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A METHOD OF SHORT-RANGE SYSTEM ANALYSIS FOR ELECTRIC UTILITIES CONTAINING NUCLEAR PLANTS

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FOR ELECTRIC UTILITIES CONTAINING NUCLEAR PLANTS
by Raymond Eng,

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ABSTRACT

An optimization procedure has been formulated and tested that will solve for the optimal generation schedule of several nuclear power reactors in an electric utility system, under short-range resource-limited conditions.

The growing fraction of electricity supplied by nuclear energy is presenting conventional utility systems with unique unit commitment problems. Due to the batch nature of the nuclear fuel cycle, a nuclear reactor, once loaded, is limited to utilize a fixed amount of thermal nuclear energy (when limited to full-power reactivity-limited burnup). Thus, due to unforeseen circumstances situations may arise when the nuclear power reactors can not or should not be based loaded at full power until their scheduled refueling date. An optimization procedure has been devised to calculate the best generation schedule for the nuclear reactor to follow until refueling is possible. The optimization is with respect to minimizing system costs over the short-range planning horizon.

The optimization procedure utilitizes a concept called Opportunity Cost of Nuclear Power (OCNP) to optimally assign the resource-limited nuclear energy to the different weeks in the short-range planning horizon. OCNP is a function of a week's system reserve capacity, its economic loading order, the customer demand function, and the composition of the utility system components. The optimized OCNP value of the short-range planning period is the utility's short-range cost of replacement energy. The system simulation program, PROCOST, used to calculate OCNP is a deterministic linear programming model capable of simulating five types of electric power plants: nuclear, fossil, peaking, hydro, and pumped-storage units. PROCOST is a versatile program capable of using load-duration curves, chronologic or modified chronogic load models. The survey nature of PROCOST allows it to be adapted to study the great variety of short-range options in the operation of a nuclear power reactor.

Using a model utility system, based on data provided by American Electric Power Service Corporation, three system optimization studies were performed. Case 1 was a single-reactor optimization, Case 2 was a two-reactor

optimization to demonstrate the optimization procedure for a multi-reactor situation. Case 3 was a modification of Case 1 where the outage schedule was adjusted to yield constant minimum monthly system reserves. Analysis of the results of the simulations lead to the following conclusions:

(1) Short-range nuclear system analysis can yield very large savings in fossil fuel costs, on the order of millions of dollars per reactor per optimization cycle.

(2) A logical method has been devised to calculate the short-range price of nuclear power, based on the system's substitutional cost of energy.

(3) The system parameters having the greatest effect on total system operating cost are (a) system reserves, (b) economic loading order and (c) the demand shape.

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Dedication

I dedicate this thesis, the culmination of twenty-one years of schooling to my dear parents who have waited patiently these many years, and to my loving wife, Mary, for her forbearance and her encouragement during the most difficult last two years.

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I am most grateful for the assistance and guidance offered by my thesis supervisors, Manson Benedict and Edward A. Mason, encouraged by their faith and understanding, and propelled by their probing insights and standard of excellence.

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TERMINOLOGY

Capacity factor: The ratio of electrical energy generated divided by the rated electrical energy.

Customer demand: The power distribution over time required to be met by the utility.

Demand shape: The distributional shape of a customer demand function.

Incremental capacity factor: The ratio of the electrical energy generated divided by the rated electrical energy for a given increment of the generating capability of a power plant.

Interval: A basic individual unit of time, as compared to a period which is a group of time intervals.

Hybrid load model: A modified chronologic load model where the three average workdays (excluding the high and low workdays) have been combined into one average workday.

Load model: The model representation of customer demand function.

Must-run: That portion of unit capacity representing its minimum level of operation without shutting down.

Nuclear capacity factor: The ratio of the thermal nuclear energy generated divided by the rated thermal nuclear energy of the reactor.

Opportunity cost: The value of a limited resource determined by the cost of the next best substitutional resource.

Period: A group of basic time units, as compared to interval, which is a single unit of time.

Scratch disk: A storage device used by computer to stored information temporarily.

System configuration: The collection of power plants available to generate power on a utility system.

System reserve capacity: The margin of system capacity above the peak load level.

Valve points: The location of throttles on the steam line of the tubine-generator.

1.0 SUMMARY

1.1 Introduction

Nuclear power system analysis is concerned with the optimal coordination of nuclear power reactors with the conventional power plants of an electric power supply system. This study is interested in the short-range time frame where the nuclear fuel has been charged to the core and the thermal energy potential available for power generation is fixed (*) until the reactor's next refueling. The short-range problem is that of optimizing the scheduling of the generation of the electricity potential available from the fuel over the short-range time horizon. This thesis study is concerned only with the resource-limited situation where the amount of available energy from the reactor is insufficient to operate the reactor at full capacity continuously until scheduled refueling. A shortage of energy is possible considering the large number of factors that are related to the original decision on the energy content in the reactor (i.e., long lead times involved in the nuclear fuel cycle, poor forecasting judgement, or forced outages). Examples of changes in the original planning assumptions which could lead to an energy-short situation are:

(1) The fuel is required to be removed from the reactor after burnup reaches 20,000 MWD/T instead of the

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(*) Only the full-power reactivity-limited burnup case is considered.

originally planned 30,000 MWD/T.

(2) The plant availability has matured faster than anticipated.

In such cases, available energy of the reactor must be rationed until the next scheduled refueling (if the refueling can not be advanced).

The motivation for the study of the resource-limited case is to develop the tools and procedures and provide a reference case to make possible the study of more complex short-range situations. Thus, the objectives of this thesis are to:

(1) Develop for the resource-limited case, a calculational model to optimize the short-range production schedule of the nuclear power plants.

Corollary: Develop a calculation model from which more complex short-range problems can be considered.

(2) Define the parameters that have significant influence on system cost, locating areas of greatest sensitivity.

(3) Develop generalized rules of thumb for utility dispatcher on the optimal use of nuclear power reactors.

Corollary: Develop a model that will present the dispatcher with a budget of nuclear energy to be expended over the short-range time horizon.

To make this complex problem tractable, a number of assumptions are made to simplify the problem. The major financial assumptions are: (1) the nuclear fuel cycle costs are fixed and independent of the reactor generation schedule; and (2) the time value of money is ignored over time horizons shorter than one year.

The major nuclear assumptions are (1) that there is no constraint on the rate of change in the power level of the reactors' operation, and (2) that in the full-power reactivity-limited situation, the total amount of thermal energy obtained from a given reactor before refueling is constant, independent of the power history of the reactor. The corollary resulting from these assumptions is that the nuclear energy in the short-range sense is cost-free. Thus, to maximize its utility to the system, the nuclear energy should be scheduled for generation in times of its greatest value to the system.

1.2 Method of Solution

The resource-limited case is viewed as an economic problem, a resource allocation problem, in deciding how to allocate a resource (nuclear energy) among many consumers (individual time intervals). The classical economic method of solution is to let the free market place decide which consumers receive the resource and the amount each receives. The free market determines allocation by the forces of supply and demand. For the short-range nuclear allocation problem, where the "actual" market price of nuclear power is ambiguous, the economist uses "shadow prices". In the resource-limited case, the supply is limited, Figure 1.1 shows the supply and demand curves for the short-range nuclear allocation problem. The market demand curve for nuclear energy is a summation of the energy demanded from all the individual time intervals. The intersection of the supply and demand curves determines an equilibrium trading price for nuclear energy that balances supply with demand. The equilibrium trading price is a mechanism that determines the allocation of the nuclear energy among all the time intervals. Each interval is allocated that amount which satisfies its own demand curve at the equilibrium price.

The determination of an interval's demand curve for nuclear energy is the key to solving the original short-range nuclear allocation problem. The shadow price an interval will pay for nuclear power is set by the competition (*), the cost of the next best substitional source of energy. This is called the Opportunity Cost of Nuclear Power (OCNP). It is obvious that OCNP will depend on the system environment in which the time interval is, i.e., the customer demand, the system reserves, the economic loading order, the amount of nuclear energy available, etc.

(*) This economic analysis assumes perfect competition and perfect communication of prices. The commodity of interest is electricity, where many sources of energy may compete with nuclear to supply this commodity.

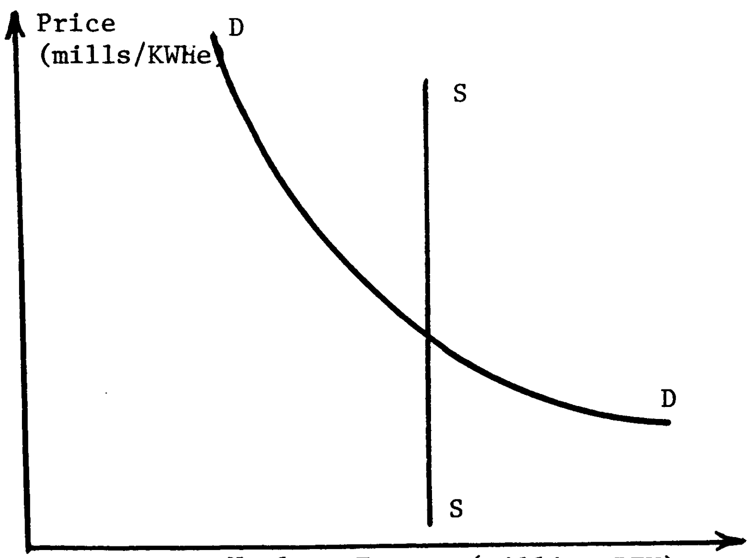


Figure 1.1 SUPPLY AND DEMAND CURVES FOR NUCLEAR ENERGY

1.3 Implementation

The basic cyclic nature of the problem makes it convenient to choose one week as the basic time interval within which to derive OCNP (demand) curves. The physical interpretation of OCNP is the cost of the displaced energy when optimally distributed nuclear energy is marginally increased. A linear programming model of a utility system that solves for the minimum system production cost with a limited amount of nuclear energy (via peak-shaving techniques) will calculated an OCNP.

A weekly OCNP curve is obtained from explicity calculating the OCNP for a number of values of nuclear energy. The optimization procedure requires a weekly OCNP curve for each week in the planning horizon to derive the gross demand curve for nuclear energy. The latter is compared with the supply of nuclear energy to establish a global OCNP for the planning period. Where the global OCNP intersects each weekly OCNP curve determines the quantity of nuclear energy allocated to each week.

1.4 Computer Programs

PROCOST and ALLOCAT are the two principal programs developed to implement the optimization procedures. PROCOST takes a series of assumed nuclear energy allotments for a particular week and determines the minimal system cost in each allotment of nuclear power via peak shaving techniques and from this OCNP. ALLOCAT takes a set of weekly OCNP values over a larger period of time and determines how much nuclear energy to allocate to each week by using the criterion that the OCNP for all weeks shall be the same.

PROCOST, the system simulation program, is a deterministic L.P. model capable of simulating five types of power plants (nuclear, fossil, peaking, hydro, and pumped-storage units) and three types of load models (chronologic, load-duration, and modified chronologic). PROCOST is composed of three parts: (1) NUC_OPT, the L.P. formulating program; (2) MPSX, the L.P. package (IBM program product); (3) PUMP_ST, the pumped-storage simulator. In the NUC_OPT section, the peaking and hydro units are explicitly simulated, and the fossil economic loading order is calculated. NUC_OPT also formats the L.P. formulation of the fossil-nuclear optimization problem for MPSX to solve. MPSX in turn writes the solution on a scratch disk for PUMP_ST to read. PUMP_ST analytically calculates the optimal pumped-storage scheduling solution. The pumped-storage unit can either operate in an economic mode to minimize system cost or in a security mode to maximize system reserve generation capability. The L.P. formulation of the nuclear scheduling problem is:

Objective function: minimize

$$\sum_{j} \sum_{i} (c_i)({}_F H_i)({}_F X_i^j)(T_j) \tag{1.1}$$

subject to the following constraints:

(customer demand constraint)

$$\left\{ \sum_{i} {}_F X_i^j + \sum_{n}^{N} \sum_{i}^{I_n} {}_n X_i^j = D^j \right\}_{j=1,\ldots,J} \tag{1.2}$$

(limited thermal nuclear resource constraint)

$$\left\{ \sum_{j} \sum_{i} ({}_n X_i^j)({}_n H_i)(T_j) = K_n \right\}_{n=1,\ldots,N} \tag{1.3}$$

(bounds, separable programming constraint)

$$\left\{ \begin{array}{lll} \text{if and only if} & {}_{F,n}X_{i-1}^j = {}_{F,n}B_{i-1} & \\ \text{then} & 0 \leq {}_{F,n}X_i^j \leq {}_{F,n}B_i & \\ \text{else} & {}_{F,n}X_i^j = 0 & \end{array} \right\}_{\substack{n=1,\ldots,N \\ j=1,\ldots,J \\ i=2,\ldots,I_n}} \tag{1.4}$$

where:

${}_F X_i^j$ = fossil power level of the i-th increment and the j-th time period (MW)

${}_n X_i^j$ = power level of the i-th increment and the j-th time interval of the n-th nuclear reactor (MW)

${}_{F,n}X_i^j$ = either ${}_FX_i^j$ or ${}_nX_i^j$

${}_FH_i$ = incremental fossil heat rate of the i-th increment of the loading order (million BTU/MWHt)

${}_nH_i$ = incremental nuclear heat rate of the i-th nuclear increment of the n-th nuclear reactor (million BTU/MWHt)

C_i = fossil fuel cost (\$/million BTU) of the i-th increment

D^j = modified customer demand of the j-th time interval (MW)

K_n = full-power reactivity-limited thermal energy available from the n-th reactor (million BTU)

${}_{F,n}B_i$ = upper bound of the i-th increment (MW)

J = total number of time intervals

N = total number of nuclear reactors

I_n = total number of increments in a nuclear reactor

T_j = duration of j-th time interval (hours)

The objective function, Eq. (1.1), to be minimized is a summation of the incremental production cost over all the increments in the economic fossil loading order (index i) and over all the time intervals in the one-week time horizon (index j). The incremental production cost is a product of the fuel cost (\$/million BTU), the incremental heat rate (million BTU/MWH) and the energy production (MWH) for each time interval. The constraints to be met are: (1) the summation of the power levels of the individual nuclear and fossil units in each time period must satisfy the modified customer demand, Eq. (1.2), while (2) limiting the total nuclear production to the available resources, Eq. (1.3).

In addition, each variable is bounded, Eq. (1.4). This is where the "separable programming" aspect is featured. All increments are fixed at the lower bound of zero until all the preceding increments have been set to their upper bound. For example, the third increment of the loading order can't be started until the second (and the first) increments are fully loaded. Without this feature, variable heat rates could not be modelled.

1.5 The Utility System

To test the optimization procedures discussed earlier, three system optimization problems were solved. The first was a single-reactor optimization problem, and the second was a multi-reactor optimization problem. The multi-reactor optimization was performed under conditions more severe than "typical" operating conditions. The third optimization problem was a modification of the first in which the monthly configurations were adjusted to yield constant system reserves over the planning horizon.

American Electric Power Service Corp. (AEP) provided the basic data from which the utility system configuration (16) was constructed. The system, composed of 52 units of five power plant types, was simulated for a short-range planning period of six months, April through September. The system included two nuclear plants (of 1100 MWe each), one hydro plant (with limited pondage and 200 MWe peak generating capacity), one pumped-storage unit (of 300 MWe generating capacity), seven peaking units and 41 fossil units for a total generating capacity of 19250 MWe.

The maintenance schedule (scheduled outage) of the individual fossil and peaking units proposed by AEP is displayed in Table 1.1. Most of the scheduled outage was placed in the spring and fall months. Since the model is deterministic, forced outage effects are simulated, treating them as scheduled outages also. Table 1.1 also displays the systematic treatment of forced outages. Peaking units are

TABLE 1.1

MAINTENANCE AND FORCED OUTAGE SCHEDULE OF PEAKING AND FOSSIL UNITS OF CASES 1 AND 2

	Maintenance Schedule												Assumed Forced Outage Schedule											
Month	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Peakers																								
1													X											
2														X	X									
3	X															X								
4			X																X					
5						X														X	X			
6		X																						X
7											X										X			
Fossil																								
1									X								X	X						
2										X													X	X
3												X										X		
4				X																		X	X	
5								X										X						
6		X																	X	X				
7				X											X									
8					X								X	X										
9											X						X	X						
10		X											X											
11										X				X	X									
12						X										X								
13											X						X	X						
14	X																		X					
15						X														X	X			
16									X													X		
17			X																				X	X
18					Y				Z															X
19																					X			
20												X										X	X	
21	X					Y		Z											X	X				
22																X	X							
23			X															X						
24				X											X									
25										X			X	X										
26							Y	Z					X											
27					X									X	X									
28									X							X								
29											X						X	X						
30		X																	X					

TABLE 1.1 (CONT'D)

	Maintenance Schedule												Assumed Forced Outage Schedule											
Month	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Fossil (Cont'd)																								
31	X																			X	X			
32				X																		X		
33	X	X	X	X	X	X	X	X	X															
34												X										X	X	
35									X														X	X
36												X									X			
37			X																					X
38				Y			Z									Z	Z		Y	Y				
39											X							X						
40					X									X	X									
41										X						Y	Y		Z	Z				

Note: An "X" represents a simulated outage for the entire month. The total time of scheduled outage for each plant corresponds to the actual observed outage rate for similar sized units. The specific forced outage schedule for each unit was chosen randomly. The maintenance schedule was chosen to lie mainly in the spring and fall months.

The "X" represents a simulated outage for Cases 1, 2, 3.

The "Y" represents a simulated outage for Cases 1 and 2.

The "Z" represents a simulated outage for Case 3.

scheduling to peak-shave until their input capacity factors are fulfilled. All the peakers had estimated capacity factors of 10% and start-up and shut-down cost of $100/start-up, except for two gas-turbine units (of 51 and 4 MWe) which has zero start-up and shut-down costs.

The individual plant parameters were supplied by AEP in 1973. The rated capacity, fuel costs and average heat-rate at rated capacity for the 41 fossil units and seven peaking units are tabulated in Table 1.2. The fuel costs do not reflect the sharp rise in fuel costs during 1974. The hydro unit with limited pondage was scheduled to generate 200 MWe for nine peak demand hours during each workday and 50 MWe at all other times. The pumped-storage unit's operating parameters were: 300 MWe capacity generator, 160 MWe capacity pump, 70% cycle efficiency, 9300 MWH reservoir capacity and 2300 MWH/week free water inflow into the reservoir.

The system treated also contained two nuclear units of 1100 MWe each. Nuclear Unit 1 was scheduled for refueling on October 1. In the six months prior to refueling which make up the planning period, Unit 1 was assumed to have 70% of the thermal energy required to operate base loaded at full rated power. In the first simulation, Unit 2 was treated as a new unit just being introduced to service under a gradual programmed start-up: 20% of full rated power throughout April, 40% of full rated power throughout May, 60% during June, 80% during July, and 100% during August and

Table 1.2

PLANT PARAMETERS OF PEAKING AND FOSSIL UNITS

Peakers	Capacity MWc	Fuel Cost $/$10^6$ Btu	Heat Rate 10^6 Btu/MWH
1	4	1.70	15.0
2	51	1.70	15.0
3	95	1.70	12.5
4	95	1.05	12.0
5	95	1.05	12.0
6	90	0.55	12.9
7	90	0.55	12.9
Fossil			
1	145	1.70	9.8
2	105	0.40	12.0
3	110	0.40	12.0
4	100	0.55	10.8
5	105	1.0	11.8
6	150	0.95	9.4
7	150	0.95	9.4
8	150	0.95	9.4
9	150	0.95	9.4
10	150	0.55	9.7
11	150	0.55	9.7
12	215	0.55	9.5
13	240	1.0	9.1
14	205	0.55	9.8
15	205	0.55	9.8
16	215	0.55	9.8
17	215	0.55	9.8
18	225	0.50	10.0
19	225	0.50	10.0
20	225	0.50	10.0
21	215	0.55	9.2
22	210	0.55	9.2
23	240	0.80	9.1
24	240	0.80	9.1
25	240	0.80	9.1
26	280	1.05	9.3
27	400	0.55	9.2
28	450	0.95	9.0
29	525	0.35	9.1
30	580	0.55	9.0
31	600	0.50	9.1
32	600	0.50	9.1
33	615	0.50	9.0
34	800	1.05	9.4
35	800	0.40	9.5
36	800	0.40	9.5
37	800	1.10	9.0
38	800	1.10	9.0
39	1,300	1.25	8.4
40	1,300	0,80	8.5
41	1,300	0.80	8.5

September.

The forecasted weekly energy consumption during the six-month (26 week) planning period is tabulated in Table 1.3. The six-month planning period spanned three seasons, spring (April and May), summer (June, July, and August) and fall (September). The weekly energy consumption was input to a seasonal load model, MODEL, to generate the detailed hourly customer demand numbers.

In the six-month period prior to refueling, a reactor with insufficient energy to run at full power until scheduled refueling can be considered a candidate for short-range resource-limited optimization. The second reactor, Nuclear Unit 2, coming on-line with a fully fueled core had an abundant supply of energy and an undetermined forced outage rate and would be undergoing a planned start-up program, so that the reactor's operation was determinate over the short range. Only reactors with limited resource and a fairly certain availability (*) over the short-range time horizon are amenable to short-range system analysis using PROCOST. Availability, at best, can only be fairly certain over a short-range time horizon.

The first system optimization (Case 1) was then to find

(*) The deterministic approach (used in the PROCOST program) assumes the availability of the reactor is known with certainty. Hence, this assumption imposes certain restrictions on the use of this short-range optimization technique. This restriction can possibly be eliminated by the utilization of the Booth-Balerieux probabilistic technique, ref. (18), for modeling forced outages in PROCOST.

TABLE 1.3

WEEKLY ENERGY FORECAST FOR PLANNING PERIOD

Month	Week	Weekly Energy (MWH)	Monthly Total (MWH)	Demand Peak (MWH)	Average Power (MWH/H)
April	1	1,860,288	7,238,361	13,577	11,073
	2	1,894,814		13,795	11,279
	3	1,801,320		13,207	10,722
	4	1,681,939		12,472	10,011
May	5	1,792,155	8,771,712	13,149	10,668
	6	1,728,221		12,747	10,287
	7	1,758,492		12,937	10,467
	8	1,801,151		13,207	10,721
	9	1,691,693		12,517	10,070
June	10	1,839,877	7,299,798	13,951	10,952
	11	1,883,604		14,227	11,212
	12	1,814,876		13,793	10,803
	13	1,761,441		13,456	10,485
July	14	1,681,810	9,122,626	12,954	10,011
	15	1,870,344		14,143	11,133
	16	1,826,914		13,869	10,874
	17	1,883,382		14,226	11,211
	18	1,860,176		14,079	11,072
August	19	1,833,500	7,589,101	13,911	10,914
	20	1,950,649		14,650	11,611
	21	1,895,024		14,299	11,280
	22	1,909,928		19,393	11,369
September	23	1,955,031	7,653,173	13,919	11,637
	24	1,868,715		13,034	11,123
	25	1,872,805		13,074	11,148
	26	1,956,622		13,939	11,647
Total		47,674,771			

the optimal distribution of weekly nuclear capacity factors of Nuclear Unit 1, whose overall thermal energy availability is 70% of rated capacity for the six-month planning period prior to refueling. The second power reactor was operated at programmed steps in power levels.

Thus, although the system contained two reactors, the first system simulation (Case 1) was a single-reactor optimization. The second system simulation (Case 2) was a complex two-reactor optimization. Case 2 used exactly the same system configuration as in Case 1, except for additional constraints on Nuclear Unit 2, which was limited to 80% of the energy used in the corresponding periods of Case 1, see Table 1.4. The goal of Case 2 was to find the optimal weekly nuclear capacity factor distribution of both nuclear reactors. Case 2 was admittedly a contrived case to illustrate: (1) a multi reactor optimization, and (2) the feasibility of the procedures to handle a complex and involved situation. Case 2 is not an ordinary straight-forward two-reactor optimization. Nuclear Unit 2 had five smaller separate planning periods, requiring a separate optimization in each period. (Nuclear Unit 2 was analogous to a collection of five reactors, with each reactor operating for only one period and shut down for the other periods.)

Case 3 is a single reactor optimization similar to Case 1. The only difference (between Case 1 and 3) is that the monthly fossil configurations were adjusted in Case 3 to

TABLE 1.4

OPERATIONAL CONSTRAINTS ON NUCLEAR UNIT 2 DURING THE TWO-REACTOR OPTIMIZATION, CASE 2

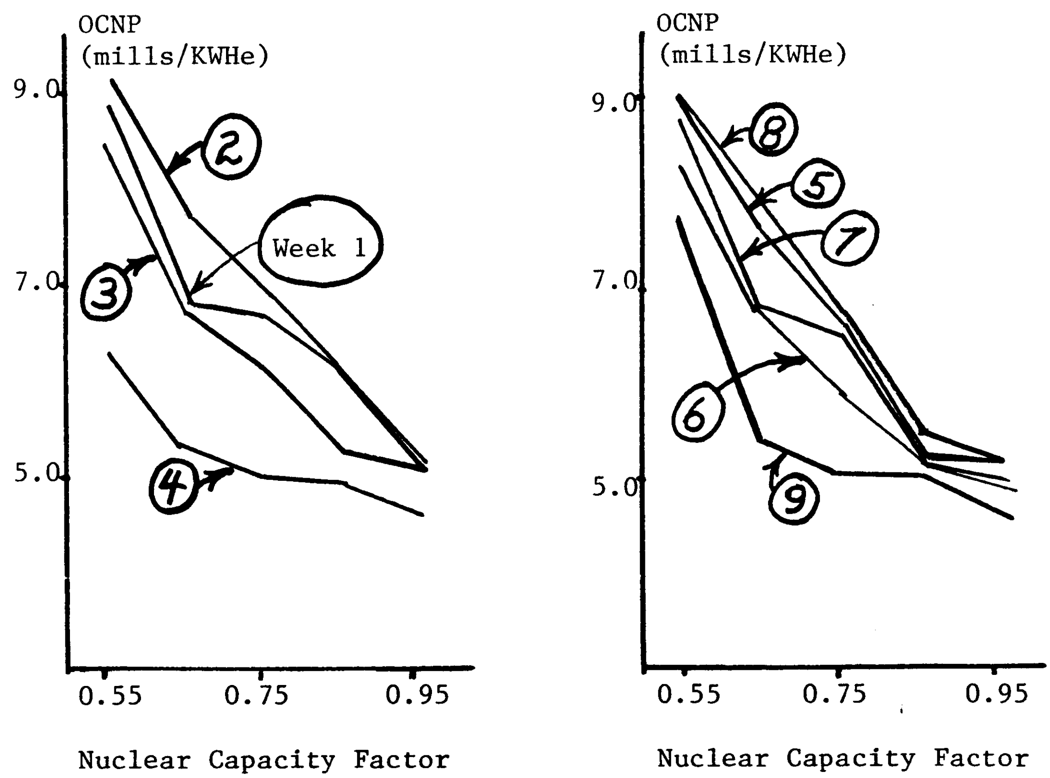
Time Period		Limitation	
Weeks	Months	Energy (% Rated)	Power (% Rated)
1-4	April	16	20
5-9	May	32	40
10-13	June	48	60
14-18	July	64	80
19-26	Aug.-Sept.	80	100

levelize the minimum monthly system reserves over the six-month planning horizon (see Table 1.1). All other system parameters of Case 3 are identical to Case 1.

Before discussing the optimization results, some fundamental characteristics of OCNP will be reviewed. Examining Figure 1.2 these distinguishing characteristics of weekly OCNP functions are discernable: (1) The OCNP functions are monotonically decreasing functions with respect to an increasing nuclear capacity factor. (2) The weekly OCNP function of different weeks (but the same monthly configurations) never cross. (3) For weeks of increasing weekly energy consumption, the OCNP function likewise increases. (4) The larger the weekly energy consumption, the larger the slope of the OCNP function. (5) The weekly OCNP functions assume a shape characteristic of their respective economic loading order. (6) The amplitude of the OCNP function varies inversely with the weekly system reserve. (7) The amplitude of the OCNP function is proportional to the average fossil fuel cost of the monthly system configuration.

Figure 1.2

TYPICAL WEEKLY OCNP FUNCTIONS
FROM THE SINGLE REACTOR
OPTIMIZATION STUDY



Note: Circled numbers refer to the week numbers from the Case 1 simulation

1.6 Case 1

The results of Case 1, the optimized weekly nuclear capacity factor distribution, Table 1.5, reflects many of the OCNP principles stated above. The overall nuclear capacity factor for the six-month planning period was 70%. The high weekly nuclear capacity factor for September reflects the unusually high fossil fuel cost for that month. All the other months have about the same fossil fuel cost, as shown in Table 1.6. Hence September due to its significantly more expensive fossil fuel cost configuration is scheduled to generate at near full capacity to displace as much of the expensive fossil fuel as possible. August and July have the lowest average weekly nuclear capacity factor, in fact, the lowest allowed, because of their large reserve capacity, Table 1.7. April has the lowest system reserve, hence the second largest set of weekly nuclear capacity factors. Thus, May is the second tightest month system reserve-wise, and also has the second highest fossil fuel configuration. May also has an above average monthly nuclear capacity factor. Within each monthly schedule, the weekly allotments of nuclear energy are proportional to the weekly energy consumption forecast, see Table 1.3.

The overall impression from the results of this optimization study for the system simulated is that the maintenance scheduled was too unbalanced in excluding summer maintenance. Gross generating capacity is large enough to handle the summer peaks while still scheduling more

Table 1.5

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION FOR THE SINGLE REACTOR OPTIMIZATION (CASE 1)

Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average Energy (10^3 MWH)
April	1	0.85	157.08	609.84	152.46
	2	0.95	175.56		
	3	0.85	157.08		
	4	0.65	120.12		
May	5	0.85	157.08	711.48	142.29
	6	0.75	138.60		
	7	0.75	138.60		
	8	0.85	157.08		
	9	0.65	120.12		
June	10	0.65	120.12	480.48	120.12
	11	0.75	138.60		
	12	0.65	120.12		
	13	0.55	101.64		
July	14	0.55	101.64	508.20	101.64
	15	0.55	101.64		
	16	0.55	101.64		
	17	0.55	101.64		
	18	0.55	101.64		
August	19	0.55	101.64	406.56	101.64
	20	0.55	101.64		
	21	0.55	101.64		
	22	0.55	101.64		
September	23	0.95	175.56	646.80	161.70
	24	0.85	157.08		
	25	0.85	157.08		
	26	0.85	157.08		
Total			3,363.36		129.36

TABLE 1.6

MONTHLY AVERAGE FOSSIL FUEL COSTS OF
THE FOSSIL CONFIGURATION
FOR CASES 1 AND 2

Month	Fuel Costs Mills/KWH
April	6.84
May	7.10
June	6.63
July	6.80
August	6.88
September	7.49

Table 1.7

WEEKLY SYSTEM RESERVE
FOR CASES 1 AND 2

Month	April				May				
Week	1	2	3	4	5	6	7	8	9
Total gross generating capacity, MW	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19.750
Fossil maintenance outage, MW	2,505	2,505	2,505	2,505	2,690	2,690	2,690	3,690	2,690
Nuclear scheduled outage,* MW	880	880	880	880	660	660	660	660	660
Fossil forced outage, MW	2,420	2,420	2,420	2,420	2,570	2,570	2,570	2,570	2,570
Net generating capacity MW	13,945	13,945	13,945	13,945	13,830	13,830	13,830	13,830	13,830
Weekly peak load, MW	13,577	13,795	13,207	12,472	13,149	12,747	12,937	13,206	12,517
Net reserve, MW	368	150	738	1,473	681	1,083	893	624	1,313

Month	June				July				
Week	10	11	12	13	14	15	16	17	18
Total gross generating capacity, MW	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage, MW	1,340	1,340	1,340	1,340	895	895	895	895	895
Nuclear scheduled outage,* MW	440	440	440	440	220	220	220	220	220
Fossil forced outage, MW	2,555	2,555	2,555	2,555	2,045	2,045	2,045	2,045	2,045
Net generating capacity, MW	15,415	15,415	15,415	15,415	16,600	16,600	16,600	16,600	16,600
Weekly peak load, MW	13,951	14,227	13,793	13,456	12,954	14,143	13,869	14,226	14,079
Net reserve, MW	1,464	1,188	1,632	1,959	3,646	2,457	2,731	2,374	2,521

Month	August				September			
Week	19	20	21	22	23	24	25	26
Total gross generating capacity, MW	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage,* MW	750	750	750	750	2,225	2,225	2,225	2,225
Nuclear maintenance outage,* MW	0	0	0	0	0	0	0	0
Fossil forced outage, MW	2,065	2,065	2,065	2,065	2,015	2,015	2,015	2,015
Net generating capacity, MW	16,915	16,915	16,915	16,915	15,510	15,510	15,510	15,510
Weekly peak load, MW	13,911	14,650	14,299	14,393	13,919	13,034	13,076	13,936
Net reserve, MW	3,054	2,315	2,666	2,572	1,591	2,476	2,434	1,574

*Program startup limitation for Nuclear Unit 2.

maintenance during August and July, and less during April and May. Also, a better mix of fossil plants should be scheduled for September to give lower fossil fuel costs. Such considerations led to the calculation of Case 3, to be discussed below.

A total system cost calculation from the optimization results of Case 1 showed a very large dollar savings, see Table 1.8. Comparing the situation of no nuclear optimization, Case 1.A (uniform hourly nuclear power generation for the entire six months), with the situation of constant weekly nuclear capacity factor, Case 1.B (optimized hourly generation), the saving was $4.1 million in fossil fuel costs. By further optimizing the weekly nuclear capacity factor distribution over the six month time horizon, Case 1.C, the saving increased by another $340,000. The total fossil fuel savings is equivalent to 66% of the nuclear fuel cost of Nuclear Unit 1, at 2.0 mills/KWHe. The order of magnitude of the savings for Case 1 indicates that even for a single-reactor utility system, short-range optimization is worth-while in the resource-limited situations.

TABLE 1.8A

SYSTEM FOSSIL FUEL COSTS AND SAVINGS FOR CASE 1

Month	Week	Case 1.A No Nuclear Optimization ($)	Case 1.B Hourly Optimization ($)	Case 1.C Hourly and Weekly Optimization ($)
April	1	10,897,641	10,703,601	10,524,562
	2	11,310,309	11,002,306	10,708,211
	3	10,401,792	10,220,996	10,056,930
	4	9,496,691	9,326,228	9,373,436
May	5	10,585,981	10,406,225	10,227,973
	6	10,078,719	9,886,612	9,830,631
	7	10,316,433	10,126,110	10,063,502
	8	10,660,648	10,482,397	10,300,385
	9	9,762,971	9,611,780	9,660,533
June	10	9,899,898	9,755,839	9,802,719
	11	10,210,651	10,063,304	10,013,456
	12	9,725,349	9,586,475	9,632,938
	13	9,369,029	9,242,724	9,387,855
July	14	8,847,012	8,746,190	8,873,310
	15	9,950,572	9,816,608	9,959,853
	16	9,670,594	9,555,670	9,692,954
	17	10,037,142	9,858,900	10,004,974
	18	9,883,377	9,753,496	9,894,948
August	19	9,623,066	9,517,456	9,652,246
	20	10,378,333	10,230,513	10,380,137
	21	10,002,896	9,877,511	10,016,482
	22	10,101,697	9,968,648	10,109,134
September	23	11,538,985	11,379,984	11,101,378
	24	10,879,069	10,716,938	10,559,049
	25	10,908,873	10,745,769	10,586,767
	26	11,551,409	11,390,192	11,216,616
Total		266,089,137	261,988,509	261,648,975
Comparison with Case 1.A		-	(4,100,628)	(4,440,162)

Case 1.A: Unit 1 is run at constant power (725 Mw), and Unit 2 is run at programmed power levels (Table 1.8B) for all three cases.

Case 1.B: The weekly energy output of Unit 1 is the same as in Case 1.A, but the hourly power level within each week is optimized.

Case 1.C: Unit 1's power levels for each hour of each week are optimized for the entire six-month planning period.

Total energy output of Unit 1 is the same in all three cases.

TABLE 1.8B

PROGRAMMED CONSTANT POWER LEVELS OF NUCLEAR UNIT 2 FOR CASES 1 AND 3

Month	Power Level (MWe)
April	220
May	440
June	660
July	880
August	1100
September	1100

1.7 Case 2

Case 2 is a two-reactor optimization, which must be solved iteratively. A summary of the optimal capacity factor distribution and system costs with each iteration for Case 2 are given in Table 1.9 and 1.10, respectively. The complete two-reactor optimization, Case 2.C, results in a total savings of $6.48 million compared with the situation of no nuclear optimization, Case 2.A. Of this, $600,000 represents the improvement from the situation of optimal hourly generation, Case 2.B, compared with the total optimization results, Case 2.C. Table 1.10 indicates that most of the savings are realized after only one complete cycle of iterations in this two-reactor system. Other simulations have confirmed the hypothesis that the multi-reactor iteration process is a rapidly convergent one.

The major conclusions of this multi-reactor all simulation are that: (1) the short-range resource-limited optimization process described in this thesis has been shown adaptable to a two-reactor situation; (2) convergence takes only a few complete cycles of iterations; (3) most of the cost savings are realized after one or two complete cycles of iterations; (4) substantial savings in fossil fuel cost are possible with short-range optimization; (5) potential cost savings increase as the amount of nuclear capacity and energy that are optimized is increased.

TABLE 1.9

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION
FOR THE TWO REACTOR OPTIMIZATION (CASE 2)

		Unit 1				Unit 2			
Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average (10^3 MWH)	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average (10^3 MWH)
April	1	0.85	157.08	591.36	147.84	0.20	36.96	118.272	29.568
	2	0.95	175.56			0.16	29.568		
	3	0.75	138.60			0.16	29.568		
	4	0.65	120.12			0.12	22.176		
May	5	0.85	157.08	711.48	142.296	0.32	59.136	295.680	59.136
	6	0.75	138.60			0.32	59.136		
	7	0.75	138.60			0.32	59.136		
	8	0.85	157.08			0.32	59.136		
	9	0.65	120.12			0.32	59.136		
June	10	0.65	120.12	443.52	110.88	0.48	88.704	354.816	88.704
	11	0.65	120.12			0.54	99.792		
	12	0.55	101.64			0.48	88.704		
	13	0.55	101.64			0.42	77.616		
July	14	0.55	101.64	508.20	101.64	0.48	88.704	591.360	118.272
	15	0.55	101.64			0.72	133.056		
	16	0.55	101.64			0.64	118.272		
	17	0.55	101.64			0.72	133.056		
	18	0.55	101.64			0.64	118.272		

TABLE 1.9 (CONT'D)

		Unit 1				Unit 2			
Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average (10^3 MWH)	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average (10^3 MWH)
August	19	0.55	101.64	406.56	101.64	0.70	129.36	554.40	138.60
	20	0.55	101.64			0.80	147.84		
	21	0.55	101.64			0.80	147.84		
	22	0.55	101.64			0.70	129.36		
September	23	0.95	175.56	702.24	175.56	0.90	166.32	628.32	157.08
	24	0.95	175.56			0.80	147.84		
	25	0.95	175.56			0.80	147.84		
	26	0.95	175.56			0.90	166.32		
Total			3,363.36		129.36		2,542.848		97.80

Table 1.10

SUMMARY OF TWO-REACTOR OPTIMIZATION COST SAVINGS AS A FUNCTION OF NUMBER OF ITERATIONS

Case	2.A	2.B	2.C			
Iterations on Weekly Energy Allocations			I	II	III	IV
Total Cost, $	271,307,945	265,428,422				264,827,357
Savings Relative to Case 2.B, $	-5,879,523	0	555,334	593,897	601,065	601,065

1.8 Case 3

The purpose of Case 3 was to examine the effect of system reserves on OCNP and on the optimal weekly nuclear capacity factor distribution. Case 3 is a modification of Case 1 where the fossil outage schedule has been adjusted to obtain a (nearly) constant minimum monthly system reserve. A comparison of the minimum monthly system reserves for Cases 1 and 3 is listed in Table 1.11. The average fossil generation costs of the monthly fossil configurations are listed in Table 1.12. The optimal weekly nuclear capacity factor distribution is listed in Table 1.13.

A comparison of the optimal nuclear capacity factor distribution for Case 1 and Case 3 shows a decrease of allocated energy for April and May, and an increase for July, August, and September. The June allotment is the same for both cases. The change in monthly allocation of nuclear energy is consistent with the change in the monthly minimum system reserve, both in direction and magnitude. April and May had large increases in reserves, thus, resulting in significant decreases in nuclear energy allotments. July and August had large decreases in system reserve, thus, resulting in significant increases in nuclear energy allotments. June had the smallest monthly change in system reserves (210 MW), not enough to change its nuclear energy allocation. September had a slight decrease in system reserves (225 MW), resulting in a slight increase the nuclear energy allotment. The comparison of the solution of

TABLE 1.11

	Minimum Monthly System Reserves (Mw)					
Month:	April	May	June	July	August	September
Case 1	150	893	1,188	2,374	2,315	1,574
Case 3	1,450	1,349	1,398	1,437	1,325	1,349

TABLE 1.12

MONTHLY AVERAGE FOSSIL GENERATION COSTS OF THE FOSSIL CONFIGURATION FOR CASE 3

Month	Generation Costs (Mills/KWH)
April	6.84
May	6.85
June	6.39
July	6.90
August	7.04
September	7.54

Table 1.13

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION FOR THE SINGLE REACTOR OPTIMIZATION (CASE 3)

Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Energy (10^3 MWH)	Monthly Average Energy (10^3 MWH)
April	1	0.85	157.08	554.40	138.60
	2	0.85	157.08		
	3	0.75	138.60		
	4	0.55	101.64		
May	5	0.85	157.08	674.52	134.90
	6	0.75	138.60		
	7	0.75	138.60		
	8	0.75	138.60		
	9	0.55	101.64		
June	10	0.65	120.12	480.48	120.12
	11	0.75	138.60		
	12	0.65	120.12		
	13	0.55	101.64		
July	14	0.55	101.64	545.16	109.03
	15	0.65	120.12		
	16	0.55	101.64		
	17	0.65	120.12		
	18	0.55	101.64		
August	19	0.55	101.64	443.51	110.88
	20	0.65	120.12		
	21	0.55	101.64		
	22	0.65	120.12		
September	23	0.95	175.56	665.28	166.32
	24	0.85	157.08		
	25	0.85	157.08		
	26	0.95	175.56		
Total			3,363.36		129.36

Case 1 with Case 3 shows conclusively the significant effect an unequal system reserve has on the optimal distribution of nuclear energy.

In terms of total system costs, Case 3 showed an improvement of about $2.2 million compared with Case 1, see Table 1.14. The comparison of case 3.A with Case 3.C, no nuclear optimization to weekly nuclear optimization, showed a savings of $4.7 million, equivalent to 70% of Unit 1 fuel cost at $2.0 mills/KWHe. This is about the same as Case 1.

Comparing Cases B to Cases C, hourly optimization to weekly optimization, the savings are $160,000 for Case 3 and $340,000 for Case 1. It is to be expected that as the system reserves becomes equalized, the optimal distribution of capacity factors becomes narrower and hence the difference in savings between hourly optimization and weekly optimization diminishes. Also, the lower capacity factors of the summer months are partially due to a seasonal influence on the shape of their customer demand function. Both spring and summer have about the same average weekly energy consumption. However summer has much higher demand peaks than the spring, hence summer also has lower demand minimums than spring. Since the lower part of the load-duration curve plays an active role in determining OCNP, it is no surprise that summer months should have lower average nuclear capacity factors (with all other parameters equal).

Because of changing economic conditions, fossil fuel

TABLE 1.14

SYSTEM FOSSIL FUEL COSTS AND SAVINGS FOR CASE 3

	Case 3.A*	Case 3.B*	Case 3.C*
System Costs ($)	263,857,559	259,348,663	259,187,244
Comparison with Case 3.A	-	(4,508,896)	(4,670,315)

Case 3.A: Unit 1 is run at constant power (725 Mw), and Unit 2 is run at programmed power levels (Table 1.8B) for all three cases.

Case 3.B: The weekly energy output of Unit 1 is the same as in Case 3.A, but the hourly power level within each week is optimized.

Case 3.C: Unit 1's power levels for each hour of each week are optimized for the entire six-month planning period.

Total energy output of Unit 1 is the same in all three cases.

costs show a great amount of variance from station to station. Hence, the monthly economic loading order will show different patterns for different maintenance schedules. The main conclusion from the system simulations performed is that equal consideration must be given to fossil fuel arrangements as well as system reserves when determining the monthly maintenance schedule.

The sample optimization problems showed that peak-shaving the nuclear energy first resulted in savings on the order of millions of dollars (per reactor per optimization cycle) and optimally distributing the weekly energy next resulted in saving on the order of hundreds of thousands of dollars (per reactor per optimization cycle). These two optimization steps were reversed to find if the order of optimization had any significant effect on their savings. The result showed that the (order of magnitude of) savings from each optimization steps is independent of their order of application.

A sample of the type of optimal load-following pattern recommended by PROCOST is shown in Figure 1.3. As shown, the reactor is essentially operated in an on-off mode. The reactor is turned off (to its minimum operating levels) during low demand intervals and turned on to full capacity during high demand intervals.

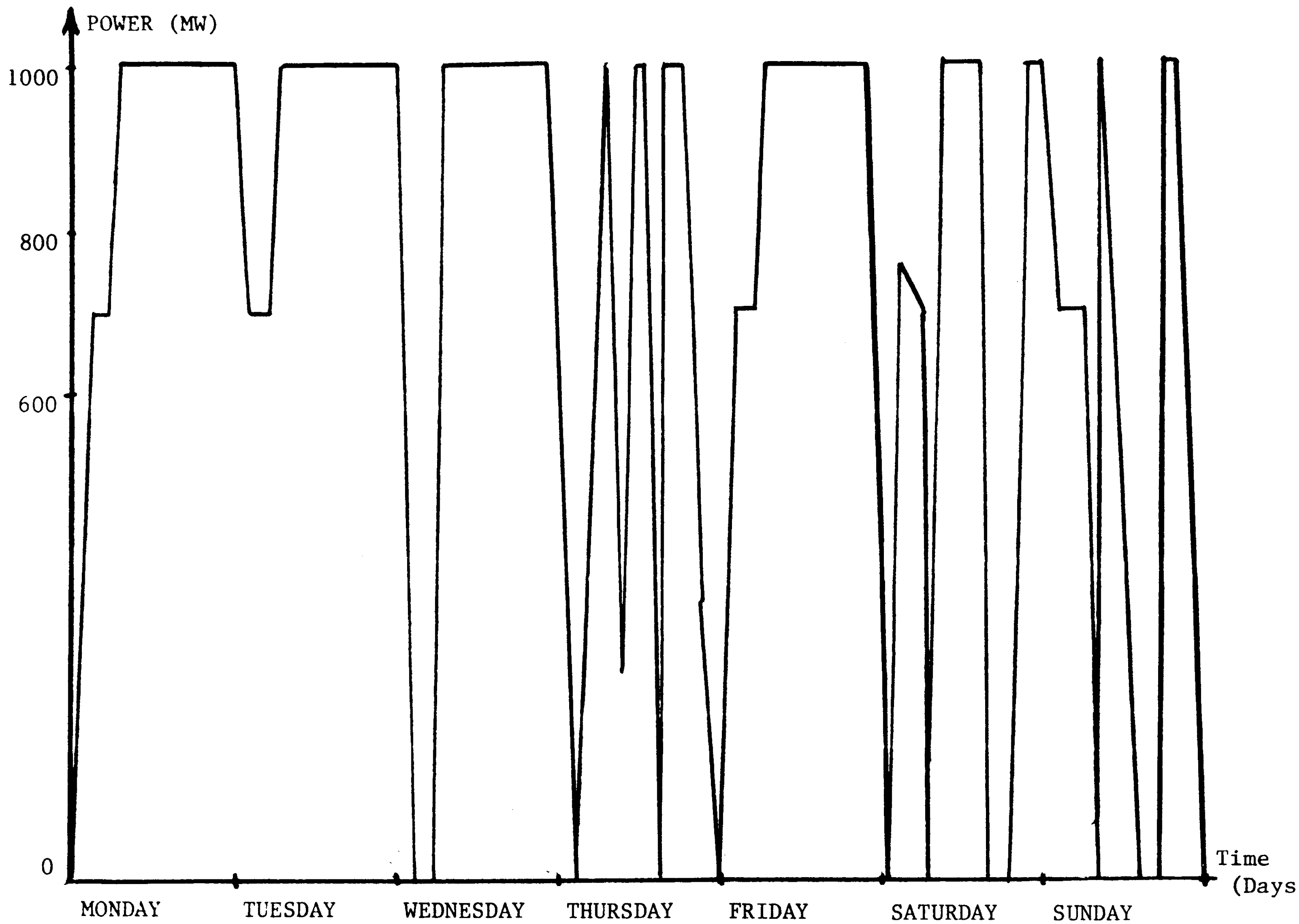


Figure 1.3 SAMPLE OPTIMAL WEEKLY NUCLEAR DISPATCHING SCHEDULE

1.9 Conclusions

(1) The system simulation performed showed the short-range optimization procedure developed to be flexible and reliable in handling a wide range of system conditions including an adaptability to multi-reactor problems as well as to single reactor optimization problems.

(2) The system simulations showed that very large savings in fossil fuel costs, on the order of millions of dollars per reactor per optimization cycle, are possible from short-range nuclear system analysis. Thus adoption of these short-range system optimization technique by the utility industry would be a worth-while undertaking.

(3) Procedural guidelines for optimal dispatching of nuclear generation (under resource-limited conditions) are to (a) peak-shave the dispatching of nuclear energy by operating at full rated power during peak demand time intervals and shutting down (or operating at minimum power) during low demand intervals, (b) follow a weekly budget of nuclear energy rationing until the next scheduled refueling date. The system simulations show that independent of the order of optimization most of short-range optimization savings (millions of dollars per reactor per optimization cycle) comes from peak-shaving the nuclear energy within each week. Hence, peak-shaving should receive the primary attention. The savings from the weekly redistribution of energy were lower, on the order of hundreds of thousands of dollars per reactor per optimization cycle.

(4) The system parameters having greatest effect on total system operating costs are (a) system reserves, (b) seasonal customer demand shape, and (c) the economic loading order (in turn comprised of the system configuration and its basic parameters such as heat rates, and fuel costs). These are the system parameters that must be considered by the system planner in devising the allocation budget of nuclear energy over the short-range planning horizon.

(5) Using the optimization techniques discused in this thesis, an unambiguous and logical method has been developed to calculate the short-range substitutional cost of nuclear power, the OCNP. OCNP is the trade price that should be used when transferring nuclear power by utilities.

2.0 INTRODUCTION TO SHORT-RANGE SYSTEM ANALYSIS

2.1 Introduction

In electric utility system planning, there are three principal time periods, the long-range (10-30 years), the mid-range (1-10 years), and the short-range (less than 1 year). The major task in long-range system analysis is the planning required to meet system expansion. The major considerations are the power plant type, its size, its location, and its date of introduction to the system. The over-all economics of nuclear power has been so favorable that over half of all new capacity planned in the U.S. is nuclear (1).

The unconventional batch nature of the nuclear power process and the long lead times in its fuel cycle requires careful planning; this aspect of system analysis is handled in mid-range planning. The major variables are the reactor's refuel batch size and enrichment. The eight-year lead time necessary for contracting enrichment services and one-year lead time in fabrication requires close coordination of the expected nuclear energy production with the rest of the system components.

In the short-range time frame, in which the nuclear reactor has been charged with its fuel, the system problem becomes that of scheduling generation of the electrical potential available from the fuel. The operating environment is known much more precisely in the short-range than in the other time frames. Moreover, all the nuclear parameters are frozen in the short-range due to its batch nature. Thus the system analysis problem is that of optimizing scheduling of the generation of the nuclear plant's limited energy potential over the short-range time horizon in a fairly known environment.

Previous studies in the long-range and mid-range system analysis have been more extensive than in the short-range analysis. The TVA Brown's Ferry study (2) comparing the economics of nuclear power plants to a fossil power plant showed conclusively the advantage of nuclear power. The mid-range system analysis problem studied at MIT (3) and Oak Ridge (4) have led to automated procedures for calculating a power reactor's batch size and enrichment over the mid-range time horizon.

In the short-range operations time frame, the published studies have been mainly limited to case studies illustrating advantages of coast-down under certain circumstances (5). This thesis study investigates the optimization in the short-range of the nuclear reactor generation schedule such to minimize system cost. The resource-limited case is studied in particular since this is where the principal planning problem lies. In the non-limited resource case, the answer is trivial, schedule the reactor at its full capacity and/or revise the refueling date. In the resource-limited case, the scheduling of when and at what capacity the nuclear plant should be operated is not so obvious.

2.2 Motivation for Resource-Limited Case

The resource-limited case, the one studied in this thesis, is the situation where the nuclear reactor doesn't have enough reactivity to run at full power continuously until its scheduled refueling date and for any of a number of reasons, early refueling is not possible. The amount of thermal nuclear energy to be extracted from the reactor is assumed fixed, limited to full-power reactivity limited burnup. The date of refueling is fixed, and the customer demand function can be forecast. Hence, the resource limited case is a straight-foward optimization problem. Much of the theoretical foundation for the resource-limited case was presented in Hans Widmer's thesis(6). Widmer noted that in short-range system analysis, "the value to the system of the given nuclear energy potential should be used (the system opportunity cost)" in finding the optimal distribution of nuclear energy.

The optimization technique used is a version of Dantzig and Wolfe's Decomposition Principle(7). Once the resource-limited case is solved, it can be extended to include the more complex features of short-range system analysis situations. The operational benefits of moving the refueling date can be quantitatively weighted against the inventory charges and other penalties. The importance of refueling during low seasonal demands can be more accurately calculated; and the significance of stretch-out and the timing of its use can also be studied in more detail. Thus, the study of the resource-limited case in this thesis will develop the tools and procedures and provide a reference case to make possible the study of the more complex short-range situations.

2.3 Goals of Thesis

The objectives of this thesis are to:

(1) Develop a calculational model for the resource-limited case to optimize the short-range production schedule of the nuclear power plants.

Corollary: Develop a calculation model from which more complex short-range problems can be considered.

(2) Define the parameters that have significant influence on system cost and the Opportunity Cost of Nuclear Power, locating areas of greatest sensitivity.

(3) Develop generalized rules of thumb for the utility dispatcher on the optimal use of nuclear power reactors.

Corollary: Develop a model that will present the dispatcher with a budget of nuclear energy to be expended over the short-range time horizon.

2.4 Perspective on Short-Range Nuclear Power System Analysis

In the early days of nuclear power, the economic justification for nuclear power plants was the main topic of study among system planners (whether to buy nuclear or to buy fossil?). Some consider the publication of TVA's Brown's Ferry Study (2) the turning point in the utility industry's acceptance of nuclear power. Long-range system analysis deals with the question of how best to meet the future growth in customer demand. The parameters are the types of plants, size of plants, and location of plants. All these parameters are closely related to the forecasted composition of the utility's future customer demand. If the demand is industrial rather than residential, then base load plants will be preferred over cycling plants. Further, to keep transmission losses to a minimum, future plants should be located as close to future load centers as possible. Hence the utility must anticipate movement of load centers, and/or creation of new ones. The sizes of new plants must be in proportion to service demanded, otherwise either capital is wasted or service requested can not be met. The economics of power production is a consideration in chosing the type of power plant (but by no means the only one). The TVA study showed that nuclear was the economically preferred choice for the Brown's Ferry site. TVA's (a system located near the Appalachian coal mines) move toward nuclear was convincing to the rest of the utility industry in overcoming the industry reluctance to try a new technology. The time scale in long-range system planning is from 10-30 years.

Once the decision to build a nuclear plant is made, the long lead times in the nuclear fuel cycle require mid-range planning to provide for the fuel services when needed. The mining industry practice is to open new mines only when demand is assured for the life of the mine (in the form of a long term contract). In most instances, money is advanced by the customer to the mining company to provide initial capital to start up the mine. The AEC presently requires a ten year notice on enrichment services. Fabrication of fuel takes about a year's time. The financial consequences of long lead times is considerable. The core of a 1000 MWe power reactor is valued at $30,000,000. Thus, the inventory carrying charges would be in the millions of dollars. This places a premium on careful planning and scheduling of fuel services (and in turn, cash flow). The optimization of the nuclear fuel cycle in this time scale is called the mid-range system analysis problem. It deals with optimizing the power production from nuclear power reactors so as to minimize system cost over the mid-range time horizon. Studies in this field at MIT and Oak Ridge (4) have developed procedures for calculating a power reactor's enrichment and batch size over a 3 to 5 year time horizon. At MIT, Paul Deaton (3) developed a System Integration Model (SIM) and a System Optimization Model (SOM). The SIM generates an optimal production schedule for a particular utility system configuration (using the Booth Baleriaux probabilistic simulation technique). The SOM searches for the optimal schedule of nuclear reactor's enrichment and batch size to meet the nuclear production schedule set by SIM.

The SOM relies on a reactor core physics model to provide the intermediate nuclear incremental cost values to perform its optimization analysis. At MIT, core simulation and optimization models (CORSOM) which simulate core physics calculations to find a minimum cost assignment of refuel enrichments and batch size for a given reactor production schedule were developed by J. Kearney (8) and H.Y. Watt (9).

Once the nuclear reactor has been charged with fuel, the system problem becomes one of scheduling the generation of the electricity potentially available from the fuel. This is the basic short-range (less than one year) nuclear power system analysis problem, which is the field of this thesis.

Short-range power system analysis is concerned with the operational aspect of producing and delivering the demanded power for the least cost (under certain rigid constraints). Given the existing network of power plants, the dispatcher must figure out which of his units to make available for the immediate future and the economical distributional dispatch of power generation from each unit.

The demand for electricity fluctuates greatly with geographical location, season and the time of day. For example, the minimum weekly demand at nights and weekends on a system may be only 35% of the corresponding weekly maximum, while the annual minimum demand may represent only 20% of the demand peak. Thus, for the system as a whole, the annual load factor may be only 50%.

To meet this type of demand requirement, the utilities have at their disposal a wide assortment of different types of power plants with different operating characteristics. The basic operating strategy of nuclear power plants coming on line today is that of base loading them because of their low fuel cost. But as nuclear plants continue to make up an increasing share of the power system capacity, there will be times when demand will be less than a system's nuclear power capacity. Therefore, the optimization of day-to-day operations of nuclear power plants and their interaction with the rest of the power pool is a problem worth investigating.

Economic dispatch is concerned with meeting the hour-by-hour load requirements from the units on the line, at least cost. The guiding optimality rule is the "equal incremental production cost criterion". The main operating cost variables are fuel costs, the transmission line losses and the operating efficiencies of generators. To a first-order approximation, the incremental operating cost is that of the fuel. Since fossil-fuel power plants are continuous processors, the cost of an extra unit of power is equal to cost of an extra unit of fuel. For a nuclear power plant, the calculations of incremental cost of power is not so simple. Nuclear fueling is a batch process whose cost is fixed in the short-range time frame.

There are a number of short-range nuclear options at the disposal of the utility to handle short-range deviations just before the scheduled refueling of a nuclear power reactor, for a variety of situations:

(1) Coast-Down: The nuclear reactor has a negative power reactivity coefficient, thus by reducing the power level of the reactor, it can be kept critical.

(2) Lower Feed Water Temperature: The nuclear reactor has a negative temperature reactivity coefficient, thus by reducing the water temperature, the reactor can be kept critical, though at lower thermal efficiency.

(3) Alter Refuel Batch Size: If availability was below that expected, one can compensate by refueling a smaller batch. However, if availability was higher than expected and one of above methods was used to extend the burnup of the fuel, increasing the refuel batch size at the last minute is not a simple task, because of the long lead times involved in fuel preparation. But if the utility has a number of reactors using the same fuel design and enrichment or belongs to a nuclear fuel swapping pool, larger refuel batch size may be feasible.

(4) Alter Enrichment: Because of the long lead times in enrichment and fabrication of fuel, this alternative is not usually possible except in cases where the utility could borrow the fuel from another reactor of its

utility system, with the same fuel design, or from a swapping pool.

(5) Move Refueling Date: With advance notice, refueling may be rescheduled for the revised date when the desired burnup is expected to be reached.

(6) Optimize Production Schedule: To refuel on schedule, optimize the fixed amount of energy available in the fuel until the scheduled refueling date.

Not all of the above options may be feasible, depending upon circumstances. Each option will involve an economic penalty of different size. Lower feed water temperatures will lower the thermodynamic efficiency of the plant. Extending burnup during the present cycle will shorten the next cycle's life time and increase its fuel cost. Refueling before desired burnup is achieved will increase fuel cost of the present cycle. Reducing batch size incurs carrying inventory charges on the unused batch. Swapping arrangements are presently unknown but can be expected to entail some service surcharge. Rationing involves the substitution of additional fossil energy to meet customer demand. Obviously, the short-range situation is a very complex and involved problem. Besides the nuclear economic considerations, system reliability considerations(*) are

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(*) The major system reliability constraints are:
1 system reserve
2 system security
3 voltage stability
4 current stability

also involved to pose additional constraints. The refueling date may be difficult to change because (1) system reserve would be dangerously low at some other time, or (2) refueling personnel may not be available, having been scheduled elsewhere.

And finally, most short-range options would affect later fuel cycles, which may make necessary a redevelopment of the mid-range plan. Generally, mid-range plans are best adhered to, despite short-range deviations as long as their underlying assumptions are still true. This would imply, that in the case of a nuclear reactor being resource limited, rationing might be the most appropriate option to use. Rationing would have the least disturbing effect on later fuel cycles, and the utility would be able to stay on schedule. As the first step at MIT toward the study of the complex short-range problem, this thesis study concentrated on optimizing the production schedule for a fixed amount of nuclear energy, option (6), to be called the Resource-Limited Case.

3.0 Resource-Limited Case

3.1 Introduction

The average production cost of nuclear generated electricity has been found to be significantly lower than that of electricity generated from fossil fuels(10,11), such that electric utilities would desire to operate the nuclear units at capacity at all times. This is not feasible when the amount of available energy from the reactor is insufficient to operate the reactor at full capacity continuously until scheduled refueling. A shortage of energy is possible considering the large number of factors that are related to the original decision on the energy content in the reactor (i.e., long lead times involved in the nuclear fuel cycle, poor forecasting judgement, or forced outages). Examples of changes in the original planning assumptions which could lead to an energy-short situation are:

(1) The fuel is required to be removed from the reactor after burnup reaches 20,000 MWD/T instead of the originally planned 30,000 MWD/T.

(2) The plant availability has matured faster than anticipated.

In such cases, available energy of the reactor must be rationed until the next scheduled refueling (if the refueling can not be advanced).

This batch-energy-limited generation characteristic of nuclear units requires modification of the techniques of dispatching and unit commitment conventionally used ("Equal Incremental Cost Rule") by the electric utility industry to handle the above case. The conventional concept of incremental cost of energy is not applicable to nuclear power plants on the time scale used by the electric utility dispatcher (i.e. one hour), because all the major costs associated the nuclear fuel cycle costs are contracted for in advance and fixed before the time of power generation. In the short-range time frame, nuclear energy has no unambiguously definable incremental cost. In fact, nuclear fuel is capitalized and depreciated in service whereas fossil fuel is expensed. The purpose of this research is to develop methods of specifying the optimum dispatching of nuclear generating units in the short-range when each nuclear unit has a fixed refueling date and a fixed amount of thermal energy potential for production by that date.

3.1.1 Method of Solution

The formulation of this problem as a single Linear Programming(L.P.) problem would involve too many variables to solve in a reasonable amount of time. The deterministic problem of solving the detailed hourly generation schedule for minimum system cost of a utility system composed of 50 units, each of four valve points, and over a one-year time horizon is of an order of magnitude of 1.6 million variables. Hence, to solve the short-range system analysis problem efficiently, the method of solution must take advantage of the special structure of the problem.

The resource-limited case is viewed by the economist as a "Resource Allocation Problem", deciding how to allocate a resource (nuclear energy) among many consumers (individual time intervals). The "economic optimal" solution is found by using the "free enterprise" method, letting the open market place decide which consumer receive a portion of the resource and the amount each receives. The free market determines allocation by the forces of supply and demand. Figure 3.1 shows a typical set of supply and demand curves. The supply curve is monotonically decreasing, as the price increases, the quantity demanded decreases. The intersection of these two curves determines an equilbrium trading price, that balances the supply with the demand for the resource. The equilibrium trading price is a mechanism that determines the allocation of the resource among many potential consumers. Each consumer is allocated just the amount that it is willing to pay for.

In the short-range nuclear allocation problem, where the "actual" market price of nuclear power is ambiguous, the economist uses "shadow prices" (26) in the analysis. In the resource-limited case, the supply is "inelastic"; the quantity of resource is fixed. Figure 3.2 shows the supply and demand curves for the short-range nuclear allocation problem. The gross resource demand curve is the summation of the resource demanded from all the possible individual consumers. The gross nuclear energy demand curve is the summation of the nuclear energy demanded from all the time

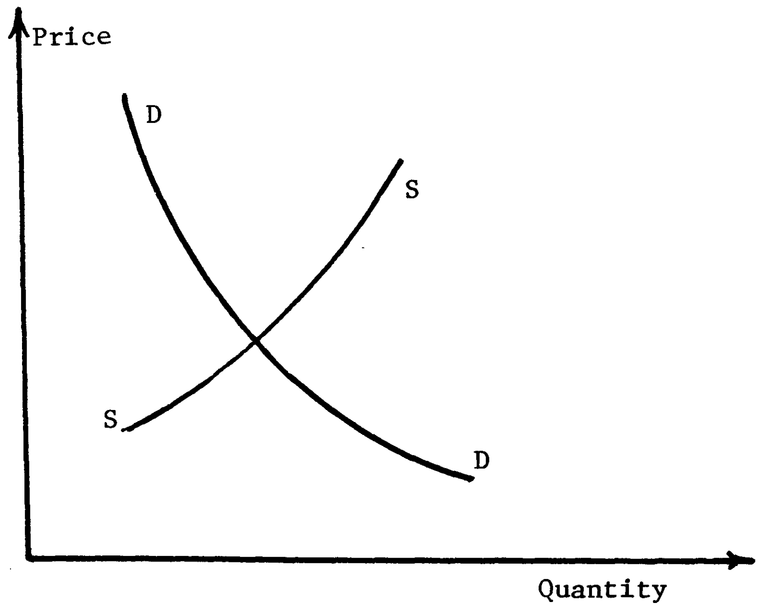


Figure 3.1 TYPICAL SUPPLY AND DEMAND CURVES

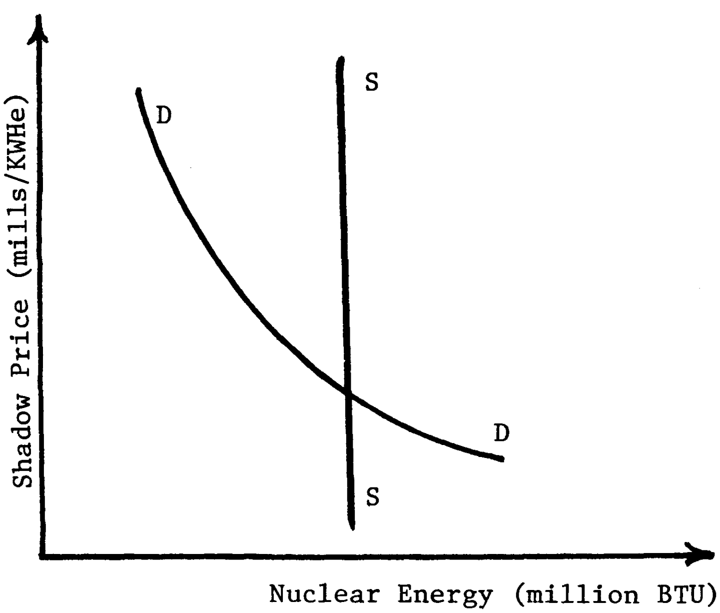


Figure 3.2 SUPPLY AND DEMAND CURVES FOR NUCLEAR ENERGY

intervals in the short-range time horizon, see Figure 3.3. Matching the gross supply curve with the gross demand curve determines an equilibrium price. Where this price intersects the individual demand curve of each time interval determines how much nuclear energy each time interval will receive, as illustrated in Figure 3.4.

A time interval's individual demand curve for nuclear energy is proportional to the "benefit" (to the system) derived from various quantities of nuclear energy. The "benefit" of nuclear energy (to the system) can be measured in terms of savings in operating costs of the other alternative source of energy. This "benefit" is termed the Opportunity Cost of Nuclear Energy (OCNP). The individual demand curve in question is a measure of OCNP for an individual time interval as a function of nuclear energy.

An individual demand curve can be calculated as follows: (1) In a single time interval, calculate the optimal system generation cost for a number of values of nuclear energy, as in Figure 3.5; (2) find an analytic fit of optimal system as a function of nuclear energy; (3) the negative derivative of that function is the OCNP curve in question, see Figure 3.6. OCNP is the incremental savings in system operating cost for an incremental change in nuclear energy.

In summary, the method of solution is as follows: (1) calculate a OCNP curve for each individual time interval in the planning horizon; (2) determine the equilibrium OCNP for

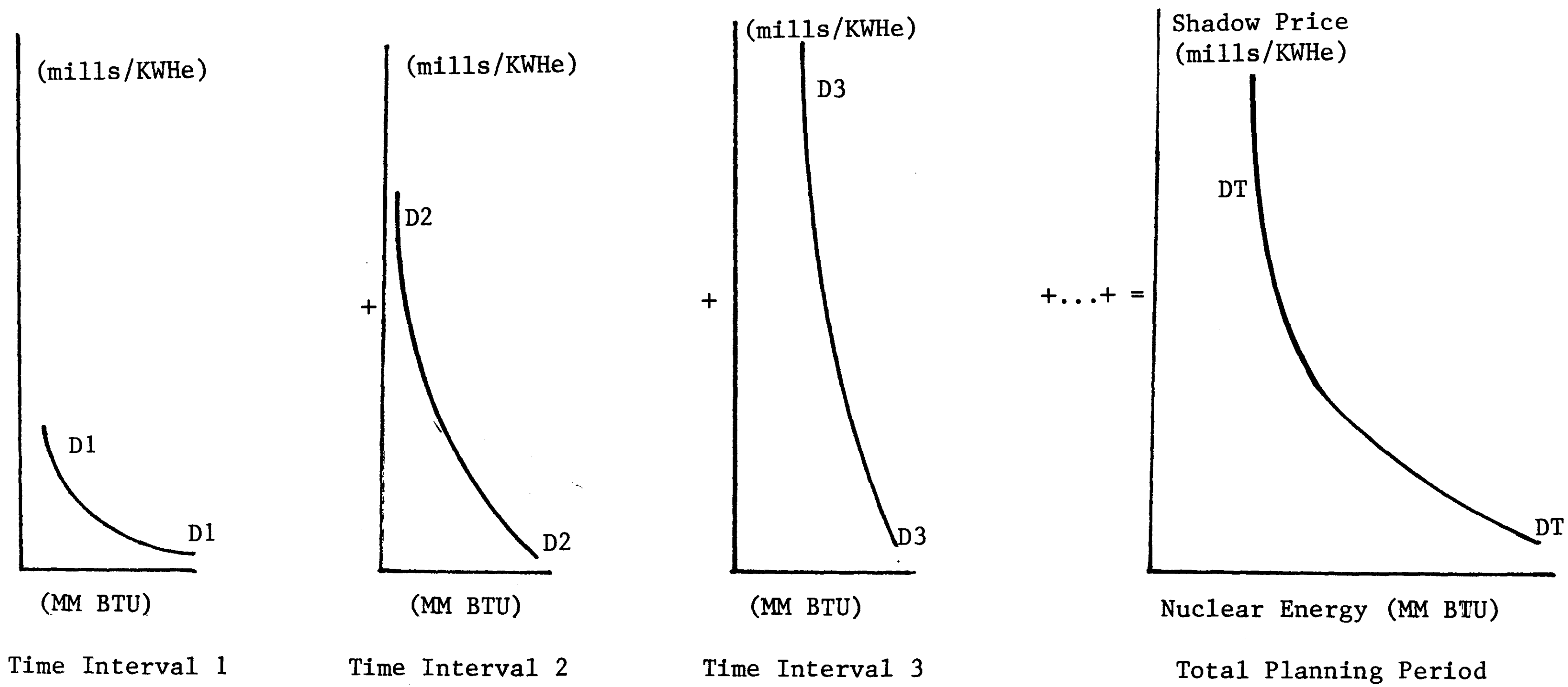


Figure 3.3 <u>FORMATION OF MARKET DEMAND CURVE FOR NUCLEAR ENERGY</u>

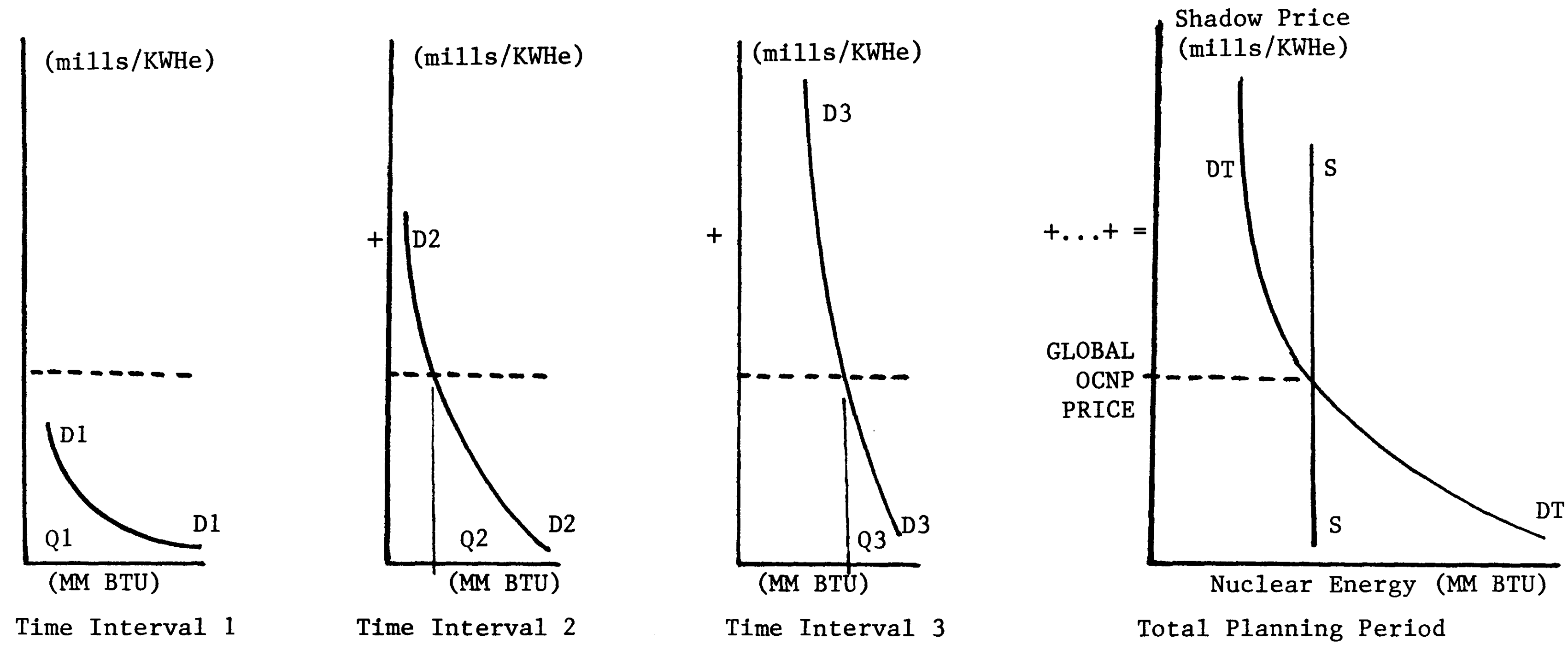


Figure 3.4 ALLOCATION OF ENERGY BY EQUILIBRIUM PRICE METHOD

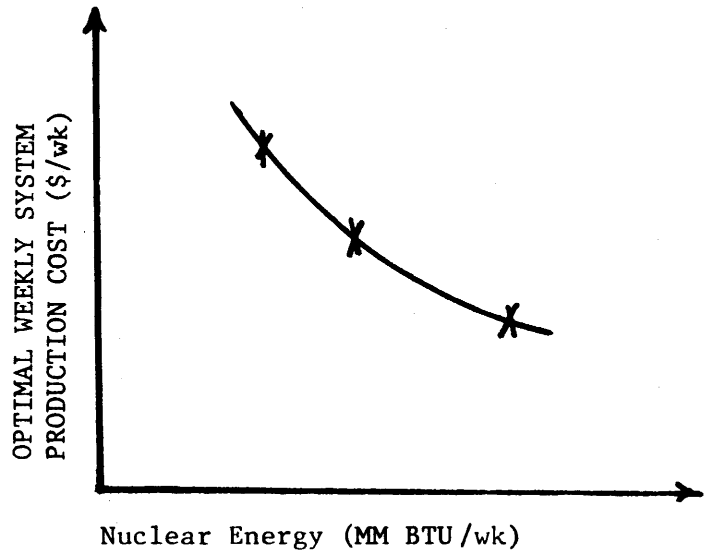
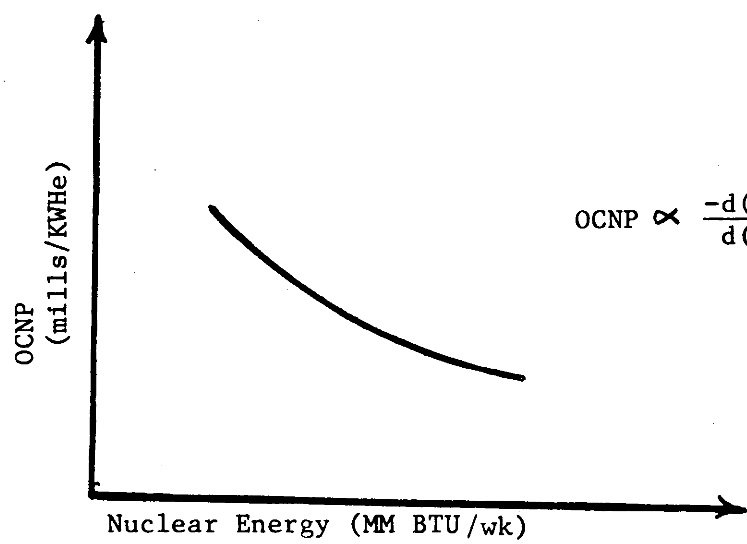


Figure 3.5 DETERMINATION OF SYSTEM COST FUNCTION



$$\text{OCNP} \propto \frac{-d(\text{System Cost})}{d(\text{Nuclear Energy})}$$

Figure 3.6 DETERMINATION OF OCNP

the planning horizon by matching the gross demand curve for nuclear energy with the supply; (3) the individual allotments of nuclear energy are those quantities read off the individual OCNP curves at the equilibrium OCNP price.

3.1.2 Implementation

The solution of the one-year time horizon problem has been shown to be a combination of the solutions of many weekly problems. Though the exact combination is not known beforehand, it is distinguish by the fact that each week in the time horizon has the same OCNP. It can be easily shown that this is a stable optimal condition.

The weekly OCNP is calculated from the viewpoint that OCNP is the cost of the displaced energy when optimally distributed nuclear energy is marginally increased. In economics, the price of the next best substitutional commodity is also called the opportunity price.

Figure 3.7 shows a simple graphical illustration of determining OCNP. Suppose a hypothetical system of two components, one nuclear unit and one fossil, and a two-hour customer demand function, 1900 MW for the first hour and 900 MW for the second hour, as shown in Figure 3.7a. The fossil unit has 1300 MWe generating capacity and the nuclear unit has 600 MWe generating capacity but only 900 MWHe of energy. The fossil unit has a typically monotonically increasing incremental generation cost curve, a portion of which is shown in Figure 3.7b. What is the OCNP for this set of system parameters? The OCNP is that cost of the alternative

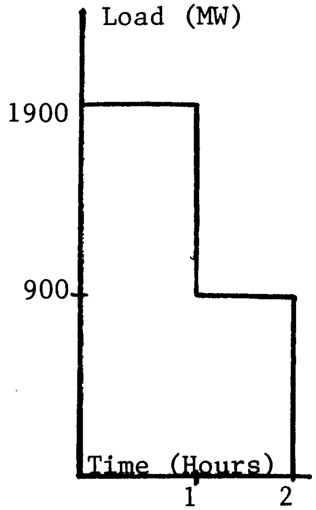


Figure 3.7A
CUSTOMER DEMAND FUNCTION

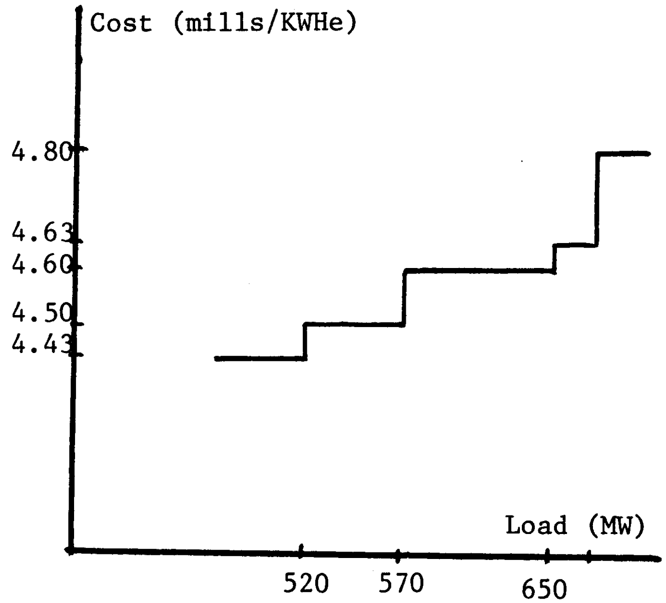


Figure 3.7B
A PORTION OF THE FOSSIL INCREMENTAL COST CURVE

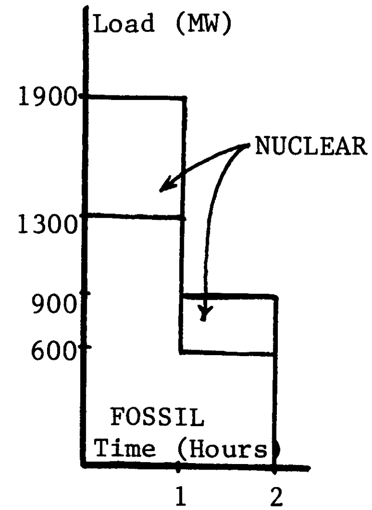


Figure 3.7C
OPTIMAL DISTRIBUTION OF NUCLEAR ENERGY

Figure 3.7 EXAMPLE OF DETERMINATION OF OCNP energy displaced by a marginal increase in the optimally assigned nuclear energy. If the nuclear unit had 1 MWHe more energy, what would be the cost of the 1 MWHe of displaced fossil energy? The optimal distribution of nuclear energy is displayed in Figure 3.7c; 600 MWH in the first hour and 300 MWH in the second (*). Since the nuclear unit is already operating at its full capacity (600 MW) in the first hour, the marginal unit of nuclear energy would be assigned to the second hour. Hence, the fossil generation scheduled for the second hour would decrease marginally from 600 MWH to 599 MWH. What is the generation cost of that one unit of fossil energy? The fossil incremental heat rate curve, Figure 3.1b indicates 4.6 mills/KWH. Hence, the OCNP of the system is 4.6 mills/KWH. The important condition prior to measuring the displaced energy cost is first to optimally assign all the nuclear energy.

The OCNP is that cost of alternative energy above which the nuclear reactor would seek to displace all other energy sources (limited by its own generating capacity) in expending all its fixed amount of energy. In this way, the nuclear energy has been distributed to minimize system generation cost, by replacing the most expensive energy alternatives. The OCNP calculated is associated with the

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(*) In this simple example, the optimal distribution of nuclear energy is the condition where the fossil unit's production in the two time intervals is as equal to each other as possible, within the capacity limitations of the units.

particular amount of weekly nuclear energy distributed, the customer demand function and the system configuration used. But weekly OCNP functions are required to describe system cost sensitivity over a range of nuclear energy values. The weekly OCNP function is found by calculating explicitly OCNP values for a number of values of nuclear energy.

The condition for optimal inter-weekly dispatching of nuclear energy is that the weekly OCNP functions for all weeks be equal, subject to the constraint that the total amount of nuclear energy used equal the amount available(*).

The OCNP optimization results in the assignment of a specific portion of total nuclear energy to be used each week so to minimize system cost over the short-range time horizon. The dispatcher would be free to utilize that and only that amount of nuclear energy budgeted to meet the weekly system demand. The dispatcher should be cautioned that any sales of nuclear energy across the connected interchange be sold at the optimized OCNP price for the planning period because the OCNP represents the short-range system substitutional cost for the nuclear energy.

The implementation of the above optimization scheme defines the time interval used for comparison of system costs and defining customer demand as one week. The

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(*) This optimization problem is analogous to the classical dispatching problem of minimizing system cost of a system of all fossil units. That solution is when all units operate at equal incremental production cost, while constrained to satisfy the total system demand.

production cost program, PROCOST, solves for the minimal system cost($/wk) for specific values of:

(1) the system configuration and its operating parameters, such as fuel costs and heat rates;

(2) customer demand; and

(3) a set of nuclear energies for the nuclear reactors.

The minimal cost solution is obtained from the optimal weekly nuclear assignment, which in turn, leads to a determination of OCNP. The minimum production cost is obtained by running the must-run (base load) units first, and then the hydro(*) and peaking units(**) are dispatched. Next, the optimal distribution of nuclear energy for the week is determined by the LP. model. As the last step, the pumped storage and fossil units interactions are calculated analytically.

The PROCOST program is run repeatedly (in the load-duration mode) for a variety of system parameters to generate the large number of data points necessary to define OCNP behavior as a function of weekly nuclear capacity factors(***) for each week in the planning horizon. For

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(*) The hydro generation schedule is calculated externally of PROCOST. PROCOST reads in the hydro schedule and subtracts it from the demand function to be fulfilled.

(**) Because of the deterministic nature of this study, usage of peaking units must be assigned, details in Section 4.2.1. Input parameters for peakers includes simulated capacity factors, fuel costs and start-up and shut-down costs.

(***) For convenience, the normalized parameter, weekly nuclear capacity factor is used in place of nuclear energy.

example, the weekly OCNP function may be sufficiently characterized by calculating OCNP values at five values of the weekly nuclear capacity factor (i.e., 0.55, 0.65, 0.75, 0.85, 0.95). Thus, for a 26 week planning horizon, 130 OCNP values need be calculated (for a single reactor optimization study). The weekly OCNP values are input to a sorting program, ALLOCAT, which determines for an overall planning period nuclear capacity factor, the optimal weekly nuclear capacity factor distribution. These optimal capacity factors are re-entered in PROCOST (in chronologic load model mode) to determine the optimal detailed hourly generation schedule for all the units being simulated in the entire short-range time horizon.

3.2 Assumptions and Idealizations

3.2.1 Deterministic Production Cost Model

The economic dispatch optimization model is a simple power flow problem where the basic time interval is one hour. Electrical circuit stability constraints and transmission loss are not considered. More detailed models concerned with load frequency control and transformer taps are described in Ref. (12,13). PROCOST, the production cost optimization model, calculates only the power distribution from several generators.

A deterministic approach was used to treat both load forecasts and forced outages in the system production cost model, PROCOST. The forecasted customer demand is assumed known with certainty as well as the time horizon (fixed fueling date). To include the effect of the probabilistic distribution of the customer demand would require the use of Stochastic Programming (27) and be quite involved. Alternatively using Risk Decision Analysis, Ref. (33), would involve less computations than Stochastic Programming but still more than the deterministic approach. Rees and Larson (23) developed a short-range optimal scheduling program using dynamic programming, but without the capability of simulating nuclear plants. The deterministic method seems to be the quickest and simplest method available.

The deterministic approach also assumes that the system configuration of available power plants is known and fixed throughout each of the week(s) simulated. This implies 100%

availability. An alternative to the deterministic approach would be to use the Booth-Balerieux probabilistic utility model (17,18,19). The probabilistic utility model incorporates individual forced outage rates in the system calculation of economically satisfying the system load. This latter model would provide a more realistic set of plant capacity factors and system production costs. The deterministic approach favors the base load units and ignores the peaking units, because of the assumed perfect availability of the thermal units. Therefore, to compensate for this bias, peaking units and hydro units are simulated explicitly to peak shave the demand curve and to meet estimated (input) capacity factors for these units. The fossil units are optimized by determining the purely economic loading order and always loading the lowest cost increments first. The nuclear and pumped-storage generation schedules are optimized to peak-shave the resulting demand function.

The peak-shaving operations of the nuclear and pumped-storage are done in series (separately) to reduce the calculational costs involved in a single larger model. The fossil fuel costs of both the two-step and single step methods are identical. The explanation is that the amount of pumped-storage energy is the same in both cases. Since the amount of nuclear is fixed, the resulting fossil generating schedule is the same. Hence, the fossil fuel costs should be the same.

In short, the deterministic approach was chosen because it was the simplest case that could be studied while retaining most of the factors significant in the short-range optimization problem.

3.2.2 Load Models

A chronological load model was used to approximate the 168 hour per week customer demand function. The chronologic nature is required to include the effects of fossil plant start-up and shut-down, and also to simulate peaking units and their start-up and shut-down costs. And the modelling of pumped-storage and hydro units (with pondage) required the chronologic model so that it was possible to check that the reservoir level remained within permitted limits. Eventually, the large size of the L.P. optimization model precluded the modelling of the fossil start-up and shut-down costs, which would have required Integer Programming (a very expensive option). The consequence of this omission was believed small, since the system configurations used in the system simulations (modelling the AEP system) had little overnight shutdown.

A chronologic load model sensitivity study concluded that a 40-interval load model was sufficiently accurate in reproducing the fossil incremental capacity factors of a 168-interval model so that the former may be used in optimization studies in place of the latter to save computation costs; the details of this study is discussed in Appendix A along with the computer programs associated with the load models.

In reproducing OCNP, load-duration load models of six intervals were fairly accurate in comparison with the more detailed models. The sensitivity study with load-duration load models are discussed in Section 5.2 and Appendix A.6 The exact number of intervals to use in few-interval models is dependent on the utility's customer demand function, its system configuration, and the accuracy desired in reproducing the results of detailed load models. The principle proven by the sensitivity studies is that a large reduction in the number of intervals will substantially reduce computation costs, without impairing accuracy.

The maximum reduction possible in the number of time intervals will depend on the feature of the model to be reproduced with accuracy. Each feature will have a different sensitivity to the number of time intervals in the load model. As discussed above, a greater reduction in intervals is possible when the feature of model of interest is OCNP rather than the fossil incremental capacity factors.

As a matter of convenience, holidays were omitted in developing the load models for the simulation studies. A low forecasted energy consumption for a week (due to a holiday) would result in a poor prediction of the week's demand function because the effect of the decreased energy consumption is spread over the entire week. The immediate effect would be a poor prediction of the weekly peaks. It has been assumed that utilities would have their own load models that would correct for this deficiency. Since writing sophisticated load models was beyond the range of this thesis, simple load models were used in the simulations, just to generate customer demand numbers. The nuclear reactor optimization procedures presented in this thesis are independent of the load models used. A summary of current industrial methods in forecasting demand is given in Ref. (20).

3.2.3 Nuclear

There are a number of nuclear assumptions in the derivation of the production cost code, PROCOST. This code places no constraints on the rate of change of the nuclear power production from one time interval to the next. Physically, the reactor is adaptable to large and quick load changes, but the fuel presently used in reactors may be constrained in its ability to meet large or rapid changes (21).

Large changes in power are also difficult late in the core life due to the Xenon-135 (Xe) problem. After a prolonged operation at full power, a large power decrease or shut down will result in a substantial build up of Xe. Late in core life, there is not enough excess reactivity to override the Xe. Thus, if allowed to build up before resuming full power operation, a power reactor must wait until the Xe decays away (40-60 hours). Schultz (14) has a very good discussion on this Xe control problem. The Xe problem rules out rapid changes in the electrical production of a reactor during its coast-down phase since its excess reactivity is then practically nil. Weekend shutdown would still be possible, however.

Furthermore the codes, as written, allow for no constraint on the minimum power level of the nuclear reactors during load-following maneuvers.

The L.P. thermal energy model is based upon the assumption that the total amount of thermal energy obtainable from a given reactor before refueling is constant, when limited to full-power reactivity-limited burnup.

3.2.4 Financial

The financial assumptions are very crucial in understanding how the system production cost is derived and applied in the optimization process. The basic financial assumption (under the short-range resource-limited condition) is that the production schedule (power history) of a power reactor has no effect on the cost of the nuclear fuel cycle. Head-end services can not be affected since they have been completed before energy is generated. Since the same end state, the full-power reactivity-limited burnup state, is reached in all cases, the tail-end services also will be unchanged. Thus the total cash outlay of the nuclear fuel cycle is undisturbed by the generation schedule.

However, more subtle effects result from the time value of money. The timing of (nuclear fuel) depreciation credits (or lease payments), and the timing of fossil fuel cost expenses do have a real financial impact on a utility earnings report, especially in times of high interest rates; see Appendix E. This effect favors use of nuclear fuel as early as possible, and defers buying fossil fuel as late as possible. In the mid-range time scale, the time value of money plays an important role in the decision process, but in the short-range time scale of interest in this thesis, the system reliability considerations outweigh the small economic benefit of distorting the system reserve capabilities. Thus, interest rates have been left out of the system cost calculations for this thesis. Even if the fuel is rented on a heat-delivered basis, the total charge is assumed paid in one lump sum so that the time element can be ignored. Hence, the basic assumption is that there is no variable cost component in the nuclear fuel cycle. The system production cost will be exclusively the fossil fuel cost (plus start-up and shut-down costs of simulated peaking units), expensed as consumed. Operation and maintenance costs are disregarded, as these are assumed to be independent of the mode of operation of the system.

4.0 OPTIMIZATION MODELS

4.1 Introduction

The optimization procedure presented here is a series of separate programs that perform separate tasks. This method insures maximum flexibility and minimum duplication of calculational efforts when performing sensitivity studies, such as changing (i) the number of weeks optimized, (ii) a week's system configuration, (iii) the planning horizon resource, or (iv) a week's demand level. The study of a system's nuclear resource is not finished with the completion of a single optimization run, but is a continuing process. The result of one run provides management insight which suggests study of new parameters for another closer examination of where the greatest sensitivities lie.

The optimization programs are as follows:

(1) PROCOST, the major program which calculates the minimal weekly system cost and the OCNP for a given set of parameters;

(2) ALLOCAT, a program which finds the optimal distribution between weeks for nuclear energy from sets of OCNP values.

(3) FOSSIL, a program that calculates the weekly system cost and OCNP for a nuclear-fossil system where the power level of the nuclear unit is held constant throughout the week.

PROCOST takes a series of assumed nuclear energy allotments for a particular week and assigns its generation to various times in the week to determine the minimal system cost for each allotment of nuclear power and from this OCNP. ALLOCAT takes a set of weekly OCNP values over a longer period of time and determines how much nuclear energy to allocate to each week by using the criterion that the OCNP for all weeks shall be the same.

PROCOST is the system production cost program that calculates the optimal generation schedule from the following input data (i) fossil plant parameters, (ii) peaking unit parameters, (iii) hydro generation schedule, (iv) nuclear unit parameters, (v) pumped-storage parameters, and (vi) customer demand function. The user has a choice of specifying whether the nuclear optimization L.P. model use a load-duration model or a true chronologic or modified chronologic load model, the choice depending on the application of the result. The pumped-storage generation schedule can be either optimized for economic operation (least operating cost) or for security operation (maximum pumped-storage reserve capacity).

ALLOCAT is a sorting program that receives as input the collection of weekly OCNP functions, with an overall nuclear capacity factor. ALLOCAT finds the optimal distribution of weekly nuclear capacity factors by using the equal opportunity cost rule.

PROCOST is usually run many times in load-duration mode to generate OCNP numbers. When the optimal inter-weekly nuclear capacity factor distribution has been solved by

ALLOCAT, the values are fed back to PROCOST (in chronologic mode) to generate the detailed hourly generation schedule of all the units. The algorithm of PROCOST is discussed in Section 4.2 and of ALLOCAT in Section 4.3.

FOSSIL is used to calculate system cost for the reference situation when there is no nuclear optimization (constant power level through the week). This simpler program can be used in place of PROCOST in generating OCNP values for the case of constant weekly nuclear power level. FOSSIL also is used to calculate OCNP values for an alternate and more direct, but approximate, optimization procedure discussed in detail in Section 4.4.

4.2 PROCOST Algorithm

The PROCOST algorithm presented here consists principally of two parts, the optimal generation schedule of nuclear units and the optimal generation schedule of pumped-storage unit. The original reason for dividing the computation was to reduce the computational costs of a single large L.P. model that included both the nuclear and pumped-storage units. Later, a number of other constraints(*) on the pumped-storage unit precluded its inclusion in an L.P. model. Figure 4.1 shows the general flow chart of the PROCOST algorithm. The nuclear

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(*) These constraints included keeping the reservoir level within bounds, the formulation of a security mode schedule, and difficulty in modelling a pumped-storage unit adequately in a load-duration environment.

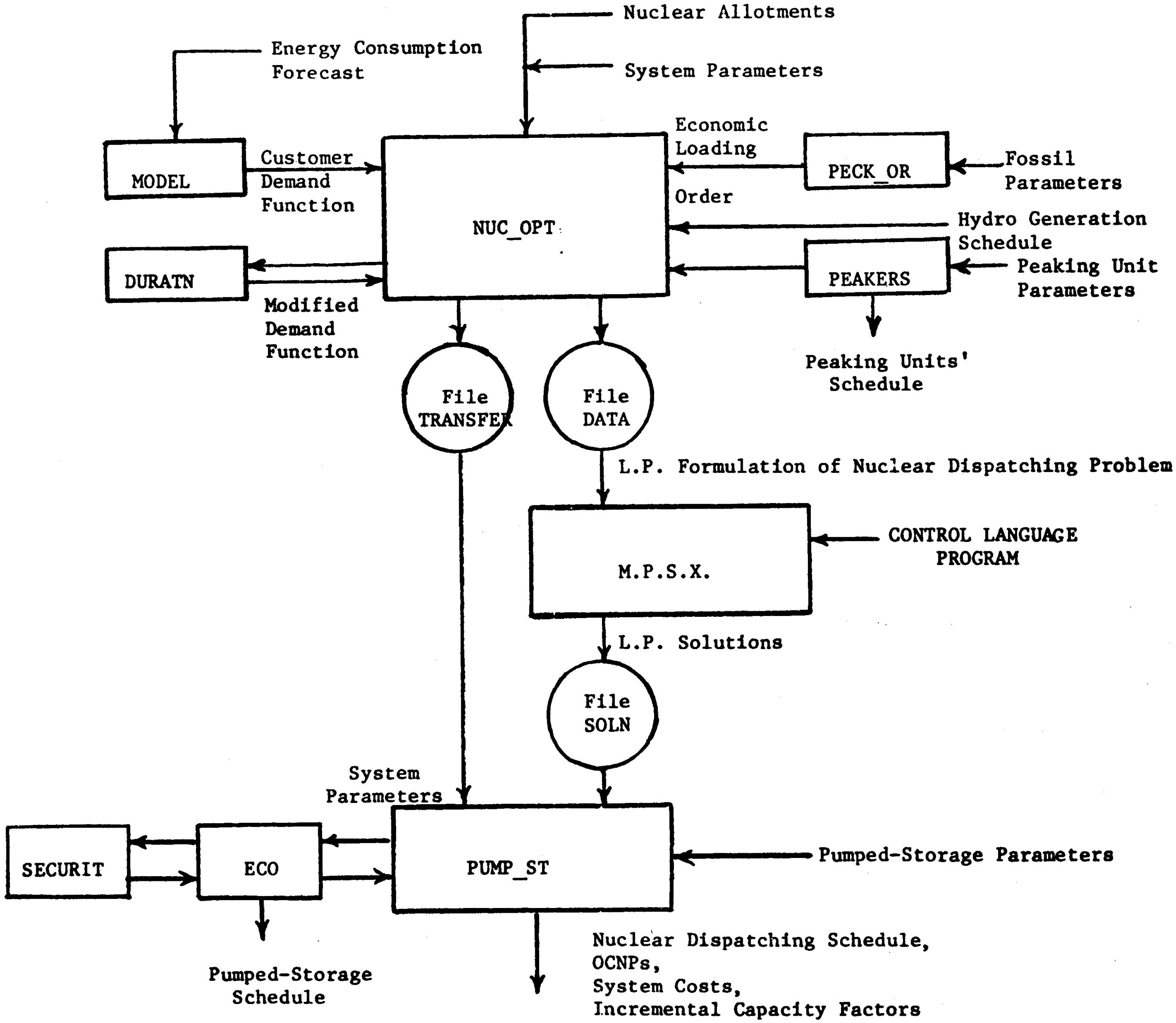

Figure 4.1 PROCOST ALGORITHM

optimization is composed of two parts, and MPSX. The L.P. formulation program, NUC_OPT, writes the L.P. formulation of the nuclear optimization problem. MPSX, an IBM program product, reads the formulation and performs a variety of L.P. optimization and parametric studies. The L.P. solution is read by the pumped-storage scheduling program, called PUMP_ST, which performs either economic or security mode scheduling.

Before NUC_OPT formulates the nuclear optimization, it also performs a simulation of the hydro and peaking units. These subprograms are described in detail in the following sections.

4.2.1 Nuclear L.P. Formulation

The nuclear scheduling problem is solved by linear programming(L.P.). To include the important feature of variable nuclear heat rates, a special version of L.P. called "separable programming" is used. IBM provides a program product called MPSX (Mathematical Programming Systems Extended) that solves separable programming problems. Thus a preprocessor is required to reformulate the utility system input parameters into the input format required for MPSX, the L.P. formulation of the nuclear scheduling problem. The input to the preprocessor, NUC_OPT, consist of a customer demand function (output from a load model program, MODEL), nuclear, fossil, and peaking units plant data and the hydro generation schedule. The hydro generation schedule may vary a great deal depending on seasonal, geographic, and climatic factors. Thus, the operation of such hydro units are calculated externally and input to the preprocessor. The preprocessor deducts the hydro schedule from the input customer demand function, resulting in a new modified customer demand function which the rest of the system units must satisfy.

The deterministic approach to a demand problem would normally under-utilize higher cost fossil and peaking units (due to the exclusion of forced outages). To partially compensate for this effect, the operation of the system peakers are simulated and forced outages of all fossil units are programmed (scheduled) into the monthly system configurations. Each peaking unit is scheduled to peak-shave the customer demand until its input capacity factor is achieved. Peaking units are called successively, the largest units first, to maximize their effect in flattening the demand function. The rationale for this method of scheduling peaking units is that peakers are observed to be utilized only during peak periods when system reserve is at its lowest point and operated at their full rated capacity. Thus peakers are modelled as single step functions, either on, or off. When needed, peaking units are turned on regardless of cost.

After the peaking unit generation schedule has been determined, the number of start-up and shut-downs for each unit is counted and total operating costs for the peakers calculated. The peaking units' schedule is then deducted from the customer demand function, resulting in a lower modified demand function which the rest of the system units must satisfy. The peaking unit simulator, PEAKERS, operates on each different weekly customer demand function. The required parameters of a peaking unit are: rated capacity(MW), estimated capacity factor, average heat rate, fuel cost, and cost of each start-up and shut-down.

The fossil plant parameters are sorted by subroutine PECK_OR that determines the economic incremental fossil loading order and also the fossil must-run level of operation. The latter is then deducted from the customer demand function, resulting in a lower modified demand function which the rest of the system facilities must satisfy. This modified demand function is the one passed to the nuclear scheduling program, MPSX. The L.P. formulation of the nuclear scheduling problem is presented as follows:

Objective function: minimize

$$\sum_j \sum_i (c_i)({}_F H_i)({}_F X_i^j)(T_j) \tag{4.1}$$

subject to the following constraints:

(customer demand constraint)

$$\left\{ \sum_i {}_F X_i^j + \sum_n^N \sum_i^{I_n} {}_n X_i^j = D^j \right\} \tag{4.2}$$

$j=1,\dots,J$

(limited thermal nuclear resource constraint)

$$\left\{ \sum_j \sum_i ({}_n X_i^j)({}_n H_i)(T_j) = K_n \right\} \tag{4.3}$$

$n=1,\dots,N$

(bounds, separable programming constraint)

$$\left\{ \begin{array}{lll} \text{if and only if} & {}_{F,n}X_{i-1}^j = {}_{F,n}B_{i-1} \\ \text{then} & 0 \le {}_{F,n}X_i^j \le {}_{F,n}B_i \\ \text{else} & {}_{F,n}X_i^j = 0 \end{array} \right\} \tag{4.4}$$

$n=1,\dots,N$

$j=1,\dots,J$

$i=2,\dots,I_n$

where:

${}_F X_i^j$ = fossil power level of the i-th increment and the j-th time period (MW)

$_nX_i^j$ = power level of the i-th increment and the j-th time period of the n-th nuclear reactor (MW)

$_{F,n}X_i^j$ = either $_FX_i^j$ or $_nX_i^j$

$_FH_i$ = incremental fossil heat rate of the i-th increment of the loading order (million BTU/MWHt)

$_nH_i$ = incremental nuclear heat rate of the i-th nuclear increment of the n-th nuclear reactor (million BTU/MWHt)

C_i = fossil fuel cost ($/million BTU) of the i-th increment

D^j = modified customer demand of the j-th period(MW)

K_n = full-power reactivity-limited thermal energy available in the n-th reactor (million BTU)

$_{F,n}B_i$ = upper bound of the i-th increment (MW)

J = total number of time periods

N = total number of nuclear reactors

I_n = total number of increments in a nuclear reactor

T_j = duration of j-th time interval (Hours)

The objective function, Eq. (4.1), to be minimized is a summation of the incremental production cost over all the increments in the fossil loading order (index i) and over the one-week time horizon (index j). The incremental production cost is a product of the fuel cost ($/million BTU), the incremental heat rate (million BTU/MWH) and the energy production (MWH) of that time period. The constraints to be met are: (1) the summation of the power levels of the individual nuclear and fossil units in each time period must satisfy the modified customer demand, Eq. (4.2), while (2) limiting the total nuclear production to the available resources, Eq. (4.3). In addition, each variable is bounded, Eq. (4.4). This is where the separable programming aspect is featured. All increments are fixed at the lower bound of zero until all the preceding increments have been set to their upper bound. For example, the third increment of the loading order can not be started until the second (and the first) increments are fully loaded. Without this feature, variable heat rates could not be modelled.

To examine this problem more closely, notice that many of the fossil increments will always be loaded independently of the amount of nuclear energy to be distributed. For example, assume a fossil imcremental loading order of 100 increments of 100 MWe each. The nuclear unit has a capacity rating of 1000 MWe. In a single time interval, suppose that the customer demand function specifies 8050 MWe to be met by the system. Then, irrespective of the optimal amount of nuclear energy assigned to this time interval a priori the first seventy fossil increments must always be fully loaded. Unfortunately, MPSX does not known this a priori. Starting from scratch, MPSX will laborously load each of the fossil increments one by one. A significant amount of computer time and storage cost is saved by having MPSX solve the following equivalent problem instead. For the time interval in question, the fossil incremental loading order is of only thirty increments of 100 MWe each. The nuclear unit is still of 1000 MWe, but the demand to be met is only 50 MWe. 7000 MWe has been subtracted from both the load demand and the fossil generating capacity. Hence (in this example), the number of variables has been reduced by two-thirds, and the solution computation time cut by an order of magnitude, just by formulating the same problem from another viewpoint. This improvement of calculating minimum fossil operating levels and subtracting them from the system problem before nuclear optimization has significantly reduced MPSX computer CPU time by almost an order of magnitude. Specific programming details of NUC_OPT are given in Appendix C.

The preprocessor, NUC_OPT, formats (writes) this information (L.P. formulation) to meet MPSX input specifications on a transfer medium (such as a scratch disk) as its final product. Execution is transferred to MPSX to solve the nuclear scheduling problem (by the revised simplex method) and write the solution on a scratch disk. Execution is then turned over to the pumped-storage program. The programming aspects of MPSX are discussed in Appendix C.3.

4.2.2 Pumped-Storage Scheduling Program

The pumped-storage scheduling program, PUMP_ST, has three modes of operation: (1) security mode to maximize pumped reserve capacity; (2) economic mode to minimize operating costs, (3) pumped-storage by-passed completely(*).

(*) If a pumped-storage unit does not exist, or is an insignificant portion of the system, or is not important in the OCNP calculational phase, then the pumped-storage scheduling routine can be skipped altogether. PUMP_ST would then be used just to interpret (and print) the nuclear L.P. solution. See Appendix C for details on this option.

The latter choice will be ignored for the remainder of this section. The pumped-storage program first reads and interprets the nuclear L.P. solution. Then control is passed to the economic subroutine, ECO, to determine the economic pumped-storage generation schedule. If the desired mode of pumping is 'security', then the security subroutine, SECURIT is called to calculated the pumping schedule that would keep the reservoir filled as much as possible. Otherwise, the economic pumping schedule is calculated. The reservoir is then checked for water overflowing or running dry. Any necessary corrections are then made and control is returned to the main program, PUMP_ST. PUMP_ST then calculates and prints the capacity factors of both the various fossil increments in the economic loading order, and of all the fossil units themselves. It also calculates total system production cost, and the OCNP. Detailed programming specifics are given in Appendix C.

This section is further divided in four subsections:

(1) Economic Pumped-Storage Theory

(2) Economic Pumped-Storage Scheduling Algorithm

(3) Pumped-Storage Security Theory

(4) Pumped-Storage Security Scheduling Algorithm

4.2.2.1 Economic Pumped-Storage Theory

The economic pumped-storage scheduling problem is an amply documented case (22). Originally, an L.P. formulation for the pumped-storage problem was devised. But since the solution is well known, this section of the program was rewritten to solve for the solution analytically. With a pumped-storage facility, a utility would pump into the storage facility at times of low customer demand and low incremental cost of power. Stored energy would be discharged at times of peak customer demand and high incremental cost of power. Thus the utility would have lowered production costs by the difference between the cost of pumping the water, and the displaced cost of generation at peak demand. If the pumped-storage facility were 100% efficient and the pump, generator and reservoir were of limitless size, the solution of the scheduling problem would be described (see Figure 4.3) by that power level, K, where: (1) if the customer demand was above K, the pumped-storage facility would generate that amount equal to difference between K and the customer demand, (2) if the customer demand was below K, the pumped-storage facility would pump that amount equal to the difference between K and the customer demand, and (3) the amount pumped and the amount generated were equal over a cycle of the demand function. This is illustrated graphically as follows: Figure 4.2 is a simple load-duration curve representing the customer demand curve for a one-week time period. Power level K is that level where area A1 equals area A2 (Figures 4.3 and 4.4) so that the fossil power production is such

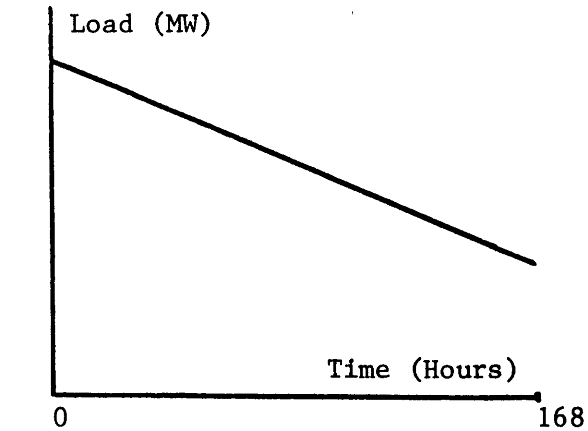

Figure 4.2
<u>ILLUSTRATIVE WEEKLY LOAD-DURATION CURVE</u>

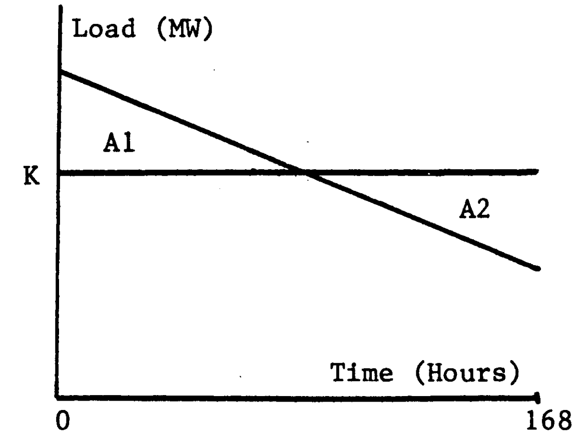

Figure 4.3
<u>OPERATION OF AN IDEALIZED PUMPED-STORAGE FACILITY</u>

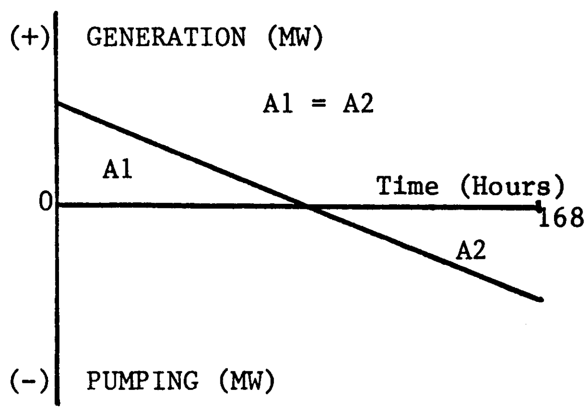

Figure 4.4
<u>PUMPED-STORAGE DURATION CURVE OF FIGURE 4.3</u>

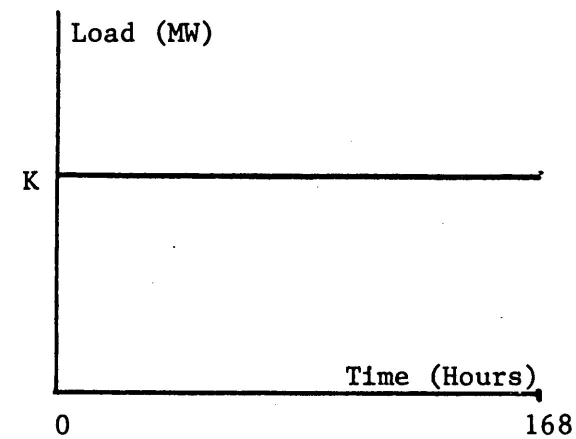

Figure 4.5
<u>FOSSIL DURATION CURVE OF FIGURE 4.3</u>

that the fossil power production is levelized (Figure 4.5) and thus, fossil fuel cost is minimized (*).

The fact is that the cycle efficiency is not 100%. Then the solution is graphically illustrated in Figure 4.6. Returning to the load duration curve, the pumped-storage facility generates power whenever the customer demand is above the power level K1 and pumps whenever the customer demand is below K2 , such that: (1) the incremental cost at K1 equals the incremental cost at K2 divided by the cycle efficiency, and (2) the energy generated A1 equals the energy stored, A2 times the cycle efficiency. The first condition is the economic minimal cost criterion and the second condition is the energy conservation principle.

The physical limitations of the generator and the pump also make the solution even more complex, as shown in Figure 4.9. G and P represent the capacity ratings of the generator and the pump, respectively, see Figure 4.10. When the customer demand is above the power level K3, the pumped-storage generator is turned on until its capacity is reached or fossil generation is reduced to K3. When the customer demand is below power level K4, then the pump of the pumped-storage facility is turned on until its capacity is reached or fossil generation has increased to K4. The economic cost criterion dictates that the incremental cost

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(*) A major assumption used here is that the fossil loading order is strictly economical, the lowest cost increments loaded first, and without regard to start-up and shut-down cost.

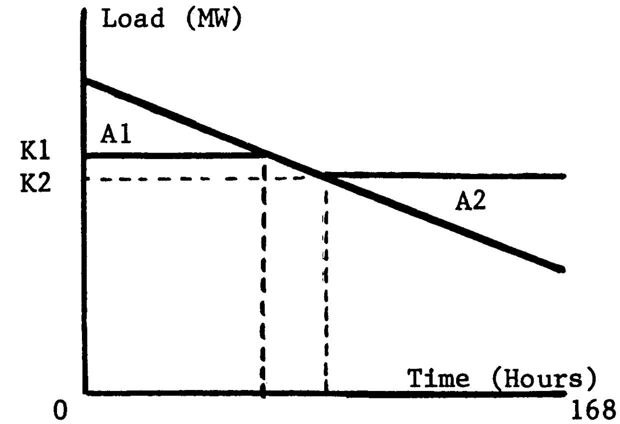

Figure 4.6
OPERATION OF AN INFINITELY LARGE PUMPED-STORAGE FACILITY

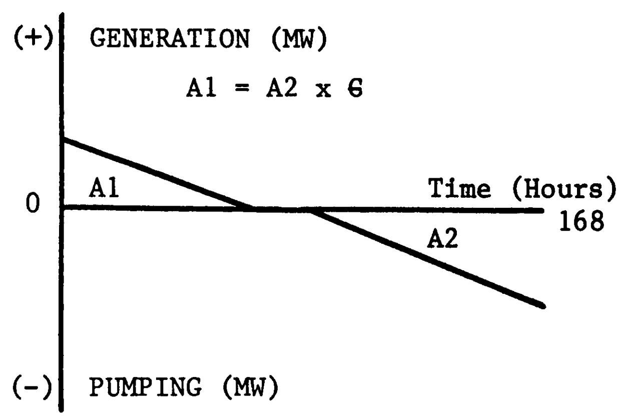

Figure 4.7
PUMPED-STORAGE DURATION CURVE OF FIGURE 4.6

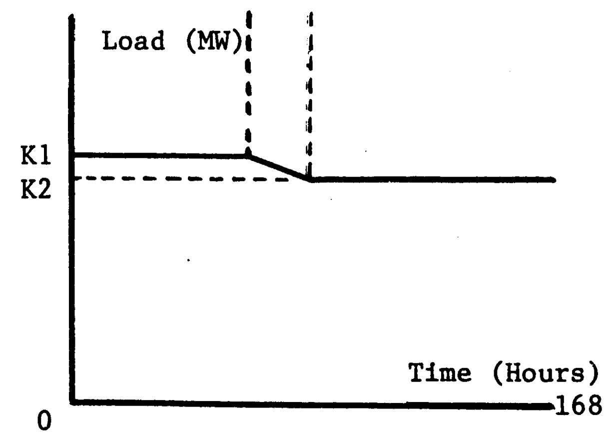

Figure 4.8
FOSSIL DURATION CURVE OF FIGURE 4.6

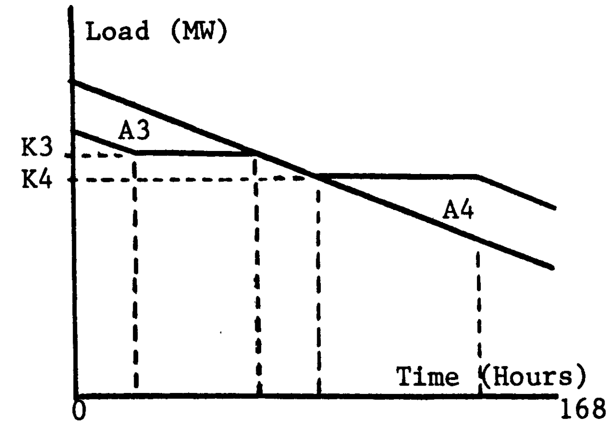

Figure 4.9
OPERATION OF A FINITE
PUMPED-STORAGE FACILITY

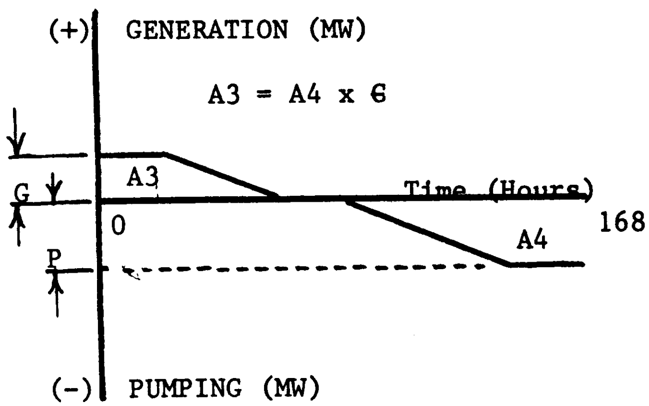

Figure 4.10
PUMPED-STORAGE DURATION
CURVE OF FIGURE 4.9

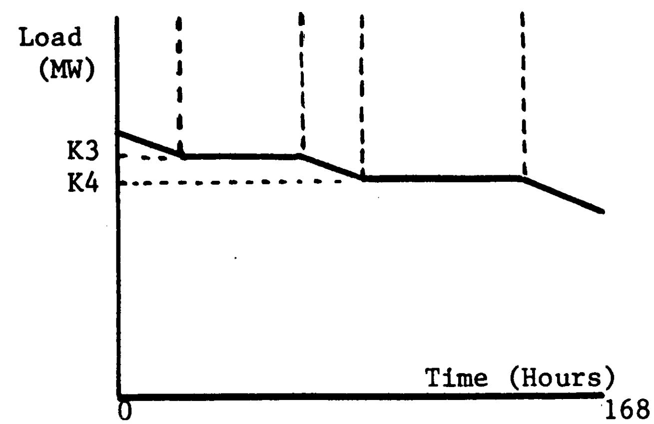

Figure 4.11
FOSSIL DURATION CURVE
OF FIGURE 4.9

at K3 equals the incremental cost at K4 divided by the cycle efficiency. The energy conservation principle dictates that the generation energy, area A3 equal the pumping energy, area A4 times the cycle efficiency (ϵ).

The physical limitation of the reservoir size requires that the chronologic water level behavior be checked for overflowing and running dry. The chronologic water level behavior will be a function of generator and pump capacity and the customer demand function. Hence, for a properly designed pumped-storage facility where a utility knows its customer demand, it looks for a site for the pumped-storage facility of compatible reservoir size which in turn dictates generator and pumping capacity in the proper proportions. So in theory, for normal operations, reservoir size should not be expected to be an active constraint. Hence, the pumped-storage scheduling algorithm searches for the solution along the only two active constraints: cost criterion and energy conservation. The algorithm checks the water level after an optimal economic schedule has been calculated. After initially using only the cost criterion as a guide to find feasible pos of cost tradeoffs, the conservation principle is used to move toward maximum energy production by the pumped-storage unit. After an optimal schedule has been calculated, the water level is examined for overflows or running dry. If such a case is found, local correction measures are taken at times of violation. Greater details on the correction measures are given in the next section. The pumped-storage facility is based on a weekly cycle, returning the water level at the end of the week to the level at the beginning of the week (an input specification). Free water inflow into the reservoir is allowed and is assumed to be uniform throughout the week.

4.2.2.2 Economic Pumped-Storage Scheduling Algorithm

In the previous section, the distinguishing characteristics of the economic pumped-storage solution were discussed. In this section, the algorithm to reach the solution is discussed, but by a slightly different path than in the previous section. In brief, the algorithm systematically examines a limited number of points that satisfies both the energy conservation principle and the economic cost criterion until the optimal solution is reached. The algorithm locates the loci of points where the energy constraint is active and then proceeds systematically to where the cost constraint is active.

The flow chart of the pumped-storage economic algorithm is shown in Figure 4.12. The main program, PUMP_ST, passes control to ECO, with all the pumped-storage operating parameters including the modified demand function that must be satisfied by the fossil increments and the pumped-storage facility. With the additional information of system variables passed from the preprocessor, the data base is formed from which the search for the solution is based. Graphically (see Figure 4.9), the solution is located where

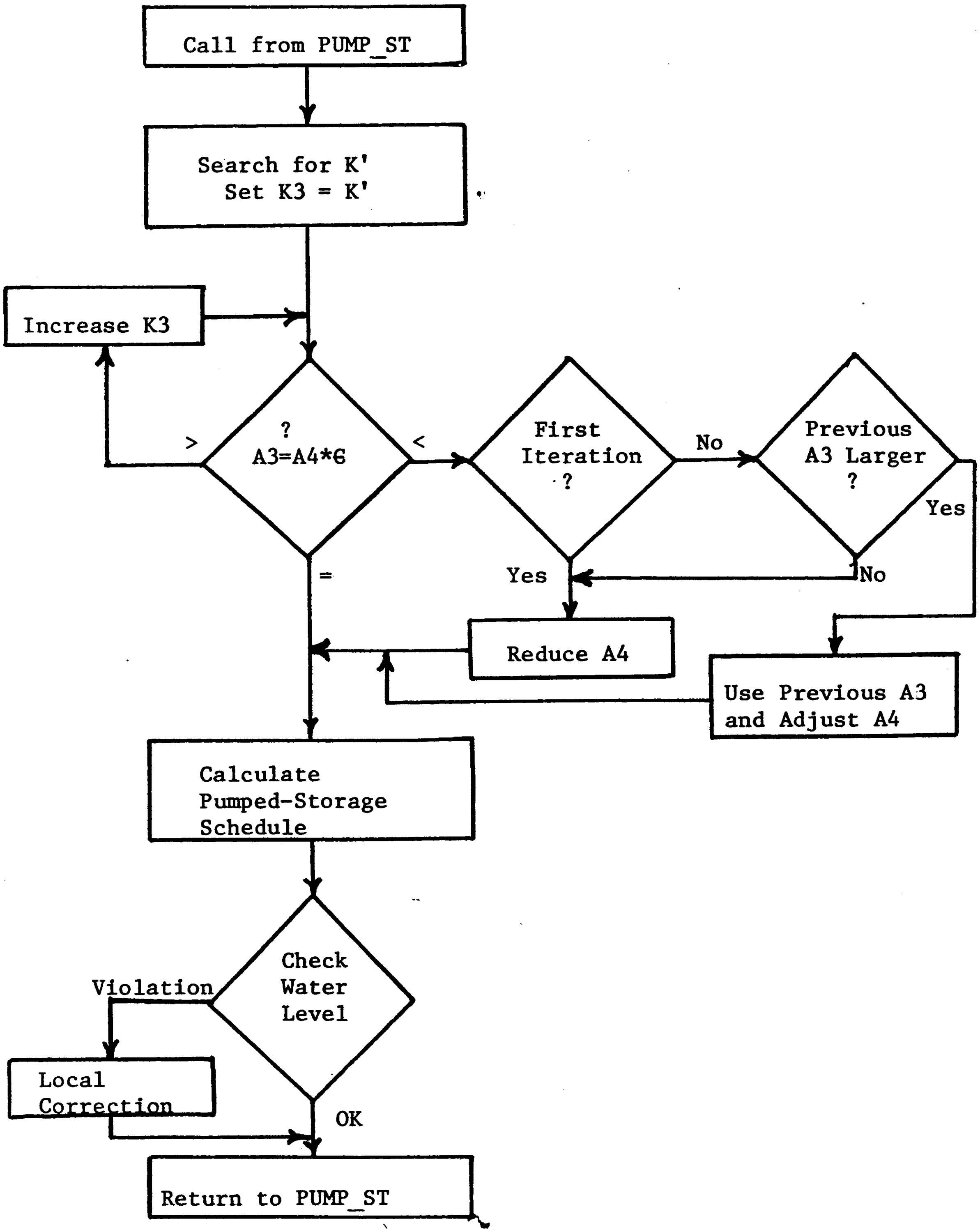

Figure 4.12 ECO FLOW-CHART

the maximum area A3 (stored energy) satisfies both the cost criterion and energy conservation principle. The maximum area (stored energy) represents the largest utilization and hence the largest cost savings. An enumerative search is made since the number of points satisfying both constraints is small (less than the number of fossil increments), and a computer can search these points very quickly. The search is started by determining the lowest feasible value of K3 (Figure 4.12), and in turn, its associated feasible value of A3 (stored energy) is calculated(*). The value of K3 is increased stepwise until the feasible value of A3 (stored energy) can no longer increase(**). At this point the optimal solution has been reached.

The starting point of the search is K' (see Figure 4.13), the lowest feasible value of K3. K' is that power level which divides the load-duration curve so that the pumped-storage facility is always pumping or generating without regard for cost, see Figures 4.14 and 4.15. This is the case where the cost criterion is not active. From this starting point, the cost criterion is then introduced. Setting K3 to K' produces a value for K4 (see Figure 4.16). The associated value of A4 is calculated which is compared with A3. As illustrated in Figures 4.17 and 4.18, where

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(*) K4 by the cost criterion is calculated from K3, which determines area A4 (pumping energy), which in turn, determines the feasible value of A3 (stored energy).

(**) Increasing K3, increases K4 which increases A4 (pumping energy), which in turn, increases the feasible value of A4 (stored energy).

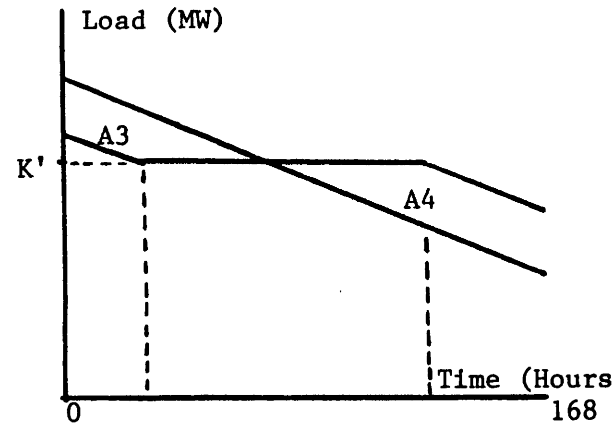


Figure 4.13
<u>FULL-UTILIZATION OF A PUMPED-STORAGE FACILITY WITHOUT REGARD TO COST</u>

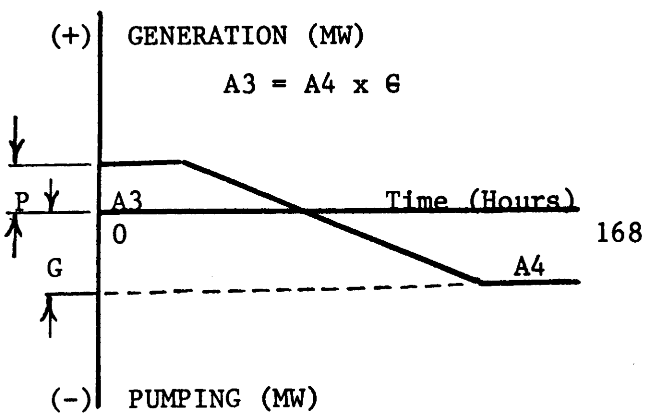


Figure 4.14
<u>PUMPED-STORAGE DURATION CURVE OF FIGURE 4.13</u>

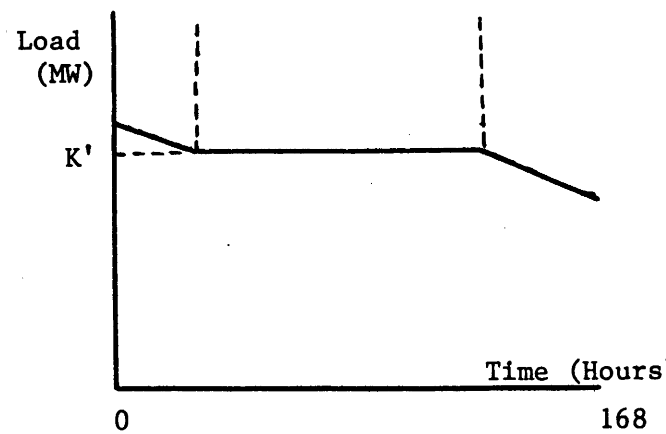


Figure 4.15
<u>FOSSIL DURATION CURVE OF FIGURE 4.13</u>

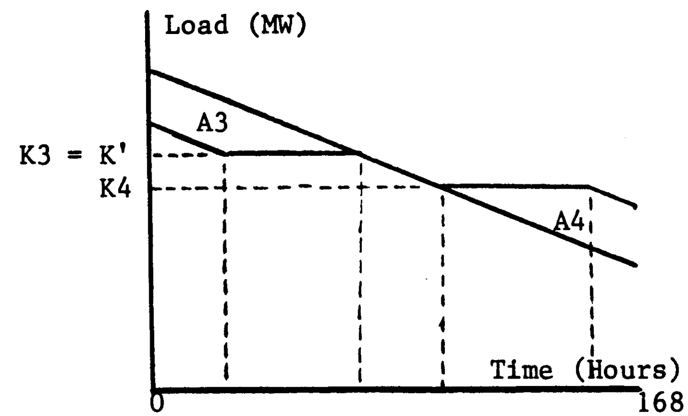


Figure 4.16
INITIAL STARTING SOLUTION OF THE PUMPED-STORAGE ALGORITHM

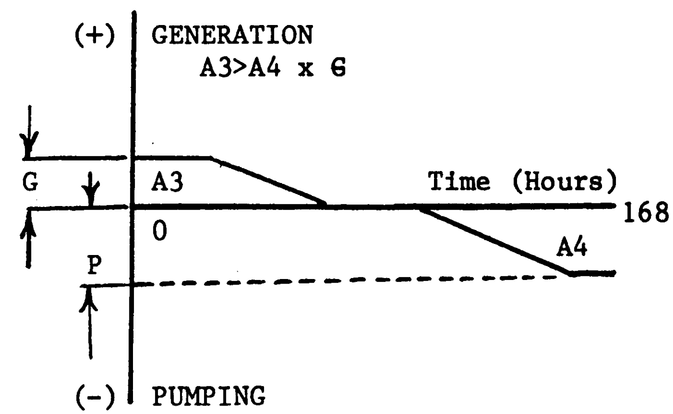


Figure 4.17
PUMPED-STORAGE DURATION CURVE OF FIGURE 4.16

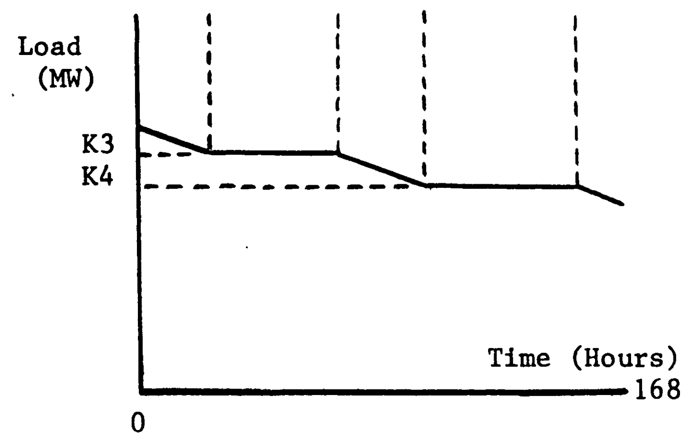


Figure 4.18
FOSSIL DURATION CURVE OF FIGURE 4.16

energy A3 is out of balance with energy A4 because A3≠ϵA4, the value of K3 is increased to the next higher incremental loading order point. K4 is reset, A3 and ϵA4 are recalculated and compared. This is repeated until they are equal or the balance shifts to the other direction. If the shift occurs, A3 and A4 are interpolated to the point at which A3=ϵA4, which determines the maximum feasible pumping. The next step is to re-sort the load duration curve of the pumped-storage facility back to a chronological load curve to check the water level. If the reservoir runs dry, generation is cut back to zero for the required number of intervals (and pumping is likewise adjusted); or if the reservoir overflows, pumping is cut back to zero for the required number of intervals (and generation is likewise adjusted). These corrective measures are not performed optimally (in a least-cost sense), but rather to correct the situation as immediately as possible (in as few time intervals as possible).

Finally, the pumped-storage schedule is complete and feasible and the incremental fossil production schedule by default is the residual load demand schedule. The detailed pumped-storage schedule is then printed (if desired), and control returned to the main program. The incremental fossil fuel costs are then calculated, and in turn, the total system production cost and the OCNP also. PUMP_ST also prints the incremental and each fossil unit's average capacity factors.

As an option, the pumping schedule may be calculated by the Pumped-Storage Security Model described in the next section, instead of the economic model discussed in this section.

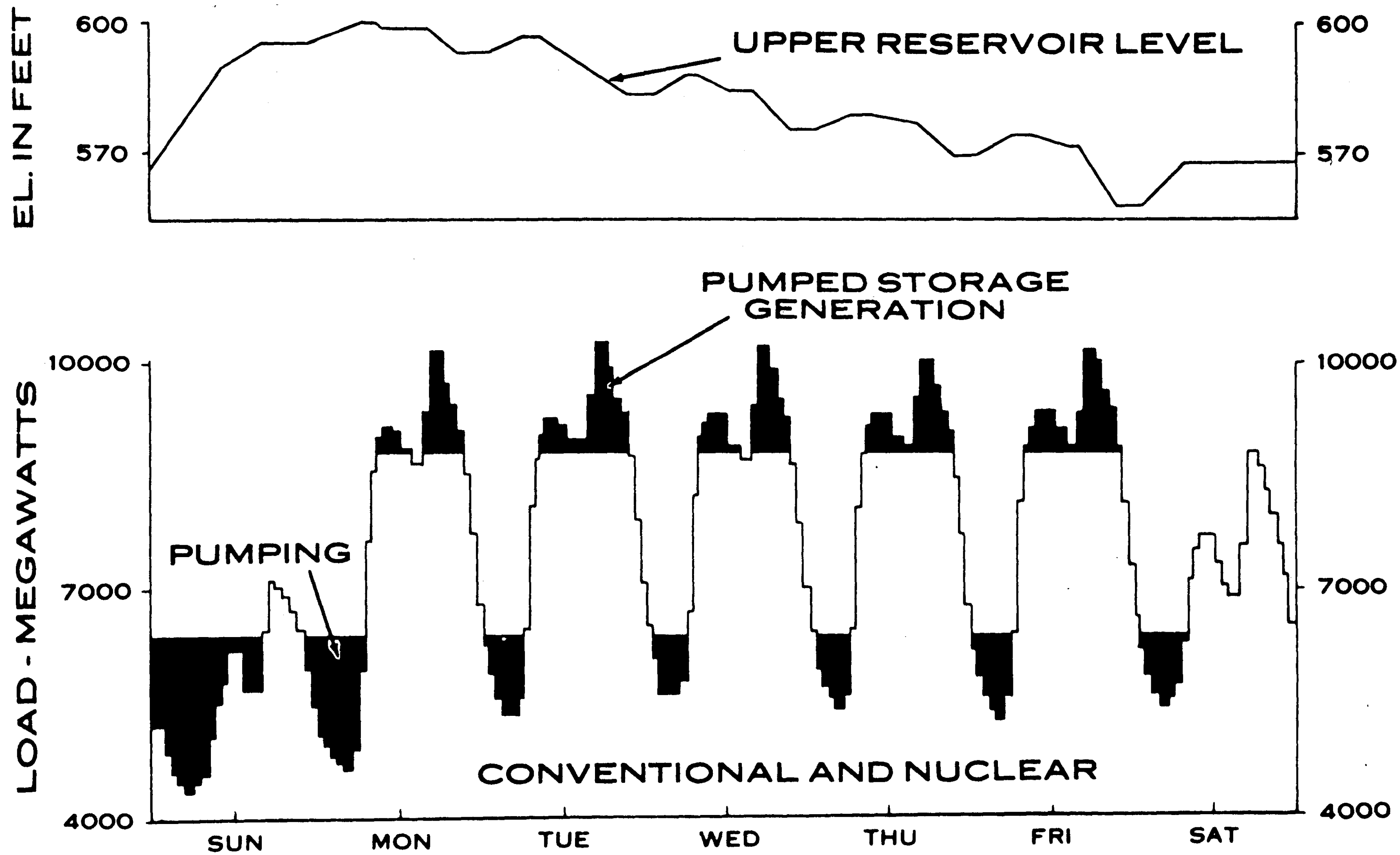
4.2.2.3 Pumped-Storage Security Theory

Pumped-storage units have proven to be reliable and versatile in helping the utility dispatcher to cope with the statistical fluctuations in meeting customer demand. The pumped-storage facility is quick to adapt to changing load demands with a minimum of strain (24). In fact, utility practice is to assign a large portion of its pumped-storage generating capacity to spinning reserve. For example, AEP's Ludington pumped-storage facility has 460 MWe generating capacity but only 300 MWe is normally scheduled on a planned basis. The remaining 160 MWe capacity is set aside as spinning reserve to take care of equipment forced outages and unexpected load changes.

For the pumped-storage facility to meet this responsibility and to be capable of handling the severest problem, the reservoir must be kept as full as possible at all times. This means that whenever the pumped-storage facility is not generating power, it will be pumping water into the reservoir until it is filled. These operational procedures are probably not the least expensive mode of operation. To provide the system with maximum security, the pumped-storage facility has pumping scheduled until the reservoir is full, even though the generation schedule

Figure 4.19

TYPICAL ECONOMIC PUMPED-STORAGE SCHEDULE



Source: Reference (22), pp. 179

doesn't require it and economically, it would be cheaper to wait until the weekend to do the pumping. As an illustration, Figure 4.19 is an example of an economic pumped-storage schedule. The figure shows that there is large amounts of pumping on weekends and only a small amount of sub-capacity pumping during the week nights. The security model proposed would do the reverse, pump at rated capacity on week nights until the reservoir is filled, leaving little pumping to be done on weekends.

4.2.2.4 Pumped-Storage Security Algorithm

The peak-shaving pumped-storage generation schedule for this security model is the same as in the economic model. It is characterized by the pumped-storage generation level (power level K3 in Figure 4.9), where if demand load is above that level, then the pumped-storage generators produced enough power to make up the difference or until its nominal capcity(*) is reached.

The pumped-storage generation schedule is first calculated in ECO, next subroutine SECURIT is called to calculate the security mode pumping schedule. SECURIT first determines the allowable time periods to schedule pumping, which takes into account a transition interval before and after generation. For each allowable time period, pumping is scheduled for each time interval starting with the time

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(*) Nominal capcity is not the rated capacity of the generators, but that capacity intended for scheduled usage, the remainder is for emergency usage.

interval of lowest demand until either the reservoir is filled, or all available intervals have been scheduled. The detailed algorithm is presented in Appendix C. When pumping for the last time period is scheduled , the final water level is set to return to the beginning-of-week level. Program control is then returned to ECO.

Three simplifying assumptions used in this model are: (i) a weekly water cycle is assumed, returning the end-of-week water level to beginning-of-week starting level; (ii) the cycle inefficiency is assumed to be all in the pumps. For example, for a 50% cycle efficient unit, the model requires a 2 MWH pumping requirement to produce 1 MWH generation resource, but produces a water level change of only 1 MWH. (iii) The (economic) scheduling method used was assumed sufficient. The pumping schedule could be further flattened by iterating over the lowest fossil increments, instead of the lowest demand levels. This would greatly increase the bookkeeping and complexity of the algorithm for a slightly smaller cost determination, hence it was not done.

The first two assumptions are also applicable to the economic pumped-storage model. These two assumptions are not fundamental to the successful execution of the program. These assumptions can be easily modified to fit the requirements of the user.

Appendix C contains the program listing of the security model and the I/O specification of the program.

4.3 ALLOCAT Algorithm

The optimal allocation of the nuclear energy between weeks is performed by the ALLOCAT program. Each week is represented by a list of OCNP values. Maximum utilization of a limited resource dictates that the first nuclear energy increment go to the week having the highest value for nuclear power, OCNP. The first increment utilized, the second increment goes to the week having the second highest OCNP value. This process is analogous to selling to the highest bidders. Each week has a list of successive lower bids (as OCNP values). The central decision maker (the algorithm), one-by-one allocates increments of nuclear energy to the highest bidder first. After each allocation, the going price moves down, until all available nuclear energy has been allocated. In this condition some weeks may have a full supply of nuclear energy (all bids taken) while other weeks may have only the minimum supply (no bids taken). This describes the algorithm used by ALLOCAT. The program is told how much nuclear energy is available and by increments, allocates the energy to the individual weeks. It keeps track of the energy allocated each week to the unit being optimized, and when all the nuclear energy is allocated, the program lists the final capacity factor distribution. Appendix D lists the program along with the input and output from Case 4 (see Section 5.6).

4.4 FOSSIL

FOSSIL is a program that calculates weekly system cost and OCNP for the case of no nuclear optimization. Thus, FOSSIL is principally used as a basis of comparison to measure the savings of the optimized nuclear dispatching schedule. Figuring the optimal fossil dispatching schedule for the case of base-loaded nuclear power (at constant power level throughout the week) is a trivial problem, since there is no nuclear optimization. The fossil algorithm is as follows: The constant nuclear power level is subtracted from the modified demand function, leaving the revised demand requirement that is to be fulfilled by the fossil units. The fossil units are represented by an economic loading order (output from NUC_OPT), hence, it is a simple table look-up operation to figure the optimal fossil dispatching schedule and operating cost. The OCNP is the incremental fossil fuel cost of the weekly average fossil demand requirement.

The simplicity of FOSSIL (and its very quick method of calculating OCNP) also makes it convenient to use FOSSIL for developing initial guesses for multi-reactor problems. This alternate solution technique inverts the order of optimization steps discussed in Section 3.1. The exact optimization procedure (discussed in Section 3.1) is to first optimally peak-shave the nuclear energy within each week in the planning horizon (using PROCOST) and secondly calculate the optimal distribution of nuclear energy between the weeks (using ALLOCAT). This procedure is referred to as the "Peak-Shave First" method. The alternate solution technique is to first calculate the optimal distribution of nuclear energy among all the weeks in the planning horizon, assuming a constant nuclear power level in each week, using FOSSIL and ALLOCAT. Secondly the optimal nuclear peak-shaved distribution is calculated (using PROCOST) for the optimized energies in the first step. This approach is referred to as the "Peak-Shave Second" method. a comparison of the two methodologies shows the "Peak-Shave Second" method to be a more direct (but approximate) method involving less computations. This method is especially useful in defining the neighborhood of the optimal solution of a multi-reactor problem where the calculation savings would be very large. Section 5.6 presents a numerical example of using the two solution techniques on the same system example.

5.0 System Optimization Studies

5.1 The System

To test the optimization procedures discussed earlier, three sample system optimization problems were solved. The first was a single-reactor optimization problem, and the second was a multi-reactor optimization problem. The multi-reactor optimization was performed under conditions more severe than "typical" operating conditions. The third optimization problem was a modification of the first in which the monthly configurations were adjusted to yield constant system reserves over the planning horizon.

American Electric Power Service Corporation (AEP) provided the basic data from which the utility system configuration (16) was constructed. The system, composed of 52 units of five power plant types, was simulated for a short-range planning period of six months, April through September. The system included two nuclear plants (of 1100 MWe each), one hydro plant (with limited pondage and 200 MWe peak generating capacity), one pumped-storage unit (of 300 MWe generating capacity), seven peaking units and 41 fossil units for a total generating capacity of 19,250 MWe. The fossil units were of three classes, large (1300-400MWe), medium (400-160 MWe) and small (below 160 MWe). The distinction between fossil classes was the shape of their average heat-rate curves. In PROCOST all fossil units are identified with one of three general shapes (or classes), with the amplitude of their average heat-rate curve being an individual scalar multiple of one of the three standardized shapes. The 41 fossil units were composed of 15 large-sized fossil units, 15 medium-sized fossil units, and 11 small-sized fossil units. The three standardized fossil average heat-rate curves are presented in Appendix B. The standardized heat-rate curve of the large fossil class is flat between 0.7 and 1.0 of rated power and steeply rising below 0.7 of rated power. The medium fossil heat-rate curve is similar to the large fossil curve except that its slope is not so steep below 0.7 of rated power. The standardized heat-rate curve of the small fossil class is very different from the other two. The small fossil curve begins at 14,000 BTU/KWH at 0.4 rated power, slopes down to 12,500 BTU/KWH at 0.7 rated power and slopes up to 13,000 BTU/KWH at rated power.

The maintenance schedule (scheduled outage) of the individual fossil and peaking units proposed by AEP is displayed in Table 5.1. Most of the scheduled outage is placed in the spring and fall months. Since the model is deterministic, forced outage effects are simulated, treating them as scheduled outages also. Table 5.1 also displays the systematic treatment of forced outages. Essentially the same forced outage rate is displayed for each of the months. As mentioned earlier, peaking units are scheduled to peak-shave until their input estimated capacity factors are fulfilled. All the peakers had estimated capacity factors of 10% and start-up and shut-down cost of $100/start-up, except for two

TABLE 5.1

MAINTENANCE AND FORCED OUTAGE SCHEDULE OF PEAKING AND FOSSIL UNITS OF CASES 1 AND 2

	Maintenance Schedule												Assumed Forced Outage Schedule											
Month	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Peakers																								
1													X											
2														X	X									
3	X															X								
4			X																X					
5						X														X	X			
6		X																						X
7											X										X			
Fossil																								
1									X								X	X						
2										X													X	X
3												X										X		
4				X																		X	X	
5								X										X						
6		X																	X	X				
7				X											X									
8					X								X	X										
9											X						X	X						
10		X											X											
11										X				X	X									
12						X										X								
13											X						X	X						
14	X																		X					
15						X														X	X			
16									X													X		
17			X																				X	X
18					X																			X
19																					X			
20												X										X	X	
21	X																		X	X				
22						X										X	X							
23			X															X						
24				X											X									
25										X			X	X										
26							X						X											
27					X									X	X									
28									X							X								
29											X						X	X						
30		X																	X					

TABLE 5.1 (CONT'D)

	Maintenance Schedule												Assumed Forced Outage Schedule											
Month	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Fossil (Cont'd)																								
31	X																			X	X			
32				X																		X		
33	X	X	X	X	X	X	X	X	X															
34												X										X	X	
35									X														X	X
36												X									X			
37			X																					X
38				X															X	X				
39											X							X						
40					X									X	X									
41										X						X	X							

Note: An "X" represents a simulated outage for the entire month. The total time of scheduled outage for each plant corresponds to the actual observed outage rate for similar sized units. The specific forced outage schedule for each unit was chosen randomly. The maintenance schedule was chosen to lie mainly in the spring and fall months.

gas-turbine units (of 51 and 4 MWe) which had zero start-up and shut-down costs.

The individual plant parameters were supplied by AEP in 1973. The rated capacity, fuel costs and average heat-rate at rated capacity for the 41 fossil units and seven peaking units are tabulated in Table 5.2. The fuel costs do not reflect the sharp rise in fuel costs during 1974. The hydro unit with limited pondage was scheduled to generate 200 MWe for nine peak demand hours during each workday and 50 MWe at all other times. The pumped-storage unit's operating parameters were: 300 MWe capacity generator, 160 MWe capacity pump, 70% cycle efficiency, 9300 MWH reservoir capacity and 2300 MWH/week free water inflow into the reservoir. The operation of pumped-storage unit has been discussed in Section 4.3.

The system treated also had two nuclear units of 1100 MWe each. Nuclear Unit 1 was scheduled for refueling on October 1. In the six months prior to refueling which make up the planning period, Unit 1 was assumed to have 70% of the energy required to operate base loaded at full rated power. In the first simulation, Unit 2 was treated as a new unit just being introduced to service under a gradual programmed start-up: 20% of full rated power throughout April, 40% of full rated power throughout May, 60% during June, 80% during July, and 100% during August and September.

The forecasted weekly energy consumption during the six months (26 week) planning period is tabulated in Table 5.3.

TABLE 5.2

PLANT PARAMETERS OF PEAKING AND FOSSIL UNITS

Peakers	Capacity MWe	Fuel Cost $/10^6 Btu	Heat Rate 10^6 Btu/MWH
1	4	1.70	15.0
2	51	1.70	15.0
3	95	1.70	12.5
4	95	1.05	12.0
5	95	1.05	12.0
6	90	0.55	12.9
7	90	0.55	12.9
Fossil			
1	145	1.70	9.8
2	105	0.40	12.0
3	110	0.40	12.0
4	100	0.55	10.8
5	105	1.0	11.8
6	150	0.95	9.4
7	150	0.95	9.4
8	150	0.95	9.4
9	150	0.95	9.4
10	150	0.55	9.7
11	150	0.55	9.7
12	215	0.55	9.5
13	240	1.0	9.1
14	205	0.55	9.8
15	205	0.55	9.8
16	215	0.55	9.8
17	215	0.55	9.8
18	225	0.50	10.0
19	225	0.50	10.0
20	225	0.50	10.0
21	215	0.55	9.2
22	210	0.55	9.2
23	240	0.80	9.1
24	240	0.80	9.1
25	240	0.80	9.1
26	280	1.05	9.3
27	400	0.55	9.2
28	450	0.95	9.0
29	525	0.35	9.1
30	580	0.55	9.0
31	600	0.50	9.1
32	600	0.50	9.1
33	615	0.50	9.0
34	800	1.05	9.4
35	800	0.40	9.5
36	800	0.40	9.5
37	800	1.10	9.0
38	800	1.10	9.0
39	1,300	1.25	8.4
40	1,300	0,80	8.5
41	1,300	0.80	8.5

Table 5.3

WEEKLY ENERGY FORECAST FOR PLANNING PERIOD

Month	Week	Weekly Energy (MWH)	Monthly Total (MWH)	Demand Peak (MWH)	Average Power (MWH/H)
April	1	1,860,288	7,238,361	13,577	11,073
	2	1,894,814		13,795	11,279
	3	1,801,320		13,207	10,722
	4	1,681,939		12,472	10,011
May	5	1,792,155	8,771,712	13,149	10,668
	6	1,728,221		12,747	10,287
	7	1,758,492		12,937	10,467
	8	1,801,151		13,207	10,721
	9	1,691,693		12,517	10,070
June	10	1,839,877	7,299,798	13,951	10,952
	11	1,883,604		14,227	11,212
	12	1,814,876		13,793	10,803
	13	1,761,441		13,456	10,485
July	14	1,681,810	9,122,626	12,954	10,011
	15	1,870,344		14,143	11,133
	16	1,826,914		13,869	10,874
	17	1,883,382		14,226	11,211
	18	1,860,176		14,079	11,072
August	19	1,833,500	7,589,101	13,911	10,914
	20	1,950,649		14,650	11,611
	21	1,895,024		14,299	11,280
	22	1,909,928		19,393	11,369
September	23	1,955,031	7,653,173	13,919	11,637
	24	1,868,715		13,034	11,123
	25	1,872,805		13,074	11,148
	26	1,956,622		13,939	11,647
Total		47,674,771			

These energy consumption numbers were supplied by AEP for simulation purposes. The six-month planning period spanned three seasons, Spring (April and May), Summer (June, July, and August) and Fall (September). The weekly energy consumption was input to a seasonal load model, MODEL, to generate the detailed hourly customer demand numbers. The weekly energy consumption was used as the independent variable of a seasonal customer demand correlation that determined the customer demand function for a week of a particular energy consumption and season. The load model is discussed in Appendix A and the detailed weekly customer demand functions generated from the energy forecasted are presented in Appendix A.4.3. The weekly peak demand of each week and the average power level inferred from the energy consumption are also tabulated in Table 5.3. The calculated peaks were obtained from MODEL; see Appendix A for details.

In the six-month period prior to refueling, a reactor with insufficient energy to run at full power until scheduled refueling can be considered a candidate for short-range resource-limited optimization. The second reactor, Nuclear Unit 2, coming on-line with a fully fueled core had an abundant supply of energy and an undetermined forced outage rate and would be undergoing a planned start-up program, so that the reactor's operation was determinate over the short range. Only reactors with limited resource and a fairly certain availability (*) over the short-range time horizon are amenable to short-range system analysis using PROCOST. Availability, at best, can only be fairly certain over a short-range time horizon.

The objective of the first system optimization (Case 1) was then to find the optimal distribution of weekly nuclear capacity factor of Nuclear Unit 1, whose overall thermal energy availability is 70% of rated capacity for the six months planning period prior to refueling. The second power reactor was operated at programmed steps in power levels.

Although the system contained two reactors, the first system simulation (Case 1) was a single-reactor optimization. The second system simulation (Case 2) was a complex two-reactor optimization. Case 2 used exactly the same system configuration as in Case 1, except for additional constraints on Nuclear Unit 2, which was limited to 80% of the energy used in the corresponding periods of Case 1, see Table 5.4. Nuclear Unit 2 was limited to 16% capacity factor on energy and 20% of power for April, 32% capacity factor on energy and 40% of power for May, 48% capacity factor on energy and 60% of power for June, 64%

(*) The deterministic approach (used in the PROCOST program) assumes the availability of the reactor is known with certainty. Hence, this assumption imposes certain restrictions on the use of this short-range optimization technique. This restriction can possibly be eliminated by the utilization of the Booth-Balerieux probabilistic technique, Ref. (16), for modelling forced outages in PROCOST.

TABLE 5.4

OPERATIONAL CONSTRAINTS ON NUCLEAR UNIT 2
DURING THE TWO-REACTOR OPTIMIZATION, CASE 2

Time Period		Limitation	
Weeks	Months	Energy (% Rated)	Power (% Rated)
1-4	April	16	20
5-9	May	32	40
10-13	June	48	60
14-18	July	64	80
19-26	Aug.-Sept.	80	100

capacity factor on energy and 80% of power for July, and 80% capacity factor and 100% of power for August and September. The goal of Case 2 was find the optimal weekly nuclear capacity factor distribution of both nuclear reactors. Case 2 was admittedly a contrived case to illustrate: (1) a multi reactor optimization, and (2) the feasibility of the procedures to handle a complex and involved situation. Case 2 is not an ordinary straight-forward two-reactor optimization. Nuclear Unit 2 had five smaller separate planning periods, requiring a separate optimization in each period. Nuclear Unit 2 was analogous to a collection of five reactors, with each reactor operating for only one period and shut down for the other periods.

Case 3 is a single reactor optimization similar to Case 1. The only difference between Case 1 and 3 is that the monthly fossil configurations were adjusted in Case 3 to levelize the minimum monthly system reserves over the six-month planning horizon. The adjusted fossil monthly maintenance and forced outage schedule for Case 3 is tabulated in Table 5.5. All other system parameters of Case 3 are identical to Case 1.

This completes the description of the system environment and the three optimization problems. A complete listing of all the parameters used in Case 3 is tabulated in Appendix C.7. The solving of the optimization problem required a very fast method to calculate OCNP values. The next section describes the load model sensitivity studies

Table 5.5

MAINTENANCE AND FORCED OUTAGE SCHEDULE
OF PEAKING AND FOSSIL UNITS FOR CASE 3

	MAINTENANCE SCHEDULE												ASSUMED FORCED OUTAGE SCHEDULE											
Month:	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
PEAKERS																								
1													x											
2														x	x									
3	x															x								
4			x																x					
5						x														x	x			
6		x																						x
7											x										x			
FOSSIL																								
1									x								x	x						
2										x													x	x
3												x										x		
4				x																		x	x	
5								x										x						
6		x																	x	x				
7				x											x									
8					x								x	x										
9											x						x	x						
10		x											x											
11										x				x	x									
12						x										x								
13											x						x	x						
14	x																		x					
15						x														x	x			
16									x													x		
17			x																				x	x
18									x															x
19										x											x			
20												x										x	x	
21	x																		x	x				
22								x								x	x							
23			x															x						
24				x											x									
25										x			x	x										
26								x					x											
27					x									x	x									
28									x							x								
29											x						x	x						
30		x																	x					

Table 5.5 (CONT'D)

	MAINTENANCE SCHEDULE												ASSUMED FORCED OUTAGE SCHEDULE											
Month:	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
FOSSIL																								
31	x																			x	x			
32				x																		x		
33	x	x	x	x	x	x	x	x	x	x														
34												x										x	x	
35									x														x	x
36												x									x			
37			x																					x
38							x									x	x							
39											x							x						
40					x									x	x									
41										x									x	x				

Note: An "x" represents a simulated outage for the entire month. The total time of scheduled outage for each plant corresponds to the actual observed outage rate for similar sized units.

undertaken to meet this goal. The subsequent sections discuss the results and the conclusions of the three system optimization problems.

5.2 Load Model Sensitivity Study

The primary intent of this thesis study was to develop a calculational procedure to analyze short-range options of a nuclear utility system that is quick, efficient and accurate. The practical usefulness of such a survey program requires that execution to be low in cost. Developing such a program by necessity involves making some sacrifices in accuracy when analyzing a large complex problem. Hence a sensitivity study was undertaken to find the optimal cost-effective load models appropriate to use in the short-range optimization procedures. As discussed in Section 3.1.1, a detailed L.P. model to determine the optimal generation schedule for a large utility system would involve a problem with a million variables. This problem can be solved piecemeal by solving many smaller problems to lead to the solution of the original large problem.

OCNP is the concept used to relate smaller weekly optimization problems to the original optimal nuclear generation schedule problem. A detailed (hourly) weekly generation problem is an L.P. problem of 10,000 variables, which while manageable, is still too large a problem to solve 500 times to generate 500 OCNP values. The first phase of the optimal nuclear generation schedule problem is to find the optimal weekly nuclear capacity factor distribution, for which only the OCNP values of the weekly optimization problem is required. Other information about the optimized solution such as system production cost, fossil incremental capacity factors, and the detailed generation scheduled are superfluous (at this stage of the optimization process).

Since only a single feature (OCNP) of the weekly optimization problem was deemed important (in the first phase), reproduction of that single feature in a much simpler calculational model was sought. For this purpose, load-duration load models were tested for their ability to reproduce OCNP values obtained from more detailed chronologic load models.

In parallel with this load-duration OCNP study, there were efforts to find a simpler chronologic load model to reduce computational costs where the chronologic demand pattern was important. The simple chronologic load model would retain the ability to reproduce the system production cost, OCNP, and fossil incremental capacity factors of a more detailed load model.

The simpler chronologic load model also provided a standard of comparison with which to judge the various load-duration load models.

The chronologic load model sensitivity study investigated a great many variations of the 168 hour weekly load model. The initial set of load models included 84 2-hour intervals, 54 3-hour intervals, and 42 4-hour intervals. Of the three, only the 84 2-hour interval load model yielded satisfactory reproduction results. Further reduction of time intervals involved the use of non-uniform time intervals and combining the three average workdays together, aside from the peak workday and low workday. Thus, a modified chronologic 40-interval load model was developed, composed of a 10-interval peak workday, a 10-interval average workday, a 10-interval low workday, and a 10-interval weekend. This 40-interval modified chronologic model reproduced with sufficient accuracy the details of the 168-hour representation. Thus, it was chosen as the standard to judge the load-duration models. Further details of the chronologic sensitivity study are presented in Appendix A.5.

Preliminary work on the load-duration sensitivity studies showed that models of very few time intervals (between six to ten) were in surprisingly good agreement compared with the very detailed load-duration models in reproducing OCNP. The details of these preliminary studies are discussed in Appendix A.6.

Before choosing a six-interval load-duration load model for generating OCNP values (required for the three system optimization studies), a number of comparisons were made with more detailed load models. The study included the comparison of the weekly OCNP function of a typical summer week obtained from six load models: a 120-interval modified chronologic model (A), two 50-interval load-duration models (B and C), a 40-interval modified chronologic model (D), and

COMPARISON OF A TYPICAL SUMMER WEEKLY OCNP FUNCTION FROM SIX LOAD MODELS

Description				Weekly Nuclear Capacity Factor of Nuclear Unit 1				
Model	No. of Time Intervals	Nuclear Heat Rate	Type of Load Model	0.55	0.65	0.75	0.85	0.95
				OCNP (Mills/KWHe)				
A	120	Variable	Hybrid	5.06	4.72	4.66	4.29	3.58
B	50	Constant	Load duration	5.06	4.77	4.66	4.29	3.58
C	50	Variable	Load duration	5.08	4.72	4.66	4.29	3.58
D	40	Variable	Hybrid	5.03	4.72	4.66	4.29	3.58
E	6	Constant	Load duration	5.03	4.72	4.66	4.29	3.58
F	6	Variable	Load duration	5.03	4.77	4.66	4.43	3.58

two six-interval load-duration models (E and F). The six models and their OCNP values are described in Table 5.6. The system environment for this comparison was the same as those conditions representing the first week in August of the first system simulation, Case 1, discussed in the previous section. The agreement in results of Model E compared with the more detailed models is very good. The difference in the weekly OCNP functions for Model E compared with the weekly OCNP function of Model A is by only one increment (at 0.55 nuclear capacity factor). Similarly, the deviation of Model E from the weekly OCNP function obtained from Model C is by only one increment at one nuclear capacity factor, and from Model B at a single increment each at two nuclear capacity factors. Model E agrees perfectly with the standard, Model D. The results of Model F (also listed in Table 5.6) are in poor agreement with the other models. Model F agrees at only two out of five points compared with Model A, and at only three out of five points compared with Model D, the standard of comparison. The fossil economic incremental loading order (derived from the August system configuration) used in this study is presented in Table 5.7.

The subtleties in calculating the correct OCNP value are illustrated from observing the differences between Model E, with a constant heat-rate and Model F, with a variable heat-rate. One model yields very accurate answers and the other contradictory values even though both models have the same number of time intervals. Since a variable nuclear

TABLE 5.7

AUGUST ECONOMIC FOSSIL LOADING ORDER

Increment	Increment Size (MW)	Cumulative Increment Size (MW)	Increment Generation Cost (Mills/KWe)	Cumulative Generation Cost ($/Hr)
1	105	105	2.85	299
2	105	210	3.00	614
3	105	315	3.20	950
4	320	635	3.40	2,038
5	320	955	3.58	3,184
6	320	1,275	3.82	4,405
7	120	1,395	4.07	4,894
8	21	1,416	4.16	4,981
9	22	1,438	4.16	5,073
10	120	1,558	4.29	5,587
11	116	1,674	4.43	6,101
12	21	1,695	4.46	6,195
13	22	1,717	4.46	6,293
14	80	1,797	4.53	6,655
15	120	1,917	4.57	7,204
16	60	1,977	4.63	7,481
17	116	2,093	4.66	8,022
18	135	2,228	4.66	8,652
19	135	2,363	4.66	9,281
20	42	2,405	4.72	9,479
21	42	2,447	4.72	9,678
22	80	2,527	4.77	10,059
23	43	2,570	4.87	10,268
24	43	2,613	4.87	10,478
25	60	2,673	4.96	10,775
26	116	2,789	4.97	11,352
27	135	2,924	5.00	12,027
28	127	3,051	5.03	12,667
29	127	3,178	5.03	13,306
30	42	3,220	5.06	13,518
31	80	3,300	5.08	13,925
32	20	3,320	5.15	14,028
33	43	3,363	5.22	14,253
34	21	3,384	5.25	14,363
35	22	3,406	5.25	14,479
36	127	3,534	5.39	15,164
37	20	3,554	5.52	15,275
38	60	3,614	5.84	15,625
39	520	4,134	6.09	18,789
40	520	4,654	6.40	22,120
41	20	4,674	6.50	22,250
42	144	4,818	6.79	23,227
43	144	4,962	6.79	24,205
44	520	5,482	6.83	27,757
45	144	5,626	7.28	28,805
46	90	5,716	7.65	29,494
47	90	5,806	7.74	30,191
48	90	5,896	8.05	30,916

TABLE 5.7 (CONT'D)

Increment	Increment Size (MW)	Cumulative Increment Size (MW)	Increment Generation Cost (Mills/KWe)	Cumulative Generation Cost ($/Hr)
49	90	5,986	8.30	31,663
50	48	6,034	8.49	32,070
51	48	6,082	8.49	32,478
52	90	6,172	8.59	33,251
53	160	6,332	8.83	34,664
54	160	6,492	8.86	36,081
55	48	6,540	9.10	36,518
56	56	6,596	9.11	37,028
57	56	6,652	9.11	37,538
58	160	6,812	9.30	39,026
59	160	6,972	9.32	40,518
60	260	7,232	9.40	42,961
61	56	7,288	9.77	43,508
62	90	7,378	9.77	44,387
63	260	7,638	9.89	46,958
64	160	7,798	9.91	48,544
65	160	7,958	9.94	50,136
66	260	8,218	10.55	52,878
67	29	8,247	14.45	53,297
68	29	8,276	15.49	53,746
69	29	8,305	18.22	54,274
70	1,500	9,805	25.00	91,774

heat-rate is the more realistic representation, it seems peculiar that the constant nuclear heat-rate model, E, gives more accurate results than the variable nuclear heat-rate model, F. The explanation lies in fact that a detailed represenatation of the nuclear heat-rate is incompatible in a coarse load model representation. In a six-interval model, each time interval represents about 20-40 hours. The nature of the L.P. model is such that the power level of each unit is constant for the duration of each time interval. This distortion effect is serious when the six-interval model schedules a reactor to generate power at a partial power level for only two time intervals, which in reality may represent 20-60 hours. In comparison, the detailed models would have scheduled the same reactor (under the same conditions) to a partial power level for only 10-30 hours. (The exact number depending on the customer demand function and the other system parameters.)

The principal reason for the smaller number of hours (in the detailed model) is that a variable nuclear heat-rate representation places a premium on operating at the most efficient power level as much as possible. Thus, a detailed model would schedule a reactor to operate at full rated power most of the time and operate at partial power as little as possible, i.e., about 20 hours a week. A six-interval model is handicapped in that each of its time interval represents 20-40 hours so that if it scheduled a reactor to be at a partial power level for only two time intervals, that may represent as much as 60 hours. The overall effect of the differences in hours at partial power is that the overall average effective nuclear heat-rate is lower for the detailed load model than the six-interval model. This implies more nuclear electricity generated (from the same amount of thermal nuclear energy) for the detailed model than the six interval model, and in turn, a lower OCNP value. Therefore, the differences in OCNP values of a six interval model, with variable nuclear heat-rate (compared to a detailed load model) are inherent.

This difference in nuclear electricity also explains why using a constant nuclear heat-rate is necessary in a six-interval model. The nuclear heat-rate value in the constant heat-rate model equaled the 100% rated power value. A six-interval model that utililizes the same amount of nuclear electricity (that a detailed model would), is more likely to calculate the same OCNP value. This argument is illustrated by examining the optimal nuclear and fossil generation schedules calculated from three load models (F, D, E as described in Table 5.6) for the same sample problem, presented in Table 5.8.

Table 5.8 deals with a typical summer week, with Nuclear Unit 1 limited to 75% average capacity factor. The solution for Model F, Table 5.8a, shows that there are two time intervals equivalent to 60 hours when Nuclear Unit 1 is at partial power. By contrast, the solution for Model D, Table 5.8b, shows that its Nuclear Unit 1 is at partial

TABLE 5.8

NUCLEAR-FOSSIL GENERATION SCHEDULE OF THREE LOAD MODELS FOR A TYPICAL SUMMER WEEK AT 0.75 NUCLEAR CAPACITY FACTOR

Table 5.8a

Six Interval Load Duration with Variable Heat Rate

Interval	Duration (Hr)	Fossil	Nuclear Unit 1
1	50	5,086	1,100
2	24	4,202	1,100
3	19	3,055	1,100
4	24	2,363	815
5	36	1,937	395
6	15	1,375	0

Table 5.8c

Six Interval Load Duration with Constant Nuclear Heat Rate

Interval	Duration (Hr)	Fossil	Nuclear Unit 1
1	50	5,086	1,100
2	24	4,202	1,100
3	19	3,055	1,100
4	24	2,078	1,100
5	36	2,057	275
6	15	1,373	0

Table 5.8b

40-Interval Modified Chronologic with Variable Heat Rate

Only intervals when Nuclear Unit 1 is at partial power are listed

Interval	Duration (Hr)	Fossil	Nuclear Unit 1
1	2	2,093	866
2	4	1,717	562
11	6	2,074	770
13	6	2,248	935
21	2	1,717	704
23	2	2,037	770
31	2	1,725	770
39	10	2,093	882
40	3	2,093	1,085

power for nine intervals for an equivalent of 37 hours. The solution of Model E, Table 5.8c, shows its Nuclear Unit 1 is scheduled for only one time interval at partial power for an equivalent of 36 hours, almost the same as Model D. Therefore, it is not surprising that Model E will yield a more consistent set of OCNP values than Model F.

A further verification for using Model E (for generating OCNP values) is the results of a study comparing the weekly OCNP functions of Model E with Model D under different system operating conditions. The four system operating conditions, taken from the first system optimization problem, included: (1) a typical spring week, the third week of April, (2) a typical summer week, the first week of August, (3) the peak summer week, the second week of August and (4) a typical fall week, the fourth week of September. The weekly OCNP functions are tabulated in Table 5.9.

The forty intervals in Model D were obtained from a reduction of the 120 interval modified chronologic load model (*). This reduction is further explained in Appendix A. The six intervals in Model E were obtained from a

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(*) The 120-interval model was a simplification of the 168-hour representation where the three sets of hours representing the three average weekdays of the week have been combined into one set of intervals.

TABLE 5.9

COMPARISON OF WEEKLY OCNP FUNCTIONS BETWEEN A SIX INTERVAL LOAD DURATION (E) MODEL AND A 40 INTERVAL HYBRID MODEL (D)

System Environment	Model	Weekly Nuclear Capacity Factor 0.55	0.65	0.75	0.85	0.95
		OCNP (Mills/KWHe)				
Typical spring	D	8.30	6.40	6.09	5.25	5.00
	E	7.74	6.40	6.09	5.25	5.03
Typical summer	D	5.03	4.72	4.66	4.29	3.58
	E	5.03	4.72	4.66	4.43	3.58
Peak summer	D	6.09	5.03	4.77	4.66	4.29
	E	6.09	5.03	4.87	4.66	4.07
Typical fall	D	7.28	6.40	6.40	6.09	5.06
	E	7.28	6.40	6.40	6.09	5.25

reduction of the same forty intervals used in Model D (**). A comparsion of the 20 OCNP values from each load model (of Table 5.9) shows differences in only six OCNP values. Of the six OCNP off-values, four out of six show differences by only one fossil increment level. Hence, only two OCNP values (from Model E) out of twenty values deviate more than one fossil increment from the the reference values (from Model D). Three of the OCNP off-values, including the two severely off-values are located at the 0.95 nuclear capacity factor where there is inherent difficulty for a six interval model to reproduce OCNP values accurately. Excluding the 0.95 nuclear capacity factor region, the agreement between the Model D and Model E is almost perfect except for three points where the difference at each point is off by only one fossil increment.

The inherent difficulty at 0.95 nuclear capacity factor (and any nuclear capacity factor near unity) lies in the fact that a few-interval load-duration model does its poorest task of approximation at the extremities of the load-duration curve. The lower end of the load-duration curve is where the OCNP of 1.0 weekly nuclear capacity factor is determined. Hence, all OCNP values for weekly

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(**) Notice that the typical summer weekly OCNP function of the model of Table 5.9 is slightly different from the model of Table 5.6. The reason is that the six-interval model of Table 5.6 was obtained from a direct reduction of the 120-interval model whereas the six-interval model of Table 5.9 was obtained from a reduction of the forty-interval load model. Hence the two six-interval models were slightly different.

nuclear capacity factor near unity, obtained from a few-interval load-duration model, are of low-accuracy. This is not a serious drawback for the few-interval load-duration model since, in the resource-limited situation, the region of interest is far below unity. Only in the non-resource-limited situation is the region of interest near unity. In such a case, the optimization procedures discussed here would not be applicable.

There is an inherent reason why four out of six OCNP off-values are positive deviations. In a variable nuclear heat-rate model, there is a bias toward scheduling nuclear generation at high (more efficient) power levels over low power levels (*). This bias effectively lowers the calculated OCNP value, because OCNP is calculated only from those intervals for which the nuclear unit is partially loaded. The average partial loading (of the nuclear power level) is higher in the many-interval model with variable heat-rate, and in turn, the critical fossil incremental power level(**) is lower, and hence OCNP is lower.

This effect is amply illustrated by re-examining Table 5.8b and Table 5.8c, an optimal solution from Model D, with variable heat-rate compared with Model E, with constant

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(*) For reasons of economy, the variable nuclear heat-rate model tends to shut down generation during some intervals which otherwise would be lightly loaded, to raise the power levels of other partially loaded intervals to more efficient operating power levels.

(**) Critical fossil incremental power level is the power level used to determine the OCNP value. Refer to Section 3.1.1 for the determination of the OCNP value.

heat-rate. Model E had a partial nuclear power setting at 275 MWe and Model D had an average nuclear partial power setting of 832 MWe. Similarly, the critical fossil incremental power level for Model E was 2057 MWe; while for Model D, the (weighted average) critical incremental power level was 2031 MWe. It is expected for two models with the same average nuclear heat-rate that the critical fossil incremental power level will be lower for a variable heat-rate model than for a constant heat-rate model. Therefore, most OCNP deviations of Model E compared with Model D would be positive, which is comfirmed by the experimental results.

It is possible to compensate for this effect by assuming a lower effective nuclear heat-rate for the constant nuclear heat-rate model than used in a detailed load model simulation. This is the justification for using an average nuclear heat-rate value equivalent to 100% rated capacity in the six-interval model for system optimization studies.

In conclusion, the satisfactory results of the six-interval load-duration model with constant nuclear heat-rate was used in obtaining the weekly OCNP functions for three system simulations. As mentioned earlier, further details on the load-duration sensitivity studies are supplied in Appendix A.6.

5.3 Single Reactor Optimization Study - Case_1

The single reactor optimization study involved finding the optimal weekly nuclear capacity factor distribution over a 26-week time horizon for a 1100 MWe nuclear reactor in the system described in Section 5.1. First, the optimization procedure is to calculate a weekly OCNP function for each week in the time horizon using PROCOST. The 26 weekly OCNP functions are tabulated in Table 5.10 and plotted in Figure 5.1 by their respective months. The OCNP values have been calculated for values of weekly nuclear capacity factor between 0.55 and 0.95 at intervals of 0.10. The values for the weekly nuclear capacity factors were chosen arbitrarily. The density and spacing of data points is at the user's discretion. The criterion depends on which of the system conditions are being modeled. Secondly, the 26 weekly OCNP functions were fed to ALLOCAT to calculate the optimal weekly nuclear capacity factor distribution. The results are tabulated in Table 5.11. The weekly nuclear capacity factors were allowed to have a maximum value of 0.95, a minimum value of 0.55 and intermediate values at intervals of 0.10. Before discussing the optimization results further, some fundamental principles of OCNP must be stated first.

Examining Figure 5.1 or Table 5.10, these distinguishing characteristics of weekly OCNP functions are discernable: (1) The OCNP functions are monotonically decreasing functions with respect to an increasing nuclear capacity factor. (2) The weekly OCNP functions of different

TABLE 5.10

WEEKLY OCNP FUNCTIONS FROM THE SINGLE REACTOR OPTIMIZATION
(CASE 1)

Month	Week	OCNP (Mills/KWHe) Weekly Nuclear Capacity Factor 0.55	0.65	0.75	0.85	0.95
April	1	8.86	6.83	6.79	6.09	5.03
	2	9.10	7.74	6.83	6.09	5.08
	3	8.49	6.79	6.09	5.25	5.03
	4	6.40	5.39	5.03	4.97	4.66
May	5	8.86	7.65	6.79	5.25	5.03
	6	8.30	6.79	5.39	5.03	4.96
	7	8.83	6.79	6.50	5.03	5.00
	8	8.86	7.74	6.79	5.39	5.03
	9	7.74	5.39	5.03	5.00	4.66
June	10	6.40	5.39	5.03	4.71	4.56
	11	6.40	6.09	5.06	4.98	4.63
	12	6.09	5.08	5.00	4.66	4.52
	13	6.09	5.03	4.96	4.66	4.28
July	14	4.96	4.56	4.28	3.82	3.50
	15	6.09	5.03	4.71	4.56	4.07
	16	5.39	4.87	4.66	4.46	3.82
	17	6.09	5.03	4.77	4.56	4.07
	18	5.84	5.00	4.66	4.56	4.07
August	19	5.03	4.71	4.66	4.28	3.58
	20	6.09	5.03	4.87	4.66	4.07
	21	5.39	5.00	4.66	4.56	3.82
	22	5.39	5.03	4.71	4.56	3.82
September	23	7.28	6.79	6.40	6.09	5.06
	24	6.83	6.40	6.09	5.06	4.87
	25	6.83	6.40	6.09	5.08	4.96
	26	7.28	6.79	6.40	6.09	5.06

Figure 5.1

WEEKLY OCNP FUNCTIONS FROM THE
SINGLE REACTOR OPTIMIZATION STUDY, CASE 1

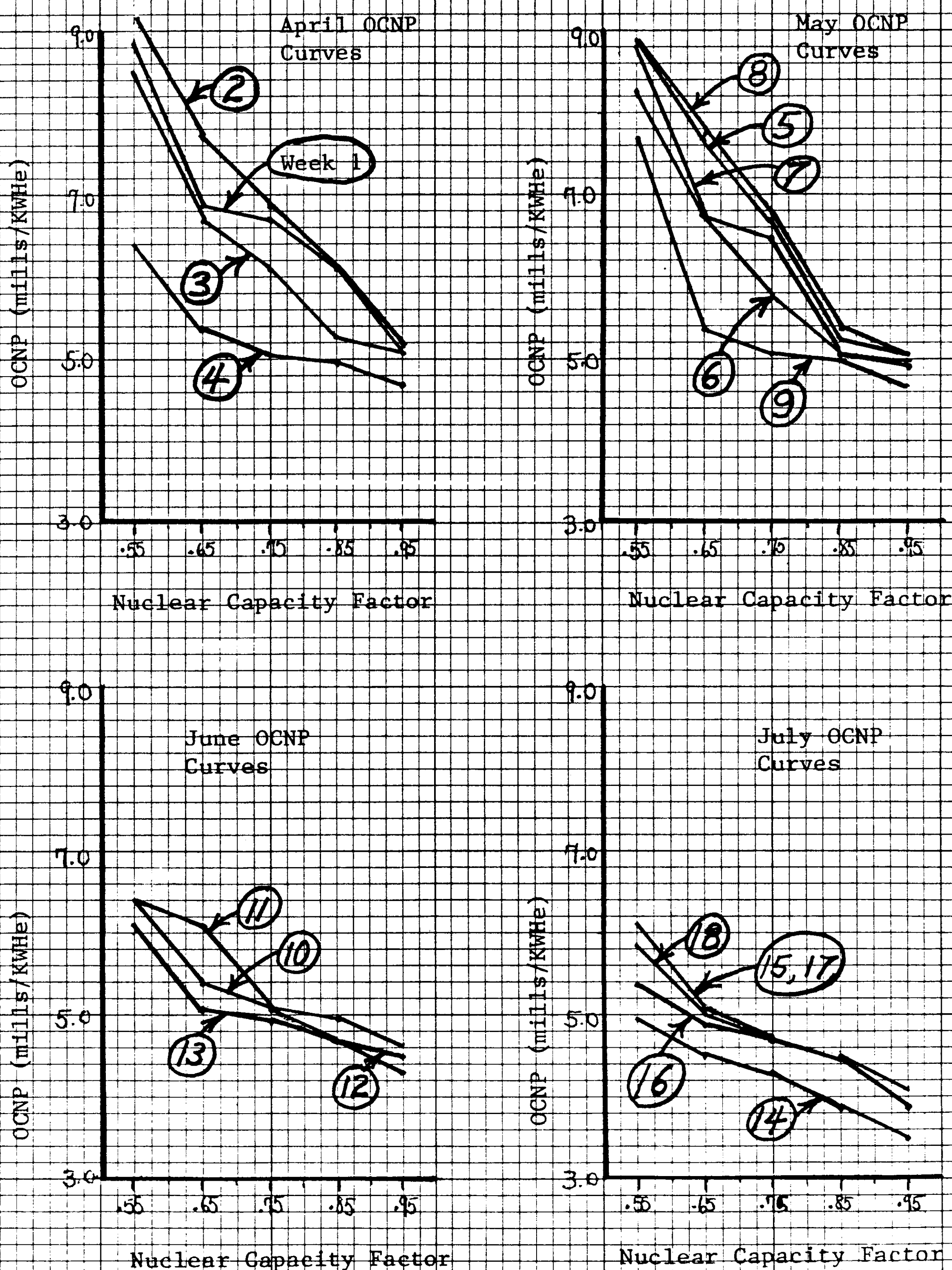
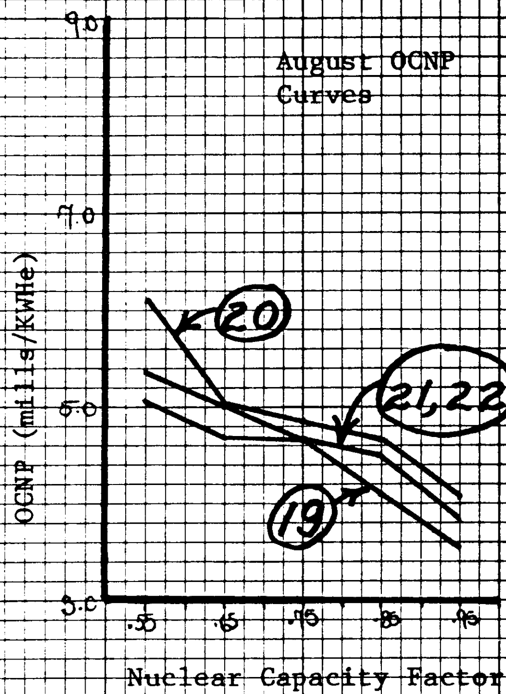


Figure 5.1 (CONT'D)



Note: Circled numbers refer to week numbers given in Table 5.10

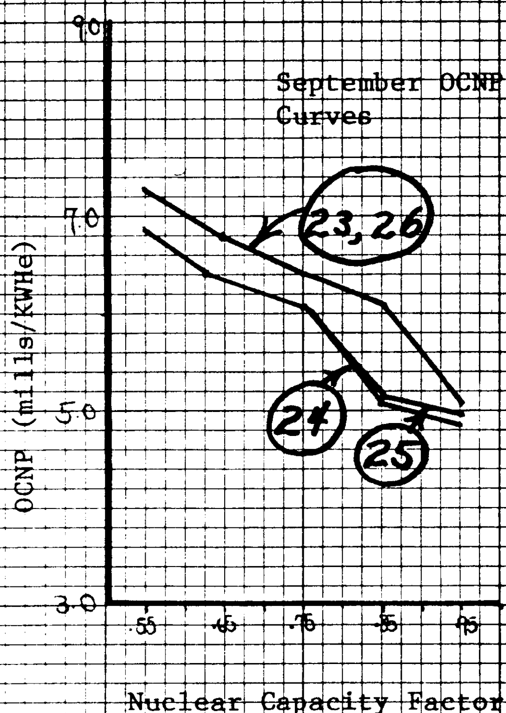


TABLE 5.11

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION FOR THE SINGLE REACTOR OPTIMIZATION (CASE 1)

Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average Energy (10^3 MWH)
April	1	0.85	157.08	609.84	152.46
	2	0.95	175.56		
	3	0.85	157.08		
	4	0.65	120.12		
May	5	0.85	157.08	711.48	142.29
	6	0.75	138.60		
	7	0.75	138.60		
	8	0.85	157.08		
	9	0.65	120.12		
June	10	0.65	120.12	480.48	120.12
	11	0.75	138.60		
	12	0.65	120.12		
	13	0.55	101.64		
July	14	0.55	101.64	508.20	101.64
	15	0.55	101.64		
	16	0.55	101.64		
	17	0.55	101.64		
	18	0.55	101.64		
August	19	0.55	101.64	406.56	101.64
	20	0.55	101.64		
	21	0.55	101.64		
	22	0.55	101.64		
September	23	0.95	175.56	646.80	161.70
	24	0.85	157.08		
	25	0.85	157.08		
	26	0.85	157.08		
Total			3,363.36		129.36

weeks (but the same monthly fossil configurations) never cross. (3) For weeks of increasing weekly energy consumption, the OCNP function likewise increases. (4) The larger the weekly energy consumption (with the same fossil configuration), the larger the slope of the OCNP function. (5) The weekly OCNP functions assumes a shape characteristic of their respective economic loading order. (6) The amplitude of the OCNP function varies inversely with the weekly system reserve. (7) The higher the average fossil fuel cost of the monthly system configuration, the higher the OCNP value.

The basis for the above characteristics of OCNP is the fact that the particular OCNP values are obtained indirectly from the economic loading order. It is the interactions of the system reserve and the demand function that determines the exact location on the economic loading order that an OCNP is read off. To clarify the latter two points (6 and 7), reference may be made to Table 5.12, a tabulation of the average fossil fuel cost of all the fossil components of the monthly system configurations, and Table 5.13, a tabulation of the system's weekly reserve.

The results of Case 1, the optimized weekly nuclear capacity factor distribution tabulated in Table 5.1 reflects many of the OCNP principles stated above. The overall nuclear capacity factor for the six-month planning period was 70%. The high weekly nuclear capacity factor for September reflects the unusually high fossil fuel cost for

TABLE 5.12

MONTHLY AVERAGE FOSSIL FUEL COSTS OF
THE FOSSIL CONFIGURATION
FOR CASES 1 AND 2

Month	Fuel Costs Mills/KWH
April	6.84
May	7.10
June	6.63
July	6.80
August	6.88
September	7.49

TABLE 5.13

WEEKLY SYSTEM RESERVE
FOR CASES 1 AND 2

Month	April				May				
Week	1	2	3	4	5	6	7	8	9
Total gross generating capacity, MW	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage, MW	2,505	2,505	2,505	2,505	2,690	2,690	2,690	3,690	2,690
Nuclear scheduled outage,* MW	880	880	880	880	660	660	660	660	660
Fossil forced outage, MW	2,420	2,420	2,420	2,420	2,570	2,570	2,570	2,570	2,570
Net generating capacity MW	13,945	13,945	13,945	13,945	13,830	13,830	13,830	13,830	13,830
Weekly peak load, MW	13,577	13,795	13,207	12,472	13,149	12,747	12,937	13,206	12,517
Net reserve, MW	368	150	738	1,473	681	1,083	893	624	1,313

Month	June				July				
Week	10	11	12	13	14	15	16	17	18
Total gross generating capacity, MW	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage, MW	1,340	1,340	1,340	1,340	895	895	895	895	895
Nuclear scheduled outage,* MW	440	440	440	440	220	220	220	220	220
Fossil forced outage, MW	2,555	2,555	2,555	2,555	2,045	2,045	2,045	2,045	2,045
Net generating capacity, MW	15,415	15,415	15,415	15,415	16,600	16,600	16,600	16,600	16,600
Weekly peak load, MW	13,951	14,227	13,793	13,456	12,954	14,143	13,869	14,226	14,079
Net reserve, MW	1,464	1,188	1,632	1,959	3,646	2,457	2,731	2,374	2,521

Month	August				September			
Week	19	20	21	22	23	24	25	26
Total gross generating capacity, MW	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage, MW	750	750	750	750	2,225	2,225	2,225	2,225
Nuclear maintenance outage,* MW	0	0	0	0	0	0	0	0
Fossil forced outage, MW	2,065	2,065	2,065	2,065	2,015	2,015	2,015	2,015
Net generating capacity, MW	16,915	16,915	16,915	16,915	15,510	15,510	15,510	15,510
Weekly peak load, MW	13,911	14,650	14,299	14,393	13,919	13,034	13,076	13,936
Net reserve, MW	3,054	2,315	2,666	2,572	1,591	2,476	2,434	1,574

*Program startup limitation for Nuclear Unit 2.

that month. All the other months have about the same fossil fuel cost, as shown in Table 5.12. September, due to its significantly more expensive fossil fuel cost configuration is scheduled to generate at near full capacity, to displace as much of the expensive fossil fuel as possible. August and July have the lowest average weekly nuclear capacity factor, in fact, the lowest allowed, because of their large reserve capacity, Table 5.13. April has the lowest system reserve, hence the second largest set of weekly nuclear capacity factors. May is the second tightest month system reserve-wise, and also has the second highest fossil fuel configuration. May also has an above average monthly nuclear capacity factor. June has the lowest fossil fuel cost configuration and sufficient reserve such that its monthly nuclear capacity factor is below the average for the whole planning period. Within each monthly schedule, the weekly allotments of nuclear energy are proportional to the weekly energy consumption forecast, see Table 5.3. The low summer (June, July, and August) weekly nuclear capacity factors also reflect a seasonal influence. Demand peaks fluctuate a great deal more during the summer than during other seasons. Hence, the average capacity factor for the summer would be lower than during any other season with the same system reserve.

The overall impression from the results of this optimization study for the system simulated is that the maintenance scheduled was too unbalanced in excluding summer maintenance. Gross generating capacity is large enough to handle the summer peaks while still scheduling more maintenance during August and July, and less during April and May. Also, a better mix of fossil plants should be scheduled for September to give a lower fossil fuel cost rate.

A total system cost calculation from the optimization results of Case 1 showed a very large dollar savings; see Table 5.14. Comparing the situation of no nuclear optimization, Case 1.A, (uniform hourly nuclear power generation for the entire six months), with the situation of constant weekly nuclear capacity factor, Case 1.B (optimized hourly generation), the saving was $4.4 million in fossil fuel costs. By further optimizing the weekly nuclear capacity factor distribution over the six-month time horizon, Case 1.C, the saving increased by another $340,000. For comparison, the total fossil fuel savings are equivalent to 66% of the nuclear fuel cost of Nuclear Unit 1, at 2.0 mills/KWH. The order of magnitude of the savings for Case 1 indicates that even for a single-reactor utility system, short-range optimization is worth-while in the resource-limited situations.

Table 5.14

SYSTEM FOSSIL FUEL COSTS AND SAVINGS FOR CASE 1

Month	Week	Case 1.A No Nuclear Optimization ($)	Case 1.B Hourly Optimization ($)	Case 1.C Hourly and Weekly Optimization ($)
April	1	10,897,641	10,703,601	10,524,562
	2	11,310,309	11,002,306	10,708,211
	3	10,401,792	10,220,996	10,056,930
	4	9,496,691	9,326,228	9,373,436
May	5	10,585,981	10,406,225	10,227,973
	6	10,078,719	9,886,612	9,830,631
	7	10,316,433	10,126,110	10,063,502
	8	10,660,648	10,482,397	10,300,385
	9	9,762,971	9,611,780	9,660,533
June	10	9,899,898	9,755,839	9,802,719
	11	10,210,651	10,063,304	10,013,456
	12	9,725,349	9,586,475	9,632,938
	13	9,369,029	9,242,724	9,387,855
July	14	8,847,012	8,746,190	8,873,310
	15	9,950,572	9,816,608	9,959,853
	16	9,670,594	9,555,670	9,692,954
	17	10,037,142	9,858,900	10,004,974
	18	9,883,377	9,753,496	9,894,948
August	19	9,623,066	9,517,456	9,652,246
	20	10,378,333	10,230,513	10,380,137
	21	10,002,896	9,877,511	10,016,482
	22	10,101,697	9,968,648	10,109,134
September	23	11,538,985	11,379,984	11,101,378
	24	10,879,069	10,716,938	10,559,049
	25	10,908,873	10,745,769	10,586,767
	26	11,551,409	11,390,192	11,216,616
Total		266,089,137	261,988,509	261,648,975
Comparison with Case 1.A		-	(4,100,628)	(4,440,162)

Case 1.A: Unit 1 is run at constant power (725 Mw), and Unit 2 is run at programmed power levels (Table 5.15) for all three cases.

Case 1.B: The weekly energy output of Unit 1 is the same as in Case 1.A, but the hourly power level within each week is optimized.

Case 1.C: Unit 1's power levels for each hour of each week are optimized for the entire six-month planning period.

Total energy output of Unit 1 is the same in all three cases.

TABLE 5.15

PROGRAMMED CONSTANT POWER LEVELS OF NUCLEAR UNIT 2 FOR CASES 1 AND 3

Month	Power Level (MWe)
April	220
May	440
June	660
July	880
August	1100
September	1100

5.4 Multi-Reactor Optimization Study - Case 2

In a multi-reactor resource-limited optimization, the optimal solution is approached iteratively. In the first iteration a weekly nuclear capacity factor distribution is assumed for all the reactors in the system except one, the first reactor to be optimized. The resulting weekly OCNP functions for that reactor (for the entire planning period) are input to ALLOCAT to calculate its optimal distribution. In the second iteration, the first reactor is assigned the capacity factor distribution obtained in the first iteration, and the second reactor is optimized (via ALLOCAT), with all the other reactors having the same weekly nuclear capacity factor distribution used in the first iteration. This process is repeated for each reactor in the system successively. The first cycle of optimization is complete when each reactor has been optimized once. A second cycle of optimization is initiated to improve on the first cycle since more complete information is then known about the operation of the system nuclear reactors. The cycles of optimization are repeated until there is a convergence of all the reactors' weekly capacity factors, or until improvement in system costs savings becomes insignificant. These optimization procedures are illustrated below.

The multi-reactor optimization problem considered in this thesis, Case 2, is an extension of the first simulation, with the added complication that Nuclear Unit 2 is also assumed to be limited in its production capacity.

The operating constraints of Unit 2 are given in Table 5.4. Nuclear Unit 1 has a 70% overall nuclear capacity factor for the same six month planning period. The remainder of the system is the same as Case 1, described in Section 5.1. The first step in finding the optimal weekly nuclear capacity factor distribution of both reactors was to calculate the weekly OCNP functions (using PROCOST). The weekly OCNP functions for Nuclear Unit 1 were calculated for weekly nuclear capacity factors from 0.55 to 0.95 at intervals of 0.10. The weekly OCNP function of Nuclear Unit 2 were calculated at four nuclear capacity factor values for April (8, 12, 16, 20%), four for May (16, 24, 32, 40%), five for June (36, 42, 48, 54, 60%), five for July (48, 56, 64, 72, 80%) and five for August and September (60, 70, 80, 90, 100%). The weekly OCNP functions for Case 2 are tabulated in Appendix B.3.

OCNP values are required for all the possible permutations of the weekly nuclear capacity factors of the two reactors to be pre-calculated because: (1) it is not known before hand which OCNP values are needed; (2) there is an economy of scale in computational efforts (and costs) in calculating all OCNP values at once, instead of by a piecemeal process. This procedure calculates many more OCNP than needed. However, OCNP calculations via six-interval load-duration models are fast enough that it is not a serious drawback. As experience (and insight) on the utility system responds is gained the system planner will be able to specify a much narrower range in nuclear capacity factors (and hence need few OCNP data points calculated). This will greatly reduce computational costs by eliminating the calculation of most of the unnecessary OCNP values and will be especially desirable as the number of reactors increases.

In deciding which reactor (Unit 1 or 2) to optimize in the first iteration, Nuclear Unit 1 was noted to be relatively 'more' resource-limited, and that Unit 2 has strict limitations on shifting its energy from week to week. Thus, it seems that starting the optimization process with Unit 1 would lead to more rapid convergence. Hence, Nuclear Unit 1 was optimized in the first iteration where Nuclear Unit 2 is assumed to have a constant weekly nuclear capacity factor distribution. Table 5.16 tabulates the nuclear capacity factor distribution of each reactor at the end of each iteration. Under Column I of Table 5.16 are listed the results of the first multi-reactor iteration. The only difference in system conditions between the first iteration of the multi-reactor optimization and the the single reactor optimization problem is that Unit 2 has 20% less energy, across the entire 26 weeks. The difference in results comparing the solution of the first iteration (of the multi reactor case) with the solution of the single reactor optimization (Table 5.11) is a shift in energy from April and June to September. To a first approximation, all months should be equally affected. As stated earlier, the

TABLE 5.16

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION
FOR THE MULTIREACTOR SIMULATION
(CASE 2)

		Limitations on Unit 2		Weekly Nuclear Capacity Factor (%)					
				Unit 2			Unit 1		
Week	Month	(% Power)	Iterations:	Initial	II	IV	Initial	I	III
1	April	20		16	20	20	70	85	85
2				16	16	16	70	95	95
3				16	16	16	70	85	75
4				16	12	12	70	55	65
5	May	40		32	32	32	70	85	85
6				32	32	32	70	75	75
7				32	32	32	70	75	75
8				32	32	32	70	85	85
9				32	32	32	70	65	65
10	June	60		48	48	48	70	65	65
11				48	54	54	70	65	65
12				48	48	48	70	55	55
13				48	42	42	70	55	55
14	July	80		64	48	48	70	55	55
15				64	72	72	70	55	55
16				64	64	64	70	55	55
17				64	72	72	70	55	55
18				64	64	64	70	55	55
19	August	100		80	70	70	70	55	55
20				80	80	80	70	55	55
21				80	80	80	70	55	55
22				80	70	70	70	55	55
23	September	100		80	90	90	70	95	95
24				80	80	80	70	95	95
25				80	80	80	70	95	95
26				80	90	90	70	95	95

reason for September's larger use of nuclear energy is its higher fossil fuel cost alternative. Hence, September has a relatively greater need for nuclear energy.

Nuclear Unit 2 has five separate planning periods in the six month planning horizon under consideration. In each of the smaller planning periods is associated a different operating capacity level and a different capacity factor objective. Hence, Unit 2 is be treated as if it is a collection of five separate reactors where only one reactor is on-line at a time.

In the second iteration, Unit 2 is optimized five times, in each of its separate planning periods. Nuclear Unit 1 is assumed to have the distribution calculated by the first iteration. The weekly OCNP functions of Unit 2 used in its optimization must be carefully matched to the proper weekly nuclear capacity factor of Nuclear Unit 1. The results of the second iteration are listed in Table 5.16 under Column II. The weekly distribution of Unit 2 (in each month) shows a correlation of nuclear capacity factors to the energy consumption pattern in each month.

For weeks of higher energy consumption, the weekly nuclear capacity factor is higher. The exception is May where most of correlation effect was already displayed in Unit 1's May weekly nuclear capacity factors. The step sizes in May's value of weekly nuclear capacity factors were large enough not to require any further changes in Unit 2's May weekly nuclear capacity factors. Optimizing each reactor of the system once completes the first cycle of the optimization process. The second cycle starts (iteration III) with Unit 1 being optimized again, from the weekly nuclear capacity factor distribution for Unit 2 solved in iteration II. The results of iteration III compared with iteration I show that only the weekly nuclear capacity factors of April have been changed, indicating that absolute convergence is near. Iteration IV of Unit 2 shows identical results to iteration II indicating convergence has been reached. Technically, Unit 1 should be optimized again to compare iteration V with iteration III, to show Unit 1 also has reached convergence. But in a two-reactor system, this step is not necessary since iteration V is based on iteration IV, and iteration III is based on iteration II. It was shown that iteration II and IV are identical, hence, iteration III and V must also be identical. Thus only two complete cycles of iteration were necessary to find complete convergence in this multi reactor simulation.

The optimal nuclear energy distribution for Case 2 is given in Table 5.17. A detailed tabulation of the weekly system costs before and after optimization is given in Table 5.18A. A summary of changes in system cost with each iteration is given in Table 5.19. The complete two-reactor optimization, Case 2.C, results in a total savings of $6.48 million compared with the situation of no nuclear optimization, Case 2.A. Of this, $600,000 represents the improvement from the situation of optimal hourly generation,

TABLE 5.17

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION
FOR THE TWO REACTOR OPTIMIZATION (CASE 2)

		Unit 1				Unit 2			
Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average (10^3 MWH)	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average (10^3 MWH)
April	1	0.85	157.08	591.36	147.84	0.20	36.96	118.272	29.568
	2	0.95	175.56			0.16	29.568		
	3	0.75	138.60			0.16	29.568		
	4	0.65	120.12			0.12	22.176		
May	5	0.85	157.08	711.48	142.296	0.32	59.136	295.680	59.136
	6	0.75	138.60			0.32	59.136		
	7	0.75	138.60			0.32	59.136		
	8	0.85	157.08			0.32	59.136		
	9	0.65	120.12			0.32	59.136		
June	10	0.65	120.12	443.52	110.88	0.48	88.704	354.816	88.704
	11	0.65	120.12			0.54	99.792		
	12	0.55	101.64			0.48	88.704		
	13	0.55	101.64			0.42	77.616		
July	14	0.55	101.64	508.20	101.64	0.48	88.704	591.360	118.272
	15	0.55	101.64			0.72	133.056		
	16	0.55	101.64			0.64	118.272		
	17	0.55	101.64			0.72	133.056		
	18	0.55	101.64			0.64	118.272		

TABLE 5.17 (CONT'D)

Month	Week	Unit 1 Capacity Factor	Unit 1 Weekly Energy (10^3 MWH)	Unit 1 Monthly Total Energy (10^3 MWH)	Unit 1 Monthly Average (10^3 MWH)	Unit 2 Capacity Factor	Unit 2 Weekly Energy (10^3 MWH)	Unit 2 Monthly Total Energy (10^3 MWH)	Unit 2 Monthly Average (10^3 MWH)
August	19	0.55	101.64	406.56	101.64	0.70	129.36	554.40	138.60
	20	0.55	101.64			0.80	147.84		
	21	0.55	101.64			0.80	147.84		
	22	0.55	101.64			0.70	129.36		
September	23	0.95	175.56	702.24	175.56	0.90	166.32	628.32	157.08
	24	0.95	175.56			0.80	147.84		
	25	0.95	175.56			0.80	147.84		
	26	0.95	175.56			0.90	166.32		
Total			3,363.36		129.36		2,542.848		97.80

TABLE 5.18A

SYSTEM FOSSIL FUEL COSTS AND SAVINGS
FOR TWO-REACTOR OPTIMIZATION
(CASE 2)

Month	Week	Case*: 2. A No Nuclear Optimization Cost ($)	2. B Hourly Optimization Cost ($)	2. C Hourly and Weekly Optimization Cost ($)
April	1	10,984,873	10,751,527	10,524,562
	2	11,436,858	11,052,846	10,749,480
	3	10,472,818	10,265,793	10,205,833
	4	9,561,435	9,364,134	9,453,621
May	5	10,735,700	10,507,216	10,310,620
	6	10,222,590	9,972,556	9,910,359
	7	10,462,552	10,220,627	10,155,671
	8	10,811,841	10,585,440	10,280,708
	9	9,902,855	9,691,986	9,745,326
June	10	10,086,561	9,868,042	9,917,193
	11	10,415,368	10,180,886	10,168,957
	12	9,905,807	9,696,814	9,852,382
	13	9,541,326	9,350,635	9,557,760
July	14	9,032,621	8,874,746	9,148,500
	15	10,176,826	9,959,049	10,029,367
	16	9,887,665	9,694,897	9,834,490
	17	10,265,846	10,042,109	10,114,799
	18	10,107,604	9,895,235	10,038,452
August	19	9,862,243	9,689,701	9,920,240
	20	10,648,551	10,411,466	10,562,431
	21	10,262,717	10,054,863	10,195,603
	22	10,364,649	10,147,153	10,390,699
September	23	11,871,600	11,615,127	11,204,110
	24	11,185,083	10,939,281	10,655,633
	25	11,217,640	10,968,761	10,684,321
	26	11,884,316	11,627,532	11,216,240
Total		271,307,945	265,428,422	264,827,357
Relative Savings compared to Case A		0	5,879,523	6,480,588

*In Case A, Unit 1 is run at constant power of 725 Mw. Unit 2 is run at predetermined power level shown in Table 5.18B.
In Case B, the weekly energy output of both units is the same as in Case A, but the hourly power level within each week is optimized.
In Case C, power levels for each hour of each week are optimized within the constraints shown in Table 5.4. Total energy output from each reactor is the same in all cases.

TABLE 5.18B

PROGRAMMED CONSTANT POWER LEVELS OF NUCLEAR UNIT 2
FOR CASE 2.A

Month	Power Level (MW)
April	167
May	330
June	497
July	667
August	853
September	853

TABLE 5.19

SUMMARY OF TWO-REACTOR OPTIMIZATION COST SAVINGS
AS A FUNCTION OF NUMBER OF ITERATIONS

Case	2.A	2.B	2.C			
Iterations on Weekly Energy Allocations			I	II	III	IV
Total Cost, $	271,307,945	265,428,422				264,827,357
Savings Relative to Case 2.B, $	-5,879,523	0	555,334	593,897	601,065	601,065

Case 2.B, compared with the total optimization results, Case 2.C.

Table 5.19 indicates that most of the savings were realized after only one complete cycle of iterations in this two-reactor system. Other simulations have confirmed the hypothesis that the multi-reactor iteration process is a rapidly convergent one.

The major conclusions of this multi reactor simulation are that: (1) the short-range resource-limited optimization process described in this thesis has been shown adaptable to a two-reactor situation, (2) convergence takes only a few complete cycles of iterations, (3) most of the cost savings is realized after one or two complete cycles of iterations, (4) substantial savings in fossil fuel cost are possible with short-range optimization, and (5) potential cost savings increase as the amount of nuclear capacity and energy that are optimized are increased.

5.5 Single Reactor Optimization Study-Case 3

The purpose of Case 3 was to examine the effect of system reserves on OCNP, and on the optimal weekly nuclear capacity factor distribution. Case 3 is a modification of Case 1 where the fossil outage schedule (Table 5.1) has been adjusted to obtain a (nearly) constant minimum monthly system reserve, see Table 5.5. The original outage schedule (Table 5.1) was altered by moving the outage of as few units as possible within the six-month planning horizon. Most of the alteration occurred in the maintenance outage schedule. The few changes made in the forced outage schedule were aimed at achieving a better balance in the monthly forced outage total compared with the monthly net generating capacity.

The 26-week OCNP values for Case 3 are listed in Table 5.20. The weekly system reserves are listed in Table 5.21. The average fossil generation costs of the monthly fossil configurations are listed in Table 5.22. The optimal weekly nuclear capacity factor distribution is listed in Table 5.23.

A comparison of the optimal nuclear capacity factor distribution for Case 1 and Case 3 (Tables 5.11 and 5.23) shows a decrease of allocated energy for April and May, and an increase for July, August, and September. The June allotment is the same for both cases. The change in monthly allocation of nuclear energy is consistent with the change in the monthly minimum system reserve, both in direction and

TABLE 5.20

WEEKLY OCNP FUNCTIONS FROM THE SINGLE REACTOR OPTIMIZATION
(Case 3)

Month	Week	Weekly Nuclear Capacity Factors:	OCNP (Mills/KWHe)				
			0.55	0.65	0.75	0.85	0.95
April	1		6.40	6.09	5.83	5.03	4.96
	2		6.79	6.40	6.09	5.08	5.00
	3		6.40	5.83	5.03	5.00	4.66
	4		5.39	5.00	4.77	4.66	4.46
May	5		6.79	6.09	5.25	5.03	4.87
	6		6.09	5.06	5.03	4.87	4.66
	7		6.40	5.39	5.03	4.97	4.66
	8		6.79	6.09	5.39	5.03	4.87
	9		6.09	5.03	4.97	4.66	4.63
June	10		6.09	5.39	5.03	4.96	4.63
	11		6.40	6.09	5.08	5.00	4.66
	12		6.09	5.08	5.03	4.72	4.57
	13		6.09	5.03	4.97	4.66	4.53
July	14		5.00	4.66	4.57	4.16	3.58
	15		6.09	5.08	5.00	4.66	4.29
	16		6.09	5.03	4.87	4.63	4.16
	17		6.40	5.08	5.00	4.66	4.29
	18		6.09	5.03	4.96	4.66	4.29
August	19		5.39	5.00	4.77	4.57	3.82
	20		6.79	5.39	5.03	4.77	4.46
	21		6.09	5.03	4.97	4.66	4.29
	22		6.40	5.08	5.00	4.66	4.43
September	23		7.28	6.79	6.40	6.09	5.25
	24		6.83	6.40	6.09	5.25	4.97
	25		6.83	6.40	6.09	5.39	5.00
	26		7.28	6.79	6.40	6.09	5.25

TABLE 5.21

WEEKLY SYSTEM RESERVE FOR CASE 3

Month	April				May				
Week	1	2	3	4	5	6	7	8	9
Total gross generating capacity, Mw	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage, Mw	1,705	1,705	1,705	1,705	2,465	2,465	2,465	2,465	2,465
Nuclear scheduled outage,* Mw	880	880	880	880	660	660	660	660	660
Fossil forced outage, Mw	1,920	1,920	1,920	1,920	2,070	2,070	2,070	2,070	2,070
Net generating capacity, Mw	15,245	15,245	15,245	15,245	14,555	14,555	14,555	14,555	14,555
Weekly peak load, Mw	13,577	13,795	13,207	12,472	13,149	12,747	12,937	13,206	12,517
Net reserve, Mw	1,668	1,450	2,038	2,773	1,406	1,708	1,618	1,349	2,038

Month	June				July				
Week	10	11	12	13	14	15	16	17	18
Total gross generating capacity, Mw	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage, Mw	1,130	1,130	1,130	1,130	1,415	1,415	1,415	1,415	1,415
Nuclear scheduled outage,* Mw	440	440	440	440	220	220	220	220	220
Fossil forced outage, Mw	2,555	2,555	2,555	2,555	2,545	2,545	2,545	2,545	2,545
Net generating capacity, Mw	15,625	15,625	15,625	15,625	15,580	15,580	15,580	15,580	15,580
Weekly peak load, Mw	13,951	14,227	13,793	13,456	12,954	14,143	13,869	14,226	14,079
Net reserve, Mw	1,674	1,398	1,842	2,169	2,626	1,437	1,711	1,354	1,501

Month	August				September			
Week	19	20	21	22	23	24	25	26
Total gross generating capacity, Mw	19,750	19,750	19,750	19,750	19,750	19,750	19,750	19,750
Fossil maintenance outage, Mw	1,240	1,240	1,240	1,240	2,500	2,500	2,500	2,500
Nuclear maintenance outage,* Mw	0	0	0	0	0	0	0	0
Fossil forced outage, Mw	2,565	2,565	2,565	2,565	2,015	2,015	2,015	2,015
Net generating capacity, Mw	15,925	15,925	15,925	19,925	15,285	15,285	15,285	15,285
Weekly peak load, Mw	13,911	14,650	14,299	14,393	13,919	13,034	13,076	13,936
Net reserve, Mw	2,064	1,325	1,676	1,582	1,366	2,251	2,209	1,349

*Program startup limitation for Nuclear Unit 2.

TABLE 5.22

MONTHLY AVERAGE FOSSIL GENERATION COSTS OF THE FOSSIL CONFIGURATION FOR CASE 3

Month	Generation Costs (Mills/KWH)
April	6.84
May	6.85
June	6.39
July	6.90
August	7.04
September	7.54

TABLE 5.23

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION FOR THE SINGLE REACTOR OPTIMIZATION (CASE 3)

Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Energy (10^3 MWH)	Monthly Average Energy (10^3 MWH)
April	1	0.85	157.08	554.40	138.60
	2	0.85	157.08		
	3	0.75	138.60		
	4	0.55	101.64		
May	5	0.85	157.08	674.52	134.90
	6	0.75	138.60		
	7	0.75	138.60		
	8	0.75	138.60		
	9	0.55	101.64		
June	10	0.65	120.12	480.48	120.12
	11	0.75	138.60		
	12	0.65	120.12		
	13	0.55	101.64		
July	14	0.55	101.64	545.16	109.03
	15	0.65	120.12		
	16	0.55	101.64		
	17	0.65	120.12		
	18	0.55	101.64		
August	19	0.55	101.64	443.51	110.88
	20	0.65	120.12		
	21	0.55	101.64		
	22	0.65	120.12		
September	23	0.95	175.56	665.28	166.32
	24	0.85	157.08		
	25	0.85	157.08		
	26	0.95	175.56		
Total			3,363.36		129.36

magnitude. April and May had large increases in reserves, hence significant decreases in nuclear energy allotments. July and August had large decreases in system reserve, hence significant increases in nuclear energy allotments. June had the smallest monthly change in system reserves (210 MW), not enough to change its nuclear energy allocation. Sepember had a slight decrease in system reserves (225 MW), hence a slight increase the nuclear energy allotment. The comparison of the solution of Case 1 with Case 3 shows conclusively the significant effect an unequal system reserve has on the optimal distribution of nuclear energy.

Table 5.24 shows the cost savings in Case 3 made possible by successively optimizing the hourly use of nuclear energy while holding weekly allocation fixed (Case 3.B) and then optimizing both hourly and weekly use of nuclear energy (Case 3.C). Hourly optimization saves $4.4 million and both hourly and weekly save $4.7 million, about 70% of Nuclear Unit 1's fuel cycle cost at 2.0 mills/KWHe.

Comparison of Table 5.24 for Case 3 with Table 5.14 for Case 1 show that the total system fossil fuel costs for the changed maintenance and forced-outage schedule of Case 3 was a little more than $2 million lower than Case 1. Comparing Cases B to Cases C, hourly optimization to weekly optimization, the savings are $160,000 for Case 3 and $340,000 for Case 1. It is to be expected that as the system reserves becomes equalized, the optimal distribution of capacity factors becomes narrower and hence the

TABLE 5.24

SYSTEM FOSSIL FUEL COSTS AND SAVINGS FOR CASE 3

Month	Week	Case 3.A	Case 3.B	Case 3.C
April	1	10,629,018	10,452,025	10,309,019
	2	10,886,122	10,707,502	10,557,379
	3	10,204,452	10,039,148	9,993,321
	4	9,421,808	9,303,841	9,435,075
May	5	10,084,300	9,898,125	9,762,328
	6	9,624,926	9,454,683	9,411,099
	7	9,839,201	9,659,938	9,614,924
	8	10,151,039	9,964,469	9,915,509
	9	9,377,179	9,212,606	9,347,943
June	10	9,632,264	9,466,427	9,613,347
	11	9,963,262	9,781,430	9,734,177
	12	9,451,599	9,295,217	9,338,910
	13	9,081,760	8,945,116	9,079,552
July	14	8,848,790	8,715,163	9,837,240
	15	10,131,453	9,943,949	9,987,474
	16	9,811,395	9,632,603	9,766,925
	17	10,229,689	10,039,813	9,996,213
	18	10,055,654	9,870,064	10,009,600
August	19	11,455,317	9,641,892	9,773,228
	20	10,770,796	10,491,448	10,535,539
	21	10,803,244	10,075,964	10,216,792
	22	11,468,438	10,185,716	10,229,252
September	23	10,011,848	11,468,807	11,199,903
	24	10,884,673	10,795,505	10,640,491
	25	10,461,200	10,825,555	10,669,462
	26	10,572,132	11,481,658	11,212,542
Total System Costs ($)		263,857,559	259,348,663	259,187,244
Comparison with Case 3.A		-	(4,508,896)	(4,670,315)

Case 3.A: Unit 1 is run at constant power (725 Mw), and Unit 2 is run at programmed power levels (Table 5.15) for all three cases.

Case 3.B: The weekly energy output of Unit 1 is the same as in Case 3.A, but the hourly power level within each week is optimized.

Case 3.C: Unit 1's power levels for each hour of each week are optimized for the entire six-month planning period.

Total energy output of Unit 1 is the same in all three cases.

difference in savings between hourly optimization and weekly optimization diminishes. As mentioned earlier, the low capacity factor of the summer months is partially due to a seasonal influence on the shape of their customer demand function. Both spring and summer have about the same average weekly energy consumption. However summer has much higher demand peaks than the spring, hence summer also has lower demand minimums than spring. Since the lower part of the load-duration curve plays an active role in determining OCNP, it is no surprise that summer months should have lower average nuclear capacity factors (with all other parameters equal).

A major determining system parameter for OCNP is the economic loading order. The economic loading order is made up of several system parameters such as fuel cost, maintenance schedule, heat-rate, etc. The slope of the OCNP curve is a reflection of the slope of the economic loading order from which OCNP is derived. A utility in the short-range has very few system parameters to manipulate. The customer demand is beyond real short term control. A large portion of fuel costs may be fixed by long-term contracts. Heat-rates are built into the physical equipment. The maintenance schedule is the only tool left which the system planner can use to manipulate system reserves and the economic loading order, and in turn OCNP. Because of changing economic conditions, fossil fuel costs show a great amount of variance from station to station.

Hence, the monthly economic loading order will show different patterns for different maintenance schedules. The main conclusion from the system simulations performed is that equal consideration must be given to fossil fuel arrangements as to system reserves when determining the monthly maintenance schedule.

5.6 Applicability

The optimization procedure used in the previous system simulations (Cases 1, 2, 3) has been to optimally peak-shave the nuclear energy within the week, and then find the optimal distribution of nuclear energy among the weeks. This procedure is referred to as the "Peak-Shave First" method. Another optimization procedure would be to optimally distribute the nuclear energy among all the weeks in the planning horizon first, then optimally peak-shave each week's energy within the week. This approach is referred to as the "Peak-Shave Second" method. As an illustration, the single-reactor optimization problem, Case 3, is repeated using the "Peak-Shave Second" method, which is referred to as Case 4.

In Case 4, the optimal weekly distribution of nuclear capacity factors was found by using FOSSIL (instead of PROCOST) to calculate the weekly OCNP functions. FOSSIL modeled the nuclear units operating at fixed power level throughout the entire week. The OCNP values were then fed to ALLOCAT to calculate the optimal weekly nuclear capacity factor distribution. This case is labelled 4.D to signify the difference in optimization procedures as compared to the previous cases. Table 5.25 tabulates the resulting optimal distribution of capacity factors and energies for Case 4.D. Notice that there is some similarity between the optimal distribution for Case 4 and the optimal distribution for Case 3. The peak-shaving of each week's nuclear energy was

TABLE 5.25

OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION FOR CASE 4

Month	Week	Capacity Factor	Weekly Energy (10^3 MWH)	Monthly Total Energy (10^3 MWH)	Monthly Average Energy (10^3 MWH)
April	1	0.80	147.84	526.68	131.67
	2	0.95	175.56		
	3	0.55	101.64		
	4	0.55	101.64		
May	5	0.95	175.56	702.24	140.45
	6	0.70	129.36		
	7	0.80	147.84		
	8	0.80	147.84		
	9	0.55	101.64		
June	10	0.55	101.64	415.80	103.95
	11	0.60	110.88		
	12	0.55	101.64		
	13	0.55	101.64		
July	14	0.55	101.64	535.92	107.18
	15	0.60	110.88		
	16	0.55	101.64		
	17	0.65	120.12		
	18	0.55	101.64		
August	19	0.55	101.64	480.48	120.12
	20	0.85	157.08		
	21	0.55	101.64		
	22	0.65	120.12		
September	23	0.95	175.56	702.24	175.56
	24	0.95	175.56		
	25	0.95	175.56		
	26	0.95	175.56		
Total			3,363.36		129.36

performed by PROCOST, Case 4.E. Table 5.26 tabulates the weekly system cost and savings (compared to Case 3.A) for Case 4. The system problem for Case 3 and 4 was exactly the same, only the optimization procedures applied were different. A comparison of the final results of Case 3.C with 4.E shows that the "Peak-Shave First" method is a better procedure, by $60,000. The cost comparison of Case 4.D with Case 3.A shows a savings of $200,000, about the same savings as the in Case 3 derived from optimally distributing the nuclear energy between the weeks. Comparing Case 4.E with Case 4.D shows that the savings from peak-shaving is $4.4 million, about the same as in Case 3. This comparison shows that the order of magnitude of the savings derived from optimally peak-shaving within the week, and optimally distributing the energy among all the weeks in the planning horizon is roughly independent of the order in which these steps are performed.

The results for Case 4 further document the conclusions of the previous cases that most of the potential savings (millions of dollars per reactor) of short-range nuclear system analysis lies in peak-shaving the operation of the nuclear reactors within a week. Lesser savings (approximately $200,000) are derived from optimally distributing the limited amount of nuclear energy among the weeks. The main reason is that the energy consumption in different weeks throughout a year are more similar to each other than the energy consumption levels for the different

TABLE 5.26

SYSTEM FOSSIL FUEL COSTS AND SAVINGS FOR CASE 4

Month	Week	Case 4.D* ($/Wk)	Case 4.E* ($/Wk)
April	1	10,476,943	10,354,228
	2	10,505,168	10,470,144
	3	10,429,517	10,189,852
	4	9,621,231	9,435,075
May	5	9,710,526	9,676,013
	6	9,627,279	9,454,683
	7	9,690,351	9,571,481
	8	9,997,943	9,871,356
	9	9,594,694	9,347,943
June	10	9,857,137	9,613,347
	11	10,122,781	9,882,328
	12	9,669,964	9,438,299
	13	9,291,620	9,079,552
July	14	9,037,960	8,837,240
	15	10,282,809	10,036,407
	16	10,028,797	9,766,925
	17	10,308,590	10,083,413
	18	10,278,442	10,009,600
August	19	11,238,865	9,773,228
	20	10,587,558	10,361,515
	21	10,616,646	10,216,792
	22	11,251,572	10,229,252
September	23	10,029,392	11,199,903
	24	10,461,847	10,552,515
	25	10,486,044	10,581,086
	26	10,453,215	11,212,542
Total		263,656,891	259,244,719
Comparison with Case 3.A:		(200,674)	(4,612,840)

(*) Case 4.D: The power level of Unit 1 (constant throughout each week) is optimally assigned for each week in the planning period.

(*) Case 4.E: The weekly energy is the same as in Case 4.D, but the hourly power level within each week is optimized (peak shaved).

The total energy output from Unit 1 is the same as in Case 3.

hours of a week. The maximum difference in weekly energy consumption is about 20% whereas the maximum difference in hourly energy consumption is about 250%.

Consideration of the two optimization procedures indicates that the "Peak-Shave First" method is the more logical optimization method. However since peak-shaving calculation are time consuming, the "Peak-Shave Second" method, which solves for the weekly distribution of energy prior to peak-shaving each week, saves computer time (with some loss in precision of the final result). This saving would be of particular importance in multi-reactor optimizations where several iterative calculational cycles are required for each reactor. The "Peak-Shaving Second" method is a more direct but approximate method of calculating the optimal dispatching schedule and hence is useful in narrowing the range in which the more accurate method may be applied, thus conserving calculational effort.

For convenience, the resource-limited case assumed a fixed refueling date in the framework of the problem. However, the date chosen is an independent variable. The study of a variable refueling date problem can be viewed as a study of a series of (related) fixed refueling date problems. There is a potential for computational savings since the utility system configuration is the same for the entire series of fixed refueling date problems. The results of many of the system calculations once performed, can be used repeatedly in each of separate fixed refueling date problems.

The "stretch-out" case can also be viewed as another version of the resource-limited problem. During the coast-down period, the power level of the nuclear power reactor is already programmed; but for the time period before coast-down has started, the problem is a resource-limited problem.

A sample of the weekly nuclear optimization recommended by PROCOST is given in Figure 5.2. As shown, the nuclear unit should be operated essentially in an on-off mode. It is turned on at full rated power during high demand time periods, and turned off (to the minimum power level) during low demand time periods, thus the optimal peak-shaving of nuclear reactor is a simple daily cycling (high-low) of the power level. A complex detailed following of the customer demand pattern is not necessary. Nuclear reactors under construction are projected to be capable of some degree of load-following cycling such as recommended by PROCOST. In the event that an on-off mode is not physically feasible for the reactors, PROCOST should be modified so as to include a minimum, or must-run, power level for each nuclear reactor involved in the optimization. See Appendix C.1 for details of suggested changes to accomplish this.

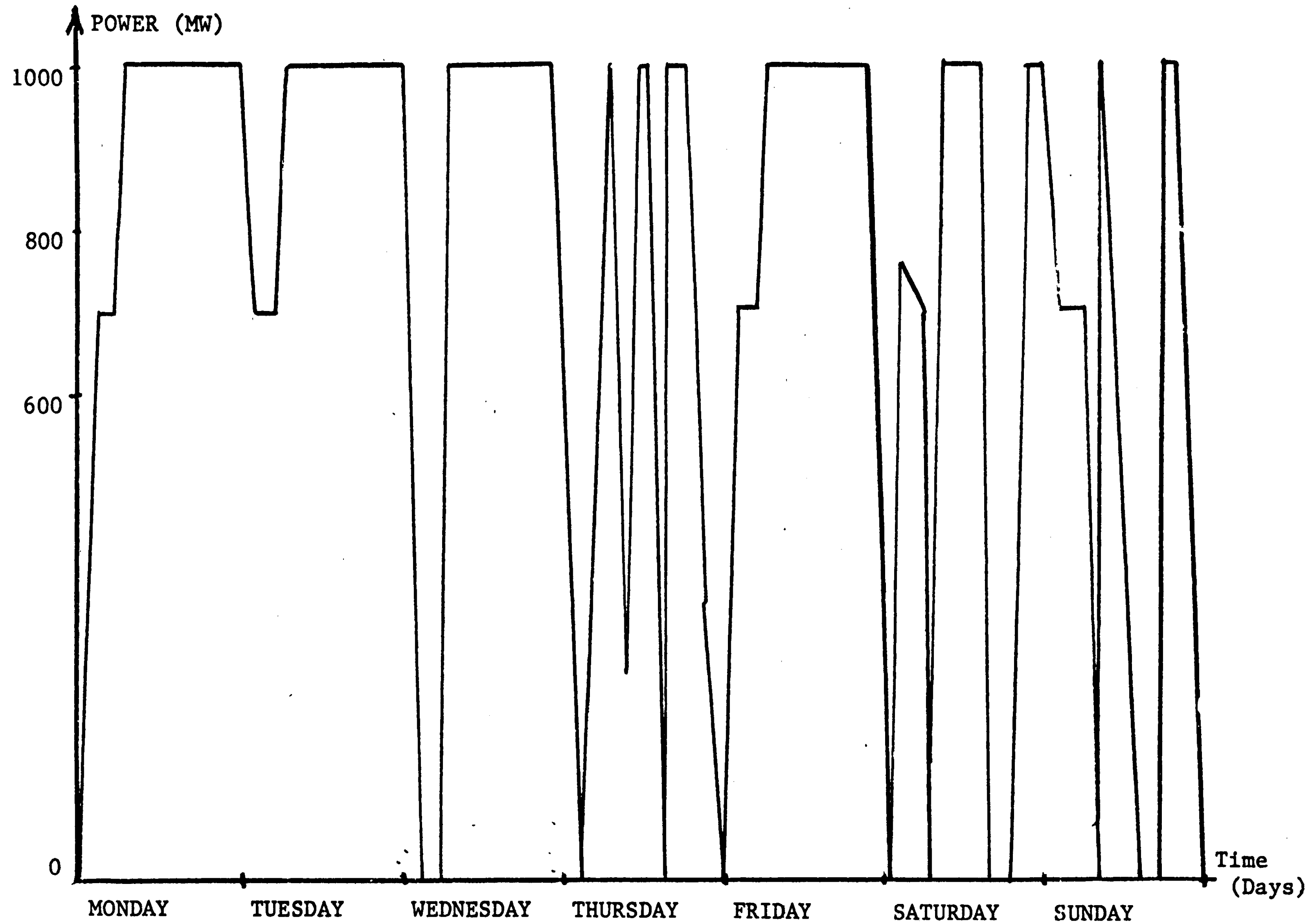


Figure 5.2 SAMPLE OPTIMAL WEEKLY NUCLEAR DISPATCHING SCHEDULE

6.0 Conclusions and Recommendations

6.1 Conclusions

(1) The system simulations performed showed the short-range optimization procedure developed to be flexible and reliable in handling a wide range of system conditions including an adaptability to multi-reactor problems as well as to single reactor optimizations.

(2) The system simulations showed that very large savings in fossil fuel costs, on the order of millions of dollars per reactor per optimization cycle, are possible from short-range nuclear system analysis. Thus use of these short-range system optimization technique by the utility industry would be a worthwhile undertaking.

(3) All short-range options can be viewed as expending a certain amount of nuclear energy in a certain time period. Thus a basis has been established for comparisons of other complex and involved short-range options.

(4) Procedural guidelines for optimal dispatching of nuclear generation (under resource-limited conditions) are to (a) peak shave the dispatching of nuclear energy by operating at peak power during peak demand time intervals and shutting down (or operating at minimum power) during low demand intervals, (b) follow a weekly budget of nuclear energy rationing until the next scheduled refueling date. The system simulations show that independent of the order of optimization most of short-range optimization savings (millions of dollars per reactor per optimization cycle)

comes from peak-shaving the nuclear energy within each week. Hence, peak-shaving should receive the primary attention. The savings from the weekly redistribution of energy were lower, on the order of hundreds of thousands of dollars per reactor per optimization cycle.

(5) The system parameters having greatest effect on total system operating costs are (a) system reserves, (b) seasonal customer demand shape, and (c) the economic loading order (in turn comprised of the system configuration and its basic parameters such as heat rates, and fuel costs). These are the system parameters that must be considered by the system planner in devising the allocation budget of nuclear energy over the short-range planning horizon.

(6) The sample system simulations have shown that the economic loading order is principally determined by the station's fuel cost (under today's economic conditions). Hence, the utility's determination of the maintenance schedule should aim at achieving a balanced fuel cost configuration in addition to a balanced system reserve configuration.

(7) Using the optimization techniques discused in this thesis, an unambiguous and logical method has been developed to calculate the short-range substitutional cost of nuclear power, the OCNP. This is the trading price that should be used when transferring nuclear power by utilities.

(8) The system simulation studies have shown the optimal solution to be sensitive to the accuracy of the

input variables (i.e. fossil fuel costs and maintenance schedule). Hence, great care is necessary in determination of system parameters. Because of the introduction of new technology (i.e. nuclear power) in the utility industry coupled with a changing economic environment, many of the old "rules of thumb" and intution may no longer valid. The new operating environment requires a reassessment of old operating practices.

(9) The scope and complexity of the system interactions illustrated in the sample system simulation demonstrate the usefulness and need for the computer as a tool in system dispatching.

6.2 Recommendations

The sample system simulations studied in this thesis showed that potential operating savings derived from short-range nuclear system analysis to be in the millions of dollars. Relatively simple models were used in the computer programs to pattern the operations of a modern utility system. The models identified the system parameters of greatest sensitivity on system cost and provided an upper limit on the potential savings that may be achievable through short-range nuclear system analysis. How much of this potential savings that can be realized depends on the operating constraints not included in the programs and validity of the assumptions used. The following is a list of recommendations to improve and define the accuracy of the computer programs and calculational technique used.

(1) The range of applicability of the deterministic approach used in PROCOST should be assessed. This may be accomplished using risk-decision analysis, Ref. (33), to measure the severity for assuming 100% availability of the nuclear reactors, see Sections 3.2.1 and 5.1. The usefulness of the Booth-Balerieux probabilistic utility model in determining OCNP should be investigated in overcoming the difficulty mentioned above. Probability theory is most accurate in dealing with a large sample or large time periods. Thus, the applicability of the probabilistic model for a one-week time period should be considered.

(2) Future load models should include the modeling of holidays in the week to study the optimal generation schedule for these periods, see Sections 3.2.2 and A.1.

(3) Minimum operating load levels should be included in the nuclear unit representation in PROCOST. The procedure for implementing this feature is discussed in Appendix C.1.

(4) Start-up and shut-down costs should be included in future simulations studies. This may require use of (a) Integer Programming or (b) multi load-duration curves in PROCOST, see Appendix C.1.

(5) PROCOST, in its present form is a general program offering a number of options. Specialized users of PROCOST should modify the program to fit their own individual requirements and achieve improved computational efficiency

and lower execution time and storage requirements. The performance of the pumped storage subroutine, ECO, especially can be improved upon. Separate chronologic and load-duration versions of PROCOST should also improve computational efficiency. Details on these changes are given in Appendix C.1.

(6) From the sample system simulation studied in Section 5.6, it was found that the "Peak-Shave Second" method yielded within 2 %, the same system cost savings as the "Peak-Shave First" method. Since the "Peak-Shave Second" method is more calculationally efficient, it is recommended that further tests should be made comparing the two solution techniques under several different system environments. If the two methods continue to show nearly the same system cost savings, then the simpler and quicker "Peak-Shave Second" method can be used in place of the "Peak-Shave First" method.

Appendix A: LOAD MODELS

A.1 Introduction

The weeky customer demand function is a necessary system input parameter for PROCOST, the production cost program. This demand function may be a set of actual demand numbers or it may be derived from a set of coefficients describing a seasonal demand function as dependent on one or two (or more) independent variables. For the case of performing sensitivity analysis, changing a single independent variable is more convenient than changing 168 numbers individually. The basic hypothesis for such a load model was that the customer demand for each hour of the week was linearly dependent on the weekly average power level. A least squares fit correlation was made for each hour of the week to the weekly average power level for each season. General utility practice has been to use the weekly peak power level as the independent variable. A comparison of the two methods (using 1971 Commonwealth Edison's customer demand) revealed that during the summer and a part of the fall seasons, the weekly peak is a better independent variable (in terms of a higher correlation coefficient) than the weekly average power level. However, the latter was used as the independent variable in the simulations discussed in this thesis, because of its overall higher correlation coefficient during the entire one year sample. Statistically, the peak fluctuates more than the mean, thus, the mean (weekly average power level) provides the higher correlation coefficient. The form of the regression is:

customer demand = coeff(1)+coeff(2)*independent variable,

where coeff is a two element array containing the regression coefficients.

A 168-interval load model was found to be computationally burdensome. Several studies were performed to find simplified load models that would yield the same system results as the 168-interval load model. Appendix A.5 reports on a chronologic load model study that found a forty-interval model that duplicated most system results very well. Appendix A.6 reports on a load-duration study that found a six-interval model that duplicated OCNP values very well. The forty-interval model is a modified chronologic load model. The three average weekdays (excluding the peak weekday and the low weekday) were found to be very similar to each other. Table A.1 shows the distribution of daily energy consumption in a work week. Thus, the three average workdays were combined to form one day in the load model. The forty-interval model consisted of a 10-interval peak weekday, a 10-interval average weekday, a 10-interval low weekday, and a 10-interval weekend. Combining weekdays together rather than combining consecutive hours together retains a greater amount of accuracy in the load model. This can be illustrated by Figure A.1. Choosing the customer demand at 3 o'clock on Monday, Tuesday and Friday (three average weekdays, excluding the high and the low), the range in values is 398

TABLE A.1

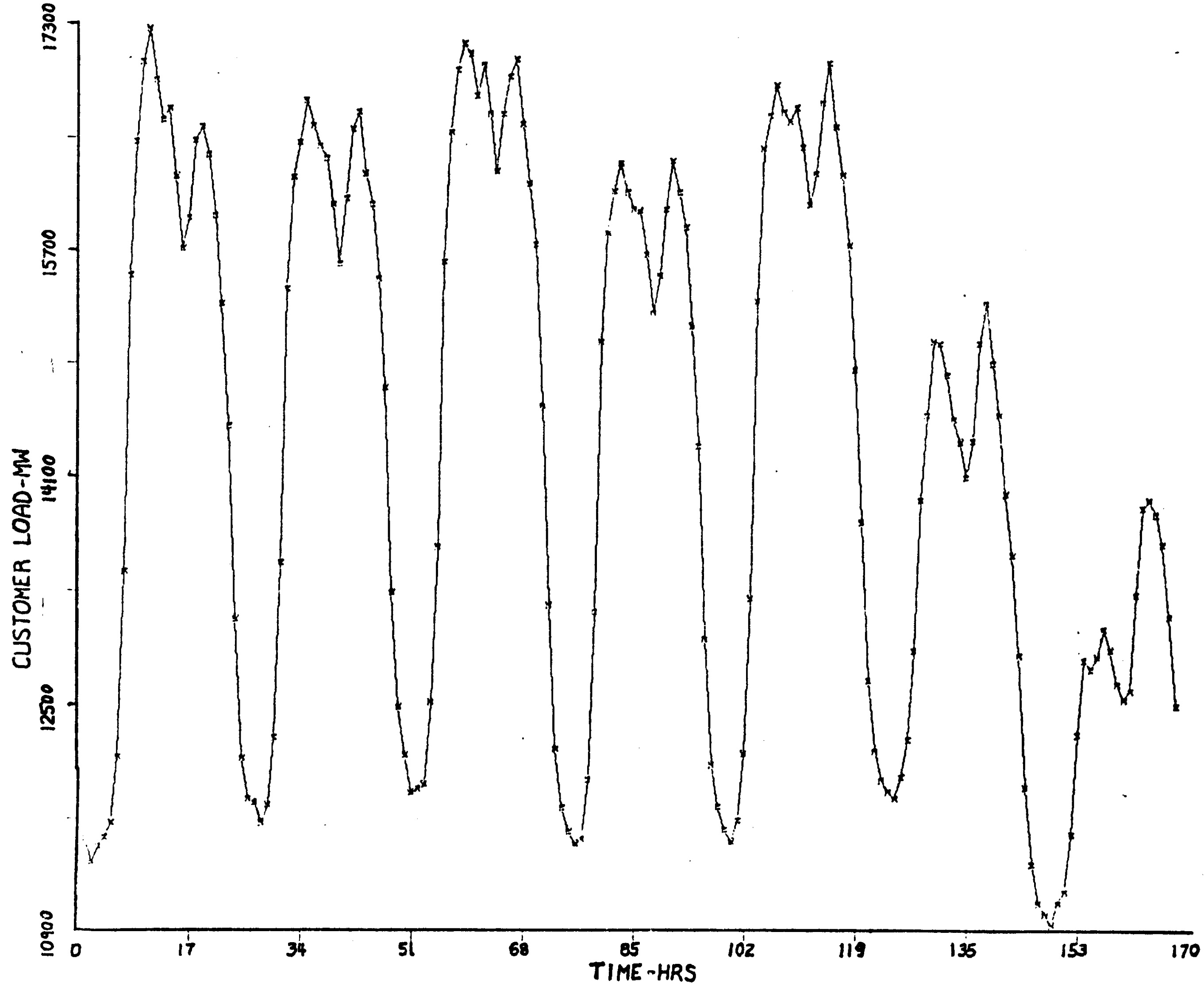
RELATIVE DAILY (WEEKDAY) ENERGY CONSUMPTION*

Week	Low Weekday	Average Weekdays			Peak Weekday
1	0.83	1.13	1.13	1.12	1.15
2	1.00	1.04	1.07	1.07	1.08
3	1.01	1.03	1.03	1.04	1.06
4	1.01	1.06	1.08	1.06	1.10
5	0.97	1.01	1.05	1.08	1.09
6	0.99	1.03	1.06	1.10	1.11
7	0.99	1.02	1.04	1.08	1.08
8	1.02	1.05	1.06	1.07	1.08
9	1.02	1.05	1.08	1.05	1.09
10	1.04	1.04	1.05	1.06	1.07
11	1.03	1.06	1.06	1.06	1.08
12	1.00	1.01	1.01	1.05	1.05
13	0.88	1.12	1.13	1.13	1.15

Note: Each number shown is the ratio of the day's energy consumption divided by 1/7 of the week's energy consumption.

The data are from the winter season of AEP's 1971 Customer Demand.

FIGURE A.1 168-HOUR REPRESENTATION OF THE WINTER CUSTOMER DEMAND FOR THE WEEK OF JAN. 11, 1971



MWH, whereas the smallest range in values on the same weekdays for 2,3,4 o'clock is 688 MWH.

The logical extension of combining weekdays together is toward load-duration curves. A six-interval load-duration model with constant nuclear heat-rate was found to yield accurate OCNP values. The demand levels of the six-intervals were chosen to be approximately equidistant from each other. The range in demand in the load-duration curve was divided into six equal intervals. Within each interval, the average demand level was calculated, yielding six demand levels.

Use of several computer programs aided formulating the different load models.

(1) PROFILE, listed in Appendix A.2 is a program that plots the contour of the average weekly demand function for a season.

(2) REGRESS, listed in Appendix A.3 is a program that calculates the weekly regression coefficients for particular combination of time intervals.

(3) MODEL, listed in Appendix A.4 is a program that calculates the individual demand function values from the forecasted weekly energy consumption and the regression coefficients.

PROFILE is a visual aid to help the system planner in deciding which of the hours of the week to combine to form the simplified load model. When a particular combination has been chosen REGRESS will calculate the regression coefficients. MODEL will use the regression coefficients to calculate the projected demand function.

The interesting feature about REGRESS is that it performs a sorting of the weekday by energy consumption. For example, the disadvantage of grouping all Mondays (or any weekday) together (to form a correlation of Monday's hours with the weekly average power) is that some Mondays are the week's lowest demand day and other times, Monday is the highest damand day. The same is true for all the weekdays. A comparison of the ratio of the daily energy comsumption to the weekly average for an entire season is tabulated in Table A.1. Interestingly, it shows that the weekly low weekday deviates more from the weekly norm than the weekly high weekday. There is a random distribution of which days are the high and low weekdays. But it shows that the other three weekdays usually show very similar energy consumption. Thus, higher correlation coefficients are obtained for developing correlation parameters for high weekdays, low days, average weekdays, and weekends rather than Mondays, Tuesdays, Wednesdays, etc. The former load model would be more representative than a week composed of 5 average weekdays.

MODEL is a computer program that calculates customer demand functions for energy consumption levels beyond the validity of the correlation the parameters were based on. Using only 1971 customer demand numbers, four seasonal sets of demand parameters were developed, However, to simulate a

1977 system demand function (for the system simulations), required a a 50% jump in power level which was as beyond the validity of the correlation. Thus, the independent variable was normalized by the average 1977 seasonal power level.

It is recommended that more accurate load models be used in the future which would include (1) provisions for holiday, and (2) stochastic demand levels.

A.2 PROFILE

A.2.1 Input Specifications

The File Structure:

COPY: file on which DEMAND resides

Input Variable Name:

DEMAND(168): the array which contains the chronologic weekly customer demand numbers. Thirteen weeks of data are required for each season.

Note: PROFILE uses the Fortran subroutine, PRTPLT (34), to do the printing of the average demand function. It is important that the JCL is in the correct order to establish the proper linkage.

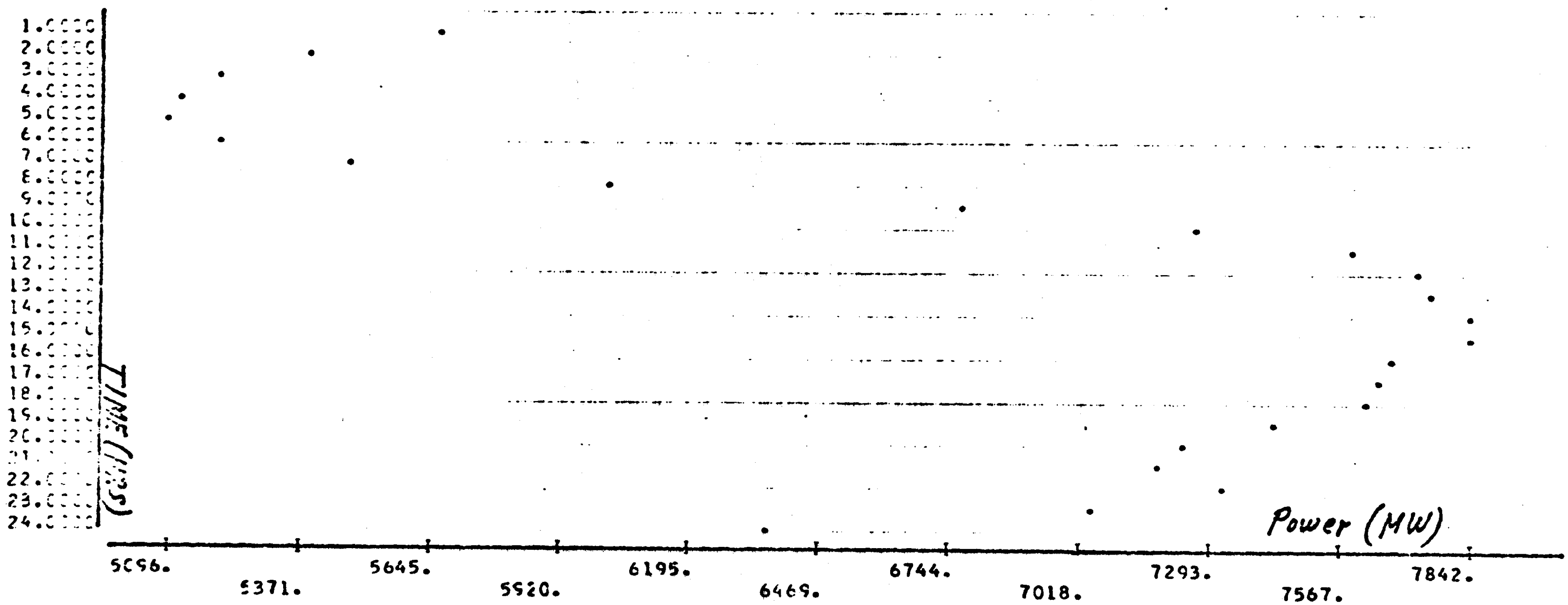
```
//TEST EXEC PLIXCGO
//C.SYSIN DD *,DCB=BLKSIZE=2000
 PROFILE: PROC OPTIONS(MAIN);
 DCL DEMAND(168) FIXED DEC, (MASTER(168),DAY(24)) FLOAT DEC;
 ON ENDFILE(COPY) GO TO BOTTOM;
 MASTER,DEMAND=0;
 DAY=0;
 DO I=1 TO 13;
 READ FILE(COPY)  INTO(DEMAND);
 MASTER=DEMAND+MASTER;
 END;
 MASTER=MASTER/13;
 TOP:
 DO I=1 TO 24;
 DAY(I)=(MASTER(I)+MASTER(I+24)+MASTER(I+48)+MASTER(I+72)+MASTER(I+96))
 /5;
 END;
 PUT PAGE EDIT (DAY   )(12 F(10),SKIP);
 PUT EDIT (SUM(MASTER)/168)(F(20))SKIP;
 PUT FILE(PUNCH) EDIT(MASTER)(8 F(10),SKIP);
 PUT FILE(PUNCH) EDIT(DAY   )(8 F(10),SKIP);
 NORDER=0;
 NPLOT=1;
  NLINES,IDIM,NVALS=168;
 JDIM,NVARS=2;

 DCL PRTPLT EXTERNAL ENTRY(FIXED BIN(31),(*,*) FLOAT REAL,
 FIXED BIN(31), FIXED BIN(31), FIXED BIN(31), FIXED BIN(31),
 FIXED BIN(31), FIXED BIN(31)) OPTIONS(FORTRAN INTER);
 DCL (NPLOT,NVALS,NVARS,NLINES,NORDER,IDIM,JDIM) FIXED BIN(31);

 BEGIN;
 DCL ARRAY(IDIM,JDIM) FLOAT REAL;
 DO I=1 TO 168;
 ARRAY(I,1)=I;   ARRAY(I,2)=MASTER(I);      END;
 CALL PRTPLT(NPLOT,ARRAY,NVALS,NVARS,NLINES,NORDER,IDIM,JDIM);
```

```
 END;                                                                     PROF0037
 NPLOT=2;                                                                 PROF0038
 NLINES,IDIM,NVALS=24;                                                    PROF0039
 BEGIN;                                                                   PROF0040
 DCL ARRAY(IDIM,JDIM) FLOAT REAL;                                         PROF0041
 DO I=1 TO 24;                                                            PROF0042
 ARRAY(I,1)=I;   ARRAY(I,2)=   DAY(I);      END;                          PROF0043
 CALL PRTPLT(NPLOT,ARRAY,NVALS,NVARS,NLINES,NORDER,IDIM,JDIM);            PROF0044
 END;                                                                     PROF0045
 BOTTOM:                                                                  PROF0046
 END PROFILE;                                                             PROF0047
//G.SYSLIB DD                                                             PROF0048
//  DD                                                                    PROF0049
//  DD                                                                    PROF0050
//  DD                                                                    PROF0051
//  DD     DSN=SYS5.MATHLIB.SUBR,DISP=SHR                                 PROF0052
//  DD     DSN=SYS1.FORTLIB,DISP=SHR                                      PROF0053
//  DD     DSN=SYS2.SSP.SUBR,DISP=SHR                                     PROF0054
//G.FT06F001  DD SYSOUT=A,DCB=(RECFM=VA,BLKSIZE=133,BUFNO=1)              PROF0055
//G.SYSPRINT DD SYSOUT=A,DCB=(RECFM=VBA,LRECL=137,BLKSIZE=141)            PROF0056
//G.COPY  DD DSN=U.M9960.8981.AEP.SUMMER.ONE13,DISP=SHR                   PROF0057
```

CHART 2



APPENDIX A.2.3 <u>SAMPLE OUTPUT FROM PROFILE</u>

A.3 REGRESS

A.3.1 Input Specifications

The File Structure:

COPY: file on which DEMAND resides (as in PROFILE, Appendix A.2.1)

SYSIN: file on which the load model parameters are inputted.

Input Variable Names by order of input on file SYSIN:

I: number of weekly DEMAND values to skip before processing.

X: number of time intervals used in representing a weekday in the load model.

Y: number of time intervals used in representing a weekend in the load model.

P: number of weeks to a season.

LEN(X): array containing the number of hours represented by each time interval in the weekday portion of the load model. If X=24, then omit LEN.

END(Y): array containing the number of hours represented by each time interval in the weekend portion of the load model. If Y=48, then omit END.

Note: REGRESS calls the Fortran subroutine, LSFIT(25) to do the least squares fit analysis. It is important that the JCL is in the correct order to establish proper linkage.

```
//TEST EXEC PLIXCGO,LIBRARY='U.C7920.10712.PLIX21.PLIBASE'
//C.SYSIN DD *,DCB=BLKSIZE=2000
 REGRESS: PROC OPTIONS(MAIN);
 DCL (X,Y,I,P,Q,S) FIXED BIN;
 GET LIST(I);
 READ FILE(COPY) IGNORE(I );
 ON ENDFILE(SYSIN) GO TO BOTTOM;
 ON ENDFILE(COPY) CLOSE FILE(COPY);
 TOP:
 GET LIST (X,Y,P);
 PUT DATA (X,Y,P);
 S=3*X+Y;
 Q=S+1;
 BEGIN;
 DCL WEEK( P, Q) FLOAT DEC;
 DCL ( END(Y),LEN(X),HIGH(2),LOW(2)) FIXED BIN,
   STRING BIT(5) VARYING, DEMAND(168)  FIXED DEC,
 (B,  K,I,E,F,G,J) FIXED BIN,
 A(5) FIXED BIN(31);

 WEEK=0;
 ON ERROR PUT DATA(E,K,KK,I,WEEK(KK,I),DEMAND(E+K));
 IF X=24  THEN LEN=1;ELSE GET LIST(LEN);
 IF Y=48  THEN END=1;ELSE GET LIST(END);
 DO I=2 TO X;
 LEN(I)=LEN(I)+LEN(I-1);
 END;
 DO I=2 TO Y;
 END(I)=END(I)+END(I-1);
 END;
 PUT DATA(LEN,END);
 PUT PAGE LIST('  HIGH, LOW, E, F, G,   AND THEIR RELATIVE SIZES');
  DO KK=1 TO P;
 READ FILE(COPY) INTO (DEMAND);
 A=0;
 DO J=1 TO 5;
```

```
DO I=1 TO 24;
A(J)=A(J)+DEMAND((J-1)*24+I);
END;
END;
A=A/24;
PUT SKIP EDIT(A)(5 F(8));
HIGH(1)=A(1);  HIGH(2)=1;
LOW(1)=A(1); LOW(2)=1;
DO I=2 TO 5;
IF LOW(1) > A(I) THEN DO;LOW(1)=A(I);LOW(2)=I; END;
IF HIGH(1) <A(I) THEN DO; HIGH(1)=A(I); HIGH(2)=I; END;
END;
WEEK(KK,Q )=SUM(DEMAND)/168;
              E=(HIGH(2)-1)*24;
DO I=1 TO X;
IF I=1 THEN B=1; ELSE B=LEN(I-1)+1;
DO K=B TO LEN(I);
WEEK(KK,I)=WEEK(KK,I)+DEMAND(E+K);
END;
WEEK(KK,I)=WEEK(KK,I)/(LEN(I)-B+1);
END;
              E=( LOW(2)-1)*24;
DO I=1 TO X;
IF I=1 THEN B=1; ELSE B=LEN(I-1)+1;
DO K=B TO LEN(I);
WEEK(KK,I+2*X)= WEEK(KK,I+2*X)+DEMAND(E+K);
END;
WEEK(KK,I+2*X)= WEEK(KK,I+2*X)/(LEN(I)-B+1);
END;
STRING='00000'B;
SUBSTR(STRING,HIGH(2),1)='1'B;
SUBSTR(STRING, LOW(2),1)='1'B;
E=INDEX(STRING,'0'B);
STRING=SUBSTR(STRING,E+1);
F=INDEX(STRING,'0'B);
STRING=SUBSTR(STRING,F+1);
```

```
G=INDEX(STRING,'0'B);
F=F+E;
G=G+F;

PUT      EDIT(HIGH(2),LOW(2),E,F,G,HIGH(1)/WEEK(KK,Q ),
LOW(1)/WEEK(KK,Q ),A(E)/WEEK(KK,Q ),A(F)/WEEK(KK,Q ),A(G)/WEEK(KK,Q ))
 (5 F(5) , X(5), 5 F(10,2));

E=(E-1)*24;
F=(F-1)*24;
G=(G-1)*24;

DO I=1 TO X;
IF I=1 THEN B=1; ELSE B=LEN(I-1)+1;
DO K=B TO LEN(I);
WEEK(KK,  X+I)=WEEK(KK,  X+I)+(DEMAND(E+K)+DEMAND(F+K)+DEMAND(G+K))/3;
END;
WEEK(KK,  X+I)=WEEK(KK,  X+I)/(LEN(I)-B+1);
END;
DO I=1 TO Y;
IF I=1 THEN B=1;ELSE B=END(I-1) +1;
DO K= B TO END(I);
WEEK(KK,3*X+I)=WEEK(KK,3*X+I)+DEMAND(120+K);
END;
WEEK(KK,3*X+I)=WEEK(KK,3*X+I)/(END(I)-B+1);
END;
END;

 DCL(NPTS,NCOEFF) FIXED BIN(31);
NCOEFF=2;
NPTS=P;
PUT EDIT((WEEK(I,1) DO I=1 TO 13))(13 F(10))SKIP(2);
BEGIN;
DCL  LSFIT EXTERNAL ENTRY(FIXED BIN(31), FIXED BIN(31),(*) REAL FLOAT,
(*) REAL FLOAT,(*) REAL FLOAT)  OPTIONS(FORTRAN INTER),
(X(NPTS),Y(NPTS) ,COEFF(NCOEFF)) FLOAT REAL    ;
```

```
 DO N=1 TO NPTS;
 X(N)=WEEK(N,Q );
 END;
 PUT  FILE(PUNCH) EDIT(X)(8 F(10),SKIP)SKIP;
 PUT SKIP EDIT(' SEASONAL REGRESSION COEFFICIENTS FOLLOWS')(A);
 DO I=1 TO S;
 DO N=1 TO NPTS;
 Y(N)=WEEK(N,I);
 END;
 CALL LSFIT(NPTS,NCOEFF,X,Y,COEFF);
 PUT SKIP EDIT(I,COEFF)(F(5)  , F(10,1), F(10,5));
 WRITE FILE(COEF) FROM(COEFF);
 END;
 END;

 END;
 GO TO TOP;
 BOTTOM:
 END REGRESS;
//G.SYSLIB DD
//  DD
//  DD
//  DD
//  DD    DSN=SYS5.MATHLIB.SUBR,DISP=SHR
//  DD    DSN=SYS1.FORTLIB,DISP=SHR
//  DD    DSN=SYS2.SSP.SUBR,DISP=SHR
//G.FT06F001  DD SYSOUT=A,DCB=(RECFM=VA,BLKSIZE=133,BUFNO=1)
//G.SYSPRINT DD SYSOUT=A,DCB=(RECFM=VBA,LRECL=137,BLKSIZE=141)
//G.COPY  DD DSN=U.M9960.8981.AEP.SUMMER.ONE13,DISP=SHR
//G.SYSIN  DD *
 9  24  48  13
    24  48  13
    24  48  12
    24  48  13
//G.COEF  DD  DSN=U.M9960.8981.REGRESS.COEFF.PTS120,DISP=OLD
```

APPENDIX A.3.3 SAMPLE OUTPUT FROM REGRESS
(Spring, Summer, Autumn, Winter)

X=	24	Y=	48	F=	13[illegible]	LEN(1)=	1	LEN(2)=	2
LEN(3)=	3	LEN(4)=	4	LEN(5)=	5	LEN(6)=	6	LEN(7)=	7
LEN(8)=	8	LEN(9)=	9	LEN(10)=	10	LEN(11)=	11	LEN(12)=	12
LEN(13)=	13	LEN(14)=	14	LEN(15)=	15	LEN(16)=	16	LEN(17)=	17
LEN(18)=	18	LEN(19)=	19	LEN(20)=	20	LEN(21)=	21	LEN(22)=	22
LEN(23)=	23	LEN(24)=	24	END(1)=	1	END(2)=	2	END(3)=	3
END(4)=	4	END(5)=	5	END(6)=	6	END(7)=	7	END(8)=	8
END(9)=	9	END(10)=	10	END(11)=	11	END(12)=	12	END(13)=	13
END(14)=	14	END(15)=	15	END(16)=	16	END(17)=	17	END(18)=	18
END(19)=	19	END(20)=	20	END(21)=	21	END(22)=	22	END(23)=	23
END(24)=	24	END(25)=	25	END(26)=	26	END(27)=	27	END(28)=	28
END(29)=	29	END(30)=	30	END(31)=	31	END(32)=	32	END(33)=	33
END(34)=	34	END(35)=	35	END(36)=	36	END(37)=	37	END(38)=	38
END(39)=	39	END(40)=	40	END(41)=	41	END(42)=	42	END(43)=	43
END(44)=	44	END(45)=	45	[illegible](46)=	46	END(47)=	47	END(48)=	48;

HIGH, LOW, E, F, G, AND THEIR RELATIVE SIZES

7812	7650	7479	7381	7139	1	5	2	3	4	1.12	1.02	1.09	1.07	1.06
6937	7288	7397	7410	7317	4	1	2	3	5	1.06	0.99	1.04	1.06	1.05
7256	7577	7632	7536	7390	3	1	2	4	5	1.08	1.03	1.08	1.07	1.05
7176	7257	7033	6761	7090	2	4	1	3	5	1.09	1.00	1.06	1.04	1.05
7174	7324	7103	6515	6276	2	5	1	3	4	1.13	0.96	1.10	1.09	1.06
6404	6741	6873	6528	6685	4	1	2	3	5	1.09	1.01	1.06	1.08	1.05
6636	6614	6695	6832	6857	5	2	1	3	4	1.07	1.04	1.04	1.05	1.07
6753	6927	6871	6666	6764	2	1	3	4	5	1.07	1.04	1.06	1.06	1.04
6993	6974	6839	6705	6785	1	4	2	3	5	1.08	1.04	1.09	1.06	1.05
6670	6712	6758	6836	6665	4	5	1	2	3	1.08	1.05	1.05	1.06	1.07
6565	6727	6680	6661	6552	2	5	1	3	4	1.08	1.05	1.05	1.07	1.07
6647	6755	6773	6733	6639	3	5	1	2	4	1.08	1.06	1.06	1.08	1.07
5224	6647	6707	6827	6590	5	1	2	3	4	1.11	0.83	1.05	1.06	1.08

6215 6435 6567 6073 6067 5977 5793 5894 5513 5939 5619 5768 5960

SEASONAL REGRESSION COEFFICIENTS FOLLOWS

1	437.5	0.94712
2	-1393.9	1.05325
3	-1767.1	1.14320
4	-2047.3	1.17709
5	-2687.0	1.28318
6	-3431.9	1.43284
7	-5057.5	1.75313
8	-4459.8	1.77652
9	-980.1	1.32916
10	187.9	1.18959
11	1142.6	1.05685
12	1545.2	0.99072
13	2029.3	0.90117
14	3034.4	0.74546
15	3114.7	0.71440
16	3225.9	0.66236
17	2798.7	0.73659
18	1399.4	0.94151
19	-414.0	1.21380
20	-2913.6	1.60105
21	-1333.0	1.36628
22	2348.2	0.79911
23	2680.7	0.68899
24	1155.7	0.82332
25	-1316.3	1.09076
26	-2079.7	1.17910
27	-2359.6	1.20855
28	-2553.6	1.23235
29	-2982.9	1.30415
30	-3803.2	1.46430
31	-4839.9	1.69342
32	-4551.9	1.76886
33	-1363.8	1.36386
34	437.1	1.12303
35	1499.9	0.97620
36	2441.0	0.82372
37	2766.9	0.76160
38	3100.8	0.71279
39	3823.0	0.58451
40	3685.2	0.57241
41	2873.6	0.70270
42	2265.7	0.79468
43	-73.3	1.14643

44	-1818.1	1.41791
45	59.4	1.13312
46	3355.3	0.67566
47	3455.5	0.54820
48	1810.6	0.65558
49	2030.1	0.44710
50	1600.2	0.57039
51	1083.5	0.64215
52	1036.1	0.64865
53	649.5	0.70556
54	130.5	0.51726
55	-2081.0	1.21944
56	-3190.9	1.50222
57	-2135.8	1.42733
58	-1334.5	1.23542
59	-1440.0	1.36507
60	-502.0	1.21581
61	290.3	1.07866
62	-111.5	1.13558
63	196.9	1.07967
64	-140.6	1.10125
65	-1253.4	1.27168
66	-1600.7	1.32352
67	-3494.5	1.60931
68	-4704.6	1.79508
69	-2837.0	1.51553
70	831.3	0.95159
71	1708.5	0.76160
72	1426.4	0.71400
73	832.5	0.73739
74	-443.6	0.98826
75	-1042.1	0.96006
76	-1127.0	0.96531
77	-2013.4	1.09923
78	-2402.5	1.17144
79	-3116.5	1.29972
80	-3403.1	1.38927
81	-2206.7	1.27027
82	-937.8	1.12545
83	-209.2	1.03469
84	182.5	0.97701
85	772.1	0.86688
86	1179.7	0.78620
87	1632.0	0.69706
88	1921.2	0.63534
89	1615.4	0.68616
90	766.6	0.92291
91	-680.3	1.05083
92	-2934.3	1.40984
93	-717.9	1.07624
94	2317.8	0.60831
95	2482.5	0.54417
96	1315.6	0.66317
97	343.3	0.74829
98	-523.2	0.84717
99	-6349.9	1.73734
100	-1482.0	0.96833
101	-1314.0	0.93503
102	-1627.8	0.98558
103	-2421.6	1.11300

```
 104   -2663.3   1.17749
 105   -1856.0   1.10246
 106    -223.8   0.67374
 107    1107.7   0.67033
 108    1296.4   0.65268
 109    1822.7   0.57362
 110    3009.2   0.37112
 111    3440.7   0.28076
 112    3509.6   0.26059
 113    3217.4   0.30779
 114    2415.2   0.44211
 115     306.7   0.78177
 116   -2458.2   1.23033
 117    -769.4   0.99839
 118    3338.0   0.39371
 119    4104.6   0.24405
 120    2950.6   0.37434                      X=        24            Y=        48            P=        13;
LEN(1)=         1      LEN(2)=         2      LEN(3)=         3      LEN(4)=         4      LEN(5)=         5
LEN(6)=         6      LEN(7)=         7      LEN(8)=         8      LEN(9)=         9      LEN(10)=       10
LEN(11)=       11      LEN(12)=       12      LEN(13)=       13      LEN(14)=       14      LEN(15)=       15
LEN(16)=       16      LEN(17)=       17      LEN(18)=       18      LEN(19)=       19      LEN(20)=       20
LEN(21)=       21      LEN(22)=       22      LEN(23)=       23      LEN(24)=       24      END(1)=         1
END(2)=         2      END(3)=         3      END(4)=         4      END(5)=         5      END(6)=         6
END(7)=         7      END(8)=         8      END(9)=         9      END(10)=       10      END(11)=       11
END(12)=       12      END(13)=       13      END(14)=       14      END(15)=       15      END(16)=       16
END(17)=       17      END(18)=       18      END(19)=       19      END(20)=       20      END(21)=       21
END(22)=       22      END(23)=       23      END(24)=       24      END(25)=       25      END(26)=       26
END(27)=       27      END(28)=       28      END(29)=       29      END(30)=       30      END(31)=       31
END(32)=       32      END(33)=       33      END(34)=       34      END(35)=       35      END(36)=       36
END(37)=       37      END(38)=       38      END(39)=       39      END(40)=       40      END(41)=       41
END(42)=       42      END(43)=       43      END(44)=       44      END(45)=       45      END(46)=       46
END(47)=       47      END(48)=       48;
```

HIGH, LOW, E, F, G, AND THEIR RELATIVE SIZES

6976	6338	6628	6643	6837	1	3	2	4	5	1.08	1.02	1.06	1.07	1.05
6911	6739	6566	6724	6885	1	3	2	4	5	1.06	1.01	1.04	1.03	1.06
6995	6957	6985	7219	7158	4	2	1	3	5	1.07	1.03	1.04	1.04	1.06
7284	7111	7108	6834	6371	1	5	2	3	4	1.13	0.99	1.10	1.10	1.06
5185	6337	6549	6673	6683	5	1	2	3	4	1.10	0.85	1.04	1.08	1.10
6625	6943	6835	6731	6734	2	1	3	4	5	1.08	1.03	1.07	1.05	1.05
6533	6491	6583	6755	6771	4	2	1	3	5	1.08	1.03	1.04	1.04	1.07
6692	6513	5473	6504	6340	1	5	2	3	4	1.09	1.04	1.07	1.06	1.06
6320	6520	6484	6376	6412	2	1	3	4	5	1.07	1.03	1.06	1.04	1.05
6819	7102	6861	6591	6556	2	4	1	3	5	1.11	1.03	1.06	1.07	1.03
6714	6928	6966	7012	7077	5	1	2	3	4	1.08	1.02	1.04	1.05	1.07
6682	6604	6741	6770	6643	4	2	1	3	5	1.07	1.05	1.06	1.07	1.05
6876	6908	6943	6995	6853	4	5	1	2	3	1.09	1.05	1.06	1.06	1.07

5364 5411 6116 5982 5985 5825 5725 5427 5552 5984 6020 5724 5831

SEASONAL REGRESSION COEFFICIENTS FOLLOWS

1	2941.5	0.44231
2	2455.5	0.47379
3	2584.4	0.42395
4	2537.4	0.39860
5	1385.4	0.51399
6	2617.8	0.41521
7	2194.3	0.52797
8	1937.4	0.65996
9	1263.8	0.91958
10	1231.9	0.97490
11	1154.1	1.04633
12	857.8	1.11538
13	1936.0	0.95892
14	1359.2	1.06031
15	514.2	1.18981
16	641.9	1.14860
17	121.9	1.22465
18	-550.6	1.32430
19	-1134.3	1.38549
20	-1769.2	1.45105
21	-2245.2	1.51486
22	-2295.2	1.54021
23	-2190.8	1.47552
24	-537.8	1.10227
25	1685.5	0.63024
26	1384.5	0.63199
27	1279.7	0.62063
28	1430.5	0.58304
29	1299.4	0.59878
30	957.4	0.67133
31	762.0	0.74039
32	175.4	0.92045
33	659.1	0.99579
34	572.6	1.05245
35	814.9	1.06294
36	1074.0	1.04458
37	774.8	1.09441
38	473.9	1.15647
39	503.8	1.15035
40	1146.9	1.02710
41	616.3	1.10577
42	731.1	1.07955
43	683.1	1.06031

44	364.8	1.07780
45	199.4	1.09615
46	1244.0	0.95455
47	1292.8	0.90210
48	1586.2	0.75000
49	-2250.6	1.21066
50	-2029.6	1.13374
51	-1984.2	1.10489
52	-2591.2	1.18236
53	-2266.4	1.12997
54	-2377.0	1.16793
55	-2533.8	1.22999
56	-5371.1	1.75699
57	-7115.1	2.13899
58	-6656.8	2.14073
59	-6490.5	2.15996
60	-5098.7	1.96154
61	-4344.4	1.84266
62	-5505.9	2.03846
63	-6036.9	2.12063
64	-5747.2	2.05157
65	-5236.7	1.96941
66	-4275.0	1.81206
67	-3910.4	1.72815
68	-4043.4	1.71941
69	-3631.0	1.64773
70	-3238.7	1.61364
71	-3209.8	1.56643
72	-1736.5	1.23514
73	1680.8	0.60664
74	694.7	0.70105
75	445.8	0.70662
76	190.4	0.72645
77	1717.6	0.47946
78	1249.4	0.55272
79	744.3	0.63899
80	1606.3	0.53737
81	1910.2	0.55957
82	2149.3	0.59353
83	1561.6	0.73427
84	1891.9	0.71154
85	1604.9	0.76224
86	2348.8	0.64510
87	1644.7	0.74476
88	758.6	0.87587
89	230.7	0.96329
90	307.4	0.95455
91	-41.1	0.99825
92	167.8	0.94143
93	71.8	0.95105
94	220.3	0.94843
95	-418.2	1.01573
96	-33.2	0.88374
97	312.5	0.75350
98	488.6	0.67996
99	1241.8	0.52950
100	1287.4	0.50295
101	663.4	0.59156
102	1438.4	0.46760
103	1609.9	0.43531

```
 104    1443.1   0.47744
 105    1216.0   0.56124
 106     745.9   0.68357
 107    -259.4   0.86976
 108    -408.8   0.92657
 109   -1582.2   1.13636
 110   -2056.1   1.21591
 111   -1773.8   1.16259
 112   -2012.0   1.19668
 113   -1842.1   1.17395
 114   -1927.6   1.18037
 115   -1928.8   1.19843
 116   -1785.8   1.16971
 117   -1695.3   1.16259
 118      63.7   0.97483
 119    -589.0   1.00874
 120    -702.5   0.97203                      X=         24           Y=         48           P=         12;
LEN(1)=         1       LEN(2)=         2       LEN(3)=         3       LEN(4)=         4       LEN(5)=         5
LEN(6)=         6       LEN(7)=         7       LEN(8)=         8       LEN(9)=         9       LEN(10)=        10
LEN(11)=        11      LEN(12)=        12      LEN(13)=        13      LEN(14)=        14      LEN(15)=        15
LEN(16)=        16      LEN(17)=        17      LEN(18)=        18      LEN(19)=        19      LEN(20)=        20
LEN(21)=        21      LEN(22)=        22      LEN(23)=        23      LEN(24)=        24      END(1)=         1
END(2)=         2       END(3)=         3       END(4)=         4       END(5)=         5       END(6)=         6
END(7)=         7       END(8)=         8       END(9)=         9       END(10)=        10      END(11)=        11
END(12)=        12      END(13)=        13      END(14)=        14      END(15)=        15      END(16)=        16
END(17)=        17      END(18)=        18      END(19)=        19      END(20)=        20      END(21)=        21
END(22)=        22      END(23)=        23      END(24)=        24      END(25)=        25      END(26)=        26
END(27)=        27      END(28)=        28      END(29)=        29      END(30)=        30      END(31)=        31
END(32)=        32      END(33)=        33      END(34)=        34      END(35)=        35      END(36)=        36
END(37)=        37      END(38)=        38      END(39)=        39      END(40)=        40      END(41)=        41
END(42)=        42      END(43)=        43      END(44)=        44      END(45)=        45      END(46)=        46
END(47)=        47      END(48)=        48;
```

HIGH, LOW, E, F, G, AND THEIR RELATIVE SIZES

5390	6816	7095	7128	7017	4	1	2	3	5	1.13	0.85	1.08	1.12	1.11
6619	6682	6752	6728	6611	3	5	1	2	4	1.07	1.05	1.05	1.06	1.07
6659	6614	6615	6648	6553	1	5	2	3	4	1.06	1.05	1.06	1.06	1.06
6729	6942	6973	6936	6537	3	5	1	2	4	1.09	1.02	1.05	1.09	1.09
6243	6181	6162	6203	6251	5	3	1	2	4	1.06	1.04	1.05	1.04	1.05
6243	6245	6272	6249	6186	3	5	1	2	4	1.06	1.05	1.06	1.06	1.06
6192	6313	6308	6379	6357	4	1	2	3	5	1.06	1.03	1.05	1.05	1.06
6295	6412	6458	6432	6334	3	1	2	4	5	1.07	1.04	1.06	1.06	1.05
6322	6334	6519	6738	6665	4	1	2	3	5	1.07	1.00	1.00	1.03	1.06
7073	7186	6992	6864	6693	2	5	1	3	4	1.10	1.02	1.08	1.07	1.05
6509	6687	6739	6689	6792	5	1	2	3	4	1.05	1.00	1.03	1.04	1.03
7440	7691	7595	6007	6670	2	4	1	3	5	1.14	0.89	1.10	1.12	0.95

5903	5615	5056	5782	5343	5343	5317	5450	5583	6083	5433	6464	0

SEASONAL REGRESSION COEFFICIENTS FOLLOWS

1	-1219.0	1.09897
2	-2251.3	1.22125
3	-2625.8	1.25966
4	-2987.6	1.31178
5	-3037.1	1.32115
6	-3470.6	1.42352
7	-4284.5	1.63632
8	-3636.5	1.66337
9	-2204.1	1.51457
10	-2109.3	1.53954
11	-2305.6	1.58325
12	-2139.0	1.55715
13	-2701.5	1.63371
14	-3190.8	1.72320
15	-1935.1	1.50468
16	-1987.4	1.49688
17	-4209.9	1.35900
18	-5955.9	2.14152
19	-6167.9	2.17274
20	-2202.0	1.54214
21	-1818.5	1.48023
22	-1876.6	1.45265
23	-1037.8	1.24350
24	-878.7	1.12279
25	330.7	0.81958
26	-876.5	0.97766
27	-1295.8	1.02923
28	-1511.2	1.05639
29	-1738.9	1.09632
30	-1868.2	1.14994
31	-2741.2	1.37045
32	-2160.9	1.40739
33	-605.9	1.24246
34	-353.6	1.24037
35	-236.6	1.23777
36	386.5	1.13788
37	376.5	1.12487
38	367.1	1.13163
39	1000.0	1.01821
40	1588.5	0.90271
41	-51.6	1.16857
42	-3224.0	1.68054
43	-4104.6	1.81656
44	-169.5	1.19563

45	773.5	1.04527
46	785.3	1.00832
47	681.1	0.95317
48	655.1	0.85952
49	356.8	0.77979
50	370.9	0.74389
51	207.3	0.75221
52	147.6	0.75442
53	2.8	0.77979
54	396.7	0.74493
55	1568.0	0.63111
56	4441.7	0.28668
57	6058.5	0.10822
58	6619.9	0.06035
59	7025.9	0.02081
60	7513.0	-0.05723
61	7861.0	-0.12351
62	9620.3	-0.41155
63	10210.9	-0.51925
64	10133.5	-0.52653
65	9508.2	-0.42144
66	6258.2	0.10354
67	5151.1	0.28044
68	8342.2	-0.22633
69	8512.9	-0.25754
70	7773.7	-0.17430
71	6887.2	-0.10094
72	4769.0	0.15349
73	1659.9	0.59001
74	-152.1	0.82687
75	-475.3	0.85172
76	-905.0	0.90921
77	-835.0	0.89412
78	-1216.3	0.96345
79	-1127.7	0.97268
80	-1055.5	1.01340
81	-890.3	1.05619
82	-52.3	0.98387
83	382.6	0.94329
84	1163.5	0.82934
85	1076.1	0.82518
86	1279.5	0.77784
87	1024.7	0.80281
88	602.6	0.95640
89	-444.6	1.03330
90	-2734.9	1.42248
91	-1871.3	1.29396
92	790.8	0.87045
93	1107.7	0.80801
94	1050.2	0.79876
95	982.4	0.75130
96	776.0	0.72451
97	82.7	0.77354
98	41.9	0.74389
99	-690.6	0.83455
100	-1038.8	0.87734
101	-983.0	0.86420
102	-1372.0	0.93210
103	-1450.8	0.95421
104	-1386.8	0.97607

105	-1500.4	1.04757
106	-499.3	0.92560
107	-581.9	0.94732
108	-228.2	0.90947
109	-92.5	0.90271
110	350.0	0.87102
111	211.1	0.81691
112	-514.7	0.92538
113	-1685.6	1.11902
114	-4094.2	1.53746
115	-3770.8	1.51093
116	-924.2	1.08117
117	-158.6	0.96774
118	-236.7	0.96618
119	-147.3	0.90947
120	-546.0	0.92755

				X=	24	Y=	48	P=	13;
LEN(1)=	1	LEN(2)=	2	LEN(3)=	3	LEN(4)=	4	LEN(5)=	5
LEN(6)=	6	LEN(7)=	7	LEN(8)=	8	LEN(9)=	9	LEN(10)=	10
LEN(11)=	11	LEN(12)=	12	LEN(13)=	13	LEN(14)=	14	LEN(15)=	15
LEN(16)=	16	LEN(17)=	17	LEN(18)=	18	LEN(19)=	19	LEN(20)=	20
LEN(21)=	21	LEN(22)=	22	LEN(23)=	23	LEN(24)=	24	END(1)=	1
END(2)=	2	END(3)=	3	END(4)=	4	END(5)=	5	END(6)=	6
END(7)=	7	END(8)=	8	END(9)=	9	END(10)=	10	END(11)=	11
END(12)=	12	END(13)=	13	END(14)=	14	END(15)=	15	END(16)=	16
END(17)=	17	END(18)=	18	END(19)=	19	END(20)=	20	END(21)=	21
END(22)=	22	END(23)=	23	END(24)=	24	END(25)=	25	END(26)=	26
END(27)=	27	END(28)=	28	END(29)=	29	END(30)=	30	END(31)=	31
END(32)=	32	END(33)=	33	END(34)=	34	END(35)=	35	END(36)=	36
END(37)=	37	END(38)=	38	END(39)=	39	END(40)=	40	END(41)=	41
END(42)=	42	END(43)=	43	END(44)=	44	END(45)=	45	END(46)=	46
END(47)=	47	END(48)=	48;						

HIGH, LOW, E, F, G, AND THEIR RELATIVE SIZES

7409	7553	7519	7654	7616	5	1	2	3	4	1.07	1.04	1.06	1.05	1.06
7257	7137	7111	7132	6929	1	5	2	3	4	1.08	1.03	1.06	1.06	1.06
7158	7446	7041	7164	7417	2	3	1	4	5	1.05	1.00	1.01	1.01	1.05
7449	7398	7526	7337	5806	3	5	1	2	4	1.15	0.88	1.13	1.13	1.12
7449	7398	7526	7337	5806	3	5	1	2	4	1.15	0.88	1.13	1.13	1.12
7275	7615	7778	7876	7807	4	1	2	3	5	1.08	1.00	1.04	1.07	1.07
7415	7416	7574	7256	7478	3	4	1	2	5	1.06	1.01	1.03	1.03	1.04
7804	8050	7960	7785	7350	2	5	1	3	4	1.10	1.00	1.06	1.08	1.06
7310	7666	8249	8154	7530	3	1	2	4	5	1.09	0.97	1.01	1.08	1.05
8365	8278	7948	7720	7457	1	5	2	3	4	1.11	0.99	1.10	1.06	1.03
7837	8119	8140	7705	7418	3	5	1	2	4	1.08	0.99	1.04	1.09	1.02
7550	7502	7421	7313	7103	1	5	2	3	4	1.08	1.02	1.07	1.06	1.05
7289	7518	7459	7278	7062	2	5	1	3	4	1.09	1.02	1.05	1.08	1.05

6373 5600 6095 6255 6295 6713 6244 6747 7059 6816 7192 6170 6191

SEASONAL REGRESSION COEFFICIENTS FOLLOWS

1	-709.9	1.00654
2	-745.0	0.98972
3	-1314.3	1.05734
4	-1292.0	1.09173
5	-1409.7	1.07666
6	-949.1	1.05079
7	-418.6	1.05983
8	625.8	1.04861
9	3042.0	0.76597
10	3537.8	0.71798
11	3672.4	0.70926
12	3285.4	0.74977
13	2738.3	0.80897
14	2570.8	0.83359
15	2398.4	0.83733
16	2000.3	0.85983
17	2448.4	0.81864
18	4244.0	0.60330
19	3617.1	0.70439
20	3688.8	0.67653
21	3781.5	0.64226
22	2996.6	0.71892
23	1921.2	0.80430
24	-975.3	1.10938
25	776.9	0.77719
26	345.0	0.81427
27	226.1	0.81988
28	-74.8	0.85696
29	3.0	0.89416
30	158.3	0.86849
31	594.3	0.89000
32	1889.4	0.84014
33	3429.1	0.68183
34	4432.1	0.56778
35	4520.4	0.56217
36	4691.9	0.52135
37	3934.1	0.61390
38	3973.2	0.60955
39	3675.5	0.62730
40	3217.1	0.65815
41	3156.0	0.68620
42	4814.3	0.48925
43	4404.8	0.56747

44	4103.6	0.59364
45	3679.4	0.63322
46	3702.9	0.55489
47	2927.9	0.64039
48	1473.6	0.75319
49	2144.1	0.53194
50	840.9	0.68962
51	166.2	0.77127
52	-70.7	0.79930
53	-426.2	0.85323
54	-1372.9	1.01496
55	-2968.3	1.31474
56	-5509.1	1.79526
57	-4465.9	1.71112
58	-4056.9	1.68090
59	-3790.7	1.65379
60	-3195.6	1.55500
61	-3649.9	1.60737
62	-4491.6	1.71860
63	-4300.9	1.66874
64	-3687.1	1.55375
65	-3605.1	1.56123
66	-2165.1	1.39859
67	-3745.0	1.62449
68	-4541.6	1.71611
69	-4286.3	1.65597
70	-3760.9	1.54908
71	-2910.4	1.36304
72	-2034.6	1.17295
73	-2199.4	1.14148
74	-2399.6	1.13462
75	-3016.9	1.20131
76	-3111.2	1.20692
77	-3226.7	1.22343
78	-3302.5	1.24618
79	-3056.0	1.23559
80	-2521.2	1.21315
81	-2494.8	1.27267
82	-2912.7	1.37270
83	-3814.4	1.51895
84	-4782.3	1.65379
85	-5121.0	1.67872
86	-6101.2	1.79620
87	-5979.2	1.75725
88	-5853.9	1.72359
89	-6143.2	1.78030
90	-4654.8	1.61889
91	-5108.8	1.71331
92	-4643.7	1.63602
93	-3935.8	1.51855
94	-3133.6	1.39174
95	-3058.3	1.33406
96	-3448.0	1.33718
97	-3756.1	1.32533
98	-4173.6	1.35338
99	-4365.4	1.36211
100	-4529.9	1.37956
101	-4550.2	1.37987
102	-4209.7	1.33531
103	-4223.5	1.34933

104	-3881.1	1.33032
105	-3969.3	1.37693
106	-3468.4	1.35120
107	-3004.8	1.29106
108	-3169.6	1.32284
109	-2989.4	1.28576
110	-2956.5	1.28108
111	-3057.2	1.27793
112	-2950.7	1.25553
113	-2235.0	1.16578
114	-381.4	0.95108
115	-1327.9	1.11966
116	-1363.7	1.12932
117	-1619.4	1.15612
118	-1727.1	1.15768
119	-1417.3	1.07354
120	-2075.2	1.12652

A.4 MODEL

A.4.1 Input Requirements

The File Structure:

LDMDL: File where the customer demand function is to be printed.

COEF: File name of dataset where the seasonal regression coefficients A and B reside.

SYSIN: File where the load model input parameters are located.

Variable Names by Order of Input in File SYSIN:

I: The number of seasons sets of A and B to be skipped on file COEF before beginning processing.

SEASON: The number of sets of seasonal parameters (A and B) to be processed in calculating all the demand function desired.

PTS: The number of time intervals used in the load model to represent a weekly customer demand function.

TIME: Array containing the number of hours represented by each time interval in the load model.

WEEKS: The number of weeks a set of seasonal parameters is used.

MEAN_POWER: The mean power level of the season for which a seasonal set of regression parameters is valid.

MEAN_ENERGY: The average weekly energy consumption value for the season being simulated.

ENERGY: The weekly energy consumption of the week for which the demand function is desired.

The last four variables are repeated for each season output desired.

Example Problem Number One:

The weekly demand function for two summer weeks and one winter week are desired. The summer weekly energy consumption values are 1,000,001 and 1,000,002 and the winter weekly energy consumption value is 1,000,100. The seasonal average summer energy is 1,000,500 and the seasonal average winter energy is 1,000,050. The seasonal power level for which the regression coefficents are valid are 6,000 and 5,000 for winter and summer, respectively.

The seasonal regression coefficients lie in the order of spring, summer, fall, and winter on file COEF. The load model is represented by four time intervals. The time duration of each interval is 41, 42, 43, 42 hours respectively.

The resulting input SYSIN file would read as follows:

```
1   3   120
41   42   43   42
2   5000   1,000,500   1,000,001   1,000,002
0   0   0
1   6000   1,000,050   1,000,100
```

Example Problem Number Two:

The input required for the weekly demand functions used in the system simulations (in Section 5.0) is listed below the program listing, in Appendix A.4.2. Appendix A.4.3 is the resulting computer output.

A.4.2 Program Listing and Sample Input

```
//   'RAY ENG',CLASS=A,REGION=128K
//   EXEC   PLIXCGO,
//C.SYSIN   DD *,DCB=BLKSIZE=2000
  MODEL: PROC OPTIONS(MAIN);
 DCL       (I,SEASONS,PTS,WEEKS,K) FIXED BIN;

 GET LIST(I,SEASONS,PTS );
 PUT DATA(I,SEASONS,PTS )SKIP;
 READ FILE(COEF) IGNORE(PTS*I);
 BLOCK: BEGIN;
  DCL (A(PTS),B(PTS), C(PTS),COEFF(2)) FLOAT DEC,TIME(PTS) FIXED BIN,
     (POWER,ENERGY,MEAN_POWER, MEAN_ENERGY, TOTAL)      FLOAT DEC(16);
 GET LIST(TIME)COPY;
 LOOP: DO K=1 TO SEASONS;
 DO I=1 TO PTS;
 READ FILE(COEF) INTO(COEFF);
 A(I)=COEFF(1);
 B(I)=COEFF(2);
 END;
  A(99)=A(100);
 B(99)=B(100);
 GET LIST(WEEKS, MEAN_POWER, MEAN_ENERGY);
 PUT DATA(WEEKS, MEAN_POWER, MEAN_ENERGY)SKIP;
 DO I=1 TO WEEKS;
 GET LIST(ENERGY);
 PUT DATA(ENERGY)SKIP(2);
 POWER=MEAN_POWER*ENERGY/MEAN_ENERGY;
 C=A+B*POWER;
 TOTAL=SUM(C*TIME);
 C=C*ENERGY/TOTAL;

 PUT FILE(LDMDL) EDIT(C)(168 F(8));
 PUT EDIT(C)(8 F(10),SKIP)SKIP;
 END;
 END LOOP;
 END BLOCK;
```

```
 PUT EDIT(' NORMAL END OF PROGRAM')(A)SKIP(2);
 END MODEL;
//G.COEF  DD  DSN=U.M9960.8981.REGRESS.COEFF.PTS120,DISP=OLD
//G.LDMDL  DD  DSN=U.M9960.8981.AEP.APR.MAY,DISP=OLD
//G.SYSIN  DD *
0  3  120
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
          9  6550  1806500
 1860288  1894814  1801320  1681939
 1792155  1728221  1758492  1801151  1691693
           13 6385  1847000  1839877   1883604   1814876   1761441
1681810   1870344   1826914   1883382   1860176   1833500   1950649
 1895024   1909928
 4  6269  2024100
 1955031  1868715  1872805  1956622
```

Appendix A.4.3

SAMPLE OUTPUT FROM MODEL

```
I=          0              SEASONS=        3        PTS=       120;
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3 3
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

WEEKS=          9          MEAN_POWER= 6.550000000000000E+03          MEAN_ENERGY= 1.806500000000000E+06;
```

ENERGY= 1.860288000000000E+06;

10096	9864	9755	9671	9795	10229	11107	12347
13106	13478	13575	13504	13307	13233	13021	12627
12749	12720	12758	12942	12937	12700	12027	11011
9915	9640	9506	9451	9542	9968	10803	12111
12860	13150	13269	13125	12972	12980	12745	12385
12495	12516	12571	12713	12641	12433	11740	10720
9139	8941	8888	8881	8976	9262	10084	11393
12218	12595	12748	12636	[illegible]	12437	12278	11960
12023	12025	12069	12151	12126	11999	11235	10245
9530	9105	8918	8837	8864	9025	9273	9794
10441	10920	11111	11115	10864	10640	10395	10187
10247	10368	10516	10791	10736	10538	10099	9501
8847	8520	8288	8268	8195	8239	8314	8664
9159	9305	9244	9353	9342	9047	8755	8645
8698	8858	9158	9566	9790	9837	9439	8987

ENERGY= 1.894814000000000E+06;

10271	10082	9991	9913	10060	10525	11458	12713
13390	13723	13794	13708	13493	13387	13169	12764
12900	12914	13008	13272	13219	12866	12170	11181
10140	9883	9755	9705	9811	10270	11152	12475
13141	13382	13470	13296	13130	13128	12866	12504
12641	12680	12808	13005	12875	12563	11854	10864
9280	9059	9020	9015	9072	9430	10336	11703
12511	12871	13030	12886	12640	12672	12501	12188
12295	12298	12401	12520	12438	12095	11393	10393
9562	9289	9116	9036	9091	9267	9541	10091
10702	11152	11325	11317	11043	10802	10539	10318
10389	10538	10733	11082	10958	10664	10211	9638
9002	8694	8487	8487	8387	8442	8542	8907
9386	9496	9383	9488	9460	9124	8814	8700
8752	8950	9319	9839	9996	9919	9489	9064

ENERGY= 1.801320000000000E+06;

9797	9493	9353	9256	9343	9725	10490	11722
12637	13058	13203	13154	12989	12969	12768	12393
12487	12387	12330	12379	12456	12418	11784	10721
9531	9225	9081	9018	9093	9453	10207	11489
12380	12754	12924	12834	12703	12728	12538	12183
12247	12235	12167	12213	12242	12212	11546	10472
9033	8739	8661	8652	8675	8974	9655	10864
11718	12125	12268	12207	12037	12035	11897	11572
11575	11559	11503	11519	11592	11563	10966	9993
9270	8792	8580	8497	8477	8613	8816	9305
9993	10524	10746	10771	10558	10362	10149	9962
10005	10078	10146	10295	10357	10323	9906	9267
8593	8221	7947	7947	7865	7892	7923	8259
8770	8997	9008	9123	9139	8916	8655	8553
8579	8702	8892	9153	9438	9697	9351	8854

ENERGY= 1.681939000000000E+06;

9193	8742	8538	8417	8429	8704	9242	10457
11689	12209	12448	12446	12345	12436	12257	11919
11960	11715	11464	11238	11482	11847	11290	10133
8753	8384	8220	8140	8154	8410	9002	10229
11407	11952	12227	12245	12158	12218	12119	11772
11744	11667	11349	11203	11433	11764	11153	9972
8717	8331	8202	8189	8168	8390	8786	9794
10706	11173	11294	11340	11267	11222	11126	10786
10668	10615	10357	10241	10512	10884	10422	9483
8743	8159	7895	7808	7694	7778	7890	8316
9088	9721	10009	10074	9939	9801	9651	9508
9515	9490	9397	9291	9599	9888	9517	8793
8049	7617	7256	7256	7199	7190	7132	7411
7985	8374	8528	8656	8729	8649	8453	8365
8357	8385	8324	8276	8726	9415	9175	8585

ENERGY= 1.792155000000000E+06;

9751	9436	9290	9192	9273	9647	10394	11625
12565	12993	13145	13100	12939	12928	12729	12356
12447	12336	12263	12291	12391	12374	11746	10676
9471	9160	9015	8950	9011	9373	10115	11392
12305	12692	12871	12789	12661	12689	12506	12151
12209	12192	12104	12136	12180	12177	11516	10434
9009	8708	8626	8617	8636	8929	9588	10782
11640	12052	12193	12140	11978	11973	11838	11512
11565	11486	11415	11421	11509	11511	10925	9954
9229	8744	8527	8444	8417	8549	8745	9229
9924	10462	10690	10717	10511	10319	10111	9927
9967	10033	10089	10218	10298	10290	9876	9230
8542	8175	7894	7894	7814	7838	7862	8185
8710	8950	8971	9087	9108	8895	8640	8538
8562	8678	8839	9085	9383	9676	9338	8834

ENERGY= 1.728221000000000E+06;

9427	9034	8654	8743	8784	9100	9726	10947
12057	12538	12740	12721	12594	12643	12455	12102
12165	11976	11800	11680	11840	12068	11482	10361
9054	8710	8554	8490	8514	8814	9469	10717
11784	12263	12497	12474	12370	12416	12292	11931
11939	11887	11666	11594	11747	11937	11305	10166
8940	8490	8380	8369	8365	8616	9123	10209
11098	11542	11672	11676	11566	11537	11425	11091
11020	10981	10801	10736	10931	11147	10633	9691
8947	8404	8161	8075	7998	8102	8249	8699
9439	10032	10294	10344	10179	10018	9844	9684
9705	9718	9657	9680	9387	10057	9658	8977
8256	7851	7524	7524	7457	7462	7439	7736
8289	8616	8714	8837	8888	8753	8532	8438
8443	8508	8540	8616	9002	9524	9244	8690

ENERGY= 1.758492000000000E+06;

9580	9224	9061	8555	9015	9359	10042	11268
12297	12754	12932	12900	12758	12778	12585	12223
12298	12146	12019	11969	12107	12213	11607	10510
9252	8923	8772	8703	8749	9079	9775	11037
12031	12466	12674	12623	12508	12545	12388	12035
12067	12032	11674	11851	11952	12051	11405	10293
8920	8593	8496	8486	8493	8764	9343	10480
11355	11783	11918	11896	11761	11743	11621	11290

11250	11220	11092	11060	11204	11319	10771	9810
9081	8565	8334	8250	8196	8313	8484	8950
9669	10236	10491	10521	10336	10161	9970	9799
9829	9867	9677	9935	10082	10167	9766	9097
8392	8004	7699	7699	7626	7640	7639	7949
8488	8774	8836	8955	8992	8820	8583	8485
8499	8588	8682	8838	9182	9596	9288	8758

ENERGY= 1.8011510000000000E+06;

9796	9492	9352	9255	9342	9724	10489	11720
12636	13057	13201	13153	12988	12969	12767	12392
12487	12387	12329	12377	12455	12417	11783	10720
9530	9224	9080	9016	9081	9452	10206	11487
12378	12753	12923	12833	12703	12727	12538	12182
12246	12235	12166	12212	12241	12211	11546	10472
9032	8739	8650	8652	8674	8973	9654	10863
11717	12124	12266	12206	12036	12034	11896	11571
11574	11557	11501	11517	11590	11562	10966	9993
9269	8791	8579	8496	8476	8612	8815	9304
9992	10522	10745	10770	10557	10362	10148	9961
10004	10077	10145	10294	10356	10323	9906	9266
8583	8220	7946	7946	7864	7891	7922	8249
8769	8997	9007	9122	9139	8915	8655	8552
8578	8701	8881	9151	9437	9697	9351	8854

ENERGY= 1.6916930000000000E+06;

9242	8804	8605	8486	8504	8788	9344	10560
11767	12279	12509	12504	12397	12479	12298	11957
12003	11770	11535	11331	11562	11893	11331	10181
8817	8453	8290	8211	8230	8495	9100	10332
11497	12019	12284	12293	12203	12259	12153	11836
11755	11714	11416	11285	11500	11800	11185	10013
8743	8365	8240	8227	8210	8439	8857	9881
10788	11250	11374	11411	11330	11288	11189	10851
10742	10692	10451	10345	10600	10939	10466	9525
8785	8211	7951	7965	7758	7846	7966	8397
9162	9786	10068	10131	9990	9847	9692	9545
9555	9538	9458	9373	9652	9924	9548	8832
8093	7656	7313	7313	7253	7247	7197	7479
8049	8425	8568	8694	8762	8671	8470	8380
8375	8411	8370	8348	8784	9438	9190	8607

WEEKS= 13 MEAN_POWER= 6.3850000000000000E+03 MEAN_ENERGY= 1.8470000000000000E+06;

ENERGY= 1.8398770000000000E+06;

9909	9419	9093	8907	8875	9055	9543	10564
11903	12853	13446	13692	13835	13953	13905	13685
13522	13538	13270	12847	12724	12916	12387	11146
9804	9305	9000	8849	8795	9001	9421	10383
11646	12512	13044	13289	13320	13481	13466	13223
13171	13082	12739	12432	12348	12596	12106	10945
9334	8922	8684	8487	8473	8697	9107	9994
11174	11983	12497	12703	12700	12844	12830	12572
12552	12484	12193	11868	11793	12096	11628	10537
9538	8874	8506	8284	8208	8205	8290	8651
9406	10201	10730	11050	11111	11109	10988	10899
10947	10983	10862	10599	10539	10766	10404	9621
8790	8288	7725	7725	7621	7598	7540	7714
8240	8771	9079	9444	9721	9776	9678	9641
9685	9777	9804	9724	9813	10238	10033	9436

ENERGY= 1.883604000000000E+06;

10024	9542	9203	9010	9069	9163	9691	10735
12142	13108	13719	13983	14085	14229	14214	13983
13940	13883	13581	13225	13119	13317	12771	11433
9968	9470	9162	9000	8951	9175	9613	10622
11896	12786	13321	13561	13605	13782	13765	13491
13459	13363	13064	12712	12633	12844	12340	11140
9599	9217	8972	8795	8767	9001	9427	10451
11731	12540	13059	13214	13179	13375	13382	13106
13064	12956	12643	12316	12222	12515	12036	10858
9696	9056	8690	8473	8333	8348	8446	8791
9552	10356	10921	11235	11310	11277	11192	11127
11193	11232	11122	10844	10787	11013	10668	9851
8986	8465	7856	7856	7775	7720	7653	7838
8386	8948	9305	9685	10017	10092	9991	9953
9990	10084	10116	10029	10116	10479	10296	9689

ENERGY= 1.814876000000000E+06;

9843	9348	9030	8847	8799	8993	9465	10465
11766	12707	13291	13526	13693	13795	13728	13514
13440	13341	13014	12631	12499	12687	12169	10982
9711	9211	8908	8762	8706	8901	9310	10246
11504	12356	12986	13134	13157	13309	13295	13071
13007	12921	12631	12272	12185	12454	11971	10833
9203	8753	8520	8311	8305	9523	8924	9732
10856	11664	12175	12411	12476	12541	12514	12267
12259	12215	11936	11612	11548	11855	11395	10353
9449	8770	8401	8176	8137	9122	8195	8571
9323	10113	10621	10944	10998	11013	10878	10768
10304	10841	10713	10459	10398	10625	10253	9490
8578	8187	7650	7650	7533	7528	7475	7643
8157	8669	8949	9306	9552	9595	9505	9463
9510	9601	9625	9551	9640	10101	9883	9291

ENERGY= 1.761441000000000E+06;

9702	9197	8895	8721	8636	8861	9297	10256
11473	12395	12958	13172	13388	13458	13350	13148
13050	12920	12574	12170	12017	12197	11699	10631
9510	9010	8711	8576	8516	8697	9075	9953
11199	12021	12548	12802	12809	12942	12929	12744
12655	12578	12294	11929	11836	12150	11685	10595
8318	8392	8168	7935	7945	8152	8533	9174
10176	10983	11488	11787	11840	11893	11840	11615
11632	11638	11386	11066	11024	11342	10897	9960
9255	8547	8177	7945	7985	7947	7981	8400
9146	9924	10388	10718	10756	10808	10641	10490
10497	10538	10396	10160	10095	10324	9930	9209
8439	7971	7490	7490	7345	7380	7336	7491
7979	8452	8673	9011	9190	9208	9135	9083
9137	9226	9244	9179	9271	9807	9562	8982

ENERGY= 1.681810000000000E+06;

9493	8973	8694	8532	8392	8664	9047	9943
11038	11931	12462	12643	12933	12955	12787	12604
12470	12292	11917	11482	11299	11467	10999	10109
9212	8711	8417	8300	8232	8369	8724	9517
10744	11522	12044	12307	12290	12394	12384	12257
12131	12066	11791	11418	11317	11698	11257	10240
8245	7855	7645	7375	7410	7598	7950	8341
9162	9969	10465	10858	10966	10927	10835	10642

9962	9476	9144	8955	8937	9105	9607	10643
12014	12971	13573	13827	13951	14081	14049	13823
13770	13698	13358	13022	12907	13102	12566	11279
9881	9382	9075	8919	8867	9082	9510	10494
11762	12639	13173	13415	13452	13621	13605	13347
13305	13212	12917	12562	12480	12711	12215	11036
9530	9059	8818	8630	8609	8838	9255	10236
11433	12241	12758	12940	12922	13091	13086	12820
12789	12703	12402	12076	11992	12290	11818	10685
9511	8959	8592	8372	8266	8271	8357	8716
9474	10273	10819	11136	11203	11187	11078	11004
11063	11099	10982	10713	10654	10981	10527	9728
8881	8370	7786	7786	7692	7654	7592	7771
8308	8853	9184	9556	9858	9923	9819	9786
9827	9920	9949	9866	9954	10350	10155	9553

ENERGY= 1.833500000000000E+06:

9892	9401	9077	8892	8856	9039	9523	10539
11868	12816	13407	13650	13799	13912	13860	13641
13575	13488	13168	12792	12667	12857	12331	11104
9781	9281	8977	8826	8772	8975	9392	10348
11510	12472	13004	13250	13278	13437	13422	13184
13129	13041	12748	12391	12306	12560	12071	10917
9338	8879	8642	8442	8430	8653	9060	9927
11093	11901	12415	12629	12630	12767	12749	12495
12477	12415	12127	11803	11731	12034	11569	10490
9515	8847	8483	8256	8190	8184	8255	8631
9385	10179	10702	11023	11082	11085	10960	10865
10910	10947	10824	10563	10503	10730	10365	9588
8762	8262	7706	7706	7598	7580	7523	7695
8219	8745	9046	9409	9678	9730	9634	9596
9640	9732	9758	9680	9769	10203	9995	9399

ENERGY= 1.950649000000000E+06:

10200	9731	9372	9169	9214	9328	9891	10999
12509	13499	14136	14428	14467	14652	14689	14442
14429	14411	14134	13803	13723	13931	13360	11872
10220	9722	9410	9233	9190	9443	9909	10989
12279	13206	13745	13978	14041	14244	14224	13900
13900	13793	13487	13142	13071	13225	12700	11439
10182	9669	9412	9267	9218	9467	9917	11152
12584	13394	13921	13996	13915	14188	14228	13925
13950	13679	13332	13002	12980	13159	12661	11351
9935	9336	8972	8763	8524	8569	8701	9005
9775	10592	11214	11519	11614	11535	11479	11476
11582	11613	11520	11220	11166	11391	11074	10204
9237	8736	8056	8056	8011	7906	7826	8028
8510	9221	9652	10054	10470	10578	10444	10430
10459	10555	10594	10495	10580	10848	10698	10077

ENERGY= 1.995024000000000E+06:

10054	9574	9232	9037	9044	9191	9717	10780
12204	13174	13790	14058	14150	14301	14295	14061
14024	13973	13675	13323	13222	13421	12872	11508
10011	9513	9204	9040	8992	9221	9664	10685
11961	12857	13393	13632	13679	13961	13843	13560
13534	13436	13136	12786	12708	12909	12402	11191
9781	9254	9047	8875	8844	9080	9510	10570
11876	12685	13206	13347	13305	13513	13526	13246
13198	13079	12760	12433	12334	12625	12142	10942

10699	10780	10567	10251	10243	10578	10155	9375
8967	8214	7842	7600	7758	7685	7679	8146
8881	9643	10040	10381	10394	10503	10288	10075
10041	10085	9923	9714	9645	9874	9449	8790
8081	7649	7252	7252	7065	7158	7130	7265
7713	8128	8261	8572	8652	8632	8584	8516
8581	8667	8676	8625	8720	9368	9084	8521

ENERGY= 1.970344000000000E+06;

9989	9504	9170	8979	8969	9130	9639	10683
12069	13030	13636	13895	14009	14145	14121	13893
13844	13778	13472	13110	12999	13195	12655	11346
9919	9420	9113	8954	8904	9122	9555	10549
11820	12703	13237	13479	13518	13691	13674	13410
13372	13278	12981	12627	12547	12769	12269	11091
9603	9127	8884	8702	8678	8909	9330	10312
11562	12371	12988	13059	13034	13214	13214	12944
12909	12813	12506	12180	12092	12388	11912	10761
9648	9001	8634	8415	8295	8305	8395	8748
9508	10309	10863	11179	11250	11226	11123	11057
11122	11156	11043	10770	10712	10938	10588	9782
8927	8411	7816	7816	7728	7683	7618	7800
8342	8895	9236	9612	9927	9996	9889	9858
9898	9991	10021	9936	10024	10406	10216	9612

ENERGY= 1.826914000000000E+06;

9875	9382	9050	8876	8836	9023	9503	10513
11832	12777	13366	13606	13761	13871	13813	13596
13527	13436	13113	12735	12608	12797	12274	11061
9756	9257	8953	8804	8749	8949	9363	10312
11572	12431	12962	13209	13235	13392	13377	13144
13086	12999	12707	12349	12264	12522	12036	10887
9290	8834	8599	8396	8386	8607	9012	9858
11009	11818	12330	12552	12558	12687	12666	12414
12400	12344	12260	11736	11656	11971	11507	10442
9491	8820	8452	8228	8171	8162	8230	8610
9363	10155	10674	10995	11053	11060	10931	10831
10873	10910	10785	10527	10466	10693	10326	9553
8732	8236	7686	7686	7575	7562	7506	7677
8197	8718	9012	9372	9633	9682	9588	9549
9594	9686	9711	9634	9724	10167	9955	9361

ENERGY= 1.983382000000000E+06;

10023	9541	9203	9010	9038	9162	9680	10734
12141	13106	13717	13981	14084	14227	14213	13992
13939	13881	13579	13223	13117	13315	12769	11431
9968	9469	9161	8999	8950	9175	9612	10621
11895	12785	13319	13560	13603	13781	13764	13489
13458	13361	13063	12711	12632	12843	12339	11139
9697	9215	8970	8793	8765	8999	9425	10449
11728	12537	13056	13211	13177	13372	13379	13104
13061	12953	12640	12313	12220	12513	12034	10857
9695	9055	8689	8472	8333	8348	8445	8790
9551	10355	10920	11234	11309	11276	11181	11125
11196	11230	11120	10843	10786	11012	10667	9850
8985	8464	7855	7855	7774	7719	7652	7837
8386	8948	9304	9684	10015	10091	9979	9951
9989	10082	10114	10027	10114	10478	10294	9687

ENERGY= 1.860176000000000E+06;

9737	9104	8738	8522	8366	8386	8489	8827
9590	10396	10971	11284	11361	11321	11233	11186
11263	11297	11189	10908	10851	11077	10737	9911
9037	8511	7890	7890	7815	7751	7682	7870
8425	8995	9364	9748	10094	10175	10060	10034
10070	10164	10197	10108	10195	10542	10364	9755

ENERGY= 1.90992800000000E+06;

10093	9616	9270	9073	9090	9229	9763	10939
12286	13261	13893	14157	14235	14395	14401	14163
14132	14090	13798	13452	13356	13558	13002	11605
10067	9569	9259	9092	9045	9281	9729	10766
12046	12951	13487	13725	13776	13963	13945	13651
13632	13532	13231	12991	12805	12994	12482	11258
9883	9394	9145	8990	8944	9184	9619	10726
12066	12875	13397	13521	13468	13694	13714	13428
13373	13240	12913	12585	12480	12768	12281	11052
9791	9166	8801	8587	8408	8435	8546	8875
9639	10449	11036	11347	11429	11378	11299	11264
11348	11381	11278	10992	10936	11162	10827	9990
9104	8572	7935	7935	7867	7793	7721	7913
8474	9056	9441	9830	10195	10283	10163	10140
10174	10269	10303	10212	10298	10624	10454	9841

WEEKS= 4 MEAN_POWER= 6.26900000000000E+03 MEAN_ENERGY= 2.02410000000000E+06;

ENERGY= 1.95503100000000E+06;

10331	9885	9615	9523	9537	9895	10808	12368
13399	13862	13993	14016	13819	13920	13791	13599
13542	13474	13430	13714	13730	13298	12476	11377
10178	9692	9497	9389	9416	9791	10680	12225
13294	13754	13949	13984	13913	13874	13770	13558
13499	13360	13254	13587	13650	13243	12401	11261
9760	9369	9152	9063	9080	9431	10358	11872
12903	13425	13745	13773	13612	13699	13581	13348
13369	13232	13163	13399	13363	12911	12061	10951
10056	9330	8938	8841	8800	8874	9152	9764
10580	11349	11712	11987	11671	11511	11311	11124
11170	11297	11461	11649	11531	11197	10631	9922
9160	8737	8213	8213	8167	8210	8316	8693
9310	9811	9905	10145	10327	10227	9934	9776
9782	10023	10335	10805	10957	10788	10300	9744

ENERGY= 1.96871500000000E+06;

9772	9257	8957	8849	8858	9164	9967	11513
12511	13071	13180	13216	12980	13035	13018	12830
12597	12374	12314	12921	12970	12551	11837	10800
9756	9190	8958	8846	8852	9200	9975	11502
12655	13117	13313	13399	13235	13293	13247	13094
12899	12497	12321	12973	13113	12725	11911	10820
9359	8987	8765	8675	8679	9048	10033	11725
12847	13394	13734	13802	13678	13911	13848	13618
13585	13179	13019	13515	13496	13001	12113	10872
9753	8905	8560	8374	8341	8379	8652	9244
10037	10843	11228	11461	11247	11111	10899	10684
10539	10566	10797	11202	11116	10792	10245	9550
8763	8355	7762	7762	7723	7731	7826	8192
8772	9336	9419	9678	9863	9805	9513	9300
9207	9233	9559	10250	10459	10292	9833	9268

ENERGY= 1.97280500000000E+06;

9798	9287	8998	8881	8891	9198	10007	11553
12648	13108	13218	13254	13020	13077	13054	12867
12632	12426	12367	12959	13006	12597	11867	10827
9776	9214	8983	8872	8879	9228	10009	11536
12686	13147	13343	13427	13263	13320	13272	13116
12927	12538	12365	13002	13138	12749	11934	10940
9378	9005	8784	8693	8698	9066	10049	11732
12850	13395	13734	13801	13675	13901	13835	13605
13575	13181	13026	13599	13499	12997	12111	10876
9767	8925	8581	8396	8362	8402	8676	9268
10063	10867	11251	11481	11267	11130	10918	10705
10664	10601	10828	11223	11136	10811	10263	9568
8782	6373	7784	7784	7744	7754	7849	8215
8797	9358	9442	9700	9885	9925	9533	9323
9235	9270	9596	10276	10483	10315	9855	9290

ENERGY= 1.956622000000000E+06;

10342	9896	9627	9536	9550	9909	10823	12393
13403	13676	14008	14031	13835	13937	13805	13614
13560	13494	13451	13728	13744	13312	12498	11388
10135	9702	9496	9399	9426	9802	10693	12238
13306	13766	13961	13995	13824	13895	13780	13566
13510	13376	13271	13599	13660	13252	12410	11259
9767	9376	9159	9070	9087	9438	10364	11875
12904	13425	13745	13772	13611	13696	13576	13343
13365	13233	13165	13396	13361	12910	12060	10953
10062	9338	9006	8850	8808	8893	9161	9774
10590	11358	11721	11895	11678	11518	11319	11132
11180	11311	11474	11657	11539	11204	10638	9929
9168	8744	8221	8221	8176	8219	8325	8702
9320	9820	9914	10153	10335	10234	9942	9785
9793	10037	10350	10815	10966	10797	10309	9753

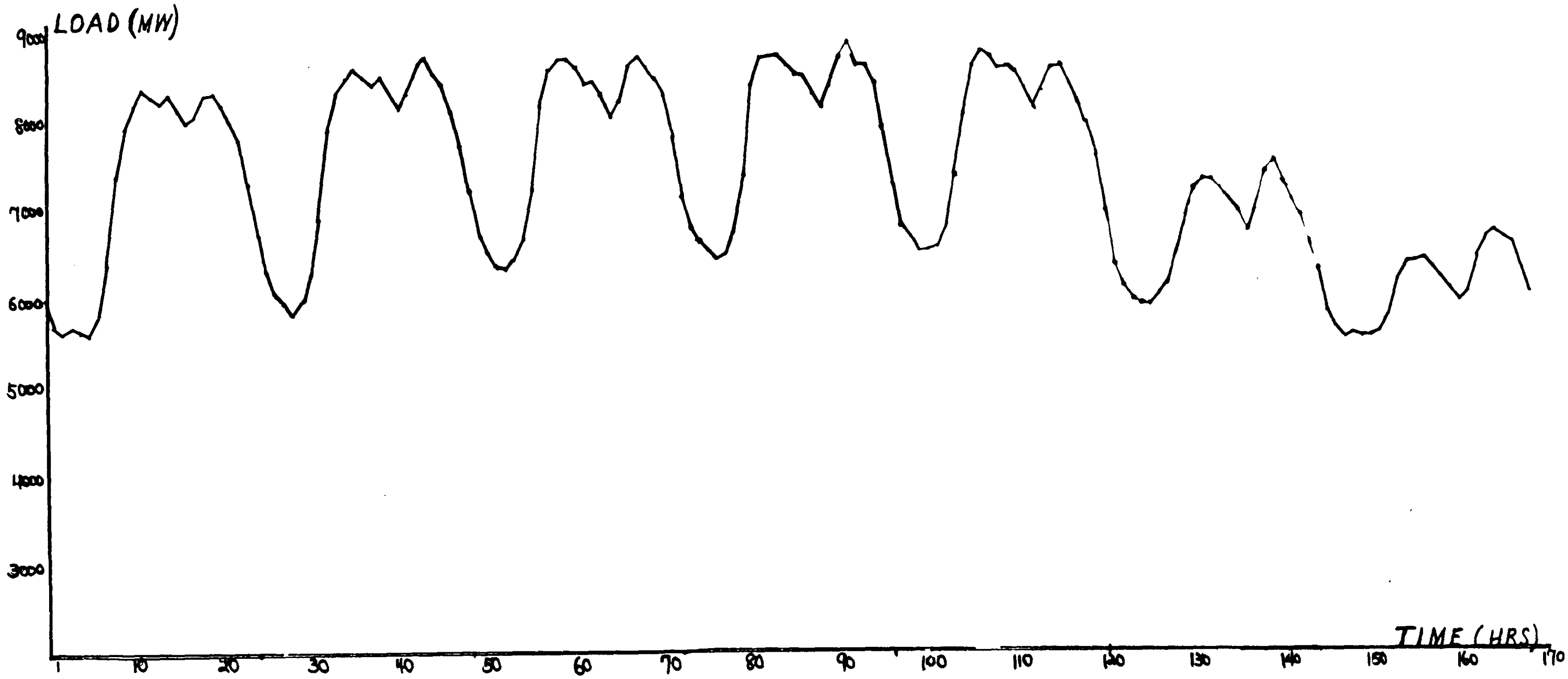
NORMAL END OF PROGRAM

A.5 Chronologic Load Model Sensitivity Study

The survey nature of the production cost program required a reduction of variables to improve its cost performance. A sensitivity study of load models was undertaken to find a configuration that would retain system accuracy for a minimum number of time intervals simulated. The criterion used for judging system accuracy was incremental capacity factors. Initially, simple averaging techniques were considered. The 168-hour-per-week representation (Figure A.2) were reduced to 84 2-hour intervals (Figure A.3) and 56 3-hour intervals (Figure A.4). Such arbitrary methods proved lacking in sufficient detail. The use of non-uniform time intervals proved more satisfactory. Starting with the 168-hour representation (Figure A.1) the investigation's depth reached the extreme of a four-interval-per-week load model (Figure A.5) which represented the high and the low of the weekdays, and the high and the low of the weekend. For these two models, a comparison of the system cost of the four-interval load model was calculated very close to the reference 168-interval model, see Table A.2. This effect was due to a cancellation of errors. The closeness in system costs between the '4' and '168' is due to the very coarse time intervals used in the '4' load model. Averaging time intervals generally lowers system production cost due to the fact that peakers operate at higher cost then the base load increments, thus averaging substitutes lower cost energy for

Figure A.2

168-HOUR REPRESENTATIVE OF THE CUSTOMER DEMAND FOR THE WEEK OF JAN. 4, 1971



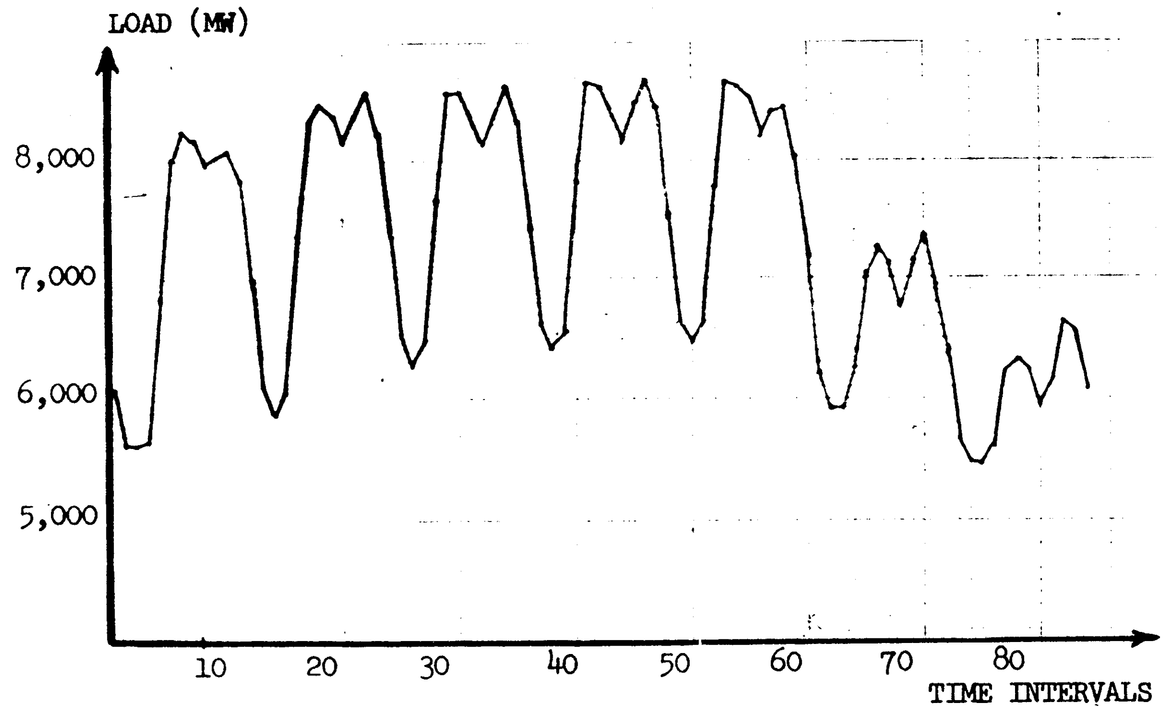


FIGURE A.3 84 INTERVAL REPRESENTATION OF THE CUSTOMER DEMAND FOR THE WEEK OF JAN. 4, 1971

Figure A.4

56-Interval Representation of the Customer Demand

for the Week of Jan. 4, 1971

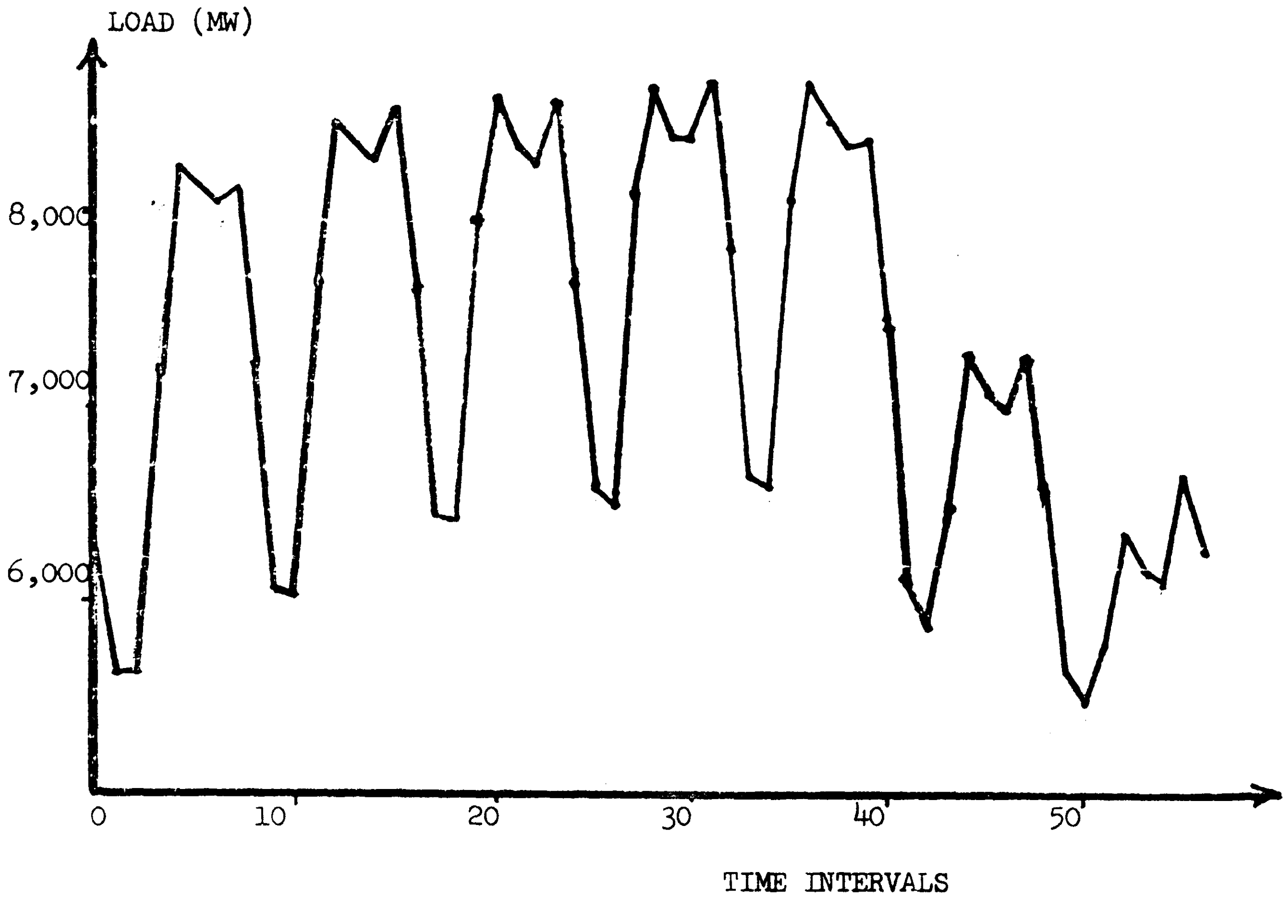


FIGURE A.5 COMPARISON OF 4-INTERVAL LOAD MODEL WITH 168-INTERVAL LOAD MODEL ON WINTER DATA

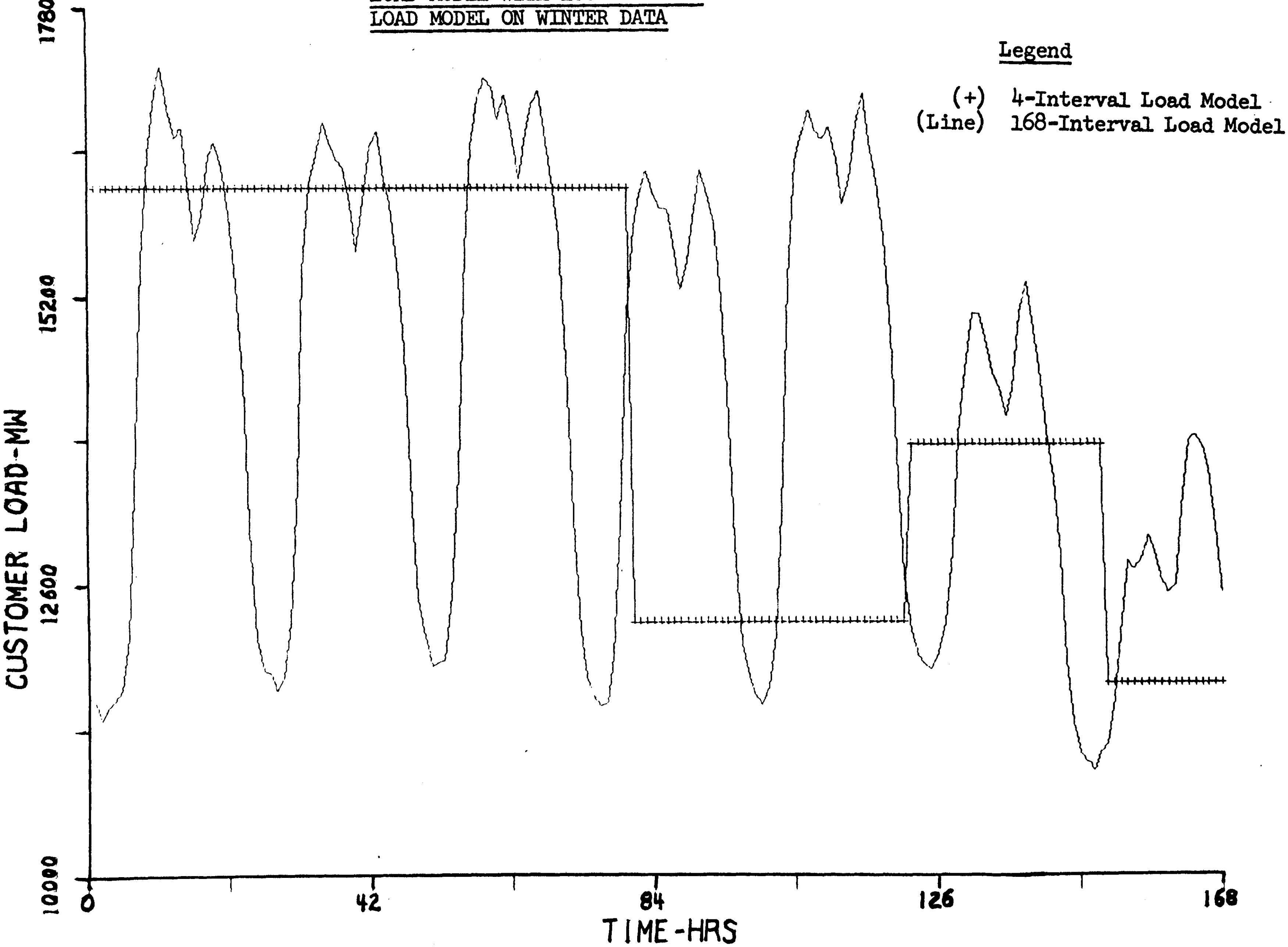


Table A.2

Optimal System Cost Comparison of 6 Load Models

(on Winter Load Data and Cost Plan 1)

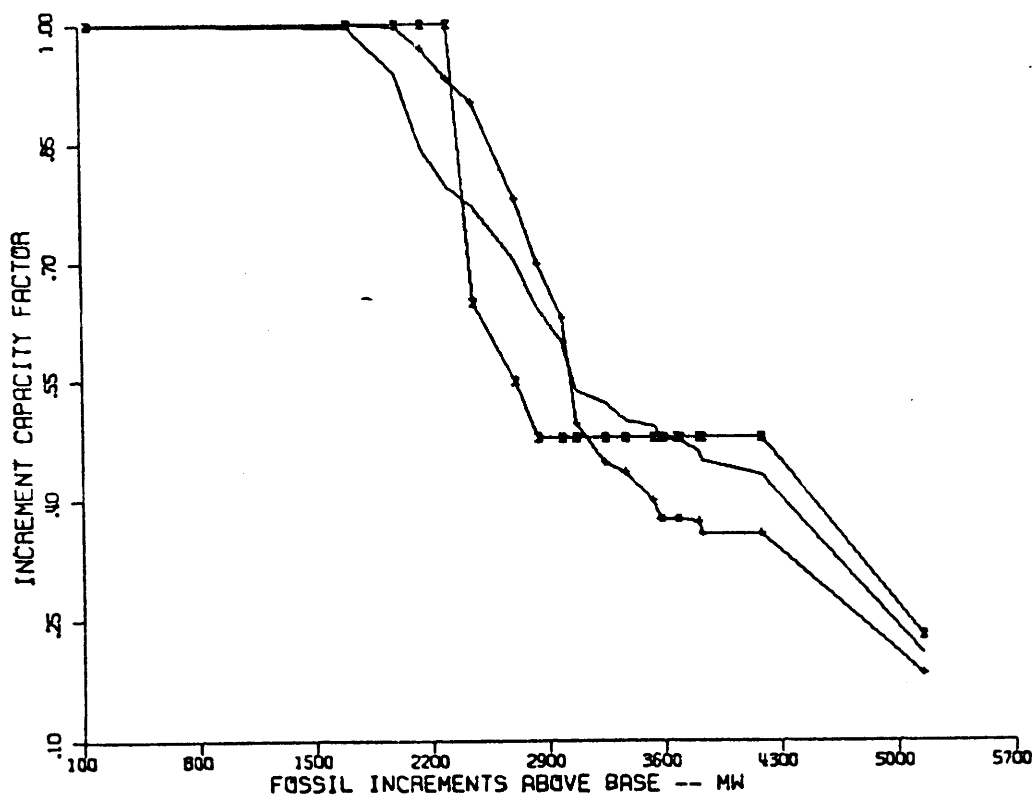
Load Model (Intervals/week)	Total System Cost ($\$10^3$/wk)
4	10,648
19	10,553
40	10,613
42	10,574
84	10,612
168	10,628

high cost energy. Table A.2 shows the trend in lower production cost with the decrease in the number of time intervals being simulated. However, the coarseness of the '4' model causes large amounts of nuclear energy to be used at inefficient (low) power levels, forcing the greater use of fossil fuel, thus offsetting the averaging effect. Of course, the capacity factors criterion for the four-interval model was not satisfied as shown in Figure A.6.

As with the simple averaging technique, the next set of models preserved the seven-day representation explicitly. There was a 42-interval load model,(Figure A.7) consisting of 7 days/week and 6 intervals/day. Also an 84-interval load model (Figure A.8) consisting of 7 days/week and 12 intervals/day. Figures A.6 and A.9 shows how these models compare with the reference case. As expected the 84-interval load model did best in reproducing the incremental capacity factors. The next modeling simplification step was to combine the average weekdays together because of their strong similarity. A 19-interval load model (Figure A.10) representing one peak day of 6 intervals, and average day (composite of the four other week days) of 6 intervals and a weekend of 7 intervals was compared with the previous results. Figure A.11 shows that the 19-interval load model very closely reproduced the results of the 42-interval load model. Both models represented 6 time intervals per day. Thus the similarity in weekdays could be used effectively to reduce the number

FIGURE A.6 COMPARISON OF INCREMENTAL FOSSIL CAPACITY FACTORS ON WINTER LOAD DATA AND COST PLAN 1

(X) 4-Interval Load Model
(+) 42-Interval Load Model
(Line) 168-Interval Load Model



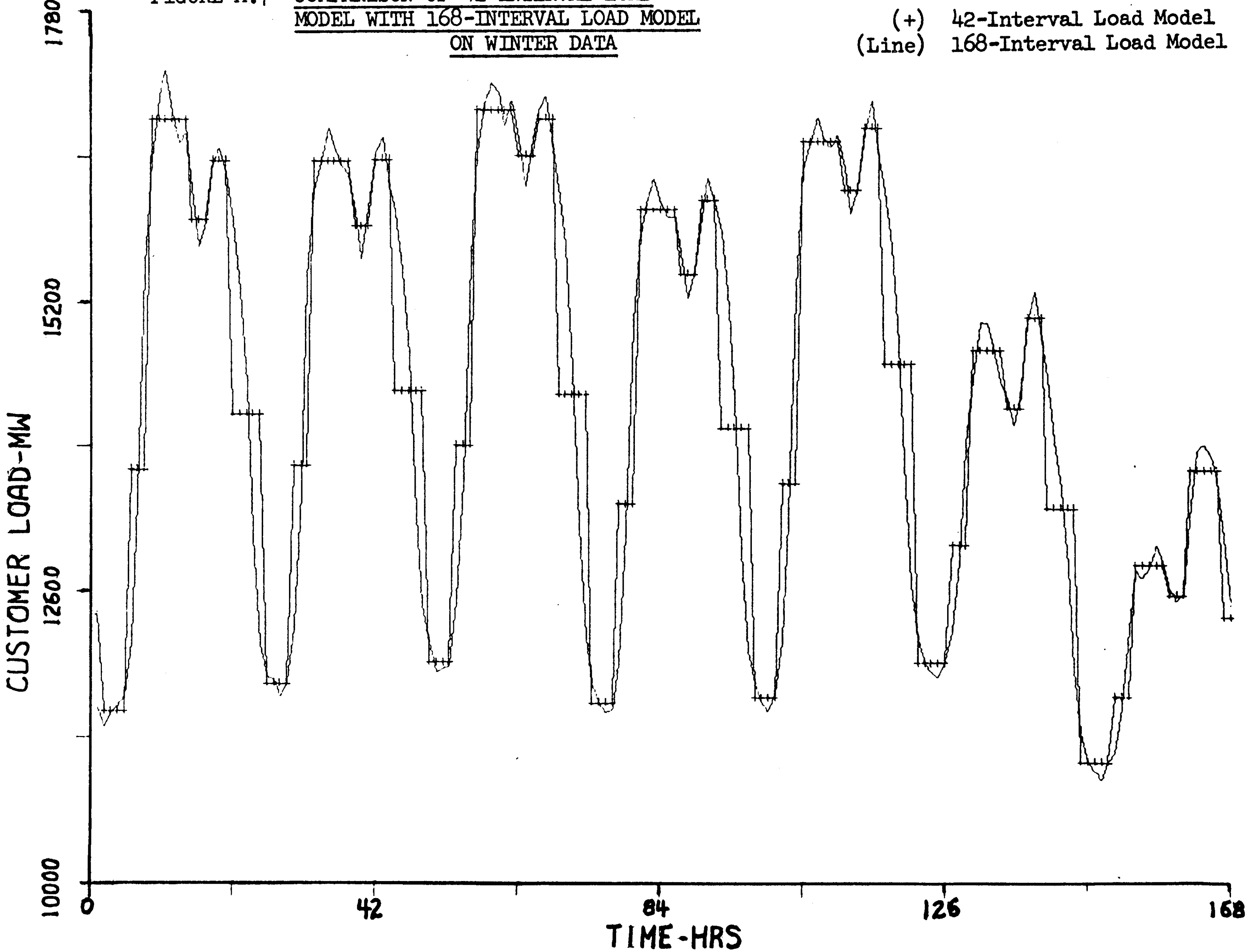


FIGURE A.7 COMPARISON OF 42-INTERVAL LOAD MODEL WITH 168-INTERVAL LOAD MODEL ON WINTER DATA

FIGURE A.8 COMPARISON OF 84-INTERVAL LOAD MODEL WITH 168-INTERVAL LOAD MODEL ON WINTER DATA

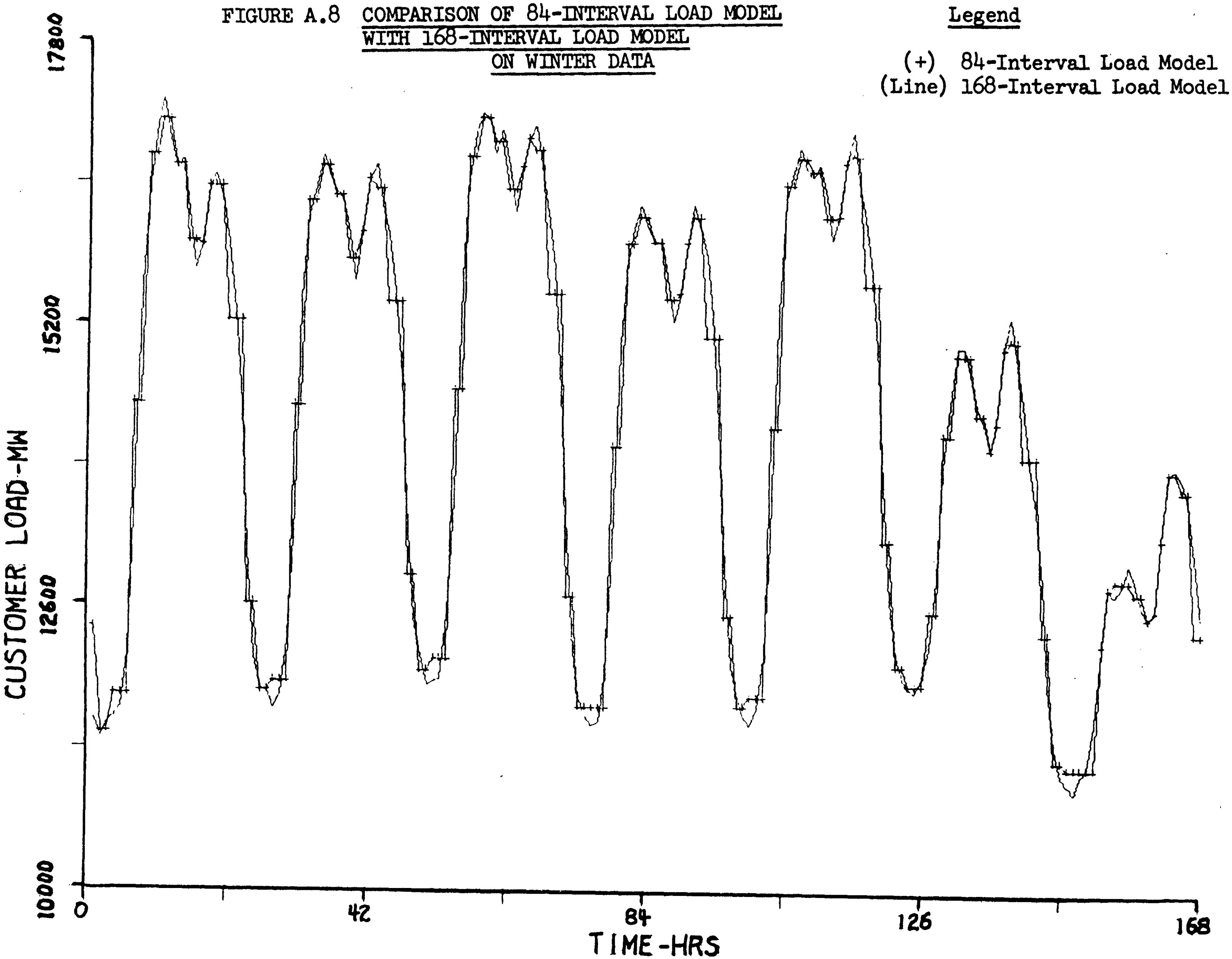


FIGURE A.9 COMPARISON OF INCREMENTAL FOSSIL CAPACITY FACTORS ON WINTER LOAD DATA AND COST PLAN 1

Legend

(+) 84-Interval Load Model
(Line) 168-Interval Load Model

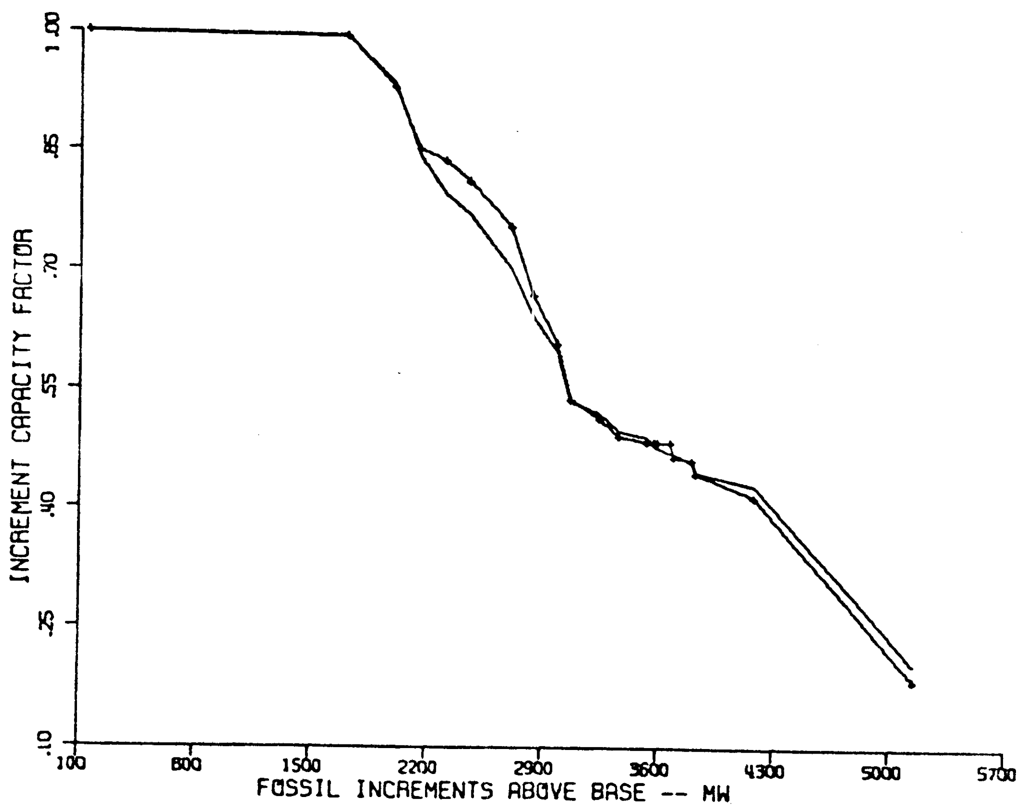


FIGURE A.10 COMPARISON OF 19-INTERVAL LOAD MODEL WITH 168-INTERVAL LOAD MODEL ON WINTER DATA

Legend

(+) 19-Interval Load Model
(Line) 168-Interval Load Model

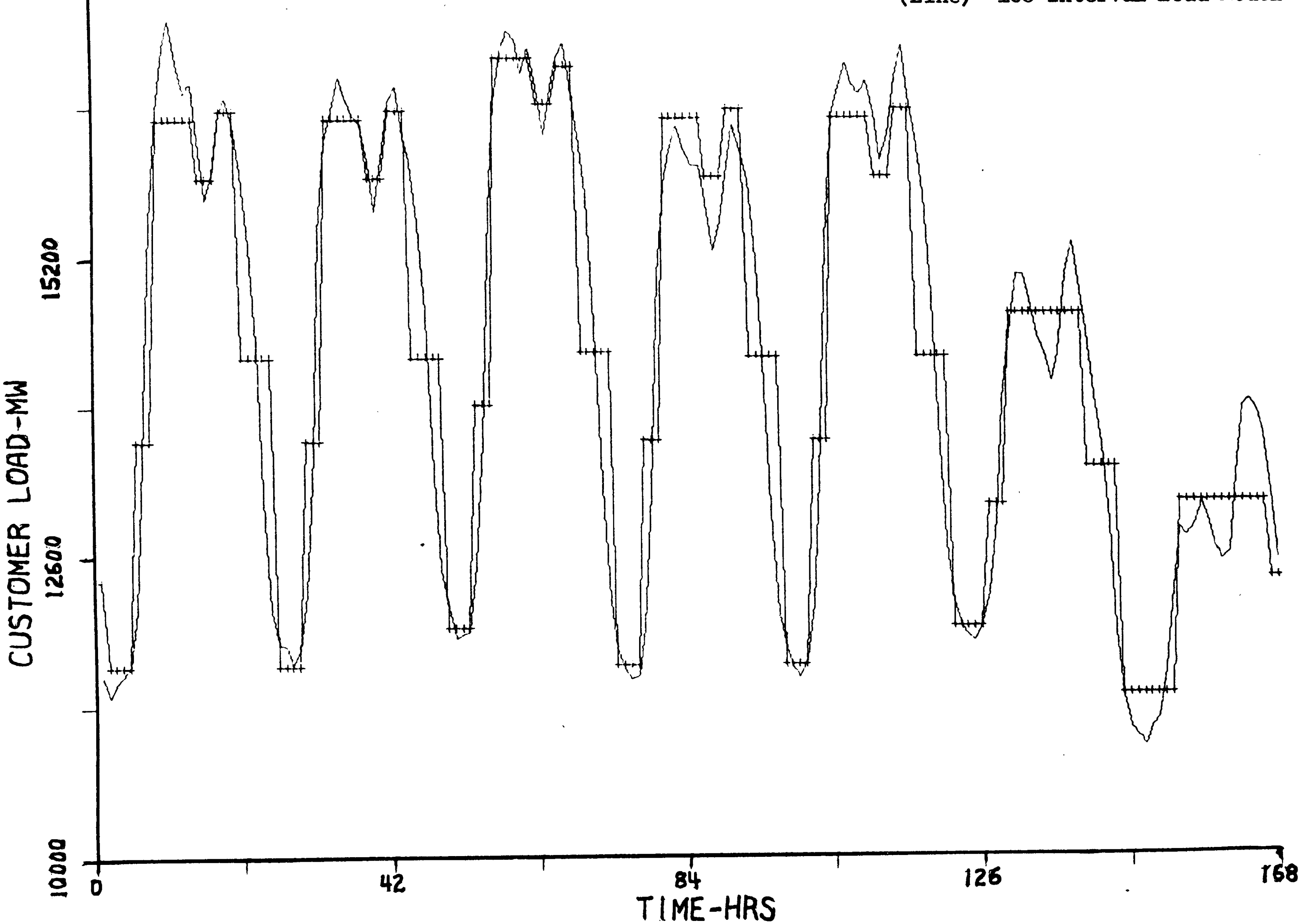
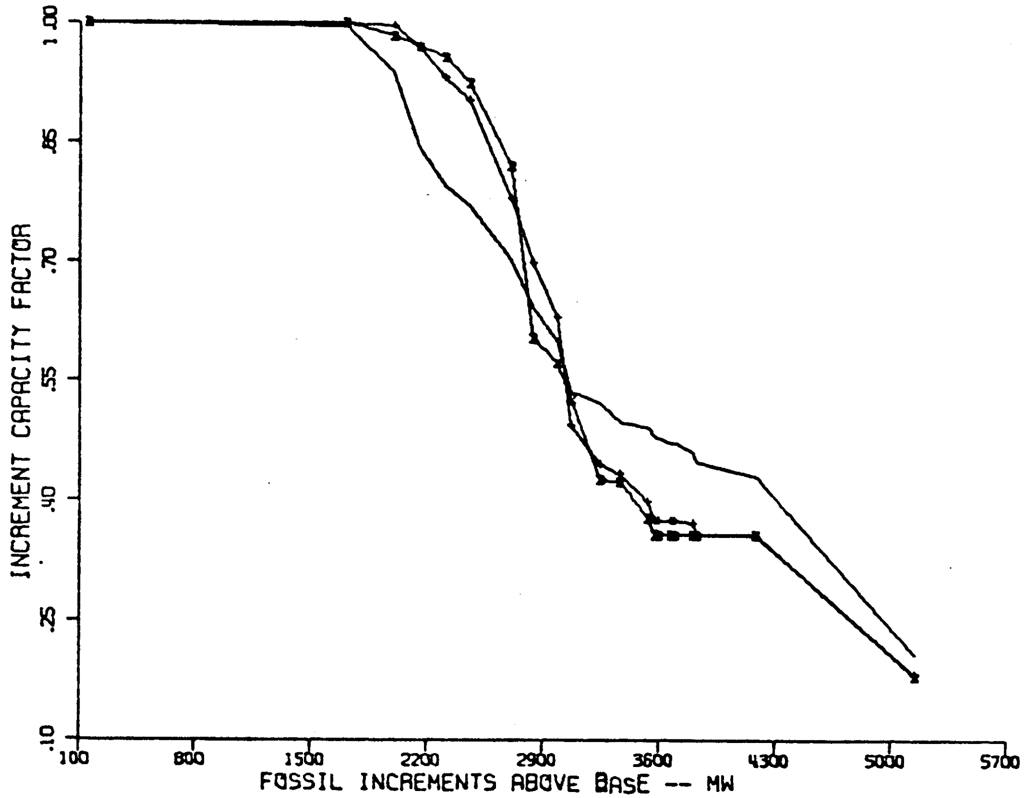


FIGURE A.11 COMPARISON OF INCREMENTAL FOSSIL CAPACITY FACTORS ON WINTER LOAD DATA AND COST PLAN 1

Legend

(X) 19-Interval Load Model
(+) 42-Interval Load Model
(Line) 168-Interval Load Model



of time intervals that had to be simulated. Table A.2 compares the weekly system production costs of the various load models using the same input parameters.

Accordingly, a 40-interval load model (Figure A.12) was formed, representing a peak weekday (10 intervals), a low weekday (10 intervals), an average weekday (composite of the three other weekdays, 10 intervals) and a weekend (10 intervals). The comparison of incremental capacity factors is shown in Figure A.13 . To demonstrate that the good comparison was not coincidental, a comparison of the 40-interval load model with the 168-interval load model was made for summer load model data, instead of winter, see Figure A.14. The comparison of incremental capacity factors with the reference (168-hours) case was again favorable, shown in Figure A.15 . The small aberrations at the high increments seem to be due to the pumped storage model.

As a further test, fossil fuel costs were changed from "Cost Plan 1" to "Cost Plan 2", Table A.3, so that the loading order of the fossil units was different. Figure A.16 shows that the incremental capacity factor distributions for the 40-interval load model and the 168-interval load model were very similar for "Cost Plan 2",also (see Figure A.13 for Cost Plan 1). The results justify using the 40-interval load model for future simulation studies in place of a 168-interval representation. Table A.4 compares the weekly system production cost of the 40-interval load model and the reference load model for the various tests referred to

FIGURE A.12 COMPARISON OF 40-INTERVAL LOAD MODEL WITH 168-INTERVAL LOAD MODEL ON WINTER DATA

Legend

(+) 40-Interval Load Model
(Line) 168-Interval Load Model

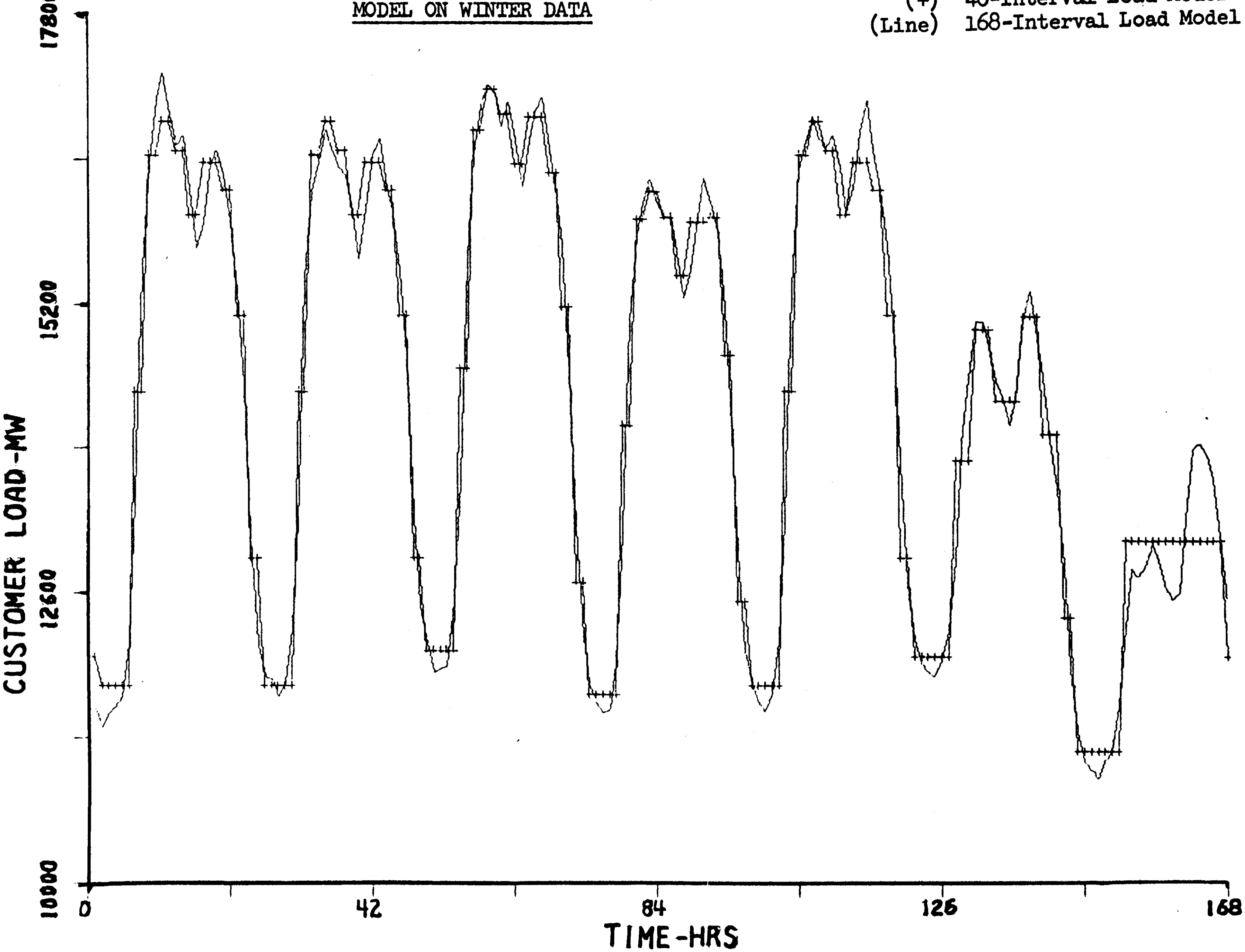


FIGURE A.13 COMPARISON OF INCREMENTAL FOSSIL CAPACITY FACTOR ON WINTER LOAD DATA AND COST PLAN 1

Legend

(X) 40-Interval Load Model
(+) 84-Interval Load Model
(Line) 168-Interval Load Model

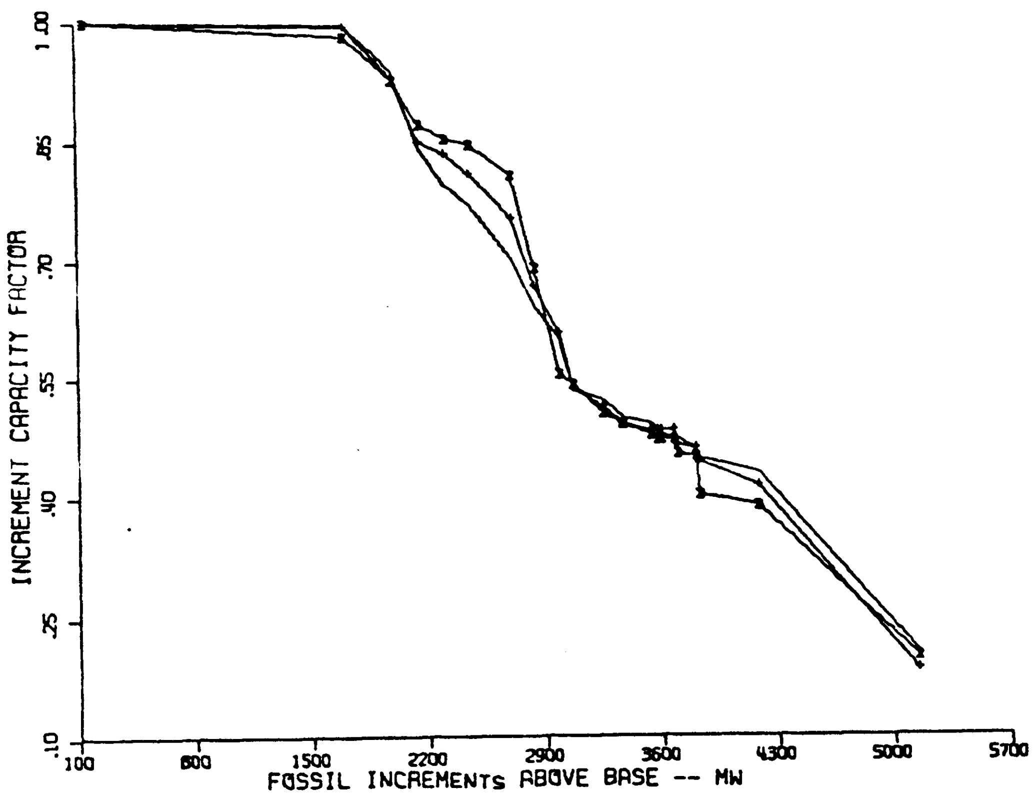


FIGURE A.14 COMPARISON OF 40-INTERVAL LOAD MODEL WITH 168-INTERVAL LOAD MODEL ON SUMMER DATA

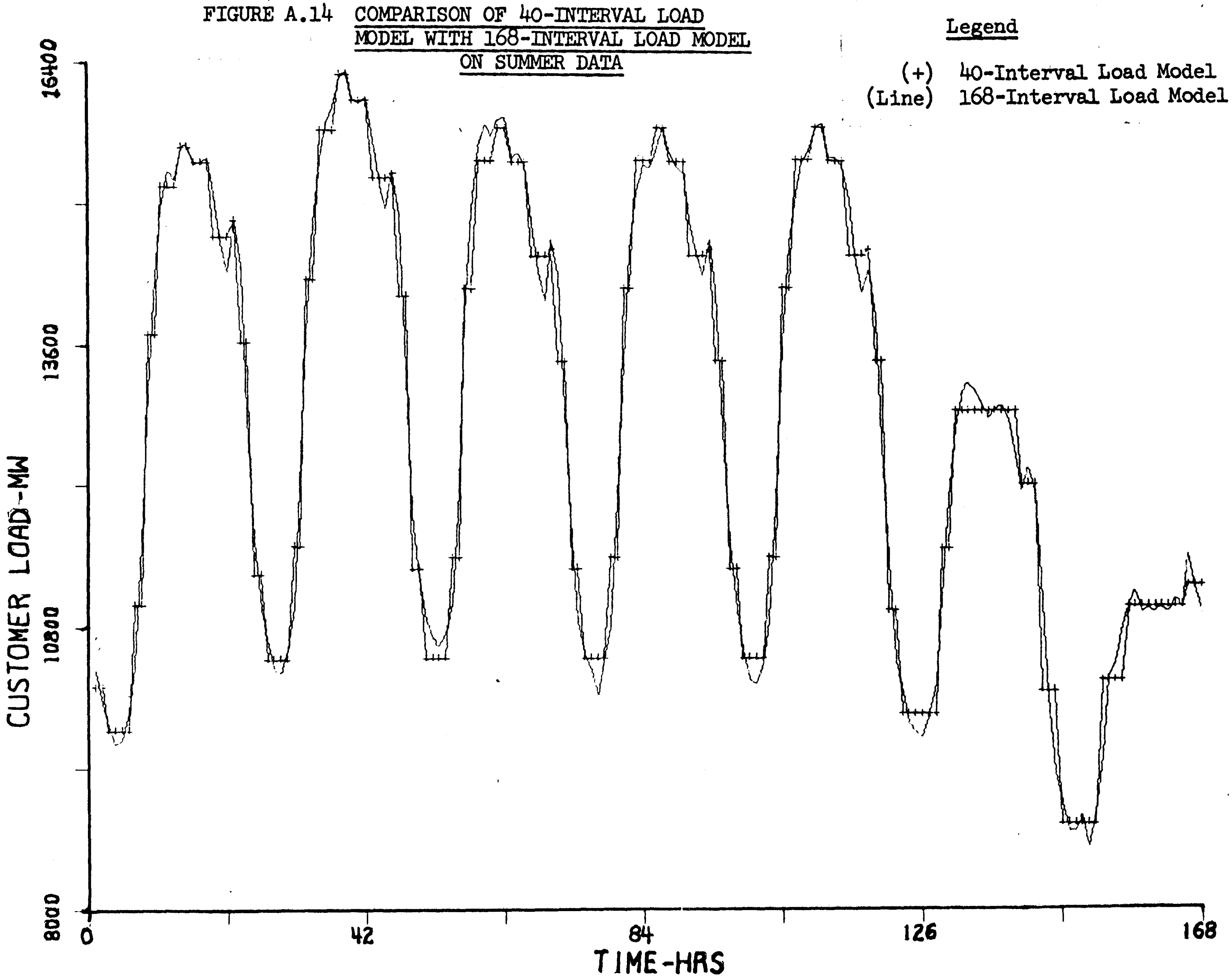


FIGURE A.15 COMPARISON OF INCREMENTAL FOSSIL CAPACITY FACTORS ON SUMMER LOAD DATA AND COST PLAN 1

Legend

(+) 40-Interval Load Model
(Line) 168-Interval Load Model

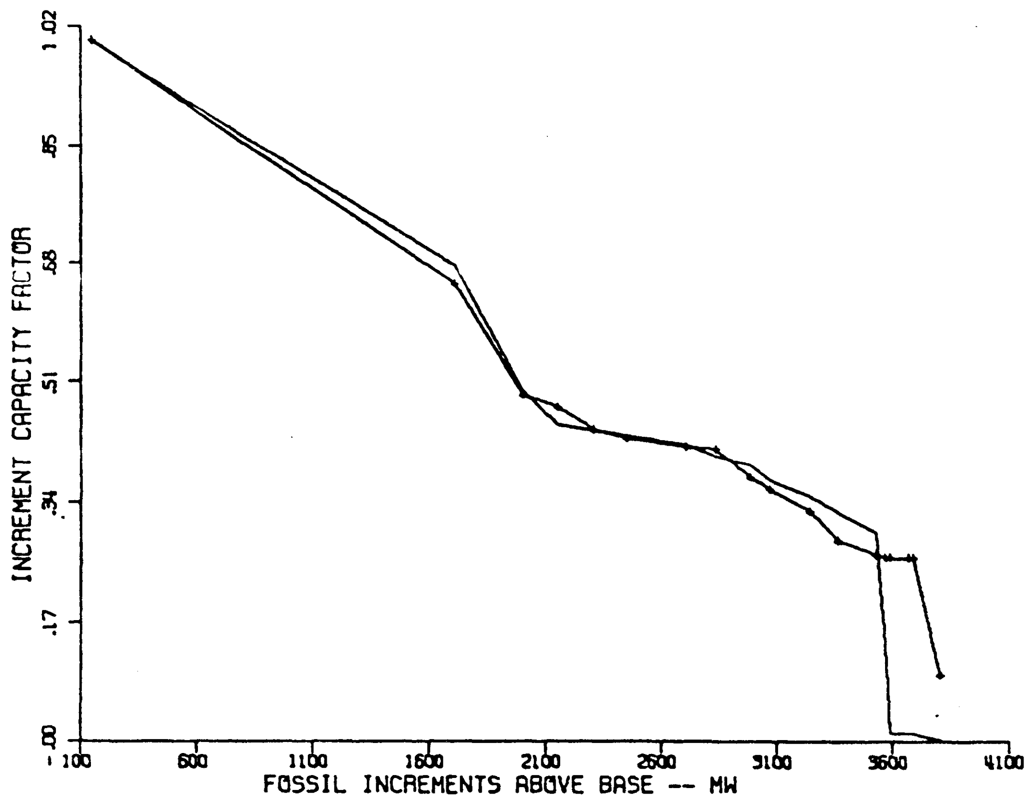


TABLE A.3

FOSSIL PLANT DATA USED IN SENSITIVITY STUDY

1. Standardized Average Heat Data:

	Power Level (% capacity)	Average Heat Rate (million Btu/MWHe)
Large:	0.64	8.98
	1.00	8.92
Medium:	0.40	9.50
	0.80	8.90
	1.00	8.90
Small:	0.40	13.50
	0.60	12.70
	0.80	12.50
	1.00	12.80

2.

	Number of 'classes' of plants	Number of Valve Points
Large:	6	2
Medium:	6	3
Small:	3	4

3. Information on each class of plants:

	No. in Class	Rated Capacity(MW)	Avg Heat Rate (10^6Btu/MWHe)	Cost 1 (¢/10^6Btu)	Cost 2 (¢/10^6Btu)
Large:	4	1,300	8.5	40	60
	4	800	9.3	80	40
	2	600	9.1	80	40
	1	580	9.0	60	80
	1	525	9.1	40	60
	1	400	9.2	60	80
Medium:	1	300	9.3	80	40
	3	240	9.1	40	60
	2	225	10.0	80	40
	3	215	9.8	40	60
	1	210	9.2	60	80
	2	205	9.8	60	80
Small:	5	150	9.4	40	60
	1	105	10.2	80	40
	1	100	10.8	60	80

FIGURE A.16 COMPARISON OF INCREMENTAL FOSSIL CAPACITY FACTORS ON WINTER LOAD DATA AND COST PLAN 2

Legend

(+) 40-Interval Load Model
(Line) 168-Interval Load Model

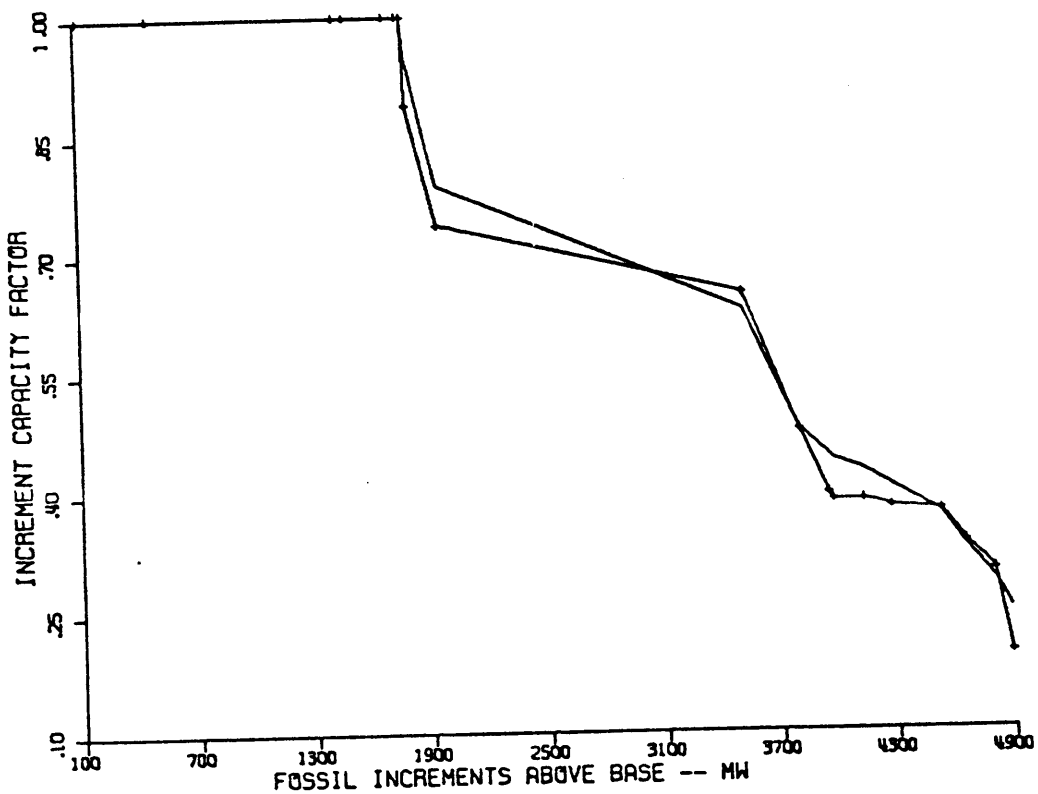


Table A.4

"Optimal System Cost Comparison of 40 Int/wk
Load Model with 168 Int/wk
Load Model (Units: $\$10^3$/wk)"

Load Model (Intervals/wk)	Winter Load, Cost Plan 1	Winter Load Cost Plan 2	Summer Load, Cost Plan 1
40	10,613	10,371	9,444
168	10,628	10,373	9,437

above. The agreement is favorable. Table A.3 also lists the plant parameters used in this study.

A.6 Load-Duration Sensitivity Study

The explicit simulation of 168 hours of the week is a costly calculation. It has been shown in the chronologic load model sensitivity study that little accuracy is lost in the prudent combination of time intervals to reduce the explicit number of intervals simulated. Depending on the particular feature of system the simulation model is trying to reproduce, the minimum number of time intervals will vary accordingly. In the previous section, the system feature to be reproduced was the incremental capacity factors, which allowed only a moderate reductions in the number of time intervals. In the reproduction of the OCNP, much less detail of the system need by reproduced. The chronologic pattern of the load model is not essential. The detailed simulation of high peaking demand intervals and low demand intervals is not so important. To find the correct value of OCNP, the model must locate the correct alternative cost to nuclear energy only at the time the nuclear energy is being exhausted. The difficulty of finding the correct alternative cost depends on the fine structure of the incremental fossil loading order. Table A.5 shows a typical fossil incremental loading order derived from a large 15,000 MWe capacity utility system. In the area of interest, the middle section of the loading order, the interval width vary from 100 MWe to 300 MWe. Some contiguous intervals have the same energy cost or only slight differences. Thus, it seems a great amount of latitude is available in reproducing the

Table A.5

TYPICAL ECONOMIC LOADING ORDER

INCREMENTAL STEP	STEP SIZE	CUMLATIVE SIZE	INCREM. FUEL COST	CUMLATIVE INCREM. FUEL COST
1	105	105	3.00	314.99
2	105	210	3.20	650.91
3	320	530	3.58	1796.26
4	320	850	3.82	3017.70
5	43	893	4.16	3196.68
6	120	1013	4.29	3710.96
7	43	1056	4.46	3902.85
8	120	1176	4.57	4451.29
9	60	1236	4.63	4728.87
10	116	1352	4.66	5269.71
11	135	1487	4.66	5899.21
12	135	1622	4.66	6528.70
13	43	1665	4.72	6731.61
14	43	1708	4.72	6934.52
15	80	1788	4.77	7315.81
16	60	1848	4.96	7613.40
17	116	1964	4.97	8190.16
18	135	2099	5.00	8865.16
19	168	2267	5.03	9709.64
20	168	2435	5.03	10554.11
21	43	2478	5.06	10771.69
22	80	2558	5.08	11178.30
23	43	2601	5.25	11404.05
24	168	2769	5.39	12309.57
25	60	2829	5.84	12659.68
26	260	3089	6.40	14324.95
27	96	3185	6.79	14976.72
28	96	3281	6.79	15628.48
29	260	3541	6.83	17404.38
30	96	3637	7.28	18103.26
31	60	3697	7.74	18567.90
32	60	3757	8.30	19066.03
33	48	3805	8.49	19473.38
34	48	3853	8.49	19880.73
35	48	3901	9.10	20317.53
36	56	3957	9.11	20827.51
37	56	4013	9.11	21337.48
38	160	4173	9.30	22824.93
39	160	4333	9.32	24316.90
40	56	4389	9.77	24863.74
41	60	4449	9.77	25449.77
42	260	4709	9.89	28021.15
43	160	4869	9.91	29607.41
44	160	5029	9.94	31198.49
45	21	5050	10.23	31413.38
46	260	5310	10.55	34155.58
47	21	5331	10.97	34385.95
48	21	5352	12.91	34656.99
49	29	5381	14.45	35075.96
50	29	5410	15.49	35525.13
51	29	5439	18.22	36053.56
52	1500	6939	25.00	73553.56

correct OCNP, as is shown by the experimental results.

Two system environments were used in the sensitivity study of load-duration models. An April load model with a non-nuclear system capacity of 12,000 MWe and an August load model with a non-nuclear system capacity of 13,000 MWe. The system parameters for the April and August system environments were the same as those used in the single reactor optimization study (Case 1) except for the modeling of the large fossil units. The large fossil units had a minimum operating level of 60% instead of 40% as used in the optimization studies.

Studying the situation of varying the capacity factor of a single reactor (1100 MWe, constant heat-rate), the April simulations were tested for load-duration models of 25, 12, 8, 6, 5, 4, 3, 2 time intervals. The list of resulting OCNP, system's cost, and incremental capacity factors are tabulated in Tables A.6, A.7, and A.8, respectively. As the number of time intervals decreases the OCNP values hardly change until the very end. The system cost numbers show only slight deterioration and even then, the changes are proportional for the various nuclear capacity factors (implying incremental system costs are the same for the various models, reinforcing the OCNP results).The incremental capacity factors, though, show marked deterioration with the reduction in the number of time intervals.

A similar single reactor case was repeated with the

TABLE A.6

OCNP COMPARISON FOR THE LOAD-DURATION SENSITIVITY STUDY
(ONE REACTOR, APRIL LOAD DATA CASE)

Weekly Nuclear Capacity Factor	Number of Time Intervals in Load-Duration Model:	OCNP (mills/10,000 Btut) 25	12	8	6	5	4	3	2
0.2		23.81	23.81	23.81	23.81	23.81	23.81	23.81	23.81
0.3		23.81	23.81	23.81	23.81	23.81	23.81	23.81	10.04
0.4		10.04	10.04	10.04	10.04	10.04	10.04	10.04	10.04
0.5		8.88	8.88	8.88	8.88	8.85	8.88	8.67	9.47
0.6		6.51	6.51	6.51	6.51	6.51	6.51	6.51	6.10
0.7		6.10	6.10	6.10	6.10	6.10	6.10	6.10	5.13
0.8		4.84	4.84	4.84	4.84	4.84	4.84	4.82	4.84
0.9		4.76	4.76	4.76	4.76	4.79	4.76	4.76	4.79

TABLE A.7

WEEKLY SYSTEM COST COMPARISON FOR LOAD-DURATION STUDY (ONE REACTOR, APRIL LOAD DATA CASE)

Weekly Nuclear Capacity Factor	System Production Costs ($/wk) Number of Time Intervals in Load Duration Model			
	25	12	8	6
0.2	12,320,625	12,319,115	12,316,938	12,309,568
0.3	11,858,624	11,857,114	11,854,938	11,847,568
0.4	11,612,667	11,606,230	11,604,761	11,600,661
0.5	11,428,551	11,421,840	11,420,752	11,416,081
0.6	11,275,089	11,268,589	11,267,895	11,264,759
0.7	11,151,751	11,145,449	11,144,807	11,142,240
0.8	11,047,553	11,041,104	11,040,363	11,039,196
0.9	10,954,547	10,948,067	10,947,350	10,946,179
	5	4	3	2
0.2	12,305,089	12,311,116	12,296,722	12,060,314
0.3	11,843,089	11,849,116	11,834,722	11,772,658
0.4	11,603,239	11,598,939	11,587,959	11,577,751
0.5	11,417,442	11,412,132	11,400,531	11,391,234
0.6	11,268,732	11,250,882	11,252,150	11,222,610
0.7	11,140,423	11,135,831	11,127,149	11,107,190
0.8	11,035,965	10,030,987	11,026,651	11,009,242
0.9	10,942,978	10,937,927	10,933,787	10,916,154

TABLE A.8
INCREMENTAL CAPACITY FACTOR COMPARISON FOR THE
LOAD DURATION SENSITIVITY STUDY
(Single Reactor, April Load Data Case)

The following tables are a comparison of the capacity factors of the 52 fossil increments in the April economic loading from eight load-duration models. The tables are arranged as follows:

The increments are labeled horizontally and the number of intervals in the load-duration models are labeled vertically. There is a separate table for each of eight values of the weekly nuclear capacity factor, ordered by descending values.

TABLE A.8A
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.90 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
N 25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
N 25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.92	0.73	0.70
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.94	0.71	0.71
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.72	0.67
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.92	0.71	0.71
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.74	0.64
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.84	0.71
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.92	0.71	0.71
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94	0.58

INCRE:	21	22	23	24	25	26	27	28	29	30
N 25:	0.69	0.66	0.64	0.63	0.61	0.59	0.57	0.57	0.52	0.50
T 12:	0.66	0.64	0.64	0.64	0.64	0.58	0.58	0.58	0.51	0.51
E 8:	0.67	0.67	0.67	0.64	0.58	0.58	0.58	0.58	0.53	0.48
R 6:	0.71	0.71	0.71	0.59	0.58	0.58	0.58	0.58	0.53	0.47
V 5:	0.64	0.64	0.64	0.64	0.64	0.64	0.53	0.50	0.50	0.50
A 4:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.50
L 3:	0.71	0.71	0.71	0.71	0.71	0.61	0.47	0.47	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	31	32	33	34	35	36	37	38	39	40
N 25:	0.49	0.48	0.48	0.48	0.48	0.47	0.46	0.46	0.46	0.45
T 12:	0.49	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.46	0.45
E 8:	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.47	0.45	0.45
R 6:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
V 5:	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.47	0.43	0.43
A 4:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
L 3:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	41	42	43	44	45	46	47	48	49	50
N 25:	0.45	0.42	0.37	0.35	0.33	0.20	0.02	0.02	0.02	0.02
T 12:	0.45	0.42	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
E 8:	0.45	0.44	0.35	0.35	0.35	0.21	0.00	0.00	0.00	0.00
R 6:	0.47	0.40	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
V 5:	0.43	0.43	0.43	0.43	0.43	0.11	0.00	0.00	0.00	0.00
A 4:	0.45	0.45	0.45	0.45	0.45	0.07	0.00	0.00	0.00	0.00
L 3:	0.47	0.47	0.47	0.47	0.47	0.00	0.00	0.00	0.00	0.00
S 2:	0.58	0.58	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52
N 25:	0.02	0.00
T 12:	0.00	0.00
E 8:	0.00	0.00
R 6:	0.00	0.00
V 5:	0.00	0.00
A 4:	0.00	0.00
L 3:	0.00	0.00
S 2:	0.00	0.00

TABLE A.8B
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.80 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
N 25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
N 25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.97	0.97	0.96
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.95
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.96	0.96
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.94
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	21	22	23	24	25	26	27	28	29	30
N 25:	0.94	0.77	0.64	0.63	0.61	0.59	0.57	0.57	0.52	0.50
T 12:	0.94	0.77	0.64	0.64	0.64	0.58	0.58	0.58	0.51	0.51
E 8:	0.96	0.75	0.67	0.64	0.58	0.58	0.58	0.58	0.53	0.48
R 6:	0.94	0.87	0.71	0.59	0.58	0.58	0.58	0.58	0.53	0.47
V 5:	0.88	0.69	0.64	0.64	0.64	0.64	0.53	0.50	0.50	0.50
A 4:	0.99	0.71	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.50
L 3:	0.79	0.71	0.71	0.71	0.71	0.61	0.47	0.47	0.47	0.47
S 2:	1.00	0.70	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	31	32	33	34	35	36	37	38	39	40
N 25:	0.49	0.48	0.48	0.48	0.48	0.47	0.46	0.46	0.46	0.45
T 12:	0.49	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.46	0.45
E 8:	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.47	0.45	0.45
R 6:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
V 5:	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.47	0.43	0.43
A 4:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
L 3:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	41	42	43	44	45	46	47	48	49	50
N 25:	0.45	0.42	0.37	0.35	0.33	0.20	0.02	0.02	0.02	0.02
T 12:	0.45	0.42	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
E 8:	0.45	0.44	0.35	0.35	0.35	0.21	0.00	0.00	0.00	0.00
R 6:	0.47	0.40	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
V 5:	0.43	0.43	0.43	0.43	0.43	0.11	0.00	0.00	0.00	0.00
A 4:	0.45	0.45	0.45	0.45	0.45	0.07	0.00	0.00	0.00	0.00
L 3:	0.47	0.47	0.47	0.47	0.47	0.00	0.00	0.00	0.00	0.00
S 2:	0.58	0.58	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52
N 25:	0.02	0.00
T 12:	0.00	0.00
E 8:	0.00	0.00
R 6:	0.00	0.00
V 5:	0.00	0.00
A 4:	0.00	0.00
L 3:	0.00	0.00
S 2:	0.00	0.00

TABLE A.8C
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.70 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
N 25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
N 25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.97	0.97	0.96
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.95
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.96	0.96
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.94
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	21	22	23	24	25	26	27	28	29	30
N 25:	0.94	0.94	0.92	0.88	0.87	0.69	0.57	0.57	0.52	0.50
T 12:	0.94	0.94	0.94	0.89	0.84	0.69	0.58	0.58	0.51	0.51
E 8:	0.96	0.96	0.96	0.86	0.84	0.69	0.58	0.58	0.53	0.48
R 6:	0.94	0.94	0.94	0.94	0.94	0.63	0.58	0.58	0.53	0.47
V 5:	0.88	0.88	0.88	0.88	0.88	0.75	0.53	0.50	0.50	0.50
A 4:	0.99	0.84	0.84	0.84	0.84	0.69	0.58	0.58	0.58	0.50
L 3:	1.00	1.00	1.00	1.00	0.75	0.67	0.47	0.47	0.47	0.47
S 2:	1.00	1.00	1.00	0.98	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	31	32	33	34	35	36	37	38	39	40
N 25:	0.49	0.48	0.48	0.48	0.48	0.47	0.46	0.46	0.46	0.45
T 12:	0.49	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.46	0.45
E 8:	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.47	0.45	0.45
R 6:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
V 5:	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.47	0.43	0.43
A 4:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
L 3:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	41	42	43	44	45	46	47	48	49	50
N 25:	0.45	0.42	0.37	0.35	0.33	0.20	0.02	0.02	0.02	0.02
T 12:	0.45	0.42	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
E 8:	0.45	0.44	0.35	0.35	0.35	0.21	0.00	0.00	0.00	0.00
R 6:	0.47	0.40	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
V 5:	0.43	0.43	0.43	0.43	0.43	0.11	0.00	0.00	0.00	0.00
A 4:	0.45	0.45	0.45	0.45	0.45	0.07	0.00	0.00	0.00	0.00
L 3:	0.47	0.47	0.47	0.47	0.47	0.00	0.00	0.00	0.00	0.00
S 2:	0.58	0.58	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52
N 25:	0.02	0.00
T 12:	0.00	0.00
E 8:	0.00	0.00
R 6:	0.00	0.00
V 5:	0.00	0.00
A 4:	0.00	0.00
L 3:	0.00	0.00
S 2:	0.00	0.00

TABLE A.8D
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.60 WEEKLY NUCLEAR CAPACITY FACTOR

	INCRE:	1	2	3	4	5	6	7	8	9	10
N	25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T	12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E	8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R	6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V	5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A	4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L	3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S	2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

	INCRE:	11	12	13	14	15	16	17	18	19	20
N	25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.97	0.97	0.96
T	12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.95
E	8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.96	0.96
R	6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.94
V	5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94
A	4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L	3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S	2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

	INCRE:	21	22	23	24	25	26	27	28	29	30
N	25:	0.94	0.94	0.92	0.88	0.87	0.83	0.81	0.74	0.65	0.50
T	12:	0.94	0.94	0.94	0.89	0.84	0.84	0.82	0.71	0.65	0.51
E	8:	0.96	0.96	0.96	0.86	0.84	0.84	0.84	0.78	0.63	0.48
R	6:	0.94	0.94	0.94	0.94	0.94	0.82	0.71	0.71	0.67	0.47
V	5:	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.75	0.57	0.50
A	4:	0.99	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.66	0.50
L	3:	1.00	1.00	1.00	1.00	0.75	0.71	0.71	0.71	0.67	0.47
S	2:	1.00	1.00	1.00	1.00	1.00	0.89	0.58	0.58	0.58	0.58

	INCRE:	31	32	33	34	35	36	37	38	39	40
N	25:	0.49	0.48	0.48	0.48	0.48	0.47	0.46	0.46	0.46	0.45
T	12:	0.49	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.46	0.45
E	8:	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.47	0.45	0.45
R	6:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
V	5:	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.47	0.43	0.43
A	4:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
L	3:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
S	2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

	INCRE:	41	42	43	44	45	46	47	48	49	50
N	25:	0.45	0.42	0.37	0.35	0.33	0.20	0.02	0.02	0.02	0.02
T	12:	0.45	0.42	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
E	8:	0.45	0.44	0.35	0.35	0.35	0.21	0.00	0.00	0.00	0.00
R	6:	0.47	0.40	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
V	5:	0.43	0.43	0.43	0.43	0.43	0.11	0.00	0.00	0.00	0.00
A	4:	0.45	0.45	0.45	0.45	0.45	0.07	0.00	0.00	0.00	0.00
L	3:	0.47	0.47	0.47	0.47	0.47	0.00	0.00	0.00	0.00	0.00
S	2:	0.58	0.58	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	INCRE:	51	52
N	25:	0.02	0.00
T	12:	0.00	0.00
E	8:	0.00	0.00
R	6:	0.00	0.00
V	5:	0.00	0.00
A	4:	0.00	0.00
L	3:	0.00	0.00
S	2:	0.00	0.00

TABLE A.8E
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.50 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
N 25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
INCRE:	11	12	13	14	15	16	17	18	19	20
N 25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.97	0.97	0.96
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.95
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.96	0.96
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.94
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
INCRE:	21	22	23	24	25	26	27	28	29	30
N 25:	0.94	0.94	0.92	0.88	0.87	0.83	0.81	0.74	0.71	0.67
T 12:	0.94	0.94	0.94	0.89	0.84	0.84	0.82	0.71	0.71	0.64
E 8:	0.96	0.96	0.96	0.86	0.84	0.84	0.84	0.78	0.67	0.67
R 6:	0.94	0.94	0.94	0.94	0.94	0.82	0.71	0.71	0.71	0.71
V 5:	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.75	0.64	0.64
A 4:	0.99	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.75	0.58
L 3:	1.00	1.00	1.00	1.00	0.75	0.71	0.71	0.71	0.71	0.71
S 2:	1.00	1.00	1.00	1.00	1.00	0.99	0.58	0.58	0.58	0.58
INCRE:	31	32	33	34	35	36	37	38	39	40
N 25:	0.64	0.64	0.64	0.61	0.61	0.61	0.60	0.58	0.49	0.45
T 12:	0.64	0.64	0.64	0.64	0.64	0.61	0.58	0.58	0.49	0.45
E 8:	0.67	0.67	0.67	0.60	0.58	0.58	0.58	0.58	0.49	0.45
R 6:	0.71	0.62	0.58	0.58	0.58	0.58	0.58	0.58	0.51	0.47
V 5:	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.63	0.43	0.43
A 4:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.49	0.45
L 3:	0.71	0.71	0.71	0.71	0.71	0.64	0.47	0.47	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
INCRE:	41	42	43	44	45	46	47	48	49	50
N 25:	0.45	0.42	0.37	0.35	0.33	0.20	0.02	0.02	0.02	0.02
T 12:	0.45	0.42	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
E 8:	0.45	0.44	0.35	0.35	0.35	0.21	0.00	0.00	0.00	0.00
R 6:	0.47	0.40	0.37	0.37	0.37	0.20	0.00	0.00	0.00	0.00
V 5:	0.43	0.43	0.43	0.43	0.43	0.11	0.00	0.00	0.00	0.00
A 4:	0.45	0.45	0.45	0.45	0.45	0.07	0.00	0.00	0.00	0.00
L 3:	0.47	0.47	0.47	0.47	0.47	0.00	0.00	0.00	0.00	0.00
S 2:	0.58	0.58	0.58	0.10	0.00	0.00	0.00	0.00	0.00	0.00
INCRE:	51	52								
N 25:	0.02	0.00								
T 12:	0.00	0.00								
E 8:	0.00	0.00								
R 6:	0.00	0.00								
V 5:	0.00	0.00								
A 4:	0.00	0.00								
L 3:	0.00	0.00								
S 2:	0.00	0.00								

TABLE A.8F
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.40 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
N 25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
N 25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.97	0.97	0.96
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.95
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.96	0.96
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.94
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	21	22	23	24	25	26	27	28	29	30
N 25:	0.94	0.94	0.92	0.88	0.87	0.83	0.81	0.74	0.71	0.67
T 12:	0.94	0.94	0.94	0.89	0.84	0.84	0.82	0.71	0.71	0.64
E 8:	0.96	0.96	0.96	0.86	0.84	0.84	0.84	0.78	0.67	0.67
R 6:	0.94	0.94	0.94	0.94	0.94	0.82	0.71	0.71	0.71	0.71
V 5:	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.75	0.64	0.64
A 4:	0.99	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.75	0.58
L 3:	1.00	1.00	1.00	1.00	0.75	0.71	0.71	0.71	0.71	0.71
S 2:	1.00	1.00	1.00	1.00	1.00	0.99	0.58	0.58	0.58	0.58

INCRE:	31	32	33	34	35	36	37	38	39	40
N 25:	0.64	0.64	0.64	0.61	0.61	0.61	0.60	0.58	0.57	0.57
T 12:	0.64	0.64	0.64	0.64	0.64	0.61	0.58	0.58	0.58	0.58
E 8:	0.67	0.67	0.67	0.60	0.58	0.58	0.58	0.58	0.58	0.58
R 6:	0.71	0.62	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
V 5:	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.53	0.50
A 4:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
L 3:	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.56	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	41	42	43	44	45	46	47	48	49	50
N 25:	0.54	0.51	0.49	0.47	0.46	0.28	0.02	0.02	0.02	0.02
T 12:	0.53	0.51	0.49	0.47	0.47	0.30	0.00	0.00	0.00	0.00
E 8:	0.58	0.50	0.48	0.48	0.48	0.29	0.00	0.00	0.00	0.00
R 6:	0.58	0.50	0.47	0.47	0.47	0.30	0.00	0.00	0.00	0.00
V 5:	0.50	0.50	0.50	0.50	0.50	0.27	0.00	0.00	0.00	0.00
A 4:	0.58	0.56	0.45	0.45	0.45	0.27	0.00	0.00	0.00	0.00
L 3:	0.47	0.47	0.47	0.47	0.47	0.30	0.00	0.00	0.00	0.00
S 2:	0.58	0.58	0.58	0.58	0.58	0.08	0.00	0.00	0.00	0.00

INCRE:	51	52
N 25:	0.02	0.00
T 12:	0.00	0.00
E 8:	0.00	0.00
R 6:	0.00	0.00
V 5:	0.00	0.00
A 4:	0.00	0.00
L 3:	0.00	0.00
S 2:	0.00	0.00

TABLE A.8G
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.30 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
N 25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
N 25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.97	0.97	0.96
T 12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.95
E 8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.96	0.96
R 6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.94
V 5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94
A 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L 3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S 2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	21	22	23	24	25	26	27	28	29	30
N 25:	0.94	0.94	0.92	0.88	0.87	0.83	0.81	0.74	0.71	0.67
T 12:	0.94	0.94	0.94	0.89	0.84	0.84	0.82	0.71	0.71	0.64
E 8:	0.96	0.96	0.96	0.86	0.84	0.84	0.84	0.78	0.67	0.67
R 6:	0.94	0.94	0.94	0.94	0.94	0.82	0.71	0.71	0.71	0.71
V 5:	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.75	0.64	0.64
A 4:	0.99	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.75	0.58
L 3:	1.00	1.00	1.00	1.00	0.75	0.71	0.71	0.71	0.71	0.71
S 2:	1.00	1.00	1.00	1.00	1.00	0.99	0.58	0.58	0.58	0.58

INCRE:	31	32	33	34	35	36	37	38	39	40
N 25:	0.64	0.64	0.64	0.61	0.61	0.61	0.60	0.58	0.57	0.57
T 12:	0.64	0.64	0.64	0.64	0.64	0.61	0.58	0.58	0.58	0.58
E 8:	0.67	0.67	0.67	0.60	0.58	0.58	0.58	0.58	0.58	0.58
R 6:	0.71	0.62	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
V 5:	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.53	0.50
A 4:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
L 3:	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.56	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58

INCRE:	41	42	43	44	45	46	47	48	49	50
N 25:	0.54	0.51	0.49	0.47	0.46	0.46	0.46	0.46	0.46	0.46
T 12:	0.53	0.51	0.49	0.47	0.47	0.47	0.47	0.46	0.45	0.45
E 8:	0.58	0.50	0.48	0.48	0.48	0.47	0.45	0.45	0.45	0.45
R 6:	0.58	0.50	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
V 5:	0.50	0.50	0.50	0.50	0.50	0.47	0.43	0.43	0.43	0.43
A 4:	0.58	0.56	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
L 3:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
S 2:	0.58	0.58	0.58	0.58	0.58	0.51	0.00	0.00	0.00	0.00

INCRE:	51	52
N 25:	0.46	0.00
T 12:	0.45	0.00
E 8:	0.45	0.00
R 6:	0.47	0.00
V 5:	0.43	0.00
A 4:	0.45	0.00
L 3:	0.47	0.00
S 2:	0.00	0.00

TABLE A.8H
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.20 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:		1	2	3	4	5	6	7	8	9	10
N	25:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
T	12:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
E	8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
R	6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
V	5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
A	4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L	3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S	2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
INCRE:		11	12	13	14	15	16	17	18	19	20
N	25:	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.97	0.97	0.96
T	12:	1.00	1.00	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.95
E	8:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.96	0.96	0.96
R	6:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.94
V	5:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.94
A	4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
L	3:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S	2:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
INCRE:		21	22	23	24	25	26	27	28	29	30
N	25:	0.94	0.94	0.92	0.88	0.87	0.83	0.81	0.74	0.71	0.67
T	12:	0.94	0.94	0.94	0.89	0.84	0.84	0.82	0.71	0.71	0.64
E	8:	0.96	0.96	0.96	0.86	0.84	0.84	0.84	0.78	0.67	0.67
R	6:	0.94	0.94	0.94	0.94	0.94	0.82	0.71	0.71	0.71	0.71
V	5:	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.75	0.64	0.64
A	4:	0.99	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.75	0.58
L	3:	1.00	1.00	1.00	1.00	0.75	0.71	0.71	0.71	0.71	0.71
S	2:	1.00	1.00	1.00	1.00	1.00	0.99	0.58	0.58	0.58	0.58
INCRE:		31	32	33	34	35	36	37	38	39	40
N	25:	0.64	0.64	0.64	0.61	0.61	0.61	0.60	0.58	0.57	0.57
T	12:	0.64	0.64	0.64	0.64	0.64	0.61	0.58	0.58	0.58	0.58
E	8:	0.67	0.67	0.67	0.60	0.58	0.58	0.58	0.58	0.58	0.58
R	6:	0.71	0.62	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
V	5:	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.53	0.50
A	4:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
L	3:	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.56	0.47	0.47
S	2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
INCRE:		41	42	43	44	45	46	47	48	49	50
N	25:	0.54	0.51	0.49	0.47	0.46	0.46	0.46	0.46	0.46	0.46
T	12:	0.53	0.51	0.49	0.47	0.47	0.47	0.47	0.46	0.45	0.45
E	8:	0.58	0.50	0.48	0.48	0.48	0.47	0.45	0.45	0.45	0.45
R	6:	0.58	0.50	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
V	5:	0.50	0.50	0.50	0.50	0.50	0.47	0.43	0.43	0.43	0.43
A	4:	0.58	0.56	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
L	3:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
S	2:	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58
INCRE:		51	52								
N	25:	0.46	0.08								
T	12:	0.45	0.08								
E	8:	0.45	0.08								
R	6:	0.47	0.08								
V	5:	0.43	0.08								
A	4:	0.45	0.08								
L	3:	0.47	0.08								
S	2:	0.58	0.01								

August system environment. Tables A.9, A.10, and A.11 show the resulting comparison of OCNP, system costs, and incremental capacity factors for six load-duration models, (20, 12, 10, 8, 6, and 4 time intervals per week). The August simulations verify the results of the April simulations.

Two-reactor simulations were also tested in the April and August environments. The April system tested two reactors (constant heat-rate) of 1100 MWe and 220 MWe rated capacity for 12 load-duration models. The resulting OCNP and system costs are tabulated in Tables A.12 and A.13, respectively. The OCNP results (Table A.12) continued to be reproduced faithfully, even at a very small number of time intervals.

In the August environment, two reactors of 1100 MWe each were simulated for 6 load models, but for a wider range of capacity factors. The resulting comparison of OCNP and system costs are shown in Tables A.14 and A.15, respectively. The results of these comparisons confirm the hypothesis that OCNP (and changes in system costs) are reproducible by load-duration models of only 6 time intervals. See Section 5.2 for more details on the load-duration study.

TABLE A.9

THE OCNP COMPARISON FOR THE LOAD-DURATION SENSITIVITY STUDY
(ONE REACTOR, AUGUST LOAD DATA CASE)

Weekly Nuclear Capacity Factor	Number of Time Intervals in Load-Duration Model:	OCNP (mills/10,000 Btu-th)					
		20	12	10	8	6	4
0.2		8.88	8.88	8.88	8.88	8.88	8.88
0.3		8.67	8.67	8.67	8.67	8.67	8.67
0.4		6.93	6.93	6.93	6.93	6.93	8.08
0.5		6.10	6.10	6.10	6.10	6.10	6.10
0.6		4.79	4.79	4.79	4.82	4.79	4.79
0.7		4.54	4.54	4.64	4.64	4.54	4.64
0.8		4.44	4.44	4.44	4.44	4.44	4.44
0.9		3.64	3.64	3.64	3.64	3.64	3.64

TABLE A.10

THE WEEKLY PRODUCTION COST COMPARISON FOR THE LOAD-DURATION SENSITIVITY STUDY
(ONE REACTOR, AUGUST LOAD DATA CASE)

Weekly Nuclear Capacity Factor	System Production Cost ($/wk) Number of Time Intervals in Load-Duration Model 20	12	10
0.2	12,126,049	12,125,590	12,124,706
0.3	11,955,110	11,954,576	11,953,615
0.4	11,801,502	11,801,444	11,799,836
0.5	11,677,486	11,677,295	11,675,563
0.6	11,571,443	11,571,240	11,569,983
0.7	11,479,508	11,479,297	11,477,874
0.8	11,392,916	11,392,719	11,391,287
0.9	11,312,014	11,311,172	11,310,365

	8	6	4
0.2	12,123,395	12,120,193	12,117,263
0.3	11,952,387	11,949,809	11,946,262
0.4	11,798,681	11,795,791	11,784,845
0.5	11,674,318	11,671,559	11,657,874
0.6	11,569,802	11,569,539	11,551,462
0.7	11,477,845	11,475,850	11,458,602
0.8	11,391,814	11,389,223	11,372,640
0.9	11,309,118	11,307,993	11,292,590

TABLE A.11

INCREMENTAL CAPACITY FACTOR COMPARISON FOR THE LOAD DURATION SENSITIVITY STUDY

(Single Reactor, August Load Data Case)

The following tables are a comparison of the capacity factors of the 60 fossil increments in the August economic loading from six load-duration models. The tables are arranged as follows:

The increments are labeled horizontally, and the number of intervals in the load-duration models are labeled vertically. There is a separate table for each of eight values of the weekly nuclear capacity factor, ordered by descending values.

TABLE A.11A
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.90 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.91	0.77	0.77	0.77	0.77	0.77	0.70
E 12:	1.00	1.00	0.98	0.94	0.73	0.71	0.71	0.71	0.71	0.71
R 10:	1.00	1.00	0.98	0.91	0.77	0.77	0.77	0.77	0.77	0.77
V 8:	1.00	1.00	1.00	0.92	0.82	0.82	0.74	0.68	0.68	0.68
A 6:	1.00	1.00	1.00	0.92	0.71	0.71	0.71	0.71	0.71	0.71
L 4:	1.00	1.00	1.00	0.92	0.82	0.82	0.82	0.82	0.82	0.82

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.69	0.69	0.67	0.64	0.64	0.60	0.59	0.59	0.59	0.59
E 12:	0.71	0.71	0.66	0.62	0.62	0.62	0.62	0.62	0.62	0.61
R 10:	0.72	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.56	0.56
V 8:	0.68	0.68	0.68	0.68	0.68	0.68	0.59	0.56	0.56	0.56
A 6:	0.71	0.71	0.71	0.70	0.56	0.56	0.56	0.56	0.56	0.56
L 4:	0.82	0.71	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.59	0.57	0.56	0.53	0.52	0.52	0.52	0.52	0.52	0.52
E 12:	0.56	0.56	0.56	0.56	0.56	0.49	0.49	0.49	0.49	0.49
R 10:	0.56	0.56	0.56	0.56	0.56	0.55	0.46	0.46	0.46	0.46
V 8:	0.56	0.56	0.56	0.56	0.56	0.56	0.49	0.45	0.45	0.45
A 6:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.47	0.45	0.45
L 4:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.46	0.46	0.46	0.44	0.42	0.42	0.41	0.37	0.32	0.30
E 12:	0.48	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.32	0.32
R 10:	0.46	0.46	0.46	0.44	0.42	0.42	0.42	0.39	0.28	0.27
V 8:	0.45	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.29	0.29
A 6:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.35	0.32	0.32
L 4:	0.55	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.27	0.27	0.27	0.27	0.26	0.04	0.04	0.04	0.03	0.00
E 12:	0.30	0.23	0.23	0.23	0.23	0.23	0.11	0.00	0.00	0.00
R 10:	0.27	0.27	0.27	0.27	0.27	0.21	0.00	0.00	0.00	0.00
V 8:	0.29	0.29	0.29	0.29	0.29	0.14	0.00	0.00	0.00	0.00
A 6:	0.32	0.32	0.32	0.32	0.24	0.00	0.00	0.00	0.00	0.00
L 4:	0.41	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.11B
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.80 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.97	0.96	0.96	0.96	0.93	0.93	0.93
E 12:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.93	0.93	0.93
R 10:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.93
V 8:	1.00	1.00	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
A 6:	1.00	1.00	1.00	0.96	0.93	0.93	0.93	0.93	0.93	0.93
L 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.93	0.81	0.67	0.64	0.64	0.60	0.59	0.59	0.59	0.59
E 12:	0.93	0.84	0.66	0.62	0.62	0.62	0.62	0.62	0.62	0.61
R 10:	0.91	0.83	0.64	0.64	0.64	0.64	0.64	0.64	0.56	0.56
V 8:	0.95	0.78	0.68	0.68	0.68	0.68	0.59	0.56	0.56	0.56
A 6:	0.93	0.84	0.71	0.70	0.56	0.56	0.56	0.56	0.56	0.56
L 4:	0.88	0.82	0.63	0.56	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.59	0.57	0.56	0.53	0.52	0.52	0.52	0.52	0.52	0.52
E 12:	0.56	0.56	0.56	0.56	0.56	0.49	0.49	0.49	0.49	0.49
R 10:	0.56	0.56	0.56	0.56	0.56	0.55	0.46	0.46	0.46	0.46
V 8:	0.56	0.56	0.56	0.56	0.56	0.56	0.49	0.45	0.45	0.45
A 6:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.47	0.45	0.45
L 4:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.46	0.46	0.46	0.44	0.42	0.42	0.41	0.37	0.32	0.30
E 12:	0.48	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.32	0.32
R 10:	0.46	0.46	0.46	0.44	0.42	0.42	0.42	0.39	0.28	0.27
V 8:	0.45	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.29	0.29
A 6:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.35	0.32	0.32
L 4:	0.55	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.27	0.27	0.27	0.27	0.26	0.04	0.04	0.04	0.03	0.00
E 12:	0.30	0.23	0.23	0.23	0.23	0.23	0.11	0.00	0.00	0.00
R 10:	0.27	0.27	0.27	0.27	0.27	0.21	0.00	0.00	0.00	0.00
V 8:	0.29	0.29	0.29	0.29	0.29	0.14	0.00	0.00	0.00	0.00
A 6:	0.32	0.32	0.32	0.32	0.24	0.00	0.00	0.00	0.00	0.00
L 4:	0.41	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.11C
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.70 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.97	0.96	0.96	0.96	0.93	0.93	0.93
E 12:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.93	0.93	0.93
R 10:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.93
V 8:	1.00	1.00	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
A 6:	1.00	1.00	1.00	0.96	0.93	0.93	0.93	0.93	0.93	0.93
L 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.93	0.93	0.91	0.88	0.82	0.82	0.78	0.59	0.59	0.59
E 12:	0.93	0.93	0.93	0.86	0.82	0.82	0.80	0.62	0.62	0.61
R 10:	0.91	0.91	0.91	0.91	0.88	0.77	0.77	0.71	0.56	0.56
V 8:	0.95	0.95	0.93	0.82	0.82	0.82	0.82	0.71	0.56	0.56
A 6:	0.93	0.93	0.93	0.93	0.93	0.93	0.68	0.56	0.56	0.56
L 4:	0.88	0.82	0.82	0.82	0.82	0.82	0.82	0.71	0.56	0.56

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.59	0.57	0.56	0.53	0.52	0.52	0.52	0.52	0.52	0.52
E 12:	0.56	0.56	0.56	0.56	0.56	0.49	0.49	0.49	0.49	0.49
R 10:	0.56	0.56	0.56	0.56	0.56	0.55	0.46	0.46	0.46	0.46
V 8:	0.56	0.56	0.56	0.56	0.56	0.56	0.49	0.45	0.45	0.45
A 6:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.47	0.45	0.45
L 4:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.46	0.46	0.46	0.44	0.42	0.42	0.41	0.37	0.32	0.30
E 12:	0.48	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.32	0.32
R 10:	0.46	0.46	0.46	0.44	0.42	0.42	0.42	0.39	0.28	0.27
V 8:	0.45	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.29	0.29
A 6:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.35	0.32	0.32
L 4:	0.55	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.27	0.27	0.27	0.27	0.26	0.04	0.04	0.04	0.03	0.00
E 12:	0.30	0.23	0.23	0.23	0.23	0.23	0.11	0.00	0.00	0.00
R 10:	0.27	0.27	0.27	0.27	0.27	0.21	0.00	0.00	0.00	0.00
V 8:	0.29	0.29	0.29	0.29	0.29	0.14	0.00	0.00	0.00	0.00
A 6:	0.32	0.32	0.32	0.32	0.24	0.00	0.00	0.00	0.00	0.00
L 4:	0.41	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.11D
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.60 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.97	0.96	0.96	0.96	0.93	0.93	0.93
E 12:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.93	0.93	0.93
R 10:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.93
V 8:	1.00	1.00	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
A 6:	1.00	1.00	1.00	0.96	0.93	0.93	0.93	0.93	0.93	0.93
L 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.93	0.93	0.91	0.88	0.82	0.82	0.82	0.77	0.77	0.77
E 12:	0.93	0.93	0.93	0.86	0.82	0.82	0.82	0.82	0.82	0.82
R 10:	0.91	0.91	0.91	0.91	0.88	0.77	0.77	0.77	0.77	0.77
V 8:	0.95	0.95	0.93	0.82	0.82	0.82	0.82	0.82	0.82	0.82
A 6:	0.93	0.93	0.93	0.93	0.93	0.93	0.82	0.71	0.71	0.71
L 4:	0.88	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.77	0.76	0.69	0.67	0.53	0.52	0.52	0.52	0.52	0.52
E 12:	0.73	0.71	0.71	0.70	0.56	0.49	0.49	0.49	0.49	0.49
R 10:	0.77	0.77	0.77	0.62	0.56	0.55	0.46	0.46	0.46	0.46
V 8:	0.82	0.68	0.68	0.68	0.60	0.56	0.49	0.45	0.45	0.45
A 6:	0.71	0.71	0.71	0.70	0.56	0.56	0.56	0.47	0.45	0.45
L 4:	0.82	0.82	0.66	0.56	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.46	0.46	0.46	0.44	0.42	0.42	0.41	0.37	0.32	0.30
E 12:	0.48	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.32	0.32
R 10:	0.46	0.46	0.46	0.44	0.42	0.42	0.42	0.39	0.28	0.27
V 8:	0.45	0.45	0.45	0.45	0.41	0.41	0.41	0.38	0.29	0.29
A 6:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.35	0.32	0.32
L 4:	0.55	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.27	0.27	0.27	0.27	0.26	0.04	0.04	0.04	0.03	0.00
E 12:	0.30	0.23	0.23	0.23	0.23	0.23	0.11	0.00	0.00	0.00
R 10:	0.27	0.27	0.27	0.27	0.27	0.21	0.00	0.00	0.00	0.00
V 8:	0.29	0.29	0.29	0.29	0.29	0.14	0.00	0.00	0.00	0.00
A 6:	0.32	0.32	0.32	0.32	0.24	0.00	0.00	0.00	0.00	0.00
L 4:	0.41	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.11E
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.50 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.97	0.96	0.96	0.96	0.93	0.93	0.93
E 12:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.93	0.93	0.93
R 10:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.93
V 8:	1.00	1.00	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
A 6:	1.00	1.00	1.00	0.96	0.93	0.93	0.93	0.93	0.93	0.93
L 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.93	0.93	0.91	0.88	0.82	0.82	0.82	0.77	0.77	0.77
E 12:	0.93	0.93	0.93	0.86	0.82	0.82	0.82	0.82	0.82	0.82
R 10:	0.91	0.91	0.91	0.91	0.88	0.77	0.77	0.77	0.77	0.77
V 8:	0.95	0.95	0.93	0.82	0.82	0.82	0.82	0.82	0.82	0.82
A 6:	0.93	0.93	0.93	0.93	0.93	0.93	0.82	0.71	0.71	0.71
L 4:	0.88	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.77	0.76	0.69	0.69	0.69	0.68	0.64	0.64	0.64	0.64
E 12:	0.73	0.71	0.71	0.71	0.71	0.66	0.62	0.62	0.62	0.62
R 10:	0.77	0.77	0.77	0.65	0.64	0.64	0.64	0.64	0.64	0.64
V 8:	0.82	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
A 6:	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
L 4:	0.82	0.82	0.82	0.74	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.64	0.59	0.59	0.53	0.42	0.42	0.41	0.37	0.32	0.30
E 12:	0.62	0.62	0.62	0.53	0.41	0.41	0.41	0.38	0.32	0.32
R 10:	0.64	0.64	0.64	0.52	0.42	0.42	0.42	0.39	0.28	0.27
V 8:	0.68	0.68	0.58	0.51	0.41	0.41	0.41	0.38	0.29	0.29
A 6:	0.62	0.56	0.56	0.51	0.45	0.45	0.45	0.35	0.32	0.32
L 4:	0.56	0.56	0.56	0.51	0.41	0.41	0.41	0.41	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.27	0.27	0.27	0.27	0.26	0.04	0.04	0.04	0.03	0.00
E 12:	0.30	0.23	0.23	0.23	0.23	0.23	0.11	0.00	0.00	0.00
R 10:	0.27	0.27	0.27	0.27	0.27	0.21	0.00	0.00	0.00	0.00
V 8:	0.29	0.29	0.29	0.29	0.29	0.14	0.00	0.00	0.00	0.00
A 6:	0.32	0.32	0.32	0.32	0.24	0.00	0.00	0.00	0.00	0.00
L 4:	0.41	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.11F
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.40 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.97	0.96	0.96	0.96	0.93	0.93	0.93
E 12:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.93	0.93	0.93
R 10:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.93
V 8:	1.00	1.00	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
A 6:	1.00	1.00	1.00	0.96	0.93	0.93	0.93	0.93	0.93	0.93
L 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.93	0.93	0.91	0.88	0.82	0.82	0.82	0.77	0.77	0.77
E 12:	0.93	0.93	0.93	0.86	0.82	0.82	0.82	0.82	0.82	0.82
R 10:	0.91	0.91	0.91	0.91	0.88	0.77	0.77	0.77	0.77	0.77
V 8:	0.95	0.95	0.93	0.82	0.82	0.82	0.82	0.82	0.82	0.82
A 6:	0.93	0.93	0.93	0.93	0.93	0.93	0.82	0.71	0.71	0.71
L 4:	0.88	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.77	0.76	0.69	0.69	0.69	0.68	0.64	0.64	0.64	0.64
E 12:	0.73	0.71	0.71	0.71	0.71	0.66	0.62	0.62	0.62	0.62
R 10:	0.77	0.77	0.77	0.65	0.64	0.64	0.64	0.64	0.64	0.64
V 8:	0.82	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
A 6:	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
L 4:	0.82	0.82	0.82	0.74	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.64	0.59	0.59	0.58	0.56	0.53	0.52	0.46	0.33	0.30
E 12:	0.62	0.62	0.62	0.58	0.56	0.56	0.50	0.46	0.33	0.32
R 10:	0.64	0.64	0.64	0.57	0.56	0.56	0.53	0.46	0.33	0.27
V 8:	0.68	0.68	0.58	0.56	0.56	0.56	0.53	0.45	0.33	0.29
A 6:	0.62	0.56	0.56	0.56	0.56	0.56	0.55	0.45	0.33	0.32
L 4:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.46	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.27	0.27	0.27	0.27	0.26	0.04	0.04	0.04	0.03	0.00
E 12:	0.30	0.23	0.23	0.23	0.23	0.23	0.11	0.00	0.00	0.00
R 10:	0.27	0.27	0.27	0.27	0.27	0.21	0.00	0.00	0.00	0.00
V 8:	0.29	0.29	0.29	0.29	0.29	0.14	0.00	0.00	0.00	0.00
A 6:	0.32	0.32	0.32	0.32	0.24	0.00	0.00	0.00	0.00	0.00
L 4:	0.41	0.41	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.11G
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.30 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.97	0.96	0.96	0.96	0.93	0.93	0.93
E 12:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.93	0.93	0.93
R 10:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.93
V 8:	1.00	1.00	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
A 6:	1.00	1.00	1.00	0.96	0.93	0.93	0.93	0.93	0.93	0.93
L 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.93	0.93	0.91	0.88	0.82	0.82	0.82	0.77	0.77	0.77
E 12:	0.93	0.93	0.93	0.86	0.82	0.82	0.82	0.82	0.82	0.82
R 10:	0.91	0.91	0.91	0.91	0.88	0.77	0.77	0.77	0.77	0.77
V 8:	0.95	0.95	0.93	0.82	0.82	0.82	0.82	0.82	0.82	0.82
A 6:	0.93	0.93	0.93	0.93	0.93	0.93	0.82	0.71	0.71	0.71
L 4:	0.88	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.77	0.76	0.69	0.69	0.69	0.68	0.64	0.64	0.64	0.64
E 12:	0.73	0.71	0.71	0.71	0.71	0.66	0.62	0.62	0.62	0.62
R 10:	0.77	0.77	0.77	0.65	0.64	0.64	0.64	0.64	0.64	0.64
V 8:	0.82	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
A 6:	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
L 4:	0.82	0.82	0.82	0.74	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.64	0.59	0.59	0.58	0.56	0.53	0.52	0.46	0.45	0.43
E 12:	0.62	0.62	0.62	0.58	0.56	0.56	0.50	0.46	0.45	0.45
R 10:	0.64	0.64	0.64	0.57	0.56	0.56	0.53	0.46	0.43	0.42
V 8:	0.68	0.68	0.58	0.56	0.56	0.56	0.53	0.45	0.45	0.44
A 6:	0.62	0.56	0.56	0.56	0.56	0.56	0.55	0.45	0.45	0.45
L 4:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.46	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.42	0.42	0.42	0.41	0.41	0.41	0.21	0.04	0.03	0.00
E 12:	0.42	0.41	0.41	0.41	0.41	0.41	0.23	0.10	0.00	0.00
R 10:	0.42	0.42	0.42	0.42	0.42	0.41	0.28	0.03	0.00	0.00
V 8:	0.41	0.41	0.41	0.41	0.41	0.41	0.29	0.05	0.00	0.00
A 6:	0.45	0.45	0.45	0.45	0.45	0.45	0.09	0.00	0.00	0.00
L 4:	0.41	0.41	0.41	0.41	0.41	0.41	0.33	0.00	0.00	0.00

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.11H
FOSSIL INCREMENTAL CAPACITY FACTOR COMPARISON FOR
0.20 WEEKLY NUCLEAR CAPACITY FACTOR

INCRE:	1	2	3	4	5	6	7	8	9	10
T 20:	1.00	1.00	0.98	0.97	0.96	0.96	0.96	0.93	0.93	0.93
E 12:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.93	0.93	0.93
R 10:	1.00	1.00	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.93
V 8:	1.00	1.00	1.00	0.95	0.95	0.95	0.95	0.95	0.95	0.95
A 6:	1.00	1.00	1.00	0.96	0.93	0.93	0.93	0.93	0.93	0.93
L 4:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

INCRE:	11	12	13	14	15	16	17	18	19	20
T 20:	0.93	0.93	0.91	0.88	0.82	0.82	0.82	0.77	0.77	0.77
E 12:	0.93	0.93	0.93	0.86	0.82	0.82	0.82	0.82	0.82	0.82
R 10:	0.91	0.91	0.91	0.91	0.88	0.77	0.77	0.77	0.77	0.77
V 8:	0.95	0.95	0.93	0.82	0.82	0.82	0.82	0.82	0.82	0.82
A 6:	0.93	0.93	0.93	0.93	0.93	0.93	0.82	0.71	0.71	0.71
L 4:	0.88	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82

INCRE:	21	22	23	24	25	26	27	28	29	30
T 20:	0.77	0.76	0.69	0.69	0.69	0.68	0.64	0.64	0.64	0.64
E 12:	0.73	0.71	0.71	0.71	0.71	0.66	0.62	0.62	0.62	0.62
R 10:	0.77	0.77	0.77	0.65	0.64	0.64	0.64	0.64	0.64	0.64
V 8:	0.82	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
A 6:	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
L 4:	0.82	0.82	0.82	0.74	0.56	0.56	0.56	0.56	0.56	0.56

INCRE:	31	32	33	34	35	36	37	38	39	40
T 20:	0.64	0.59	0.59	0.58	0.56	0.53	0.52	0.46	0.45	0.43
E 12:	0.62	0.62	0.62	0.58	0.56	0.56	0.50	0.46	0.45	0.45
R 10:	0.64	0.64	0.64	0.57	0.56	0.56	0.53	0.46	0.43	0.42
V 8:	0.68	0.68	0.58	0.56	0.56	0.56	0.53	0.45	0.45	0.44
A 6:	0.62	0.56	0.56	0.56	0.56	0.56	0.55	0.45	0.45	0.45
L 4:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.46	0.41	0.41

INCRE:	41	42	43	44	45	46	47	48	49	50
T 20:	0.42	0.42	0.42	0.41	0.41	0.41	0.41	0.38	0.38	0.15
E 12:	0.42	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.40	0.12
R 10:	0.42	0.42	0.42	0.42	0.42	0.41	0.38	0.38	0.38	0.15
V 8:	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.11
A 6:	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.37	0.32	0.12
L 4:	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.11

INCRE:	51	52	53	54	55	56	57	58	59	60
T 20:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E 12:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
R 10:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
V 8:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A 6:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
L 4:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE A.12

OCNP COMPARISON FOR THE LOAD-DURATION SENSITIVITY STUDY
(TWO-REACTOR, APRIL LOAD DATA CASE)

Weekly Nuclear Capacity Factor of Two Reactors	OCNP (mills/10,000 Btut) Number of Time Intervals in Load-Duration Model					
	50	30	20	15	10	9
0.70/0.80	5.13/3.59	5.13/3.59	5.13/3.59	5.13/3.59	5.13/3.59	5.59/3.89
0.80/0.80	4.79/3.35	4.79/3.35	4.79/3.35	4.79/3.35	4.79/3.35	4.79/3.35
0.90/0.80	4.76/3.33	4.76/3.33	4.76/3.33	4.76/3.33	4.76/3.33	4.76/3.33
	8	7	6	5	4	3
0.70/0.80	5.13/3.59	5.13/3.59	5.13/3.59	5.56/3.59	5/13/3.59	5.56/3.59
0.80/0.80	4.79/3.35	4.79/3.35	4.79/3.35	4.79/3.35	4.79/3.35	4.79/3.35
0.90/0.80	4.76/3.33	4.76/3.33	4.76/3.33	4.76/3.33	4.76/3.35	4.76/3.33

TABLE A.13

SYSTEM COST COMPARISON FOR THE LOAD-DURATION SENSITIVITY STUDY
(TWO REACTOR, APRIL LOAD DATA CASE)

Weekly Nuclear Capacity Factor of Two Reactors	System Cost ($/week) Number of Time Intervals in Load-Duration Model					
	50	30	20	15	10	9
0.70/0.80	10,891,033	10,890,930	10,890,610	10,890,670	10,889,568	10,888,652
0.80/0.80	10,794,546	10,794,461	10,794,133	10,794,234	10,793,073	10,792,347
0.90/0.80	10,701,758	10,701,672	10,701,346	10,701,446	10,700,240	10,699,562

Weekly Nuclear Capacity Factor of Two Reactors	8	7	6	5	4	3
0.70/0.80	10,889,067	10,887,958	10,889,119	10,884,958	10,885,562	10,879,209
0.80/0.80	10,792,630	10,791,548	10,792,383	10,787,979	10,789,553	10,789,811
0.90/0.80	10,699,834	10,698,710	10,699,622	10,695,174	10,696,690	10,689,051

TABLE A.14

OCNP COMPARISON FOR THE LOAD-DURATION SENSITIVITY STUDY
(TWO-REACTOR, AUGUST LOAD DATA CASE)

Weekly Nuclear Capacity Factors of Two Reactors	OCNP (Mills/10,000 Btut) Number of Time Intervals in Load-Duration Model			
	12	10	8	6
0.50/0.80	4.76/4.44	4.76/4.44	4.76/4.44	4.76/4.44
0.60/0.80	4.44/4.44	4.44/4.44	4.44/4.44	4.44/4.44
0.70/0.80	4.25/4.25	4.08/4.08	4.25/4.25	4.25/4.25
0.80/0.80	3.64/3.64	3.64/3.64	3.64/3.64	3.64/3.64
0.90/0.80	3.41/3.41	3.41/3.41	3.41/3.41	3.41/3.41

TABLE A.15

SYSTEM COST COMPARISON FOR THE LOAD-DURATION SENSITIVITY STUDY
(TWO-REACTOR, AUGUST LOAD DATA CASE)

Weekly Nuclear Capacity Factors of Two Reactors	System Cost ($/week) Number of Time Intervals in Load-Duration Model			
	12	10	8	6
0.50/0.80	10,752,167	10,752,579	10,751,793	10,749,149
0.60/0.80	10,663,824	10,664,374	10,663,790	10,661,248
0.70/0.80	10,578,992	10,579,644	10,579,004	10,576,414
0.80/0.80	10,503,629	10,504,303	10,503,708	10,501,378
0.90/0.80	10,434,784	10,435,423	10,434,828	10,432,045

Appendix B: SYSTEM PARAMETERS

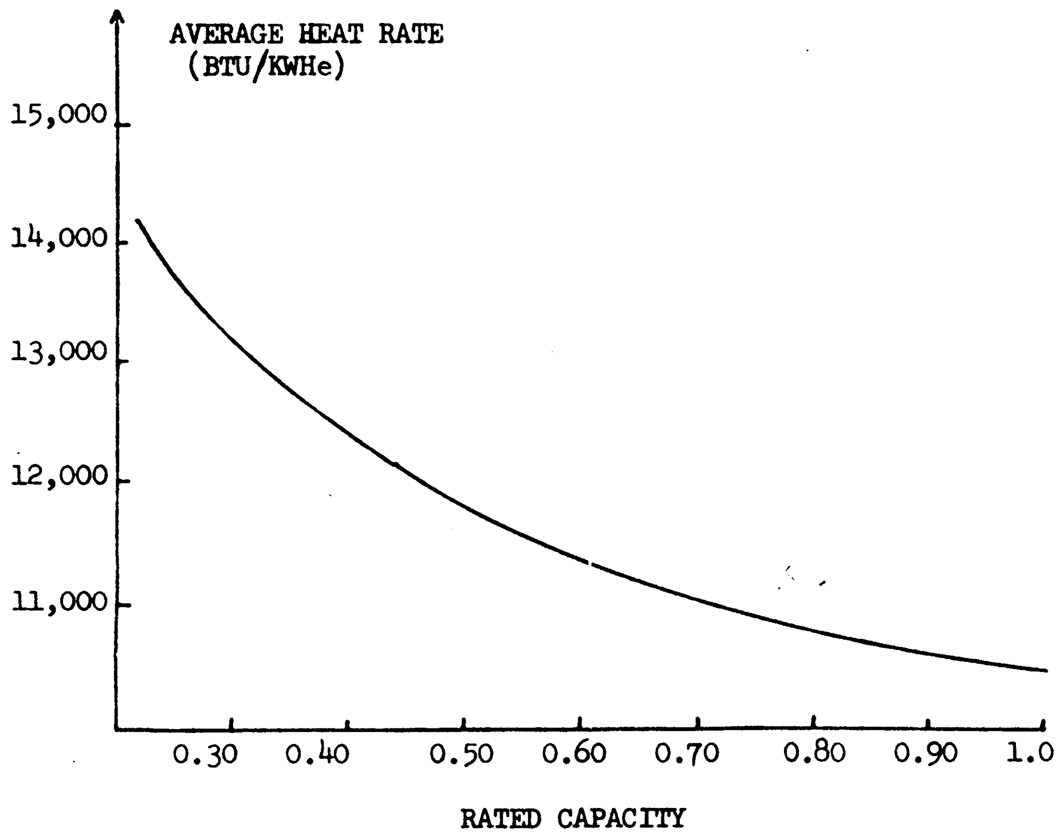
B.1 Nuclear Heat-Rates

The nuclear heat-rate data used throughout this study are obtained from Figure B.1, a result of an analytic fit made by Prof. M. Benedict from points supplied by Commonwealth Edison. Individual data points are not shown to preserve the confidentiality of the material. Of particular interest, Figure B.1 shows that operating a nuclear reactor below 70% rated capacity results in high inefficiencies. Thus, a program to maximize nuclear uttilization would avoid operation below 70% as much as possible, even to the extent of shutting down.

B.2 Fossil Heat Rates

Fossil heat-rates used in this report are obtained from a number of analytic fits derived by the author from plant data supplied by Commonwealth Edision. The plant data were measured in the years 1958-1962, and it seems to be utility practice not to update such data with the age of the plants. As such, a cause of significant deviations from optimal operations of a utility system may possibly lie in the outdated heat-rate statistics used(28). Considering the approximate nature of the statistics to the actual performance levels, standardized heat-rate curves were derived for the three types of fossil plants for which data was available: large fossil (300 - 600 MWe), medium fossil (150 - 300 MWe), and small fossil (150 - 50 MWe). The heat-rate used for individual plant would be obtained by

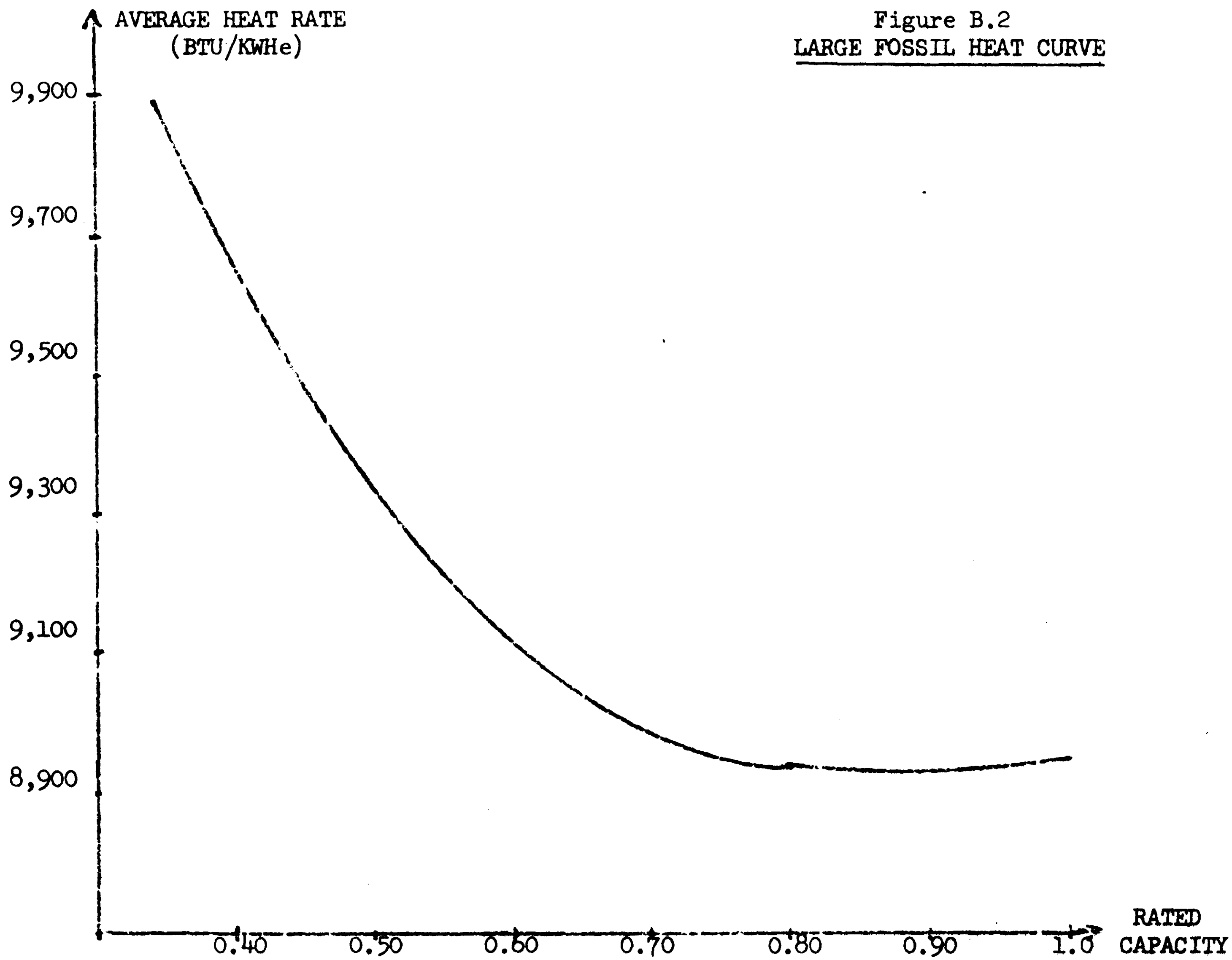
Figure B.1 NUCLEAR HEAT CURVE



multiplying the appropriate standardized heat-rate by an individual plant factor (average heat-rate at rated capacity) to lower or raise the standard curve to fit individual plant characteristics. During 1960, Commonwealth Edison had no data for the 1000 MWe class of fossil plants because none existed. Thus the heat-rates of plants used in this study are derived from the large fossil standardized heat-rate curve whereas if data were available, it would be more appropriate to use a separate standardized heat-rate curve for these extra large fossil units. Figures B.2, B.3, and B.4 show the analytically fitted standardized heat-rate curves derived for large, medium and small fossil units, respectively. The individual data points are not shown to preserve the confidentiality of the material.

Figure B.2

LARGE FOSSIL HEAT CURVE



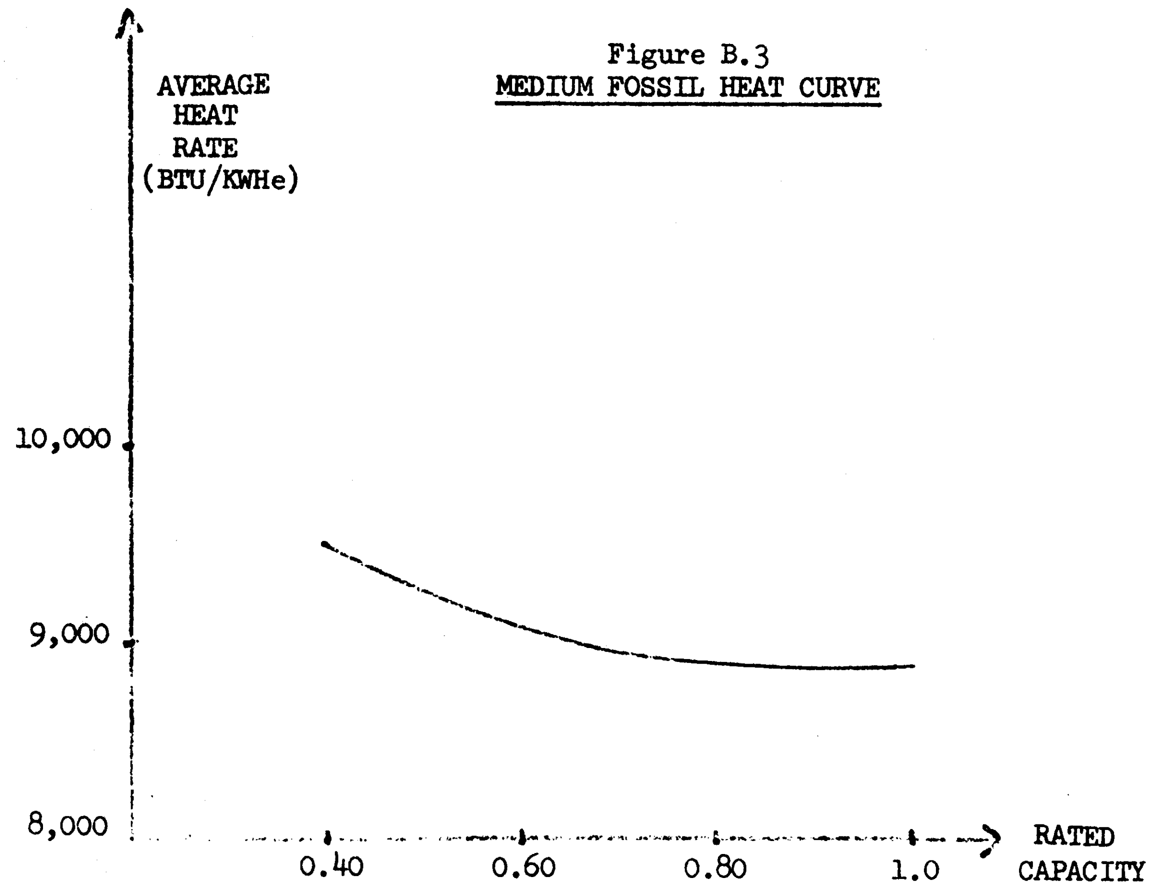
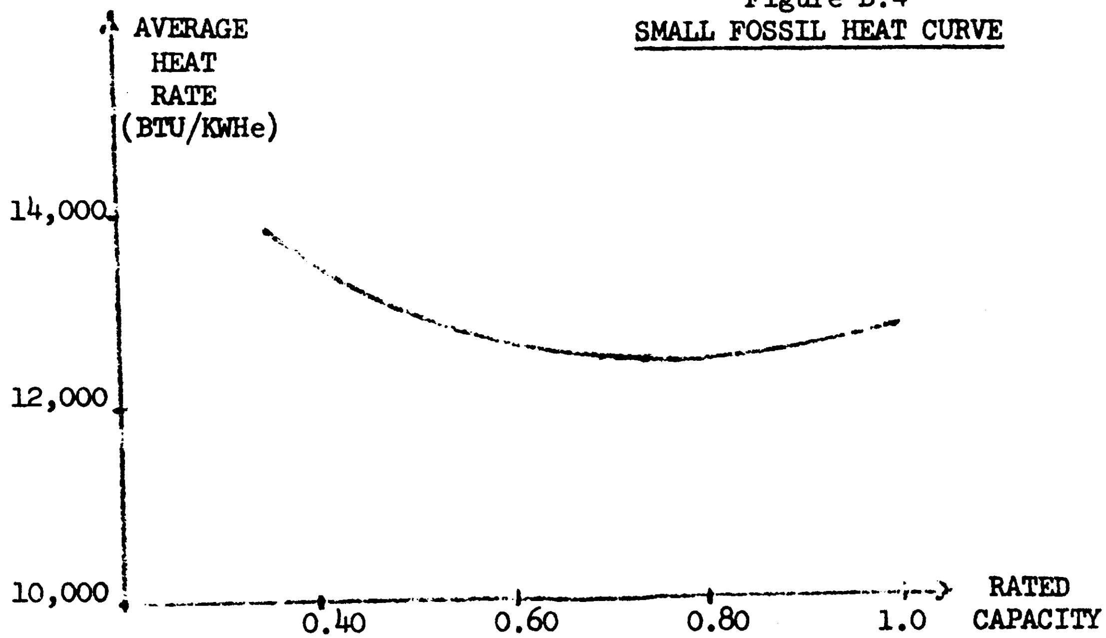


Figure B.3
MEDIUM FOSSIL HEAT CURVE

Figure B.4
SMALL FOSSIL HEAT CURVE



B.3 OCNP Values from Case 2

TABLE B.3.1

WEEKLY OCNP FUNCTIONS OF UNIT 1 FOR APRIL
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

		Weekly Nuclear Capacity Factors of				
Week	Unit 2	Unit 1: 0.55	0.65	0.75	0.85	0.95
		OCNP (mills/KWHe) of Unit 1				
1	0.20	8.86	6.83	6.79	6.09	5.03
	0.16	8.86	6.83	6.79	6.09	5.25
	0.12	9.10	7.38	6.83	6.40	5.25
	0.08	9.30	7.38	6.83	6.40	5.25
2	0.20	9.10	7.74	6.83	6.09	5.08
	0.16	9.10	8.30	6.83	6.40	5.39
	0.12	9.30	8.83	6.83	6.40	5.39
	0.08	9.32	8.83	7.28	6.40	5.39
3	0.20	8.49	6.79	6.09	5.25	5.03
	0.16	8.49	6.79	6.40	5.39	5.03
	0.12	8.49	6.83	6.40	5.84	5.03
	0.08	8.83	6.83	6.40	5.84	5.03
4	0.20	6.40	5.39	5.03	4.97	4.66
	0.16	6.40	5.39	5.03	5.00	4.72
	0.12	6.79	5.84	5.08	5.03	4.77
	0.08	6.79	6.09	5.08	5.03	4.77

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 1 FOR MAY
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

		Weekly Nuclear Capacity Factors of				
Week	Unit 2	Unit 1: 0.55	0.65	0.75	0.85	0.95
		OCNP (mills/KWHe) of Unit 1				
5	0.40	8.86	7.65	6.79	5.25	5.03
	0.32	8.86	8.05	7.28	6.79	5.22
	0.24	8.86	8.59	7.65	6.79	5.39
	0.16	9.30	8.83	8.05	6.79	5.39
6	0.40	8.30	6.79	5.39	5.03	4.96
	0.32	8.30	6.79	5.84	5.15	5.03
	0.24	8.83	7.65	6.79	5.39	5.03
	0.16	8.86	7.74	6.79	5.39	5.03
7	0.40	8.83	6.79	6.50	5.03	5.00
	0.32	8.83	7.28	6.79	5.39	5.03
	0.24	8.86	8.05	7.28	6.50	5.06
	0.16	9.11	8.30	7.28	6.50	5.06
8	0.40	8.86	7.74	6.79	5.39	4.79
	0.32	8.86	8.05	7.28	6.79	5.25
	0.24	9.11	8.83	8.05	6.79	5.39
	0.16	9.32	8.83	8.05	6.79	5.39
9	0.40	7.74	5.39	5.03	5.00	4.66
	0.32	7.74	6.79	5.39	5.03	4.97
	0.24	8.30	7.28	6.50	5.06	5.00
	0.16	8.83	7.28	6.79	5.06	5.00

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 1 FOR JUNE FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

		Weekly Nuclear Capacity Factors of				
Week	Unit 2	Unit 1: 0.55	0.65	0.75	0.85	0.95
		OCNP (mills/KWHe) of Unit 1				
10	0.60	6.40	5.39	5.03	4.71	4.56
	0.54	6.40	5.39	5.03	4.96	4.66
	0.48	6.40	5.84	5.08	5.00	4.71
	0.42	6.40	6.09	5.39	5.03	4.71
	0.36	6.40	6.09	6.09	5.03	4.71
11	0.60	6.40	6.09	5.06	4.98	4.63
	0.54	6.40	6.09	5.08	5.00	4.71
	0.48	6.40	6.09	5.39	5.03	4.98
	0.42	6.40	6.09	6.09	5.15	4.98
	0.36	6.40	6.40	6.09	5.25	4.98
12	0.60	6.09	5.08	5.00	4.66	4.52
	0.54	6.09	5.08	5.00	4.71	4.66
	0.48	6.09	5.39	5.03	4.98	4.66
	0.42	6.09	6.09	5.08	5.03	4.66
	0.36	6.40	6.09	5.39	5.03	4.66
13	0.60	6.09	5.03	4.96	4.66	4.28
	0.54	6.09	5.03	4.96	4.66	4.56
	0.48	6.09	5.03	5.00	4.71	4.66
	0.42	6.09	5.25	5.03	4.98	4.66
	0.36	6.09	5.84	5.06	5.00	4.66

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 1 FOR JULY
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

Week	Unit 2	Unit 1:	0.55	0.65	0.75	0.85	0.95
			Weekly Nuclear Capacity Factors of — OCNP (mills/KWHe) of Unit 1				
14	0.80		4.96	4.56	4.28	3.82	3.50
	0.72		4.96	4.56	4.28	4.07	3.82
	0.64		4.96	4.63	4.56	4.28	4.07
	0.56		4.96	4.66	4.56	4.52	4.07
	0.48		5.03	4.87	4.66	4.56	4.07
15	0.80		6.09	5.03	4.71	4.56	4.07
	0.72		6.09	5.03	4.77	4.66	4.52
	0.64		6.09	5.03	5.00	4.71	4.63
	0.56		6.09	5.25	5.03	4.96	4.66
	0.48		6.09	5.84	5.15	5.00	4.66
16	0.80		5.39	4.87	4.66	4.46	3.82
	0.72		5.39	4.87	4.66	4.56	4.28
	0.64		5.39	5.03	4.77	4.66	4.56
	0.56		5.39	5.03	5.00	4.71	4.56
	0.48		6.09	5.25	5.03	4.87	4.56
17	0.80		6.09	5.03	4.77	4.56	4.07
	0.72		6.09	5.03	4.87	4.66	4.56
	0.64		6.09	5.06	5.00	4.77	4.66
	0.56		6.09	5.39	5.03	5.00	4.66
	0.48		6.09	6.09	5.25	5.03	4.66
18	0.80		5.84	5.00	4.66	4.56	4.07
	0.72		5.84	5.00	4.71	4.63	4.52
	0.64		5.84	5.03	5.00	4.71	4.56
	0.56		5.84	5.22	5.03	4.96	4.66
	0.48		6.09	5.52	5.08	5.00	4.66

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 1 FOR AUGUST
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

Week	Unit 2	Unit 1:	0.55	0.65	0.75	0.85	0.95
			OCNP (mills/KWHe) of Unit 1				
19	1.00		5.03	4.71	4.66	4.28	3.58
	0.90		5.03	4.71	4.66	4.56	4.28
	0.80		5.03	4.98	4.71	4.66	4.56
	0.70		5.08	5.03	4.98	4.71	4.63
	0.60		5.84	5.08	5.03	4.96	4.63
20	1.00		6.09	5.03	4.87	4.66	4.07
	0.90		6.09	5.03	4.98	4.66	4.63
	0.80		6.09	5.08	5.03	4.98	4.66
	0.70		6.09	5.84	5.08	5.03	4.71
	0.60		6.40	6.09	5.84	5.03	4.71
21	1.00		5.39	5.00	4.66	4.56	3.82
	0.90		5.39	5.00	4.77	4.66	4.52
	0.80		5.39	5.03	4.98	4.77	4.66
	0.70		5.84	5.23	5.03	4.98	4.66
	0.60		6.09	5.84	5.23	5.00	4.66
22	1.00		5.39	5.00	4.71	4.56	3.82
	0.90		5.39	5.00	4.77	4.66	4.52
	0.80		5.39	5.03	5.00	4.77	4.66
	0.70		6.09	5.25	5.03	5.00	4.66
	0.60		6.09	6.09	5.25	5.03	4.66

Columns 0.55–0.95: Weekly Nuclear Capacity Factors

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 1 FOR SEPTEMBER
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

Week	Unit 2	Unit 1:	0.55	0.65	0.75	0.85	0.95
			Weekly Nuclear Capacity Factors of				
			OCNP (mills/KWHe) of Unit 1				
23	1.00		7.28	6.79	6.40	6.09	5.06
	0.90		7.28	6.79	6.40	6.09	6.09
	0.80		7.28	6.83	6.50	6.40	6.09
	0.70		7.28	6.83	6.83	6.50	6.40
	0.60		8.48	7.28	6.83	6.79	6.40
24	1.00		6.83	6.40	6.09	5.06	4.87
	0.90		6.83	6.40	6.09	5.84	5.06
	0.80		6.83	6.40	6.40	6.09	5.84
	0.70		6.83	6.79	6.40	6.40	6.09
	0.60		6.83	6.83	6.79	6.40	6.09
25	1.00		6.83	6.40	6.09	5.08	4.96
	0.90		6.83	6.40	6.09	5.84	5.06
	0.80		6.83	6.40	6.40	6.09	5.84
	0.70		6.83	6.79	6.40	6.40	6.09
	0.60		6.83	6.83	6.79	6.40	6.09
26	1.00		7.28	6.79	6.40	6.09	5.06
	0.90		7.28	6.79	6.40	6.09	6.09
	0.80		7.28	6.83	6.50	6.40	6.09
	0.70		7.28	6.83	6.83	6.50	6.40
	0.60		8.48	7.28	6.83	6.79	6.40

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 2 FOR APRIL
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

Week	Unit 1	Weekly Nuclear Capacity Factors of Unit 2:	0.08	0.12	0.16	0.20
			OCNP (mills/KWHe) of Unit 2			
1	0.95		9.89	6.79	5.39	5.03
	0.85		9.89	6.79	6.09	6.09
	0.75		9.89	6.83	6.79	6.09
	0.65		9.89	7.74	6.83	6.09
	0.55		9.89	9.11	7.28	6.09
2	0.95		9.89	6.83	6.09	5.08
	0.85		9.89	6.83	6.40	6.09
	0.75		9.89	6.83	6.83	6.40
	0.65		9.89	8.83	8.30	6.40
	0.55		9.89	9.30	8.49	6.40
3	0.95		9.32	6.40	5.03	5.03
	0.85		9.32	6.40	5.39	5.25
	0.75		9.32	6.40	6.40	5.39
	0.65		9.32	6.83	6.79	5.39
	0.55		9.32	8.49	6.79	5.39
4	0.95		8.49	5.03	4.72	4.66
	0.85		8.49	5.03	5.00	4.96
	0.75		8.49	5.08	5.03	4.96
	0.65		8.49	5.84	5.39	4.96
	0.55		8.49	6.79	5.39	4.96

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 2 FOR MAY
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

Week	Unit 1	Weekly Nuclear Capacity Factors of Unit 2: 0.16	0.24	0.32	0.40
		OCNP (mills/KWHe) of Unit 2			
5	0.95	9.40	7.65	5.23	5.03
	0.85	9.40	7.65	6.79	5.25
	0.75	9.40	7.74	7.28	5.39
	0.65	9.40	8.59	8.05	5.39
	0.55	9.40	8.86	8.30	5.39
6	0.95	9.32	6.79	5.03	4.96
	0.85	9.32	6.79	5.15	5.03
	0.75	9.32	6.79	5.84	5.03
	0.65	9.32	7.65	6.79	5.03
	0.55	9.32	8.83	7.28	5.03
7	0.95	9.32	6.79	5.03	5.00
	0.85	9.32	6.79	5.39	5.03
	0.75	9.32	7.28	6.79	5.03
	0.65	9.32	8.05	7.28	5.03
	0.55	9.32	8.86	7.74	5.03
8	0.95	9.77	7.65	5.25	5.03
	0.85	9.77	7.65	6.79	5.39
	0.75	9.77	8.05	7.28	5.39
	0.65	9.77	8.83	8.05	5.39
	0.55	9.77	9.11	8.30	5.39
9	0.95	4.66	4.97	5.39	9.11
	0.85	4.97	5.03	5.39	9.11
	0.75	4.97	5.39	6.50	9.11
	0.65	4.97	6.79	7.28	9.11
	0.55	4.97	6.79	8.30	9.11

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 2 FOR JUNE FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

		Weekly Nuclear Capacity Factors of				
Week	Unit 1	Unit 2: 0.36	0.42	0.48	0.54	0.60
		OCNP (mills/KWHe) of Unit 2				
10	0.95	5.39	5.00	4.72	4.66	4.57
	0.85	5.39	5.03	5.00	4.96	4.66
	0.75	6.09	5.39	5.08	5.03	4.66
	0.65	6.09	6.09	5.84	5.15	4.66
	0.55	6.40	6.09	6.09	5.15	4.66
11	0.95	6.09	5.08	4.97	4.72	4.63
	0.85	6.09	5.15	5.03	5.00	4.66
	0.75	6.09	6.09	5.39	5.08	4.66
	0.65	6.40	6.09	6.09	5.39	4.66
	0.55	6.40	6.40	6.09	5.39	4.66
12	0.95	5.25	4.97	4.66	4.66	4.53
	0.85	5.25	5.03	4.97	4.77	4.66
	0.75	5.39	5.08	5.03	5.00	4.66
	0.65	6.09	6.09	5.39	5.06	4.66
	0.55	6.40	6.09	5.84	5.06	4.66
13	0.95	5.03	4.72	4.66	4.57	4.29
	0.85	5.03	4.97	4.72	4.66	4.63
	0.75	5.06	5.03	5.00	4.96	4.63
	0.65	5.84	5.25	5.03	4.97	4.63
	0.55	6.09	6.09	5.15	4.97	4.63

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 2 FOR JULY
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

		Weekly Nuclear Capacity Factors of				
Week	Unit 1	Unit 2: 0.48	0.56	0.64	0.72	0.80
		OCNP (mills/KWHe) of Unit 2				
14	0.95	4.63	4.29	4.07	3.82	3.40
	0.85	4.63	4.53	4.29	4.07	3.82
	0.75	4.66	4.57	4.57	4.29	3.82
	0.65	4.87	4.66	4.63	4.57	3.82
	0.55	5.03	4.96	4.66	4.57	3.82
15	0.95	5.06	4.77	4.63	4.53	4.07
	0.85	5.06	4.96	4.72	4.66	4.29
	0.75	5.15	5.03	5.00	4.77	4.29
	0.65	5.84	5.25	5.03	5.00	4.29
	0.55	6.09	6.09	5.08	5.00	4.29
16	0.95	5.03	4.66	4.57	4.29	3.82
	0.85	5.03	4.72	4.66	4.57	4.29
	0.75	5.03	5.00	4.77	4.66	4.29
	0.65	5.25	5.03	5.03	4.87	4.29
	0.55	6.09	5.39	5.03	4.87	4.29
17	0.95	5.08	4.87	4.66	4.57	4.07
	0.85	5.08	5.00	4.77	4.66	4.29
	0.75	5.25	5.03	5.00	4.87	4.29
	0.65	6.09	5.39	5.06	5.00	4.29
	0.55	6.09	6.09	5.15	5.00	4.29
18	0.95	5.03	4.72	4.57	4.53	4.07
	0.85	5.03	4.96	4.72	4.63	4.29
	0.75	5.08	5.03	5.00	4.72	4.29
	0.65	5.52	5.23	5.03	5.00	4.29
	0.55	6.09	6.09	5.06	5.00	4.29

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 2 FOR AUGUST
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

		Weekly Nuclear Capacity Factors of					
Week	Unit 1	Unit 2:	0.60	0.70	0.80	0.90	1.00
			OCNP (mills/KWHe) of Unit 2				
19	0.95		5.00	4.66	4.56	4.28	3.58
	0.85		5.00	4.71	4.66	4.56	4.07
	0.75		5.03	4.98	4.71	4.66	4.07
	0.65		5.08	5.03	4.98	4.71	4.07
	0.55		5.84	5.08	5.00	4.71	4.07
20	0.95		5.84	4.98	4.66	4.63	4.07
	0.85		5.84	5.03	4.98	4.66	4.43
	0.75		5.84	5.08	5.03	4.98	4.43
	0.65		6.09	5.84	5.08	5.00	4.43
	0.55		6.40	6.09	5.39	5.00	4.43
21	0.95		5.03	4.77	4.66	4.52	3.82
	0.85		5.03	4.98	4.77	4.66	4.28
	0.75		5.22	5.03	4.98	4.77	4.28
	0.65		5.84	5.22	5.03	4.96	4.28
	0.55		6.09	5.84	5.06	4.96	4.28
22	0.95		5.08	4.87	4.66	4.52	3.82
	0.85		5.08	5 00	4.77	4.66	4.28
	0.75		5.25	5.03	5.00	4.77	4.28
	0.65		6.09	5.25	5.03	4.98	4.28
	0.55		6.09	6.09	5.08	4.98	4.28

TABLE B.3.1 (CONT'D)

WEEKLY OCNP FUNCTIONS OF UNIT 2 FOR SEPTEMBER
FROM THE MULTI-REACTOR OPTIMIZATION (CASE 2)

		Weekly Nuclear Capacity Factors of				
Week	Unit 1	Unit 2: 0.60	0.70	0.80	0.90	1.00
		OCNP (mills/KWHe) of Unit 2				
23	0.95	6.83	6.40	6.09	6.09	5.06
	0.85	6.83	6.50	6.40	6.09	5.39
	0.75	6.83	6.83	6.50	6.40	5.39
	0.65	7.28	6.83	6.83	6.40	5.39
	0.55	8.48	7.28	6.83	6.40	5.39
24	0.95	6.79	6.09	5.84	5.06	4.87
	0.85	6.79	6.40	6.09	5.84	5.03
	0.75	6.79	6.40	6.40	6.09	5.03
	0.65	6.83	6.79	6.40	6.09	5.03
	0.55	6.83	6.83	6.40	6.09	5.03
25	0.95	6.79	6.09	5.84	5.06	4.96
	0.85	6.79	6.40	6.09	5.84	5.03
	0.75	6.79	6.40	6.40	6.09	5.03
	0.65	6.83	6.79	6.40	6.40	5.03
	0.55	6.83	6.83	6.40	6.40	5.03
26	0.95	6.83	6.40	6.09	6.09	5.06
	0.85	6.83	6.50	6.40	6.09	5.39
	0.75	6.83	6.83	6.50	6.40	5.39
	0.65	7.28	6.83	6.83	6.40	5.39
	0.55	8.48	7.28	6.83	6.40	5.39

Appendix C: PROCOST

C.1 Introduction

The organization of PROCOST and the algorithm of its main components were discussed in Section 4.0. A review of MPSX and the detailed algorithm of SECURIT are covered in later sections of this Appendix. The major topic remaining is the general operating philosophy for using PROCOST. The flowchart of PROCOST is given in Figure C.1. The component subprograms of PROCOST are:

NUC_OPT: main program that writes the L.P. nuclear optimization formulation;

PEAKERS: subroutine that simulates the operation of peaking units;

PECK_OR: subroutine that formulates the fossil economic loading order;

DURATN: subroutine that calculates the load-duration load model

MPSX: the program that solves the L.P. nuclear problem;

PUMP_ST: main pumped-storage simulation program that also reads the L.P. nuclear solution, and calculates OCNP;

ECO: economic pumped-storage subroutine;

SECURIT: security pumped-storage subroutine.

The function of PROCOST is two-fold (1) to calculate OCNP values, and (2) to calculate the optimal dispatching schedule for the system's nuclear reactor(s). The latter step assumes that the modelling assumptions used in the other system components are reasonable in order to derive a

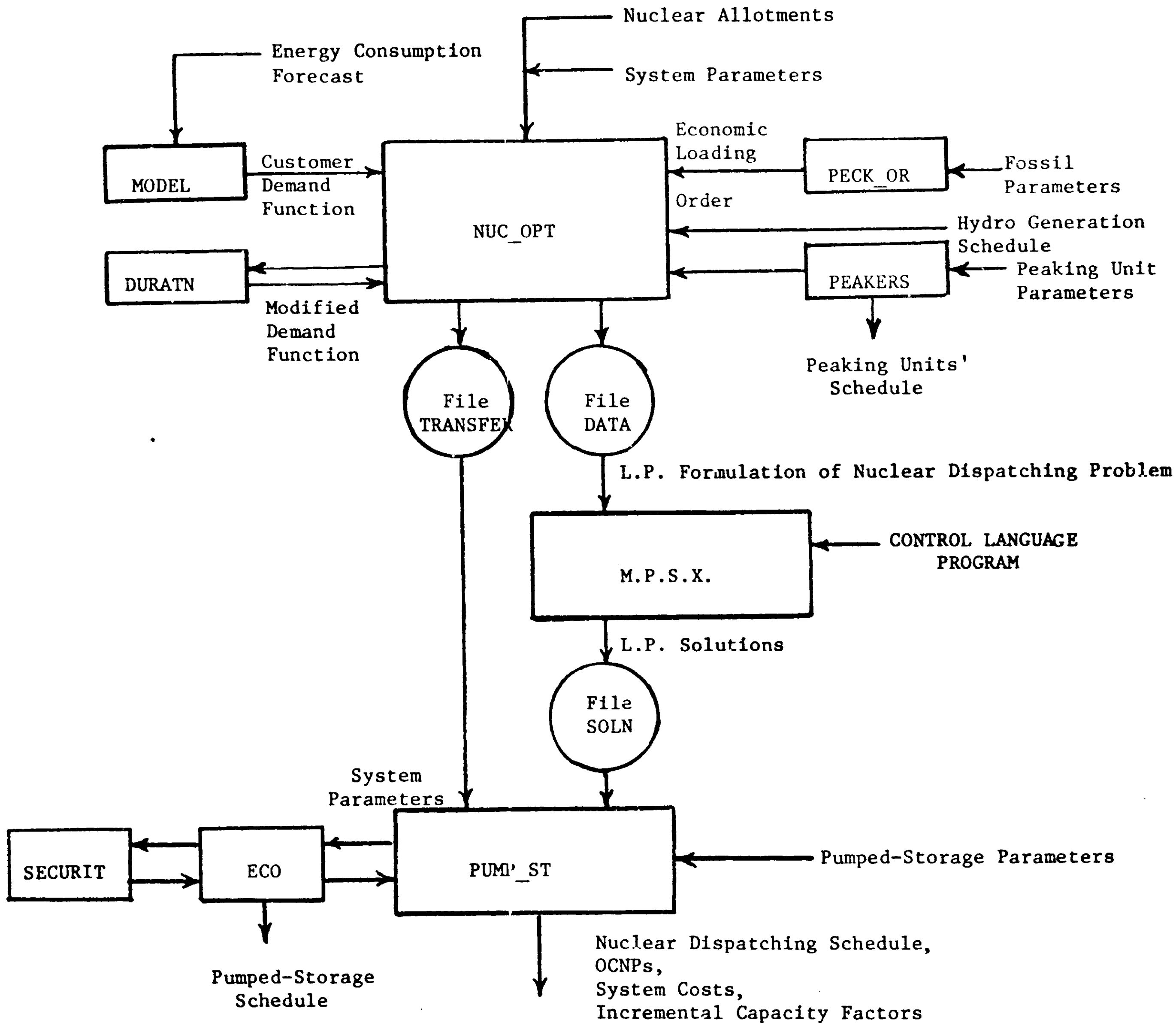


Figure C.1 PROCOST ALGORITHM

feasible and optimal nuclear dispatching schedule. Use of PROCOST is tied to the (method of) solution of the short-range problem, in as much as PROCOST attempts to supply the information (OCNP values and dispatching schedules) specified by the theory. Use of any other production cost code in place of PROCOST that supplied the same information would be also serve the purpose.

A great amount of effort has been directed toward making PROCOST a fast and efficient program. Compared with the early version, very substantial improvement in computational performance had been made. To calculate OCNP values, the current version of NUC_OPT consumes about 0.2 CPU-Sec./value, MPSX consumes about 0.2 CPU-sec/value, while PUMP_ST consumes about 1.1 CPU-sec./value. Most of the developmental effort had been toward improving the L.P. calculations, so that it is no longer the constricting job step (in terms of CPU time).

PUMP_ST was originally designed for a detailed pumped-storage optimization based on the 168-hour load model. Hence, a great deal of calculational effort is wasted when PUMP_ST is used with a six-interval load model. Therefore, it is recommended that: (1) the present pumped-storage version of PUMP_ST not be used for the OCNP calculations but reserved for use when the detailed optimization schedule is desired; (2) a simpler model of pumped-storage operation be written for OCNP (six-interval models) calculations; (3) PUMP_ST be examined to reduce the large number of calculations it performs.

PROCOST has a core-storage requirement of 230 K. The determining step is in NUC_OPT which is due to the overhead required to provide the dual capability of formulating L.P. problems with two types of load models (chronologic and load-duration) and accepting the original input (customer demand) data in any of three forms of load models. To achieve a large reduction in the storage requirement and improve CPU time, it is recommended that NUC_OPT should be divided into two versions, one for load-duration models, and other for chronologic models.

In the present version of PROCOST, there is no constraint on the minimum operating level of the reactor. To make this option available, a new input variable, referred to as MINIMUM would be read in with the rated capacity (CAPACITY) of the reactor. MINIMUM would be considered the must-run portion of the nuclear unit, and have its capacity subtracted from the demand function prior to the L.P. formulation. In the L.P. model, the operating range of the reactor would be from zero to CAPACITY-MINIMUM. The nuclear resource constraint in the L.P. model must also be modified, to subtract out the portion of energy already allocated to the must-run portion of the reactor. It is important that the nuclear heat-rate curve be use to calculate the correct value of this must-run energy. In addition, the nuclear heat-rate curve itself must be adjusted for use in the L.P. model due to the revised operating range of the reactor. Finally, MINIMUM should be added back to the nuclear optimized solution before the L.P. solution is to be printed.

The recommendations discussed above are related only to improving the numerical techniques without changing any of the modelling assumptions involved. Many of the simple assumptions and concepts in PROCOST can be improved upon. Start-up and shut-down effects can be included by allowing use of several loading orders and load-duration curves, each appropriate for only certain hours of the day. Incorporating error bands on the customer demand function should be easily implemented by MPSX parametric procedures. Other possibilities are suggested in Sections 6.2, 5.5, and 3.2.

Even through PROCOST is not perfect, it is a very flexible program. The flexibility is derived from the many options available in NUC_OPT and MPSX especially. MPSX is extensively used by the oil and gas industry. MPSX was designed as a production code where intermediate results can be saved, old L.P. problems can be saved, solutions transferred, and many other useful features intended for users with a permanent interest in L.P. models. MPSX also has a great variety of parametric analysis routines and editting capability for L.P. models. Thus, once the basic L.P. model is formulated, NUC_OPT need not be used again to alter the model. The editing facilities of MPSX have sufficient capability to perform any required adjustments to the L.P. model. The potential flexibility of MPSX makes it well suited for the type of analysis desired by the system planner, to study a variety of related and complex situations.

To facilitate manipulation of the L.P. model, a detailed description of the L.P. nuclear model is given next, in Appendix C.2. Following is a review of the MPSX control language program which dictates the optimization routines to be used on the L.P. model.

Appendix C.4 contains a detailed description of the pumped-storage security algorithm. The remaining sections of Appendix C are: description of the input specification to PROCOST; listing of PROCOST; a complete listing of the PROCOST input file SYSIN for Case 3; and a representative selection of computer output from Case 3.

C.2 L.P. MODEL

Efficient use of PROCOST requires agile manipulation of the L.P. model, in the MPSX control language program. The following is a detailed description of the L.P. model (its row and column names), to facilitate its use. The equations governing the L.P. model were given in Section 4.2.1.

The L.P. model is as follows (describing the rows from top to bottom, and the columns from left to right). The first row is the objective function, named COST, which is the summation of the incremental fossil fuel cost for the week, see Eqn. (4.1). Each time interval in the load model is simulated by a customer demand constraint equation, see Eqn. (4.2). The row name of each of these equations is of the form DEMANxxx where xxx is a three digit representation of the time interval being simulated. Each nuclear power reactor is represented by thermal nuclear resource constraint equation, see Eqn. (4.3). The row name of each of these equations is of the form NUCLRxxx where xxx is a three digit number assigned to each reactor. The constraints on each column variable is expressed by a BOUND row, see Eqn. (4.4). The BOUND row is named "BOUND1".

There is a separate column variable for each fossil and nuclear increment in each distinct time interval. The name of the fossil variables is of the form FFxxxyyy and the name of the nuclear variables is of the form Nxxxzzw where xxx is a three digit representation of the time interval number, yyy is a three digit representation of the fossil increment number, zz is a two digit representation of the reactor number, and w is a single digit representation of the nuclear increment number. The RHS column lists the values of the demand function and the nuclear resource constraints. The name of this column is RHS001. There are also RHS change columns which are used to, modify RHS columns to form new (temporary) RHS columns on which RHS parametric analysis is based. The change column named CHC000, is used to modify the customer demand function. For each nuclear resource row, there are two RHS change columns, one for positive changes, and one for negative changes. The name of these columns are of the form CHCxxx where xxx is a three digit representation of (2n-1) for positive changes, and (2n) for negative changes and where n is the reactor number.

The above description is valid for either a load-duration or a chronologic load representation in a one-week L.P. model. To represent several weeks using a load-duration model, one L.P. model is required for each week. To represent several weeks using a chronologic load model, only one L.P. model is required for each different fossil configuration. The variation in the time duration of each time interval (for different weeks in the load-duration mode) requires a new L.P. model for each week. In the chronologic load model situation, the body of L.P. model is the same for different weeks (with the same fossil configuration). The only difference is an extra RHS column for each additional week. The name of this RHS column is of the form RHSxxx where xxx is a three digit representation of the week number. This difference in the number of L.P. models generated by NUC_OPT must not be overlooked when specifying the MPSX control language program or in the PUMP_ST input parameters.

C.3 MPSX

C.3.1 Control Language Program

MPSX (IBM program product) is a general purpose linear programming package. This section is not an introduction to MPSX, but rather a technical review of some useful MPSX programming procedures developed for the PROCOST operating environment. The prospective user of MPSX is referred to References (29,30) for introductions to linear programming and MPSX. An explanation of the keywords (commands) used in the MPSX control language program is given in Reference (31). An explanation of the role of the many subroutines available in MPSX, their abilities and their restrictions is covered in Reference (32).

MPSX is composed of two job steps: a compilation step and an execution step. The first step is the compiling of the MPSX control language program, which is the specification of the optimization procedures and parametric analysis used in solving the L.P. problem. The second step is the solving of the L.P. problem by the algorithm dictated in the MPSX control language program. Control is passed to the second step automatically upon completion of the first step. This section is a review of two sample MPSX control language programs. It is assumed that the reader is familiar with MPSX, L.P., PL1, and general computer programming terminology.

The procedure for solving a simple L.P. problem is a straight-forward one. Sample 1, listed in Appendix C.3.2 is a simple example of a basic MPSX control language program solving a single L.P. problem. However, to efficiently solve a large number of related problems (as in calculating OCNP values), parametric techniques should be used. Instead of solving each problem from scratch, parametric analysis searches for a solution starting from the solution of a previously solved problem. Since the problems are related, their solutions are also similar. Thus a large amount of computations can be avoided by starting the calculations for solutions from an optimal solution of a related problem. Such an algorithm is illustrated in Sample 2. Sample 2, listed in Appendix C.3.3, is an example of a MPSX control language problem applicable to a single reactor optimization problem.

Sample 1 illustrate the basic steps in a control language problem: (1) identity the input data, "SYSTEB01"; (2) provide (or identify) the problem name, "MINIMIZE"; (3) convert the input data (located on file IN) to machine code; (4) identify the objective function, "COST"; (5) setup the problem with the appropriate bounds for solving; (6) identify the RHS, "RHS 001"; (7) solve the problem; (8) write the solution (or a portion thereof). Each of the above functions corresponds with a command in the MPSX control language. The exact sequence of commands depends on the specific problem being solved as does the parameters used with commands. The PROGRAM statement denotes the beginning of the control program and PEND denotes the end. An asterisk in column 1 denotes a comment card. A TITLE statement provides a title on every page of MPSX output. The INITIALZ command initializes all MPSX variables to default values. The first MOVE statement informs the computer, the name of the input data to be read (important, since several input models may reside in the same device). The name, SYSTEB01, is formed from the concatenation of the character variable, SYSTE, with the week number (2 digits) of the problem in NUC_OPT. The second MOVE statement identifies the name to be associated with the L.P. problem when residing in the computer's storage devices. The name, "MINIMIZE" is arbitrary, but must not duplicate a name already on the PROFILE. The CONVERT instruction reads the data named SYSTEB01 on file IN, and converts the data to machine code. The third MOVE statement identifies the name of the L.P. row to be used as the objective function (several may be available). The SETUP command prepares the problem in matrix format ready for solving. "BOUND1" is the name of the row of bounds to be used in the present optimization. Minimization is the default mode. The fourth MOVE statement identifies the name of the RHS column to be used in the optimization (several may be available). The

OPTIMIZE instruction performs the actual problem solving. The SOLUTION instruction writes the solution on the user file SOLN. Only selected information from the solution is written: columns 2, 4, and 8 of the row variables and columns 2 and 4 of those column variables beginning with the letter N (the nuclear variables). The EXIT command terminates execution of the program. The entire solution is not written since the fossil schedule must complement the nuclear schedule to fulfill the demand function (conserving space and computer operations).

Sample 1 solves a single model without performing any parametric anaylsis. Sample 2, listed in Appendix D.2 is a more elaborate program that solves a large number of similar problems through repetitive use of subroutine call statements and parametric analysis. The subroutine structure is basically similar to Sample 1 with the addition of the parametric analysis statements. The parametric analysis solves for the solution of the same basic L.P. problem for different increments of nuclear energy. Sample 2 is a typical example of how to program MPSX to obtain the values of 22 weekly OCNP functions.

The following discussion of Sample 2 will cover only those statements not explained above. The function of the MVADR statement is to change the program branch for XDOPRINT from the default procedure to the user procedure labelled SET. XDOPRINT is explained below. The XFREQLGO=0 and XFREQLGA=0 statements sets the printing of the iteration log to a minimum (which is still quite voluminous). The XPARDELT=2 statement is related to XDOPRINT and will be discussed later. The EXEC(TIP) statement is a subroutine call to TIP. Subroutine TIP is called repeatedly to solve 22 different weekly L.P. models, and perform parametric analyses. The length of the control language program is limited. Hence, when groups of commands are used repeatedly, subroutines and loops should be incorporated in the program to conserve the number of statements.

Subroutine TIP is established by using the name, TIP, as the label to the first command of the subroutine. TIP is the label to a CONVERT command. The end of subroutine is denoted by a STEP or CONTINUE command. The difference between STEP and CONTINUE is that execution is returned to the calling routine when CONTINUE is encountered, whereas STEP implies execution should go to the statement following the calling statement. Other entry points may be established in the subroutine by placing labels such as PARRR and S2 on the relevant statements. The XPARAM=0 resets the system increment variable to its inital value.

An initial optimal solution to a L.P. model is required before the program can perform parametric analysis. Parametric RHS analysis also requires knowledge of how the RHS is to be varied and at what increments to write the solution. MOVE(XCHCOL,'CHCOO2') identifies the column named 'CHCOO2' as the Change Column that is to be combined with the RHS column to form the new RHS. One unit of 'CHCOO2' will decrease the nuclear resource constraint by 5%, in the present version of NUC_OPT. The new parametric RHS is a combination the old RHS plus a multiple of 'CHCOO2'. XPARAM, the multiplier of 'CHCOO2', is increased continuously. XPARAM=0 sets its initial value to zero and XPARMAX=8, sets the final value of XPARAM to eight. PARARHS is the command which performs the parametric analysis. There is a pause each time XPARAM is a multiple of XPARADELT, which is set by the statement XPARDELT=2. When the pause occurs, XDOPRINT is signaled, which has been set to call subroutine SET, which specifies that the current solution is to be written on file SOLN.

In other words, for each of the 22 L.P. models, the solution of the basic weekly L.P. problem was solved with the inital amount of nuclear resource, along with four other values of the nuclear resource, at 10% decreasing intervals in nuclear energy. A total of 110 L.P. solutions will reside on user file SOLN.

A programming note: user files with large BLOCKSIZES will overload the buffers and result in SCC=80A. Unlimited increases in the REGION parameter on the JOB card will not alleviate the problem. The MPSX buffer core size parameter should be changed.

C.3.2: SAMPLE1, MPSX CONTROL LANGUAGE PROGRAM

```
         PROGRAM
*
*   THIS  PROGRAM PREFORMS THE  NUCLEAR ENERGY OPTIMIZATION
*
         TITLE (' ELECTRIC POWER DISPATCHING SIMULATION')
         INITIALZ
         MOVE(XDATA,'SYSTEB01')
         MOVE(XPBNAME,'MINIMIZE')
         CONVERT('FILE','IN')
         MOVE(XOBJ,'COST')
         SETUP('BOUND','BOUND1')
         MOVE(XRHS,'RHS001')
         OPTIMIZE
         SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',   X
         'CMASKS','N******',' ')
         EXIT
         PEND
```

C.3.3: SAMPLE2, MPSX CONTROL LANGUAGE PROGRAM

```
        PROGRAM
*
*  THIS  PROGRAM PREFORMS THE  NUCLEAR ENERGY OPTIMIZATION
*
        TITLE (' ELECTRIC POWER DISPATCHING SIMULATION')
        INITIALZ
        MVADR(XDOPRINT,SET)
        XSETLB=-1
        XFREQLGO=0
        XFREQLGA=0
        XPARDELT=2.
        MOVE(XPBNAME,'MINIMIZE')
        MOVE(XOBJ,'COST')
        MOVE(XRHS,'RHS001')
        MOVE(XDATA,'SYSTEA01')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA02')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA03')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA04')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA05')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA06')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA07')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA08')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA09')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEA10')
```

```
         EXEC(TIP)
         MOVE(XDATA,'SYSTEA11')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEA12')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEA13')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEB01')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEB02')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEB03')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEB04')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEB05')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEC01')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEC02')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEC03')
         EXEC(TIP)
         MOVE(XDATA,'SYSTEC04')
         EXEC(TIP)
         EXIT
TIP      CONVERT('FILE','IN')
         SETUP('BOUND','BOUND1')
PARRR    XPARAM=0.
S2       OPTIMIZE
         SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',   X
         'CMASKS','N******',' ')
         MOVE(XCHCOL,'CHC002')
         XPARAM=0.
         XPARMAX=8.
         PARARHS('CONT')
```

```
         SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',   X        SAM20073
         'CMASKS','N******',' ')                                                 SAM20074
         STEP                                                                    SAM20075
SET      SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',   X        SAM20076
         'CMASKS','N******',' ')                                                 SAM20077
         CONTINUE                                                                SAM20078
         PEND                                                                    SAM20079
```

C.4 Pumped-Storage Security Algorithm

The peak-shaving pumped-storage generation schedule for this security model is the same as in the economic model. It is characterized by the pumped-storage generation level (power level K3 in Figure 4.9), where if demand load is above that level, then the pumped-storage generators produced enough power to make up the difference or until its nominal capcity(*) is reached.

The pumping schedule flowchart is shown in Figure C.2. The pump scheduling algorithm is determined as follows:

(1) Define the periods when pumping is allowed and where it is not allowed. A bit string representing the number of time intervals in a week can serve this purpose where a '1' bit means no pumping is allowed and a '0' bit means pumping is allowed. The string is initially all '0's. The generation periods are then denoted by '1' bits from an examination of the generation schedule. The bye periods(an input specification) before and after generation periods are also denoted by '1' bits. The remaining '0' bit substrings define periods when pumping is allowable.

(2) Set pointers to the beginning and end of the next allowable pumping period.

(3) Calculate the minimum amount of pumping that can be

(*) Nominal capcity is not the rated capacity of the generators, but that capacity intended for scheduled usage, the remainder is for emergency usage.

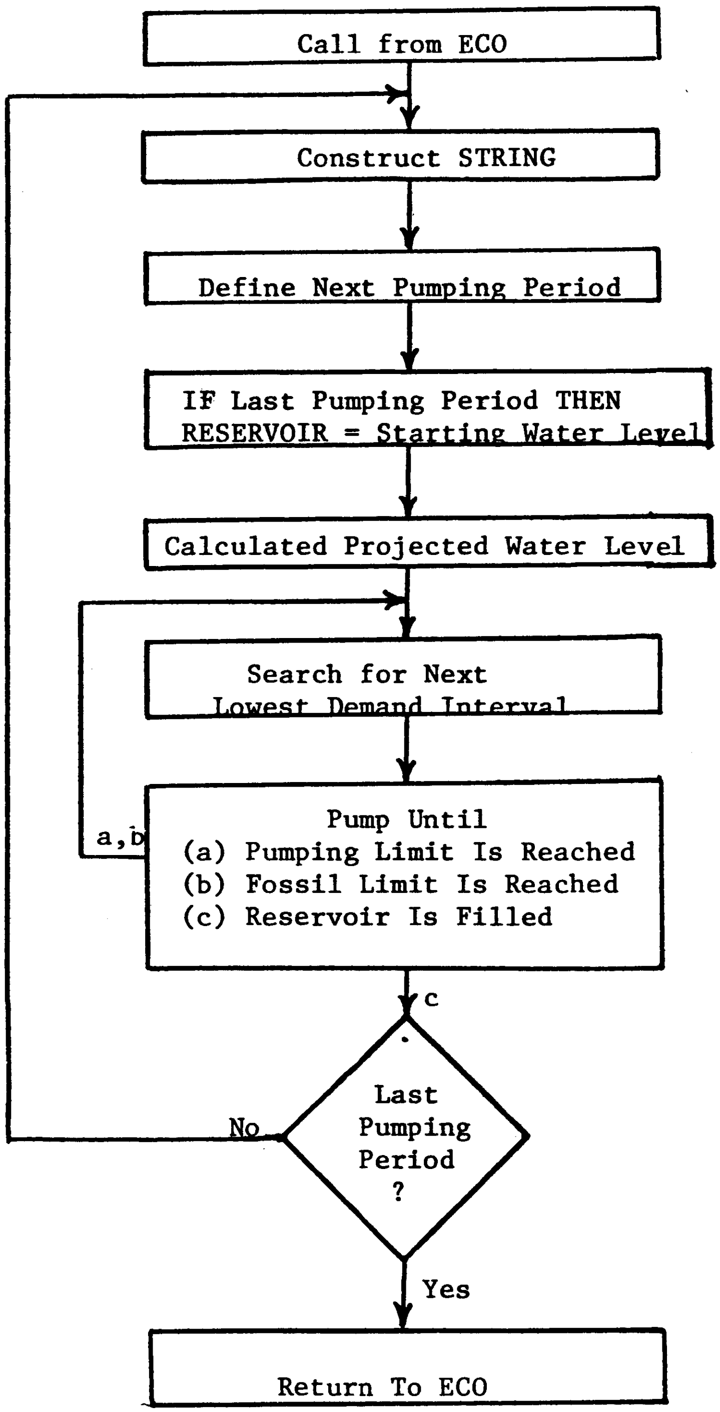


Figure C.2 SECURIT ALGORITHM

scheduled during this period before overflowing occurs. Hence, water-usage-to-date must be calculated for the present pumping period. The chronologic water level pattern is calculated by considering the generation schedule, free inflow (assumed uniform), pumping to date, and the starting water level (an input specification). The water level pattern is needed to determine the requirement of water to fill the reservoir during the present pumping period. That amount is the difference between the reservoir size and the calculated water level at the end of the period in question.

(4) Search for the lowest demand interval during the pumping period. Scheduling pumping for this interval first is the most economic choice available. The timing of the pumping schedule is determined by this step.

(5) The amount of pumping scheduled in an interval is subject to three constraints: (i) when capacity of the pump is reached, (ii) when the reservoir is filled, and (iii) when fossil load level reaches the turnaround level(*). Whichever constraint becomes active first stops the pumping and hence determines the amount scheduled.

(*) Turnaround level is that load level, above which no pumping is allowed (K4 of Figure 4.9). It would be too expensive to pump. It's determined as a certain amount(an input specification) of MW below the pumped storage generation level (K3 of Figure 4.9).

(6) If constraints (i) or (iii) becomes active repeat step 4, search for the lowest demand interval. If constraint (ii) becomes active, or time has run out (pumping has been scheduled for all allowable time intervals and reservoir is not full) then repeat step 2, defining the next pumping period. The subroutine returns to ECO when the end of the string has been reached.

C.5 Input Specification

PROCOST is composed of three program steps: (1) NUC_OPT, the preprocessor to MPSX which formulates the L.P. model; (2) MPSX, the program that solves the L.P. model; (3) PUMP_ST, the pumped-storage program. The data input to MPSX are automatically written by NUC_OPT, hence, there are no input parameters directly fed to MPSX. Control of MPSX is derived from the input data to NUC_OPT (which in turn inputs to MPSX) and the MPSX control language program (which was discussed in the previous section). The input specifications to NUC_OPT and PUMP_ST are given below.

C.5.1 NUC-OPT Input Specifications

The file structure is:

(1) DATA: a transfer medium to MPSX,

(2) HYDRO: contains the hydro generation schedule,

(3) LDMDL: contains the customer demand function,

(4) PEAKS: contains peaking unit parameters,

(5) PECK: contains fossil loading order parameters,

(6) SYSIN: contains modelling parameters,

(7) TRANSFR: transfer medium to PUMP_ST.

The DATA file is the one on which NUC_OPT writes the MPSX input L.P. data. The record format should be card image, i.e., DCB=(RECFM=FB,LRECL=80,BLKSIZE=12880).

The HYDRO file contains the values of the array variable HYD, which is the dispatching schedule of the hydro unit (calculated off line).

The LDMDL file contains the values of the array variable DEMAND, the weekly (chronologic) customer demand function.

The PEAKS file contains all the variables associated with the peaking units. One set of peaking unit variables is required for each week being simulated. If 52 weeks are being simulated, 52 sets of peaking parameters are required. Thus, there is available a large amount of flexibility in varying the peaking units available each week. A complete input set consists of the following parameters:

P_NUM: the number of peaking units for the week.

C_FACTOR: the simulated capacity factor for a peaking unit.

RATING: the rated capacity of the peaking unit, MW.

HEAT: the average heat-rate of the peaking unit at rated capacity, (million BTU/MWH).

F_COST: the fuel cost of the peaking unit, ($/million BTU).

SUSD: the average cost of one start-up and shut-down, ($).

CODE: if CODE=0, then the detailed peaking unit generation schedule is printed.

At the very least, the minimum input set consists of a zero value for P_NUM, otherwise PROCOST will ABEND. When P_NUM is not zero, the five peaking unit variables above are read successively (in the order listed above), P_NUM number of times. CODE is the last variable listed in a single set of peaking unit data.

The PECK file contains all the variables associated with the fossil economic incremental loading order. The input variables (listed in order of input) are:

N1: The number of large fossil units.

VP1: The number of valve points modelled in the large fossil units.

N2: The number of medium fossil units.

VP2: The number of valve points modelled in the medium fossil units.

N3: The number of small fossil units.

VP3: The number of valve points modelled in the small fossil units.

LGE_HEAT(VP1,2): Array containing the average heat-rate data for large fossil units.

MED_HEAT(VP2,2): Array containing the average heat-rate data for medium fossil units.

SML_HEAT(VP3,2): Array containing the average heat-rate data for small fossil units.

NLGE(N1,4): Array containing the station characteristics of large fossil units. The parameters of interest for each station are the number of units, MW capacity of each unit, the heat rate (million BTU/MWH), and the fuel cost ($/million BTU).

NMED(2,4): Array containing the station characteristics of medium fossil units. The parameters of interest for each station are the number of units, MW capacity of each unit, the heat rate (million BTU/MWH), and the fuel cost ($/million BTU).

NSML(N3,4): Array containing the station characteristics of small fossil units. The parameters of interest for each station are the number of units, MW capacity of each unit, the heat rate (million BTU/MWH), and the fuel cost ($/million BTU).

EMERG: The size (MW) of the last increment added to the economic loading order (as an insurance measure). This may represent emergency purchase capacity.

E_COST: The cost (mills/KWH) of the last increment.

The SYSIN file contains the parameters associated with the structure of the L.P. model. The names of the variables (listed in the order of input) are:

SYSTE: The name to be associated with the L.P. model to be written on file DATA. A maximum of six characters is allowed in the name.

MODE: MODE='CHR' for chronologic load model mode, and MODE='DUR' for load-duration load model mode.

TRUE: The actual number of hours represented by the load model. TRUE=168 for a weekly load model.

N1: The number of time intervals in the input load model on file LDMDL.

N2: The number of time intervals desired in the load-duration model. If MODE='CHR', then set N2=N1.

VP: The number of valve points in the input nuclear heat rate curve.

NUMBER: the number of nuclear reactors in the L.P. model.

K: the number of increments in the fossil economic incremental loading order.

PARAMETER: If no parametric analysis on the modified demand function will be performed by MPSX, set PARAMETER=0, else chose '1' or '2'. When PARAMETER=1, the change column equals 1% of the modified demand function; if PARAMETER=2, then it equals 100 MW.

WEEKS: the number of weeks using the same economic loading order and hydro generation schedule.

PECKING: ='YES' if the fossil economic incremental loading order is desired to be punched out on cards, in a format usable in FOSSIL.

='NO' if punched cards not desired.

TIME(N1): The array describing the weight (in hours) assigned to each time interval in the input load model. If TRUE=N1 then all values in TIME are automatically set equal to 1. In such a case, TIME should be omitted.

CODE(TRUE): an array containing the correspondence in which the input load model can be expanded to the basic (168) hourly load model. If TRUE=N1, omit this variable, the program will substitute the correct values.

LOAD(NUMBER): the array containing the average weekly nuclear capacity factors used in calculating the nuclear resource constraint (and included in the RHS column vectors).

EFFIC(VP,2): the array containing the nuclear incremental heat rate data.

CAPACITY(NUMBER): the array containing the capacities(MW) of the nuclear reactors.

BTU(NUMBER): the array containing the average heat rate at rated capacity for each of the nuclear reactors.

The TRANSFR file is the medium on which NUC_OPT writes the values of several system variables to be transferred to the pumped storage routine, PUMP_ST. An adequate DCB for TRANSFR is (RECFM=U,BLKSIZE=13030).

C.5.2 PUMP_ST Input Specifications

The file structure is:

(1) SYSIN: contains pumped-storage modelling parameters;

(2) TRANSFR: contains system parameters transferred from NUC_OPT;

(3) SOLN: contains the L.P. model solutions written by MPSX.

The input parameters (listed by order of input) on file SYSIN are:

MODE= 'QUCK' if only the nuclear L.P. solution is to be printed, no pumped-storage simulation,

= 'NONE' if more detailed information about system is to be printed but still no pumped-storage simulation,

= 'ECO' if the economic pumped-storage schedule is to be calculated,

= 'SEC' if security pumped-storage schedule is to be calculated.

CODE=0 if printing the detailed dispatching schedule is desired.

=1 if printing the detailed dispatching schedule is not desired.

CAPACITY= MW generation capacity of pumped-storage unit.

RATIO= cycle efficiency of pumped-storage unit (fraction).

CAP_PUMP= MW pumping capacity of pumped-storage unit.

RESERIOR= MWH size of pumped-storage reservoir.

FREE= weekly stream inflow into pumped-storage unit (MWH).

START= starting water level of reservoir (MWH).

BYE= time (Hours) of transition (rest) interval before and after generation.

TOLERANCE= The buffer (MW) below the minimum pumped-storage generation (demand) level at which no pumping is allowed.

ALLOT(N)= array containing the number of L.P. solutions solved for a weekly L.P. model, where N=1 for a load-duration model and N= the number of weeks using the same L.P. model for a chronologic load model.

I= number of descriptive character strings immediately following, that are to printed on the computer output.

TITLE= a descriptive character string with maximum length of 80 characters, entered I times.

In the load-duration mode, the last three parameters are repeated for each week having the same fossil configuration, see sample input.

The whole sequence of parameters above is repeated for each fossil configuration in PROCOST. An example of a sample input is presented in Appendix C.7, the complete listing of the card input for Case 3. In Appendix C.8 is a representative sampling of the computer output from Case 3.

Programming Notes: (1) All input parameters required on file SYSIN are format-free; (2) Caution, the use of a DUMMY file for the MPSX SYSPRINT should be reserved for those with an expert knowledge of MPSX; (3) Subroutine DURATN calls the Fortran subroutine, ISORT (35), to sort the elements of an array into ascending order. It is important that the JCL is in the correct order to establish the proper linkage.

```
//   EXEC   PLIXCL,
//   PARM.L='LIST,MAP,DCBS'
//C.SYSIN   DD *,DCB=BLKSIZE=2000
 NUC_OPT : PROCEDURE OPTIONS(MAIN);
 DCL (N1,N2,TRUE,VP,NUMBER,K,         PARAMETER,WEEKS) FIXED BIN,
                SYSTE CHAR(6) VARYING, MODE CHAR(3),PECKING CHAR(3);

 ON ENDFILE(SYSIN) GO TO BOTTOM;
    /*   BASIC PARAMETER INPUT SECTION,
         PARAMETERS USED TO DIMENSION ARRAY VARIABLES      */
 TOP:
 GET LIST(SYSTE,MODE,    TRUE,N1,N2,VP,NUMBER,K,PARAMETER,WEEKS,PECKING);
 PUT LIST(' INPUT VARIABLES FOLLOWS:')PAGE;
 PUT DATA(SYSTE,MODE,    TRUE,N1,N2,VP,NUMBER,K,PARAMETER,WEEKS,PECKING);

 BEGIN;

 DCL B_T_U FLOAT BIN, (NN,I,J,JJ,JJJ,KK,KKK,P, COD(TRUE)) FIXED BIN,
 DURATN EXTERNAL ENTRY((*) FIXED BIN(31,10),(*) FIXED BIN,(*) FIXED BIN,
 (*) FIXED BIN,(*) FIXED BIN(31,10),FIXED BIN,FIXED BIN);
 DCL PEAKERS EXTERNAL ENTRY((*) FIXED BIN(31,10), FIXED BIN,FIXED BIN,
 (*) FIXED BIN, FIXED BIN(31));
 DCL (LOAD(NUMBER)                ,EFFIC(VP,2)) FLOAT BIN,
     CAPACITY(NUMBER) FIXED DEC;
 DCL (TIME(N1),TIM(N2),TRANSFORM(K,2) )FIXED BIN, BTU(NUMBER) FLOAT BIN,
 (WORK(N1),CODE(TRUE)) FIXED BIN,(MONEY,HYD(N1)) FIXED BIN(31), (FOSSIL,
   ORDER(K),FUEL(K),CUM_ORDER(K),CUM_FUEL(K))FLOAT DEC(16),
 BASE FLOAT DEC,     ( DEMAN(N2),DEMAND(N1)) FIXED BIN(31,10),
 PECK_OR EXTERNAL ENTRY(FLOAT DEC,(*) FLOAT DEC(16), (*) FLOAT DEC(16),
 FIXED BIN,FLOAT DEC(16),(*,2) FIXED BIN);
 DCL INCRE  FIXED BIN(31,5);


    /*   HYDRO GENERATION SCHEDULE INPUT SECTION          */
 GET  FILE(HYDRO) LIST (HYD);
 PUT LIST(' HYDRO DATA FOLLOWS:')SKIP;
```

```
PUT SKIP LIST(' WEEKLY  HYDRO GENERATION SCHEDULE, INTERVAL BY INTERVAL
 (MW)');
PUT EDIT(HYD)(8 F(10),SKIP)SKIP;
   /*   IF TRUE=N1, THEN THE VALUE OF TIME AND CODE ARE OBVIOUS
        AND INPUT TO PROCOST IS NOT NECESSARY             */
IF TRUE=N1 THEN DO;
TIME=1;
 DO I=1 TO TRUE;
CODE(I)=I;
END;  END;
 ELSE GET LIST (TIME,CODE);
PUT SKIP(3) LIST(' THE TIME WEIGHING FUNCTION FOLLOWS (NUMBER OF HOURS
REPRESENTED BY EACH TIME INTERVAL):');
PUT EDIT (TIME) (8 F(10),SKIP)SKIP;
 PUT  SKIP(3) LIST(' *CODE* FOLLOWS(CORRESPONDENCE MAP FROM THE LOAD MO
DEL TO A 168 HOUR REPRESENTATION):');
PUT EDIT (CODE) (8 F(10),SKIP)SKIP;
GET LIST(LOAD,EFFIC,CAPACITY,BTU);
PUT SKIP(2) EDIT (' NUCLEAR INPUT PARAMETERS FOLLOWS:')(SKIP,A)
(' NUCLEAR INCREMENTAL HEAT RATES:',EFFIC)(SKIP,A,COL(40),12 F(8,2))
(' WEEKLY NUCLEAR CAPACITY FACTORS:',LOAD)(SKIP,A,COL(40),10 F(10,2))
(' RATED NUCLEAR CAPACITIES,MW:',CAPACITY)(SKIP,A,COL(40),10 F(10  ))
(' FULL POWER AVER HEAT RATES: ',BTU)     (SKIP,A,COL(40),10 F(10,2));

 B_T_U=0;
DO I=VP TO 2 BY -1;
EFFIC(I,1)=EFFIC(I,1)-EFFIC(I-1,1);
END;
DO I=1 TO VP;
B_T_U=B_T_U+EFFIC(I,1)*EFFIC(I,2);
END;

CALL PECK_OR(BASE,ORDER,FUEL,K,FOSSIL,TRANSFORM);
FOSSIL=FOSSIL*TRUE;
PUT SKIP(4) LIST(' ECONOMIC LOADING ORDER OF FOSSIL PLANTS');
PUT EDIT('  MUST RUN FOSSIL OPERATING LEVEL(MW) = ',BASE)(A,F(10))
```

```
 SKIP;
 PUT EDIT('  MINIMIUM FOSSIL FUEL COST($/WK) =',FOSSIL)
(A,P'$$$$,999,999V.')SKIP;
CUM_ORDER=ORDER(1);
CUM_FUEL(1)=FUEL(1)*ORDER(1);
DO I=2 TO K;
CUM_ORDER(I)=CUM_ORDER(I-1)+ORDER(I);
CUM_FUEL(I)=CUM_FUEL(I-1)+FUEL(I)*ORDER(I);
END;
 PUT EDIT(' INCREMENTAL STEP','STEP SIZE','CUMLATIVE SIZE','INCREM. GEN
ERATION',    'CUMLATIVE INCREM. GENERATION')(A, COL(24), A,COL(40),A,
COL(65),A,COL(90),A)SKIP(3);
 PUT EDIT('(MW)', '(MW)', 'CCST(MILLS/KWH)', 'COST($/HR)')
 (COL(26), A(4), COL(46), A(4), COL(65), A(15), COL(95), A(10));

 DO I=1 TO K;
PUT EDIT(I,ORDER(I),CUM_ORDER(I),FUEL(I),CUM_FUEL(I))(F(10),COL(20),
F(10),COL(40),F(10),COL(70),F(10,2),COL(95),F(10,2))    SKIP;
IF PECKING = 'YES' THEN
PUT FILE(PUNCH) EDIT(I,ORDER(I),CUM_ORDER(I),FUEL(I),CUM_FUEL(I))
(F(5), F(10), F(10), F(10,2), F(15)) SKIP;
END;
DCL TABLE(N2) FIXED BIN;
LOOP: DO JJJ=1 TO WEEKS;
GET FILE(LDMDL) LIST (DEMAND);
PUT LIST ('WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:')SKIP(3);
PUT LIST ('(INTERVAL BY INTERVAL, MW)')SKIP;
PUT  EDIT(DEMAND) (8 F(10), SKIP) SKIP;
DEMAND=DEMAND-BASE;
DEMAND=DEMAND-HYD;
DO JJ=1 TO N1;
IF DEMAND(JJ) < 0 THEN DEMAND(JJ)=0;
END;
PUT SKIP(2);
CALL PEAKERS(DEMAND,TRUE,N1,TIME,MONEY);
IF MODE='DUR' THEN DO;
```

```
                    CALL DURATN(DEMAND,WORK,TIME,TIM,DEMAN,N2,N1);
 PUT  SKIP(2) LIST(' OUTPUT FUNCTION FROM SUBROUTINE DURATION:');
PUT EDIT(DEMAN) (8 F(10),SKIP)SKIP;
DO I=1 TO TRUE;
 COD(I)=WORK(CODE(I));
END;  END;

IF MODE='CHR' THEN DO;
TIM=TIME;
DEMAN =DEMAND;
END;
PUT FILE(TRANSFR) LIST(WEEKS,TRUE,K,N2,    NUMBER,VP,
TIM, FUEL, CUM_FUEL, ORDER,CUM_ORDER,TRANSFORM,COD ,MODE,BTU,
 CAPACITY, DEMAN);
        /* L. P. INPUT SPECIFICICATION SECTION                  */
INCRE=0;
TABLE=0;
DEMAN=DEMAN -SUM(CAPACITY);
DO KK=1 TO N2;
DO KKK=1 TO K WHILE(CUM_ORDER(KKK) < DEMAN(KK));
END;
IF KKK=1 THEN GO TO BOT;
TABLE(KK)=KKK-1;
INCRE =INCRE +CUM_FUEL(KKK-1)*TIM(KK);
 BOT:  END;
MONEY=MONEY+FOSSIL;
PUT EDIT(' FOSSIL INCREMENTS, MUST RUN($/WK)', INCRE)
(SKIP(2), A, X(5), P'$$$,999,999V.');
PUT FILE(TRANSFR) LIST(MONEY,INCRE);
DEMAN=DEMAN+SUM(CAPACITY);
DO JJ=1 TO N2;
IF TABLE(JJ) > 0 THEN
DEMAN(JJ)=DEMAN(JJ)-CUM_ORDER(TABLE(JJ));
IF DEMAN (JJ) < 0 THEN DEMAN (JJ)=0;
END;
       PUT FILE(DATA) EDIT('NAME'    ,SYSTE,JJJ)
```

```
               (SKIP,COL(1),A,COL(15),A,P'99');
        PUT FILE(DATA) EDIT('ROWS')
               (SKIP,COL(1),A,COL(15),A);
        PUT FILE(DATA) EDIT('N','COST')
              (SKIP,COL(2),A,COL(5),A,P'999');
DO  I=1 TO N2;
        PUT FILE(DATA) EDIT('E','DEMAN',I)
              (SKIP,COL(2),A,COL(5),A,P'999');
END;
DO  I=1 TO NUMBER;
        PUT FILE(DATA) EDIT('L','NUCLR',I)
              (SKIP,COL(2),A,COL(5),A,P'999');
END;
         PUT FILE(DATA) EDIT('COLUMNS')
               (SKIP,COL(1),A,COL(15),A);
DO  J=1 TO N2;
         PUT FILE(DATA) EDIT('SEP',0,J,'''MARKER''','''SEPORG''')
              (SKIP,COL(5),A,P'99',P'999',COL(15),A,COL(40),A);
 DO P=TABLE(J )+1 TO K;
         PUT FILE(DATA) EDIT('FF'  ,J,P,'COST ',FUEL(P)*TIM (J))
              (SKIP,COL(5),A,P'999',P'999',    COL(15),A,
 COL(25),P'ZZZZZZZV.9999');
         PUT FILE(DATA) EDIT('FF'  ,J,P,'DEMAN',J,  +1.)
              (SKIP,COL(5),A,P'999',P'999',    COL(15),A,P'999',
 COL(25),P'ZZZZZZZV.9999');
END;
END;
              IF (VP=1 ) THEN
         PUT FILE(DATA) EDIT('ENDSEP','''MARKER''','''SEPEND''')
          (SKIP,COL(5),A(8),COL(15),A(8),COL(40),A(8));
DO  J=1 TO NUMBER;
DO  I=1 TO N2;
IF VP¬=1 THEN
         PUT FILE(DATA) EDIT('SNC',J,I,'''MARKER''','''SEPORG''')
              (SKIP,COL(5),A,P'99',P'999',COL(15),A,COL(40),A);
DO NN=1 TO VP;
```

```
        PUT FILE(DATA) EDIT('N',I,J,NN,  'DEMAN',I,1.)
              (SKIP,COL(5),A,P'999',P'99',P'9',COL(15),A,P'999',
 COL(25),P'ZZZZZZZV.9999')
                          ('N',I,J,NN,  'NUCLR',J,     EFFIC(NN,2)*
 TIM(I)*BTU(J)/B_T_U)
              (SKIP,COL(5),A,P'999',P'99',P'9',COL(15),A,P'999',
 COL(25),P'ZZZZZZZV.9999');
END;

END;
END;
IF VP¬=1 THEN
        PUT FILE(DATA) EDIT('ENDSEP','''MARKER''','''SEPEND''')
         (SKIP,COL(5),A(8),COL(15),A(8),COL(40),A(8));
       PUT FILE(DATA) EDIT
        ('RHS') (SKIP,COL(1),A,COL(15),A);
DCL (CHANGE(NUMBER),N_RHS(NUMBER)) FLOAT DEC;
N_RHS= TRUE*CAPACITY*LOAD*BTU;
CHANGE = TRUE* CAPACITY    * .05 * BTU;

DO I=1 TO WEEKS;
IF I=1 THEN GO TO NET;
GET FILE(LDMDL) LIST (DEMAN );
PUT LIST (' INPUT CUSTOMER DEMAND FUNCTION FOLLOWS:')SKIP(2);
PUT  EDIT(DEMAN ) (8 F(10), SKIP) SKIP;
DEMAN =DEMAN -BASE-HYD;
CALL PEAKERS(DEMAN ,TRUE,N2, TIM, MONEY);
MONEY=MONEY+FOSSIL;
PUT FILE(TRANSFR) LIST(DEMAN,MONEY,INCRE);
DO JJ=1 TO N2;
IF TABLE(JJ) > 0 THEN
DEMAN(JJ)=DEMAN(JJ)-CUM_ORDER(TABLE(JJ));
IF DEMAN (JJ) < 0 THEN DEMAN (JJ)=0;
END;

NET:
```

```
DO   J=1 TO N2;
        PUT FILE(DATA) EDIT
('RHS',   I  ,'DEMAN',J,DEMAN (J)   )
                (SKIP,COL(5),A,       P'999',COL(15),A,P'999',COL(25),
          P'-------V.9999');
END;
DO   J=1 TO NUMBER;
        PUT FILE(DATA) EDIT
('RHS',I,'NUCLR',J,N_RHS(J))
                (SKIP,COL(5),A,       P'999',COL(15),A,P'999',COL(25),
          P'-------V.9999');
END;
IF MODE='DUR' THEN I=WEEKS;
END;
IF PARAMETER=0 THEN GO TO SKIPP;
IF PARAMETER=1 THEN DO;
DO J=1 TO N2;
PUT FILE(DATA) EDIT('CHC',0,'DEMAN',J,DEMAN(J)/100)
                (SKIP,COL(5),A,       P'999',COL(15),A,P'999',COL(25),
          P'-------V.9999');
END;  END;
IF PARAMETER=2 THEN DO;
DO J=1 TO N2;
PUT FILE(DATA) EDIT('CHC',0,'DEMAN',J,  100)
                (SKIP,COL(5),A,       P'999',COL(15),A,P'999',COL(25),
          P'-------V.9999');
END;  END;
SKIPP:
DO I=1 TO NUMBER;
PUT FILE(DATA) EDIT('CHC',2*I-1,'NUCLR',I, CHANGE(I))
                (SKIP,COL(5),A,       P'999',COL(15),A,P'999',COL(25),
          P'-------V.9999');
PUT FILE(DATA) EDIT('CHC',2*I  ,'NUCLR',I,-CHANGE(I))
                (SKIP,COL(5),A,       P'999',COL(15),A,P'999',COL(25),
          P'-------V.9999');
END;
```

```
       PUT FILE(DATA) EDIT('BOUNDS')
               (SKIP,COL(1),A,COL(15),A);
DO  I=1 TO N2;
 DO J=TABLE(I )+1 TO K;
        PUT FILE(DATA) EDIT('UP','BOUND1','FF'  , I, J, ORDER(J))
              (SKIP,COL(2),A,COL(5),A,COL(15),A,P'999',P'999',
 COL(25),P'ZZZZZZZV.9999');
END;
END;
DO  I=1 TO NUMBER;
DO  J=1 TO N2;

DO NN=1 TO VP;
        PUT FILE(DATA) EDIT('UP','BOUND1','N',J,I,NN,CAPACITY(I)*EFFIC
  (NN,1))      (SKIP,COL(2),A,COL(5),A,COL(15),A,P'999',P'99',P'9',
 COL(25),P'ZZZZZZZV.9999');
END;


END;
END;
        PUT FILE(DATA) EDIT('ENDATA')
               (SKIP,COL(1),A,COL(15),A);
IF MODE='CHR' THEN JJJ=WEEKS;
END LOOP;
END;
GO TO TOP;
BOTTOM:
END NUC_OPT;
* PROCESS ;
 DURATN: PROC(OLD,CODE,TIME,TIM,POINT,STEPS,N1);
DCL (N1,MARKER(STEPS),TIME(*),TIM(*),TEE,I,J,CODE(*)) FIXED BIN;
DCL (SORT(N1),A,B,SUM, WORK(N1,2))
FIXED BIN(31), (STEPS,FIRST) FIXED BIN,
(OLD(*), POINT(*)) FIXED BIN(31,10),
(INTERVAL, HIGH, LOW) FIXED BIN(31),
```

```
ISORT EXTERNAL ENTRY( (*) FIXED BIN(31),FIXED BIN(31), FIXED BIN(31))
OPTIONS(FORTRAN INTER);

        /*   SET UP SORT                */
SORT=OLD;
DO I=1 TO N1;
SORT(I)=1000*SORT(I)+I;
END;

A=1;
B=N1;
CALL ISORT(SORT,A,B);
DO I=1 TO N1;
WORK(I,1)=SORT(N1+1-I)/1000;
WORK(I,2)=MOD(SORT(N1+1-I),1000);
END;
        /*   BREAK INTO INTERVALS       */
INTERVAL =(WORK(1,1)-WORK(N1,1))/STEPS;
J=0;
HIGH=WORK(1,1)+INTERVAL;
LOW=WORK(1,1); DO I=1 TO STEPS-1;
HIGH=HIGH -INTERVAL;
LOW = LOW - INTERVAL;
TOP: J=J+1;
IF  (WORK(J,1) <= HIGH) & (WORK(J,1) > LOW ) THEN GO TO TOP;
ELSE  J=J-1;
MARKER(I)=J;
END;
MARKER(STEPS)=N1;
        /*   SET MARKER                 */
FIRST=1;
DO I=1 TO STEPS;
TEE=0;
SUM=0      ;
DO J=FIRST TO MARKER(I);
SUM=SUM+WORK(J,1)*TIME(WORK(J,2));
```

```
TEE=TEE+TIME(WORK(J,2));
WORK(J,1)=I;
END;
IF                    TEE=0 THEN POINT(I)=0; ELSE
POINT(I)=SUM/TEE;
TIM (I)=TEE;
FIRST=MARKER(I)+1;
END;
DO I=1 TO N1;
SORT(I)=1000*WORK(I,2)+WORK(I,1);
END;
CALL ISORT(SORT,A,B);
DO I=1 TO N1;
CODE(I)=MOD(SORT(I),1000);
END;

RETURN;
END DURATN;
* PROCESS;
PEAKERS: PROC(DEMAND,TRUE,N1,TIME,OPERATIONS);
DCL ( TIME(*), N1,TRUE) FIXED BIN,    DEMAND(*) FIXED BIN(31,10),
( DEM(N1),DEMM(N1),MAX(2),
C_FACTOR, RATING, HEAT, F_COST, SUSD, TIME_LEFT) FLOAT BIN;
DCL P_NUM FIXED BIN, OPERATIONS FIXED BIN(31) ;
OPERATIONS=0;
GET FILE(PEAKS) LIST(P_NUM);
IF P_NUM = 0 THEN DO ;
 PUT EDIT( '  NO PEAKERS THIS WEEK')(A) SKIP(5);
GO TO NT;
END;
BEGIN;

DCL PEAK(N1,P_NUM) FLOAT BIN;
PEAK=0;
DEM=DEMAND;
DO K=1 TO P_NUM;
```

```
GET FILE(PEAKS) LIST(C_FACTOR, RATING,  HEAT, F_COST, SUSD);
PUT EDIT( ' CAPACITY FACTOR=',C_FACTOR,'RATED CAPACITY(MW)=', RATING,
'HEAT RATE(MMBTU/MWH)=', HEAT, 'FUEL COST($/MMBTU)=', F_COST,'SUSD COST
($)='
,SUSD)(A,F(5,2),X(3),A,F(4),X(3),A,  F(6,2),X(3),A,F(6,2),X(3),A,F(5))
SKIP;
DEMM=DEM;
TIME_LEFT=C_FACTOR*TRUE;
OPERATIONS=OPERATIONS+TIME_LEFT*RATING*HEAT*F_COST;
TOP:
MAX(1)=DEMM(1);
MAX(2)=1;
DO I=2 TO N1;
IF MAX(1) < DEMM(I) THEN DO;
MAX(1)=DEMM(I);
MAX(2)=I;
END;
END;
IF TIME(MAX(2)) < TIME_LEFT THEN DO;
TIME_LEFT=TIME_LEFT-TIME(MAX(2));
PEAK(MAX(2),K)=RATING;
DEMM(MAX(2))=0;
GO TO TOP;
END;
IF TIME(MAX(2)) = TIME_LEFT THEN DO;
PEAK(MAX(2),K)=RATING;
GO TO BOTTOM;
END;
PEAK(MAX(2),K)=RATING*TIME_LEFT/TIME(MAX(2));
BOTTOM:
DO I=1 TO N1;
DEM(I)=DEM(I)-PEAK(I,K);
END;
ON=0;
DO I=2 TO N1;
IF  ((PEAK(I,K) > 0) & ( PEAK(I-1,K) = 0) ) THEN ON=ON+TIME(I);
```

```
END;
OPERATIONS= OPERATIONS + ON*SUSD;
END;
PUT EDIT(' OPERATION COST OF PEAKERS= $',OPERATIONS)(COL(20),A,F(10,2))
 SKIP(2);

GET FILE(PEAKS) LIST (CODE);
PUT DATA(CODE);
IF CODE=0 THEN DO;
 PUT EDIT('  THE FOLLOWING DETAILS THE OPERATIONS MATRIX OF PEAKERS MAD
E AVAILABLE'       )(COL(10),A)SKIP(5);
PUT EDIT('TIME','DEMAND','TOTAL PEAKERS','PEAKER 1','PEAKER 2')
(COL(5),A, COL(15),A, COL(25) , A, COL(40),A,COL(50),A,COL(60),A)
SKIP(3);
DO I=1 TO N1;
PUT EDIT (I, DEMAND(I), DEMAND(I)-DEM(I), (PEAK(I,J) DO J=1 TO P_NUM))
(COL(5),F(3), COL(15), F(7)   , COL(25),F(8),10( X(6),F(4))) SKIP;
END;
END;

DEMAND=DEM;
END;
NT:
RETURN;
END PEAKERS;
* PROCESS;
 PECK_OR: PROC(BASE,R_ORDER,R_FUEL,K,BTU,TRANSFORM);


 DCL (ORDER(K),FUEL(K,2))FLOAT DEC(16), LOAD FLOAT DEC;
 DCL (MATCH,LABEL,TRANSFORM(*,2),FLAG(K) ) FIXED BIN,MIN(2) FLOAT DEC;
      DCL(N1,VP1,N2,VP2,N3,VP3)FIXED BIN;
 DCL (R_ORDER(*),R_FUEL(*), BTU) FLOAT DEC(16);

 GET FILE(PECK)
     LIST(N1,VP1,N2,VP2,N3,VP3);
```

```
PUT LIST(' THE FOLLOWING IS THE PECK FILE INPUT FOR LARGE,MEDIUM, SMALL
 FOSSIL PLANTS:');  PUT SKIP;
PUT DATA(N1,VP1,N2,VP2,N3,VP3);
PUT FILE(TRANSFR)
    LIST(N1,VP1,N2,VP2,N3,VP3);
BEGIN;
TRANSFORM=0;
FLAG=0;
DCL
  (NLGE(N1,4),NMED(N2,4),NSML(N3,4),L_HEAT(VP1),M_HEAT(VP2),S_HEAT(VP3)
 ,LGE_HEAT (VP1,2),MED_HEAT(VP2,2),SML_HEAT(VP3,2),COSTL(VP1),
 COSTM(VP2),COSTS(VP3))FLOAT DEC;
GET FILE(PECK)
    LIST(LGE_HEAT,MED_HEAT,SML_HEAT,NLGE,NMED,NSML);
PUT SKIP EDIT(' AVERAGE HEAT RATES FOR LARGE, MEDIUM AND SMALL FOSSIL P
LANTS: FRACTION OF RATED POWER, HEAT RATE(MMBTU/MWH)')(SKIP,A)
(LGE_HEAT)(SKIP,20 F(6,2))
(MED_HEAT)(SKIP,20 F(6,2))
(SML_HEAT)(SKIP,20 F(6,2)) ;
PUT EDIT(' PLANT PARAMETERS FOR LARGE, MEDIUM AND SMALL FOSSIL PLANTS:
')(SKIP(2),A);
 PUT SKIP LIST(' NUMBER,  CAPACITY(MW),  HEAT RATE(MMBTU/MWH), FUEL COS
T($/MMBTU)');
PUT EDIT
(NLGE)(SKIP(2), 20( 4 F(10,2),SKIP))
(NMED)(SKIP(2), 20( 4 F(10,2),SKIP))
(NSML)(SKIP(2), 20( 4 F(10,2),SKIP))   ;
CALL INPUT_OUTPUT(LGE_HEAT,VP1,L_HEAT,COSTL);
CALL INPUT_OUTPUT(MED_HEAT,VP2,M_HEAT,COSTM);
CALL INPUT_OUTPUT(SML_HEAT,VP3,S_HEAT,COSTS);

INPUT_OUTPUT: PROC(START,VP,FINISH,COST);
DCL VP FIXED BIN,(START(* ,2),       FINISH(*),COST(*)) FLOAT DEC;
FINISH(1)=START(1,1);
DO I=2 TO VP;
FINISH(I)=START(I,1)-START(I-1,1);
```

```
END;
COST(1)=START(1,2);
DO I=2 TO VP;
COST(I)=(START(I,1)*START(I,2)-START(I-1,1)*START(I-1,2))/FINISH(I);
END;
END;

BASE=0;
K=0;
BTU=0;
DO I=1 TO N1;
LOAD=NLGE(I,2)*LGE_HEAT(1,1)*NLGE(I,1);
BTU=BTU+COSTL(1)*LOAD*NLGE(I,3)*NLGE(I,4)/LGE_HEAT(VP1,2);
BASE=BASE+LOAD;
END;
DO I=1 TO N2;
LOAD=NMED(I,2)*MED_HEAT(1,1)*NMED(I,1);
BTU=BTU+COSTM(1)*LOAD*NMED(I,3)*NMED(I,4)/MED_HEAT(VP2,2);
BASE=BASE+LOAD;
END;
DO I=1 TO N3;
LOAD=NSML(I,2)*SML_HEAT(1,1)*NSML(I,1);
BTU=BTU+COSTS(1)*LOAD*NSML(I,3)*NSML(I,4)/SML_HEAT(VP3,2);
BASE=BASE+LOAD;
END;


DO J=2 TO VP1;
DO I=1 TO N1;
K=K+1;
LOAD=NLGE(I,2)*L_HEAT(J)*NLGE(I,1);
ORDER(K)=LOAD;
FUEL(K,1)=
   NLGE(I,4)*COSTL(J)*NLGE(I,3)/LGE_HEAT(VP1,2);
FUEL(K,2)=10*  (    +I)+J-1;
END;
```

```
END;
DO J=2 TO VP2;
DO I=1 TO N2;
K=K+1;
ORDER(K)=  NMED(I,2)*M_HEAT(J)*NMED(I,1);
FUEL(K,1)=
   NMED(I,4)*COSTM(J)*NMED(I,3)/MED_HEAT(VP2,2);
FUEL(K,2)=10*(N1    +I)+J-1;
END;
END;
DO J=2 TO VP3;
DO I=1 TO N3;
K=K+1;
ORDER(K)=NSML(I,2)*S_HEAT(J)*NSML(I,1);
FUEL(K,1)=
NSML(I,4)*COSTS(J)*NSML(I,3)/SML_HEAT(VP3,2);
FUEL(K,2)=10*(N1+N2+I)+J-1;
END;
END;
GET FILE(PECK)
    LIST(EMERG,E_COST);
K=K+1;
ORDER(K)=EMERG;
FUEL(K,1)=E_COST;
FUEL(K,2)=10*(N1+N2+N3+1)+1;

DO J=1 TO K;
AGAIN:
MIN(1)=FUEL(1,1);
MIN(2)=1;
DO I=2 TO K;
IF  (MIN(1)>FUEL(I,1)) & FLAG(I)=0 THEN DO;
MIN(1)=FUEL(I,1);
MIN(2)=I;
END;
END;
```

```
LABEL=FUEL(MIN(2),2);
IF MOD(LABEL,10)=1 THEN GO TO PLACE;
MATCH=LABEL-1;
DO PP=1 TO J;
IF MATCH=TRANSFORM(PP,2) THEN GO TO PLACE;
END;
FLAG(MIN(2))=1;
GO TO AGAIN;
PLACE: FUEL(MIN(2) ,1)=1000.;
R_FUEL(J)=MIN(1);
TRANSFORM(J,1)=MIN(2);
TRANSFORM(J,2)=FUEL(MIN(2),2);
R_ORDER(J)=ORDER(MIN(2));
FLAG=0;
END;
RETURN;

END PECK_OR;
//L.SYSLIB  DD  DSN=SYS5.MATHLIB.SUBR,DISP=SHR
//      DD
//      DD
//      DD
//      DD     DSN=SYS1.FORTLIB,DISP=SHR
//      DD     DSN=SYS2.SSP.SUBR,DISP=SHR
//SYSLMOD  DD DSN=U.M9960.8981.TEST1.LIBRARY.LMOD(NUCLEAR),DISP=OLD,
// DCB=BLKSIZE=13030,SPACE=
 PUMP_ST:
   PROC OPTIONS(MAIN);
 /* THIS PROGRAM REFORMATS THE NUCLEAR L.P. OPTIMIZATION SOLUTION AND
 CALLS THE DESIRED P.S. SUBROUTINES TO CALCULATE THE P.S. GENERATION
 SCHEDULE. THE INCREMENTAL FOSSIL CAPACITY FACTORS ARE ALSO CALCULATED
 BELOW. THE ALGORITHM OF THIS PROGRAM IS DESCRIBED IN THE APPENDIX OF
 RAY ENG'S PH.D THESIS, MIT DEPT. OF NUCLEAR ENGINEERING. ******/
   DCL
      MODE CHAR(4),
      INCRE FIXED BIN(31,5);
```

```
  DCL
     (MONEY,
     Z) FIXED BIN(31);
  DCL
     (M1,
     M2,
     M3(6),
     COUNT,
     I,
     J,
     K,
     WEEKS,
     N1,
     CUM,
     NN,
     NUMBER,
     VP,
     CODE) FIXED BIN;
  DCL
     RATIO FIXED DEC(5,3);
  DCL
     (RESERIOR,
     CAP_PUMP,
     CAPACITY,
     FREE,
     BYE,
     TOLERANCE,
     START) FIXED DEC;
     Z=0;
     ON ENDFILE(TRANSFR)
        GO TO BOTTOM;
     ON ENDFILE(SYSIN)
        GO TO BOTTOM;
PEAK:
     COUNT=0;
/*      FOSSIL PLANT PARAMETERS        */
```

```
    GET FILE(TRANSFR) LIST(M3);
    PUT SKIP LIST(' ENTER P.S. MODE AND P.S. CODE');
/*  ENTER PUMPED STORAGE OPERATION MODE AND OUTPUT CODE */
    GET FILE(SYSIN) LIST( MODE, CODE)COPY;
    PUT FILE(SYSPRINT) LIST(' ENTER PUMPED STORAGE PARAMETERS:')
    SKIP;
    PUT FILE(SYSPRINT)
    LIST(
    ' CAPACITY, RATIO, CAP_PUMP, RESERIOR, FREE, START,BYE,TOLERANCE')
    ;
    GET FILE(SYSIN) LIST (
     CAPACITY,RATIO,CAP_PUMP,RESERIOR ,FREE,START,BYE,TOLERANCE)COPY;
TOP:
    GET FILE(TRANSFR) LIST( WEEKS,N1,CUM,NN,NUMBER,VP);
BLOCK:
    BEGIN;
  DCL
    BTU(NUMBER) FIXED DEC(5,4);
  DCL
    NUC_CAP(NUMBER) FIXED DEC,
    LOAD(N1) FIXED DEC,
    (TIME(NN),
    TRANSFORM(CUM,2),
    INCREMENT(CUM),
    ORDER(N1)) FIXED BIN,
    (CUM_FUEL(CUM) ,
    STEP(CUM),
    CUM_STEP(CUM)) FIXED DEC,
    CHAR CHAR(3);
  DCL
    FUEL(CUM) FIXED DEC(5,3);
  DCL
    ALLOT(WEEKS) FIXED BIN,
    (DEMAND(NN),
    NUCLEAR(NN,NUMBER),
    FOSSIL(NN)) FIXED BIN(31,5),
```

```
    TEMP FLOAT DEC(8),
    TEM FIXED BIN(31,5);
       GET FILE(TRANSFR)
       LIST(TIME,FUEL ,CUM_FUEL,STEP,CUM_STEP,TRANSFORM, ORDER,CHAR,
       BTU, NUC_CAP,DEMAND,MONEY, INCRE);
       PUT SKIP(3);
       PUT SKIP LIST(' ENTER NUMBER OF WEEKLY PERMUTATIONS');
       IF CHAR='CHR' THEN
          GET FILE(SYSIN) LIST (ALLOT)COPY;
       ELSE
          GET FILE(SYSIN) LIST(ALLOT(1))COPY;
 DCL
    STRANG CHAR(80);
       PUT SKIP LIST(' SIMULATION DESCRIPTION: ');
       GET LIST(TEM);
       DO I=1 TO TEM;
          GET LIST(STRANG) COPY;
       END;
LOOP:
       DO M1=1 TO WEEKS;
          IF M1>1 THEN
             GET FILE(TRANSFR) LIST(DEMAND,MONEY, INCRE);
LOOP_TWO:
          DO M2=1 TO ALLOT(M1);
             PUT FILE(SYSPRINT) EDIT (
              ' OPTIMAL NUCLEAR GENERATION SCHEDULE')(A) SKIP(4);
             PUT FILE(SYSPRINT) EDIT (
              'FOR',COUNT+1,' WEEK;', M2,' ALLOCATION') (
              SKIP,A,F(5),A,F(5),A);
             Z=Z+1;
             PUT FILE(SYSPRINT) EDIT('INDEX=',Z)(X(30),A(6), F(10));
/* ************* L. P. SOLUTION READER ******************* */
/* THIS SECTION INTERPETS THE MPSX L.P. SOLUTION INTO A USABLE
FORMAT. THE L.P. SOLUTION FORMAT IS DEPENDENT UPON THE OUTPUT
INSTRUCTIONS USED IN THE MPSX CONTROL LANGUAGE PROGRAM, AND HENCE
UNDER USER CONTROL. THIS SECTION WILL READ THE OUTPUT PRODUCED BY THE
```

```
"SOLUTION" COMMAND SHOWN IN THE SAMPLE JOBS ILLUSTRATED IN THE
APPENDIX OF RAY ENG'S THESIS. */
  DCL
     1 SOL BASED(R),
        2 ACTIVE FLOAT DEC(8),
        2 DUAL FLOAT DEC(8),
        2 MAME CHAR(8);
  DCL
     1 SOLE BASED(Q),
        2 ACTIVITY FLOAT DEC(8),
        2 NAME CHAR(8);
  DCL
     1 ANS BASED (T),
        2 ALPHA (10) CHAR(8),
        2 REAL(3) FLOAT DEC(4),
        2 INTEGER(3) FIXED BIN(31),
        2 ALPH(4) CHAR(4),
        2 TITLE CHAR(80);
  DCL
     ECO EXTERNAL ENTRY(FIXED BIN, FIXED BIN,(*) FIXED DEC, FIXED BIN,
              (*) FIXED DEC, (*) FIXED DEC(5,3), CHAR(4), FIXED DEC,
  FIXED DEC(5,3), FIXED DEC, FIXED DEC, FIXED DEC, FIXED DEC, FIXED DEC
              ,FIXED DEC);
              READ FILE(SOLN) IGNORE(4);
              READ FILE(SOLN) SET(T);
              PUT FILE(SYSPRINT) EDIT(' L.P. PARAMETERS' )(
               SKIP,COL(10),A) ( 'OBJECTIVE  FUNCTION', ALPHA(3)) (
               SKIP,COL(5),A,COL(30),A) ('RHS',ALPHA(4)) (
               SKIP,COL(5),A,COL(30),A) ('STATUS',ALPH(2)) (
               SKIP,COL(5),A,COL(30),A) (
               'NUMBER  OF ITERATIONS',INTEGER(1)) (
               SKIP,COL(5),A,COL(30),A) ;
              PUT FILE(SYSPRINT)
              EDIT('FIXED FOSSIL FUEL COST($/WK)', MONEY + INCRE) (
               SKIP, COL(1),A, COL(35), P'$$$,999,999V.') (
               'VARIABLE FOSSIL FUEL COST($/WK)', REAL(1))(
```

```
 COL(50) , A, COL(85), P'$$$,$$$,999V.');
PUT FILE(SYSPRINT) EDIT (
 ' SYSTEM COST WITHOUT PUMPED STORAGE,',
MONEY + INCRE+ REAL(1) ) (A,P'$$$$,999,999V.')SKIP;
READ FILE(SOLN) IGNORE(5+NN);
PUT FILE(SYSPRINT)
EDIT('REACTOR',
'NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)') (
 COL(5),A,COL(20),A)SKIP(3);
IF VP=1 THEN
   PUT FILE(SYSPRINT) EDIT('OCNP  (MILLS/KWH)' ) (
    COL(75), A);
DO J=1 TO NUMBER;
   READ FILE(SOLN) SET(R);
   PUT FILE(SYSPRINT) EDIT(J,DUAL/10.)  (
    SKIP,COL(5),F(5), COL(25),F(8,2));
   IF VP=1 THEN
      PUT FILE(SYSPRINT) EDIT(DUAL*BTU(J)) (
       COL(80), F(8,2));
END;
READ FILE(SOLN) IGNORE(4);
FOSSIL=0;
DO J=1 TO NUMBER;
   DO I=1 TO NN;
      TEMP=0;
      DO K=1 TO VP;
         READ FILE(SOLN) SET(Q);
         TEMP=TEMP+ACTIVITY;
      END;
      TEM=TEMP;
      FOSSIL(I)=FOSSIL(I)+TEM;
      NUCLEAR(I,J)=TEM;
   END;
END;
FOSSIL=DEMAND-FOSSIL;
PUT FILE(SYSPRINT) SKIP(3)
```

```
             LIST('NUCLEAR UNIT DISPATCHING: ');
             PUT FILE(SYSPRINT) SKIP
             EDIT('INTERVAL  WEIGHTING FACTOR')(A);
             PUT FILE(SYSPRINT)
             EDIT('DEMAND','FOSSIL','NUCLEAR 1','NUCLEAR 2',
             'NUCLEAR 3','...') (X(5), 3( A,X(9 )),3(A,X(9 )));
             PUT SKIP EDIT (
             '(HOURS)', '(MW)', '(MW)', '(MW)', '(MW)', '(MW)')(
             COL(14),A(7), COL(33), A(4), X(11), A(4),
             3(X(13), A(4)));
             DO I=1 TO NN;
                PUT FILE(SYSPRINT)
                EDIT( I, TIME(I), DEMAND(I), FOSSIL(I),(
                 NUCLEAR(I,J) DO J=1 TO NUMBER)) (
                 F(5),F(12),F(20), F(15), 4 F(17))SKIP;
             END;
             READ FILE(SOLN) IGNORE(2);
/*   END OF L.P. READER SECTION    */
/* MODE OF OPERATION OF PUMPED STORAGE UNIT IS CHOSEN: (1) IF "NONE",
THEN NO P.S. UNIT IS SCHEDULED, THE PROGRAM CONTINUES WITH
CALCULATING THE FOSSIL INCREMENTAL CAPACITY FACTORS; (2) IF "QUCK",
THEN NO FURTHER PROCESSING (NO P.S. SCHEDULING, AND NO INCREMENTAL
FOSSIL CAPACITY FACTOR CALCULATIONS); (3) IF "ECO", THEN THE ECONOMIC
PUMPED STORAGE ALGORITHM IS CALLED; (4) IF "SEC", THEN THE SECURITY
P.S. ALGORITHM IS CALLED. ********************/
             DO I=1 TO N1;
                LOAD(I)= FOSSIL(ORDER(I));
             END;
             IF MODE='NONE' THEN
                GO TO REPORT;
             IF MODE='QUCK' THEN
                GO TO SHORT_CUT;
             PUT SKIP(2) LIST('PUMPED STORAGE STATISTICS:');
             IF MODE='ECO' | MODE='SEC' THEN
                CALL
                ECO(N1,CUM, LOAD,CODE, CUM_STEP,FUEL, MODE, CAPACITY,
```

```
               RATIO, CAP_PUMP, RESERIOR, FREE, START, BYE,
               TOLERANCE);
/*   PUMPED STORAGE GENERATION COST CALCULATIONS   */
  DCL
     INCREMENTAL_FOSSIL_FUEL_COST FIXED DEC(15,2);
  DCL
     P FIXED BIN;
              INCREMENTAL_FOSSIL_FUEL_COST=0;
              DO I=1 TO N1;
                -DO P=1 TO CUM;
                   IF LOAD(I) < CUM_STEP(P) THEN
                      GO TO TT;
                END;
TT:
                IF P=1 THEN
                   INCREMENTAL_FOSSIL_FUEL_COST=
                   INCREMENTAL_FOSSIL_FUEL_COST +LOAD(I)*FUEL(P);
                ELSE
                   INCREMENTAL_FOSSIL_FUEL_COST=
                   INCREMENTAL_FOSSIL_FUEL_COST+CUM_FUEL(P-1) +(
                    LOAD(I)-CUM_STEP(P-1))*FUEL(P);
              END;
              PUT SKIP(3) LIST('FOSSIL INCREMENTS RESULTS:');
              PUT FILE(SYSPRINT)
              EDIT( ' INCREMENTAL FOSSIL  FUEL COST=',
              INCREMENTAL_FOSSIL_FUEL_COST)(A,P'$$$$,999,999V.' ) SKIP;
              PUT SKIP
              EDIT(' WEEKLY SYSTEM PRODUCTION COST=',
              MONEY + INCREMENTAL_FOSSIL_FUEL_COST) (
              A, P'$$$$,999,999V.');
/*  *************** REPORT GENERATOR ************************** */
/*        OF FOSSIL INCREMENTAL CAPACITY FACTORS   *   */
  DCL
     P_FACTOR(CUM) FLOAT DEC;
  DCL
     CAP_FACTOR(CUM) FLOAT DEC;
```

```
 DCL
    MATRIX (N1,CUM) FLOAT BIN;
REPORT:
              PUT SKIP(4) LIST(' REACTORS        DCNP (MILLS/KWH)');
              DO I=1 TO NUMBER;
                 TEM=0;
                 TEMP=0;
                 DO J=1 TO N1;
                    IF (NUCLEAR(ORDER(J), I) < ( NUC_CAP(I) -1) ) & (
                    NUCLEAR(ORDER(J), I) > 0) THEN
                       DO;
                          TEMP=TEMP + LOAD(J) ;
                          TEM = TEM + 1;
                       END;
                 END;
                 IF TEM>0 THEN
                    TEMP=TEMP/TEM;
                 DO K=1 TO CUM WHILE(CUM_STEP(K) < TEMP);
                 END;
                 PUT SKIP EDIT(I, FUEL(K)) (F(5), X(10), F(5,2));
              END;
              MATRIX=0;
              DO I=1 TO N1;
                 DO J=1 TO CUM;
                    IF LOAD(I)< CUM_STEP(J) THEN
                       GO TO NEXT;
                 END;
NEXT:
                 IF J=1 THEN
                    GO TO NXT;
                 DO K=1 TO J-1;
                    MATRIX(I,K)=1;
                 END;
                 IF LOAD(I)= CUM_STEP(J-1) THEN
                    GO TO XT;
NXT:
```

```
                  MATRIX(I,J)=1 * (
                   1 - (CUM_STEP(J)-LOAD(I))/STEP(J));
XT:
               END;
               DO I=1 TO CUM;
                  TEMP=0;
                  DO J=1 TO N1;
                     TEMP=TEMP+MATRIX(J,I);
                  END;
                  P_FACTOR(I)=TEMP;
               END;
               P_FACTOR= P_FACTOR/N1;
               IF CODE=0 THEN
                  PUT FILE(PUNCH) EDIT(P_FACTOR)(10 F(8,3),SKIP)SKIP;
               PUT FILE(SYSPRINT) DATA(CODE)SKIP(2);
               PUT FILE(SYSPRINT) SKIP
               LIST( ' ECONOMIC LOADING ORDER CAPACITY FACTORS FOLLOWS')
               ;
               PUT FILE(SYSPRINT) EDIT( P_FACTOR)(10 F(8,3),SKIP)SKIP;
/* ABOVE, THE INCREMENTAL FOSSIL CAPACITY FACTORS OF THE ECONOMIC
LOADING ORDER IS CALCULATED AND PRINTED. BELOW, THE INCREMENTS ARE
ASSIGNED BACK TO THEIR ORIGINAL POWER STATIONS, AND THE AVERAGE
CAPACITY FACTOR OF A STATIONS UPPER INCREMENTS ARE CALCULATED AND
PRINTED. ***********/
               DO I=1 TO CUM;
                  CAP_FACTOR(TRANSFORM(I,1))=P_FACTOR(I);
                  INCREMENT(TRANSFORM(I,1))=STEP(I);
               END;
               PUT FILE(SYSPRINT) EDIT('LARGE FOSSIL PLANTS')(
               COL(2),A) SKIP(2);
               DO J=1 TO M3(1);
                  TEMP=0;
                  DO I=0 TO M3(2)-2;
                     TEMP=TEMP+CAP_FACTOR(I*M3(1)+J)*
                     INCREMENT(I*M3(1)+J);
                  END;
```

```
   TEM=0;
   DO I=0 TO M3(2)-2;
      TEM=TEM+INCREMENT(I*M3(1)+J);
   END;
   TEMP=TEMP/TEM;
   PUT FILE(SYSPRINT)
   EDIT('AVERAGE INCREMENTAL CAPACITY FACTOR OF UNIT ',J,
   TEMP)(X(5),A,F(3),F(10,3))SKIP;
END;
K=M3(1)*(M3(2)-1);
PUT FILE(SYSPRINT) EDIT('MEDIUM FOSSIL PLANTS')(
COL(2),A) SKIP(2);
DO J=1 TO M3(3);
   TEMP=0;
   TEM=0;
   DO I=0 TO M3(4)-2;
      TEM=INCREMENT(I*M3(3)+J+K)+TEM;
   END;
   DO I=0 TO M3(4)-2;
      TEMP=TEMP+CAP_FACTOR(I*M3(3)+J+K)*
      INCREMENT(I*M3(3)+J+ K);
   END;
   TEMP=TEMP/TEM ;
   PUT FILE(SYSPRINT)
   EDIT('AVERAGE INCREMENTAL CAPACITY FACTOR OF UNIT ',J,
   TEMP)(X(5),A,F(3),F(10,3))SKIP;
END;
PUT FILE(SYSPRINT) EDIT('SMALL FOSSIL PLANTS')(
COL(2),A) SKIP(2);
K=M3(3)*(M3(4)-1)+K;
DO J=1 TO M3(5);
   TEMP=0;
   TEM=0;
   DO I=0 TO M3(6)-2;
```

```
            TEM=STEP(I*M3(5)+J+K)+TEM;
         END;
         DO I=0 TO M3(6)-2;
            TEMP=TEMP+CAP_FACTOR(I*M3(5)+J+K)*
            STEP(I*M3(5)+J+K);
         END;
         TEMP=TEMP/TEM ;
         PUT FILE(SYSPRINT)
         EDIT('AVERAGE INCREMENTAL CAPACITY FACTOR OF UNIT ',J,

         TEMP)(X(5),A,F(3),F(10,3))SKIP;
      END;
      PUT FILE(SYSPRINT) SKIP(5);
/* THE ARRAY VARIABLE "MATRIX" CONTAINS THE DETAILED HOURLY
GENERATION SCHEDULE OF ALL THE FOSSIL INCREMENTS IF THIS SCHEDULE IS
DESIRED, THIS SECTION MAY BE ALTERED TO PRINT THE VALUES OF "MATRIX".
**********/
      PUT FILE(SYSPRINT) SKIP DATA(CODE);
      IF CODE=0 THEN
         DO;
            PUT FILE(SYSPRINT)
            EDIT(
            'OPERATIONS MATRIX OF FOSSIL INCREMENTS FOLLOWS')
            ( COL(2),A);
            PUT FILE(SYSPRINT)
            EDIT(
    ' I-TH TIME PERIOD --> ROW I,  J-TH INCREMENT --> COLUMN J'
             ) (
            A);
            PUT FILE(SYSPRINT) SKIP
            LIST(
            ' ONLY NON TRIVIAL MATRIX ELEMENTS ARE LISTED');
            PUT FILE(SYSPRINT) SKIP;
            DO I=1 TO N1;
               DO J=1 TO CUM WHILE(MATRIX(I,J)=1);
               END;
```

```
                    PUT FILE(SYSPRINT) DATA(MATRIX(I,J));
                 /*END*/
              /*END*/
SHORT_CUT:
           END LOOP_TWO;
           IF CHAR='DUR' THEN
              M1=WEEKS;
           COUNT=CCUNT+1;
        /*END*/
     END LOOP;
  END BLOCK;
/*  READ NEXT SET OF PARAMETERS                    */
  IF COUNT= WEEKS THEN
     GO TO PEAK;
  GO TO TOP;
BOTTOM:
  PUT FILE(SYSPRINT) EDIT(' NORMAL END')(A) SKIP;
/*END*/
 END PUMP_ST;
ECO :
 PROC (
 N1, CUM, NEW,CODE, CUM_STEP, FUEL, MODE, CAPACITY, RATIO, CAP_PUMP,
 RESERIOR, FREE, START, BYE, TOLERANCE);
/* THIS SUBPROGRAM PERFCRMS THE ECONOMIC PUMPED STORAGE SCHEDULING
ALGORITHM. THE DETAILED FLOW CHART IS PRESENTED IN RAY ENG'S THESIS.
THE ROLE OF THE VARIOUS VARIABLES USED ARE EXPLAINED BELOW
*************************************************************/
 DCL
    MODE CHAR(4);
 DCL
    (N1,
    CUM) FIXED BIN;
 DCL
    (P,
    N,
    M,
```

```
   KK) FIXED BIN;
DCL
   STORE(N1) FIXED DEC(15,2),
   (MAX(2),
   SUN(N1),
   ACCUM,
   MAKEUP,
   MIN(2),
   II_COST,
   INDEX_COST,
   SUN_VALUE) FIXED DEC(9,2);
DCL
   (F(CUM),
   A(CUM),
   CODE,
   PP) FIXED BIN;
DCL
   (CUM_STEP(*),
   A_CUM(CUM),
   LOAD(N1),
   NEW(*),
   FOS(N1),
   ORDER(N1)) FIXED DEC,
   TEMP FIXED DEC(15),
   (RATIO,
   FUEL(*)) FIXED DEC(5,3);
DCL
   (RESERIOR,
   CAP_PUMP,
   CAPACITY,
   FREE,
   BYE,
   TOLERANCE,
   START) FIXED DEC;
DCL
   F_COST (CUM) FIXED DEC(15);
```

```
 DCL
    SECURIT EXTERNAL ENTRY( (*) FIXED DEC, (*) FIXED DEC, FIXED DEC(5,
 3), FIXED DEC, FIXED DEC, FIXED DEC, FIXED DEC, FIXED BIN, FIXED DEC,
     FIXED DEC);
/* THE FOLLOWING SECTION IS A SORTING PROCESS TO FORM A LOAD DURATION
CURVE IN THE ARRAY VARIABLE "LOAD". "FOS" STORES THE ORIGINAL
CHRONOLOGIC DEMAND DATA AND "NEW" STORES THE NEW FOSSIL GENERATION
SCHEDULE, AFTER THE PUMPED STORAGE SCHEDULING.
***************************/
    FOS=NEW;
    DO I=1 TO N1;
       MAX(1)=FOS(1);
       MAX(2)=1;
       DO J=2 TO N1;
          IF MAX(1) < FOS(J) THEN
             DO;
                MAX(1)=FOS(J);
                MAX(2)=J;
             END;
       END;
       LOAD(I)=MAX(1);
       ORDER(I)=MAX(2);
       FOS( MAX(2) ) = -I;
    END;
    FOS=NEW;
    A,A_CUM=0;
    DO II=1 TO CUM WHILE(CUM_STEP(II)<LOAD(N1));
    END;
    DO PP=II TO CUM;
       DO J=1 TO N1 WHILE( LOAD(J) > CUM_STEP(PP));
       END;
       IF J=N1+1 THEN
          GO TO TEN;
       STORE=0;
       A(PP)=J;
/* "A(PP)" STORES THE LOCATION OF THE LOAD DURATION INTERVAL JUST
```

```
UNDER THE PP-TH FOSSIL INCREMENT. *******/
         DO K=J TO N1;
            STORE(K) = CUM_STEP(PP) - LOAD(K);
            IF STORE(K) > CAP_PUMP THEN
               STORE(K) = CAP_PUMP;
         END;
         A_CUM(PP) = SUM(STORE);
/* A_CUM(PP) RECORDS THE AMOUNT OF PUMPING ENERGY SCHEDULED WHEN THE
PP-TH INCREMENT IS THE HIGHEST COST OF THE PUMPING ENERGY SUPPLIED.
*****************************/
TEN:
      END;
/* "F(K)" RECORDS THE POSITION OF THE LOWEST LOAD DURATION INTERVAL
IN THE K-TH INCREMENT. **************/
      MAKEUP=1;
      SUN=0;
      F_COST=-FREE;
      DO K=CUM-1 TO 1 BY -1;
         DO I=1 TO N1 WHILE( CUM_STEP(K) < LOAD(I));
         END;
         IF I=1 THEN
            GO TO ED;
         STORE=0;
         F(K+1)=I-1;
         DO J=1 TO I-1;
            STORE(J)=-CUM_STEP(K)+LOAD(J);
            IF STORE(J) > CAPACITY THEN
               STORE(J)=CAPACITY;
         END;
         F_COST(K+1)=SUM(STORE)-FREE;
/* "F_COST(K)" RECORDS THE AMOUNT OF STORED ENERGY TO PEAK SHAVE UP
TO AND INCLUDING THE K-TH INCREMENT. */
ED:
      END;
/* BELOW, A SPECIAL SECTION TO CALCULATE "F_COST(1)" AND "F(1)". */
      DO I=1 TO N1;
```

```
         IF LOAD(I) > CAPACITY THEN
            STORE(I) = CAPACITY;
         ELSE
            STORE(I)=LOAD(I);
      END;
      F_COST(1)=SUM(STORE);
      F(1)=N1;
      DO KK=CUM TO 2 BY -1 WHILE ( F_COST(KK) <= 0);
      END;
/* "KK" RECORDS THE INCREMENT LEVEL WHERE PUMPING COMES INTO PLAY,
WHEREAS, THE FREE WATER INFLOW DID ALL THE PEAK SHAVING BEFORE THE
KK-TH LEVEL WAS REACHED. */
/* THE FOLLOWING SECTION CALCULATES THE INITIAL ITERATION POINT,
LEVEL K AS SHOWN IN FIGURE 4.20 IN RAY ENG'S THESIS. "SUN(I)"
REPRESENTS THE AMOUNT OF GENERATION REQUIRED TO PEAK SHAVE TO THE
I-TH LOAD DURATION INTERVAL. "ACCUM" REPRESENTS THE COMPLEMENTARY
PUMPING ENERGY. */
      DO I=1 TO N1;
         TEMP=0;
         IF I=1 THEN
            GO TO PASS;
         DO J=1 TO I-1;
            IF LOAD(J)-CAPACITY > LOAD(I) THEN
               TEMP=TEMP+CAPACITY;
            ELSE
               TEMP=TEMP+LOAD(J)-LOAD(I);
         END;
PASS:
         SUN(I)=TEMP-FREE;
         STORE=0;
         DO J=I TO N1;
            STORE(J)=LOAD(I)-LOAD(J);
            IF STORE(J) > CAP_PUMP THEN
               STORE(J)=CAP_PUMP;
         END;
         ACCUM=SUM(STORE);
```

```
         IF SUN(I) > RATIO*ACCUM THEN
            GO TO COST;
      END;
/*    INTRODUCE COST CONSTRAINT *******/
COST:
      DO P=1 TO CUM WHILE( LOAD(I) > CUM_STEP(P));
      END;
      IF P=CUM+1 THEN
         P=CUM;
/* "INDEX_COST" IS THE COST OF ENERGY BEING REPLACED AND "II_COST" IS
THE COST OF THE ENERGY BEING SUPPLIED*/
NXT:
      INDEX_COST=FUEL(P);
      II_COST=INDEX_COST * RATIO;
      DO PP=CUM TO 1 BY -1;
         IF FUEL(PP) <= II_COST THEN
            GO TO NET;
      END;
TEST: /* COST CONSTRAINT SET AT THIS LEVEL INDICATES PUMPING MAY NOT
BE ECONOMIC ************/
      P=P+1;
      SUN_VALUE=0;
      IF P > KK THEN
         DO;
            PUT SKIP LIST(' PUMPING NOT ECONOMICAL');
            GO TO NO_PUMP;
/* AFFIRMATIVE RESULT, PUMPING NOT ECONOMIC */
         END;
      GO TO NXT;
/* INCREASE LEVEL P, AND TEST AGAIN             */
NET:
      ACCUM=A_CUM(PP);
      IF ACCUM=0 THEN
         GO TO TEST;
      SUN_VALUE=ACCUM*RATIO;
      DO K=CUM TO 2 BY -1 WHILE( F_COST(K) < SUN_VALUE);
```

```
     END;
     IF FUEL( K)= INDEX_COST THEN
        DO;
           KK=K;
           GO TO SOLUTION;
        END;
     IF FUEL(K) > INDEX_COST THEN
        DO;
/* SLACK IN PUMPED STORAGE ENERGY UTILIZATION CALCULATED, TRY AGAIN
FOR HIGHER UTILIZATION. "MAKEUP" IS TEMPORARY STORAGE OF THE LAST
CALCULATED PUMPED STORAGE PUMPING LEVEL. ***********/
           MAKEUP=PP;
           P=P+1;
           GO TO NXT;
        END;
/* IF FUEL(K) < INDEX_COST THEN DO */
/* MAXIMUM ECONOMIC PUMPED STORAGE ENERGY UTILIZATION */
/* COST CONSTRAINT VIOLATED, TOO MUCH ENERGY SCHEDULED.
****************************************************** FOR THE CASE OF
TOO MUCH WATER PUMPED, THE PEAK SHAVING SCHEDULE IS FIXED, AND THE
WATER PUMPED IS ADJUSTED FROM THE GENERATION SCHEDULE */
     IF F_COST(P) >= A_CUM(MAKEUP) * RATIO THEN
        DO;
           DO M=1 TO F(P);
              IF LOAD(M)-CUM_STEP(P-1) > CAPACITY THEN
                 LOAD(M) = LOAD(M) -CAPACITY;
              ELSE
                 LOAD(M) = CUM_STEP(P-1);
           END;
           IF MODE='SEC' THEN
              GO TO READY;
           ACCUM= F_COST(P)/RATIO;
           DO M=CUM TO 1 BY -1 WHILE(A_CUM(M) > ACCUM);
           END;
           DO N=A(M) TO N1;
              IF CUM_STEP(M) - LOAD(N) > CAP_PUMP THEN
```

```
                LOAD(N) = LOAD(N) + CAP_PUMP;
             ELSE
                LOAD(N) = CUM_STEP(M);
          END;
          MAKEUP= ACCUM - A_CUM(M);
          M=M+1;
          DO N= A(M) TO N1 WHILE ( MAKEUP > 0 );
             XX= (CUM_STEP(M)-LOAD(N));
             IF XX > (CAP_PUMP-(LOAD(N)-FOS(ORDER(N)))) THEN
                XX = (CAP_PUMP-(LOAD(N)-FOS(ORDER(N))));
             IF XX < MAKEUP THEN
                DO;
                   MAKEUP=MAKEUP-XX;
                   LOAD(N)=LOAD(N)+XX;
                END;
             ELSE
                DO;
                   LOAD(N)=LOAD(N)+MAKEUP;
                   MAKEUP=0;
                END;
          END;
          GO TO READY;
       END;
/* FOR THE CASE OF TOO MUCH PEAK SHAVING RELATIVE TO PUMPING, THE
SCHEDULE IS DETERMINED BELOW. */
     PP= MAKEUP;
     SUN_VALUE=A_CUM(PP)*RATIO;
     DO KK=CUM TO 2 BY -1;
        IF F_COST(KK) > SUN_VALUE THEN
           GO TO SOLUTION;
     END;
/* PUMPING INTERVALS ARE SCHEDULED BELOW      */
SOLUTION:
     IF MODE='SEC' THEN
        GO TO NO_PUMP;
     DO K=A(PP) TO N1;
```

```
         IF CUM_STEP(PP) - LOAD(K) > CAP_PUMP THEN
            LOAD(K)=LOAD(K)+CAP_PUMP;
         ELSE
            LOAD(K)=CUM_STEP(PP);
      END;
/* GENERATION INTERVALS ARE SCHEDULED BELOW, IF NO PUMPING NECESSARY,
THE PREVIOUS SECTION IS BY PASSED. */
NO_PUMP:
      DO K=1 TO I WHILE ( SUN_VALUE > SUN(K));
      END;
      DO J=1 TO K-1;
         IF LOAD(J) > CUM_STEP(KK) THEN
            DO;
               IF LOAD(J) -CAPACITY > CUM_STEP(KK) THEN
                  LOAD(J)=LOAC(J)-CAPACITY;
               ELSE
                  LOAD(J)=CUM_STEP(KK);
            END;
      END;
      MAKEUP=SUN_VALUE-F_COST(KK+1);
      DO J=K-1 TO 1 BY -1 WHILE (MAKEUP > 0);
         XX= (LOAD(J)-CUM_STEP(KK-1));
/* "XX" REPRESENTS THE UNUSEC PUMPED STORAGE GENERATION CAPACITY FOR
THE PRESENT TIME INTERVAL */
         IF XX > (CAPACITY-FOS(ORDER(J))+LOAD(J)) THEN
            XX = (CAPACITY-FOS(ORDER(J))+LOAD(J));
         IF MAKEUP > XX THEN
            DO;
               MAKEUP=MAKEUP-XX;
               LOAD(J)=LOAD(J)-XX;
            END;
         ELSE
            DO;
               LOAD(J)=LOAD(J)-MAKEUP;
               MAKEUP=0;
            END;
```

```
    END;
/* THE BASIC ECONOMIC SCHEDULING ALGORITHM IS FINISHED. THE NEXT
SECTION CHECKS THE WATER LIMITS OF THE RESEROIR. FIRST, RESORT THE
LOAD DURATION CURVE BACK TO THE CHRONOLOGIC PATTERN, "NEW". */
READY:
    DO I=1 TO N1;
       NEW( ORDER(I) ) = LOAD(I);
    END;
    IF MODE='SEC' THEN
       CALL
       SECURIT(NEW, FOS, RATIO, START, FREE, CAP_PUMP, RESERIOR, N1,
       BYE, TOLERANCE);
REPEAT:
    STORE= FOS-NEW;
    DO I=1 TO N1;
       IF STORE(I) < 0 THEN
          STORE(I)= RATIO * STORE(I);
    END;
    STORE=STORE-(FREE/N1);
    DO I=2 TO N1;
       STORE(I)=STORE(I)+STORE(I-1);
    END;
/* "STORE" IS THE CUMULATIVE WATER LEVEL. THE SECTION BELOW
CALCULATES THE MAX AND MIN OF THE WATER LEVEL OVER A WEEK */
    STORE=START-STORE;
    MAX(1)=STORE(1);
    MAX(2)=1;
    MIN(1)=STORE(1);
    MIN(2)=1;
    DO I=2 TO N1;
       IF MAX(1) <= STORE(I) THEN
          DO;
             MAX(1)=STORE(I);
             MAX(2)=I;
          END;
       IF MIN(1) >= STORE(I) THEN
```

```
            DO;
               MIN(1)=STORE(I);
               MIN(2)=I;
            END;
         END;
/* WHEN COMPARING BEGINNING-OF-THE-WEEK WATER LEVEL TO THE
END-OF-THE-WEEK WATER LEVEL, IF THERE IS NO MATCH, THEN A SERIOUS
ERROR HAS OCCURRED SOMEWHERE */
         MAKEUP= START -STORE(N1);
         IF ABS(MAKEUP) > RESERIOR/1000 THEN
            DO;
               PUT FILE(SYSPRINT) SKIP
               LIST(
               ' ERROR IN PUMPED STORAGE ROUNTINE, PROCESSING CONTINUING');
               GO TO LISTING;
            END;
/* IF RESERVOIR IS OVERDRAWN, GENERATION IS FIRST CUT-BACK DURING THE
IMMEDIATE TIME PERIOD(WHEN OVERDRAWN). */
         IF MIN(1) <0 THEN
            DO;
               MAKEUP=-MIN(1);
               MAX(2)=MIN(2);
TOPP:
               IF NEW(MAX(2))>=FCS(MAX(2)) THEN
                  DO;
                     MAX(2)=MAX(2)-1;
                     GO TO TOPP;
                  END;
               IF MAKEUP > FOS(MAX(2)) - NEW(MAX(2)) THEN
                  DO;
                     MAKEUP=MAKEUP-FOS(MAX(2))+NEW(MAX(2));
                     NEW(MAX(2))=FOS(MAX(2));
                     MAX(2)=MAX(2)-1;
                     IF MAX(2)=0 THEN
                        DO;
                           PUT FILE(SYSPRINT) SKIP
```

```
                    LIST(
                    ' * * * * * * * * MIN WATER LEVEL TOO LOW TO COR
RECT,   PROCEEDING TO NEXT STEP * * * * * * * * * * * '
                     );
                    GO TO LISTING;
                 END;
              GO TO TOPP;
           END;
        ELSE
           NEW(MAX(2))=NEW(MAX(2))+MAKEUP;
/* COMPENSATING CUT-BACK IN PUMPING(TO BALANCE THE THE ABOVE CUT-BACK
IN GENERATION) IS ALSO SCHEDULED IN THE MOST IMMEDIATE TIME PERIOD. */
        MAX(2)=MIN(2)+1;
        MAKEUP=-MIN(1)/RATIO;
TIP:
        IF FOS(MAX(2)) >= NEW(MAX(2)) THEN
           DO;
              MAX(2)=MAX(2)+1;
              GO TO TIP;
           END;
        IF MAKEUP > NEW(MAX(2)) - FOS(MAX(2)) THEN
           DO;
              MAKEUP=MAKEUP-NEW(MAX(2))+FOS(MAX(2));
              NEW(MAX(2))=FOS(MAX(2));
              MAX(2)=MAX(2)+1;
              IF MAX(2)=N1 THEN
                 DO;
                    PUT FILE(SYSPRINT) SKIP
                    LIST(
                    ' * * * * * * * CORRECTION TO MIN PROBLEM NOT PO
SSIBLE, PROCEEDING TO NEXT STEP * * * * * * * * * * * '
                     );
                    GO TO LISTING;
                 END;
              GO TO TIP;
           END;
```

```
          ELSE
             NEW(MAX(2))=NEW(MAX(2))-MAKEUP;
          GO TO REPEAT;
/*   TEST WATER LEVEL AGAIN    */
        END;
/* IF RESERVOIR IS OVERFLOWING, CUT-BACK ON PUMPING */
     IF MAX(1) > RESERIOR THEN
        DO;
          MAKEUP = (MAX(1)-RESERIOR)/RATIO;
          MIN(2)=MAX(2);
TUP:
          IF NEW(MIN(2)) <= FOS(MIN(2)) THEN
             DO;
                MIN(2)=MIN(2)-1;
                GO TO TUP;
             END;
          IF MAKEUP > NEW(MIN(2)) - FOS(MIN(2)) THEN
             DO;
                MAKEUP=MAKEUP-NEW(MIN(2))+FOS(MIN(2));
                NEW(MIN(2))=FOS(MIN(2));
                MIN(2)=MIN(2)-1;
                IF MIN(2)=0 THEN
                   DO;
                      PUT FILE(SYSPRINT) SKIP
                      LIST(
                      ' * * * * * * * MAX WATER LEVEL TOO HIGH TO CORR
ECT,     PROCEEDING TO NEXT STEP * * * * * * * * * * * '
                       );
                      GO TO LISTING;
                   END;
                GO TO TUP;
             END;
          ELSE
             NEW(MIN(2))=NEW(MIN(2))-MAKEUP;
          MIN(2)=MAX(2)+1;
/* BELOW, IS THE COMPENSATING CUT_BACK ON GENERATION */
```

```
           MAKEUP = (MAX(1)-RESERIOR);
UOPP:
           IF FOS(MIN(2)) <= NEW(MIN(2)) THEN
              DO;
                 MIN(2)=MIN(2)+1;
                 GO TO UOPP;
              END;
           IF MAKEUP > FOS(MIN(2)) - NEW(MIN(2)) THEN
              DO;
                 MAKEUP=MAKEUP-FOS(MIN(2))+NEW(MIN(2));
                 NEW(MIN(2))=FOS(MIN(2));
                 MIN(2)=MIN(2)+1;
                 IF MIN(2)=N1 THEN
                    DO;
                       PUT FILE(SYSPRINT) SKIP
                       LIST(
                       ' * * * * * * * CORRECTION TO MAX PROBLEM NOT PO
SSIBLE, PROCEEDING TO NEXT STEP * * * * * * * * * * * * '
                        );
                       GO TO LISTING;
                    END;
                 GO TO UOPP;
              END;
           ELSE
              NEW(MIN(2))=NEW(MIN(2))+MAKEUP;
           GO TO REPEAT;
/*   RE-TEST WATER LEVEL      */
        END;
/* BELOW, IS THE PRINTING OF THE PUMPED STORAGE SCHEDULE */
LISTING: /*  RETURN TO MAIN PROGRAM TO LIST RESULTS  *//*
*************** REPORT GENERATOR ************************* *//*
PUMPED STORAGE GENERATION FIGURES */
     PUT FILE(SYSPRINT)
     EDIT('BOW WATER LEVEL=',STORE(1),'EOW WATER LEVEL=', STORE(N1),
     'MAX=', MAX(1),'MIN=', MIN(1))(
      COL(10),A,F(5),COL(50),A,F(5), X(5),A,F(5),X(5),A,F(5))SKIP(3);
```

```
    PUT FILE(SYSPRINT) EDIT('   (IN UNITS OF MWHR)')(A);
    PUT FILE(SYSPRINT) DATA(CODE) SKIP;
    IF CODE=0 THEN
       DO;
          PUT FILE(SYSPRINT) EDIT (
           'TIME','BASIC TIME','INCREMENTAL FOSSIL',
          'GENERATION/-PUMPING','WATER LEVEL')(
           COL(5),A,COL(15),A, COL(30),A,COL(55),A,COL(80),A) SKIP(2);
          PUT FILE(SYSPRINT) EDIT('   (IN UNITS OF MWHR)')(A);
          DO I=1 TO N1;
             PUT FILE(SYSPRINT)
             EDIT( I,NEW(I),FOS(I)-NEW(I),STORE(I))(
              X(8),F(12),6 F(23))SKIP(1);
          END;
       END;
    ;
    RETURN;
 END ECO ;
SECURIT :
 PROC(NEW, OLD, EFFICIENCY, START, FREE, PUMP, RESERVIOR, N1, BYE,
 TOLERANCE);
 DCL
    N1 FIXED BIN;
 DCL
    STRING VARYING BIT(N1),
    (TOLERANCE,
    TURNAROUND,
    AMT,
    LOWEST(2),
    POINT,
    FREE,
    RESERVIOR ,
    START,
    PUMP,
    BYE,
    STORE(N1),
```

```
       NEW( *),
       OLD( *),
       TEMP(N1)) FIXED DEC;
    DCL
       (MARGIN,
       WATER(N1)) FLOAT DEC,
       EFFICIENCY FIXED DEC(5,3);
/* LIGHT=1 WHEN '0' SUBSTRING IS LAST ONE IN PERIOD */
       LIGHT=0;
       POINT = 0;
       STRING=(200)'0'B;
/*     STRING FORMATION                               */
       STORE=NEW-OLD;                  /* (+)PUMPING, (-)GENERATION  */
       IF STORE(1) < 0 THEN
          SUBSTR(STRING,1,1)='1'B;
       DO I=2 TO N1;
          IF STORE(I) <0 THEN
             DO;
                SUBSTR(STRING,I,1)='1'B;
                IF STORE (I-1)=0 THEN
                   DO;
                      DO J=1 TO BYE;
                         SUBSTR(STRING,I-J,1)='1'B;
                      END;
                   END;
             END;
          ELSE
             IF STORE (I-1) < 0 THEN
                DO;
                   DO J=1 TO BYE;
                      SUBSTR( STRING,I+J-1,1)='1'B;
                   END;
                END;
       END;
/* CALCULATE TURNAROUND LEVEL  */
       TURNAROUND = 90000;
```

```
     DO I=1 TO N1;
        IF STORE(I) < 0 THEN
           DO;
              IF TURNAROUND > OLD(I) THEN
                 TURNAROUND=OLD(I);
           END;
     END;
     TURNAROUND = TURNAROUND - TOLERANCE;
/*   CALC CHRONOLOGIC WATER LEVEL BEHAVIOR        */
WATER_LEVEL:
     LENGT =INDEX(STRING,'1'B);
     IF LENGT =0 THEN
        DO;
           LENGT=LENGTH(STRING);
           IF LENGT =0 THEN
              RETURN;
           ELSE
              LENGT=LENGT+1;
           LIGHT=1;
        END;
     LENGT =LENGT -1;
     WATER= STORE;
     DO I=1 TO N1;
        IF WATER(I) >0 THEN
           WATER(I)=WATER(I)*EFFICIENCY;
     END;
     WATER= WATER+ FREE/N1;
     WATER(1)=START+WATER(1);
     DO I=2 TO N1;
        WATER(I)=WATER(I-1) + WATER(I);
     END;
/* CALC MARGIN BET RESERVIOR CAPACITY AND WATER LEVEL AT END OF
ACTIVE INTERVAL */
     MARGIN=(RESERVIOR - WATER(POINT+LENGT ))/EFFICIENCY;
     IF LIGHT=1 THEN
        DO;
```

```
            MARGIN = (START - WATER(POINT+LENGT))/EFFICIENCY;
            DO I=N1 TO 1 BY -1 WHILE (MARGIN<0);
               IF STORE(I) > 0 THEN
                  DO;
                     IF (-MARGIN) >= STORE(I) THEN
                        DO;
                           NEW(I) = OLD(I);
                           MARGIN=MARGIN+STORE(I);
                           STORE(I)=0;
                        END;
                     ELSE
                        DO;
                           NEW(I)=NEW(I)+MARGIN;
                           STORE(I)=STORE(I)+MARGIN;
                           MARGIN=0;
                           RETURN;
                        END;
                  END;
            END;
         END;
      LOWEST(1)=90000;
      TEMP=NEW;
/*    FIND LOWEST DEMAND PERIOD                       */
SORT:
      DO I= POINT+1 TO POINT + LENGT ;
         IF LOWEST(1) >=TEMP(I) THEN
            DO;
               LOWEST(1)=TEMP(I);
               LOWEST(2)=I;
            END;
      END;
      IF LOWEST(1)=90000 THEN
         GO TO NEXT_LEVEL;
      AMT=TURNAROUND - NEW(LOWEST(2));
      IF (AMT<= 0) | (MARGIN <= 0) THEN
         GO TO NEXT_LEVEL;
```

```
     IF (AMT >= MARGIN) & (PUMP >= MARGIN) THEN
        DO;
/*   RESERVIOR IS FILLED                                     */
           NEW(LOWEST(2))=NEW(LOWEST(2))+MARGIN;
           STORE(LOWEST(2))=MARGIN;
           GO TO NEXT_LEVEL;
        END;
     ELSE
        DO;
/* SCHEDULE PUMPING CAPACITY OR TIL TURNAROUND LEVEL IS REACHED */
           IF AMT > PUMP THEN
              AMT=PUMP;
           MARGIN=MARGIN-AMT;
           STORE(LOWEST(2))=AMT;
           NEW(LOWEST(2))= NEW(LOWEST(2))+AMT;
/*   FIND NEXT LOWEST DEMAND PERIOD                          */
           TEMP(LOWEST(2))=90000;
           LOWEST(1)=90000;
           GO TO SORT;
        END;
/*   MOVE POINTER                                            */
NEXT_LEVEL:
     IF LENGTH(STRING)=LENGT THEN
        RETURN;
     LENGT =LENGT +1;
     STRING=SUBSTR(STRING,LENGT );
     POINT=POINT+LENGT -1;
     LENGT =INDEX(STRING,'0'B);
     IF LENGT = 0 THEN
        RETURN;
     STRING=SUBSTR( STRING,LENGT );
     POINT=POINT+LENGT -1;
     GO TO WATER_LEVEL;
  END SECURIT ;
```

C.7 PROCOSI Input for Case 3

```
//   'RAYMOND L. ENG',CLASS=A,REGION=230K                                    CAS30001
/*MAIN  LINES=3,CARDS=7                                                      CAS30002
/*SRI LOW                                                                    CAS30003
//A EXEC PLIXG,PROG='U.M9960.8981.TEST1.LIBRARY.LMOD(NUCLEAR)',              CAS30004
//   PARM.G='ISASIZE(27200),REPORT'                                          CAS30005
//G.PLIDUMP  DD SYSOUT=A                                                     CAS30006
//G.FT06F001  DD SYSOUT=A                                                    CAS30007
//G.LDMDL  DD  DSN=U.M9960.8981.AEP.APR.MAY,DISP=OLD                         CAS30008
//G.HYDRO DD *,DCB=BLKSIZE=2000                                              CAS30009
50 50 50 50 50 50 50 50 200 200 200 200 200 200 200 50 50 50 50 200 200 50 50 50 CAS30010
                                                                             CAS30011
50 50 50 50 50 50 50 50 200 200 200 200 200 200 200 50 50 50 50 200 200 50 50 50 CAS30012
                                                                             CAS30013
50 50 50 50 50 50 50 50 200 200 200 200 200 200 200 50 50 50 50 200 200 50 50 50 CAS30014
                                                                             CAS30015
50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50      CAS30016
50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50      CAS30017
50 50 50 50 50 50 50 50 200 200 200 200 200 200 200 50 50 50 50 200 200 50 50 50 CAS30018
                                                                             CAS30019
50 50 50 50 50 50 50 50 200 200 200 200 200 200 200 50 50 50 50 200 200 50 50 50 CAS30020
                                                                             CAS30021
50 50 50 50 50 50 50 50 200 200 200 200 200 200 200 50 50 50 50 200 200 50 50 50 CAS30022
                                                                             CAS30023
50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50      CAS30024
50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50 50      CAS30025
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1  525  9.1  .35                                                                  CAS30155
1  580  9.0  .55                                                                  CAS30156
1  600  9.1  .50                                                                  CAS30157
1  800  9.4  1.05                                                                 CAS30158
2  800  9.5  .40                                                                  CAS30159
1  800  9.0  1.10                                                                 CAS30160
1  1300 8.40  1.25                                                                CAS30161
2  1300 8.5  .80                                                                  CAS30162
1  240  9.1  1.00                                                                 CAS30163
4  210  9.8  .55                                                                  CAS30164
3  225  10.  .50                                                                  CAS30165
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2  240  9.1  .80                                                                  CAS30167
1  280  9.3  1.05                                                                 CAS30168
1  145  9.8  1.70                                                                 CAS30169
1  215  12.  .40                                                                  CAS30170
 1  105 11.8  1.0                                                                 CAS30171
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2  150  9.7  .55                                                                  CAS30173
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2  800  9.5  .40                                                  CAS30183
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1  1300 8.40  1.25                                                CAS30185
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4  210  9.8  .55                                                  CAS30188
3  225  10.  .50                                                  CAS30189
1  215  9.2  .55                                                  CAS30190
3  240  9.1  .80                                                  CAS30191
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1   100  10.8  .55                                                CAS30193
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1  580  9.0  .55                                                  CAS30205
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1  800  9.4  1.05                                                 CAS30207
2  800  9.5  .40                                                  CAS30208
1  800  9.0  1.10                                                 CAS30209
2  1300 8.5  .80                                                  CAS30210
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                                                                                         CAS30346
5                      .10 95 12.5 1.7 100 .10 95 12. 1.05 100                           CAS30347
 .1 90 12.9 .55 100 .1  51 15. 1.7 0 .10 4  15. 1.7 0         1                          CAS30348
5                      .10 95 12.5 1.7 100 .10 95 12. 1.05 100                           CAS30349
 .1 90 12.9 .55 100 .1  51 15. 1.7 0 .10 4  15. 1.7 0         1                          CAS30350
5                      .10 95 12.5 1.7 100 .10 95 12. 1.05 100                           CAS30351
 .1 90 12.9 .55 100 .1  51 15. 1.7 0 .10 4  15. 1.7 0         1                          CAS30352
5                      .10 95 12.5 1.7 100 .10 95 12. 1.05 100                           CAS30353
 .1 90 12.9 .55 100 .1  51 15. 1.7 0 .10 4  15. 1.7 0         1                          CAS30354
//G.TRANSFR  DD DSN=&TRANS,UNIT=SCRATCH,DISP=(NEW,PASS),                                 CAS30355
//  SPACE=(CYL,(1,1)),                                                                   CAS30356
//  DCB=(RECFM=U,BLKSIZE=13000)                                                          CAS30357
//G.DATA  DD  DSN=&DATA,UNIT=SCRATCH,SPACE=(CYL,(25,5)),                                 CAS30358
//  DISP=(NEW,PASS),DCB=(RECFM=FB,LRECL=80,BLKSIZE=12880)                                CAS30359
//B EXEC MPSX                                                                            CAS30360
```

```
//MPSCOMP.SYSIN  DD *,DCB=(RECFM=FB,LRECL=80,BLKSIZE=2000)            CAS30361
         PROGRAM                                                      CAS30362
*                                                                     CAS30363
*  THIS  PROGRAM PREFORMS THE  NUCLEAR ENERGY OPTIMIZATION            CAS30364
*                 FOR THE AEP CASE    3                               CAS30365
         TITLE (' ELECTRIC POWER DISPATCHING SIMULATION')             CAS30366
         INITIALZ                                                     CAS30367
         MVADR(XDOPRINT,SET)                                          CAS30368
         XSETLB=-1                                                    CAS30369
         XFREQLGA=0                                                   CAS30370
         XFREQLGO=0                                                   CAS30371
         XPARDELT=2.                                                  CAS30372
         MOVE(XOBJ,'COST')                                            CAS30373
         MOVE(XPBNAME,'MINIMIZE')                                     CAS30374
         MOVE(XDATA,'SYSTEA01')                                       CAS30375
         EXEC(TIP)                                                    CAS30376
         MOVE(XDATA,'SYSTEA02')                                       CAS30377
         EXEC(TIP)                                                    CAS30378
         MOVE(XDATA,'SYSTEA03')                                       CAS30379
         EXEC(TIP)                                                    CAS30380
         MOVE(XDATA,'SYSTEA04')                                       CAS30381
         EXEC(TIP)                                                    CAS30382
         MOVE(XDATA,'SYSTEB01')                                       CAS30383
         EXEC(TIP)                                                    CAS30384
         MOVE(XDATA,'SYSTEB02')                                       CAS30385
         EXEC(TIP)                                                    CAS30386
         MOVE(XDATA,'SYSTEB03')                                       CAS30387
         EXEC(TIP)                                                    CAS30388
         MOVE(XDATA,'SYSTEB04')                                       CAS30389
         EXEC(TIP)                                                    CAS30390
         MOVE(XDATA,'SYSTEB05')                                       CAS30391
         EXEC(TIP)                                                    CAS30392
         MOVE(XDATA,'SYSTEC01')                                       CAS30393
         EXEC(TIP)                                                    CAS30394
         MOVE(XDATA,'SYSTEC02')                                       CAS30395
         EXEC(TIP)                                                    CAS30396
```

```
        MOVE(XDATA,'SYSTEC03')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEC04')
        EXEC(TIP)
        MOVE(XDATA,'SYSTED01')
        EXEC(TIP)
        MOVE(XDATA,'SYSTED02')
        EXEC(TIP)
        MOVE(XDATA,'SYSTED03')
        EXEC(TIP)
        MOVE(XDATA,'SYSTED04')
        EXEC(TIP)
        MOVE(XDATA,'SYSTED05')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEE01')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEE02')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEE03')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEE04')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEF01')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEF02')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEF03')
        EXEC(TIP)
        MOVE(XDATA,'SYSTEF04')
        EXEC(TIP)
        EXIT
TIP     CONVERT('FILE','IN')
        MOVE(XRHS,'RHS001')
        SETUP('BOUND','BOUND1')
        A=0
        EXEC(PARRR)
```

```
         STEP                                                           CAS30433
PARRR    XPARAM=0.                                                      CAS30434
         A=A+1                                                          CAS30435
         IF(A.EQ.1,S2)                                                  CAS30436
         MOVE('OPZSTART','CONTINUE')                                    CAS30437
         RESTORE('NAME','SA')                                           CAS30438
S2       OPTIMIZE                                                       CAS30439
         SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',  XCAS30440
         'CMASKS','N******',' ')                                        CAS30441
         SAVE('NAME','SA')                                              CAS30442
         MOVE(XCHCOL,'CHC002')                                          CAS30443
         XPARAM=0.                                                      CAS30444
         XPARMAX=8.                                                     CAS30445
         PARARHS('CONT')                                                CAS30446
         SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',  XCAS30447
         'CMASKS','N******',' ')                                        CAS30448
         STEP                                                           CAS30449
SET      SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',  XCAS30450
         'CMASKS','N******',' ')                                        CAS30451
         CONTINUE                                                       CAS30452
A        DC(0)                                                          CAS30453
         PEND                                                           CAS30454
//MPSEXEC.SYSPRINT  DD DUMMY                                            CAS30455
//MPSEXEC.IN  DD  DSN=&DATA,VOL=REF=*.A.G.DATA,DISP=(OLD,DELETE)        CAS30456
//MPSEXEC.SOLN  DD DSN=&SOLN,DISP=(NEW,PASS),UNIT=SCRATCH,              CAS30457
//  SPACE=(CYL,(10,5)),DCB=(RECFM=VBS,BLKSIZE=7144,LRECL=204)           CAS30458
//  EXEC PLIXG,PROG='U.M9960.8981.TEST1.LIBRARY.LMOD(TEMPNAME)'         CAS30459
//  EXEC PLIXG,PROG='U.M9960.8981.TEST1.LIBRARY.LMOD(TEMPNAME)'         CAS30460
//G.SYSIN DD *,DCB=BLKSIZE=2000                                         CAS30461
 'SEC'  1                                                               CAS30462
300  .7  160  9300  2300  7600  1  200                                  CAS30463
 5  1  'APRIL  CONFIGURATION,  WEEK 1 , P.S. SECURITY MODE CALC'        CAS30464
 5  1  'APRIL  CONFIGURATION,  WEEK 2 , P.S. SECURITY MODE CALC'        CAS30465
 5  1  'APRIL  CONFIGURATION,  WEEK 3 , P.S. SECURITY MODE CALC'        CAS30466
 5  1  'APRIL  CONFIGURATION,  WEEK 4 , P.S. SECURITY MODE CALC'        CAS30467
 'SEC'  1                                                               CAS30468
```

```
300   .7   160   9300   2300   7600   1   200                                        CAS30469
 5   1   ' MAY    CONFIGURATION,   WEEK 5 , P.S. SECURITY MODE CALC'                   CAS30470
 5   1   ' MAY    CONFIGURATION,   WEEK 6 , P.S. SECURITY MODE CALC'                   CAS30471
 5   1   ' MAY    CONFIGURATION,   WEEK 7 , P.S. SECURITY MODE CALC'                   CAS30472
 5   1   ' MAY    CONFIGURATION,   WEEK 8 , P.S. SECURITY MODE CALC'                   CAS30473
 5   1   ' MAY    CONFIGURATION,   WEEK 9 , P.S. SECURITY MODE CALC'                   CAS30474
 'SEC'   1                                                                             CAS30475
300   .7   160   9300   2300   7600   1   200                                        CAS30476
 5   1   'JUNE    CONFIGURATION,   WEEK 10, P.S. SECURITY MODE CALC'                   CAS30477
 5   1   'JUNE    CONFIGURATION,   WEEK 11, P.S. SECURITY MODE CALC'                   CAS30478
 5   1   'JUNE    CONFIGURATION,   WEEK 12, P.S. SECURITY MODE CALC'                   CAS30479
 5   1   'JUNE    CONFIGURATION,   WEEK 13, P.S. SECURITY MODE CALC'                   CAS30480
 'SEC'   1                                                                             CAS30481
300   .7   160   9300   2300   7600   1   200                                        CAS30482
 5   1   'JULY    CONFIGURATION,   WEEK 14, P.S. SECURITY MODE CALC'                   CAS30483
 5   1   'JULY    CONFIGURATION,   WEEK 15, P.S. SECURITY MODE CALC'                   CAS30484
 5   1   'JULY    CONFIGURATION,   WEEK 16, P.S. SECURITY MODE CALC'                   CAS30485
 5   1   'JULY    CONFIGURATION,   WEEK 17, P.S. SECURITY MODE CALC'                   CAS30486
 5   1   'JULY    CONFIGURATION,   WEEK 18, P.S. SECURITY MODE CALC'                   CAS30487
 'SEC'   1                                                                             CAS30488
300   .7   160   9300   2300   7600   1   200                                        CAS30489
 5   1   'AUGUST CONFIGURATION,   WEEK 19, P.S. SECURITY MODE CALC'                    CAS30490
 5   1   'AUGUST CONFIGURATION,   WEEK 20, P.S. SECURITY MODE CALC'                    CAS30491
 5   1   'AUGUST CONFIGURATION,   WEEK 21, P.S. SECURITY MODE CALC'                    CAS30492
 5   1   'AUGUST CONFIGURATION,   WEEK 22, P.S. SECURITY MODE CALC'                    CAS30493
 'SEC'   1                                                                             CAS30494
300   .7   160   9300   2300   7600   1   200                                        CAS30495
 5   1   'SEPT.   CONFIGURATION,   WEEK 23, P.S. SECURITY MODE CALC'                   CAS30496
 5   1   'SEPT.   CONFIGURATION,   WEEK 24, P.S. SECURITY MODE CALC'                   CAS30497
 5   1   'SEPT.   CONFIGURATION,   WEEK 25, P.S. SECURITY MODE CALC'                   CAS30498
 5   1   'SEPT.   CONFIGURATION,   WEEK 26, P.S. SECURITY MODE CALC'                   CAS30499
//G.TRANSFR  DD DSN=&TRANS,VOL=REF=*.A.G.TRANSFR,DISP=(OLD,DELETE)                     CAS30500
//G.SOLN  DD    DSN=&SOLN,DISP=(OLD,DELETE),VOL=REF=*.B.MPSEXEC.SOLN                   CAS30501
```

```
INPUT VARIABLES FOLLOWS:                           SYSTF='SYSTEA'          MODE='DUR'            TRUE=      168          NI=       120
                          N2=        6             VP=         1           NUMBER=          2    K=      61
PARAMETER=        0       WEEKS=       4           PECKING='NO ';
 HYDRO DATA FOLLOWS:
 WEEKLY  HYDRO GENERATION SCHEDULE, INTERVAL BY INTERVAL (MW)
        50       50       50       50       50       50       50       50
       200      200      200      200      200      200      200       50
        50       50       50      200      200       50       50       50
        50       50       50       50       50       50       50       50
       200      200      200      200      200      200      200       50
        50       50       50      200      200       50       50       50
        50       50       50       50       50       50       50       50
       200      200      200      200      200      200      200       50
        50       50       50      200      200       50       50       50
        50       50       50       50       50       50       50       50
        50       50       50       50       50       50       50       50
        50       50       50       50       50       50       50       50
        50       50       50       50       50       50       50       50
        50       50       50       50       50       50       50       50
        50       50       50       50       50       50       50       50

 THE TIME WEIGHING FUNCTION FOLLOWS (NUMBER OF HOURS REPRESENTED BY EACH TIME INTERVAL):
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         3        3        3        3        3        3        3        3
         3        3        3        3        3        3        3        3
         3        3        3        3        3        3        3        3
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1
         1        1        1        1        1        1        1        1

 *CODE* FOLLOWS(CORRESPONDENCE MAP FROM THE LOAD MODEL TO A 168 HOUR REPRESENTATION):
         1        2        3        4        5        6        7        8
         9       10       11       12       13       14       15       16
        17       18       19       20       21       22       23       24
        25       26       27       28       29       30       31       32
        33       34       35       36       37       38       39       40
        41       42       43       44       45       46       47       48
        25       26       27       28       29       30       31       32
        33       34       35       36       37       18       39       40
        41       42       43       44       45       46       47       48
        25       26       27       28       29       30       31       32
        33       34       35       36       37       38       39       40
        41       42       43       44       45       46       47       48
        49       50       51       52       53       54       55       56
        57       58       59       60       61       62       63       64
        65       66       67       68       69       70       71       72
        73       74       75       76       77       78       79       80
        81       82       83       84       85       86       87       88
        89       90       91       92       93       94       95       96
        97       98       99      100      101      102      103      104
```

APPENDIX C.8 SAMPLE OUTPUT FROM PROCOST

105	106	107	108	109	110	111	112
113	114	115	116	117	118	119	120

NUCLEAR INPUT PARAMETERS FOLLOWS:

NUCLEAR INCREMENTAL HEAT RATES:	1.00	1.05
WEEKLY NUCLEAR CAPACITY FACTORS:	0.95	1.00
RATED NUCLEAR CAPACITIES,MW:	1100	220
FULL POWER AVER HEAT RATES:	1.05	1.44

THE FOLLOWING IS THE PECK FILE INPUT FOR LARGE,MEDIUM, SMAL
L FOSSIL PLANTS:

N1= 9 VP1= 4 N2= 6 VP2= 4 N3= 5
VP3= 4;

AVERAGE HEAT RATES FOR LARGE, MEDIUM AND SMALL FOSSIL PLANTS: FRACTION OF RATED POWER, HEAT RATE(MMBTU/MWH)

0.40	0.97	0.60	0.91	0.80	0.89	1.00	0.89
0.40	0.95	0.60	0.91	0.80	0.89	1.00	0.89
0.40	1.35	0.60	1.27	0.80	1.25	1.00	1.28

PLANT PARAMETERS FOR LARGE, MEDIUM AND SMALL FOSSIL PLANTS:
NUMBER, CAPACITY(MW), HEAT RATE(MMBTU/MWH), FUEL COST($/MMBTU)

1.00	400.00	9.20	0.55
1.00	525.00	9.10	0.35
1.00	580.00	9.00	0.55
1.00	600.00	9.10	0.50
1.00	500.00	9.40	1.05
2.00	300.00	9.50	0.40
1.00	800.00	9.00	1.10
1.00	1300.00	8.40	1.25
2.00	1300.00	8.50	0.80
1.00	240.00	9.10	1.00
4.00	210.00	9.30	0.55
3.00	225.00	10.00	0.50
1.00	215.00	9.20	0.55
2.00	240.00	9.10	0.80
1.00	280.00	9.30	1.05
1.00	145.00	9.80	1.70
1.00	215.00	12.00	0.40
1.00	105.00	11.80	1.00
2.00	150.00	9.40	0.55
2.00	150.00	9.70	0.55

ECONOMIC LOADING ORDER OF FOSSIL PLANTS
MUST RUN FOSSIL OPERATING LEVEL(MW) = 5200
MINIMIUM FOSSIL FUEL COST($/WK) = $6,418,661.

INCREMENTAL STEP	STEP SIZE (MW)	CUMLATIVE SIZE (MW)	INCREM. GENERATION COST(MILLS/KWH)	CUMLATIVE INCREM, GENERATION COST($/HR)
1	105	105	2.85	299.30
2	105	210	3.00	614.30
3	105	315	3.20	950.21
4	320	635	3.40	2033.50
5	320	955	3.58	3183.35
6	320	1275	3.82	4405.28
7	120	1395	4.07	4893.94

8	43	1438	4.16	5072.92
9	120	1558	4.29	5587.20
10	116	1674	4.43	6101.09
11	43	1717	4.46	6292.98
12	80	1797	4.53	6655.27
13	120	1917	4.57	7203.71
14	60	1977	4.63	7481.29
15	116	2093	4.66	8022.13
16	135	2228	4.66	3551.62
17	135	2363	4.66	9281.12
18	43	2406	4.72	9484.03
19	43	2449	4.72	9685.94
20	80	2529	4.77	10063.22
21	60	2589	4.96	10365.82
22	116	2705	4.97	10942.58
23	135	2840	5.00	11617.38
24	168	[illegible]	5.03	12462.35
25	168	3176	5.03	13306.53
26	43	3219	5.06	13524.11
27	80	3299	5.08	13930.72
28	43	3342	5.25	14156.47
29	168	3510	5.39	15061.99
30	60	3570	5.84	15412.10
31	520	4090	6.09	18576.71
32	520	4610	6.40	21907.27
33	96	4706	6.79	22559.03
34	96	4802	6.79	23210.79
35	520	5322	6.83	26762.60
36	96	5418	7.28	27461.48
37	60	5478	7.74	27925.11
38	60	5538	8.30	28424.24
39	48	5586	8.49	28831.59
40	48	5634	8.49	29233.95
41	160	5794	8.83	30652.28
42	160	5954	8.86	32069.92
43	48	6002	9.10	32505.72
44	56	6058	9.11	33016.69
45	56	6114	9.11	33526.67
46	160	6274	9.30	35014.11
47	160	6434	9.32	35506.38
48	260	6694	9.40	38949.35
49	56	6750	9.76	39496.19
50	60	6810	9.77	40082.22
51	260	7070	9.89	42653.60
52	160	7230	9.91	44237.36
53	160	7390	9.94	45830.94
54	21	7411	10.23	46045.83
55	260	7671	10.55	48789.03
56	21	7692	10.97	49013.40
57	21	7713	12.91	49289.43
58	29	7742	14.45	49703.41
59	29	7771	15.49	50157.58
60	29	7800	18.22	50686.01
61	1500	9300	25.00	88186.01

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

10096	9864	9755	9671	9795	10229	11107	12347
13106	13478	13575	13504	13307	13233	13071	12627

12748	12720	12758	12942	12937	12700	12027	11011
9915	9640	9506	9451	9542	9968	10803	12111
12860	13150	13269	13125	12972	12980	12745	12385
12495	12516	12571	12713	12641	12433	11740	10720
9189	8941	8988	8991	8926	9262	10084	11393
12218	12595	12748	12636	12418	12437	12278	11960
12023	12025	12069	12151	12126	11899	11235	10245
9530	9105	8918	8837	8864	9025	9273	9794
10441	10920	11111	11115	10864	10640	10395	10187
10247	10368	10516	10791	10736	10538	10099	9501
5847	3520	8288	8238	8195	8239	8314	8664
9159	9305	9244	9353	9342	9047	8755	8645
8699	8859	9158	9596	9790	9837	9439	8987

CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.50	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.00	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 51	HEAT RATE(MMBTU/MWH)= 15.00	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 0
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 4	HEAT RATE(MMBTU/MWH)= 15.00	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 0

OPERATION COST OF PEAKERS= $ 88471.00 CODE= 1.00000E+00;

OUTPUT FUNCTION FROM SUBROUTINE DURATION:

7348	6733	5661	4899	4196	3427

FOSSIL INCREMENTS, MUST RUN($/WK) $3,604,484.

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

10271	10082	9991	9913	10060	10525	11468	12713
13380	13723	13794	13738	13493	13387	13169	12764
12900	12914	13038	13272	13219	12866	12170	11191
10143	9883	9755	9705	9811	10270	11152	12475
13141	13332	13470	13296	13130	13123	12866	12504
12641	12680	12808	13005	12875	12563	11854	10864
9280	9059	9070	9015	9072	9430	10336	11703
12511	12871	13030	12886	12640	12672	12501	12188
12285	12298	12411	12520	12439	12095	11393	10393
9682	9289	9116	9036	9091	9267	9541	10081
10702	11152	11325	11317	11043	10802	10539	10319
10399	10538	10733	11082	10958	10664	10211	9638
9002	8694	8487	9487	8387	8442	8542	8907
9336	9436	9333	9438	9460	9124	8814	6700
8752	8950	9319	9839	9956	9919	9489	9064

CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.50	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.00	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 51	HEAT RATE(MMBTU/MWH)= 15.00	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 0
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 4	HEAT RATE(MMBTU/MWH)= 15.00	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 0

OPERATION COST OF PEAKERS= $ 88071.00 CODE= 1.00000E+00;

OUTPUT FUNCTION FROM SUBROUTINE DURATION:

7534	6898	5881	5107	4403	3595

FOSSIL INCREMENTS, MUST RUN($/WK) $3,762,897.

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

9797	9493	9353	9256	9343	9725	10490	11727
12637	13058	13203	13154	12989	12969	12768	12393
12487	12397	12339	12379	12456	12418	11784	10721
9531	9225	9091	9018	9083	9453	10207	11489
12380	12754	12924	12834	12703	12728	12539	12133
12247	12235	12167	12213	12242	12212	11545	10472
9033	8739	8551	8652	8675	8974	9655	10664
11713	12125	12268	12207	12037	12035	11897	11572
11575	11559	11503	11519	11592	11563	10966	9993
9270	8792	8530	8497	8477	8613	8816	9305
9993	10524	10746	10771	10558	10362	10149	9962
10005	10078	10146	10295	10357	10323	9906	9267
9593	9221	7947	7947	7865	7892	7923	8250
8770	8997	9008	9123	9139	8916	8655	8553
8579	8702	8882	9153	9438	9697	9351	8854

CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 95   HEAT RATE(MMBTU/MWH)= 12.50   FUEL COST($/MMBTU)= 1.05   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 95   HEAT RATE(MMBTU/MWH)= 12.00   FUEL COST($/MMBTU)= 1.05   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 90   HEAT RATE(MMBTU/MWH)= 12.90   FUEL COST($/MMBTU)= 0.55   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 90   HEAT RATE(MMBTU/MWH)= 12.90   FUEL COST($/MMBTU)= 0.55   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 51   HEAT RATE(MMBTU/MWH)= 15.00   FUEL COST($/MMBTU)= 1.70   SUSD COST($)=   0
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=   4   HEAT RATE(MMBTU/MWH)= 15.00   FUEL COST($/MMBTU)= 1.70   SUSD COST($)=   0

OPERATION COST OF PEAKERS= $ 98671.00   CODE= 1.00000E+00;

OUTPUT FUNCTION FROM SUBROUTINE DURATION:

7013	5309	5309	4634	3845	3096

FOSSIL INCREMENTS, MUST RUN($/WK) $3,153,795.

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

9193	8742	8538	8417	8429	8704	9242	10457
11689	12269	12448	12446	12345	12436	12257	11919
11960	11715	11464	11238	11482	11847	11290	10133
8753	8384	8220	8140	8154	8410	9002	10229
11407	11952	12227	12245	12158	12218	12119	11772
11744	11667	11349	11233	11433	11764	11153	9972
8717	8331	8202	8189	8168	8390	8786	9794
10706	11173	11294	11340	11267	11222	11126	10786
10669	10615	10357	10241	10512	10984	10472	9493
8743	8159	7895	7808	7694	7778	7850	8316
9088	9721	10008	10074	9939	9801	9651	9508
9515	9490	9397	9291	9589	9888	9517	8793
8049	7617	7256	7256	7199	7190	7132	7411
7985	8374	8528	8656	8729	8649	8453	8365
8357	8385	8324	8276	8726	9415	9175	8585

CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 95   HEAT RATE(MMBTU/MWH)= 12.50   FUEL COST($/MMBTU)= 1.05   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 95   HEAT RATE(MMBTU/MWH)= 12.00   FUEL COST($/MMBTU)= 1.05   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 90   HEAT RATE(MMBTU/MWH)= 12.90   FUEL COST($/MMBTU)= 0.55   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)= 90   HEAT RATE(MMBTU/MWH)= 12.90   FUEL COST($/MMBTU)= 0.55   SUSD COST($)= 100

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CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=  51   HEAT RATE(MMBTU/MWH)= 15.00   FUEL COST($/MMBTU)=  1.70   SUSD COST($)=    0
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=   4   HEAT RATE(MMBTU/MWH)= 15.00   FUEL COST($/MMBTU)=  1.70   SUSD COST($)=    0

            OPERATION COST OF PEAKERS= $  88171.00              CODE= 1.00000E+00;

OUTPUT FUNCTION FROM SUBROUTINE DURATION:
     6345      5505      4641      3762      3077      2260

FOSSIL INCREMENTS, MUST RUN($/WK)      $2,423,449.
```

INPUT VARIABLES FOLLOWS: SYSTE='SYSTEM' MODE='DUR' TRUE= 168 N1= 120
N2= 6 VP= 1 NUMBER=, 2 K= 58
PARAMETER= 0 WEEKS= 5 PECKING='NO '
HYDRO DATA FOLLOWS:
WEEKLY HYDRO GENERATION SCHEDULE, INTERVAL BY INTERVAL (MW)

50	50	50	50	50	50	50	50
200	200	200	200	200	200	200	50
50	50	50	200	200	50	50	50
50	50	50	50	50	50	50	50
200	200	200	200	200	200	200	50
50	50	50	200	200	50	50	50
50	50	50	50	50	50	50	50
200	200	200	200	200	200	200	50
50	50	50	200	200	50	50	50
50	50	50	50	50	50	50	50
50	50	50	50	50	50	50	50
50	50	50	50	50	50	50	50
50	50	50	50	50	50	50	50
50	50	50	50	50	50	50	50
50	50	50	50	50	50	50	50

THE TIME WEIGHING FUNCTION FOLLOWS (NUMBER OF HOURS REPRESENTED BY EACH TIME INTERVAL):

1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
3	3	3	3	3	3	3	3
3	3	3	3	3	3	3	3
3	3	3	3	3	3	3	3
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1
1	1	1	1	1	1	1	1

CODE FOLLOWS(CORRESPONDENCE MAP FROM THE LOAD MODEL TO A 168 HOUR REPRESENTATION):

1	2	3	4	5	6	7	8
9	10	11	12	13	14	15	16
17	18	19	20	21	22	23	24
25	26	27	28	29	30	31	32
33	34	35	36	37	38	39	40
41	42	43	44	45	46	47	48
25	26	27	28	29	30	31	32
33	34	35	36	37	38	39	40
41	42	43	44	45	46	47	48
25	26	27	28	29	30	31	32
33	34	35	36	37	38	39	40
41	42	43	44	45	46	47	48
49	50	51	52	53	54	55	56
57	58	59	60	61	62	63	64
65	66	67	68	69	70	71	72
73	74	75	76	77	78	79	80
81	82	83	84	85	86	87	88
89	90	91	92	93	94	95	96
97	98	99	100	101	102	103	104

105	106	107	108	109	110	111	112
113	114	115	116	117	118	119	120

NUCLEAR INPUT PARAMETERS FOLLOWS:

NUCLEAR INCREMENTAL HEAT RATES:	1.00	1.05
WEEKLY NUCLEAR CAPACITY FACTORS:	0.95	1.00
RATED NUCLEAR CAPACITIES,MW:	1100	440
FULL POWER AVER HEAT RATES:	1.05	1.24

THE FOLLOWING IS THE DECK FILE INPUT FOR LARGE,MEDIUM, SMAL
L FOSSIL PLANTS:

N1= 8 VP1= 4 N2= 6 VP2= 4 N3= 5
VP3= 4:

AVERAGE HEAT RATES FOR LARGE, MEDIUM AND SMALL FOSSIL PLANTS: FRACTION OF RATED POWER, HEAT RATE(MMBTU/MWH)

0.40	0.97	0.60	0.91	0.80	0.89	1.00	0.89
0.40	0.95	0.60	0.91	0.80	0.89	1.00	0.89
0.40	1.35	0.60	1.27	0.80	1.25	1.00	1.28

PLANT PARAMETERS FOR LARGE, MEDIUM AND SMALL FOSSIL PLANTS:
NUMBER, CAPACITY(MW), HEAT RATE(MMBTU/MWH), FUEL COST($/MMBTU)

1.00	450.00	9.00	0.95
1.00	580.00	9.00	0.55
2.00	600.00	9.10	0.50
1.00	800.00	9.40	1.05
2.00	800.00	9.50	0.40
1.00	800.00	9.00	1.10
1.00	1300.00	8.40	1.25
1.00	1300.00	6.50	0.80
1.00	215.00	9.50	0.55
4.00	210.00	9.80	0.55
3.00	225.00	10.00	0.50
1.00	215.00	9.20	0.55
3.00	240.00	9.10	0.80
1.00	280.00	9.30	1.05
1.00	100.00	10.30	0.55
1.00	215.00	12.00	0.40
1.00	105.00	11.80	1.00
3.00	150.00	9.40	0.95
2.00	150.00	9.70	0.55

ECONOMIC LOADING ORDER OF FOSSIL PLANTS
MUST RUN FOSSIL OPERATING LEVEL(MW) = 4858
MINIMIUM FOSSIL FUEL COST($/WK) = $6,001,549.

INCREMENTAL STEP	STEP SIZE (MW)	CUMLATIVE SIZE (MW)	INCREM. GENERATION COST(MILLS/KWH)	CUMLATIVE INCREM. GENERATION COST($/HR)
1	320	320	3.40	1089.28
2	320	640	3.58	2233.63
3	320	960	3.82	3455.07
4	240	1200	4.07	4432.38
5	43	1243	4.16	4611.36
6	240	1483	4.29	5639.92
7	115	1599	4.43	6153.91
8	43	1642	4.46	6345.70

9	240	1882	4.57	7442.58
10	60	1942	4.63	7720.16
11	116	2058	4.66	8261.00
12	135	2193	4.66	8890.50
13	135	2328	4.66	9519.99
14	43	2371	4.72	9722.90
15	43	2414	4.72	9925.81
16	43	2457	4.87	10135.34
17	43	2500	4.87	10344.87
18	60	2560	4.96	10542.46
19	116	2676	4.97	11219.23
20	135	2811	5.00	11394.23
21	168	2979	5.03	12738.70
22	168	3147	5.03	13583.18
23	43	3190	5.06	13800.76
24	20	3210	5.15	13903.78
25	43	[illegible]	5.23	14128.45
26	43	3296	5.25	14354.20
27	168	3464	5.39	15259.72
28	20	3484	5.52	15370.17
29	60	3544	5.84	15720.28
30	260	3304	6.09	17302.59
31	260	4064	6.40	18967.86
32	20	4084	6.50	19097.80
33	144	4228	6.79	20075.45
34	144	4372	6.79	21053.09
35	260	4632	6.83	22823.99
36	144	4776	7.28	23877.31
37	90	4866	7.65	24565.99
38	90	4956	7.74	25262.35
39	90	5046	8.05	25987.74
40	90	5136	8.30	26734.93
41	90	5226	8.59	27507.87
42	160	5386	8.83	28921.21
43	160	5546	8.86	30338.95
44	56	5602	9.11	30348.32
45	56	5658	9.11	31358.79
46	160	5818	9.30	32846.24
47	160	5978	9.32	34339.21
48	260	6238	9.40	36781.48
49	56	6294	9.76	37323.32
50	90	6384	9.77	38207.36
51	260	6644	9.89	40778.74
52	160	5904	9.91	42365.00
53	160	6964	9.94	43956.08
54	21	6985	10.23	44170.97
55	260	7245	10.55	46913.17
56	21	7266	10.97	47143.54
57	21	7287	12.91	47414.58
58	1500	8787	25.00	84914.58

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

9751	9436	9290	9192	9273	9647	10394	11625
12565	12993	13145	13100	12939	12928	12729	12356
12447	12336	12263	12291	12381	12374	11746	10676
9471	9160	9015	8950	9011	9373	10115	11392
12305	12692	12871	12789	12661	12689	12506	12151
12208	12192	12104	12136	12180	12177	11516	10434

9009	8708	8626	8617	8636	8929	9588	10782
11640	12052	12193	12140	11978	11973	11838	11512
11505	11466	11415	11421	11509	11511	10925	9954
9229	8744	8527	3444	8417	8549	8745	9229
9924	10462	10690	10717	10511	10319	10111	9927
9967	10033	10089	10218	10298	10290	9876	9230
8542	8175	7894	7894	7614	7833	7862	8185
8710	9950	8971	9087	9108	8895	8640	8538
8562	8678	3839	9085	9383	9676	9338	8834

CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 95 HEAT RATE(MMBTU/MWH)= 12.00 FUEL COST($/MMBTU)= 1.05 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 95 HEAT RATE(MMBTU/MWH)= 12.50 FUEL COST($/MMBTU)= 1.70 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 95 HEAT RATE(MMBTU/MWH)= 12.00 FUEL COST($/MMBTU)= 1.05 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 90 HEAT RATE(MMBTU/MWH)= 12.90 FUEL COST($/MMBTU)= 0.55 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= [illegible] HEAT RATE(MMBTU/MWH)= 12.90 FUEL COST($/MMBTU)= 0.55 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 51 HEAT RATE(MMBTU/MWH)= 15.00 FUEL COST($/MMBTU)= 1.70 SUSD COST($)= 0
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 4 HEAT RATE(MMBTU/MWH)= 15.00 FUEL COST($/MMBTU)= 1.70 SUSD COST($)= 0

OPERATION COST OF PEAKERS= $ 122647.00 CODE= 1.00000E+00

OUTPUT FUNCTION FROM SUBROUTINE DURATION:

7269 6533 5567 4941 4065 3323

FOSSIL INCREMENTS, MUST RUN($/WK) $3,428,042.

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

9427	9034	8854	8743	8794	9100	9726	10947
12057	12533	12740	12721	12594	12643	12455	12102
12165	11976	11830	11680	11860	12068	11482	10361
9054	8710	8554	8430	8514	8814	9469	10717
11784	12263	12497	12474	12370	12416	12282	11931
11939	11837	11666	11594	11747	11937	11365	10166
8840	8490	8380	8369	8365	8616	9123	10209
11098	11542	11672	11676	11566	11537	11425	11091
11020	10981	10801	10736	10931	11147	10633	9631
9947	8404	8161	9075	7998	8102	8249	8699
9439	10032	10234	10344	10179	10018	9844	9684
9705	9718	9687	9690	9837	10057	9668	8977
8256	7851	7524	7524	7457	7462	7439	7736
8289	8616	8714	9837	8488	8753	8532	8438
8443	8503	8540	8616	9002	9524	9244	8690

CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 95 HEAT RATE(MMBTU/MWH)= 12.00 FUEL COST($/MMBTU)= 1.05 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 95 HEAT RATE(MMBTU/MWH)= 12.50 FUEL COST($/MMBTU)= 1.70 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 95 HEAT RATE(MMBTU/MWH)= 12.00 FUEL COST($/MMBTU)= 1.05 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 90 HEAT RATE(MMBTU/MWH)= 12.90 FUEL COST($/MMBTU)= 0.55 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 90 HEAT RATE(MMBTU/MWH)= 12.90 FUEL COST($/MMBTU)= 0.55 SUSD COST($)= 100
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 51 HEAT RATE(MMBTU/MWH)= 15.00 FUEL COST($/MMBTU)= 1.70 SUSD COST($)= 0
CAPACITY FACTOR= 0.10 RATED CAPACITY(MW)= 4 HEAT RATE(MMBTU/MWH)= 15.00 FUEL COST($/MMBTU)= 1.70 SUSD COST($)= 0

OPERATION COST OF PEAKERS= $ 122547.00 CODE= 1.00000E+00

OUTPUT FUNCTION FROM SUBROUTINE DURATION:

6880 5974 5224 4501 3697 2849

FOSSIL INCREMENTS, MUST RUN($/WK) $2,954,739.

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

9580	9224	9061	8555	9015	9359	10042	11268
12297	12754	12932	12900	12758	12778	12585	12223
12298	12146	12019	11965	12107	12213	11607	10510
9252	8923	8772	8703	8749	9079	9775	11037
12031	12466	12674	12623	12508	12545	12398	12035
12067	12032	11874	11851	11952	12051	11405	10293
8920	8593	8496	8486	8493	8764	9343	10480
11355	11783	11918	11896	11761	11743	11621	11290
11250	11220	11092	11060	11204	11319	10771	9810
9031	8565	8334	8750	9196	8313	8484	6950
9569	10236	10431	10521	10336	10161	9970	9799
9829	9857	9877	9935	10092	10167	9766	9397
8392	8034	7699	7699	7626	7640	7639	7949
8488	8774	8836	8955	8992	8820	8583	6495
8499	8588	8682	8838	9192	9596	9289	8758

CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.00	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.50	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.00	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 51	HEAT RATE(MMBTU/MWH)= 15.00	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 0
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 4	HEAT RATE(MMBTU/MWH)= 15.00	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 0

OPERATION COST OF PEAKERS= $ 122147.00 CODE= 1.00000E+00:

OUTPUT FUNCTION FROM SUBROUTINE DURATION:

7077	6278	5368	4673	3376	3070

FOSSIL INCREMENTS, MUST RUN($/WK) $3,158,475.

WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)

9796	9492	9352	9255	9342	9724	10489	11720
12635	13057	13201	13153	12998	12969	12767	12392
12487	12367	12329	12377	12455	12417	11783	10720
9530	9224	9080	9016	9041	9452	10206	11487
12378	12753	12923	12833	12703	12727	12538	12182
12246	12235	12156	12212	12241	12211	11546	10472
9032	8734	8650	8652	8674	8973	9654	10863
11717	12124	12265	12206	12036	12034	11896	11571
11574	11557	11501	11517	11590	11562	10966	9993
9269	8791	8579	8496	8476	8612	8815	9304
9992	10522	10745	10770	10557	10362	10148	9961
10004	10077	10145	10294	10356	10323	9906	9266
8583	8220	7945	7946	7864	7891	7922	8249
8769	8997	9007	9122	9139	8915	8655	8552
8578	8701	8831	9151	9437	9697	9351	8854

CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.00	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.50	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 95	HEAT RATE(MMBTU/MWH)= 12.00	FUEL COST($/MMBTU)= 1.05	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 90	HEAT RATE(MMBTU/MWH)= 12.90	FUEL COST($/MMBTU)= 0.55	SUSD COST($)= 100
CAPACITY FACTOR= 0.10	RATED CAPACITY(MW)= 51	HEAT RATE(MMBTU/MWH)= 15.00	FUEL COST($/MMBTU)= 1.70	SUSD COST($)= 0

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CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=   4   HEAT RATE(MMBTU/MWH)= 15.00   FUEL COST($/MMBTU)=  1.70   SUSD COST($)=   0

              OPERATION COST OF PEAKERS= $ 122347.00          CODE= 1.00000E+00;

OUTPUT FUNCTION FROM SUBROUTINE DURATION:
    7321      6636      5592      4840      4114      3371

FOSSIL INCREMENTS, MUST RUN($/WK)      $3,451,832.


WEEKLY CUSTOMER DEMAND FUNCTION FOLLOWS:
(INTERVAL BY INTERVAL, MW)
     9242      8834      8605      8486      8504      8788      9344     10560
    11757     12279     12509     12504     12397     12479     12298     11957
    12003     11770     11535     11331     11562     11893     11331     10181
     8317      8453      8290      8211      8230      8495      9100     10332
    11437     12018     12284     12293     12203     12259     12153     11806
    11785     11714     11416     11285     11500     11800     11185     10013
     8743      8365      8240      8227      8210      8434      8857      9881
    10735     11250     11374     11411     11330     11288     11189     10851
    10742     10692     10451     10345     10630     10939     10466      9525
     8780      8211      7951      7665      7758      7844      7966      8397
     9162      9736     10058     10131      9990      9847      9692      9545
     9555      9533      9458      9373      9652      9924      9548      8832
     8093      7656      7313      7313      7253      7241      7197      7479
     8049      8425      8568      9654      9762      9671      8470      8390
     8375      8411      8370      8348      8784      9438      9190      8607

CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=  55   HEAT RATE(MMBTU/MWH)= 12.00   FUEL COST($/MMBTU)=  1.05   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=  55   HEAT RATE(MMBTU/MWH)= 12.50   FUEL COST($/MMBTU)=  1.70   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=  95   HEAT RATE(MMBTU/MWH)= 12.00   FUEL COST($/MMBTU)=  1.05   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=  90   HEAT RATE(MMBTU/MWH)= 12.90   FUEL COST($/MMBTU)=  0.55   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=  90   HEAT RATE(MMBTU/MWH)= 12.90   FUEL COST($/MMBTU)=  0.55   SUSD COST($)= 100
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=  51   HEAT RATE(MMBTU/MWH)= 15.00   FUEL COST($/MMBTU)=  1.70   SUSD COST($)=   0
CAPACITY FACTOR= 0.10   RATED CAPACITY(MW)=   4   HEAT RATE(MMBTU/MWH)= 15.00   FUEL COST($/MMBTU)=  1.70   SUSD COST($)=   0

              OPERATION COST OF PEAKERS= $ 122947.00          CODE= 1.00000E+00;

OUTPUT FUNCTION FROM SUBROUTINE DURATION:
    6675      5693      4939      4120      3474      2663

FOSSIL INCREMENTS, MUST RUN($/WK)      $2,754,775.
```

```
0001          PROGRAM
0002     *
0003     *  THIS  PROGRAM PREFORMS THE  NUCLEAR ENERGY OPTIMIZATION
0004     *                 FOR THE AEP CASE    3
0005          TITLE (' ELECTRIC POWER DISPATCHING SIMULATION')
0006          INITIALZ
0100          MVADR(XDOPRINT,SET)
0101          XSETLB=-1
0102          XFREQLGA=0
0103          XFREQLGC=0
0104          XPARDELT=2.
0105          MOVE(XOBJ,'COST')
0106          MOVE(XPBNAME,'MINIMIZE')
0107          MOVE(XDATA,'SYSTEA01')
0108          EXEC(TIP)
0109          MOVE(XDATA,'SYSTEA02')
0110          EXEC(TIP)
0111          MOVE(XDATA,'SYSTEA03')
0112          EXEC(TIP)
0113          MOVE(XDATA,'SYSTEA04')
0114          EXEC(TIP)
0115          MOVE(XDATA,'SYSTEB01')
0116          EXEC(TIP)
0117          MOVE(XDATA,'SYSTEB02')
0118          EXEC(TIP)
0119          MOVE(XDATA,'SYSTEB03')
0120          EXEC(TIP)
0121          MOVE(XDATA,'SYSTEB04')
0122          EXEC(TIP)
0123          MOVE(XDATA,'SYSTEB05')
0124          EXEC(TIP)
0125          MOVE(XDATA,'SYSTEC01')
0126          EXEC(TIP)
0127          MOVE(XDATA,'SYSTEC02')
0128          EXEC(TIP)
0129          MOVE(XDATA,'SYSTEC03')
0130          EXEC(TIP)
0131          MOVE(XDATA,'SYSTEC04')
0132          EXEC(TIP)
0133          MOVE(XDATA,'SYSTED01')
0134          EXEC(TIP)
0135          MOVE(XDATA,'SYSTED02')
0136          EXEC(TIP)
0137          MOVE(XDATA,'SYSTED03')
0138          EXEC(TIP)
0139          MOVE(XDATA,'SYSTED04')
0140          EXEC(TIP)
0141          MOVE(XDATA,'SYSTED05')
0142          EXEC(TIP)
0143          MOVE(XDATA,'SYSTEE01')
0144          EXEC(TIP)
0145          MOVE(XDATA,'SYSTEE02')
0146          EXEC(TIP)
0147          MOVE(XDATA,'SYSTEE03')
```

```
                EXEC(TIP)
                MOVE(XDATA,'SYSTEE04')
                EXEC(TIP)
                MOVE(XDATA,'SYSTEF01')
                EXEC(TIP)
                MOVE(XDATA,'SYSTEF02')
                EXEC(TIP)
                MOVE(XDATA,'SYSTEF03')
                EXEC(TIP)
                MOVE(XDATA,'SYSTEF04')
                EXEC(TIP)
                EXIT
       TIP      CONVERT('FILE','IN')
                MOVE(XRHS,'RHS001')
                SETUP('BOUND','BOUND1')
                A=0
                EXEC(PARRR)
                STEP
       PARRR    XPARAM=0.
                A=A+1
                IF(A.EQ.1,S2)
                MOVE('OPZSTART','CONTINUE')
                RESTORE('NAME','SA')
       S2       OPTIMIZE
                SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',   X
                'CMASKS','N*******',' ')
                SAVE('NAME','SA')
                MOVE(XCHCOL,'CHC002')
                XPARAM=0.
                XPARMAX=8.
                PARARHS('CONT')
                SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',   X
                'CMASKS','N*******',' ')
                STEP
       SET      SOLUTION('FILE','SOLN','RSECTION','2/4/8','CSECTION','2/4/',   X
                'CMASKS','N*******',' ')
                CONTINUE
       A        DC(0)
                PEND
```

```
 ENTER P.S. MODE AND P.S. CODE
'QUCK'  1

 ENTER PUMPED STORAGE PARAMETERS:              CAPACITY, RATIO, CAP_PUMP, RESERIOR, FREE, START,BYE,TOLERANCE
300  .7  160  9300  2300  7600  1  200


 ENTER NUMBER OF WEEKLY PERMUTATIONS
 5

 SIMULATION DESCRIPTION:
'APRIL  CONFIGURATION,  WEEK 1 , NO P.S. CALC.'


 OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR    1 WEEK:     1 ALLOCATION                                 INDEX=         1
          L.P. PARAMETERS
    OBJECTIVE  FUNCTION       COST
    RHS                       RHS001
    STATUS                    MIN
    NUMBER  OF ITERATIONS               41
FIXED FOSSIL FUEL COST($/WK)      $10,111,616.   VARIABLE FOSSIL FUEL COST($/WK)       $110,538.
 SYSTEM COST WITHOUT PUMPED STORAGE, $10,222,155.

    REACTOR        NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)       OCNP  (MILLS/KWH)
       1                    4.72                                                   4.96
       2                    3.44                                                   4.96

NUCLEAR UNIT DISPATCHING:
INTERVAL  WEIGHTING FACTOR       DEMAND         FOSSIL         NUCLEAR 1         NUCLEAR 2         NUCLEAR 3     ...
               (HOURS)            (MW)           (MW)            (MW)              (MW)              (MW)
    1            62               7348           6028            1100              220
    2            16               6733           5413            1100              220
    3            17               5661           4341            1100              220
    4            20               4889           3569            1100              220
    5            33               4196           2876            1100              220
    6            20               3427           2571             638              218


 OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR    1 WEEK;     2 ALLOCATION                                 INDEX=         2
          L.P. PARAMETERS
    OBJECTIVE  FUNCTION       COST
    RHS                       RHS001
    STATUS                    MIN
    NUMBER  OF ITERATIONS               46
FIXED FOSSIL FUEL COST($/WK)      $10,111,616.   VARIABLE FOSSIL FUEL COST($/WK)       $197,402.
 SYSTEM COST WITHOUT PUMPED STORAGE, $10,309,019.

    REACTOR        NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)       OCNP  (MILLS/KWH)
       1                    4.79                                                   5.03
       2                    3.49                                                   5.03
```

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	62	7348	6028	1100	220		
2	16	6733	5413	1100	220		
3	17	5661	4341	1100	220		
4	20	4889	3569	1100	220		
5	33	4196	3176	800	220		
6	20	3427	2942	267	218		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 1 WEEK: 3 ALLOCATION INDEX= 3
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 53
FIXED FOSSIL FUEL COST($/WK) $10,111,616. VARIABLE FOSSIL FUEL COST($/WK) $287,819.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,399,436.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	5.56	5.83
2	3.51	5.06

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	62	7348	6028	1100	220		
2	16	6733	5413	1100	220		
3	17	5661	4341	1100	220		
4	20	4989	3569	1100	220		
5	33	4196	3539	437	220		
6	20	3427	3209	0	218		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 1 WEEK: 4 ALLOCATION INDEX= 4
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 56
FIXED FOSSIL FUEL COST($/WK) $10,111,616. VARIABLE FOSSIL FUEL COST($/WK) $392,997.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,504,614.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	5.80	6.09
2	3.51	5.06

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	62	7348	6028	1100	220		

2	16	6733	5413	1100	220
3	17	5661	4341	1100	220
4	20	4889	3715	954	220
5	33	4196	3976	0	220
6	20	3427	3209	0	218

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 1 WEEK: 5 ALLOCATION INDEX= 5
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 57
FIXED FOSSIL FUEL COST($/WK) $10,111,616. VARIABLE FOSSIL FUEL COST($/WK) $501,569.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,613,185.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	6.10	6.40
2	3.51	5.06

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	62	7343	6023	1100	220		
2	16	6733	5413	1100	220		
3	17	5661	4341	1100	220		
4	20	4889	4581	88	220		
5	33	4196	3976	0	220		
6	20	3427	3209	0	218		

ENTER NUMBER OF WEEKLY PERMUTATIONS
5

SIMULATION DESCRIPTION:
'APRIL CONFIGURATION, WEEK 2 , NO P.S. CALC.'

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 2 WEEK: 1 ALLOCATION INDEX= 6
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 46
FIXED FOSSIL FUEL COST($/WK) $10,269,629. VARIABLE FOSSIL FUEL COST($/WK) $200,515.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,470,144.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.76	5.00
2	3.47	5.00

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	65	7534	6214	1100	220		
2	14	6898	5578	1100	220		
3	15	5881	4561	1100	220		
4	22	5107	3787	1100	220		
5	31	4403	3083	1100	220		
6	21	3595	2717	660	218		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 2 WEEKS: 2 ALLOCATION INDEX= 7
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 53
FIXED FOSSIL FUEL COST($/WK) $10,269,629. VARIABLE FOSSIL FUEL COST($/WK) $287,750.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,557,379.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.84	5.08
2	3.53	5.08

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	65	7534	6214	1100	220		
2	14	6898	5578	1100	220		
3	15	5881	4561	1100	220		
4	22	5107	3787	1100	220		
5	31	4403	3299	884	220		
6	21	3595	3223	154	218		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 2 WEEKS: 3 ALLOCATION INDEX= 8
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 59
FIXED FOSSIL FUEL COST($/WK) $10,269,629. VARIABLE FOSSIL FUEL COST($/WK) $385,117.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,654,746.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	5.80	6.09
2	3.74	5.39

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	65	7534	6214	1100	220		

2	14	6898	5578	1100	220
3	15	5381	4561	1100	220
4	22	5107	3787	1100	220
5	31	4403	3754	429	220
6	21	3595	3377	0	218

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 2 WEEK; 4 ALLOCATION INDEX= 9
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 61
FIXED FOSSIL FUEL COST($/WK) $10,269,629. VARIABLE FOSSIL FUEL COST($/WK) $490,628.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,760,257.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	6.10	6.40
2	3.74	5.39

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	65	7534	6214	1100	220		
2	14	6898	5578	1100	220		
3	15	5381	4561	1100	220		
4	22	5107	4090	797	220		
5	31	4403	4098	86	220		
6	21	3595	3377	0	218		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 2 WEEK; 5 ALLOCATION INDEX= 10
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 65
FIXED FOSSIL FUEL COST($/WK) $10,269,629. VARIABLE FOSSIL FUEL COST($/WK) $602,553.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,872,183.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	6.47	6.79
2	3.74	5.39

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	65	7534	6214	1100	220		
2	14	6898	5578	1100	220		
3	15	5381	4610	1051	220		
4	22	5107	4724	163	220		
5	31	4403	4183	0	220		

6	21	3595	3377	0	219	

ENTER NUMBER OF WEEKLY PERMUTATIONS
5

SIMULATION DESCRIPTION:
'APRIL CONFIGURATION, WEEK 3 , NO P.S. CALC.'

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 3 WEEK: 1 ALLOCATION INDEX= 11
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 45
FIXED FOSSIL FUEL COST($/WK) $9,666,127. VARIABLE FOSSIL FUEL COST($/WK) $154,901.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,821,028.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.44	4.65
2	3.24	4.66

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	61	7013	5693	1100	220		
2	17	6309	4989	1100	220		
3	15	5309	3989	1100	220		
4	19	4634	3314	1100	220		
5	39	3845	2525	1100	220		
6	17	3096	2322	556	218		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 3 WEEK: 2 ALLOCATION INDEX= 12
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 54
FIXED FOSSIL FUEL COST($/WK) $9,666,127. VARIABLE FOSSIL FUEL COST($/WK) $240,207.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,906,335.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.76	5.00
2	3.47	5.00

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...

1	61	7013	5693	1100	220
2	17	6309	4989	1100	220
3	15	5309	3989	1100	220
4	19	4634	3314	1100	220
5	39	3845	2802	823	220
6	17	3096	2705	173	218

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 3 WEEK: 3 ALLOCATION INDEX= 13
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 58
FIXED FOSSIL FUEL COST($/WK) $9,666,127. VARIABLE FOSSIL FUEL COST($/WK) $327,193.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,993,321.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.79	5.03
2	3.49	5.03

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	61	7013	5693	1100	220		
2	17	6309	4989	1100	220		
3	15	5309	3989	1100	220		
4	19	4634	3314	1100	220		
5	39	3845	3176	449	220		
6	17	3096	2866	12	219		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 3 WEEK: 4 ALLOCATION INDEX= 14
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 65
FIXED FOSSIL FUEL COST($/WK) $9,666,127. VARIABLE FOSSIL FUEL COST($/WK) $418,848.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,084,976.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	5.56	5.83
2	3.49	5.03

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	61	7013	5693	1100	220		
2	17	6309	4989	1100	220		
3	15	5309	3989	1100	220		
4	19	4634	3510	904	220		

5	39	3845	3520	105	220
6	17	3096	2878	0	218

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 3 WEEK: 5 ALLOCATION INDEX= 15
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 70
FIXED FOSSIL FUEL COST($/WK) $9,666,127. VARIABLE FOSSIL FUEL COST($/WK) $523,724.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,189,852.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	DCNP (MILLS/KWH)
1	6.10	6.40
2	3.49	5.03

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	61	7013	5693	1100	220		
2	17	6309	4989	1100	220		
3	15	5309	4090	999	220		
4	19	4634	4126	288	220		
5	39	3845	3625	0	220		
6	17	3096	2878	0	218		

ENTER NUMBER OF WEEKLY PERMUTATIONS
5

SIMULATION DESCRIPTION:
'APRIL CONFIGURATION, WEEK 4 , NO P.S. CALC.'

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 4 WEEK: 1 ALLOCATION INDEX= 16
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 45
FIXED FOSSIL FUEL COST($/WK) $8,935,281. VARIABLE FOSSIL FUEL COST($/WK) $164,471.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,099,753.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	DCNP (MILLS/KWH)
1	4.25	4.46
2	3.10	4.46

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR	DEMAND	FOSSIL	NUCLEAR 1	NUCLEAR 2	NUCLEAR 3	...

	(HOURS)	(MW)	(MW)	(MW)	(MW)	(MW)
1	60	6345	5025	1100	220	
2	15	5505	4185	1100	220	
3	20	4641	3321	1100	220	
4	22	3762	2442	1100	220	
5	39	3077	1757	1100	220	
6	12	2260	1713	330	217	

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 4 WEEK; 2 ALLOCATION INDEX= 17
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 54
FIXED FOSSIL FUEL COST($/WK) $8,935,281. VARIABLE FOSSIL FUEL COST($/WK) $244,227.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,179,509.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.44	4.66
2	3.24	4.66

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	60	6345	5025	1100	220		
2	15	5505	4185	1100	220		
3	20	4641	3321	1100	220		
4	22	3762	2442	1100	220		
5	39	3077	2100	757	220		
6	12	2260	2043	0	217		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 4 WEEK; 3 ALLOCATION INDEX= 18
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 60
FIXED FOSSIL FUEL COST($/WK) $8,935,281. VARIABLE FOSSIL FUEL COST($/WK) $325,575.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,260,856.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.54	4.77
2	3.24	4.66

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	60	6345	5025	1100	220		
2	15	5505	4185	1100	220		
3	20	4641	3321	1100	220		

4	22	3762	2469	1074	220
5	39	3077	2529	328	220
6	12	2260	2043	0	217

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 4 WEEKS: 4 ALLOCATION INDEX= 19
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 65
FIXED FOSSIL FUEL COST($/WK) $8,935,281. VARIABLE FOSSIL FUEL COST($/WK) $411,544.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,346,825.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.76	5.00
2	3.24	4.66

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	60	6345	5025	1100	220		
2	15	5505	4185	1100	220		
3	20	4641	3321	1100	220		
4	22	3762	2705	837	220		
5	39	3077	2840	17	220		
6	12	2260	2043	0	217		

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 4 WEEKS: 5 ALLOCATION INDEX= 20
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHS001
STATUS MIN
NUMBER OF ITERATIONS 74
FIXED FOSSIL FUEL COST($/WK) $8,935,281. VARIABLE FOSSIL FUEL COST($/WK) $499,793.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,435,075.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	5.13	5.39
2	3.24	4.66

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	60	6345	5025	1100	220		
2	15	5505	4185	1100	220		
3	20	4641	3342	1079	220		
4	22	3762	3443	99	220		
5	39	3077	2857	0	220		
6	12	2260	2043	0	217		

ENTER P.S. MODE AND P.S. CODE

```
'QUICK'  1

 ENTER PUMPED STORAGE PARAMETERS:              CAPACITY, RATIO, CAP_PUMP, RESERIOR, FREE, START,BYE,TOLERANCE
300  .7  160  9300  2300  7600  1  200



 ENTER NUMBER OF WEEKLY PERMUTATIONS
 5

 SIMULATION DESCRIPTION:
'MAY    CONFIGURATION,  WEEK  5, NO P.S. CALC.'



 OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR    1 WEEKS:    1 ALLOCATION                                 INDEX=        21
         L.P. PARAMETERS
    OBJECTIVE  FUNCTION        COST
    RHS                        RHSC01
    STATUS                     MIN
    NUMBER  OF ITERATIONS              43
FIXED FOSSIL FUEL COST($/WK)       $9,552,238.   VARIABLE FOSSIL FUEL COST($/WK)       $123,774.
 SYSTEM COST WITHOUT PUMPED STORAGE,  $9,676,013.

    REACTOR         NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)        OCNP  (MILLS/KWH)
        1                    4.64                                                4.87
        2                    3.93                                                4.87

NUCLEAR UNIT DISPATCHING:
INTERVAL  WEIGHTING FACTOR       DEMAND          FOSSIL          NUCLEAR 1         NUCLEAR 2         NUCLEAR 3       ...
               (HOURS)            (MW)            (MW)             (MW)              (MW)              (MW)
    1            62               7269            5729             1100              440
    2            17               6533            4993             1100              440
    3            14               5567            4027             1100              440
    4            23               4841            3301             1100              440
    5            39               4065            2525             1100              440
    6            14               3323            2448              440              435


 OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR    1 WEEK:     2 ALLOCATION                                 INDEX=        22
         L.P. PARAMETERS
    OBJECTIVE  FUNCTION        COST
    RHS                        RHS001
    STATUS                     MIN
    NUMBER  OF ITERATIONS              51
FIXED FOSSIL FUEL COST($/WK)       $9,552,238.   VARIABLE FOSSIL FUEL COST($/WK)       $210,089.
 SYSTEM COST WITHOUT PUMPED STORAGE,  $9,762,328.

    REACTOR         NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)        OCNP  (MILLS/KWH)
        1                    4.79                                                5.03
        2                    4.05                                                5.03
```

```
NUCLEAR UNIT DISPATCHING:
INTERVAL  WEIGHTING FACTOR       DEMAND         FOSSIL        NUCLEAR 1        NUCLEAR 2        NUCLEAR 3        ...
              (HOURS)             (MW)           (MW)           (MW)             (MW)             (MW)
    1           62                7269           5729           1100             440
    2           17                6533           4993           1100             440
    3           14                5567           4027           1100             440
    4           23                4841           3301           1100             440
    5           38                4065           2847            778             440
    6           14                3323           2811             77             435
```

```
 OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR    1 WEEK;     3 ALLOCATION                                    INDEX=        23
         L.P. PARAMETERS
    OBJECTIVE  FUNCTION        COST
    RHS                        RHSC01
    STATUS                     MIN
    NUMBER  OF ITERATIONS              57
FIXED FOSSIL FUEL COST($/WK)       $9,552,238.   VARIABLE FOSSIL FUEL COST($/WK)       $297,833.
 SYSTEM COST WITHOUT PUMPED STORAGE,  $9,850,072.

    REACTOR        NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)       OCNP  (MILLS/KWH)
       1                    5.0C                                                    5.25
       2                    4.C5                                                    5.03
```

```
NUCLEAR UNIT DISPATCHING:
INTERVAL  WEIGHTING FACTOR       DEMAND         FOSSIL        NUCLEAR 1        NUCLEAR 2        NUCLEAR 3        ...
              (HOURS)             (MW)           (MW)           (MW)             (MW)             (MW)
    1           62                7269           5729           1100             440
    2           17                6533           4993           1100             440
    3           14                5567           4027           1100             440
    4           23                4841           3301           1100             440
    5           38                4065           3275            350             440
    6           14                3323           2888              0             435
```

```
 OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR    1 WEEK;     4 ALLOCATION                                    INDEX=        24
         L.P. PARAMETERS
    OBJECTIVE  FUNCTION        COST
    RHS                        RHSC01
    STATUS                     MIN
    NUMBER  OF ITERATIONS              64
FIXED FOSSIL FUEL COST($/WK)       $9,552,238.   VARIABLE FOSSIL FUEL COST($/WK)       $393,939.
 SYSTEM COST WITHOUT PUMPED STORAGE,  $9,946,178.

    REACTOR        NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)       OCNP  (MILLS/KWH)
       1                    5.80                                                    6.09
       2                    4.65                                                    5.03
```

```
NUCLEAR UNIT DISPATCHING:
INTERVAL  WEIGHTING FACTOR       DEMAND         FOSSIL        NUCLEAR 1        NUCLEAR 2        NUCLEAR 3        ...
              (HOURS)             (MW)           (MW)           (MW)             (MW)             (MW)
    1           62                7269           5729           1100             440
```

2	17	6533	4993	1100	440
3	14	5567	4027	1100	440
4	23	4841	3544	857	440
5	38	4065	3584	41	440
6	14	3323	2888	0	435

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 1 WEEK: 5 ALLOCATION INDEX= 25
L.P. PARAMETERS
OBJECTIVE FUNCTION COST
RHS RHSC01
STATUS MIN
NUMBER OF ITERATIONS 70
FIXED FOSSIL FUEL COST($/WK) $9,552,239. VARIABLE FOSSIL FUEL COST($/WK) $503,535.
SYSTEM COST WITHOUT PUMPED STORAGE, $10,055,774.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	6.47	6.79
2	4.05	5.03

NUCLEAR UNIT DISPATCHING:

INTERVAL	WEIGHTING FACTOR (HOURS)	DEMAND (MW)	FOSSIL (MW)	NUCLEAR 1 (MW)	NUCLEAR 2 (MW)	NUCLEAR 3 (MW)	...
1	62	7269	5729	1100	440		
2	17	6533	4993	1100	440		
3	14	5567	4084	1043	440		
4	23	4841	4194	207	440		
5	38	4065	3625	0	440		
6	14	3323	2888	0	435		

ENTER NUMBER OF WEEKLY PERMUTATIONS
5

SIMULATION DESCRIPTION:
'MAY CONFIGURATION, WEEK 6, NO P.S. CALC.'

OPTIMAL NUCLEAR GENERATION SCHEDULE
FOR 2 WEEKS: 1 ALLOCATION INDEX= 26
L.P. PARAMETERS.
OBJECTIVE FUNCTION COST
RHS RHSC01
STATUS MIN
NUMBER OF ITERATIONS 42
FIXED FOSSIL FUEL COST($/WK) $9,078,835. VARIABLE FOSSIL FUEL COST($/WK) $164,054.
SYSTEM COST WITHOUT PUMPED STORAGE, $9,242,890.

REACTOR	NUCLEAR L.P. OPPORTUNITY COST ($/MILLION BTU-TH)	OCNP (MILLS/KWH)
1	4.44	4.66
2	3.76	4.66

APPENDIX D: ALLOCAT

D.1 Input Specifications

Input Variable Names listed by order of input on file SYSIN:

NCF: Overall nuclear capacity factor for the planning period.

WEEKS: Number of weeks in the planning period.

LENGTH: One more than the maximum number of OCNP data points in a weekly curve.

KEY= 'SAME', if all weekly sets of OCNP values are obtained from a single set of weekly nuclear capacity factors; else KEY=(any four characters).

N=number of OCNP values in weekly representation

INTERVALS(N)=interval spacing of OCNP values

OCNP(N)=OCNP data values

If KEY≠'SAME' then the last three variables are repeated WEEKS times. If KEY='SAME' then N and INTERVALS need be listed only once.

NOTES: The number of OCNP data points for each week need not be the same. The algorithm is given in Section 4.3.

```
//  EXEC PLIXCLG,
//  PARM.C='NAG,NOESD,       NOP,NSTG,NX,NS,NA',
//  PARM.L='LIST,MAP,DCBS',
//   PARM.G='REPORT,ISASIZE(1)'
//C.SYSIN  DD *,DCB=BLKSIZE=2000
  ALLOCAT  : PROC OPTIONS(MAIN);
 DCL KEY CHAR(4);
 DCL (NCF) FIXED DEC(6,2), (WEEKS,LENGTH) FIXED DEC;
 ON ENDFILE(SYSIN) GO TO BOTTOM;
 TOP:
 GET LIST (NCF, WEEKS, LENGTH, KEY);
 PUT DATA (NCF, WEEKS, LENGTH, KEY);
 NCF=NCF*WEEKS;
 BLOCK: BEGIN;
 DCL ( INCR(WEEKS,LENGTH), OCNP(WEEKS,LENGTH),MASK1(WEEKS),
 MASK2(WEEKS), MASK3(WEEKS), MASK4(WEEKS), MAX) FIXED DEC(6,2),
 (INDEX(WEEKS) ,NUMBER, I, J, K  ) FIXED BIN;
 OCNP,INCR=0;
 PUT EDIT(' OCNP TABLE FOLLOWS:')(A) SKIP(2);
 DO I=1 TO WEEKS;
 IF (I>1) & (KEY='SAME')    THEN DO;
 DO J=1 TO NUMBER;
 INCR(I,J)=INCR(1,J);
 END;
 GO TO READ;
 END;
 GET LIST(NUMBER);
 GET LIST((INCR(I,J) DO J=1 TO NUMBER));
 READ:
 GET LIST((OCNP(I,J) DO J=1 TO NUMBER));
 PUT EDIT((OCNP(I,J) DO J=1 TO NUMBER))( 18 F(7,2))SKIP;
 MASK1(I)=INCR(I,1);
 MASK2(I)=INCR(I,2);
 MASK3(I)=OCNP(I,1);
 MASK4(I)=OCNP(I,2);
 INDEX(I)=2;
```

```
END;
PUT EDIT(' INCREMENTAL STEP TABLE FOLLOWS:')(A) SKIP(2);
DO I=1 TO WEEKS;
PUT EDIT((INCR(I,J) DO J=1 TO LENGTH))( 18 F(7,2))SKIP;
END;
NCF=NCF-SUM(MASK1);
DO J=1 TO (LENGTH-1)*WEEKS;
MAX=MASK4(1);
NUMBER=1;
DO I=2 TO WEEKS;
IF MAX < MASK4(I) THEN DO;
 MAX=MASK4(I);
 NUMBER=I;
 END;
END;
NCF=NCF-MASK2(NUMBER);
MASK1(NUMBER)=MASK1(NUMBER)+MASK2(NUMBER);
MASK3(NUMBER)=MAX;
IF NCF>0 THEN GO TO BOT;
IF NCF=0 THEN GO TO SOLN;
MASK1(NUMBER)=MASK1(NUMBER)+NCF;
GO TO SOLN;
BOT:
INDEX(NUMBER)=INDEX(NUMBER)+1;
 MASK2(NUMBER)=INCR(NUMBER,INDEX(NUMBER));
 MASK4(NUMBER)=OCNP(NUMBER,INDEX(NUMBER));
END;
SOLN:
PUT EDIT(' INTER-WEEKLY OPTIMAL  WEEKLY NUCLEAR CAPACITY FACTOR DISTRIB
UTION')(A) PAGE;
PUT EDIT(' WEEKS','CAPACITY FACTORS','OCNP')( 3(A,X(5)))SKIP;
DO K=1 TO WEEKS;
PUT EDIT(K,MASK1(K), MASK3(K))( F(5),X(12),F(6,2),X(7),F(6,2))SKIP;
END;
END BLOCK;
PUT PAGE;
```

```
 GO TO TOP;                                                                          ALLC0073
 BOTTOM:                                                                             ALLC0074
 END ALLOCAT  ;                                                                      ALLC0075
//L.SYSLMOD  DD DSN=U.M9960.8981.LIBRARY.LOAD(ALLOCAT),DISP=OLD,                    ALLC0076
// DCB=BLKSIZE=13030,SPACE=                                                          ALLC0077
//G.PLIDUMP  DD SYSOUT=A                                                             ALLC0078
//G.SYSIN DD *,DCB=BLKSIZE=2000                                                      ALLC0079
//G.SYSIN DD *,DCB=BLKSIZE=2000                                                      ALLC0080
.7  26  10  'SAME'                                                                   ALLC0081
9  .55  .05  .05  .05  .05  .05  .05  .05  .05                                      ALLC0082
    6.83    6.83    6.83    6.79    6.79    6.79    6.40    6.40    6.40             ALLC0083
    6.83    6.83    6.83    6.83    6.83    6.83    6.83    6.79    6.79             ALLC0084
    6.79    6.40    6.40    6.40    6.40    6.40    6.40    6.40    6.40             ALLC0085
    6.09    6.09    6.09    6.09    6.09    6.09    5.84    5.39    5.39             ALLC0086
    7.28    6.83    6.83    6.83    6.83    6.83    6.79    6.79    6.79             ALLC0087
    6.79    6.79    6.79    6.79    6.40    6.40    6.40    6.40    6.40             ALLC0088
    6.83    6.83    6.79    6.79    6.79    6.79    6.79    6.40    6.40             ALLC0089
    7.28    7.28    6.83    6.83    6.83    6.83    6.79    6.79    6.79             ALLC0090
    6.79    6.40    6.40    6.40    6.40    6.09    6.09    6.09    6.09             ALLC0091
    6.79    6.50    6.40    6.40    6.40    6.40    6.40    6.40    6.40             ALLC0092
    6.83    6.83    6.79    6.79    6.79    6.50    6.40    6.40    6.40             ALLC0093
    6.40    6.40    6.40    6.40    6.40    6.40    6.40    6.09    6.09             ALLC0094
    6.40    6.40    6.09    6.09    6.09    6.09    6.09    6.09    6.09             ALLC0095
    5.25    5.23    5.08    5.06    5.03    5.03    5.03    5.03    5.00             ALLC0096
    6.83    6.83    6.79    6.79    6.79    6.79    6.40    6.40    6.40             ALLC0097
    6.79    6.79    6.40    6.40    6.40    6.40    6.09    6.09    6.09             ALLC0098
    6.83    6.83    6.83    6.79    6.79    6.79    6.79    6.50    6.40             ALLC0099
    6.83    6.79    6.79    6.79    6.79    6.40    6.40    6.40    6.40             ALLC0100
    8.86    8.83    8.83    8.49    8.49    8.30    8.30    7.74    7.74             ALLC0101
    7.74    7.28    7.28    6.83    6.83    6.83    6.83    6.83    6.83             ALLC0102
    7.74    7.28    7.28    6.83    6.83    6.83    6.83    6.83    6.83             ALLC0103
    8.86    8.83    8.83    8.83    8.49    8.30    8.30    7.74    7.74             ALLC0104
    6.40    6.40    6.40    6.40    6.40    6.09    6.09    6.09    6.09             ALLC0105
    7.28    7.28    7.28    6.83    6.83    6.83    6.83    6.79    6.79             ALLC0106
    6.83    6.79    6.79    6.79    6.79    6.79    6.40    6.40    6.40             ALLC0107
    6.83    6.83    6.83    6.79    6.79    6.79    6.79    6.50    6.40             ALLC0108
```

APPENDIX D.3 SAMPLE OUTPUT FROM ALLOCAT

```
NCF=      0.70           WEEKS=       26           LENGTH=       10           KEY='SAME';
```

OCNP TABLE FOLLOWS:

6.83	6.83	6.83	6.79	6.79	6.79	6.40	6.40	6.40
6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.79	6.79
6.79	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40
6.09	6.09	6.09	6.09	6.09	6.09	5.84	5.39	5.39
7.28	6.83	6.83	6.83	6.83	6.83	6.79	6.79	6.79
6.79	6.79	6.79	6.79	6.40	6.40	6.40	6.40	6.40
6.83	6.83	6.79	6.79	6.79	6.79	6.79	6.40	6.40
7.28	7.28	6.83	6.83	6.83	6.83	6.79	6.79	6.79
6.79	6.40	6.40	6.40	6.40	6.09	6.09	6.09	6.09
6.79	6.50	6.40	6.40	6.40	6.40	6.40	6.40	6.40
6.83	6.83	6.79	6.79	6.79	6.50	6.40	6.40	6.40
6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.09	6.09
6.40	6.40	6.09	6.09	6.09	6.09	[illegible]	6.09	6.09
5.25	5.23	5.08	5.06	5.03	5.03	[illegible]	5.03	5.00
6.83	6.83	6.79	6.79	6.79	6.79	6.40	6.40	6.40
6.79	6.79	6.40	6.40	6.40	6.40	6.09	6.09	6.09
6.83	6.83	6.83	6.79	6.79	6.79	6.79	6.50	6.40
6.83	6.79	6.79	6.79	6.79	6.40	6.40	6.40	6.40
8.86	8.83	8.83	8.49	8.49	8.30	8.30	7.74	7.74
7.74	7.28	7.28	6.83	6.83	6.83	6.83	6.83	6.83
7.74	7.28	7.28	6.83	6.83	6.83	6.83	6.83	6.83
8.86	8.83	8.33	8.83	8.49	8.30	8.30	7.74	7.74
6.40	6.40	6.40	6.40	6.40	6.09	6.09	6.09	6.09
7.28	7.28	7.28	6.83	6.83	6.83	6.83	6.79	6.79
6.83	6.79	6.79	6.79	6.79	6.79	6.40	6.40	6.40
6.83	6.83	6.83	6.79	6.79	6.79	6.79	6.50	6.40

INCREMENTAL STEP TABLE FOLLOWS:

0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00
0.55	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00

INTER-WEEKLY OPTIMAL WEEKLY NUCLEAR CAPACITY FACTOR DISTRIBUTION

WEEKS	CAPACITY FACTORS	OCNP
1	0.80	6.79
2	0.95	6.79
3	0.55	6.79
4	0.55	6.09
5	0.95	6.79
6	0.70	6.79
7	0.80	6.79
8	0.90	6.83
9	0.55	6.79
10	0.55	6.79
11	0.60	6.83
12	0.55	6.40
13	0.55	6.40
14	0.55	5.25
15	0.60	6.83
16	0.55	6.79
17	0.65	6.83
18	0.55	6.83
19	0.95	7.74
20	0.95	6.83
21	0.95	6.83
22	0.95	7.74
23	0.55	6.40
24	0.85	6.83
25	0.55	6.83
26	0.65	6.83

Appendix E: Effect of Time Value of Money

An experiment was made in which the result of optimizing a system for minimum discounted production cost was compared with result of optimizing the the system for minimum undiscounted production cost. Although the optimum system generation schedules for the two cases were quite different, a comparison of discounted production costs for both schedules showed that they were practically identical. In summary, disregarding the time value of money has very little effect on the financial consequences of the short-range optimization.

A system of four units with a system capacity of 2400 MWe of which 44% was nuclear was studied over a one-year time horizon with a discount factor of 8%. Table E.1 lists the parameters used. The time horizon used in this study was one year, consisting of 26 equal time intervals. The biweekly electric system demand was obtained by using 1% of the total biweekly demand of electricity of the United States, from June 1971 to May 1972 (15). The system under consideration consisted of two 536 MWe nuclear plants, each with the heat-rate vs. % power characteristics given in Table E.1 and two 670 MWe fossil plants with the heat-rate vs. % power characteristics given there. These average heat-rate characteristics are those recommended by Commonwealth Edison. The cost of heat to each nuclear plant was taken as 0.45 mills/KWHt; to fossil unit No. 1, 1.8 mills/KWHt; and to fossil unit No. 2, 2.0 mills/KWHt.

TABLE E.1

PARAMETERS OF THE COST OF MONEY EXPERIMENT

PERIOD	BIWEEKLY (10^6KWH) DEMAND
1	617
2	669
3	665
4	666
5	638
6	667
7	657
8	654
9	613
10	594
11	590
12	606
13	603
14	635
15	631
16	619
17	654
18	670
19	645
20	645
21	638
22	628
23	629
24	625
25	615
26	638

2 Identical Fossil Units
670 MWe capacity

% Power	33%	50%	70%	100%
Heat Rate	9,920	9,340	8,980	8,950

Unit 1: 1.8 mills/KWHt fuel cost
Unit 2: 2.0 mills/KWHt fuel cost

2 Identical Nuclear Units
536 MWe capacity

% Power	30%	50%	70%	100%
Heat Rate (Btu/Kwhr)	13,200	11,800	11,000	10,500

Unit 3: refuel date, period No. 20
before refueling, 77% avg capacity factor
after refueling, 99% avg capacity factor

Unit 4: refuel date, period No. 10
before refueling, 72% avg capacity factor
after refueling, 96% avg capacity factor

Average cost of Nuclear Heat
0.45 mills/KWHt

Thermal energy available in one nuclear unit (No. 3) was limited to 8.5 million MWHt, prior to scheduled refueling in biweekly period No. 20. After refueling, this unit was assumed available 99% of the time. The thermal energy available in the second nuclear unit (No. 4) was limited to 4.0 million MWHt prior to refueling in biweekly period No. 10. After refueling, this unit was assumed to be available 96% of the time. Refueling downtime was neglected.

The method of optimization used was linear programming, IBM's MPSX program product. The objective function was the variable costs of this system, assumed to be the cost of the fuel for the fossil plants and the income tax depreciation credit for the nuclear heat utilized.

The solution of the optimization studies is displayed as follows: in Figures E.1 and E.2, the solid lines plot the biweekly generation distribution for each of the system's units for the case of no discounting, i.e., zero effective cost of money; and, the dashed lines display the case of discounting both the fossil fuel costs and the nuclear fuel tax credits.

From the comparison of the solid and dashed lines, notice that the effect of the discounting is to shift the assignment of the fossil units to operate at lower capacity factors in the earlier time intervals and at higher capacity in the later time intervals. Correspondingly, the nuclear units are operating at higher capacity factors in the earlier time periods. This is not surprising because

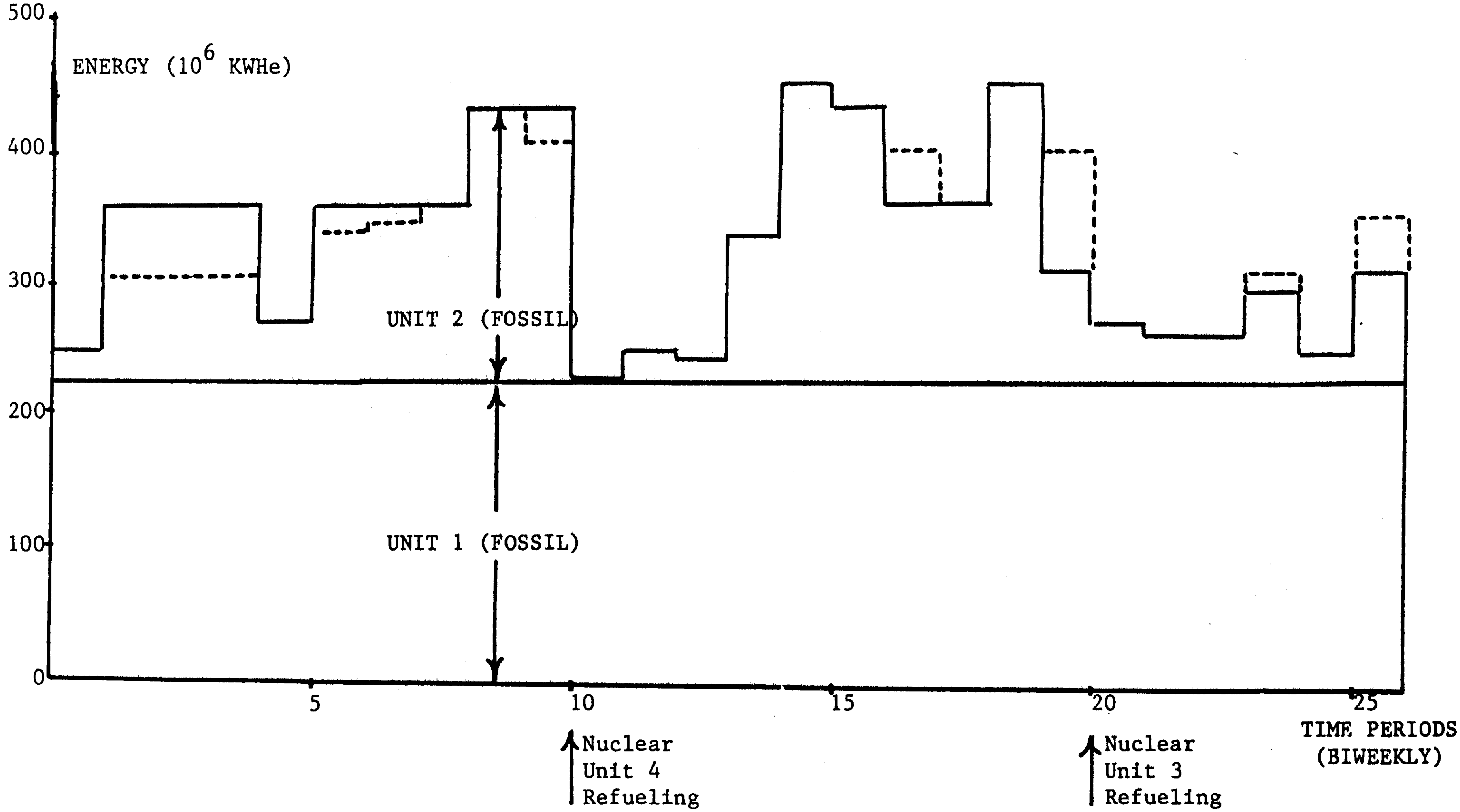

Figure E.1 FOSSIL PRODUCTION SCHEDULE

Legend
____ no discounting production schedule
---- production shift due to discounting

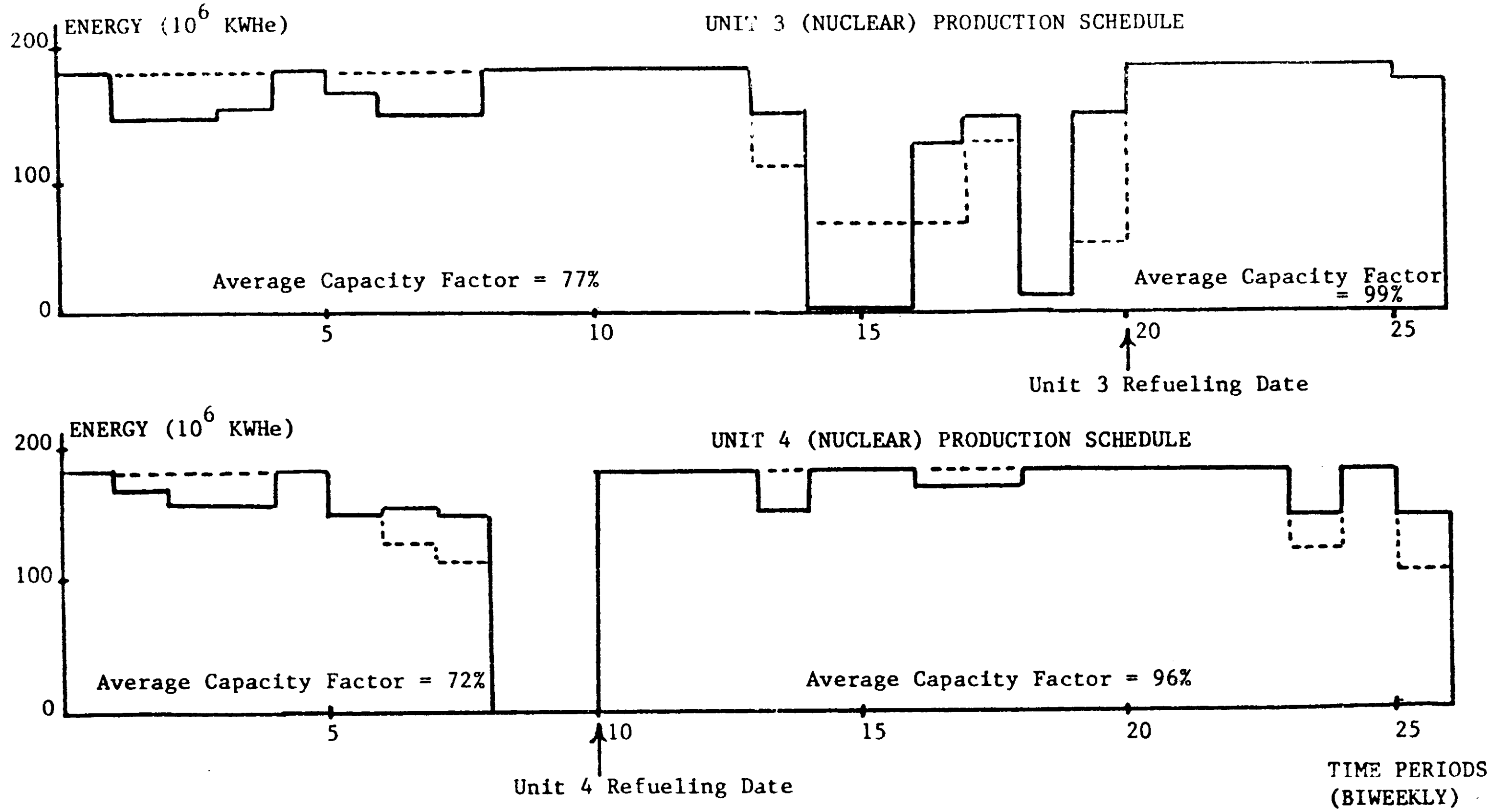

Figure E.2 NUCLEAR PRODUCTION SCHEDULE

Legend
—— no discounting production schedule
--- production shift due to discounting

Objective Function
no discounting, $29.5 million
with discounting, $29.4 million

discounting naturally has the effect of postponing cash outflows as much as possible and taking tax credits as soon as possible.

But what is the magnitude of this effect? Is it of concern where the largest time period in our studies is only one year? The change in the objective function from the comparison of the total-discounting case with the no-discounting case was 0.31%. But for a system where the average customer demand is about 10,000 MWe and the nuclear plants supplied about 48% of the power, the use of discounting represents a saving of about half million dollars per year. However, the frequent fluctuations of the market price of fossil fuel and the stochastic nature of the customer demand function introduces error bounds larger than the savings involved. As large as this savings may sound economically, the reliability considerations as mentioned in Section 2.4 subjectively outweight the savings of distorting the production schedule to favor nuclear utilization early in time over later periods of time.

Even though discounting is a very important factor in considering alternatives in the mid-range horizon, its use in the short-range is considered to be swamped by reliability concerns caused by the random statistical nature of events in the short-run (160). Hence, discounting has not been taken into account in the present short-range studies.

Appendix F: FOSSIL

F.1 Input Specifications

Input variables listed by order of input on file SYSIN:

N= number of time intervals in weekly load model.

N1= number of increments in the fossil economic loading order.

NN= number of weeks using the same loading order.

NUMBER= number of nuclear energy values to be read.

DEMAND(NN,N)= array containing the modified customer demand functions.

TIME(NN,N)= array containing the number of hours each time interval (in the load model) represents.

NUCLEAR(NUMBER)= array containing the nuclear energies(MWe).

Economic Loading Order= use card output from PROCOST.

The items of interest on the cards are the cumulative interval sizes(MW), incremental fuel cost (mills/KWHe), and the cumulative generation cost ($/HR).

For multiple cases, the whole set of variables is repeated for each set of fossil configurations.

The sample input (Appendix F.2) is a portion of that used for Case 4. The sample output (Appendix F.3) is the entire output of FOSSIL for Case 4. The OCNP values obtained from the FOSSIL output are the same as those used in the sample input to ALLOCAT, in Appendix D.2.

```
//  EXEC  PLIXCGO
//C.SYSIN  DD *,DCB=BLKSIZE=2000
 FOSSIL: PROC OPTIONS(MAIN);
  DCL (N,N1,NN,NUMBER)FIXED BIN;
 ON ENDFILE(SYSIN) GO TO BOTTOM;
 TOP: GET LIST( N, N1, NN, NUMBER) COPY;

 BLOCK: BEGIN;
 DCL CCNP FLOAT DEC(16) ;
 DCL (DEMAND(NN,N), TIME(NN,N), NTEMP, C_STEP(N1), NUCLEAR(NUMBER) )
 FIXED BIN(31), TOTAL FIXED DEC (15,2);
 DCL (FUEL(N1), C_FUEL(N1) ) FIXED DEC(15,2);
  GET LIST (DEMAND, TIME, NUCLEAR) COPY;
 DO I=1 TO N1;
 GET EDIT( C_STEP(I), FUEL(I), C_FUEL(I) )(SKIP,X(15), F(10), F(10,2),
 F(15) );
 END;
 DO J=1 TO NN;
 DO M=1 TO NUMBER;
 PUT SKIP DATA(NUCLEAR(M));
 TOTAL=0;
 OCNP=0;
 DO I=1 TO N;
 NTEMP= DEMAND(J,I) - NUCLEAR(M);
 OCNP=CCNP+NTEMP*TIME(J,I);
 DO K=N1 TO 1 BY -1  WHILE(NTEMP < C_STEP(K));
 END;
  IF K=0  THEN TOTAL=TOTAL+NTEMP*FUEL(K+1)*TIME(J,I);  ELSE
 TOTAL=TOTAL+TIME(J,I)
                    *((NTEMP-C_STEP(K))*FUEL(K+1)+C_FUEL(K));
 END;
 OCNP=OCNP/168.;
 DO  K=1 TO N1 WHILE(OCNP > C_STEP(K));
 END;
 OCNP=  FUEL(K);
 PUT SKIP;
```

```
 PUT DATA(      M,J,TOTAL,OCNP);
 PUT FILE(PUNCH) EDIT(OCNP)(F(8,2));
 END;
 PUT SKIP FILE(PUNCH);
 END BLOCK;
 GO TO TOP;
 BOTTOM:
 END FOSSIL;
//G.SYSIN  DD *,DCB=BLKSIZE=2000
6  61  4  9
7348  6733  5661  4889  4196  3427
7534  6898  5881  5107  4403  3595
7013  6309  5309  4634  3845  3096
6345  5505  4641  3762  3077  2260
62  16  17  20  33  20
65  14  15  22  31  21
61  17  15  19  39  17
60  15  20  22  39  12
 755  816  878  943  1004  1070  1133  1194  1254
    1         105         105        2.85           299
    2         105         210        3.00           614
    3         105         315        3.20           950
    4         320         635        3.40          2038
    5         320         955        3.58          3184
    6         320        1275        3.82          4405
    7         120        1395        4.07          4894
    8          43        1438        4.16          5073
    9         120        1558        4.29          5587
   10         116        1674        4.43          6101
   11          43        1717        4.46          6293
   12          80        1797        4.53          6655
   13         120        1917        4.57          7204
   14          60        1977        4.63          7481
   15         116        2093        4.66          8022
   16         135        2228        4.66          8652
   17         135        2363        4.66          9281
```

18	43	2406	4.72	9484	FOSS0073
19	43	2449	4.72	9687	FOSS0074
20	80	2529	4.77	10068	FOSS0075
21	60	2589	4.96	10366	FOSS0076
22	116	2705	4.97	10943	FOSS0077
23	135	2840	5.00	11618	FOSS0078
24	168	3008	5.03	12462	FOSS0079
25	168	3176	5.03	13307	FOSS0080
26	43	3219	5.06	13524	FOSS0081
27	80	3299	5.08	13931	FOSS0082
28	43	3342	5.25	14156	FOSS0083
29	168	3510	5.39	15062	FOSS0084
30	60	3570	5.84	15412	FOSS0085
31	520	4090	6.09	18577	FOSS0086
32	520	4610	6.40	21907	FOSS0087
33	96	4706	6.79	22559	FOSS0088
34	96	4802	6.79	23211	FOSS0089
35	520	5322	6.83	26763	FOSS0090
36	96	5418	7.28	27461	FOSS0091
37	60	5478	7.74	27926	FOSS0092
38	60	5538	8.30	28424	FOSS0093
39	48	5586	8.49	28832	FOSS0094
40	48	5634	8.49	29239	FOSS0095
41	160	5794	8.83	30652	FOSS0096
42	160	5954	8.86	32070	FOSS0097
43	48	6002	9.10	32507	FOSS0098
44	56	6058	9.11	33017	FOSS0099
45	56	6114	9.11	33527	FOSS0100
46	160	6274	9.30	35014	FOSS0101
47	160	6434	9.32	36506	FOSS0102
48	260	6694	9.40	38949	FOSS0103
49	56	6750	9.76	39496	FOSS0104
50	60	6810	9.77	40082	FOSS0105
51	260	7070	9.89	42654	FOSS0106
52	160	7230	9.91	44240	FOSS0107
53	160	7390	9.94	45831	FOSS0108

54	21	7411	10.23	46046	FOSS0109
55	260	7671	10.55	48788	FOSS0110
56	21	7692	10.97	49018	FOSS0111
57	21	7713	12.91	49289	FOSS0112
58	29	7742	14.45	49708	FOSS0113
59	29	7771	15.49	50158	FOSS0114
60	29	7800	18.22	50686	FOSS0115
61	1500	9300	25.00	88186	FOSS0116

APPENDIX F.3 SAMPLE OUTPUT FROM FOSSIL

```
6  61  4  9
7348  6733  5661  4889  4196  3427
7534  6898  5981  5107  4403  3595
7013  6309  5309  4634  3845  3096
6345  5505  4641  3762  3077  2260
62  16  17  20  33  20
65  14  15  22  31  21
61  17  15  19  39  17
60  15  20  22  39  12
 755  816  878  943  1004  1070  1133  1194  1254

NUCLEAR(1)=      755;
M=    1          J=   1   TOTAL=   4356765.25   OCNP= 6.829999999999999E+00;
NUCLEAR(2)=      816;
M=    2          J=   1   TOTAL=   4280791.29   OCNP= 6.829999999999999E+00;
NUCLEAR(3)=      878;
M=    3          J=   1   TOTAL=   4204091.86   OCNP= 6.829999999999999E+00;
NUCLEAR(4)=      943;
M=    4          J=   1   TOTAL=   4124322.89   OCNP= 6.789999999999999E+00;
NUCLEAR(5)=     1004;
M=    5          J=   1   TOTAL=   4050036.07   OCNP= 6.789999999999999E+00;
NUCLEAR(6)=     1070;
M=    6          J=   1   TOTAL=   3969810.57   OCNP= 6.789999999999999E+00;
NUCLEAR(7)=     1133;
M=    7          J=   1   TOTAL=   3893584.73   OCNP= 6.399999999999999E+00;
NUCLEAR(8)=     1194;
M=    8          J=   1   TOTAL=   3820676.32   OCNP= 6.399999999999999E+00;
NUCLEAR(9)=     1254;
M=    9          J=   1   TOTAL=   3748969.61   OCNP= 6.399999999999999E+00;
NUCLEAR(1)=      755;
M=    1          J=   2   TOTAL=   4622190.77   OCNP= 6.829999999999999E+00;
NUCLEAR(2)=      816;
M=    2          J=   2   TOTAL=   4542848.02   OCNP= 6.829999999999999E+00;
NUCLEAR(3)=      878;
M=    3          J=   2   TOTAL=   4463613.90   OCNP= 6.829999999999999E+00;
NUCLEAR(4)=      943;
M=    4          J=   2   TOTAL=   4381899.32   OCNP= 6.829999999999999E+00;
NUCLEAR(5)=     1004;
M=    5          J=   2   TOTAL=   4305680.05   OCNP= 6.829999999999999E+00;
NUCLEAR(6)=     1070;
M=    6          J=   2   TOTAL=   4223667.11   OCNP= 6.829999999999999E+00;
NUCLEAR(7)=     1133;
M=    7          J=   2   TOTAL=   4146139.81   OCNP= 6.829999999999999E+00;
NUCLEAR(8)=     1194;
M=    8          J=   2   TOTAL=   4071647.50   OCNP= 6.789999999999999E+00;
NUCLEAR(9)=     1254;
M=    9          J=   2   TOTAL=   3998435.75   OCNP= 6.789999999999999E+00;
NUCLEAR(1)=      755;
M=    1          J=   3   TOTAL=   3922184.75   OCNP= 6.789999999999999E+00;
NUCLEAR(2)=      816;
M=    2          J=   3   TOTAL=   3849245.53   OCNP= 6.399999999999999E+00;
NUCLEAR(3)=      878;
M=    3          J=   3   TOTAL=   3775572.87   OCNP= 6.399999999999999E+00;
NUCLEAR(4)=      943;
M=    4          J=   3   TOTAL=   3699452.60   OCNP= 6.399999999999999E+00;
NUCLEAR(5)=     1004;
M=    5          J=   3   TOTAL=   3628424.77   OCNP= 6.399999999999999E+00;
NUCLEAR(6)=     1070;
M=    6          J=   3   TOTAL=   3552211.70   OCNP= 6.399999999999999E+00;
NUCLEAR(7)=     1133;
```

```
M=          7          J=        3          TOTAL=      3480609.65          OCNP= 6.399999999999999E+00;
NUCLEAR(8)=         1194;
M=          8          J=        3          TOTAL=      3411610.65          OCNP= 6.399999999999999E+00;
NUCLEAR(9)=         1254;
M=          9          J=        3          TOTAL=      3344440.62          OCNP= 6.399999999999999E+00;
NUCLEAR(1)=          755;
M=          1          J=        4          TOTAL=      3114399.44          OCNP= 6.089999999999999E+00;
NUCLEAR(2)=          816;
M=          2          J=        4          TOTAL=      3049792.76          OCNP= 6.089999999999999E+00;
NUCLEAR(3)=          878;
M=          3          J=        4          TOTAL=      2983108.92          OCNP= 6.089999999999999E+00;
NUCLEAR(4)=          943;
M=          4          J=        4          TOTAL=      2916965.25          OCNP= 6.089999999999999E+00;.
NUCLEAR(5)=         1004;
M=          5          J=        4          TOTAL=      2856314.93          OCNP= 6.089999999999999E+00;
NUCLEAR(6)=         1070;
M=          6          J=        4          TOTAL=      2792049.02          OCNP= 6.089999999999999E+00;
NUCLEAR(7)=         1133;
M=          7          J=        4          TOTAL=      2731670.77          OCNP= 5.839999999999999E+00;
NUCLEAR(8)=         1194;
M=          8          J=        4          TOTAL=      2673810.27          OCNP= 5.389999999999999E+00;
NUCLEAR(9)=         1254;
M=          9          J=        4          TOTAL=      2617143.80          OCNP= 5.389999999999999E+00;

6   58   5   9
7269   6533   5567   4841          4065   3323
6880   5974   5224   4501   3697          2849
7077   6278   5368   4673   3876   3070
7321   6636   5592   4340   4114   3371
6675   5693   4939   4120   3474   2663
62   17   14   23   38   14
65   14   13   22   43   11
62   17   14   21   42   12
62   16   18   20   38   14
65   13   19   20   39   12
975   1036   1098   1163   1224   1290   1353   1414   1474

NUCLEAR(1)=          975;
M=          1          J=        1          TOTAL=      4194695.17          OCNP= 7.279999999999999E+00;
NUCLEAR(2)=         1036;
M=          2          J=        1          TOTAL=      4118191.62          OCNP= 6.829999999999999E+00;
NUCLEAR(3)=         1098;
M=          3          J=        1          TOTAL=      4042181.38          OCNP= 6.829999999999999E+00;
NUCLEAR(4)=         1163;
M=          4          J=        1          TOTAL=      3962553.25          OCNP= 6.829999999999999E+00;
NUCLEAR(5)=         1224;
M=          5          J=        1          TOTAL=      3887873.62          OCNP= 6.829999999999999E+00;
NUCLEAR(6)=         1290;
M=          6          J=        1          TOTAL=      3807117.18          OCNP= 6.829999999999999E+00;
NUCLEAR(7)=         1353;
M=          7          J=        1          TOTAL=      3730794.25          OCNP= 6.789999999999999E+00;
NUCLEAR(8)=         1414;
M=          8          J=        1          TOTAL=      3657726.08          OCNP= 6.789999999999999E+00;
NUCLEAR(9)=         1474;
M=          9          J=        1          TOTAL=      3586330.09          OCNP= 6.789999999999999E+00;
NUCLEAR(1)=          975;
M=          1          J=        2          TOTAL=      3726295.67          OCNP= 6.789999999999999E+00;
NUCLEAR(2)=         1036;
M=          2          J=        2          TOTAL=      3653315.83          OCNP= 6.789999999999999E+00;
NUCLEAR(3)=         1098;
```

```
M=          3          J=       2          TOTAL=       3579929.58               OCNP= 6.789999999999999E+00;
NUCLEAR(4)=         1163;
M=          4          J=       2          TOTAL=       3503182.82               OCNP= 6.789999999999999E+00;
NUCLEAR(5)=         1224;
M=          5          J=       2          TOTAL=       3431732.00               OCNP= 6.399999999999999E+00;
NUCLEAR(6)=         1290;
M=          6          J=       2          TOTAL=       3355881.01               OCNP= 6.399999999999999E+00;
NUCLEAR(7)=         1353;
M=          7          J=       2          TOTAL=       3284335.14               OCNP= 6.399999999999999E+00;
NUCLEAR(8)=         1414;
M=          8          J=       2          TOTAL=       3216348.29               OCNP= 6.399999999999999E+00;
NUCLEAR(9)=         1474;
M=          9          J=       2          TOTAL=       3149806.31               OCNP= 6.399999999999999E+00;
NUCLEAR(1)=          975;
M=          1          J=       3          TOTAL=       3946690.52               OCNP= 6.829999999999999E+00;
NUCLEAR(2)=         1036;
M=          2          J=       3          TOTAL=       3872091.25               OCNP= 6.829999999999999E+00;
NUCLEAR(3)=         1098;
M=          3          J=       3          TOTAL=       3796514.10               OCNP= 6.789999999999999E+00;
NUCLEAR(4)=         1163;
M=          4          J=       3          TOTAL=       3717908.78               OCNP= 6.789999999999999E+00;
NUCLEAR(5)=         1224;
M=          5          J=       3          TOTAL=       3644872.50               OCNP= 6.789999999999999E+00;
NUCLEAR(6)=         1290;
M=          6          J=       3          TOTAL=       3566654.63               OCNP= 6.789999999999999E+00;
NUCLEAR(7)=         1353;
M=          7          J=       3          TOTAL=       3492533.23               OCNP= 6.789999999999999E+00;
NUCLEAR(8)=         1414;
M=          8          J=       3          TOTAL=       3421129.87               OCNP= 6.399999999999999E+00;
NUCLEAR(9)=         1474;
M=          9          J=       3          TOTAL=       3352046.94               OCNP= 6.399999999999999E+00;
NUCLEAR(1)=          975;
M=          1          J=       4          TOTAL=       4263340.76               OCNP= 7.279999999999999E+00;
NUCLEAR(2)=         1036;
M=          2          J=       4          TOTAL=       4186502.10               OCNP= 7.279999999999999E+00;
NUCLEAR(3)=         1098;
M=          3          J=       4          TOTAL=       4109269.05               OCNP= 6.829999999999999E+00;
NUCLEAR(4)=         1163;
M=          4          J=       4          TOTAL=       4029593.51               OCNP= 6.829999999999999E+00;
NUCLEAR(5)=         1224;
M=          5          J=       4          TOTAL=       3954849.36               OCNP= 6.829999999999999E+00;
NUCLEAR(6)=         1290;
M=          6          J=       4          TOTAL=       3874047.46               OCNP= 6.829999999999999E+00;
NUCLEAR(7)=         1353;
M=          7          J=       4          TOTAL=       3797188.11               OCNP= 6.789999999999999E+00;
NUCLEAR(8)=         1414;
M=          8          J=       4          TOTAL=       3723678.81               OCNP= 6.789999999999999E+00;
NUCLEAR(9)=         1474;
M=          9          J=       4          TOTAL=       3651736.67               OCNP= 6.789999999999999E+00;
NUCLEAR(1)=          975;
M=          1          J=       5          TOTAL=       3470198.13               OCNP= 6.789999999999999E+00;
NUCLEAR(2)=         1036;
M=          2          J=       5          TOTAL=       3399369.48               OCNP= 6.399999999999999E+00;
NUCLEAR(3)=         1098;
M=          3          J=       5          TOTAL=       3328385.31               OCNP= 6.399999999999999E+00;
NUCLEAR(4)=         1163;
M=          4          J=       5          TOTAL=       3254914.17               OCNP= 6.399999999999999E+00;
NUCLEAR(5)=         1224;
M=          5          J=       5          TOTAL=       3186948.84               OCNP= 6.399999999999999E+00;
NUCLEAR(6)=         1290;
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M=          6              J=       5              TOTAL=        3113392.44              OCNP= 6.0899999999999999E+00;
NUCLEAR(7)=              1353;
M=          7              J=       5              TOTAL=        3043383.73              OCNP= 6.0899999999999999E+00;
NUCLEAR(8)=              1414;
M=          8              J=       5              TOTAL=        2975719.28              OCNP= 6.0899999999999999E+00;
NUCLEAR(9)=              1474;
M=          9              J=       5              TOTAL=        2909906.58              OCNP= 6.0899999999999999E+00;

6   52   4   9
8015   7131   5971   4995   4140   3152
8322   7416   6190   5172   4247   3189
7862   6988   5833   4853   4034   3057
7561   6693   5688   4679   3880   2899
50   24   19   24   36   15
52   22   20   26   36   12
47   27   19   24   36   15
42   28   20   23   38   17
1195   1256   1318   1383   1444   1510   1573   1634   1694

NUCLEAR(1)=              1195;
M=          1              J=       1              TOTAL=        4157854.35              OCNP= 6.7899999999999999E+00;
NUCLEAR(2)=              1256;
M=          2              J=       1              TOTAL=        4084603.37              OCNP= 6.5000000000000000E+00;
NUCLEAR(3)=              1318;
M=          3              J=       1              TOTAL=        4011345.41              OCNP= 6.3999999999999999E+00;
NUCLEAR(4)=              1383;
M=          4              J=       1              TOTAL=        3935316.96              OCNP= 6.3999999999999999E+00;
NUCLEAR(5)=              1444;
M=          5              J=       1              TOTAL=        3865075.07              OCNP= 6.3999999999999999E+00;
NUCLEAR(6)=              1510;
M=          6              J=       1              TOTAL=        3789509.28              OCNP= 6.3999999999999999E+00;
NUCLEAR(7)=              1573;
M=          7              J=       1              TOTAL=        3718210.38              OCNP= 6.3999999999999999E+00;
NUCLEAR(8)=              1634;
M=          8              J=       1              TOTAL=        3650111.78              OCNP= 6.3999999999999999E+00;
NUCLEAR(9)=              1694;
M=          9              J=       1              TOTAL=        3584006.20              OCNP= 6.3999999999999999E+00;
NUCLEAR(1)=              1195;
M=          1              J=       2              TOTAL=        4498951.54              OCNP= 6.8299999999999999E+00;
NUCLEAR(2)=              1256;
M=          2              J=       2              TOTAL=        4423197.71              OCNP= 6.8299999999999999E+00;
NUCLEAR(3)=              1318;
M=          3              J=       2              TOTAL=        4346393.40              OCNP= 6.7899999999999999E+00;
NUCLEAR(4)=              1383;
M=          4              J=       2              TOTAL=        4266130.39              OCNP= 6.7899999999999999E+00;
NUCLEAR(5)=              1444;
M=          5              J=       2              TOTAL=        4191389.17              OCNP= 6.7899999999999999E+00;
NUCLEAR(6)=              1510;
M=          6              J=       2              TOTAL=        4111026.07              OCNP= 6.5000000000000000E+00;
NUCLEAR(7)=              1573;
M=          7              J=       2              TOTAL=        4036078.78              OCNP= 6.3999999999999999E+00;
NUCLEAR(8)=              1634;
M=          8              J=       2              TOTAL=        3965460.04              OCNP= 6.3999999999999999E+00;
NUCLEAR(9)=              1694;
M=          9              J=       2              TOTAL=        3896380.97              OCNP= 6.3999999999999999E+00;
NUCLEAR(1)=              1195;
M=          1              J=       3              TOTAL=        3970680.66              OCNP= 6.3999999999999999E+00;
NUCLEAR(2)=              1256;
M=          2              J=       3              TOTAL=        3899736.56              OCNP= 6.3999999999999999E+00;
NUCLEAR(3)=              1318;
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M=          3          J=     3       TOTAL=     3828840.27        OCNP= 6.399999999999999E+00;
NUCLEAR(4)=         1393;
M=          4          J=     3       TOTAL=     3754583.52        OCNP= 6.399999999999999E+00;
NUCLEAR(5)=         1444;
M=          5          J=     3       TOTAL=     3686061.95        OCNP= 6.399999999999999E+00;
NUCLEAR(6)=         1510;
M=          6          J=     3       TOTAL=     3612946.86        OCNP= 6.399999999999999E+00;
NUCLEAR(7)=         1573;
M=          7          J=     3       TOTAL=     3544282.85        OCNP= 6.399999999999999E+00;
NUCLEAR(8)=         1634;
M=          8          J=     3       TOTAL=     3478519.70        OCNP= 6.089999999999999E+00;
NUCLEAR(9)=         1694;
M=          9          J=     3       TOTAL=     3414298.72        OCNP= 6.089999999999999E+00;
NUCLEAR(1)=         1195;
M=          1          J=     4       TOTAL=     3592336.61        OCNP= 6.399999999999999E+00;
NUCLEAR(2)=         1256;
M=          2          J=     4       TOTAL=     3525886.57        OCNP= 6.399999999999999E+00;
NUCLEAR(3)=         1318;
M=          3          J=     4       TOTAL=     3459669.95        OCNP= 6.089999999999999E+00;
NUCLEAR(4)=         1383;
M=          4          J=     4       TOTAL=     3390599.10        OCNP= 6.089999999999999E+00;
NUCLEAR(5)=         1444;
M=          5          J=     4       TOTAL=     3325966.43        OCNP= 6.089999999999999E+00;
NUCLEAR(6)=         1510;
M=          6          J=     4       TOTAL=     3256220.65        OCNP= 6.089999999999999E+00;
NUCLEAR(7)=         1573;
M=          7          J=     4       TOTAL=     3190616.00        OCNP= 6.089999999999999E+00;
NUCLEAR(8)=         1634;
M=          8          J=     4       TOTAL=     3127369.81        OCNP= 6.089999999999999E+00;
NUCLEAR(9)=         1694;
M=          9          J=     4       TOTAL=     3065844.90        OCNP= 6.089999999999999E+00;

6   67   5   9
6852   5971   5114   4190   3358   2403
8012   7111   5929   4907   3981   2935
7709   6824   5690   4711   3875   2893
8110   7205   5978   4960   4036   2578
7936   7037   5373   4901   3576   2901
40   24   25   19   41   19
52   22   19   27   36   12
50   24   19   24   36   15
52   22   20        26   36   12
52   22   19   24   39   12
1415   1476   1538   1603   1660   1730   1793   1854   1914

NUCLEAR(1)=         1415;
M=          1          J=     1       TOTAL=     2626639.70        OCNP= 5.250000000000000E+00;
NUCLEAR(2)=         1476;
M=          2          J=     1       TOTAL=     2564724.70        OCNP= 5.229999999999999E+00;
NUCLEAR(3)=         1538;
M=          3          J=     1       TOTAL=     2502753.49        OCNP= 5.079999999999999E+00;
NUCLEAR(4)=         1603;
M=          4          J=     1       TOTAL=     2439412.73        OCNP= 5.059999999999999E+00;
NUCLEAR(5)=         1660;
M=          5          J=     1       TOTAL=     2384281.56        OCNP= 5.029999999999999E+00;
NUCLEAR(6)=         1730;
M=          6          J=     1       TOTAL=     2317041.78        OCNP= 5.029999999999999E+00;
NUCLEAR(7)=         1793;
M=          7          J=     1       TOTAL=     2257416.39        OCNP= 5.029999999999999E+00;
NUCLEAR(8)=         1854;
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M=        8     J=     1     TOTAL=     2201036.51     OCNP= 5.029999999999999E+00;
NUCLEAR(9)=     1914;
M=        9     J=     1     TOTAL=     2146541.89     OCNP= 5.000000000000000E+00;
NUCLEAR(1)=     1415;
M=        1     J=     2     TOTAL=     3945692.30     OCNP= 6.829999999999999E+00;
NUCLEAR(2)=     1476;
M=        2     J=     2     TOTAL=     3872698.80     OCNP= 6.829999999999999E+00;
NUCLEAR(3)=     1538;
M=        3     J=     2     TOTAL=     3798796.75     OCNP= 6.789999999999999E+00;
NUCLEAR(4)=     1603;
M=        4     J=     2     TOTAL=     3722664.30     OCNP= 6.789999999999999E+00;
NUCLEAR(5)=     1660;
M=        5     J=     2     TOTAL=     3656213.93     OCNP= 6.789999999999999E+00;
NUCLEAR(6)=     1730;
M=        6     J=     2     TOTAL=     3574948.82     OCNP= 6.789999999999999E+00;
NUCLEAR(7)=     1793;
M=        7     J=     2     TOTAL=     3502221.90     OCNP= 6.399999999999999E+00;
NUCLEAR(8)=     1854;
M=        8     J=     2     TOTAL=     3432545.88     OCNP= 6.399999999999999E+00;
NUCLEAR(9)=     1914;
M=        9     J=     2     TOTAL=     3364339.75     OCNP= 6.399999999999999E+00;
NUCLEAR(1)=     1415;
M=        1     J=     3     TOTAL=     3616676.75     OCNP= 6.789999999999999E+00;
NUCLEAR(2)=     1476;
M=        2     J=     3     TOTAL=     3548161.05     OCNP= 6.789999999999999E+00;
NUCLEAR(3)=     1538;
M=        3     J=     3     TOTAL=     3476708.19     OCNP= 6.399999999999999E+00;
NUCLEAR(4)=     1603;
M=        4     J=     3     TOTAL=     3402555.47     OCNP= 6.399999999999999E+00;
NUCLEAR(5)=     1660;
M=        5     J=     3     TOTAL=     3337921.52     OCNP= 6.399999999999999E+00;
NUCLEAR(6)=     1730;
M=        6     J=     3     TOTAL=     3259006.62     OCNP= 6.399999999999999E+00;
NUCLEAR(7)=     1793;
M=        7     J=     3     TOTAL=     3188390.55     OCNP= 6.089999999999999E+00;
NUCLEAR(8)=     1854;
M=        8     J=     3     TOTAL=     3121050.00     OCNP= 6.089999999999999E+00;
NUCLEAR(9)=     1914;
M=        9     J=     3     TOTAL=     3055238.40     OCNP= 6.089999999999999E+00;
NUCLEAR(1)=     1415;
M=        1     J=     4     TOTAL=     4046839.86     OCNP= 6.829999999999999E+00;
NUCLEAR(2)=     1476;
M=        2     J=     4     TOTAL=     3972894.81     OCNP= 6.829999999999999E+00;
NUCLEAR(3)=     1538;
M=        3     J=     4     TOTAL=     3898469.80     OCNP= 6.829999999999999E+00;
NUCLEAR(4)=     1603;
M=        4     J=     4     TOTAL=     3820950.02     OCNP= 6.789999999999999E+00;
NUCLEAR(5)=     1660;
M=        5     J=     4     TOTAL=     3753460.75     OCNP= 6.789999999999999E+00;
NUCLEAR(6)=     1730;
M=        6     J=     4     TOTAL=     3671817.81     OCNP= 6.789999999999999E+00;
NUCLEAR(7)=     1793;
M=        7     J=     4     TOTAL=     3598482.37     OCNP= 6.789999999999999E+00;
NUCLEAR(8)=     1854;
M=        8     J=     4     TOTAL=     3528119.30     OCNP= 6.500000000000000E+00;
NUCLEAR(9)=     1914;
M=        9     J=     4     TOTAL=     3459190.83     OCNP= 6.399999999999999E+00;
NUCLEAR(1)=     1415;
M=        1     J=     5     TOTAL=     3868022.13     OCNP= 6.829999999999999E+00;
NUCLEAR(2)=     1476;
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```
M=          2            J=      5          TOTAL=      3795315.72            OCNP= 6.789999999999999E+00;
NUCLEAR(3)=          1538;
M=          3            J=      5          TOTAL=      3722802.23            OCNP= 6.789999999999999E+00;
NUCLEAR(4)=          1603;
M=          4            J=      5          TOTAL=      3646962.51            OCNP= 6.789999999999999E+00;
NUCLEAR(5)=          1660;
M=          5            J=      5          TOTAL=      3580818.23            OCNP= 6.789999999999999E+00;
NUCLEAR(6)=          1730;
M=          6            J=      5          TOTAL=      3500044.45            OCNP= 6.399999999999999E+00;
NUCLEAR(7)=          1793;
M=          7            J=      5          TOTAL=      3428097.75            OCNP= 6.399999999999999E+00;
NUCLEAR(8)=          1854;
M=          8            J=      5          TOTAL=      3358739.40            OCNP= 6.399999999999999E+00;
NUCLEAR(9)=          1914;
M=          9            J=      5          TOTAL=      3290837.50            OCNP= 6.399999999999999E+00;

6  64  4  9
8397  7222  6327  5405  4549  3542
7919  7117  6046  4978  4073  3170
7935  6951  5941  4972  4058  3151
8407  7231  6335  5415  4572  3593
70  11  13  20  38  11
64  12  21  20  38  13
65  15  16  19  39  12
70  11  13  20  37  12
1635  1696  1758  1823  1884  1950  2013  2074  2134

NUCLEAR(1)=          1635;
M=          1            J=      1          TOTAL=      5060038.39            OCNP= 8.859999999999999E+00;
NUCLEAR(2)=          1696;
M=          2            J=      1          TOTAL=      4996060.45            OCNP= 8.829999999999999E+00;
NUCLEAR(3)=          1758;
M=          3            J=      1          TOTAL=      4911284.65            OCNP= 8.829999999999999E+00;
NUCLEAR(4)=          1823;
M=          4            J=      1          TOTAL=      4822539.39            OCNP= 8.489999999999999E+00;
NUCLEAR(5)=          1884;
M=          5            J=      1          TOTAL=      4739741.39            OCNP= 8.489999999999999E+00;
NUCLEAR(6)=          1950;
M=          6            J=      1          TOTAL=      4650592.00            OCNP= 8.299999999999999E+00;
NUCLEAR(7)=          2013;
M=          7            J=      1          TOTAL=      4566223.39            OCNP= 8.299999999999999E+00;
NUCLEAR(8)=          2074;
M=          8            J=      1          TOTAL=      4484914.23            OCNP= 7.739999999999999E+00;
NUCLEAR(9)=          2134;
M=          9            J=      1          TOTAL=      4405649.05            OCNP= 7.739999999999999E+00;
NUCLEAR(1)=          1635;
M=          1            J=      2          TOTAL=      4381344.98            OCNP= 7.739999999999999E+00;
NUCLEAR(2)=          1696;
M=          2            J=      2          TOTAL=      4301229.29            OCNP= 7.279999999999999E+00;
NUCLEAR(3)=          1758;
M=          3            J=      2          TOTAL=      4220689.38            OCNP= 7.279999999999999E+00;
NUCLEAR(4)=          1823;
M=          4            J=      2          TOTAL=      4138001.35            OCNP= 6.829999999999999E+00;
NUCLEAR(5)=          1884;
M=          5            J=      2          TOTAL=      4062003.78            OCNP= 6.829999999999999E+00;
NUCLEAR(6)=          1950;
M=          6            J=      2          TOTAL=      3990207.79            OCNP= 6.829999999999999E+00;
NUCLEAR(7)=          2013;
M=          7            J=      2          TOTAL=      3902490.82            OCNP= 6.829999999999999E+00;
NUCLEAR(8)=          2074;
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M=          8          J=     2          TOTAL=     3827240.85          OCNP= 6.829999999999999E+00;
NUCLEAR(9)=          2134;
M=          9          J=     2          TOTAL=     3754042.22          OCNP= 6.829999999999999E+00;
NUCLEAR(1)=          1635;
M=          1          J=     3          TOTAL=     4414813.94          OCNP= 7.739999999999999E+00;
NUCLEAR(2)=          1696;
M=          2          J=     3          TOTAL=     4334265.00          OCNP= 7.279999999999999E+00;
NUCLEAR(3)=          1758;
M=          3          J=     3          TOTAL=     4253588.94          OCNP= 7.279999999999999E+00;
NUCLEAR(4)=          1823;
M=          4          J=     3          TOTAL=     4170224.91          OCNP= 6.829999999999999E+00;
NUCLEAR(5)=          1884;
M=          5          J=     3          TOTAL=     4093781.71          OCNP= 6.829999999999999E+00;
NUCLEAR(6)=          1950;
M=          6          J=     3          TOTAL=     4011380.91          OCNP= 6.829999999999999E+00;
NUCLEAR(7)=          2013;
M=          7          J=     3          TOTAL=     3933009.00          OCNP= 6.829999999999999E+00;
NUCLEAR(8)=          2074;
M=          8          J=     3          TOTAL=     3857397.30          OCNP= 6.829999999999999E+00;
NUCLEAR(9)=          2134;
M=          9          J=     3          TOTAL=     3783330.16          OCNP= 6.829999999999999E+00;
NUCLEAR(1)=          1635;
M=          1          J=     4          TOTAL=     5093288.54          OCNP= 8.859999999999999E+00;
NUCLEAR(2)=          1696;
M=          2          J=     4          TOTAL=     5009157.32          OCNP= 8.829999999999999E+00;
NUCLEAR(3)=          1758;
M=          3          J=     4          TOTAL=     4924340.56          OCNP= 8.829999999999999E+00;
NUCLEAR(4)=          1823;
M=          4          J=     4          TOTAL=     4835559.34          OCNP= 8.829999999999999E+00;
NUCLEAR(5)=          1884;
M=          5          J=     4          TOTAL=     4752786.38          OCNP= 8.489999999999999E+00;
NUCLEAR(6)=          1950;
M=          6          J=     4          TOTAL=     4663648.66          OCNP= 8.299999999999999E+00;
NUCLEAR(7)=          2013;
M=          7          J=     4          TOTAL=     4579218.21          OCNP= 8.299999999999999E+00;
NUCLEAR(8)=          2074;
M=          8          J=     4          TOTAL=     4497949.23          OCNP= 7.739999999999999E+00;
NUCLEAR(9)=          2134;
M=          9          J=     4          TOTAL=     4418555.52          OCNP= 7.739999999999999E+00;

6   61   4   9
7683   6798   5651   4674   3828   2843
9513   7529   6158   5191   4257   3123
8112   7166   5938   4952   4010   2941
8224   7275   6015   5038   4073   2990
50   24   19   24   36   15
55   20   23   21   37   12
53   22   19   26   36   12
53   22   19   26   36   12
1635   1696   1758   1823   1984   1950   2013   2074   2134

NUCLEAR(1)=          1635;
M=          1          J=     1          TOTAL=     3393900.70          OCNP= 6.399999999999999E+00;
NUCLEAR(2)=          1696;
M=          2          J=     1          TOTAL=     3324539.56          OCNP= 6.399999999999999E+00;
NUCLEAR(3)=          1758;
M=          3          J=     1          TOTAL=     3254314.14          OCNP= 6.399999999999999E+00;
NUCLEAR(4)=          1823;
M=          4          J=     1          TOTAL=     3180881.98          OCNP= 6.399999999999999E+00;
NUCLEAR(5)=          1884;
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M=          5          J=     1     TOTAL=     3112345.50          OCNP= 6.399999999999999E+00;
NUCLEAR(6)=         1950;
M=          6          J=     1     TOTAL=     3039885.27          OCNP= 6.089999999999999E+00;
NUCLEAR(7)=         2013;
M=          7          J=     1     TOTAL=     2971766.16          OCNP= 6.089999999999999E+00;
NUCLEAR(8)=         2074;
M=          8          J=     1     TOTAL=     2905982.64          OCNP= 6.089999999999999E+00;
NUCLEAR(9)=         2134;
M=          9          J=     1     TOTAL=     2841843.38          OCNP= 6.089999999999999E+00;
NUCLEAR(1)=         1635;
M=          1          J=     2     TOTAL=     4286229.95          OCNP= 7.279999999999999E+00;
NUCLEAR(2)=         1696;
M=          2          J=     2     TOTAL=     4210001.21          OCNP= 7.279999999999999E+00;
NUCLEAR(3)=         1758;
M=          3          J=     2     TOTAL=     4133163.78          OCNP= 7.279999999999999E+00;
NUCLEAR(4)=         1823;
M=          4          J=     2     TOTAL=     4053589.56          OCNP= 6.829999999999999E+00;
NUCLEAR(5)=         1884;
M=          5          J=     2     TOTAL=     3979545.28          OCNP= 6.829999999999999E+00;
NUCLEAR(6)=         1950;
M=          6          J=     2     TOTAL=     3900267.93          OCNP= 6.829999999999999E+00;
NUCLEAR(7)=         2013;
M=          7          J=     2     TOTAL=     3825555.51          OCNP= 6.829999999999999E+00;
NUCLEAR(8)=         2074;
M=          8          J=     2     TOTAL=     3753835.53          OCNP= 6.789999999999999E+00;
NUCLEAR(9)=         2134;
M=          9          J=     2     TOTAL=     3683408.26          OCNP= 6.789999999999999E+00;
NUCLEAR(1)=         1635;
M=          1          J=     3     TOTAL=     3850553.72          OCNP= 6.829999999999999E+00;
NUCLEAR(2)=         1696;
M=          2          J=     3     TOTAL=     3778773.65          OCNP= 6.789999999999999E+00;
NUCLEAR(3)=         1758;
M=          3          J=     3     TOTAL=     3706120.47          OCNP= 6.789999999999999E+00;
NUCLEAR(4)=         1823;
M=          4          J=     3     TOTAL=     3630217.57          OCNP= 6.789999999999999E+00;
NUCLEAR(5)=         1884;
M=          5          J=     3     TOTAL=     3559088.66          OCNP= 6.789999999999999E+00;
NUCLEAR(6)=         1950;
M=          6          J=     3     TOTAL=     3482933.02          OCNP= 6.789999999999999E+00;
NUCLEAR(7)=         2013;
M=          7          J=     3     TOTAL=     3410757.61          OCNP= 6.399999999999999E+00;
NUCLEAR(8)=         2074;
M=          8          J=     3     TOTAL=     3341106.58          OCNP= 6.399999999999999E+00;
NUCLEAR(9)=         2134;
M=          9          J=     3     TOTAL=     3272844.04          OCNP= 6.399999999999999E+00;
NUCLEAR(1)=         1635;
M=          1          J=     4     TOTAL=     3963825.98          OCNP= 6.829999999999999E+00;
NUCLEAR(2)=         1696;
M=          2          J=     4     TOTAL=     3890642.13          OCNP= 6.829999999999999E+00;
NUCLEAR(3)=         1758;
M=          3          J=     4     TOTAL=     3817623.87          OCNP= 6.829999999999999E+00;
NUCLEAR(4)=         1823;
M=          4          J=     4     TOTAL=     3741459.90          OCNP= 6.789999999999999E+00;
NUCLEAR(5)=         1884;
M=          5          J=     4     TOTAL=     3670094.95          OCNP= 6.789999999999999E+00;
NUCLEAR(6)=         1950;
M=          6          J=     4     TOTAL=     3592894.41          OCNP= 6.789999999999999E+00;
NUCLEAR(7)=         2013;
M=          7          J=     4     TOTAL=     3519872.06          OCNP= 6.789999999999999E+00;
NUCLEAR(8)=         2074;
```

```
M=        8           J=        4           TOTAL=        3449967.27                     OCNP= 6.500000000000000E+00;
NUCLEAR(9)=           2134;
M=        9           J=        4           TOTAL=        3381402.23                     OCNP= 6.399999999999999E+00;
```

```
  JJJJJJJJJJ    JJJJJJJJJJ     00000000    9999999999    3333333333         444
  JJJJJJJJJJ    JJJJJJJJJJ    0000000000  999999999999  333333333333       4444
        JJ            JJ     00        00 99        99  33        33     44 44
        JJ            JJ     00        00 99        99            33    44  44
        JJ            JJ     00        00 99        99            33   44   44
        JJ            JJ     00        00 999999999999          3333  44444444444
        JJ            JJ     00        00 999999999999          3333 444444444444
        JJ            JJ     00        00           99            33        44
JJ      JJ    JJ      JJ     00        00           99            33        44
JJ      JJ    JJ      JJ     00        00 99        99  33        33        44
 JJJJJJJJ      JJJJJJJJ       0000000000  999999999999  333333333333        44
  JJJJJJ        JJJJJJ         00000000    9999999999    3333333333         44
```

```
 SSSSSSSSSS   YY        YY   SSSSSSSSSS   LL             000000000000  UU        UU  TTTTTTTTTTTT
SSSSSSSSSSSS  YY        YY  SSSSSSSSSSSS  LL             000000000000  UU        UU  TTTTTTTTTTTT
SS        SS   YY      YY   SS        SS  LL             00        00  UU        UU       TT
SS              YY    YY    SS            LL             00        00  UU        UU       TT
SSS              YY  YY     SSS           LL             00        00  UU        UU       TT
 SSSSSSSSS        YYYY       SSSSSSSSS    LL             00        00  UU        UU       TT
  SSSSSSSSS        YY         SSSSSSSSS   LL             00        00  UU        UU       TT
         SSS       YY                SSS  LL             00        00  UU        UU       TT
          SS       YY                 SS  LL             00        00  UU        UU       TT
SS        SS       YY       SS        SS  LL             00        00  UU        UU       TT
SSSSSSSSSSSS       YY       SSSSSSSSSSSS  LLLLLLLLLLLL   000000000000  UUUUUUUUUUUU       TT
 SSSSSSSSSS        YY        SSSSSSSSSS   LLLLLLLLLLLL   000000000000   UUUUUUUUUU        TT
```

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Biographical Note

Raymond Eng was born on February 2, 1948 in Bronx, New York. He attended elementary school at P.S. 200 and junior high school at P.S. 128, and high school at Brooklyn Technical High School, all located in Brooklyn, New York. For his undergraduate studies, he attended Massachusetts Institute of Technology from September 1965 to June 1969. He received a B.S. degree from the Department of Chemistry majoring in Chemical Physics and minoring in Economics. He received a Uniroyal Scholarship during his junior and senior year.

His undergraduate research in Nuclear Chemistry, titled "Isomeric-Yield Ratios of Cd-117 in the (n,γ) and (d,p) Reactions", was published in the Journal of Inorganic and Nuclear Chemistry, Volume 35, 1973, pp 371-380, Pergamon Press, Great Britain.

He was awarded a three-year AEC fellowship to continue his graduate work in M.I.T.'s Department of Nuclear Engineering, majoring in Nuclear Fuel Management. His minor was in Management.

He was also extensively involved in a variety of extra-curricular activities. He was elected member of the Graduate Student Council, elected Social Chairman and Treasurer of Ashdown House, and elected President of the MIT Chinese Student Club during his graduate residence years.