A COMPUTERIZED ANALYSIS OF TIME-OF-USE RATES FOR MASSACHUSETTS

prepared by

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The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utility regulation.

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CHAPTER 1
INTRODUCTION

In February of 1978, The National Regulatory Research Institute (NRRI) established a Regulatory Assistance Program designed to offer technical assistance to state regulatory authorities and their staffs in areas where expertise was lacking. The Massachusetts Department of Public Utilities (MDPU) applied for assistance under this program to investigate electric rate implementation issues of importance to the State. In response to this request, NRRI provided funds for this project and selected the authors to perform the analysis.

The requested work consisted of the development of a methodology to evaluate the costs and benefits of various peak load pricing strategies. On October 6, 1978, the ten investor-owned electric utility companies in Massachusetts filed with the Commission plans for the mandatory implementation of peak load pricing. The Commission expected a variety of responses containing a number of different implementation strategies. Each of these implementation plans is the subject of a separate proceeding. The Commission concluded that a uniform methodology for evaluating the costs and benefits of each plan would be a valuable analytical tool in the decision making process.

These plans for the mandatory implementation of peak load pricing represent the culmination of a generic rate structure order issued December 29, 1977. As part of the implementation process, each utility company has already submitted load research plans, load management plans and optional peak load pricing rates.

There is a general agreement that it may not be economically efficient to put an entire customer class on time-of-use rates. The largest consumers in any class have the greatest potential for realizing benefits that are greater than the costs. In its request for assistance the Commission argued that the major economic benefits of time-of-use pricing include fuel cost savings (from more efficient intermediate and base plant generation rather than peaker plants generation) and capacity cost savings (from deferring construction of generation facilities).

To estimate the fuel cost savings, a utility's projected load duration curves reflecting the continuation of status quo electricity pricing policies, as well as estimated load duration curve showing changes due to time-of-use pricing are needed. These curves would be an input for a utility cost simulation model; this model should also incorporate data on the utility's generation mix, plant specific fuel costs and maintenance schedules. The major costs that a utility would incur in switching to time-of-use pricing would be metering and billing costs.

To meet the needs of the MDPU a work program was established. The program consisted of six tasks:

Task 1. The NRRI will evaluate several models of electricity production and distribution to meet the objectives of the project work plan. The NRRI will use several criteria for evaluation including conceptual design, mathematical structure, programming language and program output. The final product will be the selection of a model or elements of several models that can be combined into an integrated model.

Task 2. The NRRI will evaluate the computer hardware and software capabilities at the disposal of the MPDU. This evaluation will include a comparative analysis of computer capabilities with the needed requirements determined under Task 1.

Task 3. The NRRI will take the model as selected in Task 1, reprogram and make such additional program changes as may be necessary to make the model operational for the MPDU system.

Task 4. The NRRI will debug the program on The Ohio State University computer system.

Task 5. The NRRI will place the program on the MDPU computer. This task includes testing program performance with real time data and to make any necessary program modifications.

Task 6. The NRRI will prepare documentation of all efforts in the form of a user's manual. This task will include on-site training sessions for MDPU staff that will insure maximum transfer of knowledge concerning the model and its uses for evaluating peak load pricing plans submitted by utilities.

The resulting computerized rates analysis package is composed of the following two analyses:

- o The analysis of the shift in consumer demand from peak to off-peak periods that is due to the rate differential and the resulting change in load curves; and

- o The analysis of the chnage in operating and capital costs, due to economic dispatching and acquisition of plants to meet the altered demand.

The computer program SHIFT has been developed for the analysis of the first problem. The second analysis can be carried out with the help of the computer program DISPATCH. In the normal course of analysis of proposed time-of-day rates, the analyst would first investigate the effect on consumers using program SHIFT that produces load frequency data for any number of scenarios. Program DISPATCH is then run to compare the energy costs of the baseline and alternative scenarios. Capital cost savings can also be assessed through several runs of program DISPATCH, with changes in the data of acquisition of new plants. The system reliability statistics provide a mechanism to assess the adequacy of the altered system in meeting the shifted demands.

CHAPTER 2
PROGRAM SHIFT

Program SHIFT is designed to allow the investigation of various assumptions as to the degree of consumer shifting of electricity usage, and the rate of growth of usage from year to year. The major purpose of program SHIFT is to produce the load probability curves, required as input to program DISPATCH, for both a baseline and time-of-day scenario. Given hourly electricity usage data and a set of assumptions supplied by the user, the program produces load probability curves and load statistics, by season, for each year in the scenario. The user supplied assumptions are specified for each year of a scenario, and include: (1) the rate of growth of total usage from the previous year; (2) the percentage reduction in peak period usage; and (3) the percentage of the usage which is shifted from peak to off-peak periods.

Input Data

Program SHIFT requires two types of input. The first of these, <u>Usage Cards</u>, are read on FORTRAN unit 10 (the cards are placed immediately behind the card: //FT10F001 DD *) and consist of base-year hourly electricity usage. These data are specified on two punched cards per day of the base year (normally the last year for which complete load data are available for the utility). These Usage Cards contain the <u>month</u>, <u>day</u> and <u>day of the week</u> (Monday = 1; Tuesday = 2; etc.; Holidays = 8), followed by the 24 hourly loads in megawatts, punched 12 to a card, beginning with 12:00 p.m. - 1:00 a.m. and ending with 11:00 p.m. - 12:00 p.m. Usage Cards are required for 31 days for each of the 12 months of the year. Loads for days that do not exist (e.g., February 31) may be specified by 24 hourly loads of 0. However, the month, day, and day of the week must still be specified on these Usage Cards.

The format of the Usage Cards for a particular day is as follows:

Card	Columns	Format	Contents
1	1-2	I2	The month (1 - 12)
1	3-4	I2	The day of the month (1 - 31)
1	5-6	2X	The last two digits of the base year (not read)
1	7	1X	The numeral 1 to indicate the first Usage Card for this date (not read)
1	16	I1	The day of the week (Monday = 1, Tuesday = 2, etc., Holiday = 8)
1	21-25	F5.0	MWh usage for 12:00 p.m. to 1:00 a.m.
1	26-30	F5.0	MWh usage for 1:00 a.m. to 2:00 a.m.
	.		
	.		
	.		
1	76-80	F5.0	MWh usage for 11:00 a.m. to 12:00 a.m.
2	1-6		Duplicate Columns 16 of card 1
2	7	1X	The numeral 2 (not read)
2	21-25	F5.0	MWh usage for 12:00 a.m. to 1:00 p.m.
	.		
	.		
	.		
2	76-80	F5.0	MWh usage for 11:00 p.m. to 12:00 p.m.

In all cases, where a number (and its associated decimal point) does not completely fill the columns allocated, the number should be <u>right</u> justified. That is, the extreme right digit (or decimal point) should be at the extreme right column of the field.

While columns five through 15 are not read by the program, it is suggested that the <u>year</u> and the <u>card number</u> be punched in this field to facilitate resorting, should the deck be shuffled. The format of the Usage Cards is exactly that used by utilities in reporting their usage data to the Edison Electric Institute. Sample Usage Cards for January 1 and 2, 1977 are shown below:

1	1771	8	1602	1530	1463	1427	1390	1391	1402	1438	1432	1461	1521	1566
1	1772		1558	1538	1534	1486	1519	1631	1712	1728	1707	1673	1613	1548
1	2771	7	1437	1383	1342	1335	1321	1338	1362	1405	1446	1462	1476	1498
1	2772		1495	1480	1442	1461	1521	1629	1690	1678	1660	1617	1513	1393

The second type of input data is read on FORTRAN Unit 5 (the cards are placed immediately behind the //FT05F001 DD * card) and includes the Peak Card, followed by any number of Year Cards. The peak period is defined on the Peak Card by the starting and ending hours of the weekday peak period. Weekends and holidays are assumed to be off-peak. The starting hour of the peak period is punched in columns 1-3 of the Peak Card, and the ending hour is punched in columns 4-6.

The Year Card specifies the current year, the assumed rate of growth in demand from the previous year and two parameters that indicate the degree of assumed shift in consumer demand. The first parameter specifies the percentage of reduction in peak-period usage due to the differential rate. The second parameter indicates what percentage of the total reduction in peak-period usage is to be reallocated to off-peak periods. For example, if these two parameters are specified as 3.00 and 100.00, then peak-period usage is reduced by 3 percent (i.e., all peak hour loads are set to 97 percent of their prior values) and off-peak loads are increased (in proportion to their prior values) so that total usage is unchanged.

The Year Cards, which specify the year, growth rate, percent reduction and percent reallocated, are punched in the following format:

Column	Format	Contents
1-4	I4	Year
5-10	F6.2	Growth rate from previous year (in percent)
11-16	F6.2	Percentage reduction in peak period usage
17-22	F6.2	Percent reallocated to off-peak periods

The following example indicates that demand for 1981 is assumed to grow at 4 percent from 1980, and that 3 percent of peak-period usage is to be shifted to off-peak periods:

1981 4.00 3.00 100.

Year Cards are entered in chronological order within a given scenario. Program SHIFT can handle any number of scenarios. A new scenario is started simply by specifying the first year of the scenario on the Year Card, along with the other parameters. The fact that the Year Card is <u>not</u> in chronological order will alert program SHIFT to begin a new scenario. Table 2-1 below is an example of the inputs to program SHIFT which describe three scenarios.

Table 2-1 Three SHIFT Scenarios

Card Number	Contents			
1	10 21			
2	1979	4.00		
3	1980	4.00		
4	1981	4.00		
5	1982	4.00		
6	1983	4.00		
7	1979	4.00	6.00	100.
8	1980	4.00	6.00	100.
9	1981	4.00	6.00	100.
10	1982	4.00	6.00	100.
11	1983	4.00	6.00	100.
12	1979	4.00	2.00	100.
13	1980	4.00	4.00	100.
14	1981	4.00	6.00	100.
15	1982	4.00	8.00	100.
16	1983	4.00	10.0	100.

Card 1 (the Peak Card) indicates that the peak period is from 9:00 a.m. (the start of hour 10) through 9:00 p.m. (the end of hour 21) inclusive, on weekdays. Year Cards 2 through 6 specify the baseline scenario of 4 percent year-to-year growth in usage from 1979 to 1983, with no shift in demand. Year Cards 7 through 11 specify the first alternative scenario, that of a 6 percent shift in usage from peak to off-peak periods, with total demand as in the baseline scenario. In the third scenario (Year Cards 12 through 16), consumers adjust to the time-of-day rates by gradually shifting usage to off-peak periods. In 1979, only 2 percent of usage is shifted, but by 1983, 10 percent of peak period usage has shifted to off-peak periods.

Table 2-2 indicates all the inputs required for a run of program SHIFT on the MDPW computer.

<u>Output</u>

Program SHIFT produces load probability curves and load statistics as output. These outputs are provided for each of the four seasons---spring, 4/1 through 6/30; summer, 7/1 through 9/30; autumn, 10/1 through 12/31; and winter, 1/1 through 3/31--and on an annual basis. The primary output is the <u>Load Probability Curve</u> that displays megawatts (MW) on the X-axis and the probability of meeting or exceeding that particular load value on the Y-axis. Since the loads are ordered from the lowest hourly usage (base load) to the highest (peak load), the probabilities range from one to nearly zero. For ease of printing, the Load Probability Curve is shifted, so that the loads increase (and the probabilities decrease) from the top to the bottom of the page, and the probabilities are indicated across the page. A typical Load Probability Curve is shown in Figure 2.1.

In addition to the Load Probability Curve, program SHIFT prints the load factor (ratio of average load to peak load in percentage terms), the total number of megawatt-hours demanded during the period and the time (month/day/hour) of the occurrence of the peak load (printed to the right and bottom of the Load Probability Curve, on the line corresponding to the peak load).

In addition to the above printed output, program SHIFT also produces <u>punched</u> output that is used as <u>input</u> to program DISPATCH. The punched output consists of three cards per year, followed by five sets of loads

Table 2-2 Inputs Required for Program SHIFT

```
//SHIFT JOB 88888,ELP,CLASS=L
//S1 EXEC PGM=SHIFT
//STEPLIB DD DSN=DPWLOAD,DISP=SHR          Program SHIFT Control Cards
//FT05F001 DD *
010021                                     Peak Card
1978   4.0
1979   4.0
1980   4.0
1981   4.0
1982   4.0
1978   4.0   5.00 100.
1979   4.0   5.00 100.
1980   4.0   5.00 100.                     Year Cards
1981   4.0   5.00 100.
1982   4.0   5.00 100.
1978   4.0 2.00  100.
1979   4.0 4.0  100.
1980   4.0 6.00  100.
1981   4.0 8.00  100.
1982   4.0 10.0  100.
/*
//FT10F001 DD *                                                                                     Control Cards
 1 17711020112181     1602 1530 1463 1427 1390 1391 1402 1438 1432 1461 1521 1566
 1 1772102 10-21      1558 1538 1534 1486 1519 1631 1712 1728 1707 1673 1613 1548
 1 27711020112171     1437 1383 1342 1335 1321 1338 1362 1405 1446 1462 1476 1498
 1 2772102 15-16      1495 1480 1442 1461 1521 1629 1690 1678 1660 1617 1513 1393
                                    .
                                    .
                                    .
                                    .                                                               Usage Cards
                                    .
                                    .
                                    .
12307711020112151     1506 1436 1385 1364 1351 1395 1471 1632 1737 1838 1892 1901
1230772102 32  1      1896 1879 1811 1764 1811 1864 1911 1869 1818 1749 1630 1499
12317711020112161     1393 1285 1223 1187 1196 1218 1217 1297 1393 1460 1545 1576
1231772102 36  5      1567 1554 1539 1527 1571 1668 1716 1688 1617 1570 1481 1442
/*
//FT06F001 DD SYSOUT=A
//FT08F001 DD SYSOUT=B                                                                              Control Cards
/*
```

LOAD PROBABILITY CURVE FOR THE PERIOD 10/ 1/ 1-12/31/24, AUTUMN 1981.
GROWTH RATE OF 4.0% FROM AUTUMN 1980.

PERCENT REDUCTION IN PEAK PERIOD LOADS 8.00%

PERCENT REALLOCATED TO OFF PEAK PERIODS 100.0%

LOAD MW	PROB
1061.1	1.00000
1100.9	0.99909
1140.8	0.99639
1180.7	0.99233
1220.5	0.98825
1260.4	0.98102
1300.3	0.97468
1340.1	0.96381
1380.0	0.94841
1419.9	0.93073
1459.7	0.90803
1499.6	0.87813
1539.4	0.84555
1579.3	0.81792
1619.2	0.78804
1659.0	0.75684
1698.9	0.72105
1738.8	0.68799
1778.6	0.64589
1818.5	0.60150
1858.4	0.55345
1898.2	0.49905
1938.1	0.43744
1978.0	0.37000
2017.8	0.31836
2057.7	0.27759
2097.6	0.24548
2137.4	0.21058
2177.3	0.17887
2217.2	0.15486
2257.0	0.12635
2296.9	0.10234
2336.8	0.08694
2376.6	0.06747
2416.5	0.05300
2456.4	0.03943
2496.2	0.03081
2536.1	0.02402
2576.0	0.01586
2615.8	0.01360
2655.7	0.00997
2695.6	0.00725
2735.4	0.00544
2775.3	0.00453
2815.2	0.00226
2855.0	0.00181
2894.9	0.00136
2934.7	0.00136
2974.6	0.00045
3014.5	0.00045

(12/ 6/22)

* LOAD FACTOR 62.0, TOTAL MEGAWATT HOURS 4126317. *

Figure 2.1 Load Probability Curve

and probabilities, one for each season as well as annual loads and probabilities. The first three cards include:

- a title card that is printed by program DISPATCH;
- a card containing the number of points (50) from each Load Probability Curve that will follow, the year, the number of days in each season and the number of days in the year; and
- a card that contains the year and the peak demands for each month.

The 50 pairs of loads and probabilities follow next, punched five pairs to a card, where the loads and probabilities are those that are printed alongside the Load Probability graph. This summarization of the load curve provides sufficient information to the dispatching algorithm of program DISPATCH.

Algorithm

The Load Probability Curve is calculated by dividing the interval between the base and peak loads into 50 subintervals of equal width. Each hourly load in the period of interest is allocated to the correct subinterval, and the count for that subinterval and all lower subintervals is increased by one. Dividing the final subinterval counts by the total number of hours in the period yields the probability of meeting or exceeding the hourly load in question.

CHAPTER 3
PROGRAM DISPATCH

Program DISPATCH is designed to calculate the production cost of electricity generated during a specified period. As such, it is well suited to calculate the effects on generation costs of changes in consumer behavior of the type described in program SHIFT. In addition, its capabilities allow the user to vary the year in which new generation capacity is acquired, thus providing a mechanism to study the savings in capital costs associated with the implementation of time-of-day rates.

DISPATCH simulates the load dispatch on a seasonal basis by using a probabilistic simulation method. The load for a season is represented by a load duration curve for that season obtained from the load probability data supplied by program SHIFT. The forced outage rate and the maintenance outage rate for each season are combined and incorporated into the equivalent load duration curve. DISPATCH also calculates the LOLP (Loss-of-Load Probability) and the system reliability.

Input Data

Program DISPATCH input data are of three types:

- o Program Operating Parameters (POP Cards) that are read on FORTRAN Unit 5 (these cards are placed between the //FT05F001 DD * card and the /* card);
- o Plant Cards that are read on FORTRAN Unit 15 (between the //FT15F001 DD * card and the next /* card);
- o Load Cards that are read on FORTRAN Unit 25 (between the //FT25F001 DD * card and the last /* card).

POP Cards

The 1st POP Card contains the name of the utility, punched in the first 32 columns of the card.

The 2nd POP Card contains the base year for which the plant data were calculated (e.g., 1977).

The 3rd POP Card specifies the costs to be considered when the loading order of plants is determined. Four methods are available for determining the loading order. Method 1 considers only fuel costs; method 2, fuel plus maintenance costs; method 3, fuel plus operation costs; and method 4, fuel plus operation and maintenance costs. Since fuel costs alone account for a large proportion of total costs, method 1 is recommended.

The 4th POP Card specifies the loading method for plants. The Fixed Block Method is specified by punching a 1. The Spinning Reserve Method is specified by punching a 2.

The Fixed Block Method loads plants in the most economical dispatching order within a given plant type and without regard to reserve capacity. All base plants are loaded first, followed by all cyclical plants and then peakers. A maximum of three loading steps per plant is permitted. Plants loaded in two steps are loaded to half capacity first. After all plants of that type are loaded to half capacity, they are loaded to full capacity. Plants loaded in three steps are loaded first to half capacity, then to three-quarters capacity, and finally to full capacity. The Spinning Reserve Method maintains some base plants loaded at no more than half capacity. This protects against loss of load due to a forced outage of the largest fully loaded base plant. Any number of loading steps is permitted for each plant type. A minmum of two loading steps is required for base plants. The Spinning Reserve Method is recommended.

The 5th POP Card specifies the number of loading steps for each of the three plant types: base, cyclical and peaking. Given that large generating plants need not be fully loaded at all times, specifying more than one loading step allows the program to load some plants partially to meet the load profile more efficiently.

The minimum number of loading steps for the Spinning Reserve Method is 2,1,1 for the three types of plants, respectively. Specifying more loading steps, particularly for base plants with large generating capacity, provides more accuracy, with some additional computation expense. Adding more loading steps to relatively small cyclical and peaking units provides little if any additional accuracy.

The 6th POP Card specifies annual price escalation rates for the seven fuel types: (1) Coal, (2) Light Oil, (3) Heavy Oil, (4) Natural Gas, (5) Nuclear Fuel, (6) Contract Electricity and (7) Hydroelectric Power. These seven numbers are specified as percentages.

The 7th POP Card specifies the three annual escalation rates of maintenance costs for (1) base, (2) cyclical and (3) peaking plants. These three rates are specified as percentages.

The 8th POP Card specifies the three annual escalation rates (in percent) of operation costs for the three types of plants in the order listed above.

The 9th POP Card specifies the discount rate to be applied to all costs, after they are inflated by the specified escalation rates. Given that energy savings will be discounted outside of program DISPATCH, it is recommended that the discount rate be set to zero.

The 10th POP Card specifies the level of output desired by the user. Level 0 produces only the minimal output (Input Data Summaries, and two pages per year of Annual System Summaries) and is recommended for production runs of the program. Level 3 produces the maximum amount of output, including seasonal operating summaries and the input Load Probability Curves, and is suggested for the initial run to check input data. Levels 1 and 2 produce intermediate amounts of output. Table 3-2 indicates the output produced by printout levels 0 through 3.

Sample POP Cards are shown in Table 3-1 following, with the values of the parameters set at the recommended levels:

Table 3-1 POP Cards

Card Number	Contents
1	Back Bay Power and Light
2	1977
3	1
4	2
5	2 1 1
6	5. 10. 8. 12. 7. 4. 0.
7	8. 8. 8.
8	6. 6. 6.
9	0.
10	3

Table 3-2 Printout Levels

Printout Levels 0	1	2	3	Output
X	X	X	X	Generation Plant Parameters
X	X	X	X	Summary of Program Operation Parameters (POP)
				<u>Each Year</u>
			X	Spring Load Probability Curve
			X	Spring Plant Operation Summary
		X	X	Spring Generation and Fuel Use Summary
			X	Spring Load Probability Curve
			X	Summer Plant Operation Summary
		X	X	Summer Generation and Fuel Use Summary
			X	Autumn Load Probability Curve
			X	Autumn Plant Operation Summary
		X	X	Autumn Generation and Fuel Use Summary
			X	Winter Load Probability Curve
			X	Winter Plant Operation Summary
		X	X	Winter Generation and Fuel Use Summary
	X	X	X	Annual Load Probability Curve
X	X	X	X	Annual Plant Operation Summary
	X	X	X	Annual Maintenance Schedule
X	X	X	X	Annual Generation and Fuel Use Summary
				<u>End of Simulation</u>
X	X	X	X	Study Period Plant Operation Summary
X	X	X	X	Study Period Generation and Fuel Use Summary
X	X	X	X	System Load Parameters by Year

Plant Cards

The plant data are specified on two cards per plant, as follows:

Card	Columns	Format	Contents
1	1-5	I5	MDPU plant number - an identification number for the plant.
1	7-26	5A4	The plant name.
1	27-31	F5.0	The fractional ownership of the unit by the utility being considered (1.00 = total ownership).
1	33-37	F5.0	The summer capacity of the unit in MW.
1	38-42	F5.0	The winter capacity of the unit in MW.
1	43-47	I5	The year the unit came (or will come) on-line.
1	48-52	I5	The year the unit will be retired.
1	53-54	I2	The fuel type: (1) Coal, (2) Light Oil, (3) Heavy Oil, (4) Natural Gas, (5) Nuclear, (6) Contract or Purchased Electricity or (7) Hydroelectric.
1	55-56	I2	The type of plant: (1) Base, (2) Cyclical or (3) Peaking. For purchased power enter 3.
2	1-26		Duplicate columns 1-26 of the 1st card.
2	33-38	F6.0	The average heat rate for the unit in BTU per kWh. For purchased power enter 10000.
2	40-46	F7.0	The cost (in cents per million BTU) for the primary fuel of the unit. For purchased power enter the cost of power in dollars per MWh.
2	48-53	F6.0	The marginal operating cost of the unit in dollars per MWh. For purchased power enter 0.
2	55-60	F6.0	The marginal maintenance cost of the unit in dollars per MWh. For purchased power enter 0.
2	71-73	F3.0	The number of planned outage days per year for maintenance. For purchased power enter 0.
2	75-79	F5.0	The historic forced outage rate of the unit. For purchased power enter 0.

In all cases, where a number (and its associated decimal point) does not completely fill the columns allocated, the number should be right justified. That is, the extreme right digit (or decimal point) should be at the extreme right column of the field. Sample Plant Cards are shown below.

```
200411BECKJORD 6          0.375   434. 440. 1969 2000 1  1
200412BECKJORD 6                  9898.  87.200  0.325   0.396      48. 1328
200451STUART 1            0.390   585. 585. 1971 2000 1  1
200452STUART 1                    9674.  97.660  0.222   0.659      48. 1328
```

Load Cards

The Load Cards that are required as input to program DISPATCH are simply the punched output of program SHIFT. As program DISPATCH handles only one scenario at a time, the punched output must be separated into scenarios. This is facilitated by the location of title cards at the beginning of each year of punched output.

An example of the input cards to run program DISPATCH on the MDPW computer is shown in Table 3-3.

Output

As discussed above, the amount of output produced by program DISPATCH is controlled by the printout level specified on POP Card 10. The discussion below pertains to the output produced by printout level 3. Printout levels 0, 1 or 2 produce less output.

Program DISPATCH first reproduces the input data, both the Program Operation Parameters and the plant data. For each season, the program prints the Load Probability Curve, and a unit-by-unit summary of the MWh produced during that season, as well as the fuel, operating, maintenance and the total unit running cost for that season. In addition, the system MWh production and the fuel, operating, maintenance and total system running costs are printed out. A similar summary is produced annually and for the entire simulation period.

```
//DISPATCH JOB 88888,ELP,CLASS=L
//S1 EXEC PGM=DISPATCH
//STEPLIB DC DSN=DPWLOAD,DISP=SHR                   Program DISPATCH Control Cards
//FT05F001 CD *
CINCINATTI GAS AND ELECTRIC CO.    POP Cards:  Name of Utility
1977                                           Base Year
1                                              Dispatching Costs ( 1=Fuel Costs)
2                                              Loading Method  (2=Spinning Reserve)
2 1 1                                          Number of Loading Steps
0. 0. 0. 0.  0. 0. 0.                          Escalation Rates Fuel
0. 0. 0.                                       Escalation Rates Maintenance
0. 0. 0.                                       Escalation Rates Operation
0.                                             Discount Rate
0                                              Printout Level
/*                                                                                        Control
//FT15F001 CD *                                                                           Cards
200411BECKJCRD 6          0.375  434.  440.  1969 2000 1 1  9725. 9350. 9250. 1  1
200412BECKJCRD 6          0.353  9898.  87.200  0.325  0.396   795567. 48 .13281
200451STUART 1            0.390  585.  585.  1971 2000 1 1  9255. 9125. 8975. 4  1
200452STUART 1            0.221  9674.  97.660  0.222  0.659  4826866. 48 .13281
                                        .
                                        .
                                        .                                                 Plant Cards
                                        .
200491KILLEN STATION 2    0.510  600.  600.  1982 2000 1 1  9800. 9800. 9800. 1  1
200492KILLEN STATION 2    0.250  9800.  90.000  0.400  0.400         0. 50 .20201
200491KILLEN STATION 1    0.510  600.  600.  1985 2000 1 1  9800. 9800. 9800. 2  1
200492KILLEN STATION 1    0.250  9800.  90.000  0.400  0.400         0. 50 .20201
/*                                                                                        Control
//FT25F001 CD *                                                                           Cards
**DATA FOR 1978,  4.0% GROWTH FROM 1977   SHIFTED ( 5.00%,100.0%)**                       Title Card
050 1978  91  92  92  90 3651.0000000                                                     1978
 19782457.2457.2457.2886.2886.2886.2587.2587.2587.2450.2450.2450.
  940.2 1.000000  971.1 0.998614 1002.1 0.989894 1033.0 0.982088 1063.9 0.972897
 1094.9 0.963255 1125.8 0.947226 1156.8 0.927084 1187.7 0.910590 1218.7 0.885816
 1249.6 0.860118 1280.6 0.831279 1311.5 0.794204 1342.5 0.771750 1373.4 0.746105
 1404.3 0.718653 1435.3 0.685187 1466.2 0.660891 1497.2 0.634329 1528.1 0.605911          Load Cards
 1559.1 0.578404 1590.0 0.545446 1621.0 0.516575 1651.9 0.489094 1682.9 0.454277
 1713.8 0.412131 1744.8 0.359059 1775.7 0.316946 1806.6 0.272485 1837.6 0.240425
 1868.5 0.215714 1899.5 0.192349 1930.4 0.176328 1961.4 0.155741 1992.3 0.139253          -Spring 1978
 2023.3 0.118174 2054.2 0.102137 2085.2 0.086561 2116.1 0.074193 2147.0 0.065950
 2178.0 0.052209 2208.9 0.042132 2239.9 0.034341 2270.8 0.027468 2301.8 0.018781
 2332.7 0.012362 2363.7 0.008705 2394.6 0.005499 2425.6 0.002289 2456.5 0.000915
                                        .
```

Table 3-3 DISPATCH Input Cards

Table 3-3 (continued) DISPATCH Input Cards

.
.

Annual 1978

```
  940.2 1.000000  979.9 0.999076 1019.6 0.994738 1059.3 0.988113 1099.0 0.980909
 1138.8 0.970501 1178.5 0.955196 1218.2 0.937227 1257.9 0.913007 1297.6 0.883080
 1337.3 0.854640 1377.1 0.825782 1416.8 0.797586 1456.5 0.765052 1496.2 0.734562
 1535.9 0.698937 1575.7 0.660355 1615.4 0.623020 1655.1 0.579751 1694.8 0.533717
 1734.5 0.474107 1774.3 0.420675 1814.0 0.367268 1853.7 0.321507 1893.4 0.280987
 1933.1 0.245033 1972.8 0.208641 2012.6 0.181019 2052.3 0.151577 2092.0 0.129429
 2131.7 0.109916 2171.4 0.092560 2211.2 0.075779 2250.9 0.064597 2290.6 0.053181
 2330.3 0.043360 2370.0 0.036856 2409.8 0.031158 2449.5 0.026021 2489.2 0.022369
 2528.9 0.019516 2568.6 0.016318 2608.3 0.013124 2648.1 0.010724 2687.8 0.008212
 2727.5 0.005590 2767.2 0.003423 2806.9 0.001253 2846.7 0.000570 2886.4 0.000341
```

Title Card 1979

```
**DATA FOR 1979,  4.0% GROWTH FROM 1978   SHIFTED ( 5.00%,100.0%)**
```

Spring 1979

```
050 1979  91  92  92  90 3651.0000000
 19792555.2555.2555.3002.3002.3002.2690.2690.2690.2548.2548.2548.
  977.8 1.000000 1009.9 0.998614 1042.1 0.989894 1074.3 0.982088 1106.5 0.972898
 1138.7 0.963255 1170.9 0.947226 1203.1 0.927084 1235.2 0.910590 1267.4 0.885816
 1299.6 0.860118 1331.8 0.831279 1364.0 0.794204 1396.2 0.771750 1428.3 0.746105
 1460.5 0.718653 1492.7 0.685187 1524.9 0.660891 1557.1 0.634329 1589.3 0.605912
 1621.4 0.578404 1653.6 0.545447 1685.8 0.516575 1718.0 0.489094 1750.2 0.454278
 1782.4 0.412131 1814.5 0.359060 1846.7 0.316946 1878.9 0.272485 1911.1 0.240425
 1943.3 0.215714 1975.5 0.192349 2007.6 0.176328 2039.8 0.155741 2072.0 0.139253
 2104.2 0.118174 2136.4 0.102137 2168.6 0.086561 2200.7 0.074193 2232.9 0.065950
 2265.1 0.052209 2297.3 0.042132 2329.5 0.034341 2361.7 0.027468 2393.8 0.018781
 2426.0 0.012362 2458.2 0.008705 2490.4 0.005499 2522.6 0.002289 2554.8 0.000915
```

.
.
.

Annual 1982

```
1099.9 1.000000 1146.3 0.999076 1192.8 0.994738 1239.2 0.988113 1285.7 0.980909
1332.2 0.970501 1378.6 0.955196 1425.1 0.937227 1471.6 0.913007 1518.0 0.883079
1564.5 0.854640 1611.0 0.825782 1657.4 0.797586 1703.9 0.765052 1750.4 0.734561
1796.8 0.698937 1843.3 0.660354 1889.8 0.623020 1936.2 0.579751 1982.7 0.533717
2029.2 0.474106 2075.6 0.420675 2122.1 0.367268 2168.6 0.321506 2215.0 0.280987
2261.5 0.245033 2308.0 0.208640 2354.4 0.181019 2400.9 0.151576 2447.3 0.129429
2493.8 0.109916 2540.3 0.092560 2586.7 0.075779 2633.2 0.064597 2679.7 0.053180
2726.1 0.043360 2772.6 0.036856 2819.1 0.031157 2865.5 0.026021 2912.0 0.022369
2958.5 0.019516 3004.9 0.016318 3051.4 0.013124 3097.9 0.010724 3144.3 0.008212
3190.8 0.005590 3237.3 0.003423 3283.7 0.001253 3330.2 0.000570 3376.7 0.000341
```

Control Cards

```
/*
//FT06F001 DD SYSOUT=A
//
```

Algorithm

Incremental Production Cost

The marginal running cost (or incremental cost), MC_i, for unit i may be written as:

$$MC_i = FC_i + OP_i + MN_i$$

where FC_i: the marginal fuel cost in \$/MWh
OP_i: the marginal operating (non fuel) cost in \$/MWh
MN_i: the marginal maintenance cost in \$/MWh

The marginal operating and maintenance costs are relatively small compared to the marginal fuel cost. Although it is desirable to split the operating and maintenance costs into fixed and variable portions, 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 (MFC) for unit i, in \$/MWh is defined as follows:

$$MFC_i = \underset{(¢/10^6 BTU)}{\text{BTU Cost}} * \underset{(BTU/kWh)}{\text{Incremental Heat Rate}} * 10^{-5}$$

The BTU 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 depends on the load at which a unit is operated and the temperature of the condenser intake water.

The average running cost for a unit is defined as:

$$AMC_i = (Ht.Rt_i)_{av} * \text{BTU Cost} * 10^{-5} + (OP_i)_{av} + (MN_i)_{av}$$

where AMC_i: the average running cost of production by unit i, and
$(Ht.Rt_i)_{av}$: the average incremental heat rate of unit i.

Use of the average running cost causes some error in simulating dispatch and estimating the production cost for a unit if the study period is short. However, for the entire simulation the error is small.

Contract and Other Purchased Power

Contract and other purchased power are handled in the DISPATCH program in the following manner. For each purchased power contract, a dummy plant is defined. These dummy plants are specified in the input as type 3 (or peaking) plants (see Input Data section). The BTU Cost for these dummy plants is set equal to the total cost of the purchased power in $/MWH, and the average heat rate is set at 10000, thus making the marginal cost equal to the total cost of the purchased power. The plant capacity (summer and winter) 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 fractional ownership of these plants should be considered to be 100% since 100 percent of the power is available to the company under simulation. The planned maintenance and forced outage days should 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.

Loading Order

In determining the loading order of generating units, the units are grouped into three types: (1) base load units, (2) cyclical (or shoulder) units and (3) peaking units. The generating system is assumed to be generating at least the sum of the minimum loading levels of the available base units. (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 average running cost.

Loading of cycling units starts when the system demand exceeds the total capacity of the base units excluding the base units in maintenance. Cycling units are loaded in the order of increasing average running cost. Peaking units are loaded in the order of increasing average running cost but not loaded until all the cycling units are loaded to their full capacity. The loading order (priority) is illustrated in Table 3-4.

The energy generated by each unit is calculated by a probabilistic simulation method. This method takes the effects of forced outage and maintenance outages into account in the form of an availability factor for each season.

Table 3-4 The Loading Order

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

CHAPTER 4
COST/BENEFIT ANALYSIS

The decision to implement time-of-day electric rates should be based on an assessment of whether or not the savings (both energy and capital) exceed the immediate and long-term costs of the investment in meters.

This section describes the use of programs SHIFT and DISPATCH in a cost/benefit analysis. A necessary analytical tool of cost/benefit analysis is a discounting method that converts all future costs and benefits to current dollars. To facilitate this analysis, a table of discount factors, capitalization rates and capital recovery factors is provided as Table 4-1. A Time-of-Day Analysis Form is provided as Table 4-3 later in the chapter.

Use of Programs SHIFT and DISPATCH

To provide the data required for the cost/benefit analysis, the programs should be run in the following manner:

1. Run SHIFT to generate load frequency curves for the baseline and time-of-day scenerio.

2. Run DISPATCH for the baseline scenerio.

3. Run DISPATCH for the time-of-day scenerio. Total generation costs should decline from run 2 as a larger proportion of demand is met by base and cyclical units. System reliability should increase as the Loss-of-Load Probability (LOLP) decreases.

4. Delay plants (by changing the date the plant comes on-line on the Plant Card) and possibly advance other plants until the reliability statistics are essentially unchanged from the baseline scenerio (Run 2). This may require several iterations of program DISPATCH. If delaying or advancing an entire plant causes too large a change in the reliability statistics, it is possible to "sell" or "buy" generating capacity by changing the percentage ownership of a plant on the Plant Card.

Table 4-1 DISCOUNT FACTORS, CAPITALIZATION RATES AND CAPITAL RECOVERY FACTORS

Discount Factors

Year	6%	8%	10%	12%	14%
0	1.000	1.000	1.000	1.000	1.000
1	.943	.926	.909	.893	.877
2	.890	.857	.826	.797	.769
3	.840	.794	.751	.712	.675
4	.792	.735	.683	.636	.592
5	.747	.681	.621	.567	.519
6	.705	.630	.564	.507	.456
7	.665	.583	.513	.452	.400
8	.627	.540	.467	.404	.351
9	.592	.500	.424	.361	.308
10	.558	.463	.386	.322	.270
11	.527	.429	.350	.287	.237
12	.497	.397	.319	.257	.208
15	.417	.315	.239	.183	.140
20	.312	.215	.149	.104	.073
25	.233	.146	.092	.059	.038
30	.174	.099	.057	.033	.020

Capitalization Rates

	6%	8%	10%	12%	14%
Capitalization Rate	16.667	12.500	10.000	8.333	7.143

Capital Recovery Factors

Estimated Life (yrs)	6%	8%	10%	12%	14%
5	.2374	.2505	.2638	.2774	.2913
10	.1359	.1490	.1627	.1770	.1917
15	.1030	.1168	.1315	.1468	.1628
20	.0872	.1019	.1175	.1339	.1510
25	.0782	.0937	.1102	.1275	.1455
30	.0726	.0888	.1061	.1241	.1428
35	.0690	.0858	.1037	.1223	.1414
40	.0665	.0839	.1023	.1213	.1407

A comparison of the results of runs 2 and 4 should now indicate the magnitude of the energy and capital savings.

Energy Savings

Both simulations with program DISPATCH should produce approximately the same amount of MWh generation, assuming that the second shift parameter was set to 100. in program SHIFT. Thus, any difference in total generation costs is attributable to the energy savings due to time-of-day rates.

To discount these year-by-year energy savings, we will make use of the Analysis Form provided. First, enter the difference in total costs from the annual summaries printed by DISPATCH, under the column "Energy Savings" next to the appropriate year. This is done for each year of the simulation period. Select a discount rate and enter the discount factors in the column provided, starting with the discount factor for year 0 next to the current year. Next, multiply each energy saving by the discount factor and enter the result in the column "Discounted Savings." Finally, sum the numbers in this column to get the "Total Discounted Energy Savings."

In our example (Table 4-2), Back Bay Power & Light achieved energy savings of $200,000, $300,000, $250,000, $200,000 and $200,000 for the years 1979 through 1983. These are entered on the sample form, along with the discount factors for a 10 percent discount rate. Total discounted energy savings are computed to be $966,000.

The stream of energy savings will probably approach some asymptotic value, which can be assumed to be the continuing energy savings indefinitely into the future. If so, enter this number and the year it is assumed to begin (usually the year after the last year of the DISPATCH simulation) in the continuing energy savings section of the form. This saving is multiplied by the capitalization rate to convert to the value of a perpetual stream and multiplied by the discount factor to convert to the present value.

In our example, we can assume that Back Bay Power & Light will continue to save $200,000 annually in energy costs beginning in 1984. Since

Table 4-2 Sample Time-of-Day Analysis Form

UTILITY: Back Bay Power & Light Co. ASSUMPTIONS: 4% growth, 5% shift, 10% discount rate

ENERGY SAVINGS

Annual Energy Savings

Year	Energy Savings	*	Discount Factor	=	Discounted Savings
1979	200,000		1,000		200,000
1980	300,000		.909		272,700
1981	250,000		.826		206,500
1982	200,000		.751		150,200
1983	200,000		.683		136,600
1984					
1985					
1986					
1987					
1988					
1989					
1990					

Total Discounted Energy Savings 966,000 (I)

Continuing Energy Savings

Year	Expected Continuing Energy Savings	*	Capitalization Rate	*	Discount Factor	=	Value of Continuing Energy Savings	
1984	200,000		10.000		.621		1,242,000	(II)

CAPITAL COST SAVINGS

	Plant	-	Salvage Value	x	Discount Factor	+	Acquisition Cost	+	Installation Cost	=	Depreciable Value	*	Capital Recovery Factor	=	Annual Capital Cost Savings
1.	Arlington Gas		-200,000		.057		1,000,000		100,000		1,088,600		.1061		115,500
2.	Berkeley Oil		0				600,000		50,000		650,000		.1061		68,965
3.															

Enter in the appropriate year(s) below the Annual Capital Cost Savings (ACCS) for each plant delayed (+) or advanced (-).

Table 4-2 Sample Time-of-Day Analysis Form - page 2

Annual Capital Cost Savings (+ or -)

Year	Plant 1	+	Plant 2	+	Plant 3	=	Total ACCS	*	Discount Factor	=	Discounted Capital Savings
1979											
1980	115,500						115,500		.909		104,990
1981	115,500		-68,965				46,535		.826		38,438
1982											
1983											
1984											
1985											
1986											
1987											
1988											
1989											
1990											

Total Discounted Capital Savings: 143,428 (III)

METERING COST

Cost per Meter	+	Installation Cost	=	Installed Meter Cost	*	Number of Meters	=	Initial Metering Cost	
150.		25		175		5,000		875,000	(IV)

Annual Incremental Metering Cost	*	Capitalization Rate	=	Capitalized Annual Metering Cost	
50,000		10.000		500,000	(V)

TOTAL BENEFITS AND COSTS

Total Benefits (I + II + III)	-	Total Cost (IV + V)	=	Net Benefits
2,351,428		1,375,000		+976,428

the capitalization rate for 10 percent is 10.0, and the discount factor for 5 years is .621, we compute the present value of continuing energy savings to be $1,242,000.

Capital Cost Savings

The value of deferring a plant investment for a year is the value of that year's payment on the bonds used to finance the plant. That figure, for a $1 investment, is known as the capital recovery factor and depends on both the interest rate and the estimated life of the asset (assumed to be equal to the term of the bonds). As with other benefits that accrue in the future, capital cost savings must be discounted back to the present.

In our example, because of time-of-day rates, we find that Back Bay Power and Light can delay the Arlington Gas plant from 1980 to 1982. However, to maintain the same system reliability, it must advance the Berkeley Oil plant from 1982 to 1981. The Arlington Gas plant will cost $1 million, $100,000 to install and have a salvage value of $200,000. The Berkeley Oil plant will cost $600,000, $50,000 to install, and will have no salvage value. Both plants are assumed to have 30 year lives, and a 10 percent interest rate is used. We find that Arlington Gas has an annual capital cost of $115,500 and Berkeley Oil of $68,965.

On the second page of the analysis form, we enter +115,500 in column 1 under 1980 and 1981, since Arlington Gas has been delayed from 1980 to 1982. In column two, we enter -68,965 in the row corresponding to 1981, since Berkeley Gas has advanced from 1982 to 1981. Total Capital savings are computed to be $143,428.

Metering Costs

Metering costs are composed of two elements: (1) the cost of acquiring and installing the meters for all affected consumers; and (2) the recurring incremental cost associated with time-of-day rates, such as the additional expense of meter reading and incremental billing costs.

In our example, Back Bay Power and Light estimates that dual meters will cost $150 each, plus $25 to install for each of its 5,000 customers. Thus, the initial metering cost will amount to $875,000.

In addition, Back Bay Power and Light estimates that it will incur annual costs of $10 per customer for additional meter reading and billing expenses. The capitalized value of this $50,000 expense is $500,000.

Total Benefits and Costs

The total benefits consist of the sum of:

- Total Discounted Energy Savings,
- Value of Continuing Energy Savings, and
- Total Discounted Capital Savings.

In our example, the total benefits amount to $2,351,428.

The total costs are the sum of initial and annual metering costs. In our example these amount to $1,375,000. Thus, if Back Bay Power & Light Company implements time-of-day rates, it will achieve a net benefit of $976,428.

Table 4-3 Time-of-Day Analysis Form

UTILITY: ______________________ ASSUMPTIONS: ______________________

ENERGY SAVINGS

Annual Energy Savings

Year	Energy Savings	*	Discount Factor	=	Discounted Savings
1978					
1979					
1980					
1981					
1982					
1983					
1984					
1985					
1986					
1987					
1988					
1989					

Total Discounted Energy Savings [ ] (I)

Continuing Energy Savings

Year	Expected Continuing Energy Savings	*	Capitalization Rate	*	Discount Factor	=	Value of Continuing Energy Savings	
								(II)

CAPITAL COST SAVINGS

	Plant	-	Salvage Value	x	Discount Factor	+	Acquisition Cost	+	Installation Cost	=	Depreciable Value	*	Capital Recovery Factor	=	Annual Capital Cost Savings
1															
2															
3															

Enter in the appropriate year(s) below the Annual Capital Cost Savings (ACCS) for each plant delayed (+) or advanced (-).

Table 4-3 Time-of-Day Analysis Form - page 2

Annual Capital Cost Savings (+ or -)

Year	Plant 1	+	Plant 2	+	Plant 3	=	Total ACCS	*	Discount Factor	=	Discounted Capital Savings
1978	____		____		____		____		____		____
1979	____		____		____		____		____		____
1980	____		____		____		____		____		____
1981	____		____		____		____		____		____
1982	____		____		____		____		____		____
1983	____		____		____		____		____		____
1984	____		____		____		____		____		____
1985	____		____		____		____		____		____
1986	____		____		____		____		____		____
1987	____		____		____		____		____		____
1988	____		____		____		____		____		____
1989	____		____		____		____		____		____

Total Discounted Capital Savings [ ] (III)

METERING COST

Cost per Meter	+	Installation Cost	=	Installed Meter Cost	*	Number of Meters	=	Initial Metering Cost	
____		____		____		____		[ ]	(IV)

Annual Incremental Metering Cost	*	Capitalization Rate	=	Capitalized Annual Metering Cost	
____		____		[ ]	(V)

TOTAL BENEFITS AND COSTS

Total Benefits (I + II + III)	-	Total Cost (IV + V)	=	Net Benefits
[ ]		[ ]		[ ]