READ IN YEAR & COMPANY NAME FOR THIS APPLICATION
I
READ HOURLY LOAD (WHOLE YEAR)
end file
INITIALIZE PARAMETERS
DO TO 30 INDEXING TO MONTH
B
DO TO 25 INDEXING BY HOUR
SUM UP FOR NUMBER OF HOURS IN MONTH
FIND THE PEAK HOUR OF EACH MONTH
SUM UP FOR NUMBER OF HOURS IN YEAR
25
A


B
A
IS THE PEAK DAY OF THE MONTH NOT A SUNDAY ?
YES
NO
CHECK (AND CORRECT IF NEEDED) THE SEQUENTIAL NUMBER OF THE PEAK DAY
30
READ IN THAT PERCENTAGE OF PEAK LOAD WHICH WILL BE CONSIDERED AS A CUT-OFF LEVEL
K
DO TO 40
INDEXING BY MONTH
D
INITIALIZE THE VARIABLES FOR THE PROBABILITY TO EXCEED THE CUT-OFF LEVEL THIS MONTH AND FOR THE NUMBER OF WEEKHOURS THAT THIS LEVEL WAS EXCEEDED
DO TO 40
INDEXING BY HOUR
D
DO TO 40
INDEXING BY THE TYPE OF DAY
D
C


C
D
40
INITIALIZE VARIABLES FOR THE NUMBER OF HOURS IN EACH DAY THAT THE LOAD EXCEEDED THE CUT-OFF LEVEL, AND FOR THE PROBABILITY IN EACH DAY OF THE MONTH FOR THIS TO HAPPEN
DO TO 60 INDEXING BY MONTH
F
CALCULATE CUT-OFF LEVEL
DO TO 50 INDEXING BY DAY
IS THE LOAD IN THE FIRST HOUR = 0 ?
YES
NO
DO TO 45 INDEXING BY HOUR
SUM UP THE NUMBER OF HOURS FOR WHICH LOAD EXCEEDS THE CUT-OFF LEVEL
45
50
E


E
IS THE NUMBER OF WEEKDAY HOURS THAT LOAD EXCEEDED CUT-OFF DURING MONTH =0 ?
YES
NO
DO TO 55
INDEXING BY THE DAYS OF THE WEEK
DO TO 55
INDEXING BY HOUR OF DAY
CALCULATE THE PROBABILITY THAT LOAD EXCEED CUT-OFF LEVEL IN WEEKDAYS
F
SUM UP PROBABILITY FOR WEEKDAYS AND TOTAL NUMBER OF WEEKDAY HOURS
55
60
CALCULATE THE NUMBER OF HOURS IN THE YEAR THAT THE LOAD EXCEEDS CUT-OFF
G


G
IS CUT-OFF LEVEL GIVEN AS A PERCENTAGE ?
YES
A'
K
IS HOURYR EQUAL TO 0?
YES
PRINT LOAD DID NOT EXCEED LEVEL
NO
B'
NO
DO TO 90 INDEXING BY MONTH
90
CALCULATE MONTHLY PROBABILITY OF LOAD EXCEEDING CUT-OFF LEVEL
DO TO 120 INDEXING BY MONTH
PRINT: OUTPUT (2 TABLES)
H
DO TO 110 INDEXING BY HOUR
G
CALCULATE CUMMULATIVE PROBABILITIES
J


J
G
110
PRINT:
CUMMULATIVE PROBABILITIES
(ONE TABLE)
H
I
YES
IS
IT DESIRED
THAT
THE APPLICATION
BE REPEATED
?
NO
STOP

References

(1) "Operation Manual for the Peak Probability Program" The Ohio State University, Department of Mechanical Engineering, July 1977.

CHAPTER 12

SYSTEM LOAD CHARACTERISTICS OF ELECTRIC UTILITIES

12.1 Objectives

The objective of the study described in this chapter is to provide basic information to be used by the WASP code. In preparing the input for the WASP program, the load characteristics during a year are represented by the load duration curves of four periods† (seasons) in the year. It has been recognized that the definition of the four periods has a significant effect on the maintenance schedule which is automatically scheduled within the WASP program. The four periods must be defined in such a way that the maintenance spaces in the system capacity during the off-peak season are clearly recognized rather than based on the calendar.

As the model utilities, the CAPCO group and DP&L are selected. The present work consists of the four studies, each of which is reported in the subsequent sections. In Section 12.2, the characteristics of the weekly peak load for the CAPCO group is studied. In Section 12.4, four functional seasons (periods) are determined. In Section 12.5, the effects of component demand on load duration curves is studied.

12.2 Weekly Load Factor and Its Variation During a Year

The variation of the weekly load factor during a year and its relation to the yearly peak are studied in this section. The hourly load data of the CAPCO group for 1973 and 1974 is used as the data base.

The load factor in a period is defined as the average load versus the peak in the period. Using the hourly load data, the weekly load factor P(I) may be easily calculated, where I is the index to denote the week considered. The ratio of a weekly peak to the yearly peak R(I) is calculated by dividing the weekly load factor by the yearly peak. The product of P(I) and R(I) gives the ratio of the average weekly load

† Although WASP allows 12 subintervals in each year, four subintervals per year are used in the WASP applications described in the subsequent chapters.

to the yearly peak S(I). The average of S(I) for 52 weeks in a year becomes the yearly average load factor. Those three factors were calculated for 1973 and 1974 CAPCO loads. The results are shown in Figure 1 through 6.

In Figures 1 and 2, a low weekly load factor is indicative of high daily peaks in the week and accordingly a large fluctuation of load in the week. On the other hand, a high weekly load factor means a small fluctuation of load in the week. It is seen in Figures 1 and 2 that load fluctuation in a week is relatively small (high weekly load factor) during the 1st through 20th and 38th through 52nd weeks. The load fluctuation in a week is relatively high (low weekly load factor) during the 21st and 39th weeks. It should be noticed also that very low load factors occur in the weeks of special holidays as marked in Figures 1 and 2.

Figures 3 and 4 show that weekly peaks fluctuate rather violently during summer, but the fluctuation is much milder in other periods. The wild fluctuation during the summer is probably due to the response of air conditioning to the cycle of hot and cool weather. The ratio of weekly average to the yearly peak shown in Figures 5 and 6 fluctuate less significantly than the weekly peak. Nevertheless, the tendency of the fluctuation during summer is very similar to the weekly peak, thus reflecting the effect of weather variations.

12.3 Daily Variation of Loads in a Month

In order to study the variation of daily peak, average and minimum loads of CAPCO in typical months, January and July of 1973 and 1974 are chosen. The following three ratios for two weeks in January and July are shown in Figures 7 and 8:

Daily Peak/Daily Average
Daily Peak/Daily Minimum
Daily Peak/Yearly Peak

It is observed that the daily ratio of peak to average fluctuates very little even during weekends. This indicates that the hourly load shape varies little even if the average load or the peak load change from day to day.

12.4 Study on the Definition of Four Seasons

The objective of this section is to determine four seasons for use in the WASP code. The seasons may not have an equal length. In order to achieve this breakdown, three approaches are taken: (i) peak load frequency, (ii) load duration, and (iii) weekly peak cyclic variations. The final objective of these analyses is to develop normalized typical load duration curves for each season.

(i) Peak Load Frequency

In this approach the annual cyclic variations in peak loads are observed. The ratio of the daily peak load to the annual peak load, which we designate as the D.A. ratio, is taken. The year is divided into ten day time segments. The scale for the D.A. ratio is divided into equally spaced intervals of 0.03 width. In each ten day period, the number of counts that the D.A. ratios fall into each interval is taken. The results of this counting for all the ten day periods are shown in Table 1, 2, and 3 for CAPCO 1972, 1973 and 1974, respectively. These tables show rather clearly how a year should be divided into four intervals depending on the characteristics in each interval. The summer season is characterized by large fluctuations in the D.A. ratio, while the autumn season has relatively little fluctuation.

Two ways of defining the four seasons are shown below:

First Choice:

Winter	12/1 - 3/1	(91 days)
Spring	3/2 - 5/31	(91 days)
Summer	6/1 - 8/31	(92 days)
Autumn	9/1 - 11/30	(91 days)

Second Choice:

Winter and Spring:	same as above	
Summer	6/1 - 9/8	(100 days)
Autumn	9/9 - 11/30	(83 days)

In the above first choice, the lengths of each season are made almost equal. With this choice, however, often the autumn season will involve high D.A. ratio's which occur early in September. To avoid this problem, the summer period is made longer and the autumn period is made shorter in the second choice so that the autumn will be characterized by more uniform D.A. ratios.

(ii) Comparison of Yearly Variations in Normalized Seasonal Load Duration Curves

The purpose of this portion of the analysis is to determine the validity of the dates chosen in (i) by checking the shapes of normalized seasonal load duration curves for a few years. In order to observe the variation in the shape of these curves, new curves are generated which we designate as the load-duration-difference curve. The CAPCO 1972 load data was used as the data base. Each point on the 1973 and 1974 load duration curves was subtracted from the equivalent point on the 1972 CAPCO load duration curve to give the two load duration difference curves. These are shown in Figures 9 through 16.

An analysis of the results yields two conclusions. First, if the seasons are selected as suggested in Subsection (i) the normalized load duration curves change very little from year to year. Secondly, the positive to negative variation of the load-duration-difference curves indicates that the load duration curves for CAPCO 1972 and 1974 are flatter than the load duration curve for CAPCO 1972.

(iii) Variations of Weekly Peaks

It was attempted to determine the periods of seasons by another approach. In this attempt, weekly peak loads during a year are plotted in Figures 17 through Figure 20. The periods of four seasons are found by the following procedures:

(a) The local maximums and minimums of the plotted curve are found to be:

1/21, 4/23, 7/22 and 10/19

(The load duration curves for the four periods divided by those dates are shown in Figures 21 and 22 for reference.)

(b) Starting dates for the four seasons are found by advancing the above days by 45 days:

Winter	12/3 - 3/6
Spring	3/7 - 6/6

Summer	6/7 - 9/4
Autumn	9/5 - 12/2

It can be observed that the above definition of four seasons is in a reasonable agreement with that in Subsection (i).

12.5 Comparative Analysis of Load Duration Curves for Different Utilities

The objective of this section is to study the effects of component demand on the shape of seasonal load duration curves through the comparison of various CAPCO utilities whose component breakdowns are known. The load duration curves are compared on a seasonal basis so that any seasonal peculiarities associated with a particular utility may be observed.

(i) Approach

The four utilities considered in this study are Cleveland Electric Illuminating Company (CEI), Dayton Power and Light (DP&L), Duquesne and Ohio Edison (OHE). These four utilities were chosen in order to obtain an entire spectrum of component makeup. The entire component breakdown for CAPCO utilities is shown in Table 4 and 5. The three major demand components are residential, industrial and commercial.

The main effort of analysis is directed at determining the effects of the annual total industrial consumption versus the annual total residential/commercial consumption on the appearance of normalized load duration curves. For the purpose of comparison, the following ratios were calculated first based on the kWh sales for different customer categories:

$$\text{Ratio} = \frac{\text{Industrial Load}}{\text{Commercial Load} + \text{Residential Load}}$$

The kWh sale dates were taken from Ohio Power Siting Commission Form FE-1(c) and summarized in Table 4 and 5. The ratios thus calculated are shown below:

Utility	1973	1974
CEI	1.2170	1.127
Duquesne	0.9917	1.0355
DP&L	0.6233	0.5751
OHE	0.9586	0.9154

These ratios provide a basis of comparison between utilities based on the degree of industrialization. The seasonal load duration curves for these four utilities are shown in Figures 23 through 26.

(ii) Analysis of Result

The initial striking feature of the load duration curves is the fact the DP&L load duration curve is significantly lower and more steeply sloped than that of the other utilities for all seasons. This would indicate that commercial and residential loads provide greater fluctuation in load than the industrial load. On the basis of this, one would expect that CEI would have the flattest, and hence the highest load duration curve, although this is not exactly true. In fact, the Duquesne's load or Ohio Edison's load has less variation than CEI's in some seasons. Apparently other factors than simply industrial loads versus residnetial and commercial affect the load duration curves. The effects of local weather effects, type of industrial activities, the type of commercial activities (large office buildings versus small establishments, the business hours) and many other related factors influence the nature of the load duration curve. In order for a proper analysis to be made, the hourly component-load data should be collected for various types of industrial activities, various types of commercial enterprises and different categories of residential consumers.

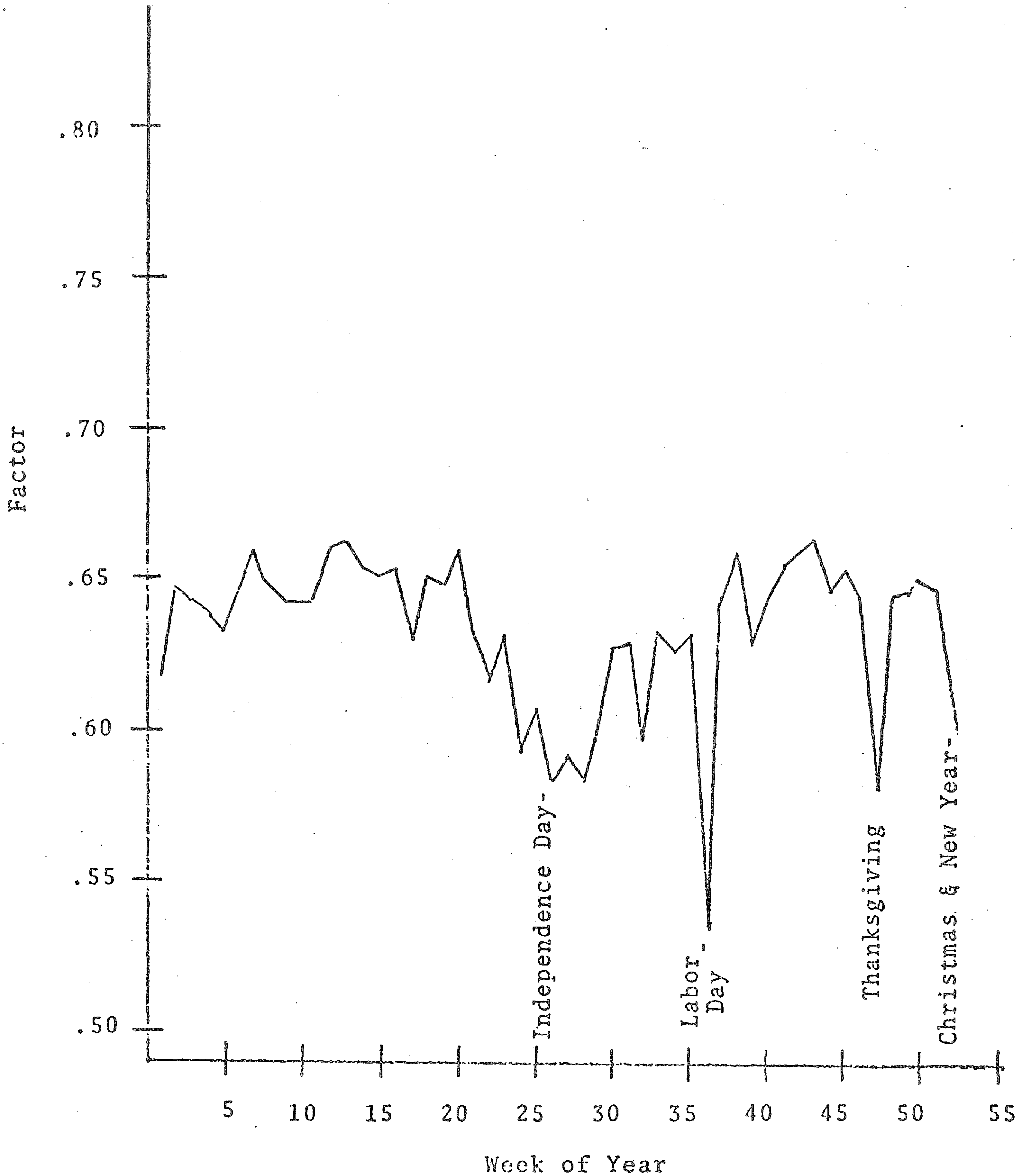


Figure 1 Weekly Load Factor P(I) for CAPCO 1973

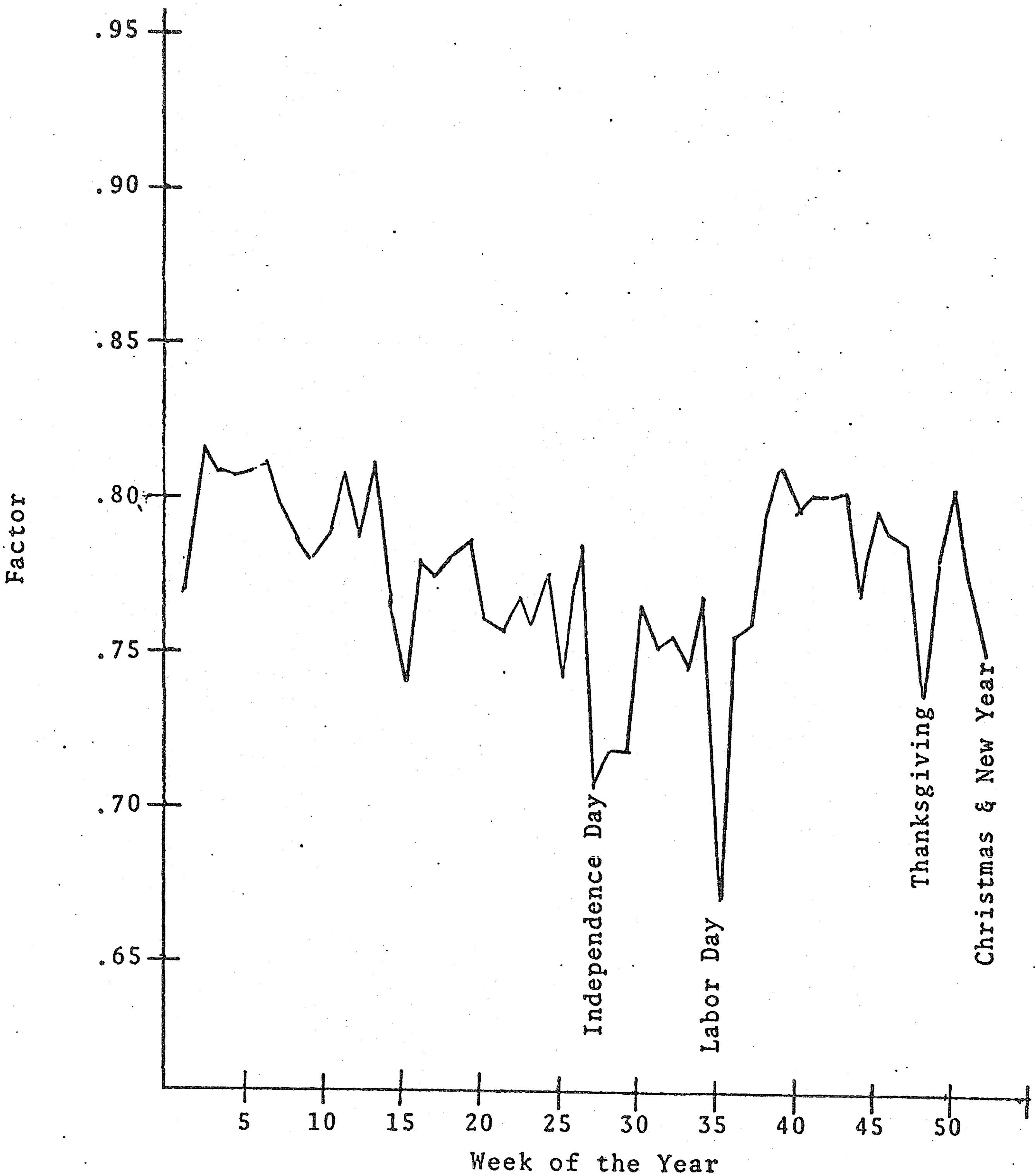


Figure 2 Weekly Load Factor P(I) for CAPCO 1974

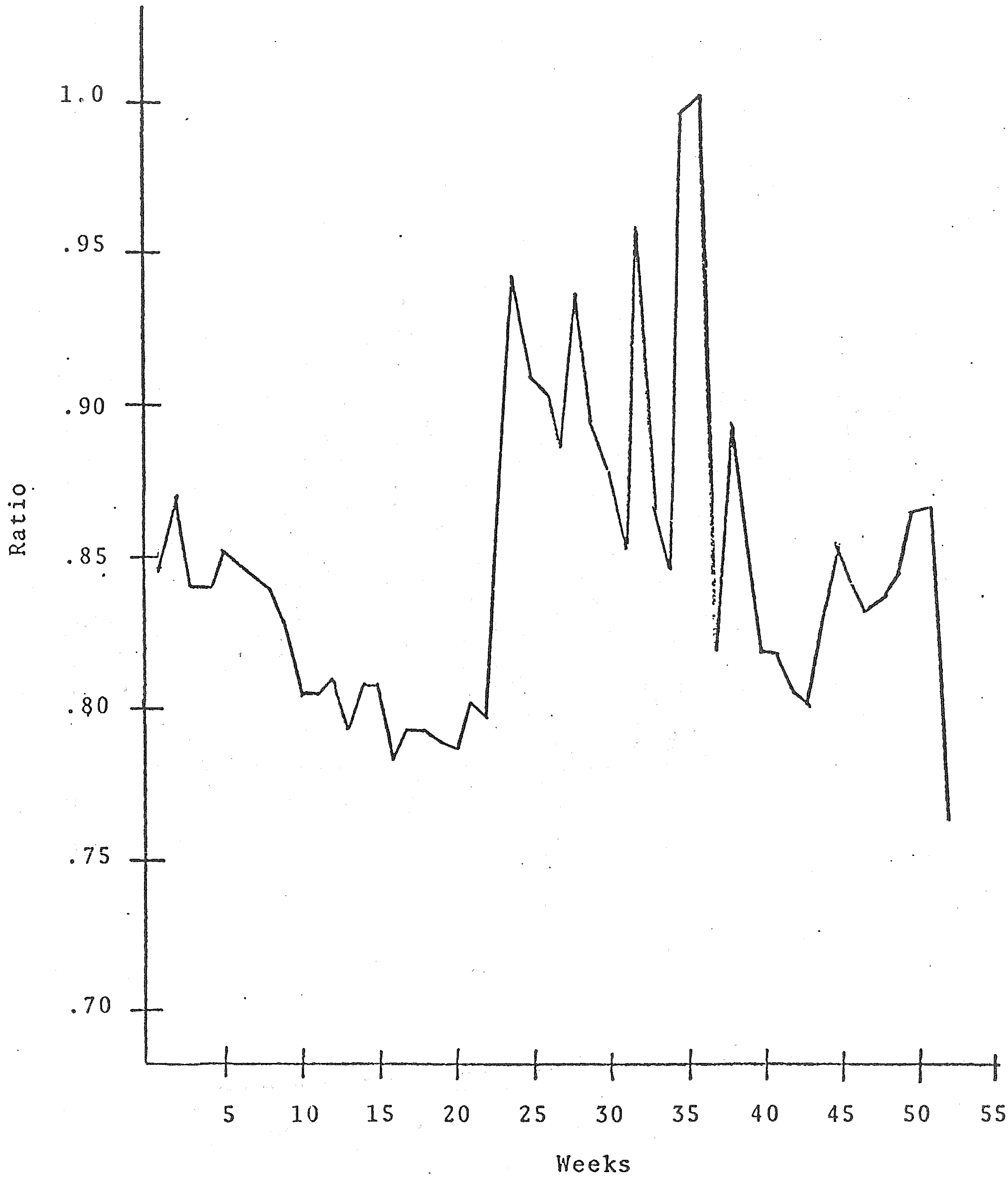


Figure 3 Weekly Peak versus Yearly Peak Ratio R(I) for CAPCO 1973

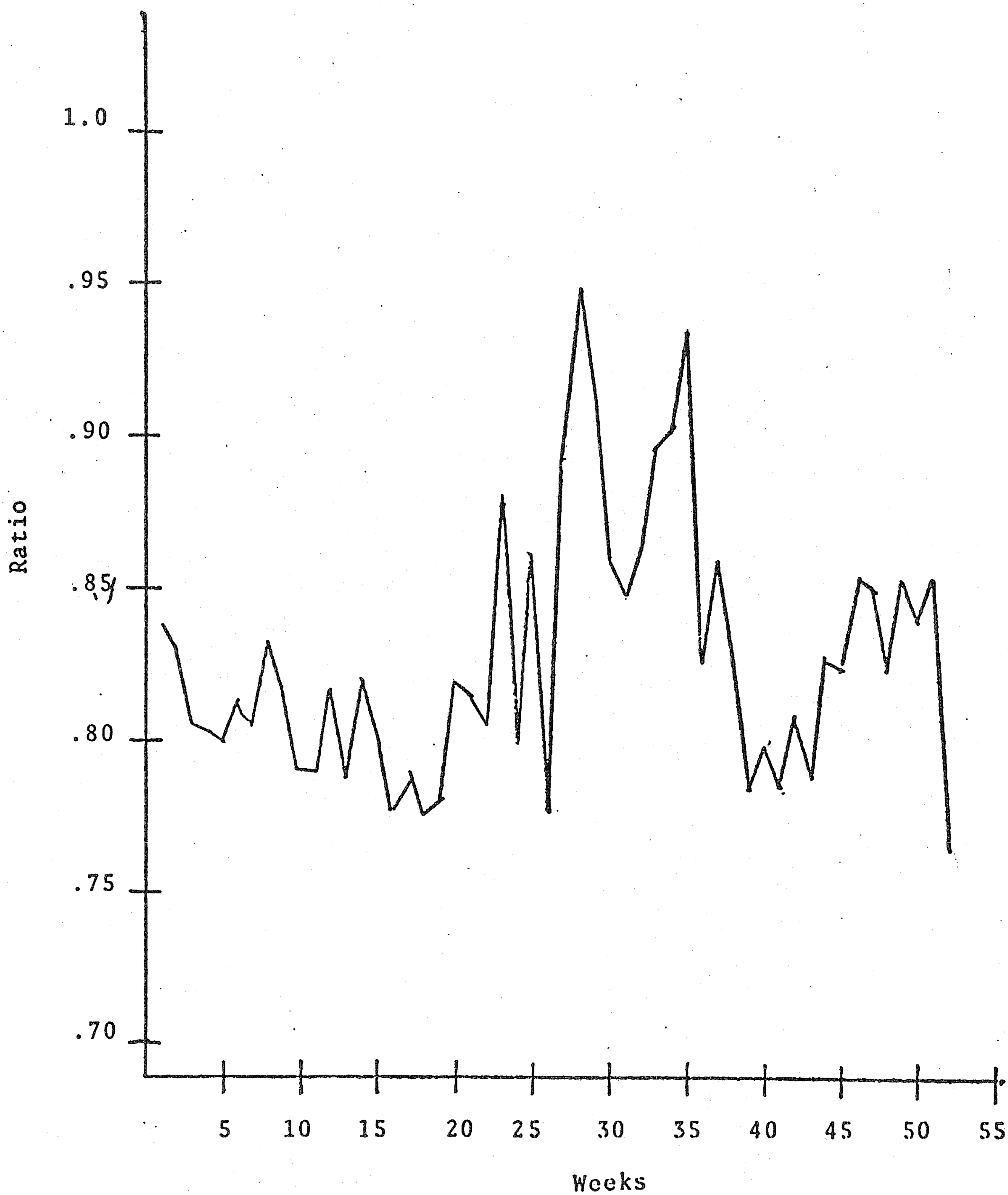


Figure 4 Weekly Peak versus Yearly Peak Ratio
R(I) for CAPCO 1974

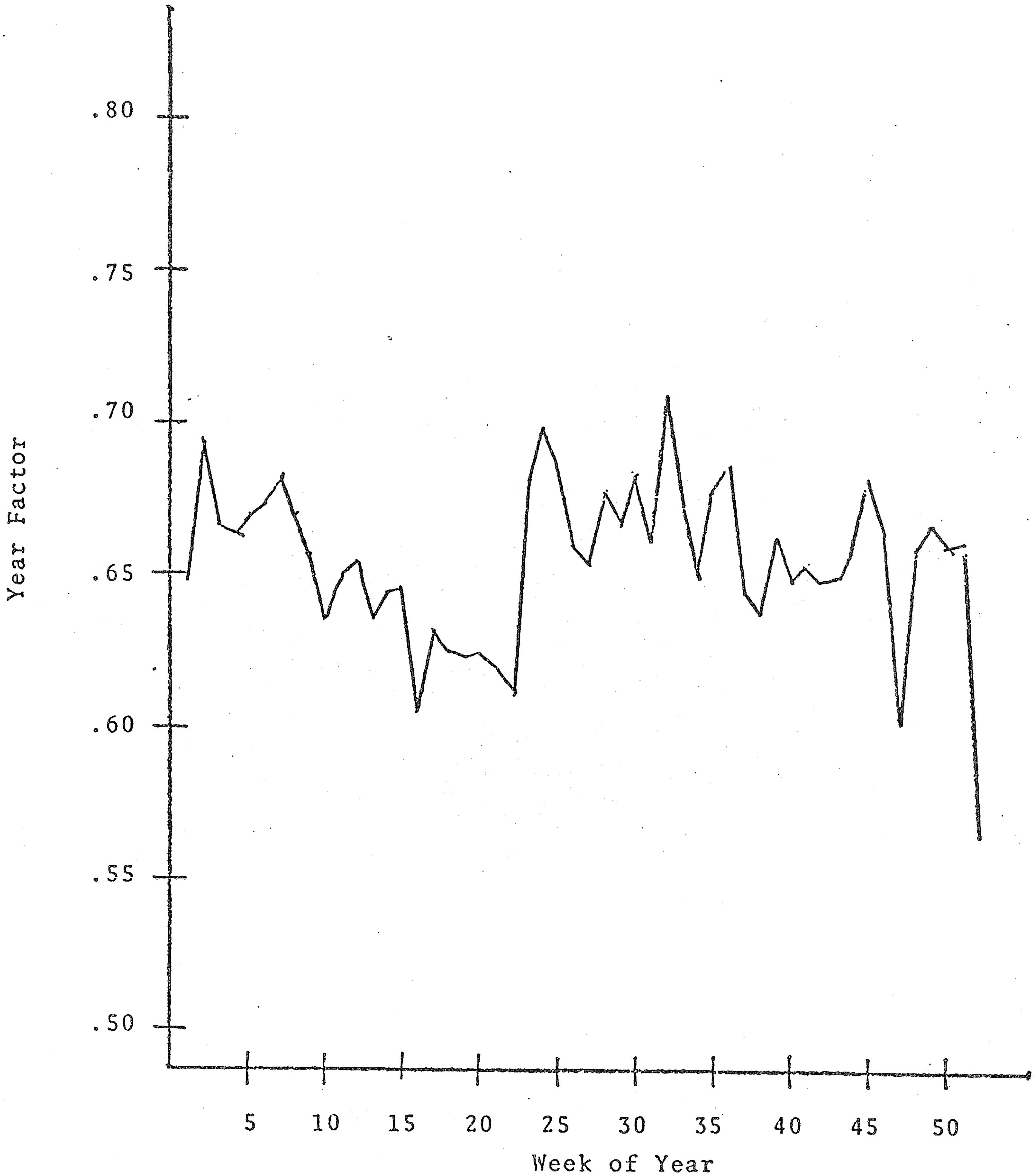


Figure 5 Weekly Average Yearly Peak Ratio for CAPCO 1973

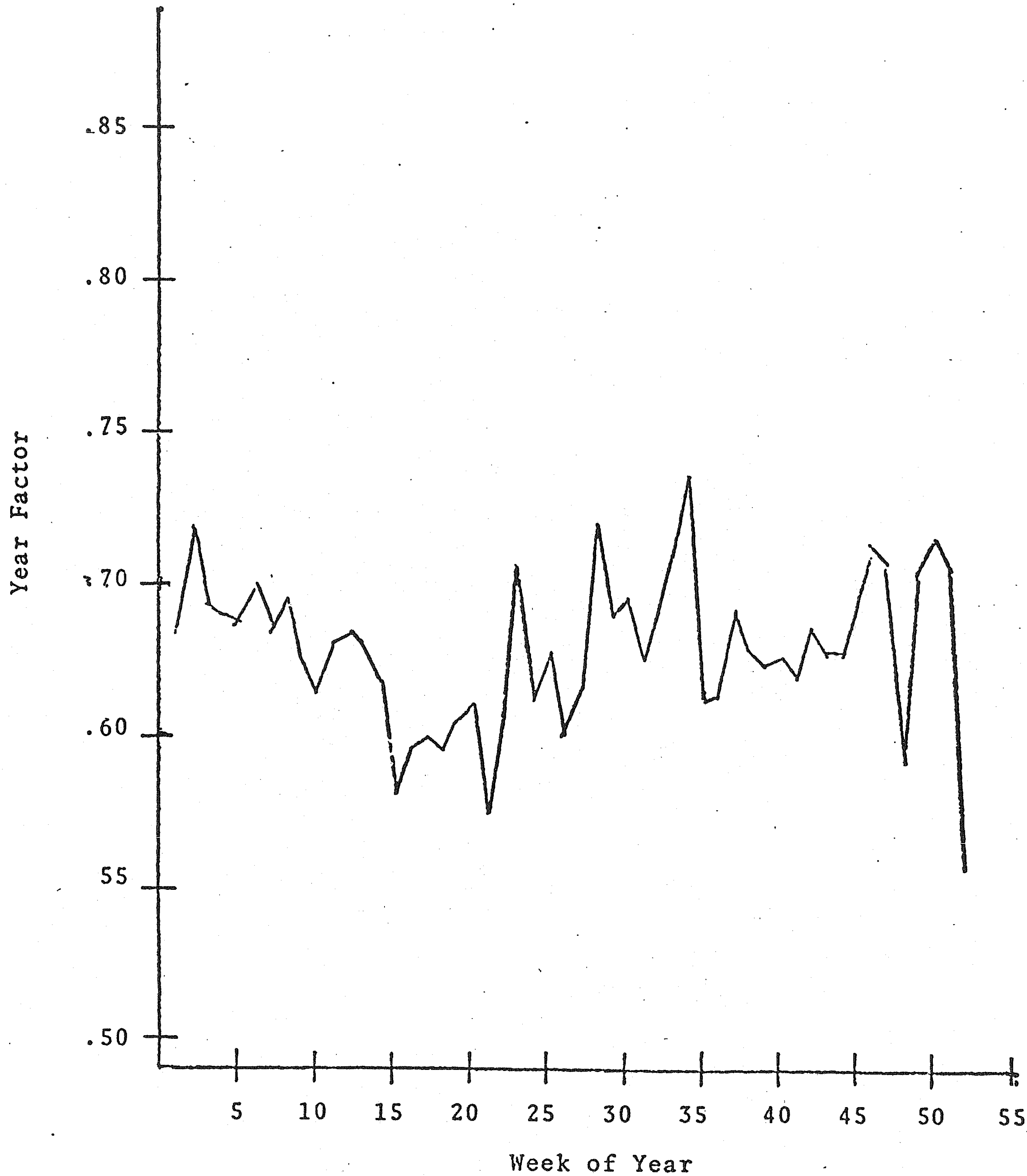


Figure 6 Weekly Average Yearly Peak Ratio for CAPCO 1974

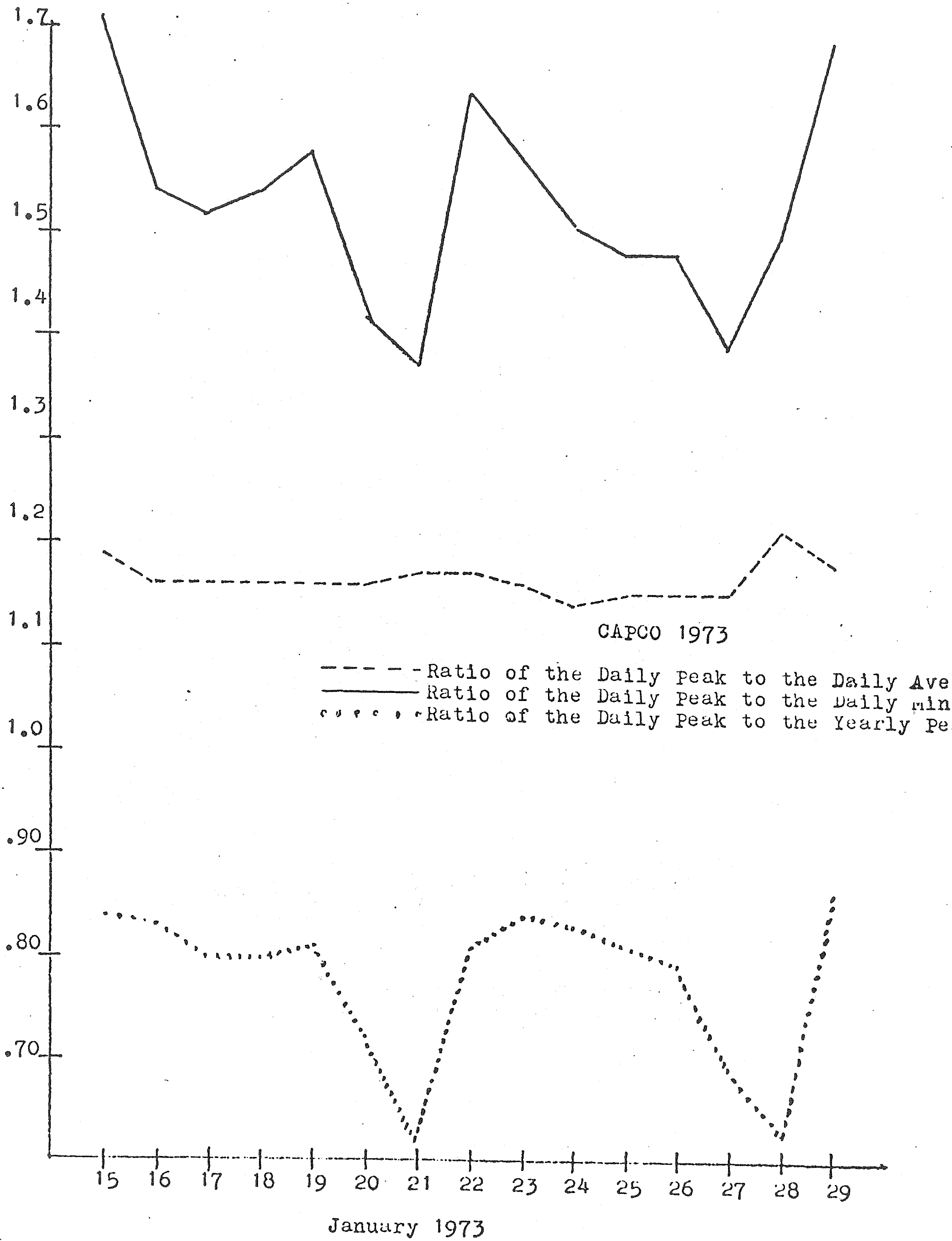

1.7
1.6
1.5
1.4
1.3
1.2
1.1
1.0
.90
.80
.70
CAPCO 1973
Ratio of the Daily Peak to the Daily Ave
Ratio of the Daily Peak to the Daily min
Ratio of the Daily Peak to the Yearly Pe
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
January 1973

Figure 7

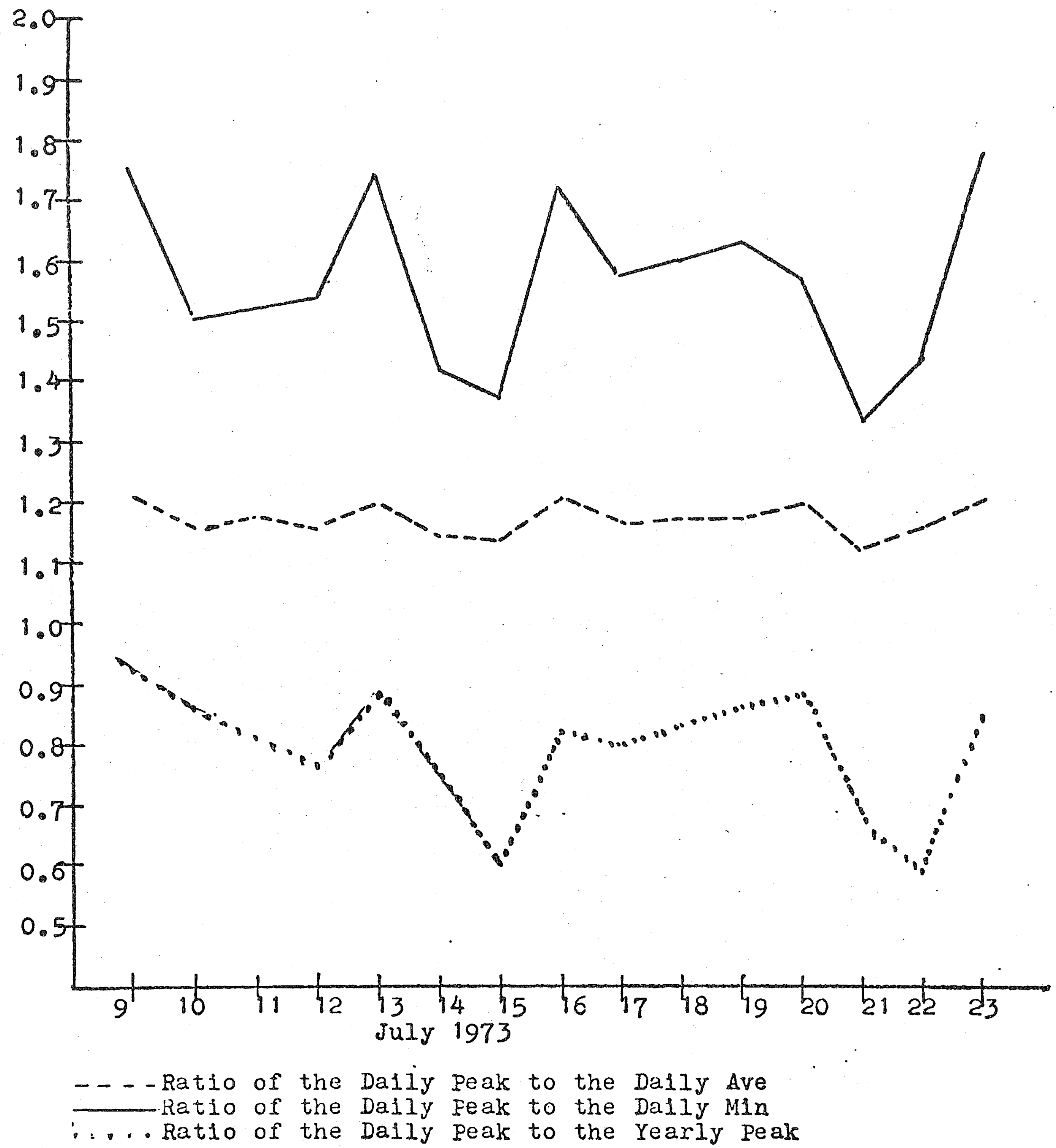

2.0
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
July 1973
- - - - Ratio of the Daily Peak to the Daily Ave
——— Ratio of the Daily Peak to the Daily Min
. . . . . Ratio of the Daily Peak to the Yearly Peak

Figure 8

TABLE 1

R Frequency Chart I

CAPCO 1972
P = A Ten Day Period
Peak = 9,534

R / P	.64 ≥	.67 .65	.70 .68	.73 .71	.76 .74	.79 .77	.82 .80	.85 .83	.88 .86	.91 .89	.94 .92	.97 .95	1.00 .98	
Jan. 1-Jan. 10	3		1				3	2	1					
Jan. 11-Jan. 20		1		1			2	6						
Jan. 21-Jan. 30	2	1	1				1	2	3					
Jan. 31-Feb. 9	1		1					3	5					
Feb. 10-Feb. 19	1	1		1			3	3	1					
Feb. 20-Mar. 1	2		1				3	4						
Mar. 2-Mar. 11	1		1				3	4	1					
Mar. 12-Mar. 21	2	2					4	2						
Mar. 22-Mar. 31	1	1				1	4	3						
April 1-April 10	3	2					3	2						
April 11-April 20	2					1	7							
April 21-April 30	2	1				2	5							
May 1-May 10	3						6	1						
May 11-May 20	2					1	6	1						
May 21-May 30	4	1					1	1	3					
May 31-June 9	2	1					2	5	1					
June 10-June 19	4						1	1	1	1	1			
June 20-June 29	1						3	2		1	1			
June 30-July 9	2			1					1		4	2		
July 10-July 19	2			1					1		5	2		
July 20-July 29				1			2	2		1		2	2	Peak
July 30-Aug. 8	4						1		4	1				
Aug. 9-Aug. 18	1	1				1	3	2		1	1			
Aug. 19-Aug. 28	2		1		1					1	4	1		
Aug. 29-Sept. 7	2	1						2	1	4				
Sept. 8-Sept. 17	1	1	1					1	4		1			
Sept. 18-Sept. 27	1	2					1	2	1	2				
Sept. 28-Oct. 7	1	1						8						
Oct. 8-Oct. 17	2	1	1					5	1					
Oct. 18-Oct. 27	1		1					7	1					
Oct. 28-Nov. 6	2		1	1				2	4					
Nov. 7-Nov. 10		1			1			1	2	5				
Nov. 11-Nov. 26	1		1	1	2				1	4				
Nov. 27-Dec. 6		2			1					6	1			
Dec. 7-Dec. 16				1		1				1	6	1		
Dec. 17-Dec. 26	2				2			1	1		3	1		
Dec. 27-Dec. 31														

TABLE 2

CAPCO 1973
P = A Ten Day Period
Peak = 10,565

(Ratio) Frequency Chart II

R / P	.64 ≥	.67 .65	.70 .68	.73 .71	.76 .74	.79 .77	.82 .80	.85 .83	.88 .86	.91 .89	.94 .92	.97 .95	1.00 .98	
Jan. 1-Jan. 10	1	1			1			4	3					
Jan. 11-Jan. 20	1			2			3	3	1					
Jan. 21-Jan. 30	2		1			1	2	3	1					
Jan. 31-Feb. 9	1		1			1	6	1						
Feb. 10-Feb. 19	2			2			3	3						
Feb. 20-Mar. 1	1			1			5	3						
Mar. 2-Mar. 11	2	2				5	1							
Mar. 12-Mar. 21	1		1			4	4							
Mar. 22-Mar. 31	1	2				6	1							
April 1-April 10	2	1				2	5							
April 11-April 20	1	2				6	1							
April 21-April 30	3	1				6								
May 1-May 10	2					8								
May 11-May 20	3	1				6								
May 21-May 30	3					5	2							
May 31-June 9	1	1		1		2		2	3					
June 10-June 19	1		1	1				3	1	1	2			
June 20-June 29	1		1			1		2	3	2				
June 30-July 9	3		1	1			1	1	1	1	1			
July 10-July 19	1				1	1	2	2	2	1				
July 20-July 29	2		1	1				2	2	4				
July 30-Aug. 8	1	1					3	2	2	1	1			
Aug. 9-Aug. 18	1		1	1				2	3	1		1		
Aug. 19-Aug. 28	1		1	1		3	1	1					2	
Aug. 29-Sept. 7			1		1	1		1	1			2	3	Peak
Sept. 8-Sept. 17	2	2				2	4							
Sept. 18-Sept. 27	1	1				4	2	1	1					
Sept. 28-Oct. 7	3		1			1	4	1						
Oct. 8-Oct. 17	1	1				1	6							
Oct. 18-Oct. 27	1	2				5	2							
Oct. 28-Nov. 6	2		1			1	2	4						
Nov. 7-Nov. 10	1			1			3	5						
Nov. 11-Nov. 26	4		2			1	2	1						
Nov. 27-Dec. 6	1		1				5	3						
Dec. 7-Dec. 16	1	1		2			2	1	3					
Dec. 17-Dec. 26	3			1	1			2	3					
Dec. 27-Dec. 31														

TABLE 3

Frequency Chart III

CAPCO 1974
P = A Ten Day Period
Peak = 10,160

P \ R	.64 ≥	.67 .65	.70 .68	.73 .71	.76 .74	.79 .77	.82 .80	.85 .83	.88 .86	.91 .89	.94 .92	.97 .95	1.00 .98	
Jan. 1-Jan. 10		2			1				5	2				
Jan. 11-Jan. 20	1		1		1			3	4					
Jan. 21-Jan. 30	1		1				1	6	1					
Jan. 31-Feb. 9	1		2					6	1					
Feb. 10-Feb. 19	2		1					6	1					
Feb. 20-Mar. 1		1	1	1				6	2					
Mar. 2-Mar. 11	2	1	1				5	1						
Mar. 12-Mar. 21	1		1				1	7						
Mar. 22-Mar. 31	2		2					5	1					
April 1-April 10	1		1			1	2	3	1					
April 11-April 20	2	2				1	5							
April 21-April 30	3					1	2	4						
May 1-May 10	2						6	2						
May 11-May 20	3	1					2	2	1					
May 21-May 30	3						2	4	1					
May 31-June 9	1	1	1	1				1	3	2				
June 10-June 19	1		1				1	6			1			
June 20-June 29	1	1	1				4	2		2				
June 30-July 9	1	2	1			1		1	1		2		1	Peak
July 10-July 19				2				2	2		2	2		
July 20-July 29	1	1	1		1			2	2	2				
July 30-Aug. 8	1		1				1	3	3	1				
Aug. 9-Aug. 18	2			1	1				2	1	2	1		
Aug. 19-Aug. 28		1			1				1			4	1	
Aug. 29-Sept. 7	2	2					3	1	1	1				
Sept. 8-Sept. 17	2		1					3	2	3				
Sept. 18-Sept. 27	1		1				1	6	1					
Sept. 28-Oct. 7	2	1	1					6						
Oct. 8-Oct. 17	1	1					4	4						
Oct. 18-Oct. 27	2	1	1					5	1					
Oct. 28-Nov. 6	1		1					4	4					
Nov. 7-Nov. 10	1		1	1				1	4	2				
Nov. 11-Nov. 26		2		1					5	2				
Nov. 27-Dec. 6	1	1	1	1			1	1	4					
Dec. 7-Dec. 16			2	2					1	5				
Dec. 17-Dec. 26	1	1	1		1	1	1		1	3				
Dec. 27-Dec. 31														

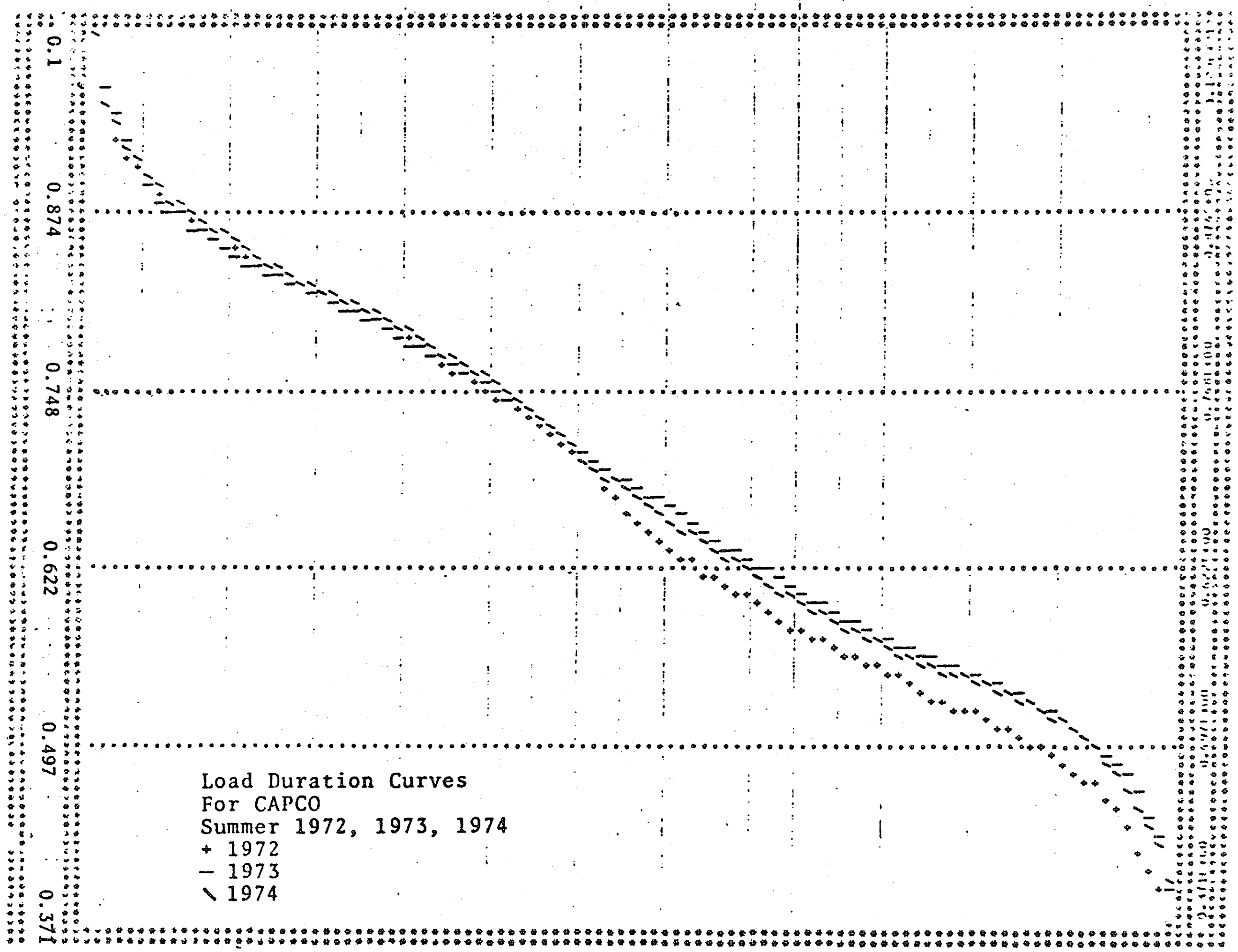

0.1
0.874
0.748
0.622
0.497
0.371
Load Duration Curves
For CAPCO
Summer 1972, 1973, 1974
+ 1972
— 1973
\ 1974

FIGURE 9

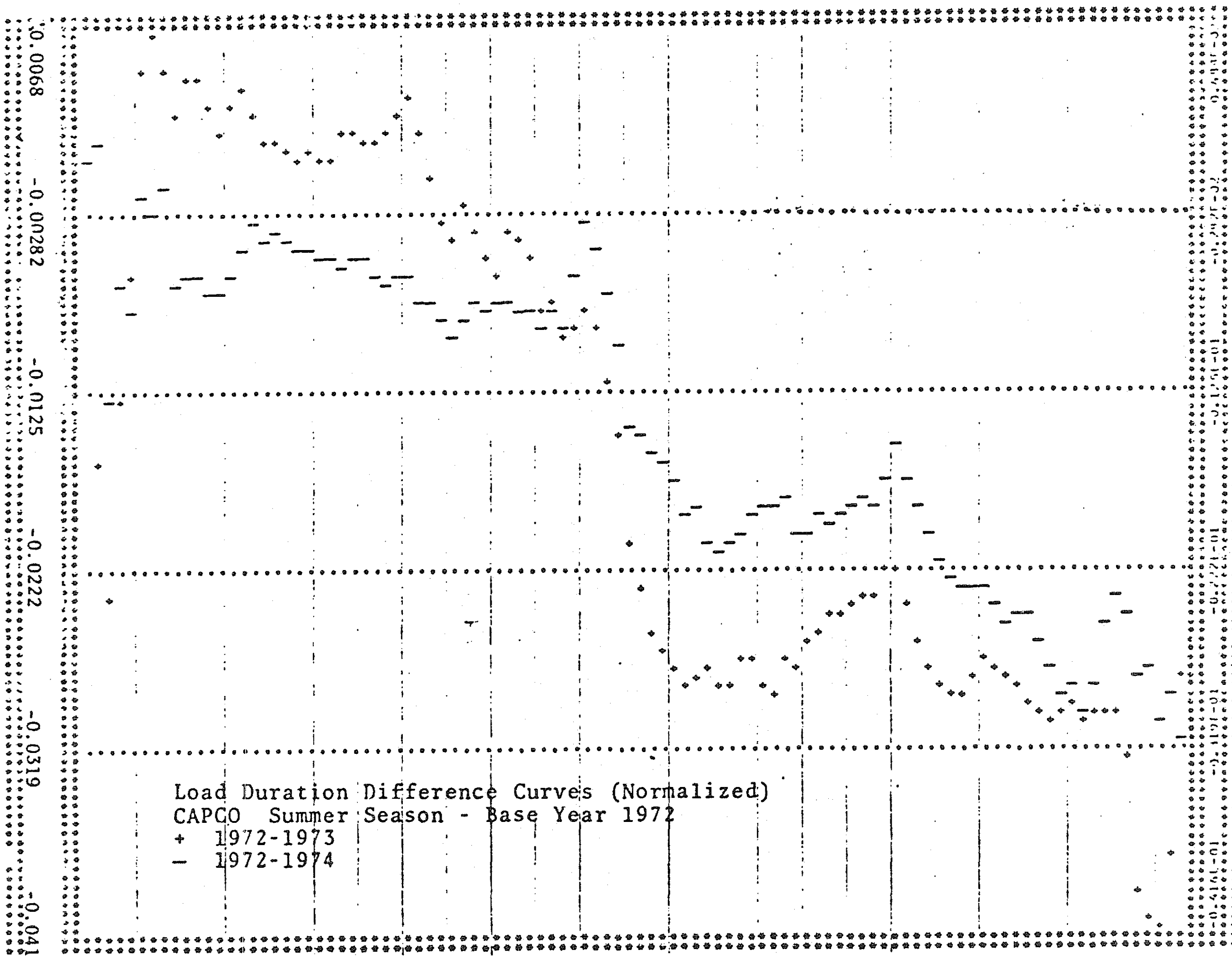
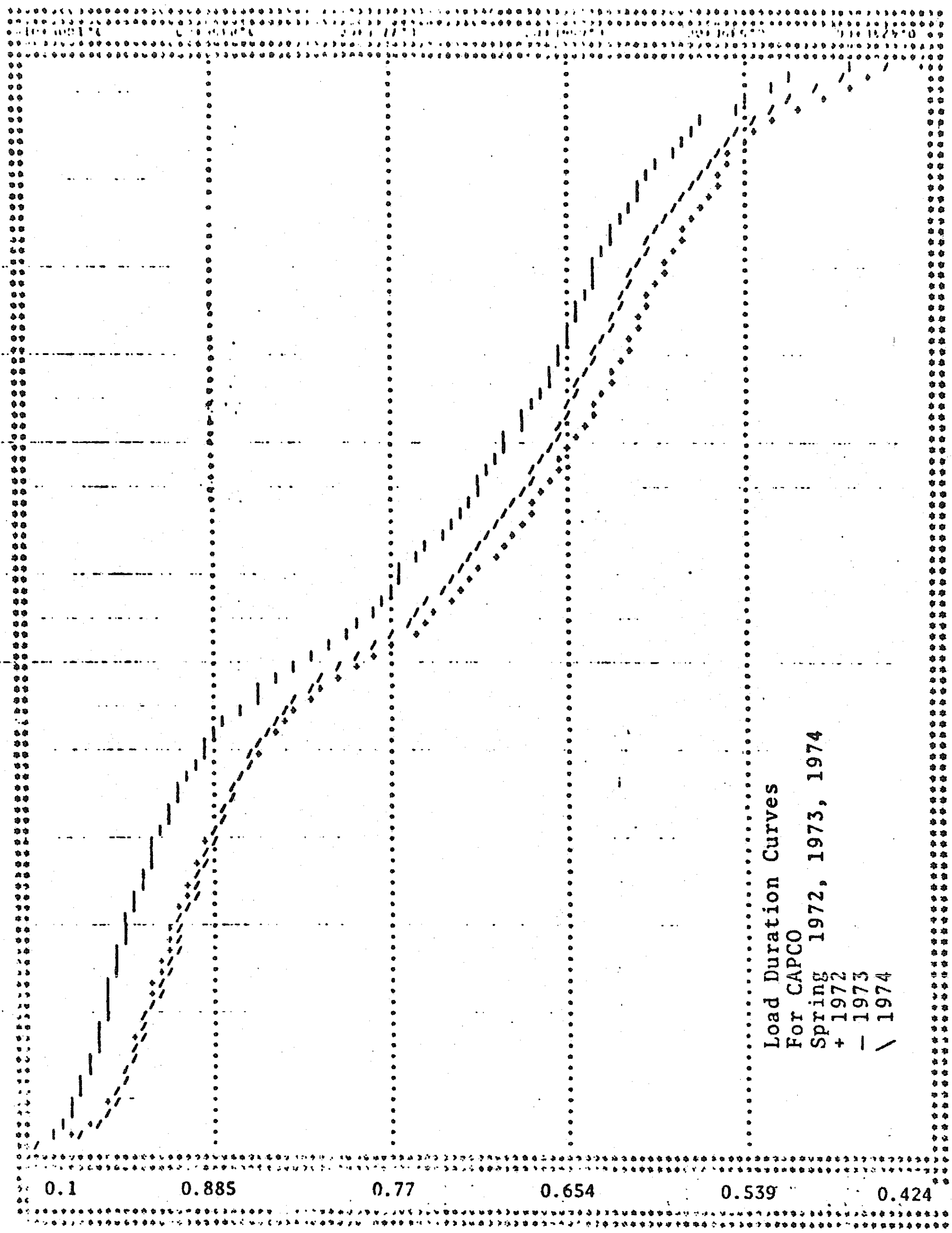

0.0068
-0.00282
-0.0125
-0.0222
-0.0319
-0.0416
Load Duration Difference Curves (Normalized)
CAPCO Summer Season - Base Year 1972
+ 1972-1973
— 1972-1974

FIGURE 10



Load Duration Curves
For CAPCO
Spring 1972, 1973, 1974
+ 1972
– 1973
\ 1974
0.1
0.885
0.77
0.654
0.539
0.424

FIGURE 11

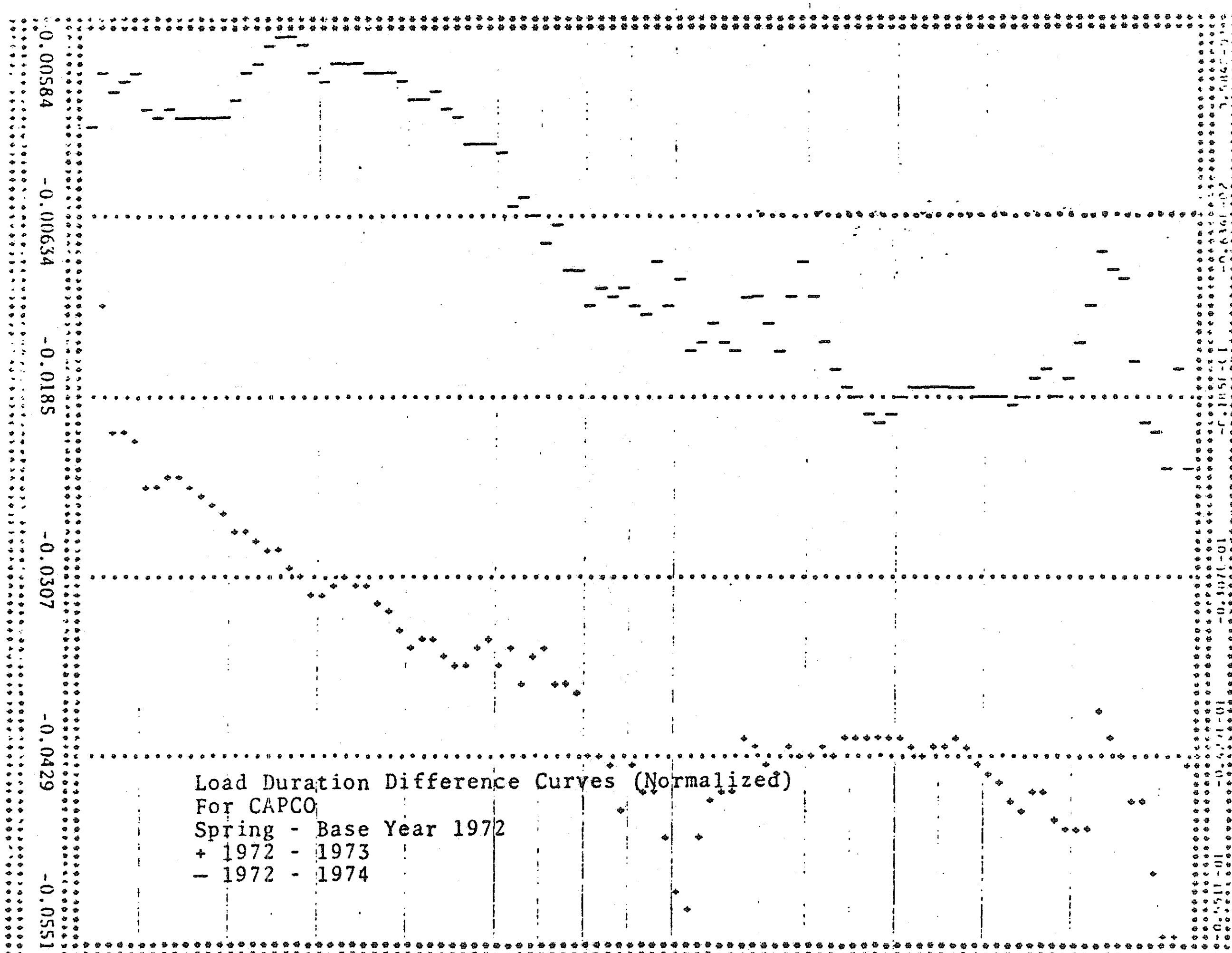

0.00584
-0.00634
-0.0185
-0.0307
-0.0429
-0.0551
Load Duration Difference Curves (Normalized)
For CAPCO
Spring - Base Year 1972
+ 1972 - 1973
— 1972 - 1974

FIGURE 12

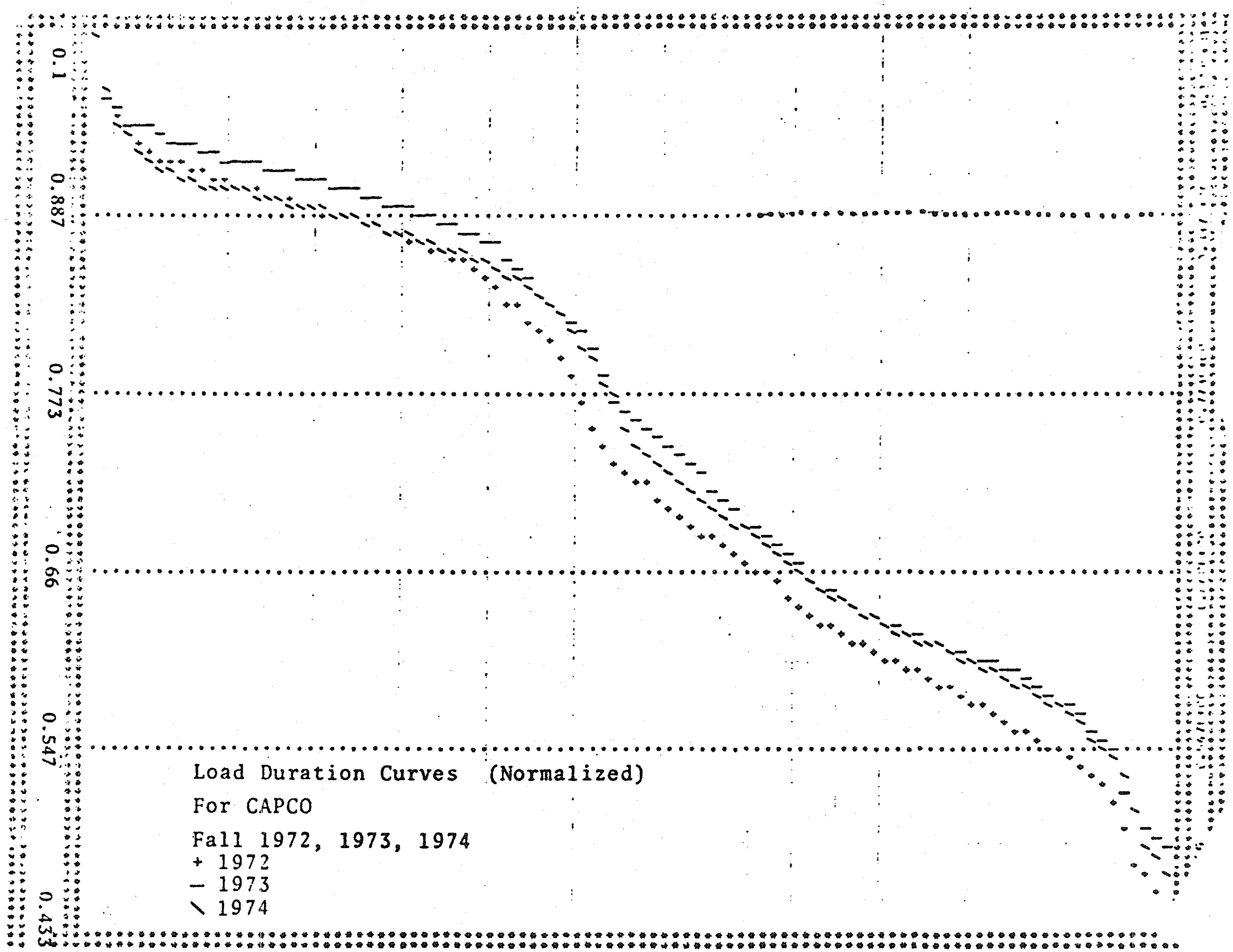

0.1
0.887
0.773
0.66
0.547
0.433
Load Duration Curves (Normalized)
For CAPCO
Fall 1972, 1973, 1974
+ 1972
— 1973
\ 1974

FIGURE 13

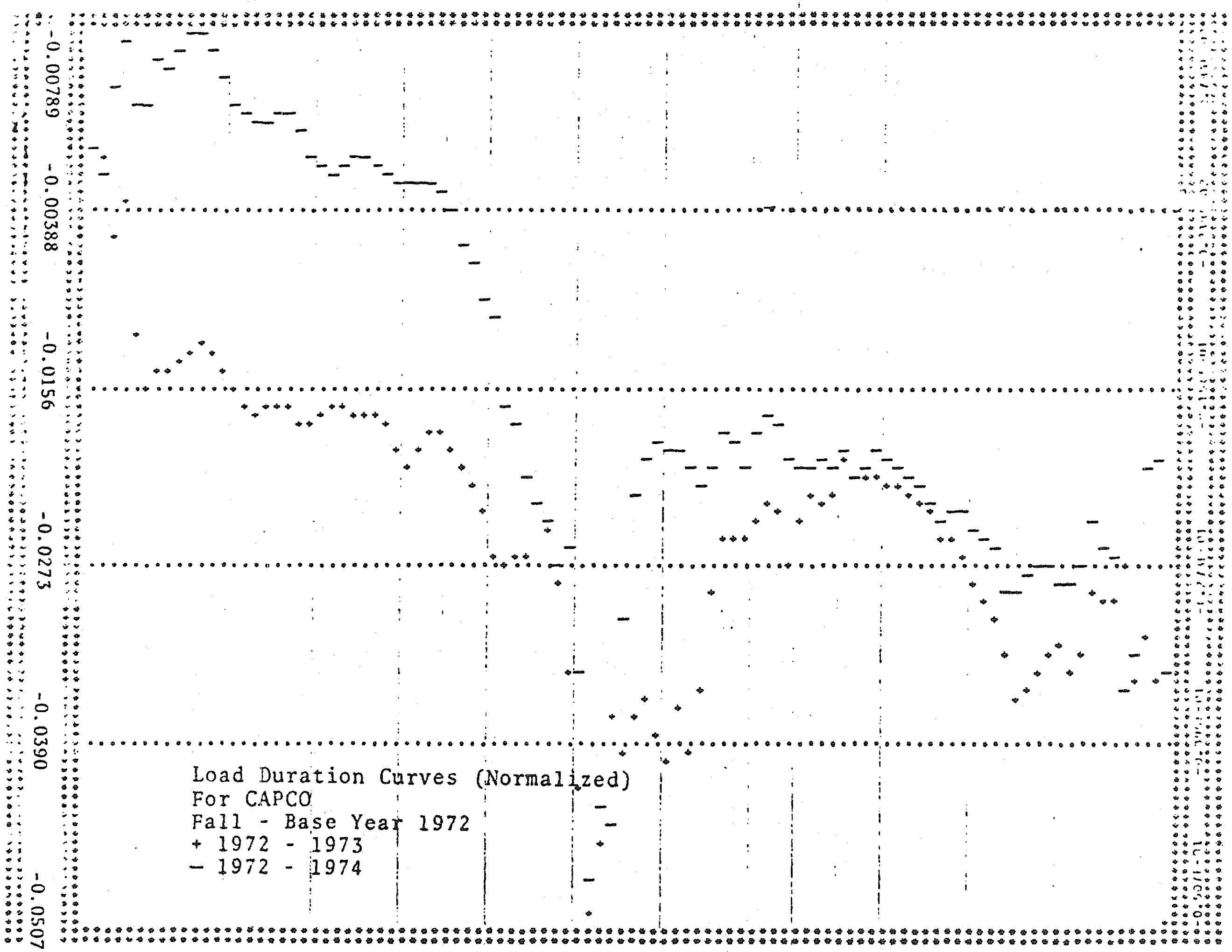

Load Duration Curves (Normalized)
For CAPCO
Fall - Base Year 1972
+ 1972 - 1973
— 1972 - 1974
-0.00789
-0.00388
-0.0156
-0.0273
-0.0390
-0.0507

FIGURE 14

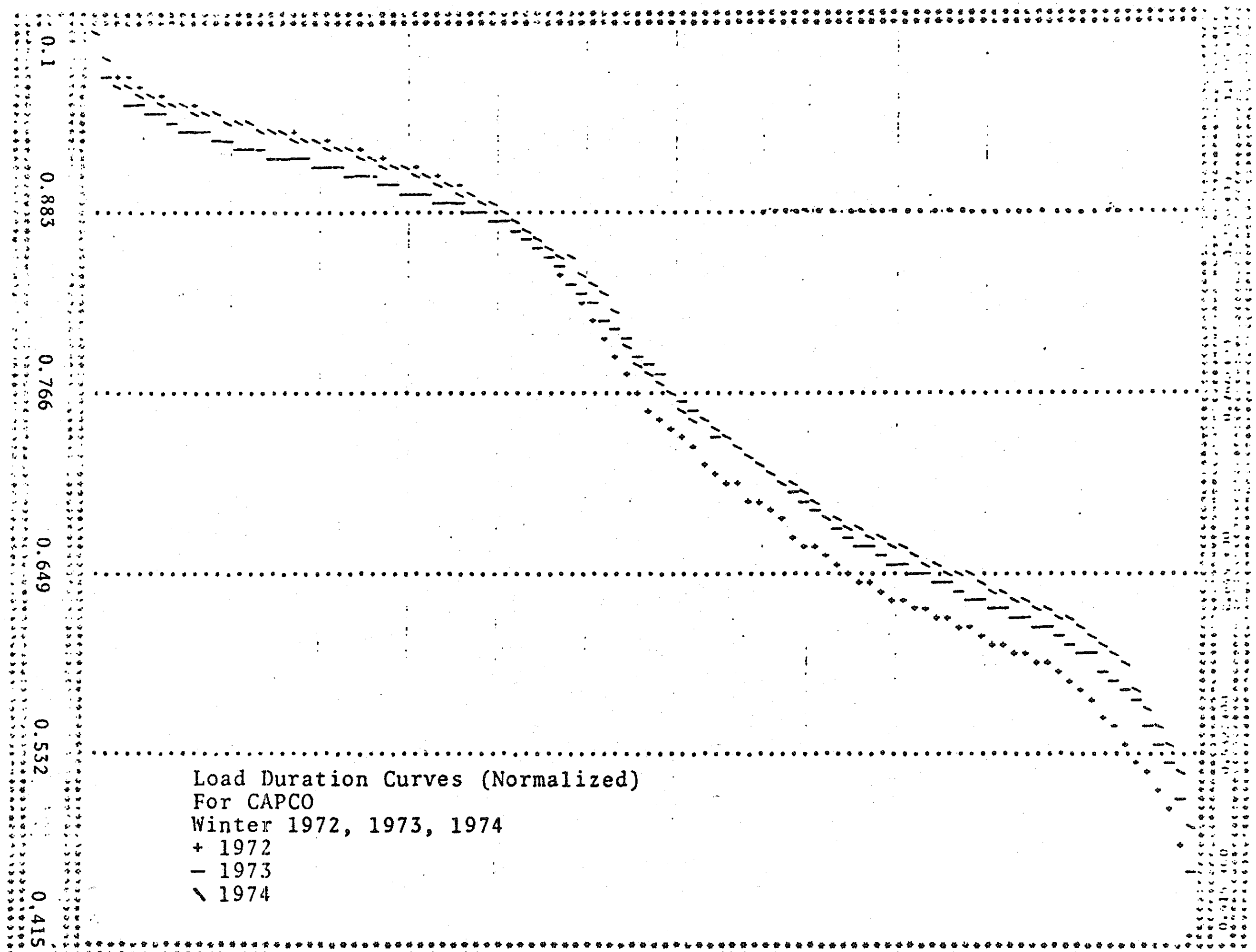

0.1
0.883
0.766
0.649
0.532
0.415
Load Duration Curves (Normalized)
For CAPCO
Winter 1972, 1973, 1974
+ 1972
— 1973
\ 1974

FIGURE 15

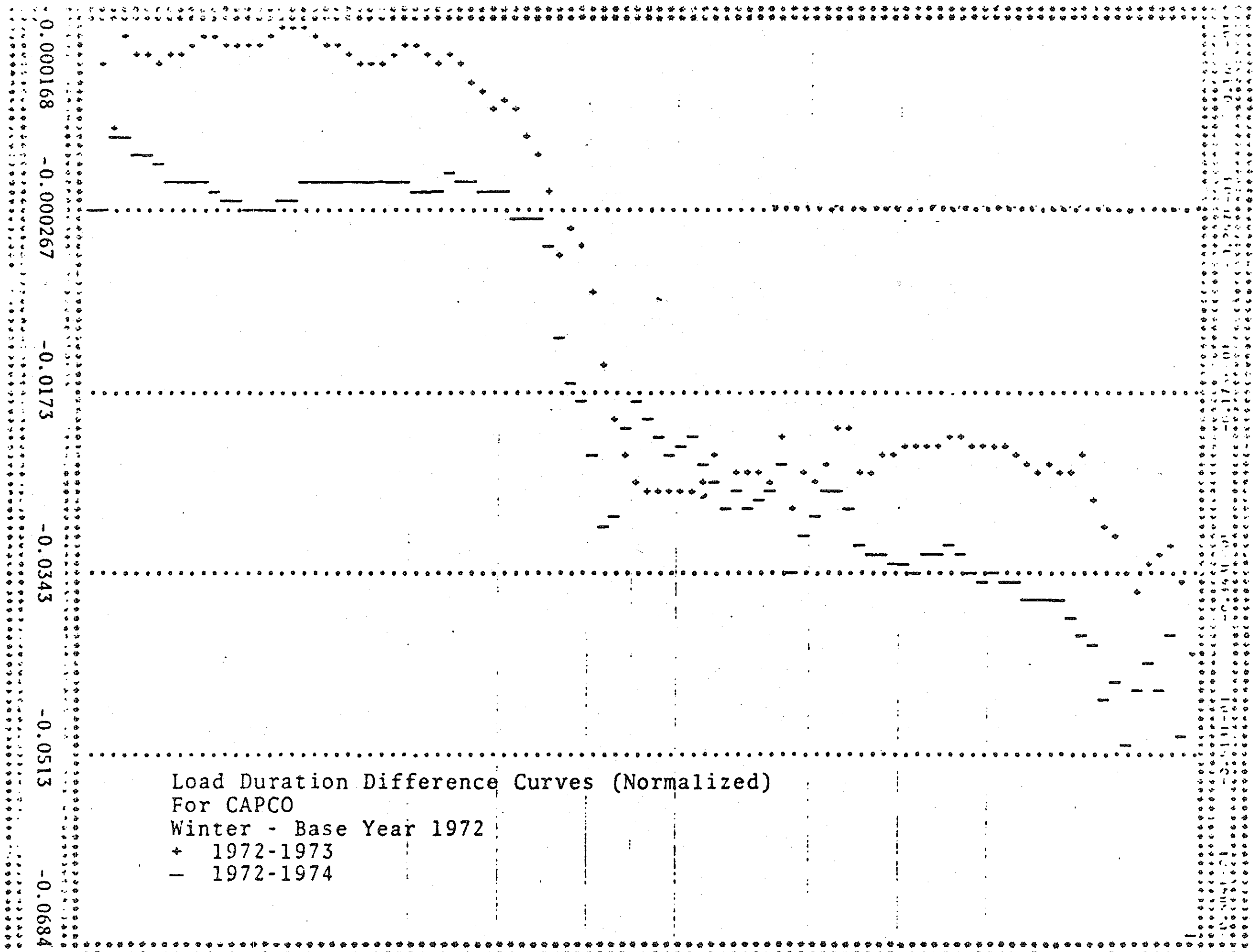

0.000168
-0.000267
-0.0173
-0.0343
-0.0513
-0.0684
Load Duration Difference Curves (Normalized)
For CAPCO
Winter - Base Year 1972
+ 1972-1973
— 1972-1974

FIGURE 16

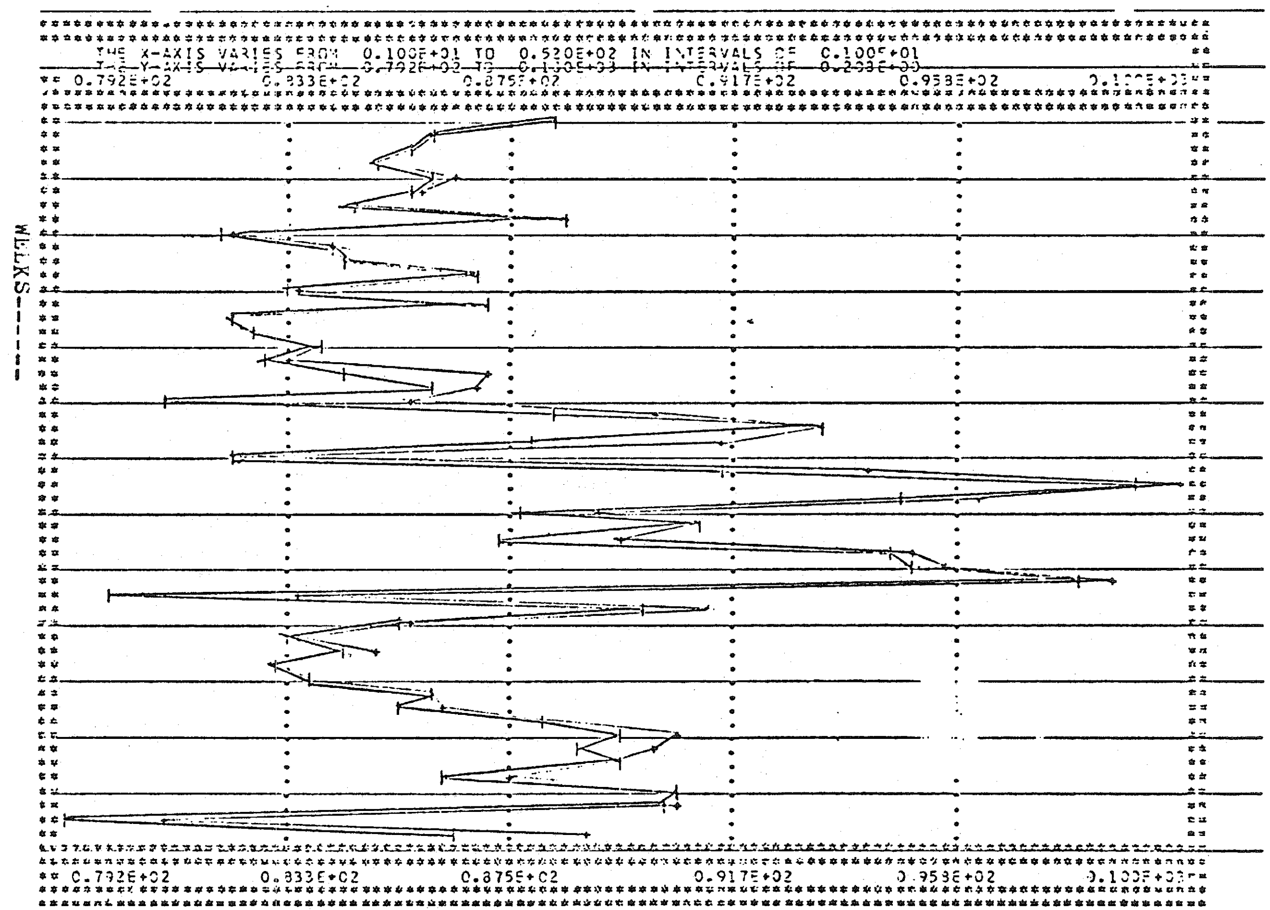


FIGURE 17 Weekly Peak Loads
And Weekly Average Peak Loads
CAPCO 1974 (a)

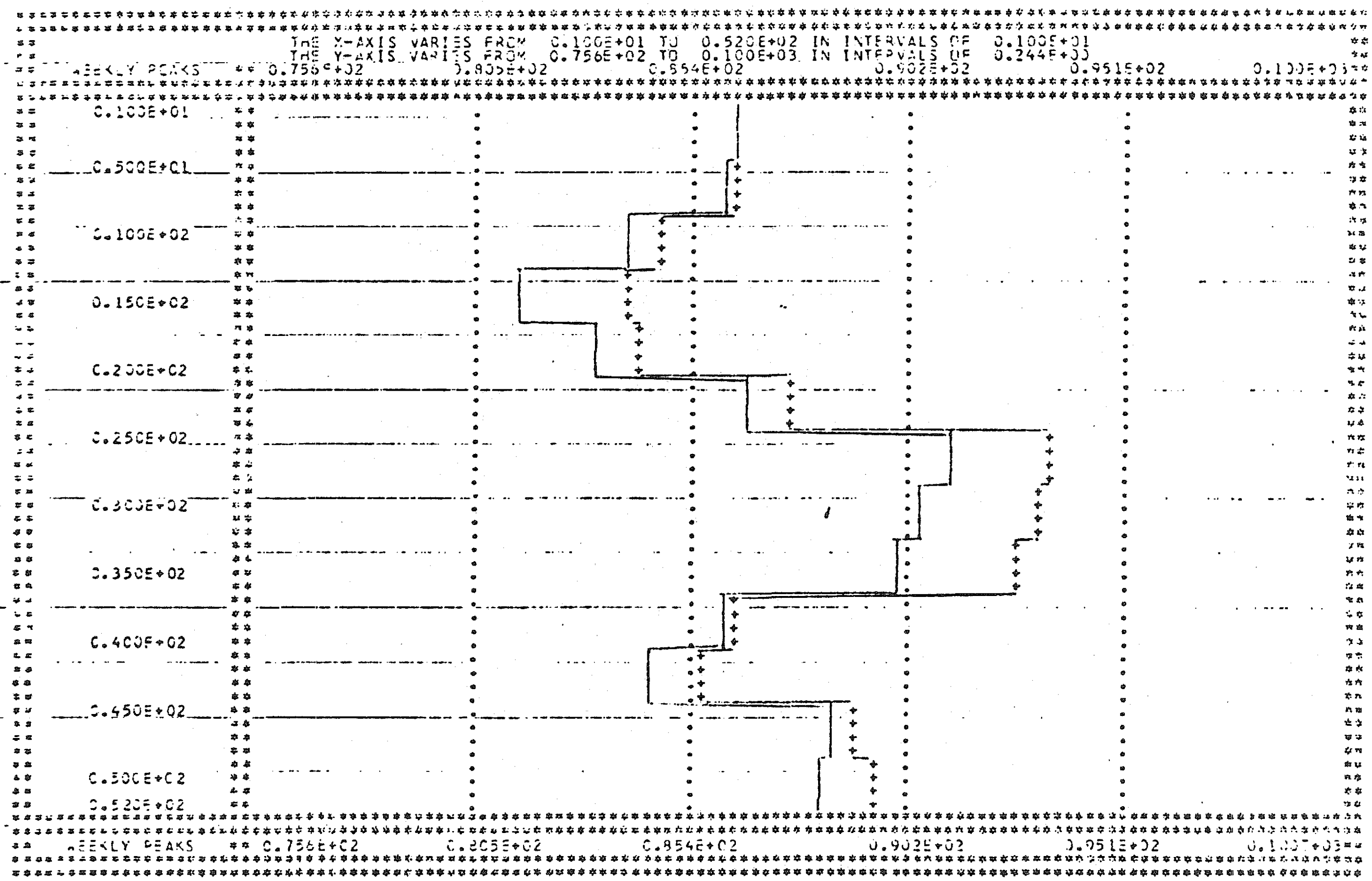


FIGURE 18 Weekly Peak Loads
and Weekly Average Peak Loads
CAPCO (b)

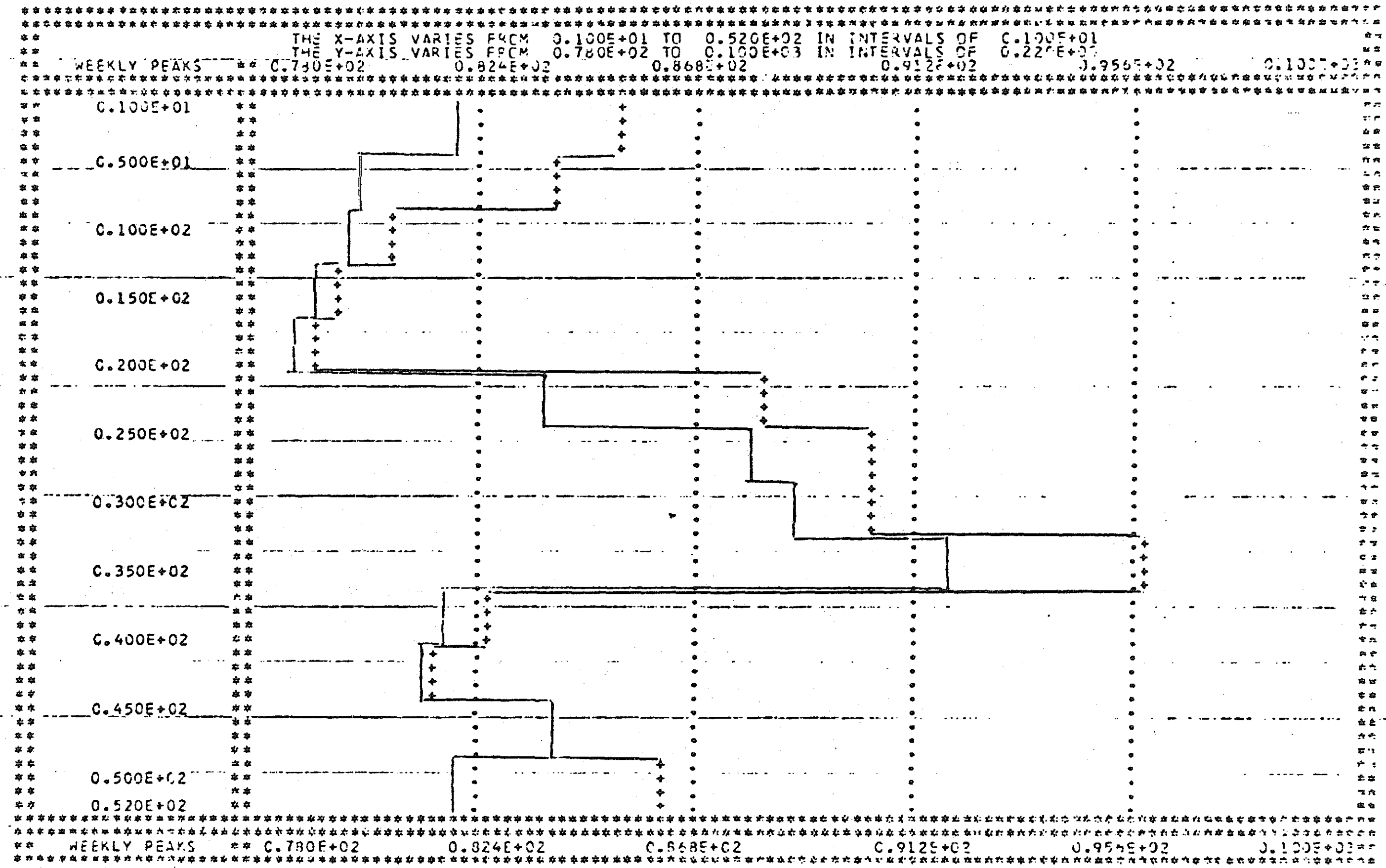


FIGURE 19 Weekly Peak Loads
And Weekly Average Peak Loads
CAPCO 1973

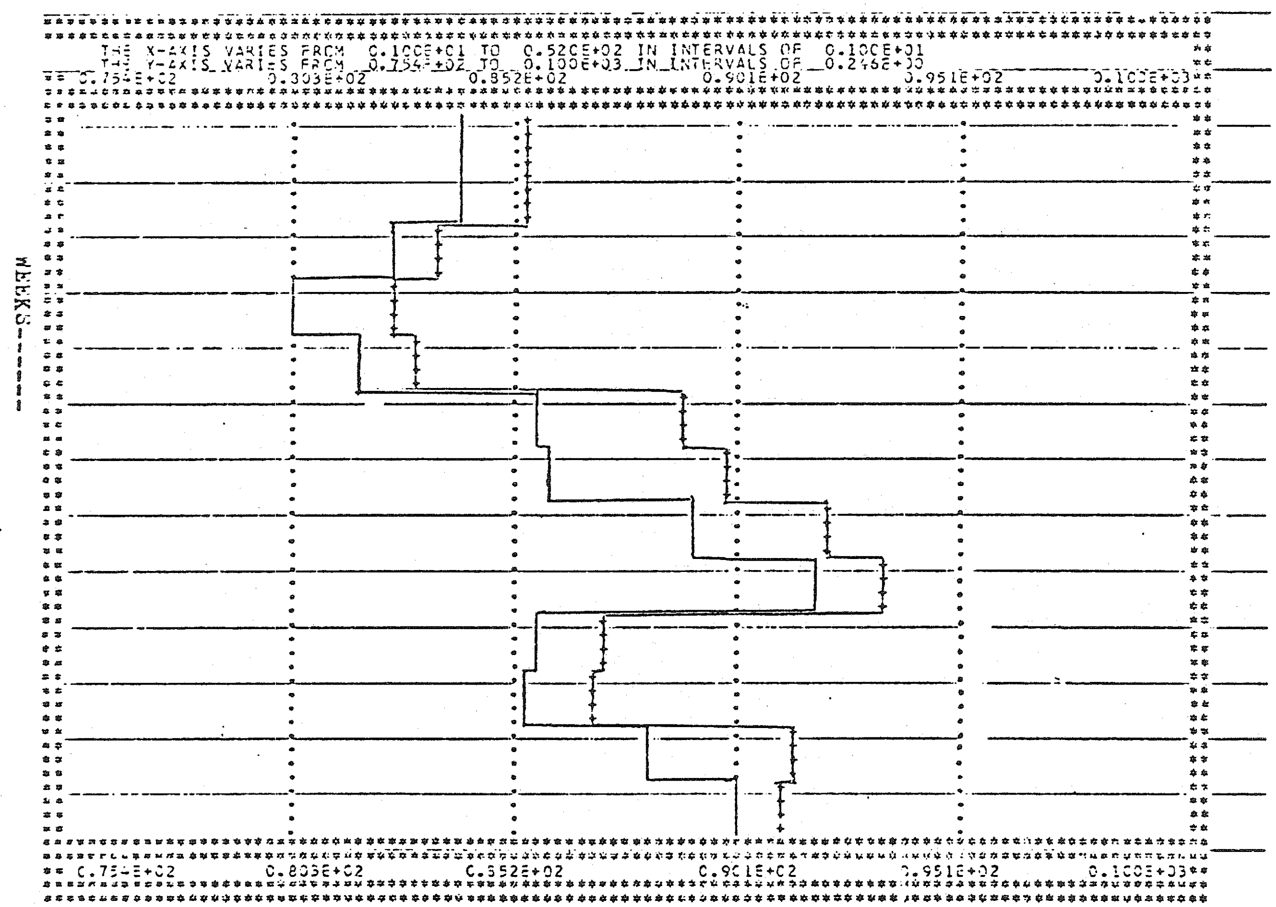


FIGURE 20 Weekly Peak Loads
And Weekly Average Peak Load
CAPCO 1972

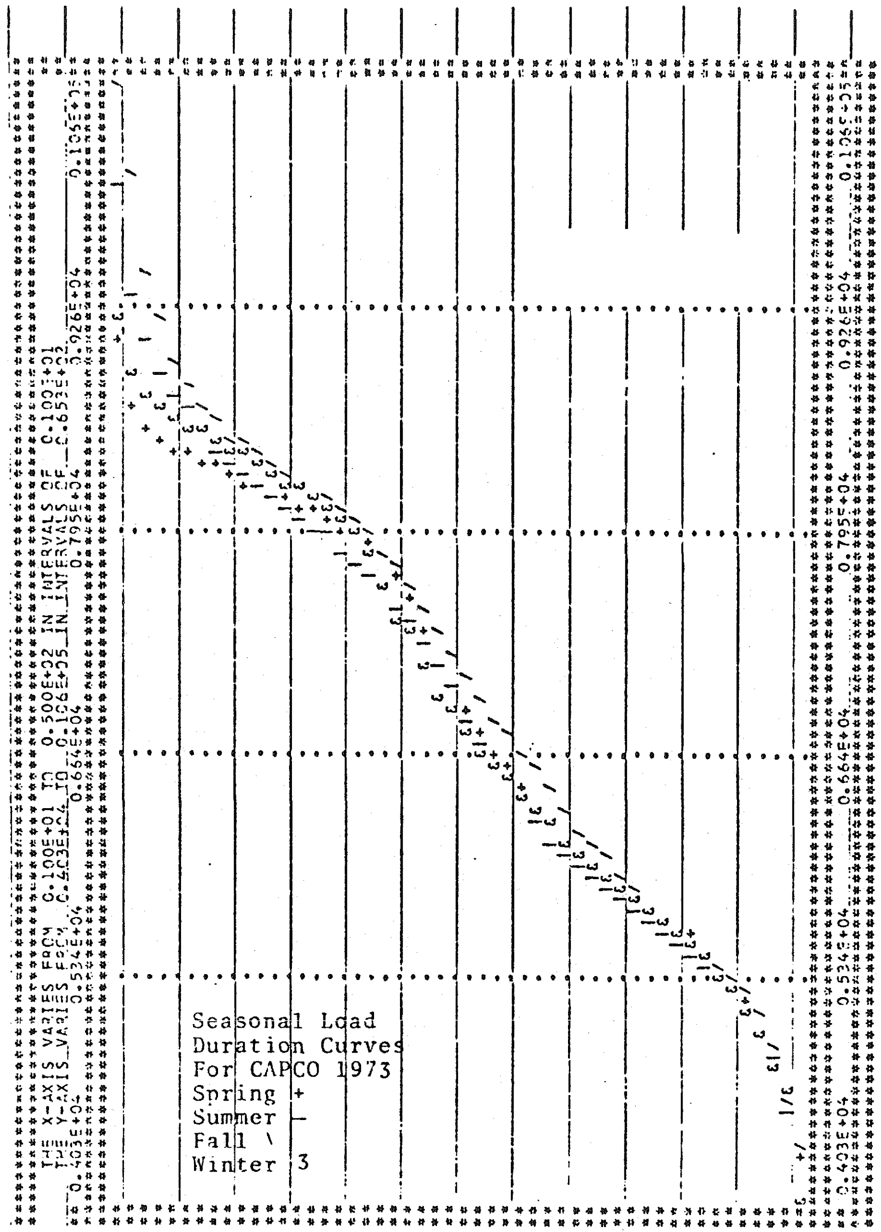

THE X-AXIS VARIES FROM 0.100E+01 TO 0.500E+02 IN INTERVALS OF 0.100E+01
THE Y-AXIS VARIES FROM 0.403E+04 TO 0.106E+05 IN INTERVALS OF 0.653E+03
0.403E+04
0.534E+04
0.664E+04
0.795E+04
0.926E+04
0.106E+05
Seasonal Load
Duration Curves
For CAPCO 1973
Spring +
Summer –
Fall \
Winter 3

FIGURE 21

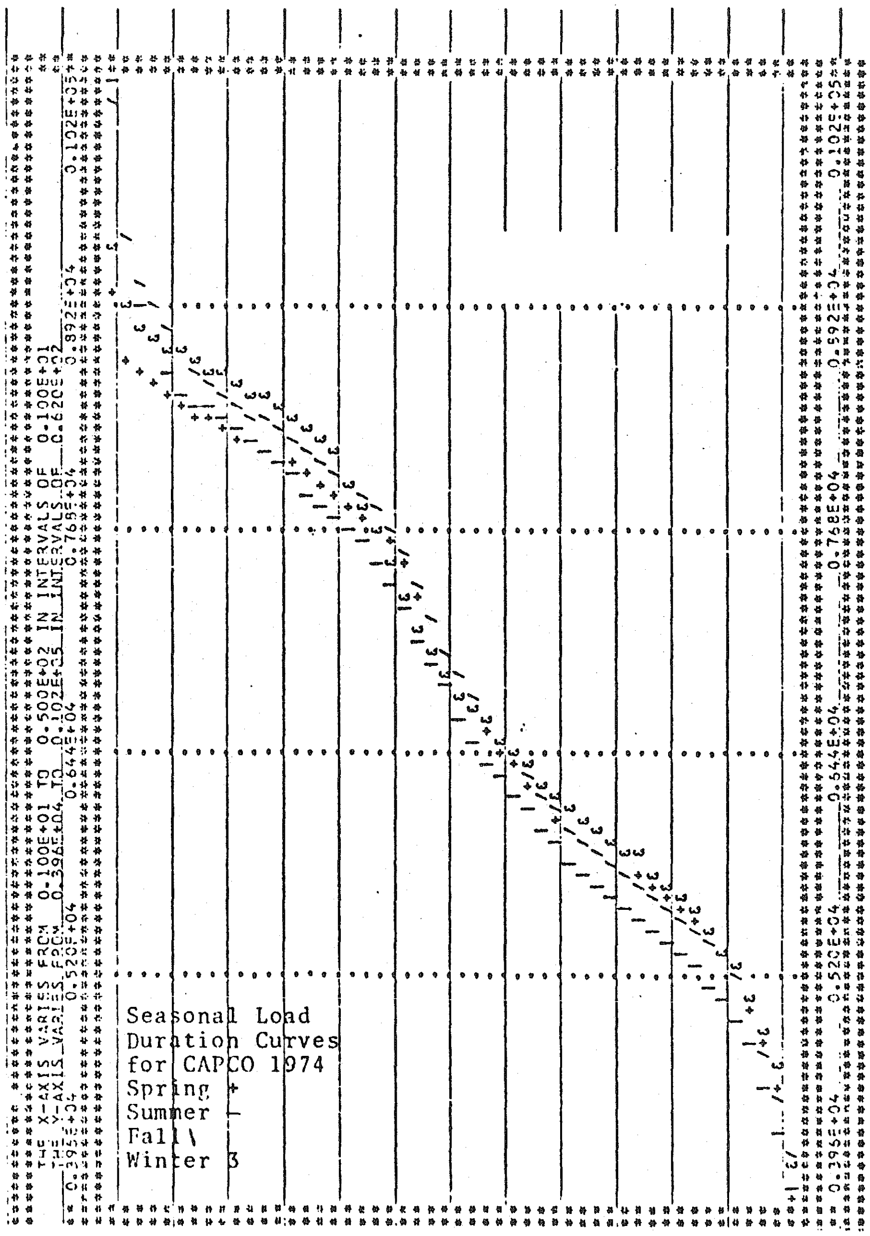

THE X-AXIS VARIES FROM 0.100E+01 TO 0.500E+02 IN INTERVALS OF 0.100E+01
THE Y-AXIS VARIES FROM 0.396E+04 TO 0.102E+05 IN INTERVALS OF 0.620E+02
0.396E+04
0.520E+04
0.644E+04
0.768E+04
0.892E+04
0.102E+05
Seasonal Load
Duration Curves
for CAPCO 1974
Spring +
Summer –
Fall \
Winter 3

FIGURE 22

TABLE 4

MWh

1973

Utility	DP & L	Ohio Edison	CEI	Columbus & Southern	Toledo Edison	Duquesne	CAPCO
Residential & Rural Demand	2,855,857 31.21%	4,708,635 24.59%	3,910,018 21.51%	2,543,388 31.74%	1,551,861 22.08%	2,610,309 19.6%	13,461,879 22.1%
Commercial Demand	1,617,761 17.68%	3,618,336 18.9%	3,569,689 19.64%	2,308,499 28.26%	1,102,495 15.69%	3,623,474 27.21%	12,342,184 20.27%
Industrial Demand	2,798,284 30.59%	7,983,856 41.69%	9,103,173 50.08%	2,068,359 25.32%	3,231,549 45.98%	6,180,710 46.42%	28,378,722 46.6%
Street Lighting	58,740 0.64%	129,765 0.68%	135,303 0.77%	20.707 0.25%	54,258 0.77%	108,692 0.82%	438,561 0.72%
Electric Transportation	7,868 0.12%	-0- -0-	29,366 0.16%	-0- -0-	-0- -0-	14,470 0.108%	29,366 0.05%
Losses & Unaccounted	756,950 8.27%	1,561,374 8.15%	1,103,326 6.07%	634,087 7.76%	455,628 6.48%	744,452 5.59%	4,042,954 6.64%
Other Demand	1,054,250 11.52%	1,147,227 5.99%	324,911 1.79%	543,997 6.66%	632,139 8.99%	32,881 0.25%	2,210,050 3.63%
Total Consumption	7,143,620 100%	19,149,193	18,175,786	8,169,032	7,027,930	13,315,018	60,903,716

From Form FE-1(c)

TABLE 5

MWh

1974

Utility	DP & L	Ohio Edison	CEI	Columbus & Southern	Toledo Edison	Duquesne	CAPCO
Residential & Rural Demand	2,968,084 32.57%	4,910,221 25.77%	4,046,000 22,59%	2,661,498 32.31%	1,660,479 22.73%	2,575,287 19.27%	14,217,479 22.51%
Commercial Demand	1,604,280 17.61%	3,608,261 18.94%	3,575,000 19.96%	2,327,008 28.25%	1,162,664 15.92%	3,552,889 26,58%	12,923,664 20.46%
Industrial Demand	2,629,521 28.86%	7,798,335 40.93%	8,549,000 47.73%	2,005,679 24,34%	3,304,600 45.25%	6,745,354 47,48%	28,530,600 45.19%
Street Lighting	58,740 0.64%	133,856 0.7%	136,900 0.76%	21,507 0.26%	54,981 0.75%	113,706 0.85%	454,881 0.72%
Electric Transportation	9,333 0.102%	-0- -0-	29,366 .16%	-0- -0-	-0- -0-	14,896 0.11%	40,000 0.06%
Losses & Unaccounted	702,550 7.71%	1,428,093 7.5%	1,238,363 6.91%	652,116 7.92%	448,199 6.14%	730,524 5.47%	4,636,562 7.34%
Other Demand	1,139,458 12.51%	1,193,921 6.16%	334,000 1.86%	570,803 6.93%	672,961 9.21%	32,521 0.24%	2,335,961 3.7%
Total	9,111,966 100%	19,052,688	17,909,263	8,238,611	7,303,884	13,365,177	63,139,147

From Form FE-1(c)

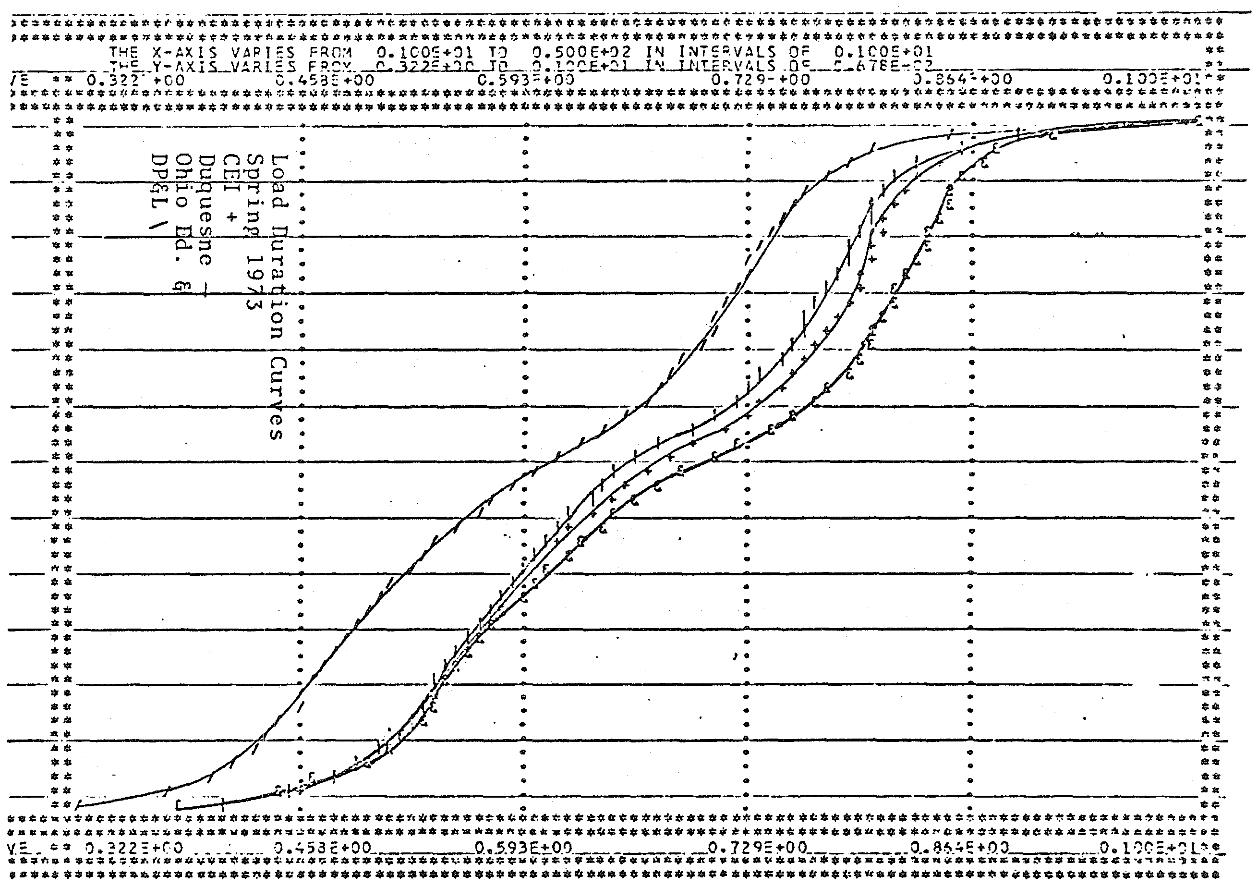

THE X-AXIS VARIES FROM 0.100E+01 TO 0.500E+02 IN INTERVALS OF 0.100E+01
THE Y-AXIS VARIES FROM 0.322E+00 TO 0.100E+01 IN INTERVALS OF 0.678E-02
0.322E+00
0.458E+00
0.593E+00
0.729E+00
0.864E+00
0.100E+01
Load Duration Curves
Spring 1973
CEI +
Duquesne -
Ohio Ed. &
DP&L \

FIGURE 23

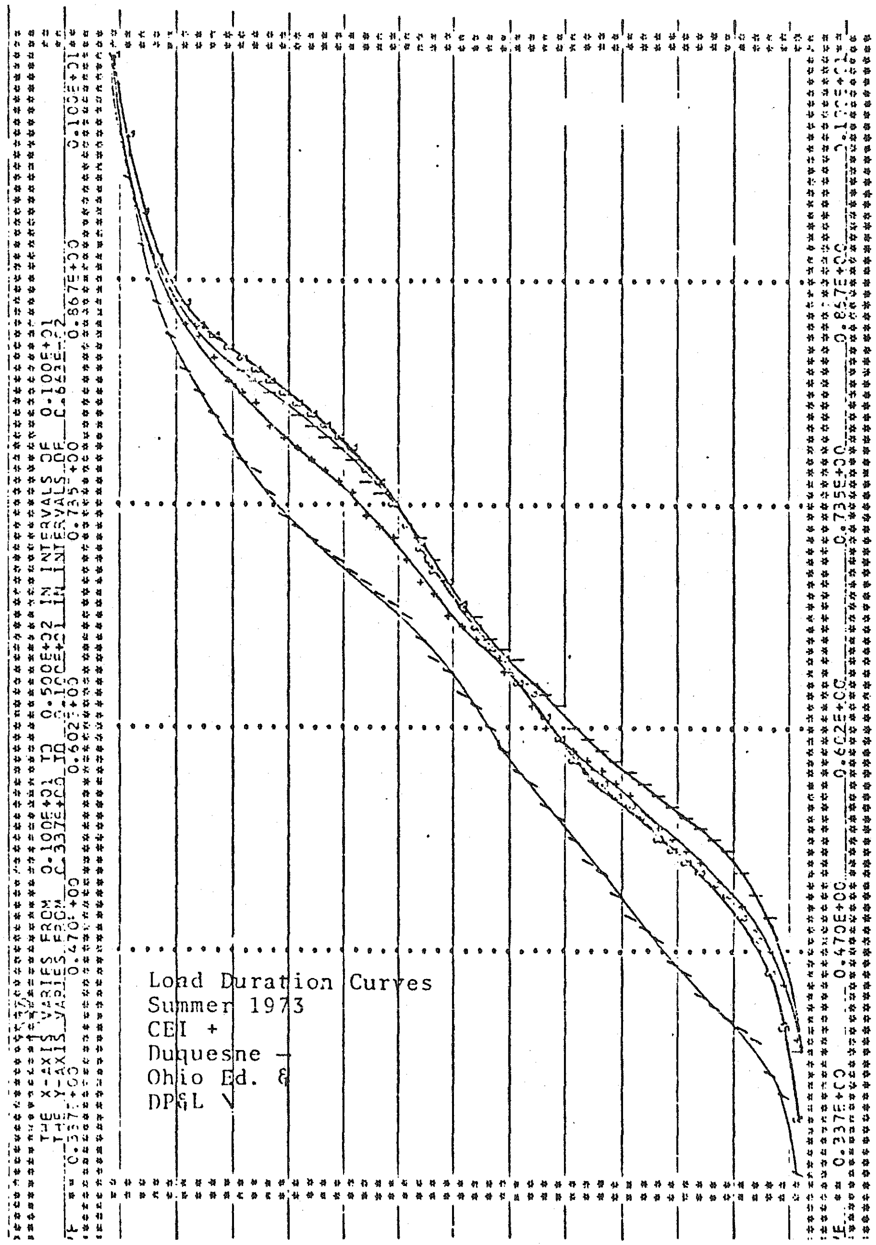

THE X-AXIS VARIES FROM 0.100E+01 TO 0.500E+02 IN INTERVALS OF 0.100E+01
THE Y-AXIS VARIES FROM 0.337E+00 TO 0.100E+01 IN INTERVALS OF 0.663E-02
0.337E+00
0.470E+00
0.602E+00
0.735E+00
0.867E+00
0.100E+01
Load Duration Curves
Summer 1973
CEI +
Duquesne -
Ohio Ed. &
DP&L \

FIGURE 24

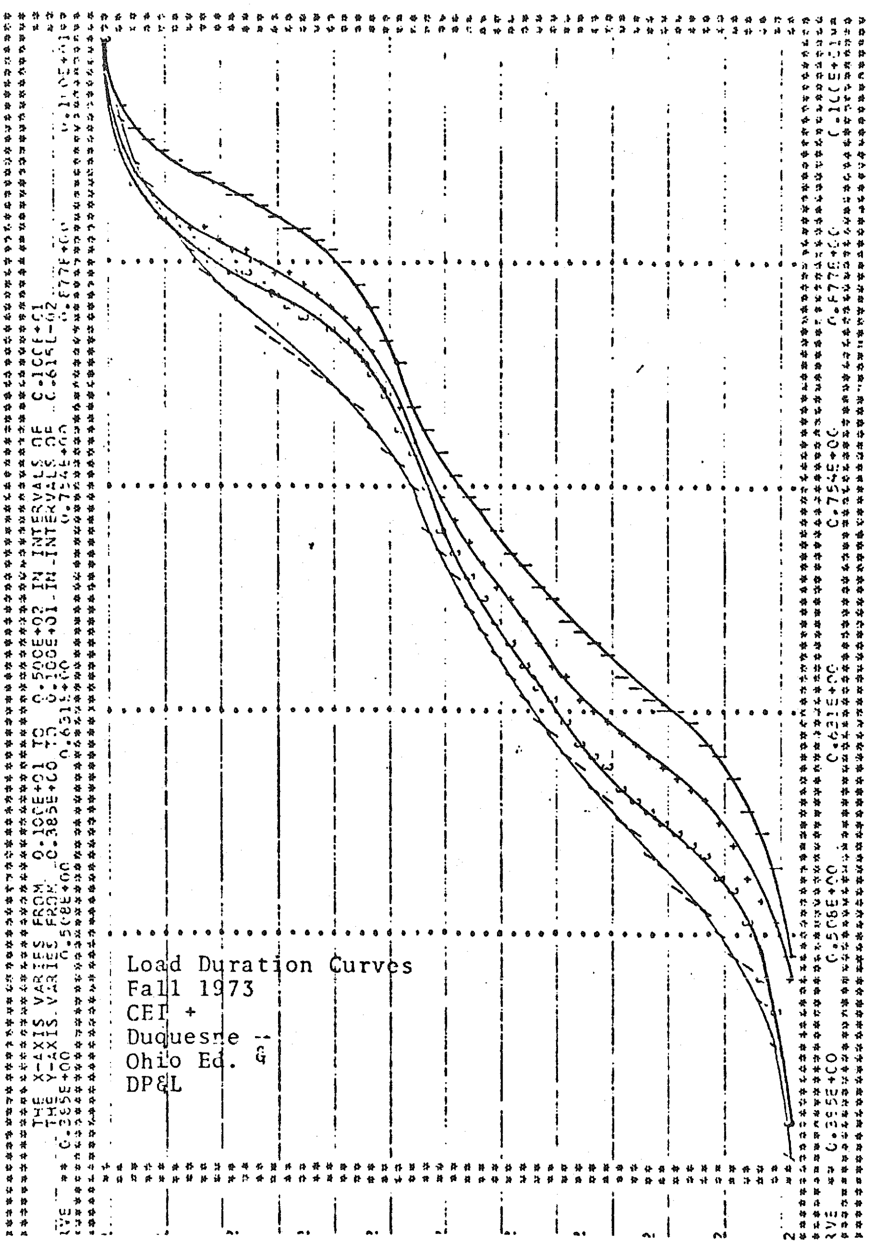

THE X-AXIS VARIES FROM 0.100E+01 TO 0.500E+02 IN INTERVALS OF 0.100E+01
THE Y-AXIS VARIES FROM 0.385E+00 TO 0.100E+01 IN INTERVALS OF 0.615E-02
Load Duration Curves
Fall 1973
CEI +
Duquesne --
Ohio Ed. G
DP&L

FIGURE 25

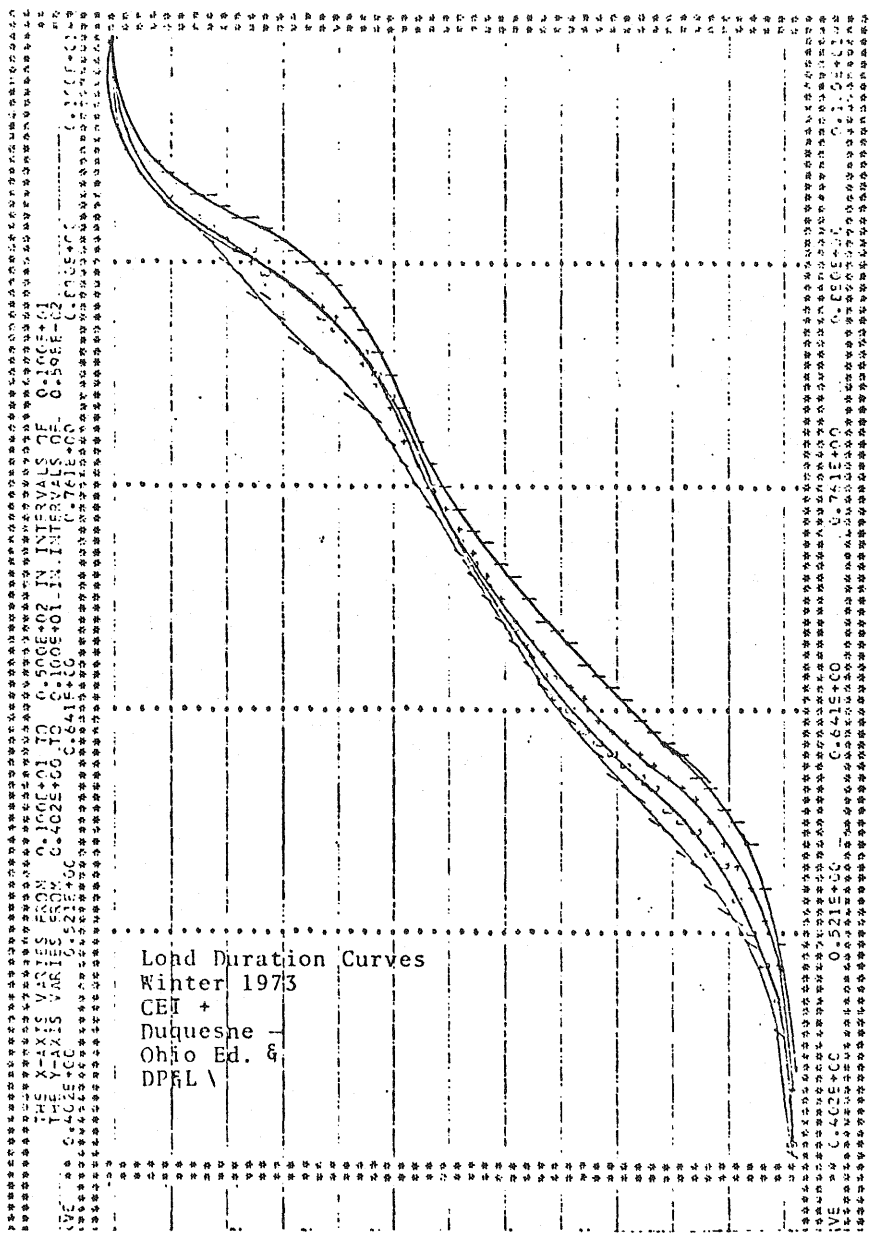


FIGURE 26

CHAPTER 13

ESTIMATION OF POWER PLANT CONSTRUCTION COST IN OHIO

13.1 Introduction

This chapter describes a method of obtaining construction cost input data for WASP. By the proposed method relationships among cost, capacity and year of construction completion for plants of various types are developed. This method utilizes cost estimates for plants actually scheduled to operate in the region and time period of application of WASP.

Prior to discussion of the proposed method, background information about construction costs is presented in Sections 13.2, 13.3 and 13.4. In Section 13.2 the nature of construction cost estimates is discussed. In Section 13.3 current trends in construction cost are analyzed, and in Section 13.4 the effect of various parameters on construction costs is discussed. In Section 13.5 the proposed method is applied to nuclear and coal-fired plants in Ohio and its vicinity. Results obtained in this report are based on 1977 estimates. Results based on 1976 estimates have been reported in reference 1.

13.2 Nature of Construction Cost Estimation

The costs for construction projects of electric utilities are usually estimated by engineering firms. Conceptual cost estimates, on the other hand, may be obtained through computer programs such as CONCEPT[2]. Conceptual estimates are based on standard cost models and consequently they do not reflect such peculiar conditions that exist to a specific company or a specific project.

The cash flow distribution during construction is frequently depicted by a (cumulative) "Cash Flow Curve." Two sample Cash Flow Curves are shown in Figure 1. In that figure the duration of construction of a nuclear power plant is assumed to be 7.5 years and that of a coal plant is 6 years. In this illustration the

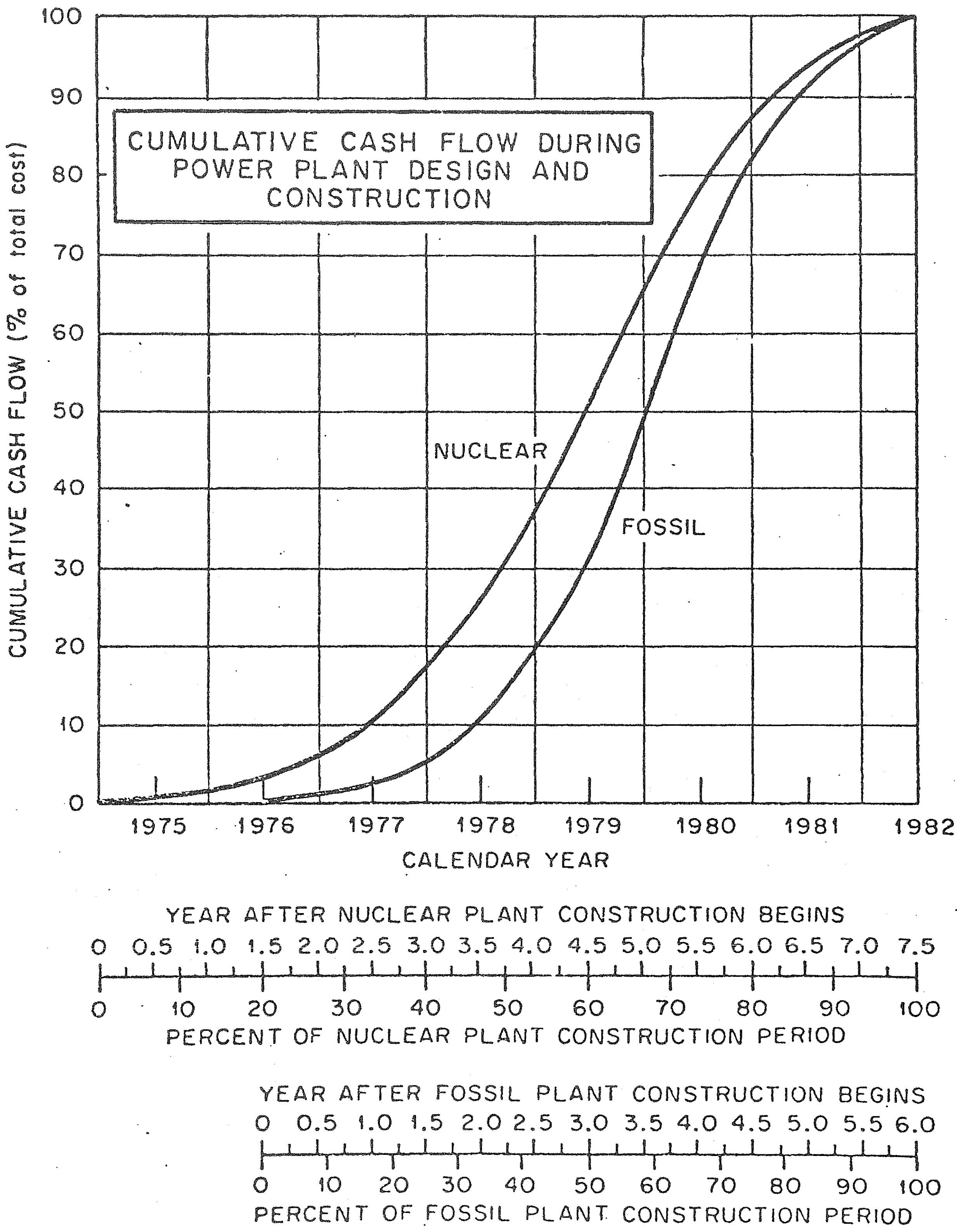


Figure 1. Distribution of project cash flows during power plant design and construction (3). The length of the periods indicated may not by typical of current projects.

nuclear steam supply system is contracted for at the beginning of 1975, the construction permit is received in mid-1977, and the project is completed in mid-1982. For the coal plant the steam supply system is contracted for in mid-1976, the construction permit is received in mid-1978, and construction is completed in mid-1982 (3).*

The construction cost of a power plant consists of a direct and an indirect cost component. Direct costs are those associated with structures, facilities, land, and plant equipment. Because of escalation in the cost of materials and labor during the construction period, the amount of direct costs varies depending upon when payments for such structures, facilities, etc. are made. Indirect costs include the cost of such facilities, equipment, and services that are used for construction, taxes, and interest. These costs are strongly dependent upon the duration of construction. For example, the amount of interest during construction† depends on the length of time between investment and project completion.

When an estimate for the cost of a project is prepared, a contingency allowance must be included with each major account. Because it is also anticipated that during the course of construction the cost of materials and labor will change, cost increases must be calculated and included in the estimate under the heading "Escalation During Construction." Escalation during construction must be calculated for each expense from the base year at which the estimate for an expense was made until such expense is incurred.

The accuracy of an estimate depends upon the accuracy of the forecast of financial parameters such as escalation and interest and upon how closely the cash flow curve is followed. During the several years of the construction period, the forecasts for financial parameters change, and deviations from the original schedule frequently occur. For these reasons, estimates must be updated from time to time to include corrections to the cash flow record

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*These schedules may not be typical of current projects.

†Sometimes called "Allowance For Funds During Construction" (AFDC).

for the period between the last prediction and the present as well as new forecasts and schedules for the remainder of the construction period.

13.3 Current Trends of Construction Costs

Final costs of power plants which came on line during the present decade are significantly higher than originally estimated. Annually updated estimates for the plants currently under construction show the same trend[4]. This trend can be illustrated by observing changes in the estimated final cost of power plants in Ohio; relevant data are presented in Table 1. This table contains three sections. In section (a), unit costs* and dates of expected commercial operations are shown as of 1976. In section (b), the same items are presented updated as of 1977. In section (c), the net delay and cost increase between 1976 and 1977 estimates are calculated. The data in sections (a) and (b) of Table 1 are from annual utility reports to the Securities and Exchange Commission. From the data in Table 1, it becomes apparent that, with the exception of one plant, all others which were scheduled to be on line after 1979 have been deferred by one or two years. Also, regardless of whether there is a delay or not, every cost estimate with the exception of one has been increased. The estimate which has been decreased reflects the decision to procure low-sulfur coal instead of building SO_2 removing equipment[5]. In general, cost increases are due to inflation and the increased cost of money, delays in the completion of construction and changes in safety and environmental standards.

The average annual escalation rate of total steam plant construction costs in the North-Central U.S. between January 1, 1970 and January 1, 1977 was 9.4%. The lowest in that period was 2.4% during 1972 and the highest was 26.2% during 1974. During 1976 the

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$$\text{*Unit Cost} = \frac{\text{Plant Construction Cost (\$)}}{\text{Plant Net Capacity (kW}_e\text{)}}$$

Table 1 Estimated Unit Costs and Dates of Expected Commercial Operation of Steam Electric Power Plants Being Built by Ohio Utilities

Source: Utility Annual Reports to the Securities & Exchange Commission

Plant Name	* C or N	Capacity MW_e	(a) as of 1976		(b) as of 1977		(c) Comparison	
			Year of Line	Cost $\$/kW_e$	Year on Line	Cost $\$/kW_e$	Delay Years	Cost Increase $\$/kW_e$
Mansfield 2,3	C	2x825	1977,1979	564	1977,1980	617	1	53
Conesville 6	C	375	1978	292	1978	326	0	34
Miami Fort 8	C	500	1978	338	1978	266	0	-72
Zimmer 1,2	N	792+1150	1979,1986	828	1979,1987	894	1	66
East Bend 1,2	C	2x600	1980,1982	527	1981,1984	594	3	67
Perry 1,2	N	2x1205	1980,1982	660	1981,1983	853	2	193
Poston 5	C	375	1981	803	1983	942	2	139
Killen 1,2	C	2x600	1981,1983	466	1982,1985	547	3	81
Beaver Valley 2	N	885	1981		1982	1072	1	
Davis Besse 2,3	N	2x906	1983,1985	804	1985,1987	1357	4	553
Poston 6	C	375	1983	581	1985	666	2	85
Erie 1,2	N	2x1260	1984,1986	945	1986,1988	1047	4	102

* C: Coal, N: Nuclear

annual escalation rate was 5.4%. These figures were derived from the Handy-Whitman Index[6].

Delays increase final construction costs mainly because of more interest during construction. Delays are due to longer licensing times, intervenor actions, changes in safety and environmental standards coupled with changes in design and retrofitting, shortages in construction personnel and materials, inadequate productivity. Utilities have also deferred the completion of some of their projects because of difficulties in raising the necessary funds.[7-12]

Changing safety and environmental standards have a significant impact upon the cost of power plants. Thus, in addition to the direct cost of compliance with new standards, delays resulting from the revision of designs and retrofitting have affected indirect costs as well.

Safety design changes made to nuclear power plants in the past are related to containment structures, seismic criteria, IEEE requirements, emergency core cooling, allowable radiation doses for postulated accidents, design bases for post-accident hydrogen control systems, restrictions of routine release of low-level radioactivity, etc.[3,13].

Environment-related changes have affected both coal-fired and nuclear power plants. Common to both (but affecting coal-fired plants less) have been changes in the allowable intake velocity of cooling water and temperature rise in the condenser. As a result, a major scale-up of water intake structures, condenser pipes and pumps was required. Changes related to noise levels have also been made. Other environmental restrictions applicable to coal but not to nuclear power plants relate to particulates, SO_2 and NO_x emissions, limestone handling, ash system, and sewage treatment[3,14].

13.4 Effect of Financial and Design Parameters on Construction Costs

The cost of a power plant depends on a number of financial and design parameters. Major parameters which influence construction costs are escalation rates, interest rates, wages and length of a work week, length of the period of construction, type of plant (coal, nuclear, etc., single or multiple unit), plant capacity, plant location (e.g. south-east or north-central U.S., etc.), environmental restrictions and method of compliance (e.g., SO_2 removing equipment vs. procurement of low sulfur coal), type of cooling system, desired degree of plant availability, novelty of design, plant site (e.g., on a mine, near a river).

The sensitivity of plant costs to the above parameters (excluding the last three) can be examined by using the CONCEPT program[2]. Basically, CONCEPT assumes that a given plant will have the same components regardless of location and time of construction. The program contains reference designs for various types of plants. When the cost of a given plant is sought, the cost components of the reference plant will be adjusted according to local cost indices, time escalation parameters, and size scaling factors to produce the cost for the given plant[2].

Size-related scaling factors are stored in CONCEPT for each of the major components of a plant. For each component, scaling relations used by CONCEPT are of the form:

$$\text{Cost} = \text{constant} \cdot (\text{Size})^r$$

where r is called the scaling exponent. The value of r is different for each component; moreover there exists disagreement among different estimators about the proper value of r for a given component. The exponents used by CONCEPT are usually in the middle of the range of those of other estimators[2].

Results of a study of the sensitivity of construction costs to various parameters, using CONCEPT, were reported by the AEC[3] in 1974. Many of the parameters used in that study have changed since the time of the study, (e.g. estimates for escalation rates, interest rates, duration of construction, etc.). Nevertheless their results can be useful in providing a qualitative indication of the effects of various parameters on constructing costs; a summary of these results is presented below:

- Cost variations due to plant location were within ±8% of the U.S. average; in Ohio, costs were calculated to be within ±2% of the U.S. average.

- Assuming escalation rates of 10% per year for labor and 5% per year for materials, interest rate of 7.5% per year, it was calculated that one year's delay in the completion of construction increased final cost by 7%.
- When the duration of construction was set to 6 years for coal plants and 7.5 years for nuclear plants, it was found that a 1% increase in the escalation rate for equipment and materials led to a 3% increase in total costs; a 1% increase in the escalation rate for site labor led to a 1.5% increase in total costs.
- A 1% increase in the interest rate increased total costs by 3% for nuclear plants, and by 2% for coal plants.
- Alternative heat rejection systems were investigated, and it was found that when natural draft towers are used, total costs increase by 2 - 3% over the case when mechanical draft towers are used.
- When the cost of SO_2 removing equipment was included, the total cost was higher by 21% than when not.
- Multiple-unit plants have a lower total cost per kw provided that subsequent units are completed soon after the first one. Savings are mainly due to reduced indirect costs for subsequent units. If subsequent units are sufficiently delayed, however, interst and escalation during construction may outweigh these savings. For a dual-unit plant where the second unit came on line one year after the first, CONCEPT calculated total savings on the order of 5% over the unit cost of the first unit.
- Total cost differences as a function of size were found to be as much as 30%. The variation of unit cost as a function of capacity for various types of plants is shown in Figure 2. This figure was obtained from Reference 3.

13.5 A Method of Providing Capital Cost Data Input to WASP

Construction cost data required as input to WASP consist of unit cost estimates for various types (coal-fired, nuclear, etc.) and capacities of plants coming on line in any year of the study

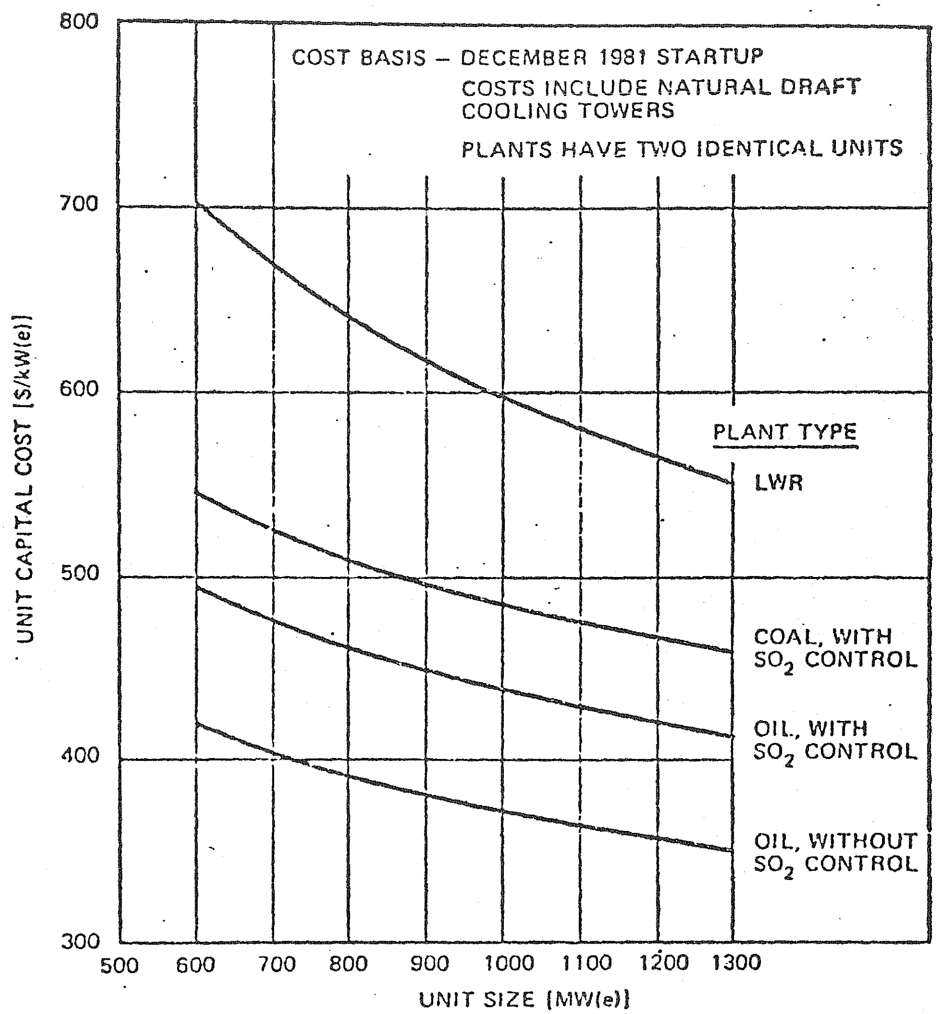

Figure 2. Unit capital costs of power plants as a function of unit size. Adapted from reference-3. This figure is furnished to indicate the relationship between unit cost and unit size. Actual numbers may not be typical of current projects.

horizon. As a result of non-uniform delays in construction completion the costs of similar plants coming on line in the same year may be quite different. If it is desired that construction data for WASP be compatible with cost estimates for actual plants on schedule, then it becomes difficult to obtain such data for WASP by means of conceptual programs.

When cost estimates for actual plants are available, it is possible to create a set of input data for WASP which, as a whole, is compatible with cost estimates for actual plants. In this section, we describe the method which was used to obtain such input for the application of WASP to Ohio utilities.

In deriving a convenient formula which will supply data for WASP, we assume that the cost of a plant in a separable function of capacity, x, and year of construction completion, t. Further, it is assumed that the cost of a plant of a given design can be found by adjusting the cost of a standard-design plant by a multiplicative correction factor. The formula which is sought is of the form

$$UC(x,t) = K \cdot S(x) \cdot F(t)$$

where

- UC: unit cost, $\$/kW_e$,
- x: plant capacity, MW_e,
- t: year of completion of construction,
- K: multiplicative, design-correction factor,
- S: a function which expresses cost variation with capacity for plants of standard design and is normalized to unity for a reference plant,
- F: a function which expresses cost variation with year of completion of construction for the reference plant of standard design.

The design-dependent factor, K, can be found by using the CONCEPT code or some other means. For example, if the CONCEPT code indicates that the cost of a plant with natural draft towers is 3% higher than for a plant with mechanical draft towers, and the latter type of plant is assumed to be the standard design, then

K is set to 1.03.

The capacity-dependent function, S, can be obtained by using the CONCEPT Code. Graphs of unit cost, y, as a function of capacity, x, of plants with identical designs and construction periods, obtained by CONCEPT, are shown in Figure 2. The curves of figure 2 are fitted as

$$y(x) = \text{Constant} \cdot x^r \qquad (3)$$

where

$r = -0.26$ for coal plants, and

$r = -0.32$ for nuclear plants.

If $y(x_0)$ denotes the unit cost of a reference plant of capacity x_0, then $s(x)$ is obtained by using Eq. (3) as

$$S(x) = \frac{y(x)}{y(x_0)} = \left(\frac{x}{x_0}\right)^r \qquad (4)$$

The function F(t) can be found by fitting construction costs estimates for plants scheduled by Ohio utilities as a function of the year of construction completion. Since F(t) must represent the functional relationship between cost and year of construction completion of plants of the same design and of reference capacity, prior to fitting, the cost estimates for individual plants must be adjusted to represent cost estimates for the reference capacity and standard design plant. Adjustments for differences in design can be made using the correction factor, K. Adjustments for differences in capacity are made by using Eq.(4). If F_i is the estimated cost for the standard design but with the actual capacity, x, the estimate for the reference capacity is given by

$$F_i = F_i \left(\frac{x_o}{x}\right)^r \qquad (5)$$

where x is the capacity of the actual plant, and x_0 the reference capacity. This is repeated for all available cost estimates by Ohio utilities. The values of F_i's thus obtained are fitted by a function of the year of completion of construction, t, as

$$F(t) = ae^{bt} \qquad (6)$$

where a and b are constants determined by the fit.

The annual rate of construction cost escalation, R, is found from Eq. (6) as

$$R = e^{b} - 1,$$

where R is the annual rate defined by (7)

$$R = \frac{\text{Construction Cost of Reference Plant Completed in Year N}}{\text{Construction Cost of Reference Plant Completed in Year N-1}} - 1. \tag{8}$$

The basic cost estimates for individual plants scheduled by Ohio utilities are shown in Table 2. Of the cost estimates listed in Table 2, the original estimate for Killen does not include the cost of SO_2 removing equipment. The cost estimate for that plant as presented in Table 2 has been multiplied by K = 1.23 to reflect the cost of SO_2 removing equipment.

Some of the cost estimates in Table 2 are for the total cost of multiple-unit plants. These estimates are not used in that form. Rather, adjustments are made so that these estimates represent the cost of the first unit. Next these estimates are translated into the cost of reference-capacity plants. The reference capacity for nuclear plants is chosen as 1000 MW_e, and for coal-fired plants as 600 MW_e. Every unit cost estimate for the reference capacity based on the i'th plant on schedule is given by Eq. (5)

with

$$x_o = \begin{cases} 600 & \text{for coal-fired plants} \\ 1000 & \text{for nuclear plants} \end{cases} \tag{9}$$

and

$$r = \begin{cases} -0.26 & \text{for coal-fired plants} \\ -0.32 & \text{for nuclear plants} \end{cases} \tag{10}$$

The resulting estimates, $\tilde{F}_i$, are listed in Table 3. By fitting the estimates of Table 3, $\tilde{F}_i$, as a function of the year of completion of construction, t, one obtains

$$F(t) = 396.33\ e^{0.09(t-1975)} \quad \text{for coal plants} \tag{11}$$

including the cost of SO_2 removing equipment, and

$$F(t) = 560.53\ e^{0.06(t-1975)} \quad \text{for nuclear plants.} \tag{12}$$

In Equations (11) and (12) t is the year of plant completion and

Table 2. Unit cost-estimates for plants scheduled by Ohio electric utilities (Data from References 9, 10, 14)

Coal-Fired Plants					Nuclear Plants				
i	Plant Name	Capacity Mw(e)	Year of Operation	Unit Cost F_i \$/kw(e)	i	Plant Name	Capacity Mw(e)	Year of Operation	Unit Cost F_i \$/kw(e)
1	Mansfield 1	825	1976	464	1	Beaver Valley 1	885	1976	650(***)
2	Conesville 5	375	1976	393	2	Davis Besse 1	906	1977	630(***)
3	Mansfield 3	875	1980	767(***)	3	Zimmer 1	792	1979	670
4	Poston 5	375	1983	942	4	Perry 1,2(*)	2 x 1205	1981,1983	853
5	Killen 1,2(*)	2 X 600	1982,1985	673(**)	5	Beaver Valley 2	885	1982	1072
6	East Bend 1,2(*)	2 X 600	1981,1984	594	6	Davis Besse 2,3(*)	2 X 906	1985,1987	1357
					7	Erie 1,2(*)	3 X 1260	1986,1988	1047
					8	Zimmer 2	1150	1987	1049

(*) Total cost of two units available.

(**) The cost for hypothetical SO_2 removing equipment has been added.

(***) Data obtained from PUCO staff.

Table 3. Unit Cost estimates of first unit, reference size plants including the cost of SO_2 removing equipment.

Coal-Fired Plants				Nuclear Plants			
i	Plant Name	Year of Operation	Unit Cost, $\tilde{F}_i$/\$/Kwe	i	Plant Name	Year of Operation	Unit Cost, $\tilde{F}_i$ \$/Kwe
1	Mansfield 1	1976	504	1	Beaver Valley 1	1976	625
2	Conesville 5	1976	348	2	Davis Besse 1	1977	610
3	Mansfield 3	1980	833	3	Zimmer 1	1979	622
4	Poston 5	1983	834	4	Perry 1	1981	824
5	Killen 1	1982	673	5	Beaver Valley 2	1982	1031
6	East Bend 1	1981	594	6	Davis Besse 2	1985	1196
				7	Erie 1	1986	1026
				8	Zimmer 2	1987	1097

F is the unit cost of the reference plant. The cost of a plant of different size, UC(x,t) can then be calculated by

$$UC(x,t) = K(\frac{x}{x_o})^r F(t). \quad (13)$$

For coal plants without SO_2 removing equipment K = 1/1.23; otherwise K = 1. Results of this fit are shown plotted in Figures 3 and 4.

The uniform, annual construction cost escalation rate, R, obtained as the result of the present fitting is equal to 9.4% per year for coal-fired plants and 6.2% per year for nuclear plants. In order to explain the apparent disparity in the escalation rate between coal and nuclear plants, additional information about each specific plant is needed. As noted in reference 1, such information may be obtained from various utility companies. Until uncertainties in the data are resolved, it is recommended that in applications of WASP a range of R be used.

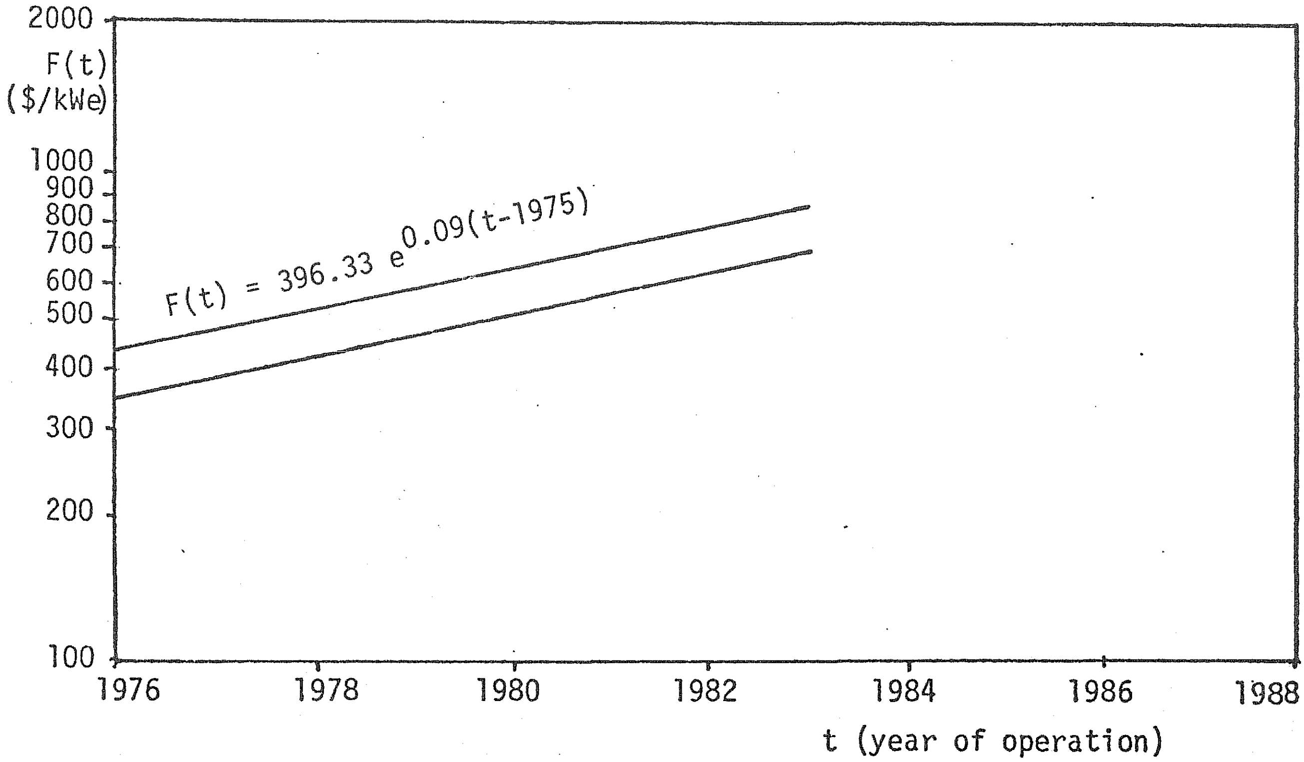

Figure 3. Unit cost as a function of year of operation for the standard, 600 MWe coal plant with (upper curve), and without (lower curve) SO_2 removing equipment.

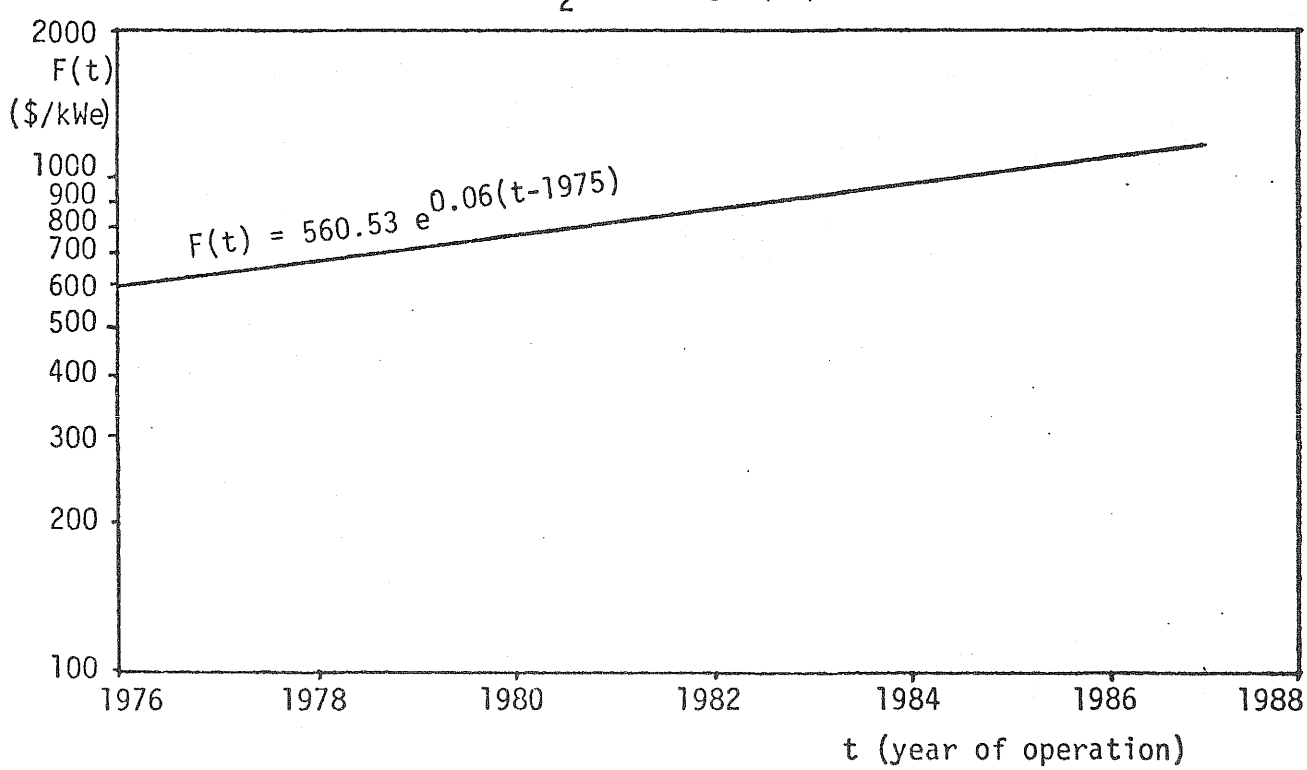

Figure 4. Unit cost as a function of year of operation for the standard, 1000 MWe nuclear plant.

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CHAPTER 14

COST OF RELIABILITY STUDY

14.1 Methodology

The objective of the cost of reliability study is to determine the relative total generation cost of a utility expanding in an optional manner as a function of reliability constraint. The study considers the Dayton Power & Light Company (DP&L) as a model system. Subject to a given reliability criterion the optimal expansion policy for the next ten years is determined by the WASP code and the associated value of the objective function, defined as the sum over all years of the study of the cost of construction plus the operation and maintenance (O&M) cost less any plant salvage value† all discounted back to 1975 dollars, is calculated. The process is repeated for other reliability levels thus yielding a curve of total system cost versus reliability level. The loss-of-load probability (LOLP), defined as the probability that the system will have to call upon emergency measures to meet the load, is used as a reliability criterion in this study.

14.2. Input Data

The input data for each of the six modules discussed in Chapter 4 is described below.

14.2.1. FIXSYS Data

The data for FIXSYS is shown in Table 1. Each column in Table 1 is numbered and its meaning is explained at the bottom of the table. For example, the first entry in the first column of Table 1 refers to Connesville unit #4 (code name CON4) having one identical unit, a minimum and maximum net generating capacity of 60 MWe and 132 MWe, respectively††, a base load heat rate of 8940/Btu/kWhe and an average incremental

†Each expansion candidate has a plant life associated with it. The WASP code assumed that at the end of the study period the utility goes out of business and sells all its equipment. The salvage value of each unit in the expansion schedule is calculated based on the number of years of plant life remaining at the end of the study period and is subtracted from the cost of construction for that unit to arrive at an effective capital cost for the unit.

††Since a number of the plants in the DP&L system are jointly owned with Columbus & Southern Ohio Electric (C&SO) and Cincinnati Gas & Electric (Continued)

heat rate of 8808 Btu/kWhe (the calculation of heat rate data is given in Appendix 14A0, a domestic fuel cost of 102¢/million Btu, a foreign fuel cost of 0¢/million Btu (not used in this study), a plant type code of 4 (coal-fired), a plant location number set to 1 in this version of WASP, a forced outage rate of 30.2%, 42 days per year of scheduled maintenance, a maintenance class size of 800 MW (see Table 2), an expected energy generation per year of 0 GWH (for hydro stations only) and a fixed variable non-fuel O&M cost of 0.044$/kW-month and 0.709¢/kWh, respectively. The names of the units to which the code names refer are shown in Appendix 14C.

The last entry in the first column of Table 1 (OHPC) is a contract with the Ohio Power Company which is modeled as a ficticious plant having a capacity equal to the amount specified in the contract, a 0.0% forced outage rate and no maintenance requirements. Because the utility pays the capacity cost for this contract whether or not it uses the power, the contract is modeled as a ficticious plant instead of being included with emergency power. The minimum and maximum operating levels, heat rate data and the forced outage rates are taken from information supplied by DP&L. The domestic fuel costs are taken from a letter from Mr. Allen Hill of DP&L dated November 24, 1975. The number of days per year of scheduled maintenance are taken from a Faculty Engineering Conference paper by Mr. R.X. French[2], and the O&M costs are the result of work done by S. Tzemos with the PUCO. Tzemos separated the appropriate financial accounts in the 1975 annual report, FPC Form 1,[2] into those attributed to fixed O&M costs and those attributed to variable O&M costs, summing each and converting to the proper units for use in FIXSYS.

WASP requires the grouping of maintenance outages into a maximum of seven classes. The capacity of each unit takes one of the seven values. The divisions are rather arbitrary but should be selected so as to minimize the deviation from reality. Table 2 displays the maintenance classes; these divisions are used for the cost of reliability and power pooling† studies and for both the FIXSYS and VARSYS modules.

(Cont.)
(CG&E) the power available from these plants is given in terms of what available to DP&L.

†See Chapter 15

Table 1 FIXSYS Data-Cost of Reliability Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CON4	1	60	132	8940	8808	102	0	4	1	30.2	47	800	0	0.044	0.709
FOR7	1	72	176	9017	8918	102	0	4	1	20.0	42	500	0	0.153	0.153
PEK6	1	75	220	8755	8694	102	0	4	1	33.1	42	500	0	0.032	1.249
STI3	3	80	205	8731	8655	102	0	4	1	21.1	42	600	0	0.017	0.528
STU4	1	80	205	8785	8668	102	0	4	1	17.1	42	600	0	0.017	0.528
HU36	4	15	68	9649	9612	102	0	4	1	6.5	22	60	0	0.062	1.162
HUT1	1	61	61	10706	10706	102	0	4	1	4.9	22	60	0	0.062	1.162
HUT2	1	60	60	9621	9621	102	0	4	1	6.7	22	60	0	0.062	1.162
TAI4	1	70	140	9087	9062	102	0	4	1	16.9	29	140	0	0.057	1.555
TAI5	1	130	130	9757	9757	102	0	4	1	15.5	29	140	0	0.057	1.555
TTOP	1	160	150	11811	11811	102	0	4	1	16.0	29	140	0	0.087	1.555
MOND	1	14	14	10204	10204	232	0	1	1	25.8	16	20	0	0.162	0.978
SIDD	1	14	14	10204	10204	232	0	1	1	21.4	16	20	0	0.140	0.162
STUD	1	4	4	10204	10204	232	0	1	1	10.0	16	20	0	0.024	0.133
TAID	1	11	11	10204	10204	232	0	1	1	9.7	16	20	0	0.163	0.978
HUGT	1	34	34	10911	10911	232	0	2	1	6.8	16	20	0	0.157	0.285
YA47	4	21	21	11212	11212	232	0	2	1	6.2	16	20	0	0.148	0.287
YA12	3	24	24	11211	11211	232	0	2	1	11.1	16	20	0	0.148	0.267
OHPC	1	150	150	10000	10000	101	0	4	1	0.0	0	0	0	2.282	0.000

Item Descriptions

1) Code Name for Power Station
2) Number of Identical Units
3) Minimum Operating Level (MWE)
4) Maximum Generating Capacity (MWE)
5) Heat Rate at Minimum Operating Level (BTU/KWHE)
6) Average Incremental Heat Rate (BTU/KWHE)
7) Domestic Fuel Cost (Cents/Million BTU)
8) Foreign Fuel Cost (Not Used in this Study)
9) Plant Type (0=Nuclear; 1=Gas Turbine; 2=Diesel; 4=Coal-Fired)
10) Plant Location Number (Set to 1 in this Version of WASP)
11) Forced Outage Rate (%)
12) Number of Scheduled Maintenance Days per Year
13) Maintenance Class Size (MW) -
14) Expected Energy Generation (GWH) - For Hydro Stations Only
15) Fixed Non-Fuel O&M Cost ($/KW-Month)
16) Variable Non-Fuel O&M Cost (Cents/KWE)

Table 2 Maintenance Classes

Capacity Range (MW)	Maintenance Class (MW)
0 - 39	20
40 - 99	60
100 - 199	140
200 - 549	500
550 - 699	600
700 - 949	800
950 & Over	1000

The energy and demand charges associated with the contract with Ohio Power Company are modeled as a fuel cost and a fixed O&M cost, respectively, as follows[3]:

Energy Charge:

$$\frac{\$6{,}501{,}972 \text{ energy charge}}{644{,}714{,}000 \text{ kWh consumed}} \times \frac{1 \text{ kWh}}{10{,}000 \text{ Btu}} = 101 \frac{¢}{10^6 \text{ Btu}}$$

Demand Charge:

$$\frac{\$4{,}107{,}500 \text{ demand charge per yr.} + \$0 \text{ other charges per yr.}}{150{,}000 \text{ KW demand} \times 12 \text{ months per yr.}}$$

$$= 2.282 \frac{\$}{\text{KW-month}}$$

14.2.2 VARSYS Data

The input data for VARSYS is shown in Table 3. The meaning of each column is the same as those for the FIXSYS module. The five expansion candidates, namely, 800 NW nuclear unit, 1000 MW nuclear unit, 600 MW coal unit, 800 MW coal unit and 50 MW gas turbine unit are considered. It is assumed that DP&L will own one third of the large units and 100% of the gas turbine units. The plant data for these units are taken from Appendix E of the IAEA Nuclear Power Planning Study Procedures Manual[4] and from DP&L's 1975 Uniform Statistical Report[5].

Table 3 VARSYS Data-Cost of Reliability Study

N800	0	178	267	10710	9360	51	0	0	1	14.0	42	800	0	0.470	1.000
N10H	0	222	333	10710	9360	51	0	0	1	16.0	42	1000	0	0.400	0.840
0600	0	67	200	10680	8890	102	0	4	1	12.0	42	600	0	1.250	2.630
0800	0	89	267	10640	8850	102	0	4	1	14.0	42	800	0	1.150	2.430
GT50	0	50	50	13810	13810	126	0	2	1	5.0	14	60	0	0.400	0.000

Item Descriptions

1) Code Name for Power Station
2) Number of Identical Units - Set to 0 in VARSYS
3) Minimum Operating Level (MWE)
4) Maximum Generating Capacity (MWE)
5) Heat Rate at Minimum Operating Level (BTU/KWHE)
6) Average Incremental Heat Rate (BTU/KWHE)
7) Domestic Fuel Cost (Cents/Million BTU)
8) Foreign Fuel Cost (Not Used in this Sduty)
9) Plant Type (0=Nuclear; 1=Gas Turbine; 2=Diesel; 4=Coal-Fired)
10) Plant Location Number (Set to 1 in this Version of WASP)
11) Forced Outage Rate (%)
12) Number of Schuduled Maintenance Days Per Year
13) Maintenance Class Size (MW) -
14) Expected Energy Generation (GWH) - For Hydro Stations Only
15) Fixed Non-Fuel O&M Cost ($/KW-Month)
16) Variable Non-Fuel O&M Cost (Cents/KWH)

14.2.3 LOADSY Data

The LOADSY module requires the following information:

1. annual peak loads,
2. the ratio of each seasonal peak to the annual peak load; and,
3. the normalized (i.e., peak load - 1.0) load duration curve for each season.

Each of the normalized load duration curves are represented by a fifth-order polynomial as determined by the LOADFIT program[6]. LOADFIT is a computer program that generates a normalized load duration curve from hourly load data and then fits an n-th order polynomial to the normalized load duration curve by least-squares methods. It can be executed for an entire year or seasonally. Appendix 14B shows how the seasonal to annual peak load ratio data are calculated. The LOADSY data is summarized in Table 4.

14.2.4 CONGEN Data

The following data is required in the CONGEN module:

1. The permissible capacity range expressed as a percentage of the yearly peak load; e.g., with a peak load of 1,000 MW and a capacity range specification of 10 to 25%, the allowed capacity range would be 1,100 MW to 1,250 MW.
2. The reliability level that must be maintained. The LOLP used as the reliability criterion.

The data used in CONGEN is summarized in Table 4

Table 4

LOADSY Data - Cost of Reliability Study

Year	Yearly Peak Load(MW)	Seasonal to Annual Peak Load Ratios Winter	Spring	Summer	Autumn
1976	1948	0.975	0.783	1.000	0.714
1977	2105	0.963	0.758	1.000	0.691
1978	2277	0.964	0.722	1.000	0.658
1979	2459	0.970	0.686	1.000	0.626
1980	2658	0.971	0.647	1.000	0.590
1981	2863	0.975	0.622	1.000	0.567
1982	3083	0.975	0.593	1.000	0.541
1983	3305	0.975	0.577	1.000	0.527
1984	3528	0.977	0.560	1.000	0.511
1985	3763	0.976	0.554	1.000	0.505
1986	3999	0.979	0.549	1.000	0.501

Table 5

CONGEN Data - Cost of Reliability Study

Case Number	Capacity Range (% of Peak Load)	LOL Criterion (Days/Year)
1	0 - 70	0.3
2	25 - 50	1.0
3	0 - 40	5.0
4	10 - 25	10.0
5	0 - 20	20.0

14.2.5 MERSIM Data

The loading order of the generating units must be provided as input for the MERSIM module. All units that have a minimum operating level greater than 0 MW must be represented by two entries in the loading order: a base block of capacity (loaded first) and a load following or a peak block of capacity (loaded afterward). Units having a minimum operating level of 0 MW (e.g., peaking units) are represented in the loading order by a single entry. The loading order is shown in Table 6 and was determined from marginal cost considerations[7].

14.2.6 DYNPRO Data

The input data for the DYNPRO module is summarized in Tables 7 and 8. This data remains the same for all cases[8,9] and consists of the plant life, capital cost at the beginning of the study and capital cost escalation rate for each expansion candidate as well as the base year for present-worth calculations, discount rate applied to all capital and operating costs and the escalation rates on operating costs by plant type which applies to units in the FIXSYS and VARSYS modules.

Table 6

MERSIM Data - Cost of Reliability Study

Loading Order	WASP Name	Block	Loading Order	WASP Name	Block
1	N10H	Base	19	TAI4	Base
2	N800	Base	20	TAI4	Peak
3	C800	Base	21	TAI5	Base
4	CON4	Base	22	HU36	Base
5	C600	Base	23	HU36	Peak
6	FOR7	Base	24	HUT2	Base
7	BEK6	Base	25	HUT1	Base
8	ST13	Base	26	GT50	Base
9	STU4	Base	27	HUGT	Base
10	N10H	Peak	28	YA13	Base
11	N800	Peak	29	YA47	Base
12	C800	Peak	30	TTOP	Base
13	CON4	Peak	31	TAID	Base
14	C600	Peak	32	MOND	Base
15	FOR7	Peak	33	STUD	Base
16	BEK6	Peak	34	SIDD	Base
17	ST13	Peak	35	OHPC	Base
18	STU4	Peak			

Table 7

DYNPRO Data for Expansion Candidates - Cost of Reliability Study

WASP Name	Plant Life (Yrs.)	Capital Cost In 1976 ($/KW)	Escalation Rate On Capital Cost (%)
N800	35	494	11.5
N10H	35	460	11.5
C600	30	380	11.5
C800	30	353	11.5
GT50	20	150	8.0

Base year for present-worth calculations: 1975

Discount rate applied to all capital and operating costs: 9.25%

Table 8

DYNPRO Operating Cost Data - Cost of Reliability Study

Plant Type	Escalation Rate On Operating Costs (%)
Nuclear	5.3
Coal-Fired	6.5
Diesel	4.5
Gas-Trubine	4.5

14.3 Results

The cost of reliability study involves the determination of economically optimal system expansion policies for DP&L and their relative cost subject to various reliability levels. The results of this part consist of those optimal expansion policies and the associated values of the objective function. The five hypothetical expansion candidates and the existing DP&L system discussed in Section 14.2 are used.

Tables 9 through 13 show the optimal expansion policies. The LOLP criterion used in each case is shown at the top of each table.

The numbers in each row represent the cumulative number of units of each type installed and on-line at the beginning of that year. It is interesting to note that none of the optimal expansion policies included any coal-fired units. The costs assumed in this study (see Section 14.2) evidently make the nuclear units far more economical and thus they are chosen to the exclusion of the coal-fired units. The value of the optimal expansion schedule objective function for the length of the study period is shown at the bottom of each table in units of millions of 1975 dollars.

Figure 1 shows the installed capacity for each case by year and the system peak load by year. The reserve margin (percent of system peak load by which the installed capacity exceeds the peak load) increases as the LOLP criterion becomes more conservative. For some cases the reserve margin is extremely high; e.g., 41% for Case 1 in 1986.

Table 9

Optimal Expansion Schedule for Case 1 (0.3 D/Y)

YEAR	N800	N10H	C600	C800	GT50
1986	6	4	0	0	3
1985	5	4	0	0	3
1984	4	4	0	0	3
1983	3	4	0	0	3
1982	2	4	0	0	3
1981	1	4	0	0	3
1980	1	4	0	0	0
1979	1	4	0	0	0
1978	1	3	0	0	0
1977	0	3	0	0	0
1976	0	2	0	0	0

Objective Function (10^6 1975\$) = 1941.

Table 10

Optimal Expansion Schedule for Case 2 (1.0 D/Y)

YEAR	N800	N10H	C600	C800	GT50
1986	5	4	0	0	2
1985	4	4	0	0	2
1984	3	4	0	0	2
1983	2	4	0	0	2
1982	2	4	0	0	1
1981	2	3	0	0	1
1980	2	2	0	0	1
1979	2	1	0	0	1
1978	2	1	0	0	0
1977	1	1	0	0	0
1976	0	1	0	0	0

Objective Function (10^6 1975$) = 1865.

Table 11

Optimal Expansion Schedule for Case 3 (5.0 D/Y)

YEAR	N800	N10H	C600	C800	GT50
1986	5	3	0	0	0
1985	4	3	0	0	0
1984	3	3	0	0	0
1983	2	3	0	0	0
1982	1	3	0	0	0
1981	1	3	0	0	0
1980	1	3	0	0	0
1979	1	1	0	0	0
1978	1	1	0	0	0
1977	0	1	0	0	0
1976	0	0	0	0	0

Objective Function (10^6 1975$) = 1774.

Table 12

Optimal Expansion Schedule for Case 4 (10.0 C/Y)

YEAR	N800	N10H	C600	C800	GT50
1986	4	3	0	0	1
1985	3	3	0	0	1
1984	2	3	0	0	1
1983	2	2	0	0	1
1982	2	2	0	0	1
1981	1	2	0	0	1
1980	1	1	0	0	1
1979	1	0	0	0	1
1978	1	0	0	0	0
1977	0	0	0	0	0

Objective Function (10^6 1975$) = 1727.

Table 13

Optimal Expansion Schedule for Case 4 (20.0 D/Y)

YEAR	N800	N10H	C600	C800	GT50
1986	3	3	0	0	0
1985	2	3	0	0	0
1984	1	3	0	0	0
1983	1	3	0	0	0
1982	1	2	0	0	0
1981	1	1	0	0	0
1980	1	1	0	0	0
1979	0	1	0	0	0
1978	0	0	0	0	0
1977	0	0	0	0	0
1976	0	0	0	0	0

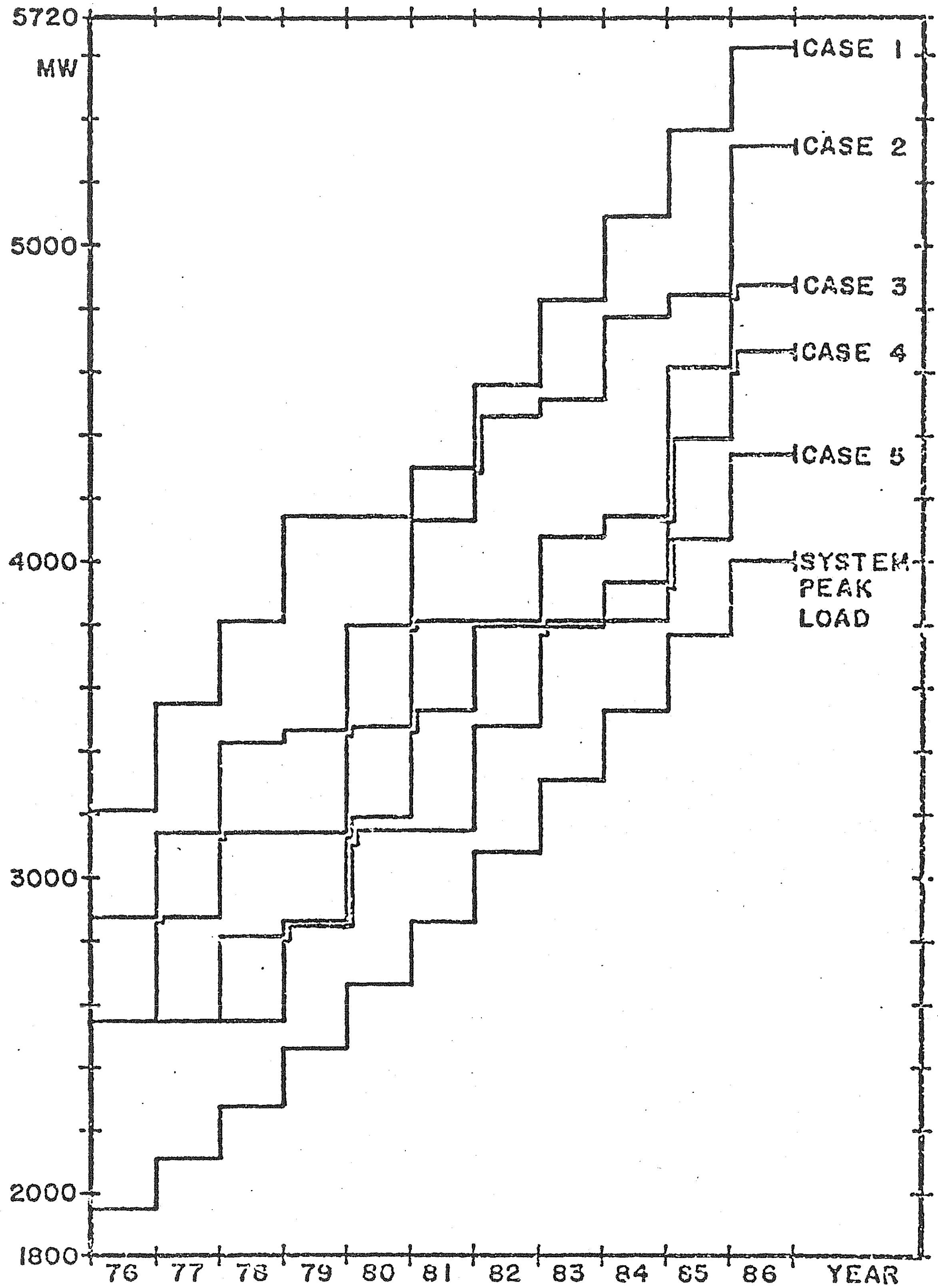

Figure 1 Installed Capacity and System Peak for Cost of Reliability Study

Figure 2 is a plot of the LOLP criterion against the value of the optimal solution objective function. The graph is interpreted as follows:

a. As the LOLP approaches 365 days/year the objective function becomes very small (only O&M costs of the existing system), thus accounting for the concavity of the curve for values of CDP greater than 10.0 days/year.

b. In the range of LOLP less than 1.0 days/year it becomes increasingly difficult to maintain a given reliability level, thus the objective function increases at an increasing rate.

c. For a LOLP between 1.0 and 10.0 days/year the curve is roughly linear on the semilog plot. This region of the curve represents a transition area betwen the two regions described above and thus the curve is neither concave nor convex in shape.

14.4 Summary of Results

Figure 2 shows that the value of the objective function is quite sensitive to changes in the reliability level that must be maintained. For example, if the system planners decided back in the mid-1960's to maintain a LOLP of 10.0 days per year instead of 1.0 days per year during 1976-1986, a savings of $138 million over the eleven year period or $12.5 million per year would have resulted. This savings is 7.4% of the value of the objective function associated with the 1.0 days per year LOLP criterion. It must be remembered, however, that the expansion candidates are hypothetical and due to the long lead time associated with large thermal units the optimal expansion schedules obtained would be unrealistic for a utility beginning its planning at the present time. The main purpose of the study is to quantify the relative cost of maintaining various levels of reliability as the utility expands.

Another important point is that, as the reliability constraint is relaxed, the utility would have to purchase more power from neighboring utilities to meet its load. The increased cost of purchased power would tend to offset the savings from relaxing the reliability constraint, which results primarily from deferred construction expenses.

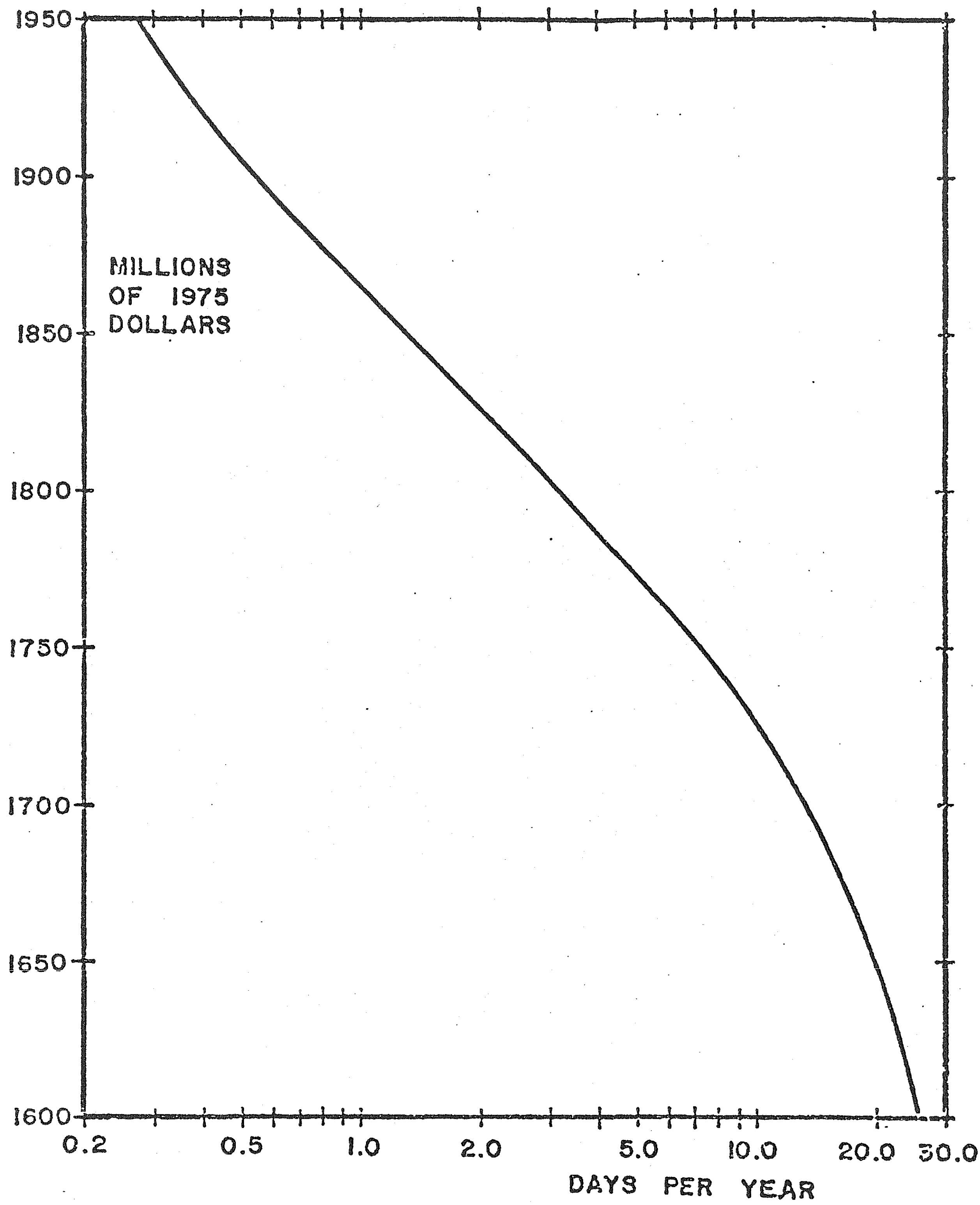

Figure 2 Effect of Loss-of-Load Probability Criterion on the Value of the Objective Function (1976-1986)

APPENDIX 14A

DOCUMENTATION OF HEAT RATE DATA †

The purpose of this appendix is to document the calculation of the heat rate data required in the FIXSYS module of the WASP programs The incremental heat rates and net power output at minimum, best point (minimum heat rate), and maximum operating levels for most units were supplied by the utilities. From these data the base load heat rate and average incremental heat rate (used to obtain full load heat rate) were determined and used as input for FIXSYS. In some cases the heat rate data reported by the three utilities for jointly-owned units did not correspond. For those cases the data reported by one of the owners was used.††

As a brief explanation of incremental heat rate and heat rate consider Figure A-1. Figure A-1(a) which is referred to as the power plant input-output curve shows the relationship between the heat rate of thermal energyinto the power plant (I Btu/hr) and the power output of the plant (L KWe). The heat rate is defined as the average thermal power per unit electrical power output at the level L. In mathematic terms the heat rate as a function of the electrical power output is

$$HR(L) = \frac{I(L)}{L} \quad . \tag{A-1}$$

A typical example of a heat rate curve is plotted in Figure A 1(c).

The incremental heat rate is defined as the slope of the input-output curve or the ratio of the change in thermal power into the system to electrical power out:

$$IR(L) = \frac{dI(L)}{dL} \tag{A-2}$$

An incremental heat rate curve is shown in Figure A-1(c).

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†This appendix includes the data used in Chapters 14 and 15.

††The differences,usually less than 5%, were not realized until the data from Columbus & Southern Ohio Electric Co. (CSO) and the Cincinnati Gas & Electric Co. (CG&E) were reported. Thus, some of the data used in the power pooling study (see Section 14.4) for the Dayton Power & Light Co. (DPL) does not agree with the corresponding numbers in the cost of reliability study (see Section 14.2).

The efficiency of the plant as a function of the power output is shown in Figure A-1(b).

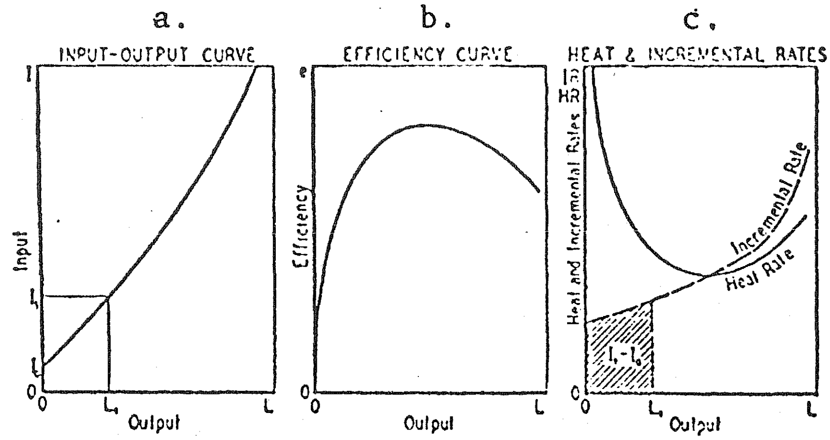

Figure A.1 Typical Input/Output Performance Curves for A Large Thermal Unit Showing:

(a) the Input-Output Curve (Btu/hr; kW output),

(b) the thermal efficiency curve; and

(c) the heat rate and incremental heat rate curve. (But/kWhe vs. kWe output)

The percent efficiency is defined as:

$$e(L) = \frac{k}{HR(L)} \times 100 \tag{A-3}$$

where k is a conversion factor. With HR(L) given in units of Btu/Kwhe, $k = 3413 \frac{\text{But}}{\text{kWh}}$.

The data supplied by the utilities is incremental heat rate data. The input data required for FIXSYS is heat rate data. The heat rate data is calculated from the incremental heat rate data in the following manner.

From the definition of incremental rate, Equation A-2,

$$dI - IRdL \tag{A-4}$$

or

$$I_1 - I_0 = \int_{L_0}^{L_1} IRdL \tag{A-5}$$

This is shown as the shaded area in Figure A 1(c). Assuming the IR curve can be modeled as a straight line for short intervals,

$$I_1 - I_0 = \tfrac{1}{2}(IR_0 + IR_1)(L_1 - L_0) \qquad \text{(A-6)}$$

Examining the incremental heat rate data supplied by the utilities shows that this assumption is reasonable between the minimum and best point loads, and between the best point and maximum loads. One important point to note about Figure A-1(c) is that the incremental heat rate and the heat rate are equal when the heat rate is a minimum; namely, at the best point load. Skrotski and Vopat [10] show that this is true of any generating unit whose performance is described by these curves.

Defining state 1 as the minimum operating level, state 2 the best point and state 3 the maximum level, the base load heat rate (HR_1) can be determined as follows:

Realizing that:

$$I_2 = HR_2 L_2 \qquad \text{(A-7)}$$

and $$HR_2 = IR_2 \qquad \text{(A-8)}$$

then $$I_2 = IR_2 L_2 \qquad \text{(A-9)}$$

also, $$I_1 = I_2 - \tfrac{1}{2}(IR_1 + IR_2)(L_2 - L_1) \qquad \text{(A-10)}$$

and since $$HR_1 = I_1 / L_1 \qquad \text{(A-11)}$$

then $$HR_1 = \frac{IR_2 L_2 - \tfrac{1}{2}(IR_1 + IR_2)(L_2 - L_1)}{L_3} \qquad \text{(A-12)}$$

In the FIXSYS module the average incremental heat rate (AIR) is used to determine the full load heat rate (HR_3) from the equation with

$$HR_3 = \frac{HR_1 x L_1 + AIR(L_3 - L_1)}{L_3} \qquad \text{(A-13)}$$

However, it is AIR that is inputted in FIXSYS. Working backward, the full load heat rate was obtained form an analysis similar to that used to calculate HR_1 and then AIR was calculated for input to FIXSYS. With Eq. (A-4), we have

$$I_3 - I_2 = \int_{L_2}^{L_3} IRDL \simeq \tfrac{1}{2} (IR_3 + IR_2)(L_3 - L_2). \qquad \text{(A-14)}$$

With Eq. (A-9), Eq. (A-14) becomes

$$I_3 = IR_2L_2 + \tfrac{1}{2} (IR_3 + IR_2)(L_3 - L_2) \qquad \text{(A-15)}$$

So, HR_3 becomes

$$HR_3 = \frac{IR_2L_2 + \tfrac{1}{2} (IR_3 + IR_2)(L_3 - L_2)}{L_3} \qquad \text{(A-16)}$$

For input to FIXSYS, AIR was calculated from Eq. (A-13).

$$AIR = \frac{HR_3L3 - HR_1L_1}{L_3 - L_1} \qquad \text{(A-17)}$$

As an example of the calculation, the data supplied for Conesville Unit 4 by DPL (used in the cost of reliability study) is used here to find HR_1 and AIR.

Given:	IR_1 = 8367 Btu/Kwhe	L_1 = 364 MW
	IR_1 = 8808 Btu/Kwhe	L_2 = 582 MW
	IR_3 = 9251 Btu/Kwhe	L_3 = 800 MW

$$\int_{L_1}^{L_2} IRdL = \tfrac{1}{2}(8367 + 8808)(582 - 364) = 1872075 \text{ Btu/hr.}$$

$$I_2 = 8808 \times 582 = 5126256 \text{ Btu/hr.}$$

$$HR_1 = \frac{5126256 - 1872075}{364} = 8940 \text{ Btu/Kwhe}$$

$$\int_{L_2}^{L_3} IRdL = \tfrac{1}{2}(8808 + 9251)(800 - 582) = 1968431 \text{ Btu/hr,}$$

$$HR_3 = \frac{5126256 + 1968431}{800} = 8868 \text{ Btu/kWhe}$$

$$AIR = \frac{8868 \times 800 - 8940 \times 364}{800 - 364} = 8808 \text{ Btu/kWhe}$$

For units having only one block of capacity (e.g., diesels and gas turbines), HR_1 and AIR were set equal to the full load heat rate. In the cost of reliability study, HR_3 for peaking units was calculated as shown above, but in the power pooling study the values of HR_3 for these units were taken from Federal Power Commission Form No. 12 reports supplied by the PUCO.. These reports were not used for other units because the data was supplied for entire stations only; thus, it was not suitable for input to FIXSYS for those individual units.

Two of the utilities, CGE and CSO, reported that most of their units did not have a minimum point in the heat rate curve that could be called a best point. In those cases it was assumed the maximum load was the best point load. Most units are capable of operating at power levels above their stated maximum load for short periods of time, but it is relatively expensive to do so; in all likelyhood, the heat rate increases as the power output is increased above the stated maximum level. Thus, the maximum load probably represents a best point on the heat rate curve. In this case,

$$IR_2 = IR_3 = HR_2 = HR_3 \qquad \text{(A-18)}$$

and

$$L_2 = L_3 \qquad \text{(A-19)}$$

HR_1 and AIR can be calculated as before.

Firm contracts with other companies, which were modeled as ficticious plants, were assumed to have a full load heat rate of 10,000 Btu/kWhe. Tables A-1 through A-4 summarize the incremental heat rate and net power output data used in the work. Table A-5 shows all jointly-owned units, both existing and planned, as used in the power pooling study. This data was used in the FIXSYS and VARSYS modules.

Table A-1 Incremental Heat Rate and Power Output Data - DPL - Cost of Reliability Study

Unit Name	Incremental Heat Rates (BTU/KWHE) Min. Load	B.P. Load	Max. Load	Unit Net Power Output (MW) Min. Load	B.P. Load	Max. Load	Base Load Heat Rate (BTU/KWHE)	Average Incre. Heat Rate (BTU/KWHE)
CON4	8367	8808	9251	364	582	800	8940	8808
FOR7	8660	8918	9176	200	345	490	9012	8918
BEK6	8387	8644	9035	150	280	440	8755	8694
ST13	8439	8650	8881	230	407	585	8731	8655
STU4	8409	8680	8904	230	407	585	8785	8668
HU36	9585	9615	9675	15	49	68	9649	9612
HUT1	9650	10575	11500	0	44	61	10706	10706
HUT2	9585	9615	9675	0	49	60	9621	9621
TAI4	9024	9074	9124	70	105	140	9087	9062
TAI4	9702	9752	9802	0	105	130	9757	9757
TTOP	11735	11800	11850	0	85	150	11811	11811
MOND	10180	10200	10220	0	8	14	10204	10204
SIDD	10180	10200	10200	0	8	14	10204	10204
STUD	10180	10200	10220	0	3	11	10204	10204
TAID	10180	10200	10220	0	7	11	10204	10204
HUGT	10850	10900	10950	0	20	34	10911	10911
YA47	11150	11200	11250	0	11	21	11212	11212
YA13	11150	11200	11250	0	13	24	11211	11211

Table A-2 Incremental Heat Rate and Power Output Data - DPL - Power Pooling Study

Unit Name	Incremental Heat Rates (BTU/KWHE) Min. Load	B.P. Load	Max. Load	Unit Net Power Output (MW) Min. Load	B.P. Load	Max. Load	Base Load Heat Rate (BTU/KWHE)	Average Incre. Heat Rate (BTU/KWHE
CON4*	--	--	--	--	--	--	9850	8785
FOR7**	--	--	--	--	--	--	9673	9046
BEK6*	--	--	--	--	--	--	9182	8502
ST13*	--	--	--	--	--	--	9742	8694
STU4*	--	--	--	--	--	--	9715	8740
HU36	9585	9615	9675	15	49	68	9649	9612
HUT1	9650	10575	11500	0	44	61	10706	10706
HUT2	9585	9615	9675	0	49	60	9621	9621
TAI4	9024	9074	9124	70	105	140	9087	9062
TAI5	9702	9752	9802	0	105	130	9757	9757
TTOP	11735	11800	11850	0	85	150	11811	11811
MOND	--	--	--	0	8	14	10300	10300
SIDD	--	--	--	0	8	14	10300	10300
STUD	--	--	--	0	3	11	10300	10300
TAID	--	--	--	0	7	11	10300	10300
HUGT	--	--	--	0	20	34	15500	15500
YA47	--	--	--	0	11	21	15656	15656
YA13	--	--	--	0	13	24	14000	14000

* See Table A-4

** See Table A-3

Table A-3 Incremental Heat Rate and Power Output Data - CGE - Power Pooling Study

Unit Name	Incremental Heat Rates (BTU/KWHE) Min. Load	B.P. Load	Max. Load	Unit Net Power Output (MW) Min. Load	B.P. Load	Max. Load	Base Load Heat Rate (BTU/KWHE)	Average Incre. Heat Rate (BTU/KWHE)
CON4*	--	--	--	--	--	--	9850	8785
FOR7	8789	--	9303	205	--	500	9673	9046
BEK6*	--	--	--	--	--	--	9182	8502
ST13*	--	--	--	--	--	--	9742	8694
SUT4*	--	--	--	--	--	--	9715	8740
FOR3	12033	--	13468	18	--	59	15102	12751
FOR4	12210	--	12671	18	--	59	13196	12441
FOR5	10533	--	12363	33	--	80	13666	11448
FOR6	8951	--	9231	74	--	165	9403	9091
W125**	--	--	--	39	--	95	13000	12067
W346**	--	--	--	41	--	100	13000	12068
BEK1	9104	--	11116	36	--	85	12485	10110
BEK2	8654	--	10317	37	--	98	11688	9485
BEK3	8931	--	9781	56	--	124	10297	9356
BEK4	9087	--	9333	64	--	153	9504	9210
BEK5	8800	--	9117	110	--	238	9301	8959
STUD	--	--	--	0	--	11	10300	10300
F12T	--	--	--	0	--	46	9087	9087
F36T	--	--	--	0	--	14	9658	9658
B14T	--	--	--	0	--	45	9637	9637
DC1T	--	--	--	0	--	74	11811	11811
D23T	--	--	--	0	--	14	9658	9658
D45T	--	--	--	0	--	15	10926	10926

* See Table A-4

** Heat rates taken from Reference 11.

Table A-4 Incremental Heat Rate and Power Output Data - CSO - Power Pooling Study

Unit Name	Incremental Heat Rates (BTU/KWHE)			Unit Net Power Output (MW)			Base Load Heat Rate (BTU/KWHE)	Average Incre. Heat Rate (BTU/KWHE)
	Min. Load	B.P. Load	Max. Load	Min. Load	B.P. Load	Max. Load		
CON4	8319	--	9251	350	--	800	9850	8785
BEK6	8264	--	8740	152	--	434	9182	8502
ST13	8281	--	9108	231	--	585	9742	8694
STU4	8344	--	9135	231	--	570	9715	8740
PI34	9385	--	15044	13	--	29	18526	12215
PIC5	10043	--	11133	13	--	95	14571	10588
PO12	10713	11070	12490	15	37	45	11332	11128
PO34	10516	--	12558	25	--	71	14437	11537
CO12	9910	--	10575	60	--	122	10919	10242
CON3	9561	10501	13309	65	161	178	11195	10313
STUD	--	--	--	0	--	11	10300	10300
PI6T	--	--	--	0	--	17	11163	11163
POSD	--	--	--	0	--	14	9962	9962
COND	--	--	--	0	--	14	9962	9962
PEDD	--	--	--	0	--	14	9962	9962
ADDD	--	--	--	0	--	14	9962	9962
WA78	--	--	--	0	--	29	10240	10240
WA9T	--	--	--	0	--	158	11990	11990

Table A-5 Jointly-Owned Generating Units

WASP Name	Date First On-Line	Net Summer Unit Generating Capacity (MW)			
		Total	DPL	CGE	CSO
CON4	6-73	800	132	320	348
BEK6	7-69	434	217	163	54
STUD	10-69	11	4	4	3
ST13	10-70→5-72	585	205	228	152
STU4	6-74	570	200	222	148
FOR7	5-75	500	180	320	-
FOR8	1-78*	500*	180	320	-
ESB1	1-82*	600*	294	306	-
ESB2	1-80*	600*	294	306	-
ESB3	1-84*	800*	392	408	-
KIL1	1-83*	600*	294	306	-
KIL2	1-81*	600*	294	306	-
ZIM1	1-79*	792*	249	317	226
ZIM2	1-86*	1150*	362	460	328

* Preliminary

APPENDIX B

DOCUMENTATION OF SEASONAL TO ANNUAL PEAK LOAD RATIO DATA †

The purpose of this appendix is to document the calculation of the seasonal to annual peak load ratio data required in the LOADSY module of the WASP program. The LOADFIT program 12, executed to obtain the coefficients of the fifth-order polynomial used to describe the normalized seasonal load duration curves, also provided the following pertinent information by season: the summation of all loads (i.e., the area under the load duration curve), the peak load and the number of hours in the period. The hourly load data for a recent year (hereafter referred to as the base year) was used in LOADFIT. With this information the seasonal load factor (SLF) was obtained from the relation:

$$SLF_i = \frac{(\Sigma\ HL)_i}{SP_i * H} \qquad (B\text{-}1)$$

where HL = hourly load (MW) - summationover all loads in season i

SP_i = seasonal peak load for season i (MW)

H = number of hours in season - identical for all seasons

Defining P_i as:

$$P_i = SLF_i * SAR_i \qquad (B\text{-}2)$$

where: AP = the annual peak load (MW)

SAR_i = SP_i/Ap the ratio of seasonal peak load to the annual peak load for season i

and substituting Equation B-1 into B-2 yeidls:

$$P_i = \frac{(\Sigma\ HL)_i}{H * AP} \qquad (B\text{-}3)$$

† This appendix includes the data used in Chapters 14 and 15.

Recognizing that:

$$\sum_{i=1}^{4} P_i = \frac{\sum_{i=1}^{4} (\Sigma HL)_i}{H x AP} \quad \text{(B-4a)}$$

$$= \frac{\Sigma \text{ (All hourly loads in year)}}{H x AP} \quad \text{(B-4b)}$$

then it can be seen that:

$$4ALF = \sum_{i=1}^{4} P_i = \sum_{i=1}^{4} (SLF_i x Sar_i) \quad \text{(B-5)}$$

Because the normalized load duration curves remained the same for all years of the study, the seasonal load factors also remained the same for all years, and those numbers were used in the above equation. The ten year forecast supplied by each utility gave projected winter and summer peak loads and the annual load factor for each of the next ten eyars. Thus, the SAR for the winter can be calculated directly and, realizing that the SAR for the summer is 1.0, the only variables remaining in the above equation are the SAR's for the spring and autumn. Assuming:

$$\frac{(SAR)sp}{(SAR)au} = \frac{(SAR)sp \text{ for base year}}{(SAR)au \text{ for base year}} = \text{a constant} \quad \text{(B-6)}$$

it is possible to solve for the SAR's as shown below.

Table B.1 displays the pertinent load data sued in the cost of reliability study.

Table B-1 Load Data - Cost of Reliability Study

Season Number	Season	Seasonal Summation Of Loads (mWh)	Numbers Of Hours In Season	Seasonal Peak Load (MW)	Seasonal Load Factor (%)	Seasonal to Annual Peak Load Ratio
1	Winter	2283254	2190	1436	72.6	0.8145
2	Spring	2184109	2190	1633	61.1	0.9263
3	Summer	2414549	2190	1763	62.5	1.0000
4	Autumn	2269945	2190	1490	69.6	0.3452

From Table B.1:

$$\frac{(SAR)_2}{(SAR)_4} = \frac{0.9263}{0.8452} = 1.096 \qquad \text{(B-7)}$$

For 1976, ALF = 57.7%, the summer peak load = 1948 MW and the winter peak load = 1899 MW. Thus:

$$SAR_1 = \frac{1899}{1948} = 0.975 \qquad \text{(B-8)}$$

With the above information, Equation B-6 yields:

$$SAR_4 = 0.714$$

and

$$SAR_2 = 1.096 \times 0.714 \quad 0.783$$

Table B.2 summarizes the SAR calculations by year for the cost of reliability study.

Table B-2 Seasonal to Annual Peak Load Ratios Cost of Reliability Study

Year	Summer Peak Load (MW)	Winter Peak Load (MW)	Annual Load Factor (%)	Seasonal to Annual Peak Load Ratios		
				Winter	Autumn	Spring
1976	1948	1899	57.7	0.975	0.714	0.783
1977	2105	2026	56.7	0.963	0.691	0.758
1978	2277	2194	55.6	0.964	0.658	0.722
1979	2459	2384	54.6	0.970	0.626	0.686
1980	2658	2580	53.4	0.971	0.590	0.647
1981	2863	2791	52.7	0.975	0.567	0.622
1982	3083	3006	51.8	0.975	0.541	0.593
1983	3305	3221	51.3	0.975	0.527	0.577
1984	3528	3448	50.8	0.977	0.511	0.560
1985	3763	3672	50.6	0.976	0.505	0.554
1986	3999	3913	50.5	0.979	0.501	0.549

Tables B.3 through B.8 summarize the load data and seasonal to annual peak load ratios for each of the three utilities in the power pooling study.

The summer and winter peak loads for CCD are less than the sum of the appropriate peak loads from the constituent utilities because the peaks do not occur on the same day. For 1975, the CCD summer peak load (from LOADFIT) was 5924 MW while the sum of the summer peaks of the three component utilities was 5965 MW. The ratio of these figures is:

$$\frac{5924}{5965} = 0.9931 \tag{B-9}$$

Assuming this relationship holds true for each year of the study:

$$AP_{CCD} = 0.9931\ (AP_{DPL} + AP_{CGE} + AP_{CSO}) \tag{B-10}$$

The winter peak load is obtained the same way. For 1975, the CCD winter peak load was 4883 MW while the sum of the components was 4920 MW. The ratio of these figures is:

$$\frac{4883}{4920} = 0.9925 \tag{B-11}$$

Thus, $SP_{1,CCD} = 0.9925\ (SP_{1,DPL} + SP_{1,CGE} + SP_{1,CSO})$ (B-12)

It is also necessary to obtain the annual load factor for CCD from the information provided. From the defintion of annual load factor:

$$AP \times ALF = \frac{\Sigma\ HL\ \text{in year}}{8760\ \text{hours in year}} \tag{B-13}$$

where: AP = Annual Peak Load (MW)

ALF = Annual Load Factor

HL = Hourly Load (MW)

then,

$$\sum_{j=1}^{3} AP_j x ALF_j = \frac{\sum_{j=1}^{3} (\Sigma HL)_j}{8760} = \frac{\Sigma HL\ \text{for CCD}}{8760} = ALF_{CCD} \times AP_{CCD} \tag{B-14}$$

where j = the number of the component utility

Thus, $$ALF_{CCD} = \frac{\sum_{j=1}^{3} AP_j x ALF_j}{AP_{CCD}} \qquad (B-15)$$

With these relationships it is possible to calculate the seasonal to annual peak load ratios as before. Tables B.9 and B.10 summarize the load information for CCD for use in the powerpooling study.

The objective of this appendix was to document the calculation of the seasonal to annual peak load ratio data required in the LOADSY module of the WASP code. It is believed the assumptions made in this analysis are reasonable. Probably the most questionable assumption is that shown in Equation B-7, namely that the ratio of the seasonal to annual peak load ratios for the spring and autumn seasons remained constant for every year of the study. This assumption was mde to allow solution of Equation B-6 for the seasonal to annual peak load ratios.

Table B-3 Load Data - DPL - Power Pooling Study

Season Number	Season	Seasonal Summation Of Loads (MWH)	Numbers Of Hours In Season	Seasonal Peak Load (MW)	Seasonal Load Factor (%)	Seasonal to Annual Peak Load Ratio
1	Winter	2376130	2190	1611	67.3	0.945
2	Spring	2184411	2190	1687	59.1	0.989
3	Summer	2351371	2190	1705	63.0	1.000
4	Autumn	2313864	2190	1705	62.0	1.000

Base Year: 1975

Table B-4 Seasonal to Annual Peak Load Ratios - DPL- Power Pooling Study

Year	Summer Peak Load (MW)	Winter Peak Load (MW)	Annual Load Factor (%)	Seasonal to Annual Peak Load Ratios Winter	Autumn	Spring
1975	1705	1611	--	0.945	1.000	0.989
1976	1948	1899	57.7	0.975	0.848	0.838
1977	2105	2026	56.7	0.963	0.821	0.812
1978	2277	2194	55.6	0.964	0.784	0.775
1979	2459	2384	54.6	0.970	0.747	0.739
1980	2658	2580	53.4	0.971	0.707	0.699
1981	2863	2791	52.7	0.975	0.682	0.674
1982	3083	3006	51.8	0.975	0.652	0.645
1983	3305	3221	51.3	0.975	0.635	0.628
1984	3528	3448	50.8	0.977	0.617	0.611
1985	3763	3672	50.6	0.976	0.611	0.605
1986	3999	3913	50.5	0.979	0.606	0.600

Table B-5 Load Data - CGE - Power Pooling Study

Season Number	Season	Seasonal Summation Of Loads (MWH)	Numbers Of Hours In Season	Seasonal Peak Load (MW)	Seasonal Load Factor (%)	Seasonal to Annual Peak Load Ratio
1	Winter	3115727	2190	1967	72.3	0.783
2	Spring	3088182	2190	2429	58.1	0.967
3	Summer	3483082	2190	2511	63.3	1.000
4	Autumn	3085104	2190	2107	66.9	0.839

Base Year: 1975

Table B-6 Seasonal to Annual Peak Load Ratios - CGE - Power Pooling Study

Year	Summer Peak Load (MW)	Winter Peak Load (MW)	Annual Load Factor (%)	Seasonal to Annual Peak Load Ratios		
				Winter	Autumn	Spring
1975	2511	1967	--	0.783	0.839	0.967
1976	2770	2300	56.8	0.830	0.777	0.896
1977	2990	2440	56.8	0.816	0.785	0.905
1978	3170	2580	56.9	0.814	0.789	0.909
1979	3360	2740	56.8	0.815	0.785	0.905
1980	3560	2910	56.8	0.817	0.784	0.904
1981	3770	3090	57.0	0.820	0.789	0.909
1982	4000	3280	57.3	0.820	0.797	0.919
1983	4240	3480	57.7	0.821	0.809	0.933
1984	4490	3690	58.1	0.822	0.820	0.946
1985	4760	3910	58.6	0.821	0.836	0.964
1986	5070	4170	59.0	0.822	0.847	0.977

Table B-7 Load Data - CSO - Power Pooling Study

Season Number	Season	Seasonal Summation Of Loads (MWH)	Numbers Of Hours In Season	Seasonal Peak Load (MW)	Seasonal Load Factor (%)	Seasonal to Annual Peak Load Ratio
1	Winter	2087188	2190	1342	71.0	0.767
2	Spring	2075359	2190	1684	56.3	0.963
3	Summer	2262350	2190	1749	59.1	1.000
4	Autumn	2052138	2190	1501	62.5	0.858

Base Year: 1975

Table B-8 Seasonal to Annual Peak Load Ratios - CSO - Power Pooling Study

Year	Summer Peak Load (MW)	Winter Peak Load (MW)	Annual Load Factor (%)	Seasonal to Annual Peak Load Ratios		
				Winter	Autumn	Spring
1975	1749	1342	--	0.767	0.858	0.963
1976	1834	1453	55.6	0.792	0.851	0.954
1977	1952	1565	55.8	0.802	0.851	0.955
1978	2067	1652	56.1	0.799	0.863	0.968
1979	2184	1776	55.8	0.813	0.845	0.948
1980	2308	1902	55.9	0.824	0.842	0.945
1981	2436	2033	56.4	0.835	0.852	0.956
1982	2570	2182	56.7	0.849	0.853	0.957
1983	2712	2325	57.0	0.857	0.858	0.963
1984	2860	2474	57.1	0.865	0.857	0.962
1985	3019	2634	57.8	0.872	0.875	0.982
1986	3187	2803	58.5	0.880	0.893	0.999

Table B-9 Load Data - CSO - Power Pooling Study

Season Number	Season	Seasonal Summation Of Loads (MWH)	Numbers Of Hours In Season	Seasonal Peak Load (MW)	Seasonal Load Factor (%)	Seasonal to Annual Peak Load Ratio
1	Winter	7579045	2190	4883	70.9	0.824
2	Spring	7347952	2190	5744	58.4	0.970
3	Summer	8096803	2190	5924	62.4	1.000
4	Autumn	7451106	2190	5313	64.1	0.897

Base Year: 1975

Table B-10 Seasonal to Annual Peak Load Ratios - CSO - Power Pooling Study

Year	Summer Peak Load (MW)	Winter Peak Load (MW)	Annual Load Factor (%)	Seasonal to Annual Peak Load Ratios		
				Winter	Autumn	Spring
1975	5924	4883	--	0.824	0.897	0.970
1976	6507	5609	57.1	0.862	0.624	0.675
1977	6999	5986	56.9	0.855	0.624	0,674
1978	7462	6378	56.7	0.855	0.617	0.667
1979	7948	6848	56.2	0.862	0.596	0,645
1980	8467	7336	55,9	0,866	0.584	0.631
1981	9007	7854	55.9	0.872	0,579	0.626
1982	9587	8404	55.8	0.877	0.572	0,618
1983	10186	8958	55.8	0.879	0,570	0.616
1984	10803	9540	55.9	0,883	0.570	0.616
1985	11463	10139	56.2	0,884	0.579	0.626
1986	12172	10804	56,5	0,888	0.585	0.633

APPENDIX C

WASP GENERATING UNIT CODES†

The WASP program requires that each generating unit entry in FIXSYS and VARSYS has a four character code name for that entry. Tables C.1 through C.3 show the code names for the generating units used in this work and the accompanying units names. Table C.4 displays the same information for the planned generating units used in the work.

† This appendix includes the information used in Chapters 14 and 15.

TABLE C-1

WASP CODE NAMES FOR THE DAYTON POWER & LIGHT COMPANY GENERATING UNITS

Unit Name	WASP Code Name
Conesville 4	CON4
Miami Fort 7	FOR7
Beckjord 6	BEK6
Stuart 1-3	ST13
Stuart 4	STU4
Hutchings 3-6	HU36
Hutchings 1	HUT1
Hutchings 2	HUT2
Tait 4	TAI4
Tait 5	TAI5
Tait Topping	TTOP
Monument Diesel	MOND
Sidney Diesel	SIDD
Stuart Diesel	STUD
Tait Diesel	TAID
Hutchings G.T.	HUGT
Yankee G.T.4-7	YA47
Yankee G.T.1-3	YA13
Ohio Power Company Contract	OHPC

TABLE C -2

WASP CODE NAMES FOR THE CINCINNATTI GAS AND ELECTRIC COMPANY GENERATING UNITS

Unit Name		WASP Code Name
Conesville	4	CON4
Miami Fort	7	FOR7
Beckjord	6	BEK6
Stuart	1-3	ST13
Stuart	4	STU4
Miami Fort	3	FOR3
Miami Fort	4	FOR4
Miami Fort	5	FOR5
Miami Fort	6	FOR6
West End	1,2,5	W125
West End	3,4,6	W346
Beckjord	1	BEK1
Beckjord	2	BEK2
Beckjord	3	BEK3
Beckjord	4	BEK4
Beckjord	5	BEK5
Stuart Diesel		STUD
Miami Fort G.T.	1-2	F12T
Miami Fort G.T.	3-6	F36T
Beckjord G.T.	1-4	B14T
Dicks Creek G.T.	1	DC1T
Dicks Creek G.T.	2-3	D23T
Dicks Creek G.T.	4-5	D45T

TABLE C.3

WASP CODE NAMES FOR COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY GENERATING UNITS

Unit Name	WASP Code Name
Conesville 4	CON4
Beckjord 6	BEK6
Stuart 1-3	ST13
Stuart 4	STU4
Picway 3-4	PI34
Picway 5	PIC5
Poston 1-2	PO12
Poston 3-4	PO34
Conesville 1-2	CO12
Conesville 3	CON3
Stuart Diesel	STUD
Picway G.T. 6	PI6T
Poston Diesel	POSD
Conesville Diesel	COND
Pedro Diesel	PEDD
Addison Diesel	ADDD
Walnut G.T. 7-8	WA78
Walnut G.T. 9	WA9T
Ohio Power Company Contract	OHPC

References

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(2) R. X. French, "System Reserve Margins and Their Effect on Reliability", Paper FEC-P144, Faculty Engineering Conference, Chicago, Illinois, March 12, 1976.

(3) 1975 Annual Report of The Dayton Power and Light Company to the Federal Power Commission, F.P.C. Form No. 1, pages 422-423, 431-441.

(4) International Atomic Energy Agency (IAEA) Nuclear Power Planning Study Procedures Manual, Appendix E.

(5) 1975 Uniform Statistical Report for The Dayton Power and Light Company to the American Gas Association, Edison Electric Institute and Financial Analysts, pages E18-E20.

(6) D. A. Goellner, "LOADFIT - A Program for Fitting Utility Load-Duration Curves With Least-Squares Polynomials", Combustion Engineering Computer Program, November 1975.

(7) J. Brown, M. S. Gerber and S. Nakamura, "Operations Manual for the MARC-III Electric Utility Simulation Program", The Mechanical Engineering Department of The Ohio State University, December 1976.

(8) Private communication with R. Lubbers and C. Poseidon, Graduate Research Associates at The Ohio State University.

(9) C. Poseidon, "Status of Construction Cost Data for Electric Power Plants in Ohio", Memo submitted to The Public Utilities Commission of Ohio from The Department of Nuclear Engineering, The Ohio State University, October 19, 1976.

(10) B.G.A. Skrotzki and W.A. Vopat, Power Station Engineering and Economy, McGraw-Hill, New York 1960.

(11) 1975 Power System Statement from the Cincinnati Gas and Electric Company to the Federal Power Commission, F.P.C. Form No. 12.

(12) D.A. Goellner, "FOADFIT - A Program for Fitting Utility Load-Duration Curves with Least-Square Polynomials", Combination Engineering Computer Program, Nov. 1975.

CHAPTER 15

POWER POOLING STUDY

15.1 Methodology

The objective of the power pooling study[1] is to investigate the savings associated with the pooling of generating facilities and load requirements of the Dayton Power & Light Company (DP&L) with the Cincinnati Gas & Electric Company (CG&E) and Columbus & Southern Ohio Electric Company (C&SOE), to form a single utility (CCD). This study, however, is does not intended to predict the real reliability levels or financial conditions of these companies, because several assumptions are made in the basic data and their accuracy is not guaranteed. The reader should rather consider this as a theoretical analysis of the reliability level of three hypothetical utilities.

The present analysis is made by running the WASP program for five cases as follows:

Case 1	DPL	(no optimization)
Case 2	CGE	(no optimization)
Case 3	CSO	(no optimization)
Case 4	CCD	(no optimization)
Case 5	CCD*	(optimization)

The first three cases are run for each of DPL, CGE and CSO, respectively, assuming that the expansion schedule is fixed according to the expansion schedule of each company. From these runs, the annual loss-of-load probability and the total cost of operation and construction for the twelve years planning period is estimated, provided that each of these companies is operated as a hypothetically isolated system. In Case 4, the generating systems of the three companies are hypothetically consolidated into a group and their generating units are dispatched for the aggregated demand of the three systems. The procedure for the WASP calculation for Case 4 is the same as for the previous cases except a much larger number of generating units is involved. Case 5 is treated rather differently. Instead of a fixed construction schedule, there is an option which allows the completion of each unit under construction to be delayed a year or two. Under this condition the completion year for each unit is selected by the dynamic programming module, DYNPRO. The loss-of-load criterion for Case 5 is set at two days per year. This is comparable to the loss-of-load probability found for Case 1 and 2.

The designated study period is the twelve years from 1975 to 1986. All the costs are expressed in 1975 dollars.

15.2 Input Data

The input data for each of the six modules discussed in Chapter 4 is described below.

15.2.1. FIXSYS Data

The data for FIXSYS is summarized in Tables 1 through 4, the format of which is identical to Table 1 of Chapter 14. Contracts with other companies are handled as discussed in Section 14.2. Some of the plant data for jointly-owned units differs from Chapter 14 because of conflicting data obtained from the three utilities.

The fuel costs for each plant were obtained from the 1975 FPC Form 1 annual reports[2,3,4]. Since fixed and variable O&M costs for CGE and CSO were not available when this work was performed, the DPL costs are used to estimate the O&M costs for the unit of other companies. It is assumed that similar units have similar O&M costs. O&M costs, however, are a relatively small component of the overall objective function, thus the error associated with these approximations is negligible[5].

15.2.2. VARSYS Data

The input data for VARSYS is summarized in Tables 5 through 8. The data is taken from Appendix E of the IAEA Nuclear Power Planning Study Procedures Manual[6] as well as from DPL's 1975 Uniform Statistical Report[7].

15.2.3. LOADSY Data

The LOADSY data is shown in Appendix 14-B.

Table 1

FIXSYS Data-DPL-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CON4	1	58	132	9850	8785	88	0	4	1	10.2	42	800	0	0.444	0.708
FOR7	1	74	180	9673	9046	75	0	4	1	10.0	42	500	0	0.153	0.153
BEK6	1	78	217	9182	8502	83	0	4	1	10.0	42	500	0	0.032	1.249
STI3	3	81	205	9742	8604	99	0	4	1	13.0	42	600	0	0.017	0.528
STU4	1	81	200	9715	8740	99	0	4	1	13.0	42	600	0	0.017	0.528
HU36	4	15	68	9649	9612	128	0	4	1	6.5	22	60	0	0.062	1.162
HUT1	1	61	61	10706	10706	128	0	4	1	4.9	22	60	0	0.062	1.162
HUT2	1	60	60	9621	9621	128	0	4	1	6.7	22	60	0	0.062	1.162
TAI4	1	70	140	9087	9062	123	0	4	1	16.9	29	140	0	0.057	1.555
TAI5	1	130	130	9757	9757	123	0	4	1	15.5	29	140	0	0.057	1.555
TTOP	1	150	150	11811	11811	123	0	4	1	16.0	29	140	0	0.057	1.555
MOND	1	14	14	10300	10300	235	0	2	1	25.9	16	20	0	0.162	0.978
SIDD	1	14	14	10300	10300	232	0	2	1	21.4	16	20	0	0.140	1.162
STUD	1	4	4	10300	10300	236	0	2	1	10.0	16	20	0	0.024	0.133
TAID	1	11	11	10300	10300	235	0	2	1	9.7	16	20	0	0.162	0.978
HUGT	1	34	34	15500	15500	237	0	1	1	6.8	16	20	0	0.152	0.288
YA47	4	21	21	15656	15656	234	0	1	1	6.2	16	20	0	0.149	0.267

Item Description (See Table 1 of Chapter 14)

Table 2

FIXSYS Data-CGE-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CON4	1	140	320	9850	8785	88	0	4	1	10.2	42	800	0	0.044	0.700
FOR7	1	132	320	9673	9046	75	0	4	1	10.0	42	500	0	0.153	0.153
BEK6	1	56	163	9182	8502	83	0	4	1	10.0	42	500	0	0.032	1.249
STI3	3	90	228	9742	8694	99	0	4	1	13.0	42	600	0	0.017	0.528
STU4	1	90	222	9715	8740	99	0	4	1	13.0	42	600	0	0.017	0.528
FOR3	1	18	59	15102	12751	90	0	1	1	5.0	22	60	0	0.062	1.162
FOR4	1	18	59	13196	12441	80	0	4	1	5.0	22	60	0	0.062	1.162
FOR5	1	33	80	13666	11448	80	0	4	1	5.0	22	60	0	0.062	1.162
FOR6	1	74	165	9403	9091	90	0	4	1	7.0	29	140	0	0.057	1.555
W125	1	39	95	13000	12067	141	0	1	1	10.0	30	60	0	0.152	0.288
W346	1	41	100	13000	12068	141	0	1	1	10.0	30	140	0	0.152	0.288
BEK1	1	36	85	12485	10110	86	0	4	1	7.0	30	60	0	0.062	1.162
BEK2	1	37	98	11688	9485	86	0	4	1	7.0	30	140	0	0.062	1.162
BEK3	1	56	124	10297	9356	86	0	4	1	10.0	30	140	0	0.057	1.555
BEK4	1	64	153	9504	9210	86	0	4	1	13.0	29	140	0	0.057	1.555
BEK5	1	110	238	9301	8959	86	0	4	1	10.0	34	500	0	0.013	0.528
STUD	1	4	4	10300	10300	236	0	2	1	10.0	16	20	0	0.024	0.133
FI2T	2	46	46	9087	9087	236	0	1	1	10.0	16	60	0	0.149	0.267
F36T	4	14	14	9656	9656	236	0	1	1	10.0	16	20	0	0.149	0.267
BI4T	4	45	45	9837	9637	235	0	1	1	10.0	16	60	0	0.149	0.267
D01T	1	74	74	11811	11811	242	0	1	1	10.0	16	60	0	0.149	0.267
D23T	2	14	14	9658	9658	242	0	1	1	10.0	16	20	0	0.149	0.267
D45T	2	15	15	10926	10926	242	0	1	1	10.0	16	20	0	0.149	0.267

Table 3

FIXSYS Data-CSO-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CON4	1	152	348	9850	8785	88	0	4	1	10.2	42	800	0	0.044	0.709
BEK6	1	19	54	9182	8502	83	0	4	1	10.0	42	500	0	0.032	1.249
STI3	3	60	152	9742	8694	99	0	4	1	13.0	42	600	0	0.017	0.528
STU4	1	60	148	9715	8740	99	0	4	1	13.0	42	600	0	0.017	0.528
PI34	2	13	29	18526	12215	85	0	4	1	7.2	22	20	0	0.062	1.162
PIC5	1	13	95	14571	10588	85	0	4	1	3.2	22	60	0	0.062	1.162
PO12	2	15	45	11332	11128	83	0	4	1	4.9	22	60	0	0.062	1.162
PO34	3	25	71	14437	11537	83	0	4	1	5.0	22	60	0	0.062	1.162
CO12	2	60	122	10919	10242	87	0	4	1	12.4	30	140	0	0.057	1.555
CON3	1	65	178	11195	10313	87	0	4	1	10.1	29	140	0	0.057	1.555
STUD	1	3	3	10300	10300	236	0	2	1	10.0	16	20	0	0.024	0.133
PI6T	1	17	17	11163	11163	202	0	1	1	63.2	16	20	0	0.149	0.267
POSD	1	14	14	9962	9962	214	0	2	1	8.2	16	20	0	0.140	1.162
COND	1	14	14	9962	9962	228	0	2	1	16.2	16	20	0	0.140	1.162
PEDD	1	14	14	9962	9962	214	0	2	1	5.3	16	20	0	0.162	0.978
ADDD	1	14	14	9962	9962	216	0	2	1	16.0	16	20	0	0.162	0.978
WA78	2	29	29	10240	10240	178	0	1	1	11.2	16	20	0	0.149	0.267
WA9T	1	158	158	11990	11990	178	1	1	1	0.7	16	140	0	0.149	0.267
OHPC	1	250	250	10000	10000	132	0	4	1	0.0	0	0	0	1.100	0.000

Table 4

FIXSYS Data-CCD-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CON4	1	350	800	9850	8785	88	0	4	1	10.2	42	800	0	0.044	0.709
FOR7	1	206	500	9673	9046	75	0	4	1	10.0	42	500	0	0.153	0.153
BEK6	1	153	434	9182	8502	83	0	4	1	10.0	42	500	0	0.032	1.240
ST13	3	231	585	9742	8694	99	0	4	1	13.0	42	600	0	0.017	0.528
STU4	1	231	570	9715	8740	99	0	4	1	13.0	42	600	0	0.017	0.528
HU36	4	15	68	9549	9612	128	0	4	1	6.5	22	60	0	0.062	1.162
HUT1	1	61	61	10706	10706	128	0	4	1	4.9	22	60	0	0.062	1.162
HUT2	1	60	60	9621	9621	128	0	4	1	6.7	22	60	0	0.062	1.162
TAI4	1	70	140	9087	9062	123	0	4	1	16.9	29	140	0	0.057	1.555
TAI5	1	130	130	9757	9757	123	0	4	1	15.5	29	140	0	0.057	1.555
TTOP	1	150	150	11811	11811	123	0	4	1	16.0	29	140	0	0.057	1.555
MOND	1	14	14	10300	10300	235	0	2	1	25.8	16	20	0	0.162	0.978
SIDD	1	14	14	10300	10300	232	0	2	1	21.4	16	20	0	0.140	1.162
TAID	1	11	11	10300	10300	235	0	2	1	9.7	16	20	0	0.162	0.978
HUGT	1	34	34	15500	15500	237	0	1	1	6.8	16	20	0	0.152	0.288
YA47	4	21	21	15656	15656	234	0	1	1	6.2	16	20	0	0.149	0.267
YA13	3	24	24	14000	14000	234	0	1	1	11.1	16	20	0	0.149	0.267
OHPC	1	150	150	10000	10000	101	0	4	1	0.0	0	0	0	2.202	0.000
FOR3	1	18	59	15102	12751	80	0	1	1	5.0	22	60	0	0.062	1.162
FOR4	1	18	59	13196	12441	80	0	4	1	5.0	22	60	0	0.062	1.162
FOR5	1	33	80	13666	11448	80	0	4	1	5.0	22	60	0	0.062	1.162
FOR6	1	74	165	9403	9091	80	0	4	1	7.0	29	140	0	0.057	1.665
WI25	1	39	95	13000	12067	141	0	1	1	20.0	30	60	0	0.157	0.288
W346	1	41	100	13000	12068	141	0	1	1	10.0	30	140	0	0.152	0.288
BEK1	1	36	85	12485	10110	86	0	4	1	7.0	30	60	0	0.062	1.162
BEK2	1	37	98	11688	9485	86	0	4	1	7.0	30	140	0	0.062	1.162
BEK3	1	56	124	10297	9355	86	0	4	1	10.0	30	140	0	0.057	1.555
BEK4	1	64	153	9504	9210	86	0	4	1	13.0	29	140	0	0.057	1.555
BEK5	1	110	238	9301	8959	86	0	4	1	10.0	34	500	0	0.017	0.528
F12T	2	46	46	9087	9087	236	0	1	1	10.0	16	60	0	0.149	0.267
F36T	4	14	14	9658	9658	236	0	1	1	10.0	16	20	0	0.149	0.267
B14T	4	45	45	9637	9637	235	0	1	1	10.0	16	60	0	0.149	0.267

Table 4 (Continued)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
DOIT	1	72	74	11811	11811	242	0	1	1	10.0	16	60	0	0.149	0.267
D23T	2	14	14	9658	9658	242	0	1	1	10.0	16	20	0	0.149	0.267
D45T	2	15	15	10926	10926	242	0	1	1	10.0	16	20	0	0.149	0.267
PI34	2	13	29	18526	12215	85	0	4	1	7.2	22	20	0	0.062	1.162
PIC5	1	13	95	14571	10588	85	0	4	1	3.2	22	60	0	0.062	1.162
PO12	2	15	45	11332	11128	83	0	4	1	4.9	22	60	0	0.062	1.162
PO34	2	25	71	14437	11537	83	0	4	1	5.0	22	60	0	0.062	1.162
CO12	2	60	122	10919	10242	87	0	4	1	12.4	30	140	0	0.057	1.555
CON3	1	65	178	11195	10313	87	0	4	1	10.1	29	140	0	0.057	1.555
PI6T	1	17	17	11163	11163	202	0	1	1	68.2	16	20	0	0.149	0.267
POSD	1	14	14	9962	9962	214	0	2	1	8.2	16	20	0	0.140	1.162
COND	1	14	14	9962	9962	228	0	2	1	16.2	16	20	0	0.140	1.162
PEDD	1	14	14	9962	9962	214	0	2	1	5.3	16	20	0	0.162	0.978
ADDD	1	14	14	9962	9962	216	0	2	1	16.0	16	20	0	0.462	0.978
WA78	2	29	29	10240	10240	178	0	1	1	11.2	16	20	0	0.149	0.267
WA9T	1	158	158	11990	11990	178	0	1	1	0.7	16	140	0	0.149	0.267
OPCC	1	250	250	10000	10000	132	0	4	1	0.0	0	0	0	1.100	0.000
STUD	1	11	11	10300	10300	236	0	2	1	10.0	16	20	0	0.024	0.133

Table 5
VARSYS Data-DPL-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
ZIM1	0	166	249	10710	9360	40	0	0	1	14.0	42	800	0	0.470	1.000
ZIM2	0	241	362	10710	9360	40	0	0	1	17.5	42	1000	0	0.370	0.770
FOR8	0	60	180	10695	8910	100	0	4	1	10.5	42	500	0	1.390	2.930
KIL1	0	98	294	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
KIL2	0	98	294	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB1	0	98	294	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB2	0	98	294	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB3	0	131	392	10640	8850	100	0	4	1	14.0	42	800	0	1.150	2.430

Table 6
VARSYS Data-CGE-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
ZIM1	0	211	317	10710	9360	40	0	0	1	14.0	42	800	0	0.470	1.000
ZIM2	0	307	460	10710	9360	40	0	0	1	17.5	42	1000	0	0.370	0.770
FOR8	0	107	320	10695	8910	100	0	4	1	10.5	42	500	0	1.390	2.930
KIL1	0	102	306	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESP1	0	102	306	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB2	0	102	306	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB3	0	136	408	10640	8850	100	0	4	1	14.0	42	800	0	1.150	2.430

Table 7

VARSYS Data-CSO-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
ZIM1	0	151	226	10710	9360	40	0	0	1	14.0	42	800	0	0.470	1.000
ZIM2	0	219	328	10710	9360	40	0	0	1	17.5	42	1000	0	0.370	0.770
CON5	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
CON6	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
POS5	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
POS6	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
NEW1	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340

Table 8

VARSYS Data-CCD-Power Pooling Study

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
ZIM1	0	528	792	10710	9360	40	0	0	1	14.0	42	800	0	0.470	1.000
ZIM2	0	767	1150	10710	9360	40	0	0	1	17.5	42	1000	0	0.370	0.770
FOR8	0	167	500	10695	8910	100	0	4	1	10.5	42	500	0	1.390	2.930
KIL1	0	200	600	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
KIL2	0	200	600	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB1	0	200	600	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB2	0	200	600	10680	8890	100	0	4	1	12.0	42	600	0	1.250	2.630
ESB3	0	267	800	10640	8850	100	0	4	1	14.0	42	800	0	1.150	2.430
CON5	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
CON6	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
POS5	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
POS6	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340
NEW1	0	125	375	10725	8939	100	0	4	1	8.5	40	500	0	1.590	3.340

15.2.4. CONGEN Data

Input data for CONGEN is required only for Case 5. For this run a capacity range of 0 to 50% and a LOLP criterion of 2.0 days per year are used.

15.2.5. MERSIM Data

The loading orders used in the MERSIM module are shown in Tables 9 through 12. Note that all units in FIXSYS and VARSYS are included in the loading order. The loading order is determined by increasing incremental cost at the base load level.

15.2.6. DYNPRO Data

The DYNPRO input data is shown in Tables 13 and 14. The escalation rates on capital cost are set to 0% because the capital costs which are already adjusted for escalation are used. The capital costs for the optimized expansion schedule are revised as shown in Table 13. Zimmer #2 and Newbury Site #1 are postponed beyond the end of the study (1986) and are not included in the optimized expansion schedule.

15.3 Results

The results of the WASP runs for the five cases mentioned in Section 15.1 are summarized in Table 15, in which the annual LOLP for the period of twelve years and the value of the objective function at the end of 1986 are shown.

It is observed that LOLP of DPL (Case 1) and CGE (Case 2) is substantially higher than that of CSO (Case 3) each of which are hypothetically assumed to be isolated.

The total of the objective functions for the three companies (Cases 1, 2 and 3), which includes all the construction, operating and maintenance costs until 1986, is 5620 $M in 1975 dollars. On the other hand, the objective function for the hypothetically consolidated system, CCD, (Case 4) is 5196 million dollars, which is 424 million dollars (or 7.5%) less than the total of the objective functions for the three isolated systems. This 7.5% savings results from generation diversity as well as load diversity among the three systems. Generation diversity refers to the fact that the variety of plants available for customer service is wider for CCD than for any of the three systems operating independently. Thus, the generating units are always more economically used by dispatching the whole system as one consolidated system. Load diversity refers to the fact that, since the load profiles of the three systems are different, peak load for each system tends to be averaged out when combined. For example, if the load on the DPL system is high at a particular time but the load on the CGE system is low, DPL's high load is covered by using CGE's idle units which are more efficient and cheaper to operate than the peaking units available at DPL.

The last column of Table 15 shows the results of the WASP run for Case 5 which allows one or two years delay in completing future units under the constraint of two days per year of LOLP. The system thus, determined is designated by CCD*. The LOLP of two days per year is, of course, unrealistically large for such a consolidated system, but it is meaningful in estimating the relationship between the LOLP criterion and the amount of savings. Table 16 shows how the original schedule for completing units can be delayed if the LOLP criterion is two days per year. The objective function for CCD* is 4,724 million dollars, which is 472 million dollars (or 9.1%) less than that of CCD.

Table 9

MERSIM Data-DPL-Power Pooling Study

Loading Order	WASP Name	Block	Loading Order	WASP Name	Block
1	ZIM2	Base	22	ESB2	Peak
2	ZIM1	Base	23	FOR8	Peak
3	ESB3	Base	24	FOR7	Peak
4	CON4	Base	25	BEK6	Peak
5	KIL1	Base	26	ST13	Peak
6	KIL2	Base	27	STU4	Peak
7	ESB1	Base	28	TAI4	Base
8	ESB2	Base	29	TAI4	Peak
9	FOR8	Base	30	TAI5	Base
10	FOR7	Base	31	HU36	Base
11	BEK6	Base	32	HU36	Peak
12	ST13	Base	33	HUT2	Base
13	STU4	Base	34	HUT1	Base
14	OHPC	Base	35	HUGT	Base
15	ZIM2	Peak	36	YA13	Base
16	ZIM1	Peak	37	YA47	Base
17	ESB3	Peak	38	TTOP	Base
18	CON4	Peak	39	TAID	Base
19	KIL1	Peak	40	MOND	Base
20	KIL2	Peak	41	STUD	Base
21	ESB1	Peak	42	SIDD	Base

Table 10

MERSIM Data-CGE-Power Pooling Study

Loading Order	WASP Name	Block	Loading Order	WASP Name	Block
1	ZIM2	Base	29	FOR6	Base
2	ZIM1	Base	30	BEK5	Peak
3	ESB3	Base	31	BEK4	Base
4	CON4	Base	32	BEK4	Peak
5	KIL1	Base	33	BEK3	Base
6	KIL2	Base	34	BEK3	Peak
7	ESB1	Base	35	BEK2	Base
8	ESB2	Base	36	BEK2	Peak
9	FOR8	Base	37	FOR4	Base
10	FOR7	Base	38	FOR4	Peak
11	BEK6	Base	39	BEK1	Base
12	ST13	Base	40	BEK1	Peak
13	STU4	Base	41	FOR5	Base
14	ZIM2	Peak	2	FOR5	Peak
15	ZIM1	Peak	43	FOR3	Base
16	ESB3	Peak	44	FOR3	Peak
17	CON4	Peak	45	W125	Base
18	KIL1	Peak	46	W125	Peak
19	KIL2	Peak	47	W346	Base
20	ESB1	Peak	48	W346	Peak
21	ESB2	Peak	49	F12T	Base
22	FOR8	Peak	50	B14T	Base
23	FOR7	Peak	51	F36T	Base
24	BEK6	Peak	52	D23T	Base
25	ST13	Peak	53	STUD	Base
26	STU4	Peak	54	D45T	Base
27	FOR6	Base	55	DC1T	Base
28	FOR6	Peak			

Table 11

MERSIM Data-CSO-Power Pooling Study

Loading Order	WASP Name	Block	Loading Order	WASP Name	Block
1	ZIM2	Base	23	NEW1	Peak
2	ZIM1	Base	24	PO12	Base
3	CON4	Base	25	PO12	Peak
4	BEK6	Base	26	CO12	Base
5	STL3	Base	27	CO12	Peak
6	STU4	Base	28	CON3	Base
7	CON5	Base	29	CON3	Peak
8	CON6	Base	30	PO34	Base
9	POS5	Base	31	PO34	Peak
10	POS6	Base	32	PIC5	Base
11	NEW1	Base	33	PIC5	Peak
12	OHPC	Base	34	PI34	Base
13	ZIM2	Peak	35	PI34	Peak
14	ZIM1	Peak	36	WA78	Base
15	CON4	Peak	37	POSD	Base
16	BEK6	Peak	38	PEDD	Base
17	STI3	Peak	39	WA9T	Base
18	STU4	Peak	40	ADDD	Base
19	CON5	Peak	41	PI6T	Base
20	CON6	Peak	42	COND	Base
21	POS5	Peak	43	STUD	Base
22	POS6	Peak			

Table 12

MERSIM Data-CCD-Power Pooling Study

Loading Order	WASP Name	Block	Loading Order	WASP Name	Block
1	ZIM2	Base	26	KIL2	Peak
2	ZIM1	Base	27	ESB1	Peak
3	ESB3	Base	28	ESB2	Peak
4	CON4	Base	29	FOR8	Peak
5	KIL1	Base	30	FOR7	Peak
6	KIL2	Base	31	BEK6	Peak
7	ESB1	Base	32	STI3	Peak
8	ESB2	Base	33	STU4	Peak
9	FOR8	Base	34	CON5	Peak
10	FOR7	Base	35	CON6	Peak
11	BEK6	Base	36	POS5	Peak
12	STI3	Base	37	POS6	Peak
13	STU4	Base	38	NEW1	Peak
14	CON5	Base	39	FOR6	Base
15	CON6	Base	40	FOR6	Peak
16	POS5	Base	41	BEK5	Base
17	POS6	Base	42	BEK5	Peak
18	NEW1	Base	43	BEK4	Base
19	OHPC	Base	44	BEK4	Peak
20	OPCC	Base	45	BEK3	Base
21	ZIM2	Peak	46	BEK3	Peak
22	ZIM1	Peak	47	PO12	Base
23	ESB3	Peak	48	PO12	Peak
24	CON4	Peak	49	CO12	Base
25	KIL1	Peak	50	CO12	Peak

Table 12 (Continued)

Loading Order	WASP Name	Block	Loading Order	WASP Name	Block
51	CON3	Base	76	PI34	Peak
52	CON3	Peak	77	WA78	Base
53	BEK2	Base	78	W125	Base
54	BEK2	Peak	79	W125	Peak
55	FOR4	Base	80	W346	Base
56	FOR4	Peak	81	W346	Peak
57	BEK1	Base	82	POSD	Base
58	BEK1	Peak	83	PEDD	Base
59	FOR5	Base	84	WA9T	Base
60	FOR5	Peak	85	F12T	Base
61	TAI4	Peak	87	PI6T	Base
63	PO34	Base	88	B14T	Base
64	TAI5	Base	90	F36T	Base
65	FOR3	Base	91	D23T	Base
67	FOR3	Peak	92	SIDD	Base
68	HUT2	Base	93	MOND	Base
69	HU36	Base	94	TAID	Base
70	HU36	Peak	95	STUD	Base
71	PIC5	Base	96	D45T	Base
72	PIC5	Peak	97	DCiT	Base
73	HUT1	Base	98	YA13	Base
74	TTOP	Base	99	YA47	Base
75	PI34	Base	100	HUGT	Base

Table 13

DYNPRO Capital Cost Data for All Candidates-Power Pooling Study

WASP Name	Original On-Line Date	Capital Cost In Original On-Line Year ($/KW)	Optimized On-Line Date	Capital Cost In Optimized On-Line Year ($/KW)
ZIM1	1979	634	1980	687
ZIM2	1986	963	--	--
FOR8	1978	341	1980	400
KIL1	1983	564	1985	662
KIL2	1981	568	1983	667
ESB1	1982	534	1984	627
ESB2	1980	528	1982	620
ESB3	1984	669	1986	785
CON5	1976	393	1978	461
CON6	1978	292	1979	316
POS5	1981	803	1981	803
POS6	1983	581	1985	682
NEW1	1985	868	--	--

Base year for present-worth calculations: 1975

Discount rate applied to all capital and operating costs: 9.25%

Table 14

DYNPRO Data-Power Pooling Study

Plant Type	Plant Life (Yrs.)	Escalation Rate On Operating Costs (%)
Nuclear	35	5.5
Coal-Fired	30	5.0
Diesel	--	4.5
Gas-Turbine	--	4.5

Table 15
Results-Power Pooling Study

Loss-of-Load Probability (Days/Year)					
Year	DPL	CGE	CSO	CCD	CCD*
1975	0.131	0.181	0.197	0.036	0.036
1976	0.658	0.749	0.041	0.065	0.190
1977	1.803	2.268	0.001	0.285	0.725
1978	1.792	2.133	0.029	0.153	1.151
1979	1.624	2.281	0.018	0.160	1.869
1980	1.227	1.691	0.045	0.171	0.564
1981	0.988	1.703	0.023	0.108	1.072
1982	0.846	1.861	0.056	0.155	1.336
1983	0.733	1.694	0.020	0.087	1.503
1984	0.511	1.276	0.052	0.092	1.727
1985	1.483	3.286	0.023	0.182	1.176
1986	1.261	3.710	0.020	0.202	1.431
Objective Function	1674	2181	1765	5196	4724
(10^6 1975$)	Total of DPL + CGE + CSO = 5620				

Table 16

Postponed Unit On-Line Dates

WASP Name	Original On-Line Date	Optimized* On-Line Date	Number of Years Postponed
ZIM1	1979	1980	1
ZIM2	1986	--	---
FOR8	1978	1980	2
KIL1	1983	1985	2
KIL2	1981	1983	2
ESB1	1982	1984	2
ESB2	1980	1982	2
ESB3	1984	1986	2
CON5	1976	1978	2
CON6	1978	1979	1
POS5	1981	1981	0
POS6	1983	1985	2
NEW1	1985	--	---

* The optimal on-line dates are determined subject to the following constraints:

1) Expansion candidates are identical to those the three utilities are planning to install.

2) The on-line dates of each unit are allowed to be postponed one or two years from the original on-line date.

3) The reliability criterion's comparable with the reliability levels obtained from DPL and CGE (2.0 days/year CDP).

References

(1) 1975 Annual Report of The Dayton Power and Light Company to the Federal Power Commission, F.P.C. Form No. 1, pages 422-423, 431-441.

(2) 1975 Annual Report of The Cincinnati Gas and Electric Company to the Federal Power Commission, F.P.C. Form No. 1, pages 431-441.

(3) 1975 Annual Report of Columbus and Southern Ohio Electric Company to the Federal Power Commission, F.P.C. Form No. 1, pages 422-423, 431-441.

(4) Private communication with R. Lubbers and C. Poseidon, Graduate Research Associates at The Ohio State University.

(5) International Atomic Energy Agency (IAEA) Nuclear Power Planning Study Procedures Manual, Appendix E.

(6) 1975 Uniform Statistical Report for The Dayton Power and Light Company to the American Gas Association, Edison Institute and Financial Analysts, pages E18-E20.

CHAPTER 16

THE EFFECTS OF RADIO CONTROL FOR RESIDENTIAL ELECTRIC WATER HEATERS

16.1 Introduction

The increasing cost of fossile fuels has provided an incentive for electric utilities to seek new and more economical methods of producing electrical power. As a consequence, a wide variety of electrical load management techniques are now being developed.[1-8] One such technique involves controlling residential loads, particularly water heaters, in order to shift load "peaks" to load "valleys." The purpose of this study[†] is to evaluate the advantages that might be gained from this type of load management. The Dayton Power and Light Company serves as a model for an analysis of the effect of radio control of residential water heaters on the operation and capacity costs. This study is, however, based on two heuristic assumptions: (1) the diversified load of water heaters before control is constantly 1 kW per one water heater, and (2) the total controllable electric load is 100 MW (or equivalently 100,000 water heaters). These two assumptions are necessary because no measured data for the diversified load or total load of residential water heaters is available for the DP&L system

In order to perform this evaluation, a computer model was developed to simulate load curve shaping via the radio control of electric water heaters. This model was used to investigate two schemes for electric water heater control. The first scheme reduces the daily load to the lowest possible level. The second scheme initiates control on the basis of an effective demand level (real demand and outages). This type of control requires information about forced and planned plant outages, marginal production costs and the forecast hourly demand. The advantages of load control are deter-

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[†] The material in this chapter is based on the Master's thesis of Mr. David J. Pasz, "The Effect of Residential Control on Power System Economics," The Ohio State University, 1977. Mr. Pasz's work for this thesis was partially supported by the PUCO.

mined by using the MARC-3A program and the LOLP program, which are described in Chapters 3 and 5 respectively.

16.2 A Brief Overview of Load Control

Time-of-day pricing and automatic load control are thought to offer high potential as a means of shifting electrical demand from a peak load time to an off-peak time, i.e., although in the U.S. application of automatic load control is far more advanced than time-of-day pricing. Time-of-day pricing is used very little in this country because it requires time-of-day metering which involves a high investment cost or cumbersome and expensive maintenance.

Automatic load control for residential users may be implemented by using either ripple control, time clock switching, two-way distribution line control, or radio control. Among these, the radio control is the most widely used in the U.S.[7] In the case of Detroit Edison[9] for example, the controlled water heaters are broken down into 10 control groups, each of which is controlled by a different radio signal. The control signals are first transmitted to remote transmittal stations by telephone lines and then transmitted to the customer's radio signal receivers.

The first requirement for automatic load control is the existence of a deferrable load. For example, irrigation pumps and swimming pool circulation pumps are deferrable. The electric load is also deferrable if the consumed electric energy is stored at the user's side as is the case with electric storage heaters made of magnesite bricks, water heaters, air conditions and refrigerators. Although radio control of water heaters has been most successful in the U.S., the feasibility of controlling other resinential equipment is also being studied.

A water heater stores energy in hot water. A typical single electric water heater draws 4 of electricity when its heater is on. The electric load is turned off when the hot water reaches a certain temperature and remains off until the stored energy decreases to a preset low level. The total load for all the residential heaters is therefore diversified because of this on-and-off operation. The average load of electric water heaters is called the diversified load (of water heaters). Although the uncontrolled diversified load varies with the time of day, it is approximately 1 kW as illustrated in Figure 1.

Suppose a group of N water heaters, each having 4 kW heating element and 1 kW of diversified load, is turned off for a certain period by a radio control device. If the electricity is turned off for a long period, the energy stored in the tanks will be depleted so that all the electric heaters will be turned on as soon as electricity becomes available. This means 4N kW electric load for each water heater is drawn from the generating system. In general, the electic load after a shut-off period depends upon the length of the shut-off period. A load profile of the diversified demand after various lengths of shut-off time is shown in Figure 2.

16.3 Algorithms of the CONTROL Program

In the present study, the hourly system load data of DP&L for 9/1/1975 - 8/31/1976 is used as the system load without radio control and the change in the system load due to the radio control of 100,000 water heaters is estimated. Since there is no measured data for the water heaters of DP&L residential customers, the diversified load of a water heater without control is rather arbitrarily assumed to be 1kW. In other words, 100 MW of a constant load is subject to radio control.

The diversified load of water heaters under radio-control is simulated in this study by the Residential Load Control Simulation program, which is abbreviated as CONTROL program. The 100,000 water heaters are divided into 10 equal groups, each of which has a constant 10MW diversified load demand before control. This program determines how to turn on and off the electricity for each group, according to the two alternative schemes:

(1) Load Leveling (LL): the load is controlled to minimize the peak load of each day.

(2) Economic Load Shaping (ELS): the load is controlled to minimize the highest marginal production cost in a day.

In scheduling load control, it is assumed that the hourly load and the emergency shutdown time in a day are predetermined. This is

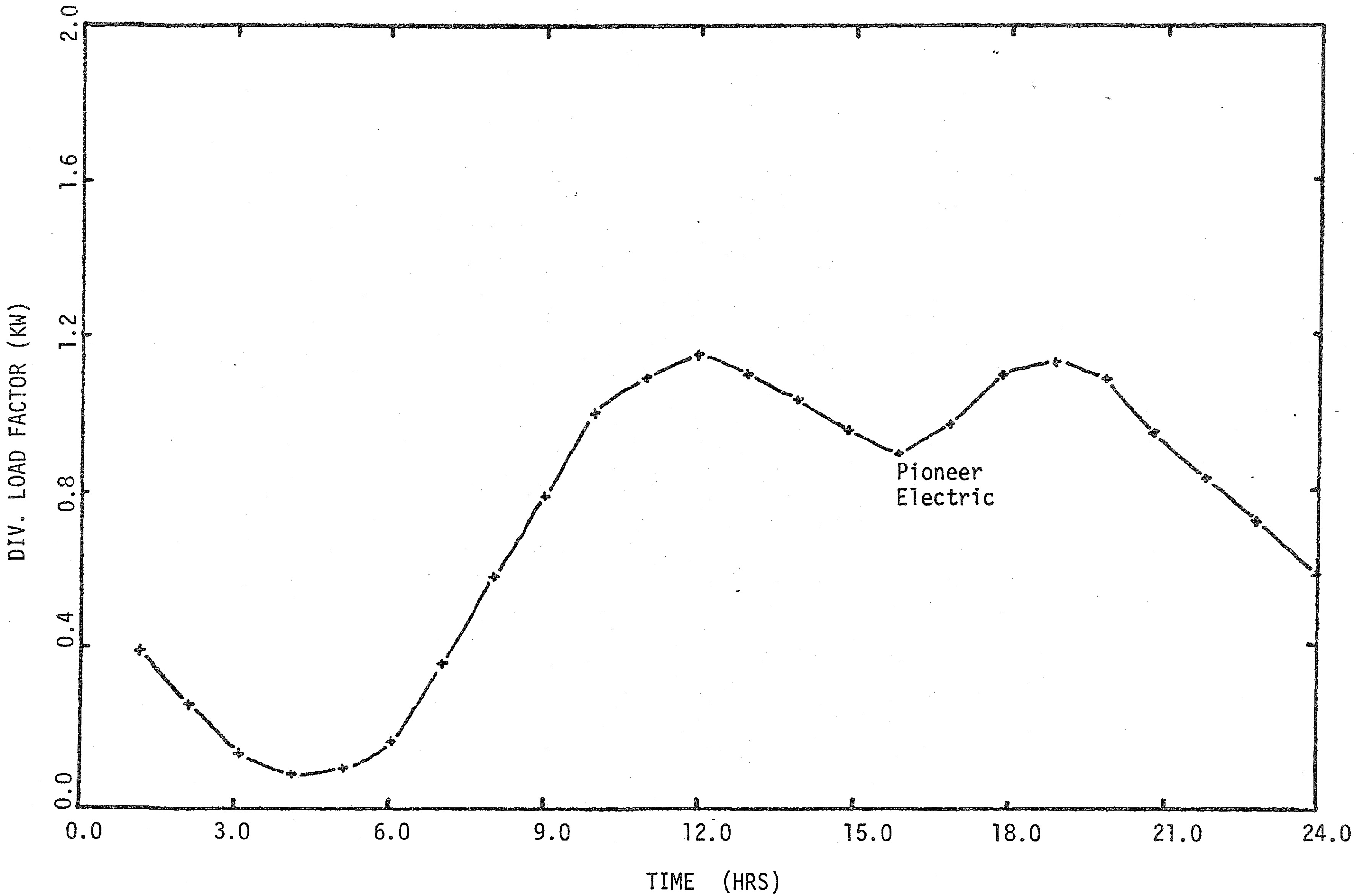

Figure 1 Diversified Load Profile of Water Heaters Determined by Pioneer Electric

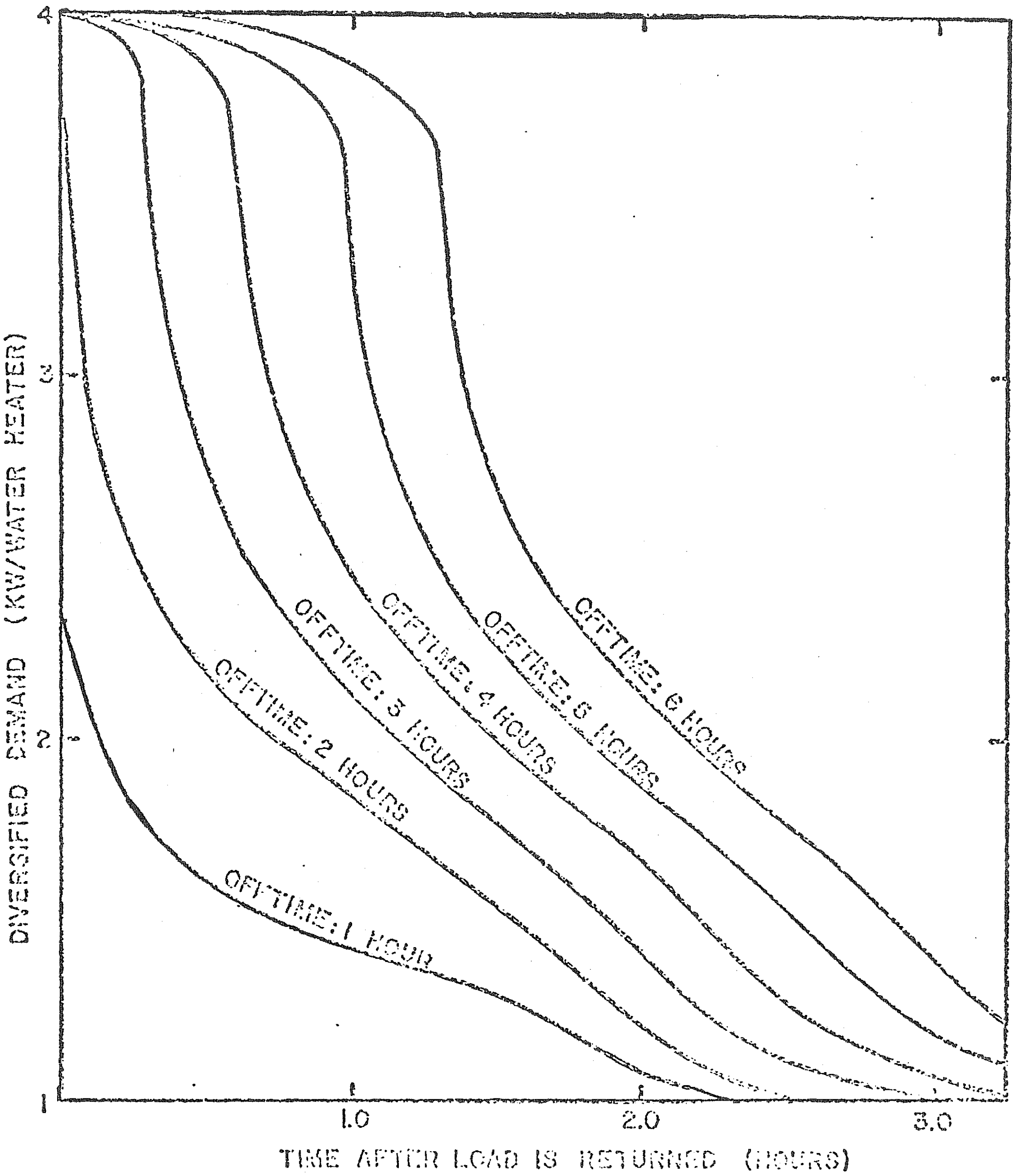

Figure 2 Typical Load Profile After Various Lengths of Shut-Off Time. These curves were derived from Detroit Edison and Motorola data.

too unrealistic an assumption, because the load demand and outages can be predicted with reasonable accuracy several hours in advance. In the next paragraphs, the algorithms of the program for Load Leveling as well as for Economic Load Shaping are outlined.

For simplicity of explanation, suppose first we get a prescribed threshold load level below which the system load has to be maintained. The program considers the hourly load of each day in chronological order. For each hour, it compares the system hourly load with the prescribed threshold load. If the system load has been lower than the threshold, no action for load control is taken and the program goes to the next hour. If the threshold is exceeded for the first time, the computer decides to shut off electricity for the necessary number of groups. The lowest group numbers available are picked up. If the load of the next hour still exceeds the threshold in spite of a number of shut-off water heater groups, then additional groups are shut off. This continues as long as the threshold is exceeded and there are groups that can be shut off.

When the load decreases, just the reverse occurs. If the load drops below the threshold, as many groups as possible that have been shut off are turned on in the order of the longest shut-off period. When those water heaters have been turned on, the total electrical load is calculated based on the length of shut-off shown in Table 1, which is developed by taking the hourly average of the load shown in Fig. 2. As mentioned before, all the water heaters shut off for six hours are turned on regardless of the threshold.

Table 1 Payback after Various Shut-Off Hours

Amount of Payback (KW)

Shut-off Length, hrs	Payback* (KW)		
	1st hr	2nd hr	3rd hr
1	0.702	0.249	0.049
2	1.403	0.498	0.098
3	2.080	0.738	0.182
4	2.656	0.992	0.352
5	2.982	1.419	0.599
6	3.000	2.080	0.920

*Payback is the additional power drawn after the shut-off. For example, if the shut-off is one hour, the diversified power drawn is 1.702, 1.249 and 1.049 KW during the 1st, 2nd and 3rd hours, after the shut-off respectively.

It is assumed that each group can be shut off at most twice a day, but electricity is made available for at least three hours between two consecutive shut-offs in a day.

Even though we have assumed that the threshold level is prescribed, the controlled system load shape is affected by the value of the threshold. For example, suppose the threshold is set too low. The system load can be maintained at the threshold level for some period after the uncontrolled system load exceeds the threshold. However, it is conceivable that all the water heaters would be turned on at once after the shut-off and, as a consequence, the controlled system load would far exceed the uncontrolled system load. Therefore, in the CONTROL program, the threshold is optimized for each day assuming the uncontrolled hourly system load is prescribed. This optimum level is arrived at after an exhaustive research.

In summary for this section the following assumptions are made:

(1) The uncontrolled diversified load of an electric water heater is always 1 kW.

(2) Electricity for a group of water heaters is shut off for a period of one to six hours.

(3) The effect of a shut-off lasts only three hours.

(4) The diversified electric load during the three hours after a period of shut-off is assumed as shown in Table 1.

(5) 100,000 electric water heaters exist in the system. This is equivalent to a 100 MW constant diversified load under the first assumption.

(6) The total of 100,000 water heaters are divided into 10 control groups, each of which has 10 MW of uncontrolled diversity load.

16.4 Effect of Radio Control of Water Heaters

The effects of the radio load control of water heaters are evaluated from two viewpoints: operation cost saving and capital cost saving. The current DP&L generating system is assumed to be as shown in Table 2.

The CONTROL program generated the controlled hourly load data in which the 100 MW uncontrolled diversified load is altered. An example of uncontrolled and controlled load profiles is shown in Fig. 3. Table 3 shows the seasonal summary of the peak load and load factors before and after control for the DP&L hourly data of 9/1/75 - 8/31/1975.

To estimate the savings in operation cost gained by radio control of water heaters, MARC-3A (described in Chapter 3) was run three times: first for all the hours with uncontrolled demand, second for the controlled load with load leveling (LL), and third for the controlled economic load shaping (ELS). The difference (reduction) in the operating costs for uncontrolled and controlled data is the total annual saving and is shown in Table 3. Radio control reduces annual operation cost about 0.14% with LL and 0.17% with ELS.

The capacity saving† with the radio control is found by using the relation between the LOLP criterion and levelized construction cost developed in Chapter 14. For this purpose the LOLP program was run for the three load data. The LOLP for the uncontrolled load (UNS) is 1.027 day/year as shown in Table 3. The LOLP for the Load Leveling control is 0.914 day/year which is lower than the uncontrolled LOLP by 0.113. Suppose the uncontrolled LOLP of 1.027 is the standard reliability criterion for the system expansion, then the construction cost saving caused by 0.113 day/year decrease in LOLP for the next two years is estimated from Fig. 2 of Chapter14 as $887,000. Similarly, the reduction in LOLP of ELS from UNS, which is 1.027 - 0.938 = 0.089, yields the saving of $698,000 in construction cost.

In summary, the load control of 100,000 water heaters is estimated to save $1,024,000 with LL and $864,000 with ELS, as shown in Table 4.

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† The saving in construction cost is greatly overstimated in Mr. Pasz's thesis because of some serious mistakes in dealing with the reliability calculation. Namely, the reliability level used in Fig. is based on hourly data, while the reliability value used by Pasz is based on the assumption that in each day the system laod is equal to the peak load of the day.

TABLE 2 UNIT IDENTIFICATION AND CAPACITY DATA FOR DAYTON POWER AND LIGHT

Unit No.	Unit Name	% Own	Capacity (MW)	Type
1	Miami Fort 7	36.00	500.00	Base
2	Beckford 6	50.00	440.00	Base
3	Conesville 4	16.50	800.00	Base
4	J. M. Stuart 1	35.00	585.00	Base
5	J. M. Stuart 2	35.00	585.00	Base
6	J. M. Stuart 3	35.00	585.00	Base
7	J. M. Stuart 4	35.00	585.00	Base
8	Stuart Diesels	36.36	11.00	Peaker
9	Tait 4	100.00	140.00	Cycling
10	Tait 5	100.00	130.00	Cycling
11	Tait Topping	100.00	150.00	Cycling
12	Hutchings 1	100.00	61.00	Cycling
13	Hutchings 2	100.00	60.00	Cycling
14	Hutchings 3	100.00	67.00	Cycling
15	Hutchings 4	100.00	67.00	Cycling
16	Hutchings 5	100.00	67.00	Cycling
17	Hutchings 6	100.00	67.00	Cycling
18	Hutchings G. T.	100.00	32.00	Peaker
19	Yankee 1	100.00	21.00	Peaker
20	Yankee 2	100.00	21.00	Peaker
21	Yankee 3	100.00	21.00	Peaker
22	Yankee 4	100.00	18.00	Peaker
23	Yankee 5	100.00	18.00	Peaker
24	Yankee 6	100.00	18.00	Peaker
25	Yankee 7	100.00	18.00	Peaker
26	Tait Diesels	100.00	11.00	Peaker
27	Monument Diesels	100.00	14.00	Peaker
28	Sidney Diesel	100.00	14.00	Peaker
29	Ohio Power Contract	100.00	150.00	Peaker
30	Ovec Contract	100.00	100.00	Peaker

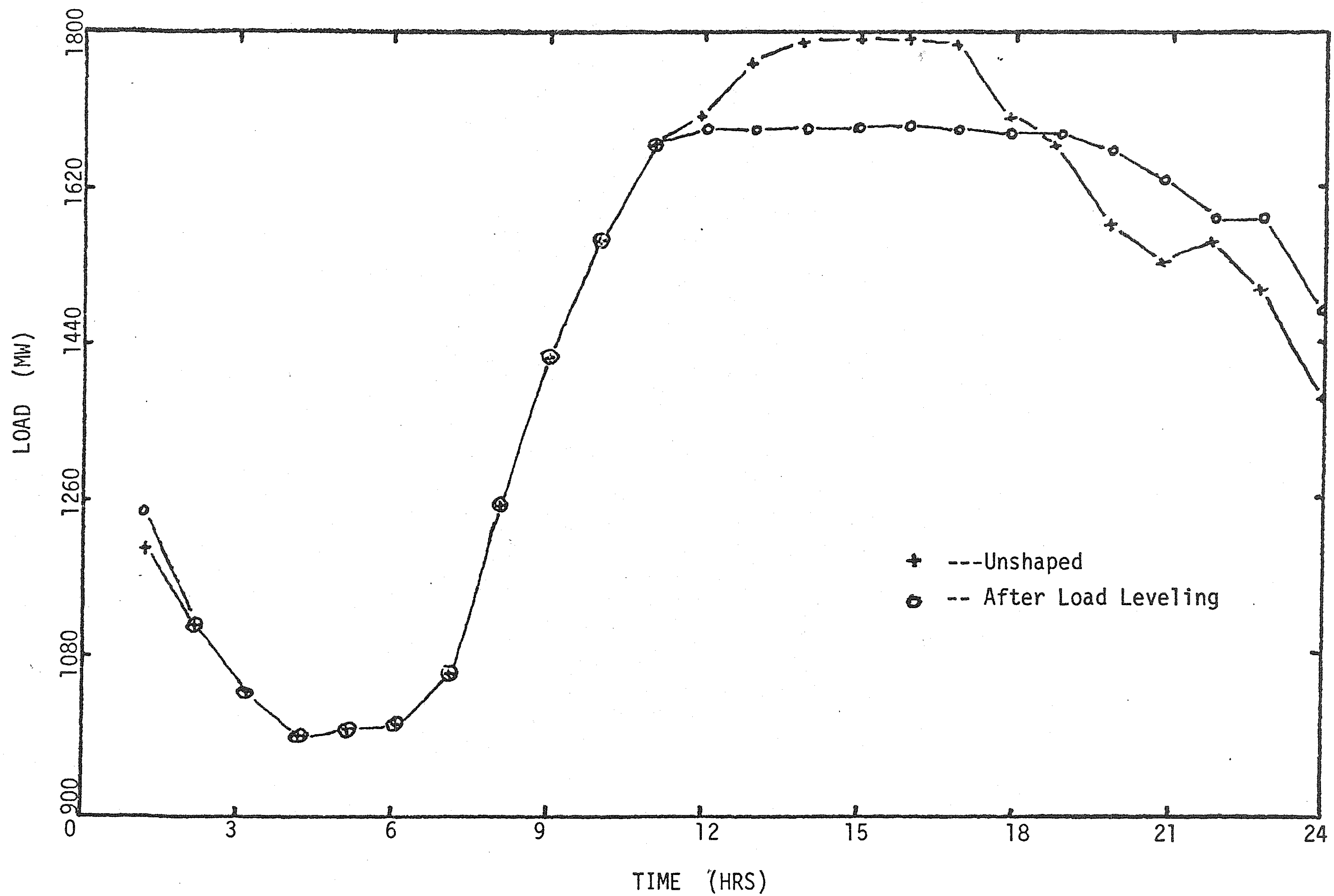

Figure 3 Hourly Record Summer Peak Load Values for Unshaped and Load Leveled Data

Table 3 Effect of Load Control

	Average Load MW	Peak Load MW	Load Factor %	Saving in Operation Cost Absolute $	Saving in Operation Cost %	LOLP
Fall 1975						
UNS*	1,010	1,586	63.7	-	-	-
LL*	1,010	1,486	68.0	27,000	0.12	-
ELS*	1,010	1,502	67.2	32,000	0.14	-
Winter 1975						
UNS	1,184	1,740	68.1	-	-	-
LL	1,184	1,676	70.7	43,000	0.16	-
ELS	1,184	1,695	69.9	71,000	0.26	-
SPRING 1976						
UNS	1,043	1,519	68.7	-	-	-
LL	1,043	1,457	71.6	23,000	0.10	-
ELS	1,043	1,461	71.5	24,000	0.10	-
SUMMER 1976						
UNS	1,115	1,793	62.2	-	-	-
LL	1,115	1,693	65.0	44,000	0.18	-
ELS	1,115	1,700	65.6	39,000	0.15	-
Annual Summary						
UNS	-	-	-	-	-	1.027
LL	-	-	-	137,000	0.14	0.914
ELS	-	-	-	166,000	0.17	0.938

*UNS: unshaped, LL: Load Leveling, ELS: Economy Load Shaping

Table 4 Annual Saving by the Radio Control of 100,000 Electric Water Heaters

	Saving in Operation Cost	Saving in Construction Cost	Total Saving
LL	137,000	887,000	1,024,000
ELS	166,000	698,000	864,000

References

(1) T. Laaspere, A. O. Converse, "Creative Electric Load Management," IEEE Spectrum, February 1975, pp. 46-50.

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(4) T. Laaspere, "Review of Load Management Techniques," Thayer School of Engineering, Dartmouth College, 1975.

(5) P. E. Weatherby, "An Evaluation of the Load Reduction Program for Central Air Conditioning," Cobb Electric Membership Corporation, October 1976.

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(7) D. W. Miller, et al., "A Final Report to PUCO on the Evaluation of Metering and Related Technical Aspects for Implementing Improved Electric Utility Rate Structures," The Ohio State University, October 14, 1975.

(8) R. L. Roberts, "Proceedings of the Seminar on Load Management," Minot, North Dakota, March 16, 1976.

(9) Edison Public Information, Detroit Edison Company, December 13, 1976.

APPENDIX 16A
USER'S GUIDE FOR THE RESIDENTIAL LOAD CONTROL SIMULATION PROGRAM

16A.1 Introduction

The residential Load Control Simulation Program (CONTROL) is a fast and efficient means of evaluating load control as a load management option. The concept and explanation of the CONTROL Program is presented in Section 16.3. The purpose of this appendix is to describe the procedures and data needed to use the CONTROL Program to investigate the effects of water heater control on the system demand curve.

First the Job Control Language (JCL) needed to compile and execute the CONTROL Program on The Ohio State University IBM 370/165 is discussed. Then a description of the input data and appropriate formats is presented along with a sample setup. A description of the output and output options, along with a sample output, follows.

16A.2 CONTROL-JCL Requirements

The CONTROL Program is written in FORTRAN for use of the use of the IBM 370/165. The code is easy to execute as it requires only six JCL cards. These cards are shown in Figure 16A-1. The first card indicates that a maximum of 30,000 lines and 2,000 cards can be produced. These values can be changed if necessary. The first card also indicates that the execution class is C and that 252 K of storage is required. If CONTROL is not being used in the optimizing mode the execution class may be changed to class B for decreased turnaround time.

The second card shows that the program should be compiled by the catalogued procedure FORTRUN with a running time of no longer than three minutes. The time parameter can be changed to accommodate longer execution times, however, three minutes should be sufficient for most purposes.

```
// (30000,2000),CLASS=C,REGION=252K
```

FIRST CARD

```
// EXEC PROC=FORTRUN,TIME=3
```

```
//CMP.SYSIN DD *
```

SOURCE DECK GOES HERE

```
//GO.SYSIN DD *
```

DATA GOES HERE

```
/*
```

```
//
```

LAST CARD

Figure A-1 Job Control Cards Required to Run the CONTROL Program on an IBM 370

The third card tells the computer that the source program is to be read in from cards. The CONTROL program directly follows this card. The forth JCL card should be placed after the program and before the data. This card indicates that the data is to be read from cards. The last two cards go directly after the data to indicate the end of the card file.

16A.3 Input Data and Data Formats

The significance of the parameters needed to stimulate the control of electric water heaters is discussed in Section 16.3 (i.e., diversified demand, threshold, maximum time a water heater is allowed to be off and the minimum time a water heater must be left on before being returned to off status). This section defines the order and format of this data for the purposes of executing the CONTROL Program. Each data card will be discussed individually.

CARD 1: This card puts a limit on the number of hours a water heater can be left off when control is used in the optimizing mode. If control is not used in the optimizing mode this card will be ignored. This parameter should be placed in Column 1 in an I1 format. If this card is left blank, six hours is chosen by default.

CARD 2: This card contains the first 12 hours of the diversified load factor profile to be used. The diversified load factor for the first hour should start in Column 1 in an F5.3 format. The diversified load factor for the second hour should start in column 6 in an F5.3 format and so on. The diversified load factor should be specified in kilowatts.

CARD 3: Same as card 2, for the hours of 13 through 24.

CARD 4: The total number of water heaters available for control is placed on this card. It should start in column 1 in an F5.0 format.

CARD 5: This card contains three control parameters. The first parameter indicates whether or not more than one day is to be analyzed. If only one day is to be analyzed, 01 should be specified starting in column 1 in an I2 format. If more than one day is to be analyzed, a 00 should be placed there. The second parameter specifies the type of load to be controlled. Presently only water heaters are valid for which a 00 should be placed starting in column 4 (I2 format). The third parameter specifies whether or not card output is desired in addition to the printout. If -1 is specified in columns 7 and 8, card output (described in the next section) will be provided. If 00 is specified, no card output is provided.

CARD 6: This card specifies two parameters. The first is the maximum number of hours a water heater is allowed to be left off. This should be placed in column 1 in an I3 format. This number should not have a fractional portion (i.e., no fractions of an hour should be used). If zero is specified for this number the program will optimize with respect to using the upper limit specified in card 1. The second parameter specifies the cycle gap or number of hours a water heater must be left on before it is allowed to return to off status. This number should be placed in column 15 in an F5.3 format. If a zero is placed for this number the program will optimize with respect to it.

CARD 7: This card specifies the threshold value to be used. It should be started in column 1 in an F5.0 format. If a zero is specified for this number the program will optimize with respect to it.

CARD 8: This card specifies the number of days to be analyzed. It should be placed, starting in column 7 in an I4 format. If only one day is to be analyzed, this card should be eliminated.

CARD 9: These cards specify the day being controlled and the hourly loads for that day. The month, day and year being controlled should be placed in the first 6 columns in a 3I2 format. Column 7 through 15 can be used for identification purposes. Column 16 specifies the day of the week. Monday through Sunday are specified by 1 through 7 respectively. If the day is a holiday it should be specified as 8. Column 21 through 80 should contain 12 hours of load data in a 12I5 format. These cards are necessary to specify each day of load data. All load data should be specified in megawatts.

An example of a typical data setup is shown in Figure A-2. For this example a six-hour ceiling was placed on the number of hours a water heater can be left off (Card 1). The average Pioneer divsersified load profile, shown in Table 1 of Section 16.3, is used (Cards 2 and 3). Card 4 indicates that 100,000 water heaters are available for control. The fifth card shows that more than one day will be controlled, that water heaters will be controlled, and that card output is desired. The sixth and seventh cards show that the program should optimize the results with respect to the maximum water heater offtime, the cycle gap and the threshold value simultaneously. Card 8 indicates that three days are to be controlled. Finally, Cards 9 through 14 show hourly load data for January 23 through 25 of 1976 (obtained from DP&L). The output resulting from this data will be discussed in the next section.

16A.4 Output Description

There are two different means of obtaining output from the CONTROL Program: printout and cards. For every day of control, two 8-1/2" x 11" pages of computer printout are generated. The easiest way to describe the output is with an example. Using the sample input data of Figure A-2 the CONTROL Program was executed. The resulting computer printout is shown in Figure A-3. The sample input data called for control over three days, thus six pages of printout were obtained. As shown, it indicates the type of load being controlled (presently water heaters only), the total number of water heaters and the number of water heaters in each control group (the total number of water heaters divided by 10, since there are 10 control groups). Then the threshold level which was maintained is documented. Note that directly under threshold level is a message which says that the threshold level was chosen by the program. This message will be written whenever the threshold level

```
6
                                                  FIRST CARD
.399 .253 .125 .078 .037 .152 .367 .594 .8031.0161.1061.168
1.1231.060 .978 .916 .9911.1181.1501.112 .967 .855 .751 .607
100000.0
00 00 -1
0.0        0.0
0.0
0003
 12376 USLC 1  5      1110 1074 1044 1046 1063 1131 1286 1517 1572 1565 1556 1483
 12376 USLC 2  5      1435 1398 1338 1276 1273 1281 1368 1336 1257 1220 1131 1055
 12476 USLC 1  6       948  896  856  851  648  868  913  984 1092 1157 1188 1179
 12476 USLC 2  6      1175 1134 1094 1066 1099 1164 1259 1232 1190 1156 1095 1035
 12576 USLC 1  7       956  917  895  884  882  884  915  947 1015 1081 1128 1163
 12576 USLC 2  7      1209 1172 1128 1096 1102 1142 1153 1126 1083 1048  993  900
                                                  LAST CARD
```

Figure A.2 Typical Data Setup for Use in the CONTROL Program

LOAD CONTROL SUMMARY FOR 1/23/76
(DAY NUMBER 1 OF 3)

TYPE OF LOAD(S) TO BE CONTROLLED -- WATER HEATERS

TOTAL NUMBER OF CONTROL UNITS -- 100000.

NUMBER OF UNITS IN EACH OF THE 10 CONTROL GROUPS -- 10000.

THRESHHOLD LEVEL -- 1492.00
(SPECIFIED BY PROGRAM)

MAXIMUM TIME A UNIT IS ALLOWED TO BE LEFT OFF -- 6.00 HOURS
(SPECIED BY PROGRAM) -- 6 HOUR LIMIT

MAXIMUM TIME A UNIT MUST BE LEFT ON BEFORE IT IS ALLOWED
TO BE RETURNED TO OFF STATUS -- 3.00 HOURS

HOURLY LOAD DATA

HOUR	UNSHAPED(MW)	SHAPED(MW)	DIV LOAD FAC(KW)
1:00	1110.00	1110.00	0.40
2:00	1074.00	1074.00	0.25
3:00	1044.00	1044.00	0.13
4:00	1046.00	1046.00	0.08
5:00	1063.00	1063.00	0.09
6:00	1131.00	1131.00	0.15
7:00	1286.00	1286.00	0.37
8:00	1517.00	1487.30	0.59
9:00	1572.00	1491.20	0.81
10:00	1565.00	1483.40	1.02
11:00	1556.00	1487.77	1.11
12:00	1483.00	1466.35	1.17
13:00	1435.00	1464.21	1.12
14:00	1398.00	1468.76	1.06
15:00	1338.00	1439.66	0.98
16:00	1276.00	1332.03	0.92
17:00	1273.00	1292.26	0.99
18:00	1281.00	1280.99	1.12
19:00	1368.00	1367.99	1.15
20:00	1336.00	1335.99	1.11
21:00	1257.00	1256.99	0.97
22:00	1220.00	1219.99	0.86
23:00	1131.00	1130.99	0.75
24:00	1055.00	1054.99	0.61

NOTE: PAYBACK MAY EXTEND INTO THE FOLLOWING DAY

UNSHAPED LOAD PEAK VALUE -- 1572.00 MEGAWATTS

UNSHAPED PEAK LOAD TIME -- 9:00 HOURS

SHAPED LOAD PEAK VALUE -- 1491.20 MEGAWATTS

SHAPED LOAD PEAK TIME -- 9:00 HOURS

Figure A-3 Sample Output from Control Using the Sample Input Data in Figure A-2.

CONTROL GROUP STATUS FOR 1/23/76

FIRST CYCLE

GROUP #	TIME OFF	TIME ON	TOTAL TIME OFF
1	8.	10.	2.
2	8.	11.	3.
3	8.	12.	4.
4	8.	12.	4.
5	8.	13.	5.
6	9.	13.	4.
7	9.	14.	5.
8	9.	14.	5.
9	9.	15.	6.
10	9.	15.	6.

SECOND CYCLE

GROUP #	TIME OFF	TIME ON	TOTAL TIME OFF
1	0.	0.	0.
2	0.	0.	0.
3	0.	0.	0.
4	0.	0.	0.
5	0.	0.	0.
6	0.	0.	0.
7	0.	0.	0.
8	0.	0.	0.
9	0.	0.	0.
10	0.	0.	0.

TOTAL TIME PER GROUP

GROUP #	TOTAL TIME OFF
1	2.
2	3.
3	4.
4	4.
5	5.
6	4.
7	5.
8	5.
9	6.
10	6.

Figure A-3 (Continued)

LOAD CONTROL SUMMARY FOR 1/24/76

(DAY NUMBER 2 OF 3)

TYPE OF LOAD(S) TO BE CONTROLLED -- WATER HEATERS

TOTAL NUMBER OF CONTROL UNITS -- 100000.

NUMBER OF UNITS IN EACH OF THE 10 CONTROL GROUPS -- 10000.

THRESHHOLD LEVEL -- 1160.00
(SPECIFIED BY PROGRAM)

MAXIMUM TIME A UNIT IS ALLOWED TO BE LEFT OFF -- 5.00 HOURS
(SPECIED BY PROGRAM) -- 6 HOUR LIMIT

MAXIMUM TIME A UNIT MUST BE LEFT ON BEFORE IT IS ALLOWED
TO BE RETURNED TO OFF STATUS -- 3.00 HOURS

HOURLY LOAD DATA

HOUR	UNSHAPED(MW)	SHAPED(MW)	DIV LOAD FAC(KW)
1:00	948.00	948.00	0.40
2:00	896.00	895.99	0.25
3:00	856.00	855.99	0.13
4:00	851.00	850.99	0.08
5:00	848.00	847.99	0.09
6:00	868.00	867.99	0.15
7:00	913.00	913.00	0.37
8:00	984.00	984.00	0.59
9:00	1092.00	1092.00	0.81
10:00	1157.00	1157.00	1.02
11:00	1188.00	1154.82	1.11
12:00	1179.00	1143.96	1.17
13:00	1175.00	1141.30	1.12
14:00	1134.00	1136.34	1.06
15:00	1094.00	1122.16	0.98
16:00	1066.00	1111.52	0.92
17:00	1099.00	1118.34	0.99
18:00	1164.00	1159.31	1.12
19:00	1259.00	1155.49	1.15
20:00	1232.00	1158.94	1.11
21:00	1190.00	1143.81	0.97
22:00	1156.00	1133.82	0.86
23:00	1095.00	1128.23	0.75
24:00	1035.00	1154.34	0.61

NOTE: PAYBACK MAY EXTEND INTO THE FOLLOWING DAY

UNSHAPED LOAD PEAK VALUE -- 1259.00 MEGAWATTS

UNSHAPED PEAK LOAD TIME -- 19:00 HOURS

SHAPED LOAD PEAK VALUE -- 1159.31 MEGAWATTS

SHAPED LOAD PEAK TIME -- 18:00 HOURS

Figure A-3 (Continued)

CONTROL GROUP STATUS FOR 1/24/76

FIRST CYCLE

GROUP #	TIME OFF	TIME ON	TOTAL TIME OFF
1	11.	14.	3.
2	11.	15.	4.
3	11.	16.	5.
4	18.	20.	2.
5	19.	21.	2.
6	19.	22.	3.
7	19.	23.	4.
8	19.	23.	4.
9	19.	24.	5.
10	19.	24.	5.

SECOND CYCLE

GROUP #	TIME OFF	TIME ON	TOTAL TIME OFF
1	19.	24.	5.
2	19.	24.	5.
3	24.	25.	1.
4	24.	25.	1.
5	24.	25.	1.
6	0.	0.	0.
7	0.	0.	0.
8	0.	0.	0.
9	0.	0.	0.
10	0.	0.	0.

TOTAL TIME PER GROUP

GROUP #	TOTAL TIME OFF
1	8.
2	9.
3	6.
4	3.
5	3.
6	3.
7	4.
8	4.
9	5.
10	5.

Figure A-3 (Continued)

LOAD CONTROL SUMMARY FOR 1/25/76

(DAY NUMBER 3 OF 3)

TYPE OF LOAD(S) TO BE CONTROLLED -- WATER HEATERS

TOTAL NUMBER OF CONTROL UNITS -- 100000.

NUMBER OF UNITS IN EACH OF THE 10 CONTROL GROUPS -- 10000.

THRESHHOLD LEVEL -- 1138.00
(SPECIFIED BY PROGRAM)

MAXIMUM TIME A UNIT IS ALLOWED TO BE LEFT OFF -- 6.00 HOURS
(SPECIED BY PROGRAM) -- 6 HOUR LIMIT

MAXIMUM TIME A UNIT MUST BE LEFT ON BEFORE IT IS ALLOWED
TO BE RETURNED TO OFF STATUS -- 3.00 HOURS

HOURLY LOAD DATA

HOUR	UNSHAPED(MW)	SHAPED(MW)	DIV LOAD FAC(KW)
1:00	956.00	1030.85	0.40
2:00	917.00	944.67	0.25
3:00	895.00	895.87	0.13
4:00	884.00	883.98	0.08
5:00	882.00	881.98	0.09
6:00	884.00	883.98	0.15
7:00	915.00	915.00	0.37
8:00	947.00	947.00	0.59
9:00	1015.00	1015.00	0.81
10:00	1081.00	1081.00	1.02
11:00	1128.00	1128.00	1.11
12:00	1163.00	1127.96	1.17
13:00	1209.00	1130.39	1.12
14:00	1172.00	1124.47	1.06
15:00	1128.00	1108.03	0.98
16:00	1096.00	1128.54	0.92
17:00	1102.00	1129.79	0.99
18:00	1142.00	1135.47	1.12
19:00	1153.00	1137.94	1.15
20:00	1126.00	1129.41	1.11
21:00	1083.00	1135.97	0.97
22:00	1048.00	1110.79	0.86
23:00	993.00	1012.22	0.75
24:00	900.00	903.91	0.61
25:00	1030.85	1030.85	0.40
26:00	944.67	944.66	0.25
27:00	895.87	895.86	0.13
28:00	883.98	883.97	0.08
29:00	881.98	881.97	0.09
30:00	883.98	883.97	0.15

UNSHAPED LOAD PEAK VALUE -- 1209.00 MEGAWATTS

UNSHAPED PEAK LOAD TIME -- 13:00 HOURS

SHAPED LOAD PEAK VALUE -- 1137.94 MEGAWATTS

SHAPED LOAD PEAK TIME -- 19:00 HOURS

Figure A-3 (Continued)

CONTROL GROUP STATUS FOR 1/25/76

FIRST CYCLE

GROUP #	TIME OFF	TIME ON	TOTAL TIME OFF
1	12.	14.	2.
2	12.	15.	3.
3	12.	16.	4.
4	13.	16.	3.
5	13.	17.	4.
6	13.	19.	6.
7	13.	19.	6.
8	19.	20.	1.
9	19.	20.	1.
10	19.	21.	2.

SECOND CYCLE

GROUP #	TIME OFF	TIME ON	TOTAL TIME OFF
1	19.	21.	2.
2	19.	21.	2.
3	19.	22.	3.
4	19.	22.	3.
5	0.	0.	0.
6	0.	0.	0.
7	0.	0.	0.
8	0.	0.	0.
9	0.	0.	0.
10	0.	0.	0.

TOTAL TIME PER GROUP

GROUP #	TOTAL TIME OFF
1	4.
2	5.
3	7.
4	6.
5	4.
6	6.
7	6.
8	1.
9	1.
10	2.

Figure A-3 (Continued)

The next two cards represent the unshaped load curve (USLC) in the same format as it was inputted. The next two cards represent the shaped load curve (SLC) in the same format as the unshaped load curve. The card which follows this is filled with asterisks to indicate the end of the summary for this day. A similar summary is then given for the rest of the day for which control is used.

12376		1492.	6.		1572.	9		1491.	9					
12376	USLC 1	5	1110	1074	1044	1046	1063	1131	1286	1517	1572	1565	1556	1483
12376	USLC 2	5	1435	1398	1338	1276	1273	1281	1368	1336	1257	1220	1131	1055
12376	SLC 1	5	1110	1074	1044	1046	1063	1131	1286	1487	1491	1483	1488	1466
12376	SLC 2	5	1464	1469	1440	1332	1292	1281	1368	1336	1257	1220	1131	1055
12476		1160.	5.		1259.	19		1159.	18					
12476	USLC 1	6	948	896	856	851	848	868	913	984	1092	1157	1188	1179
12476	USLC 2	6	1175	1134	1094	1066	1099	1164	1259	1232	1190	1156	1095	1035
12476	SLC 1	6	948	896	856	851	848	868	913	984	1092	1157	1155	1144
12476	SLC 2	6	1141	1136	1122	1112	1118	1159	1155	1159	1144	1134	1128	1154
12576		1133.	6.		1209.	13		1138.	19					
12576	USLC 1	7	956	917	895	884	882	884	915	947	1015	1081	1128	1163
12576	USLC 2	7	1209	1172	1123	1096	1102	1142	1153	1126	1083	1048	993	900
12576	USLC 3		1030	944	895	883	881	883						
12576	SLC 1	7	1031	945	896	884	882	884	915	947	1015	1081	1128	1128
12576	SLC 2	7	1130	1124	1108	1129	1130	1135	1138	1129	1136	1111	1012	904
12576	SLC 3		1031	945	896	884	882	884						

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Figure A.4 Sample Card Output for Input Data of Figure A-3