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POWER SYSTEM SIMULATION AND OPTIMIZATION MODELS FOR PLANNING NUCLEAR REFUELING CYCLES*

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1. INTRODUCTION

The historical responsibilities of electric utilities to supply load on demand and to produce electric energy at minimum cost continue to grow increasingly complex. The rapid growth of demand for electric energy, the number and diversity of alternative generation processes, the existence of problems which are system-dependent, the growing costs of supplying electric energy, and the recognition of new constraints in utility operations all contribute to the problem.

Because of the difficulty of the tasks facing utility system planners, there has been motivation to develop mathematical models to assist in assessing the cost and system reliability of alternative generation strategies. These models may be functionally categorized into three groups.

1. Short-range (few weeks) system operation (dispatching or unit-commitment model). This model is concerned with the day-to-day operation of the system. Questions answered would relate to economic dispatch of units, inter-utility sales and purchases, start up and shut down of generating units.
2. Mid-range (few years) system operation ("strategic optimization" or system integration model). This model is concerned with questions that relate to such areas as scheduling nuclear refueling, scheduling maintenance outages, schedules for utilization of nuclear and hydro energy, incremental cost for economic dispatch of nuclear units, future fuel requirements, and generation reliability.

3. Long-range (few decades) expansion model. This model is concerned with questions related to type, size and timing of capacity additions, retirement of older units, transmission planning, fuel requirements, and price projections.

The work described in this paper is concerned with mid-range system operation. The system being modeled may include a mix of fossil, nuclear, hydro, pumped-storage, and peaking units. For any predetermined nuclear refueling schedule, the program (ORSIM) determines an approximately optimal plan of operation for the system. This includes the determination of a maintenance schedule for the non-nuclear units and a schedule of energy delivery for each plant in the system. The criterion of optimality is the minimization of the total discounted operating cost of the system over the specified study period. Over this period, the model computes the expected station load factors, the loss of load probability and unserved energy for the system, and the production costs of operating so as to meet the forecasted loads on the system. The code takes account of variations and growth in demand over the planning horizon, occurrence of unit forced outages, planned shutdowns for nuclear refuelings, maintenance scheduling, allocations of fixed hydro and nuclear energies, and interactions between nuclear unit reloadings and fuel costs.

2. THEORETICAL BASIS OF ORSIM

This computer model is designed to help answer the following fundamental question: In what way should a particular electric power generation system operate in the mid-range future if it is to provide the energy demanded from it at the lowest possible cost? One is therefore searching for a particular mode of operation which, over a multi-year planning horizon will minimize the total, present-valued operating cost. In the ORSIM code, this search is guided by a generation simulation model (SIMUL) which estimates the expected energy to be generated by every station in the system over the planning horizon.

2.1 The Use of Probabilistic Simulation Techniques in Utility Production Costing

Prior to 1960 a load duration curve, constructed by rearranging hourly loads in decreasing order of magnitude, often was utilized for the kind of simulation discussed above. Forced outage effects were approximated by reducing the rated capacities of the stations in the system. Horizontal lines could then be drawn at the resulting "effective" capacities of the various generating units and the areas formed between these lines (see Fig. 1) represented an approximation of the generation requirements for each unit. Qualitatively, this method tends to treat forced outages as an average effect rather than as a random effect. As a consequence, the procedure underestimates the operation of reserve units (typically, peaking units) to cover unexpected forced outages and, in fact, overestimates the reliability of the system. Since the cost of operating peaking units and of purchasing interchange energy is high, the use of average, effective capacities tends to underestimate the total system operating cost. Fig. 1

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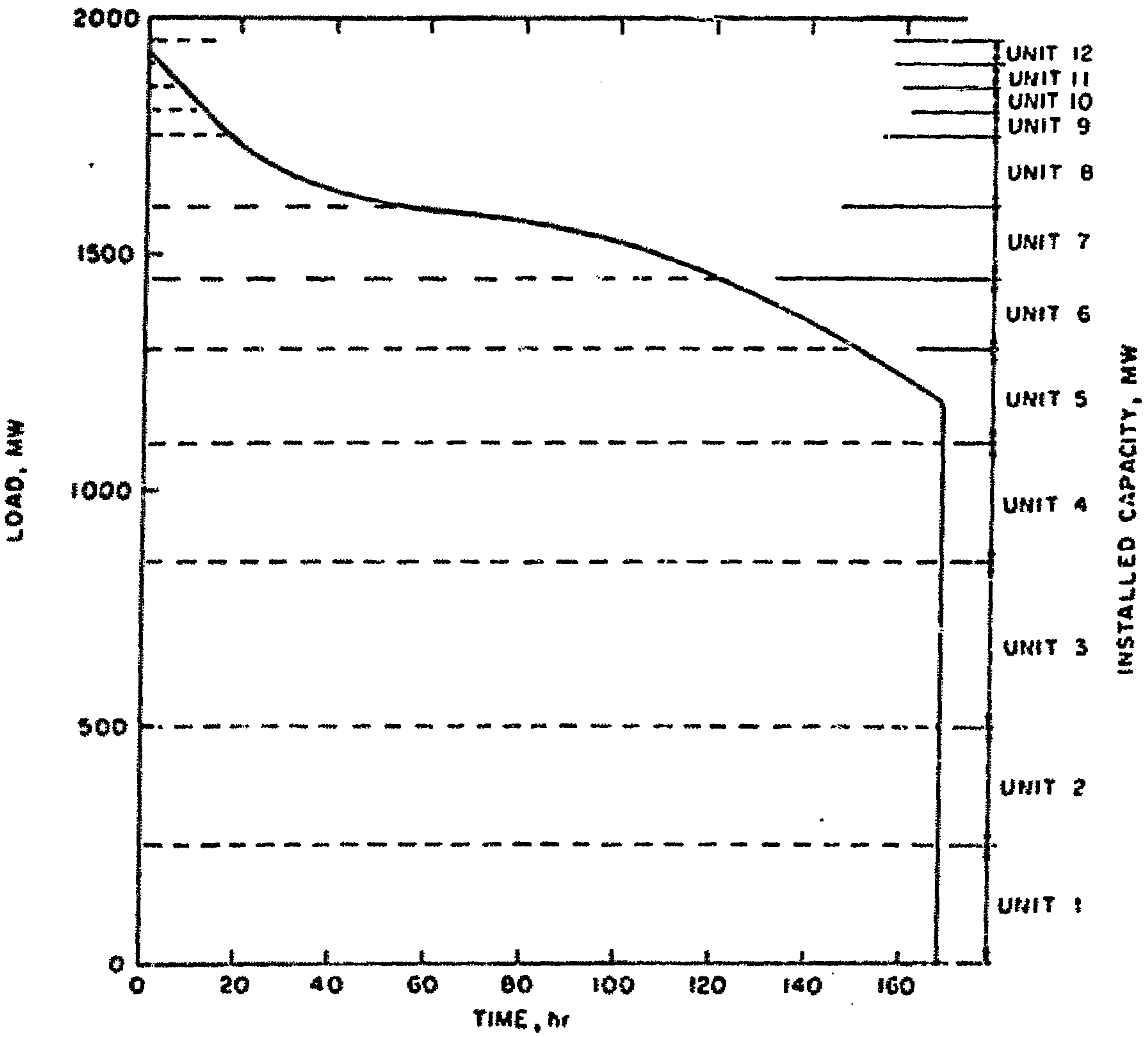

Fig. 1 Estimating Unit Loadings via a Load Duration Curve.

This phenomenon falls under the province of what R. R. Booth[1] calls Lake's Law. Booth states the law as "the cost of operation will always be higher than that under average conditions," and he points out that the magnitude of the problem becomes increasingly important in systems tending towards: Ref. 1

1. a small number of units;
2. a wide range of unit production costs;
3. high outage rates;
4. large variability in loads;
5. large variability of energy availability.

Because many modern utility systems are acquiring these characteristics, and because of the random nature of events such as forced outages, both Monte-Carlo techniques[2] and probabilistic simulation techniques[3,4,5] have been developed to simulate utility system operation. Because Monte-Carlo approaches require considerable computational effort to perform multi-year, iterative analyses, the present work utilizes a probabilistic simulation approach to guide the optimization search. This approach statically incorporates the random effects of unit outages into the load duration curve. Given a hierarchical loading order of generating units, the model calculates the probability of loss of load, the expected generation, and the hours of operation for each plant. The basic algorithm is described by Ref. 5, and is summarized in Appendix A. (For a similar treatment, see Ref. 6.) Ref 2-5 Ref 5 Ref 6

2.2 The Use of Probabilistic Simulation Techniques in the ORSIM Code

In describing the use of this probabilistic model in the ORSIM code, at least three areas need attention:

1. the determination of a hierarchical loading order for use by the probablistic simulation model,

2. the determination of the optimal energy expected from the hydro and energy-fixed nuclear units in any subinterval of the planning horizon,
3. a discussion of how the probabilistic simulation model actually guides the search for an optimum, multi-year generation strategy.

The first two of these topics are considered below, along with a brief discussion regarding the special difficulties posed by integrating nuclear units into the generating system. The third topic is the subject of Section 3 of this paper.

2.2a The Use of Incremental Costs and Economic Ordering Rules in Probabilistic Simulation

It may be recalled from the preceding section that for the probabilistic simulator to determine the expected generation over any subinterval of the planning horizon, a loading order must be specified. In this section, it will be noted that by choosing the loading order in accordance with increasing discounted incremental costs, one satisfies the conditions necessary for minimizing the total discounted operating cost over the planning horizon for systems comprised of both nuclear and fossil stations. Consider for a moment such a system.

For the nuclear plants in this system, one may observe that if the length of the operating intervals between refuelings (i.e., fuel cycle calendar lengths) are specified exogeneously to the system cost minimization problem, then the total discounted operating cost for each unit depends, to a close approximation, only on the energies produced between refuelings. This is not exactly correct, since the cost do vary depending on the distribution of energies produced within the subintervals comprising each cycle, through economic considerations such as tax allowances, and physical considerations such as temperature-reactivity dependence and radioactive decay effects.

However, these effects tend to be of second order importance in the calculations of fuel cycle cost and have been neglected in the present work. Thus, if the refueling intervals are fixed, the expenditure times and discount factors will remain the same when the cycle energies and, consequently, the magnitude of the cash outlays are varied.

The total discounted cost associated with the nuclear unit, n, may therefore be written functionally, in terms of fuel cycle energies, as $TDC_n\ (E_{n1}, E_{n2},\ldots E_{nk},\ldots E_{nK})$, where the index k refers to the refueling cycle interval and K is the maximum number of cycles within the planning horizon. Each fuel cycle, k, will then generally be composed of a number of basic subintervals, $i \in k$.

For fossil units, the functional dependence is on the subintervals, i, since these typically represent "out-of-pocket" costs uniquely associated with the energies produced in the subintervals. Moreover, because the costs of each subinterval may be assumed to be functionally independent of the costs associated with other subintervals for fossil units, the total discounted cost function may be decomposed. Thus

$$TDC_f(E_{f1}, E_{f2},\ldots E_{fi},\ldots E_{fI}) = \sum_{i=1}^{I} TDC_i(E_{fi}) \tag{1}$$

where I is the total number of subintervals in the planning horizon. The problem of minimizing the total discounted operating cost may now be formulated as a constrained, multivariable search problem. Thus, in a system with N nuclear units, and F fossil units, one is seeking to minimize

$$TDC = \sum_{n \in N} TDC_n\ (E_{n1}, E_{n2},\ldots E_{nk},\ldots E_{nK}) + \sum_{f \in F} \sum_{i=1}^{I} TDC_{fi}\ (E_{fi}) \tag{2}$$

subject to: $$E_{nk} = \sum_{i \in K} E_{ni}; \text{ all } k \in K \text{ provided } i \in I, \tag{3}$$

$$L_i = \sum_{n \in N} E_{ni} + \sum_{f \in F} E_{fi} \quad ; \text{ all } i \in I, \tag{4}$$

and $$E_{pi}^{min} \le E_{pi} \le E_{pi}^{max} \quad , p = n,f; \text{ all } i \in I. \tag{5}$$

Equation (3) is a requirement that the energies delivered by the nuclear units during all subintervals within a given cycle must sum to the total cycle energy. Equation (4) specifies that the system demand, L_i, during subinterval i must be met. (Note that $E_{ni} = 0$ if i is a subinterval in which unit n is being refueled; and that, similarly, $E_{fi} = 0$ if i is a subinterval in which maintenance is planned for unit f.) Equation (5) guarantees that the time-integrated capacity constraints be met for all units.

If one applies the Kuhn-Tucker theorem of non-linear programming[9] to the global optimization problem, the following set of conditions necessary for the existence of the optimum may be obtained[7] for every subinterval i. Ref 9 Ref 7

For the fossil units, one finds that

$$\frac{dTDC_{fi}}{dE_{fi}} - U_{oi} - u_{fi} + U_{fi} \ge o \quad , \tag{6}$$

where U_{oi} is a Lagrangian multiplier for the i^{th} subinterval demand constraint (4), u_{fi} and U_{fi} are multipliers for the lower and upper limit capacity constraints (5) and where, from (2),

$$\frac{\partial TDC_f}{\partial E_{fi}} = \frac{d\ TDC_{fi}}{d\ E_{fi}} \tag{7}$$

has been used.

For the nuclear units, it is required that

$$\sum_{k \in K} \frac{\partial TDC_n}{\partial E_{nk}} \Delta_{ki} - U_{oi} - u_{ri} + U_{ni} \geq 0 \quad , \tag{8}$$

where

$$\frac{\partial E_{nk}}{\partial E_{ni}} \equiv \Delta_{ki} = \begin{cases} 1 \text{ if } i \in k \\ 0 \text{ if } i \notin k \end{cases} \tag{9}$$

The first term in equation (8) is the discounted incremental energy cost for nuclear unit n, during subinterval i. It is perhaps worthwhile to note what happens as i moves through the planning horizon. For all $i \in k = 1$, the first cycle, the sum over k will pick out only the k = 1 term, and the discounted incremental cost will be $\frac{\partial TDC_n}{\partial E_{n1}}$. Similarly, for all $i \in k = K$, the cost function will be $\frac{\partial TDC_n}{\partial E_{nK}}$. For subintervals between cycles, the values will be zero, but here the nuclear unit is unavailable and does not enter the simulation.

Additionally, the conditions require that equations (4) and (5) be explicitly satisfied and that

$$U_{ri} \, (E_{ni}^{min} - E_{ni}) = 0 \qquad i = 1, 2, \ldots I; \; r = n, f, \tag{10}$$

and

$$U_{ri} \, (E_{ni} - E_{ni}^{max}) - 0 \qquad i = 1, 2, \ldots I; \; r = n, f \tag{11}$$

Importantly, it can be shown that these conditions are identical in form to those obtained by considering the cost minimization problem for a single subinterval, and that they can be met if and only if one orders the generating units in accordance with increasing incremental, discounted costs.[7,8] Thus, Ref 7-8 if one views the problem of minimizing the total, discounted operating cost of a generation system in terms of a constrained, multivariable optimization problem, one finds that it is necessary to use the incremental, discounted cost ordering rule in order to obtain a global optimum. Any other ordering rule will violate the Kuhn-Tucker conditions.

2.2b <u>All Fossil Systems</u>

Early in this paper, it was noted that, in the ORSIM code, the probabilistic simulation model was utilized in searching for an optimum mode of system operation over a multi-year planning horizon. If one is dealing with a system comprised entirely of fossil generating stations, then the search for a global optimum is an easy one.

For this case, two simplifying assumptions may be made. First, one may assume that the various subintervals in the planning horizon decouple from one another. Thus, operating strategy for the n^{th} subinterval a month, for example, does not depend on the decisions made in any subsequent month. Second, one may assume that, for all-fossil systems, one may choose blocks of capacity for which incremental operating costs for a particular unit are not functions of energy.

The first assumption implies that one may simulate the operation of an electric power generation system over a multi-year planning horizon by successively simulating that system over the subintervals of the planning horizon; and that, for this special case, the incremental costs do not depend on the history of unit operation. It also implies that the optimum mode of operation can be found by independently optimizing system operation over each of the subintervals. Consequently, to determine the optimal mode of operation for an all-fossil system, one has only to make use of the incremental discounted cost ordering rule in performing successive system simulations — marching out to the end of the planning horizon. The second assumption allows one to derive an optimum solution in a non-iterative manner. Thus one need make only one pass through the subintervals of the planning horizon.

2.2c The Integration of Hydro and Energy-Fixed Nuclear Stations

The situation for all fossil systems is complicated somewhat by the existence of hydro and energy-fixed nuclear units. These units differ from fossil units in that they are limited to generating a fixed amount of energy over some portion, perhaps all, of the planning horizon. In the case of the hydro unit, this amount of energy is typically determined by reservoir constraints and energy inflow conditions. The energy-fixed nuclear unit, on the other hand, is a special class of nuclear unit for which the refueling decisions have already been made, thereby "fixing" the amount of energy contained in the core. Its position in the loading order is therefore independent of any incremental cost considerations.

For these units, it is required that one optimally determine the amount of energy to be delivered in each subinterval of the planning horizon. Economic off-loading by these units within each subinterval is then assured by the manner in which the probabilistic simulation is accomplished. One thus utilizes the incremental discounted cost loading order criteria to optimize the systems operation over a subinterval and then attempts to improve this suboptimization by economically off-loading the more expensive units by the amount of energy the hydro and energy fixed nuclear units are to generate in that subinterval. The integration of these units over a multi-year planning horizon is described briefly in this section; the most serious effect of dealing with these units is that now the various subintervals of the planning horizon are coupled together.

For both hydro and energy-fixed nuclear units, limits of operation exist which govern the allowable generation of the station over a particular subinterval of time. These limits are established by the economics of unit operation, reservoir reserve margins, and station capacity. Having established such limits, one may approach the problem of energy allocation by utilizing the classical methods of dynamic programming. Each subinterval thus becomes a stage in the DP analysis, and various states are established as the amounts usable energy stored in the unit over the subintervals of interest.

The decisions which are to be made concern the amount of energy which should be generated over each subinterval of interest. The limits of allowable operation thus limit the number of ways one can progress from one stage to another by bracketing the number of allowable states per stage. Decisions about the rejection of trajectories entering the same state of a particular stage are made on the basis of an energy-fixed nuclear unit.

Consider first the case of energy-fixed nuclear unit. Suppose that for such a unit one has decided that a certain amount of energy (say MW megawatt-hours) will be generated over the j^{th} fuel cycle. What is to be determined is how that energy shall be distributed over the subintervals of the fuel cycle so as to minimize the system's operating cost. It has been determined that in each subinterval of the fuel cycle, the reactor may generate between MWMIN and MWMAX megawatt-hours of energy.

If the J^{th} fuel cycle contains N subintervals (stages) then the total energy which is available from the core is MW megawatt-hours in stage 1 and 0 in stage N + 1. Thus there exists only one state for these two stages. The limits of operation then govern how one may have arrived at the N + 1 stage.

The most energy which could have been generated in this process is MWMAX and the least is MWMIN. Accordingly, the feasible states of the N^{th} stage range from one which contains MWMAX megawatt-hours of energy yet to be generated to one which contains MWMIN megawatt-hours of energy yet to be generated. The only thing remaining to be done is to discretize the interval, producing NPT feasable states, calculate the energy generated by the unit in going from the only allowable state of the N + 1 stage to each of the NPT feasable states of the Nth stage, and obtain the system's discounted operating cost for each of the NPT trajectories. One may now proceed backward through the N remaining stages (each having NPT possible states), accumulating the costs of system operation for each trajectory and eliminating trajectories which are infeasible and which are more expensive than others entering a particular state. When at least one comes to stage 1, all trajectories but that one having the lowest cost have been eliminated. One thus obtains the optimal allocation of energy from the energy-fixed nuclear unit over the subintervals of the fuel cycle being considered.

Energy allocation for the hydro unit is accomplished in essentially the same manner. Here, however, the number of allowable states in any stage must span a varying range of energy from stage to stage — a range governed not only by hydro usage but by maximum and minimum reservoir levels and inflow conditions. These states consequently correspond to discrete values of feasable reservoir energy levels. Also, for the hydro station, one typically must span the entire planning horizon. Consequently, the starting point for the backward DP is taken as the first subinterval beyond the planning horizon. The amount of energy in the reservoir for this pseudo stage is inputed to the code as is the initial energy. Thus, just as in the case of energy-fixed, nuclear energy allocation, there exists only one allowable state in the first and last stages of the DP. Again, when one at last comes to stage 1, all trajectories except that one having the lowest cost have been eliminated and the optimum amount of energy to be generated in each subinterval has been determined.

2.2d The Integration of Nuclear Stations

The existence of nuclear stations in the system violate both of the simplifying assumptions appropriate to all-fossil systems. The preceding analysis implicitly assumed that one has incremental unit operating costs available. For the nuclear units, however, these costs are non-linear functions of energy; they cannot be specified *a priori*. The implication for ORSIM is that the code is iterative in nature.

Earlier in this report, the use of incremental costs as loading order criteria was discussed. If one adopts this criteria, then it is possible to utilize probabilistic simulation analyses to obtain the expected energies of all the generating units in systems with fossil, pumped-storage, hydro, and energy-fixed nuclear capacity, corresponding to an optimum mode of system operation over a multi-year planning horizon. Since nuclear incremental costs are energy-dependent, however, one would have to know the energies for the nuclear units in advance in order to have the proper value of incremental costs to use. Accordingly, the ORSIM code requires that these costs be re-evaluated according to the calculated values of expected energies and that additional passes through the subintervals of the planning horizon be made until either there is no change in the loading order determinations or the change in the total, discounted operating cost is negligibly small.

The code thus requires some means of determining the cost of operating a nuclear unit in order to provide a specified amount of energy. Specifically, it requires that a refueling scheme be identified which is capable of producing a specified amount of energy in each fuel cycle of the planning horizon at the lowest possible cost. Additionally, the incremental costs (defined, again, as $\frac{\partial TDC_n}{\partial E_{nk}}$) must be calculated for this mode of operation. At this point, it is perhaps wise to recall that, in the ORSIM code, the nuclear fuel cycle lengths are input parameters; and, since their maintenance outages are assumed to coincide with refueling outages, they fall into the category of those units with preplanned maintenance outages. Consequently, ORSIM is capable of considering alternative fuel cycle lengths only in a parametric sense.

Since the nuclear fuel cycle lengths are fixed, the optimization of nuclear refueling seeks to determine for each reactor for each fuel cycle:[10] Ref 10

1. The number and location of the fuel assemblies to be replaced.
2. The pattern in which the remaining assemblies are to be shifted to new locations.
3. The optimal fissile uranium and plutonium enrichment in each reload assembly.
4. The optimum control poison policy for the entire reactor.

To accomplish this task, several computer codes have been developed[10,11,12,13] which simulate the physics of the reactor fuel management problem and which are computationally inexpensive to use. These codes act as computational tools which allow the ORSIM user to calculate energy-dependent nuclear incremental discounted costs and to obtain near optimum refueling decisions given that the expected energy from each fuel cycle and the lengths of each fuel cycle are known. By supplying cost information and nuclear cycle refueling strategy for each pass through the planning horizon, the codes make possible the integration of nuclear units into the generating system.

2.3 An Interpretation of the ORSIM Iterative Procedure as a Direct Climbing Approach to Optimization

In the last section, it was noted that the optimization of the total discounted operating cost of an electric power generation system is attempted in the ORSIM program by a straightforward, iterative procedure. Simply stated, this procedure consists of:

1. Calculating the maintenance outages for all units without prescheduled maintenance.
2. Estimating the incremental discounted cost of producing energy by each station in the system for every period in the planning horizon.
3. Utilizing the incremental discounted costs of energy generation to produce, via a probabilistic simulation, the expected energies generated by each station in the system in each period of the planning horizon.
4. Utilizing these expected energies to calculate the total discounted operating cost and to produce a new set of incremental discounted costs, thereby setting the stage for the next iteration.

This iterative procedure may be interpreted functionally from a flow chart of the logic of the ORSIM code, shown in Figure 2. Geometrically, one may interpret this iterative procedure as a direct climbing approach which is capable of achieving a global optimum (here, the minimization of total discounted operating costs).

Equation 16 states that one may express the objective function, the total discounted cost, as a function of $(N + F)* I \equiv K$ variables. These variables are the energies that the stations of the system generate over the planning horizon. N is the number of nuclear stations in the system; F the number of non-nuclear stations in the system; I the number of periods in the planning horizon.

This multivariable search problem may now be stated in geometrical terms. One desires to find the optimum (minimum) of the objective function TDC which depends on the independent variables E_{pi} $p = f, n; i = 1,\ldots I$. An analytic expression of the function is not available, but the value of TDC for any particular set of values of the E_{pi} can be determined. One may now interpret a point in the E_{pi} $p = f, n; i = 1,\ldots I$ hyperplane (where TDC = 0) as a possible experiment and the point above it (the value of TDC corresponding to the E_{pi}) as an experimental outcome, lying on the response hypersurface. Each new experiment thus gives the elevation of a new point on this hypersurface. What is required, then, is that one be able to utilize each experimental outcome to move the search toward a new experiment capable of producing an improved outcome (here, a reduction in the calculated value of TDC).

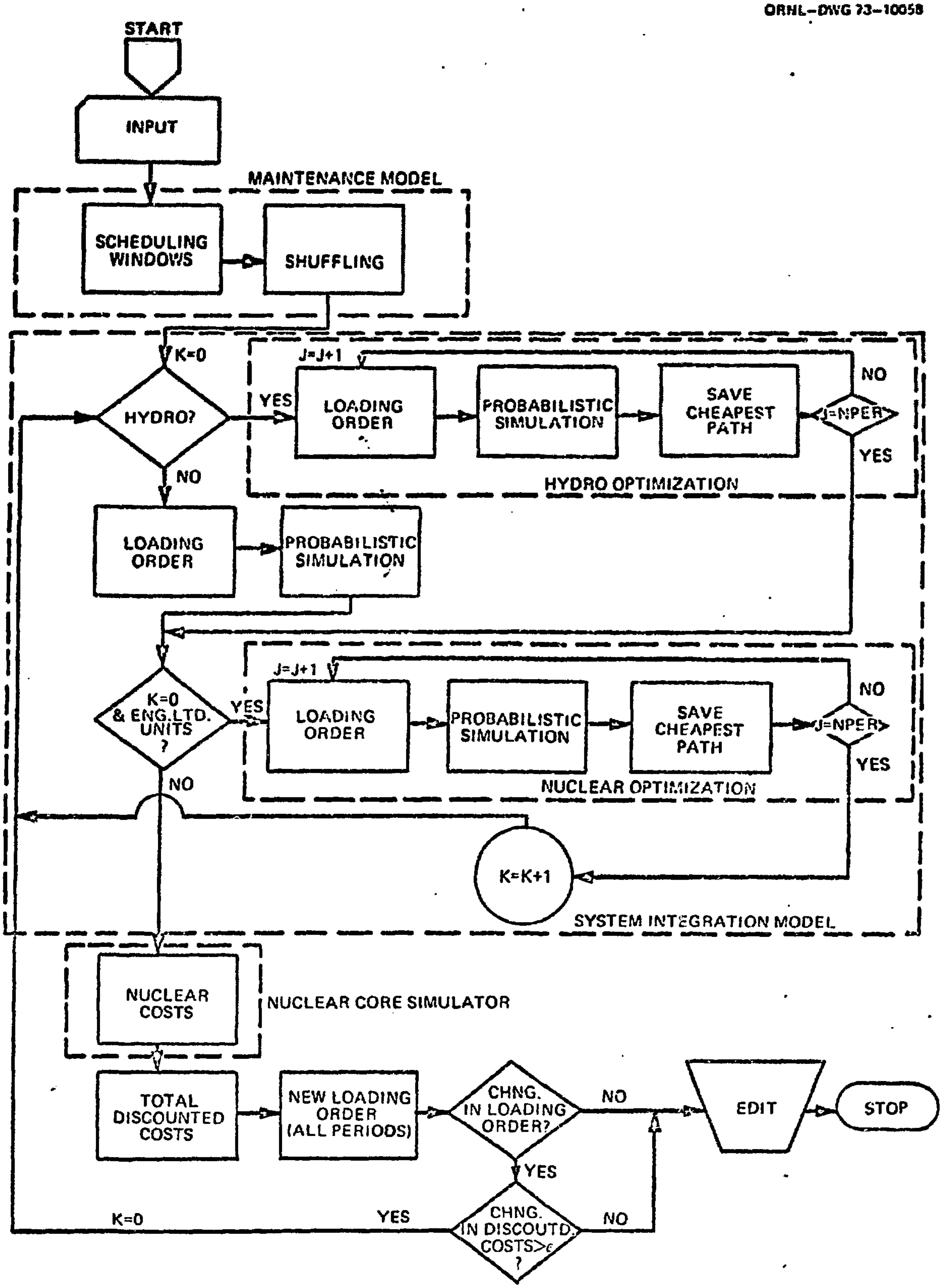

Fig. 2. ORSIM Flowchart

To accomplish this, one should seek the direction of movement which makes the decrease in the objective function, TDC, the greatest. The search for a feasible direction of movement which the greatest reduction on the objective function may then be viewed as an optimization problem which one may approach using the method of Lagrangian Multipliers. When this is done, one finds (see reference 7) that the conditions which insure that the optimum direction of movement is taken are met by the conditions described earlier for the minimization of TDC. Following Section 2.2a, one thus finds that the discounted incremental cost loading order criterion satisfies the conditions necessary to insure that we are searching in the direction in which TDC is declining the fastest.

3. NUMERICAL RESULTS

The task of determining an optimum strategy for system operation becomes clearer if one considers a hypothetical electric power generation system. Suppose, for example, that the Atlantic and Pacific Power and Light Electric Company (APPLE) is attempting to ascertain which of two alternative nuclear fuel cycle lengths for a planned nuclear installation should be used over the 1976-1980 time period. The utility's generation system is characterized by the information presented in Table 1. Tables 2a and 2b depict the two alternative refueling schedules being considered for nuclear unit NU02.

To compare these two refueling schedules, two ORSIM runs were made. Summaries of system operation are presented in Tables 3a and 3b. These results indicate that APPLE might well consider the refueling schedule of Table 2b. ORSIM calculates a discounted system cost savings of over $4 million for this strategy, over the 60-months of the study. For this case the savings in replacement energy costs for the 18-month fuel cycle

Table 1. Generating System Data

Name	No of Units	Unit Capacity (MW)	Unit Availability (%)	Incremental[a] Fuel Cost (mills/kWHe)
NU01	1	1089.0	87.0	1.22
NU02	1	1089.0	87.0	1.22
NU03	1	395.0	91.0	1.13
NU04	1	789.0	94.0	1.20
NU05	1	200.0	93.3	1.13
NU06	1	789.0	93.0	1.20
NU07	1	789.0	91.0	1.20
NU08	1	1048.0	85.0	1.21
NU09	1	1048.0	85.0	1.21
NU10	1	1070.0	85.0	1.21
NU11	1	1070.0	85.0	1.21
BF01	1	500.0	90.0	7.16
BF02	1	500.0	90.0	7.16
BF03	1	500.0	90.0	7.16
BF04	1	500.0	90.0	7.16
BF05	1	500.0	90.0	7.16
BF06	1	500.0	90.0	7.00
BF07	1	840.0	85.0	6.58
BF08	1	840.0	85.0	6.58
BF09	1	336.0	85.0	6.08
BF10	1	616.0	85.0	6.59
BF11	1	616.0	85.0	6.59
BF12	1	617.0	85.0	6.39
BF13	1	617.0	85.0	6.39
BF14	1	350.0	85.0	5.91
BF15	1	553.0	85.0	7.03
BF16	1	334.0	85.0	5.89
BF17	1	358.0	85.0	5.91
BF18	1	360.0	85.0	6.51
BF19	1	336.0	85.0	5.92
BF20	1	230.0	85.0	5.90
BF21	1	222.0	85.0	6.29
MF01	1	270.0	85.0	6.21
MF02	1	148.0	95.0	10.15
MF03	1	150.0	95.0	9.85
MF04	1	158.0	95.0	6.69
MF05	1	162.0	67.0	9.67
MF06	1	162.0	67.0	9.42
MF07	1	150.0	67.0	7.66
MF08	1	205.0	67.0	9.00
MF09	1	116.0	67.0	7.46
MF10	1	114.0	67.0	8.64
MF11	1	65.0	95.0	7.01
MF12	1	57.0	95.0	6.17
MF13	1	119.0	95.0	7.17
MF14	1	159.0	95.0	6.36
MF15	1	158.0	95.0	6.40
MF16	1	232.0	67.0	7.52
MF17	1	129.0	67.0	7.25
MF18	1	50.0	95.0	8.05
MF19	1	38.0	95.0	8.49
MF20	1	22.0	95.0	8.64
MF21	1	35.0	95.0	8.49
MF22	1	84.0	67.0	10.90
PK01	1	140.0	95.0	16.50
PK02	1	117.0	95.0	16.90
PK03	1	140.0	95.0	16.50
PK04	1	280.0	95.0	16.50
PK05	1	260.0	95.0	15.70
PK06	1	128.0	95.0	16.50
PK07	1	192.0	95.0	16.50
PK08	1	260.0	95.0	18.75
PK09	1	130.0	95.0	17.90
PK10	1	22.0	95.0	20.00
PK11	1	600.0	95.0	16.40
PS01	1	624.0	100.0	0.0
H	1	400.00	99.0	0.0
INT1[b]	1	0.0	100.0	22.00
INT2	1	0.0	100.0	25.00

[a]for nuclear units this is an initial guess

[b]INT2 = Interchange required by capacity restrictions, includes loss of load
INT1 = Intrechange required by other energy shortages

Table 2a. Refueling Schedule for Nuclear Units

Unit	Months Unit is Down													
NU01	4	5	16	17	28	29	40	41	52	53	0	0	0	0	0
NU02	2	3	14	15	26	27	38	39	50	51	0	0	0	0	0
NU03	3	4	15	16	27	28	39	40	51	52	0	0	0	0	0
NU04	10	11	22	23	34	35	46	47	58	59	0	0	0	0	0
NU05	1	2	3	13	14	15	25	26	27	37	38	39	49	50	51
NU06	1	2	13	14	25	26	37	38	49	50	0	0	0	0	0
NU07	10	11	22	23	34	35	46	47	58	59	0	0	0	0	0
NU08	36	37	43	49	0	0	0	0	0	0	0	0	0	0	0
NU09	48	49	0	0	0	0	0	0	0	0	0	0	0	0	0
NU10	51	52	0	0	0	0	0	0	0	0	0	0	0	0	0
NU11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Nuclear Unit ---- NU02

Fuel Cycle	Month Started	Month Ended
1	-29	-12
2	- 9	1
3	4	13
4	16	25
5	28	37
6	40	49
7	52	61
8	64	73
9	76	85
10	88	97

Table 2b. Refueling Schedule for Nuclear Units

Unit	Months Unit is Down														
NU01	4	5	16	17	28	29	40	41	52	53	0	0	0	0	0
NU02	2	3	20	21	38	39	56	57	0	0	0	0	0	0	0
NU03	3	4	15	16	27	28	39	40	51	52	0	0	0	0	0
NU04	10	11	22	23	34	35	46	47	58	59	0	0	0	0	0
NU05	1	2	3	13	14	15	25	26	27	37	38	39	49	50	51
NU06	1	2	13	14	25	26	37	38	49	50	0	0	0	0	0
NU07	10	11	22	23	34	35	46	47	58	59	0	0	0	0	0
NU08	36	37	48	49	0	0	0	0	0	0	0	0	0	0	0
NU09	48	49	0	0	0	0	0	0	0	0	0	0	0	0	0
NU10	51	52	0	0	0	0	0	0	0	0	0	0	0	0	0
NU11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Nuclear Unit ----- NU02

Fuel Cycle	Month Started	Month Ended
1	-29	-12
2	- 9	1
3	4	19
4	22	37
5	40	55
6	58	73
7	76	91
8	94	109
9	112	127
10	130	145

Table 3a. Summary of System Operation

Energy Supplied by System (GWHRE)

Year	Total Energy Generated	Total Energy For Pumping	Total Energy Delivered
1	74,424.6	953.9	73,470.6
2	79,474.0	885.8	78,581.4
3	84,059.9	994.5	83,065.4
4	89,198.1	1,082.5	88,115.6
5	94,418.3	1,169.6	93,248.7

Breakdown of Energy Generated (GWHRE)

Year	Energy From Nuclear	Energy From Base Fossil	Energy From Midrange Fossil	Energy From Peakers	Energy From PMP.Stg.+Hydro	Energy Purchased
1	32,751.6	36,404.8	3,412.5	167.1	1,688.6	25.1
2	35,889.0	38,592.4	3,401.1	176.1	1,415.4	12.2
3	43,376.2	36,267.9	2,835.6	87.8	1,492.4	5.6
4	52,359.1	33,007.0	2,289.7	91.5	1,450.9	7.3
5	56,397.5	33,916.0	2,405.5	104.3	1,595.1	10.4

Breakdown of Costs (Discounted 10^6\$)

Nuclear Costs	Base Fossil Costs	Midrange Fossil Costs	Peaker Costs	Costs of Purchased Energy	Total Costs
289.85	809.35	67.52	7.98	1.21	1,175.91

Breakdown of Levelized Unit Costs (M/kWH)

Nuclear Costs	Base Fossil Costs	Midrange Fossil Costs	Peaker Costs	Costs of Purchased Energy	Total Costs
1.85	6.01	6.12	16.43	25.00	3.84

System Operating Cost	\$1,175.91	$\times 10^6$
Maintenance Cost	16.04	$\times 10^6$
TOTAL	\$1,191.95	$\times 10^6$

Table 3b. Summary of System Operation

Energy Supplied by System (GWHRE)

Year	Total Energy Generated	Total Energy For Pumping	Total Energy Delivered
1	74,447.9	977.3	73,470.5
2	79,515.6	936.5	78,579.0
3	84,142.0	1,076.8	83,065.2
4	89,221.0	1,105.4	88.115.6
5	94,385.7	1,148.4	93,237.3

Breakdown of Energy Generated (GWHRE)

Year	Energy From Nuclear	Energy From Base Fossil	Energy From Midrange Fossil	Energy From Peakers	Energy From Pmp.Stg. + Hydro	Energy Purchased
1	32,749.6	36,498.2	3,290.9	166.2	1,743.0	25.1
2	35,965.5	38,488.6	3,390.9	238.9	1,431.6	20.9
3	44,596.3	35,194.2	2,738.1	86.9	1,526.5	5.6
4	52,204.5	33,156.8	2,259.2	91.3	1,509.2	7.3
5	56,276.0	33,942.2	2,470.5	159.1	1,537.9	21.7

Breakdown of Costs (Discounted $10^6$$)

Nuclear Costs	Base Fossil Costs	Midrange Fossil Costs	Peaker Costs	Costs of Purchased Energy	Total Costs
289.31	804.87	66.60	9.32	1.55	1,171.64

Breakdown of Levelized Unit Costs (M/kWH)

Nuclear Costs	Base Fossil. Costs	Midrange Fossil Costs	Peaker Costs	Costs of Purchased Energy	Total Costs
1.84	6.01	6.14	16.45	25.0	3.83

System Operating Cost	$1,171.64	$\times 10^6$
Maintenance Cost	15.42	$\times 10^6$
TOTAL	$1,191.95	$\times 10^6$

were more than enough to offset the increased costs due to refueling during peak load periods.

An alternative way of viewing the effect of this strategy is presented in Figures 3a, 3b, 4a, and 4b. Figure 3a depicts the results of ORSIM's maintenance scheduling block for the refueling scheme of Table 2a; Figure 3b then depicts the results from the refueling scheme of Table 2b.

In Figures 4a and 4b, the plants in the generation system are plotted on the X-axis, the months in the planning horizon are plotted on the Y-axis, and the load factor of each generating station in each month is plotted in the Z-direction. From these perspective representations several features of the system may be discerned at a glance. For example, the nuclear plants may be observed generating substantial amounts of energy on the left of the plot, and the effect of the summer peak load periods and of nuclear refueling schedules may be observed by noting those months which require additional generation from the system's more expensive mid-range fossil plants and peaking units.

4. CONCLUSIONS

The ORSIM model appears to be a useful tool for planning nuclear refueling cycles. Moreover, experience gained with ORSIM on sample problems suggests that this model could be useful in a wide range of assessment studies. The basic application of ORSIM is to derive "optimal" operating strategies for a utility generation system, given the installed capacity, demands for energy, fossil costs, and other plant and system data. Output includes unit load factors on a month-by-month schedule and the total operating cost for the system.

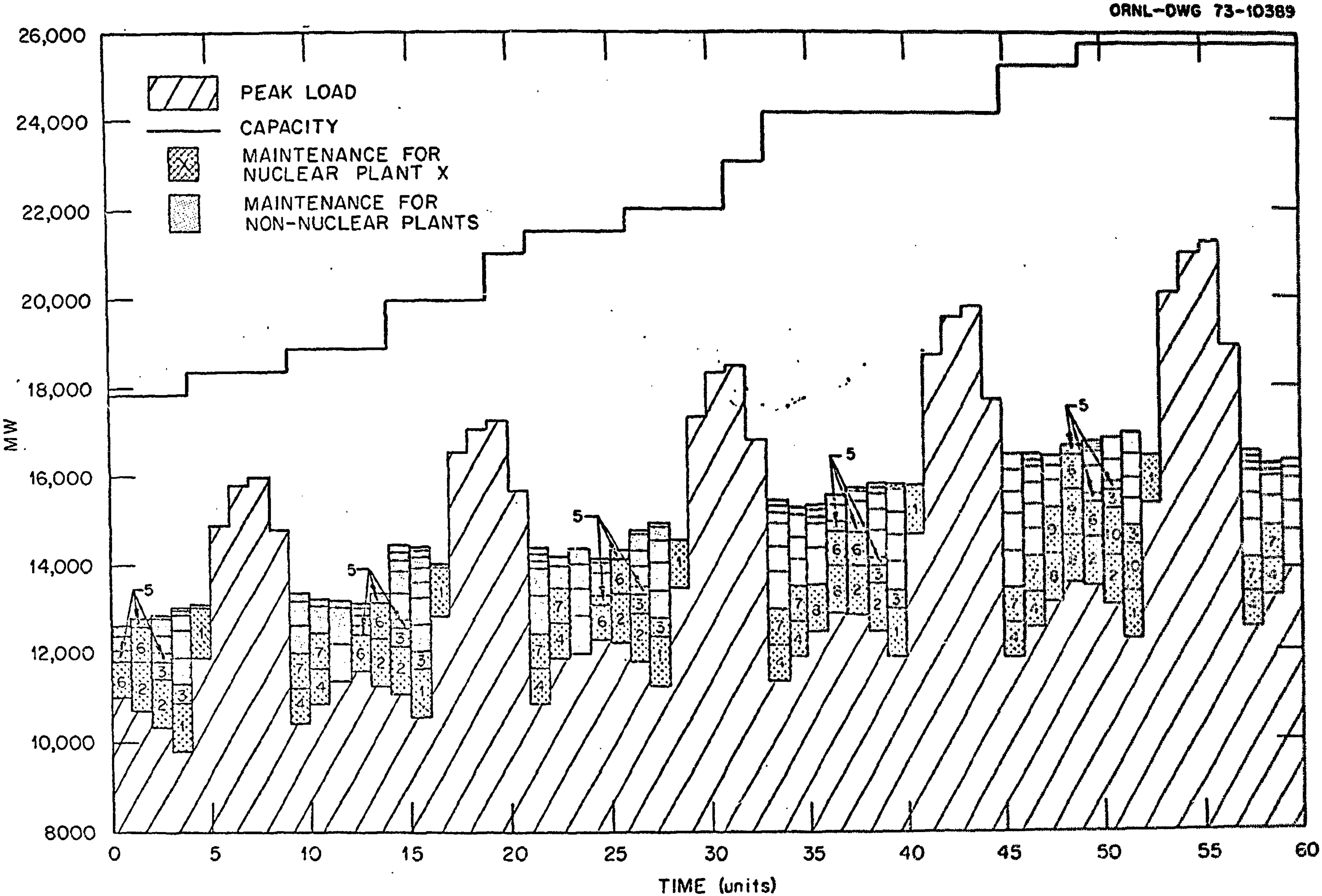

Fig. 3a. Maintenance Schedule

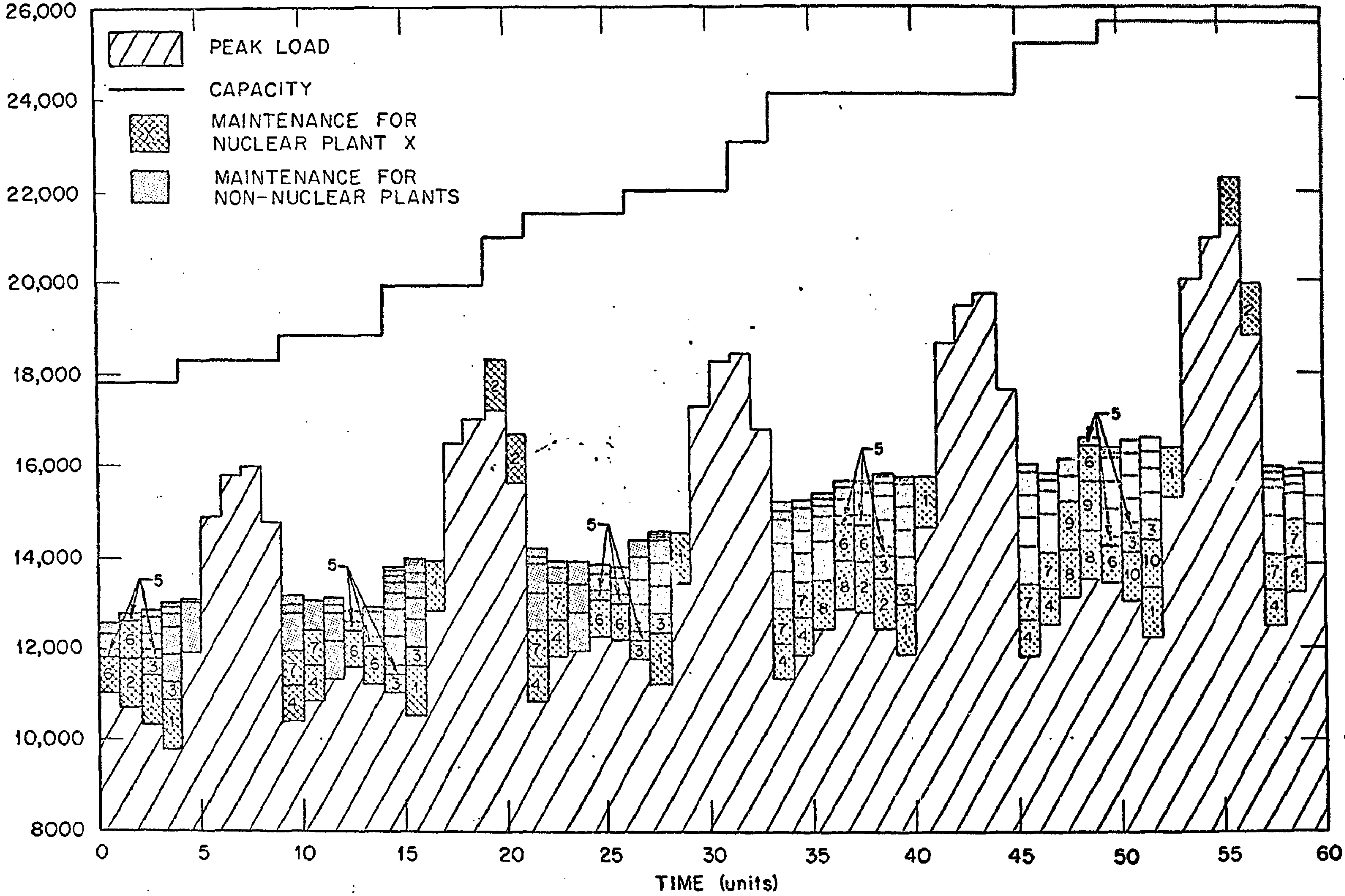

Fig. 3b. Maintenance Schedule

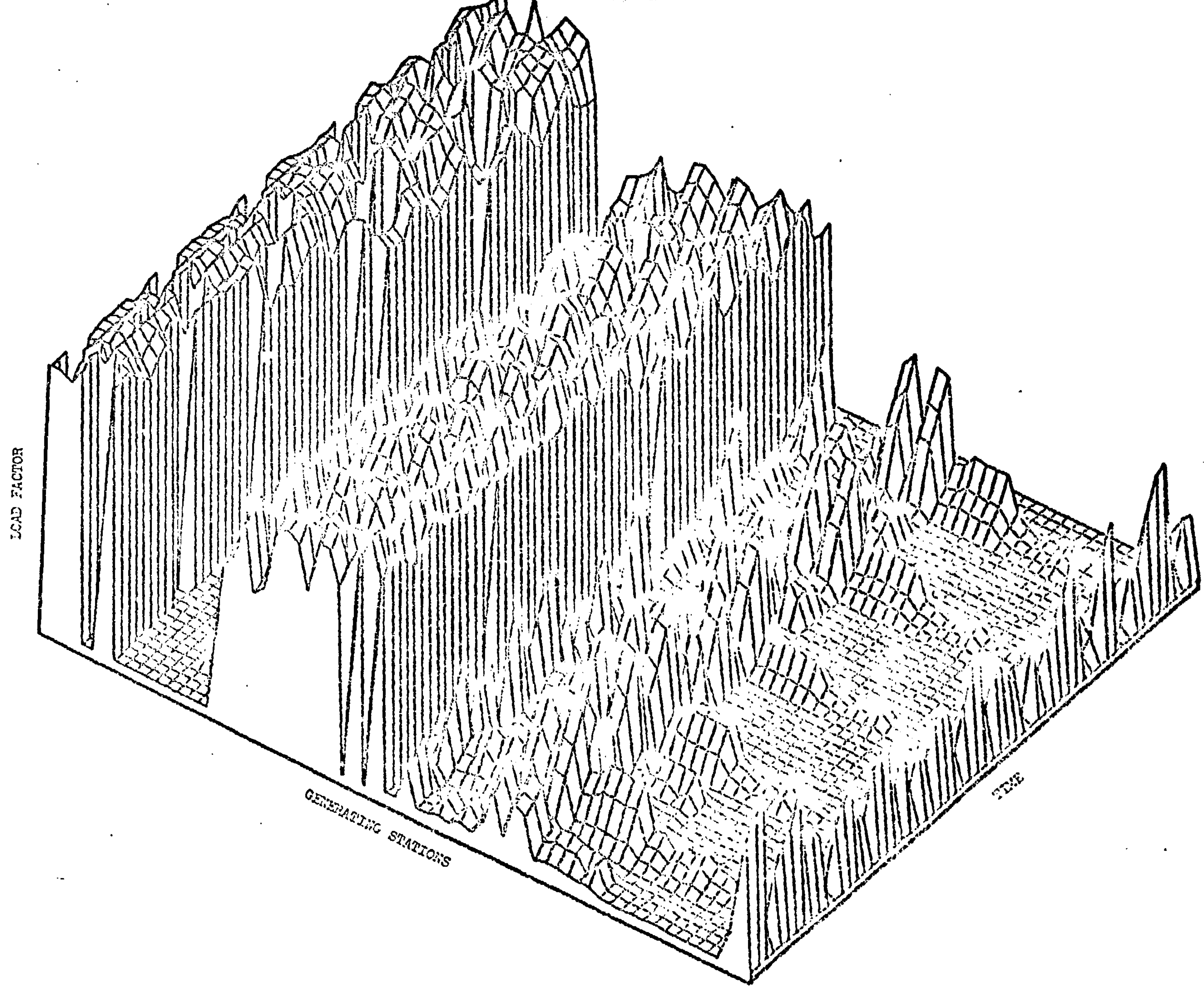

Fig. 4a. Perspective Plot of Load Factor
Refueling Schedule of Table 2a

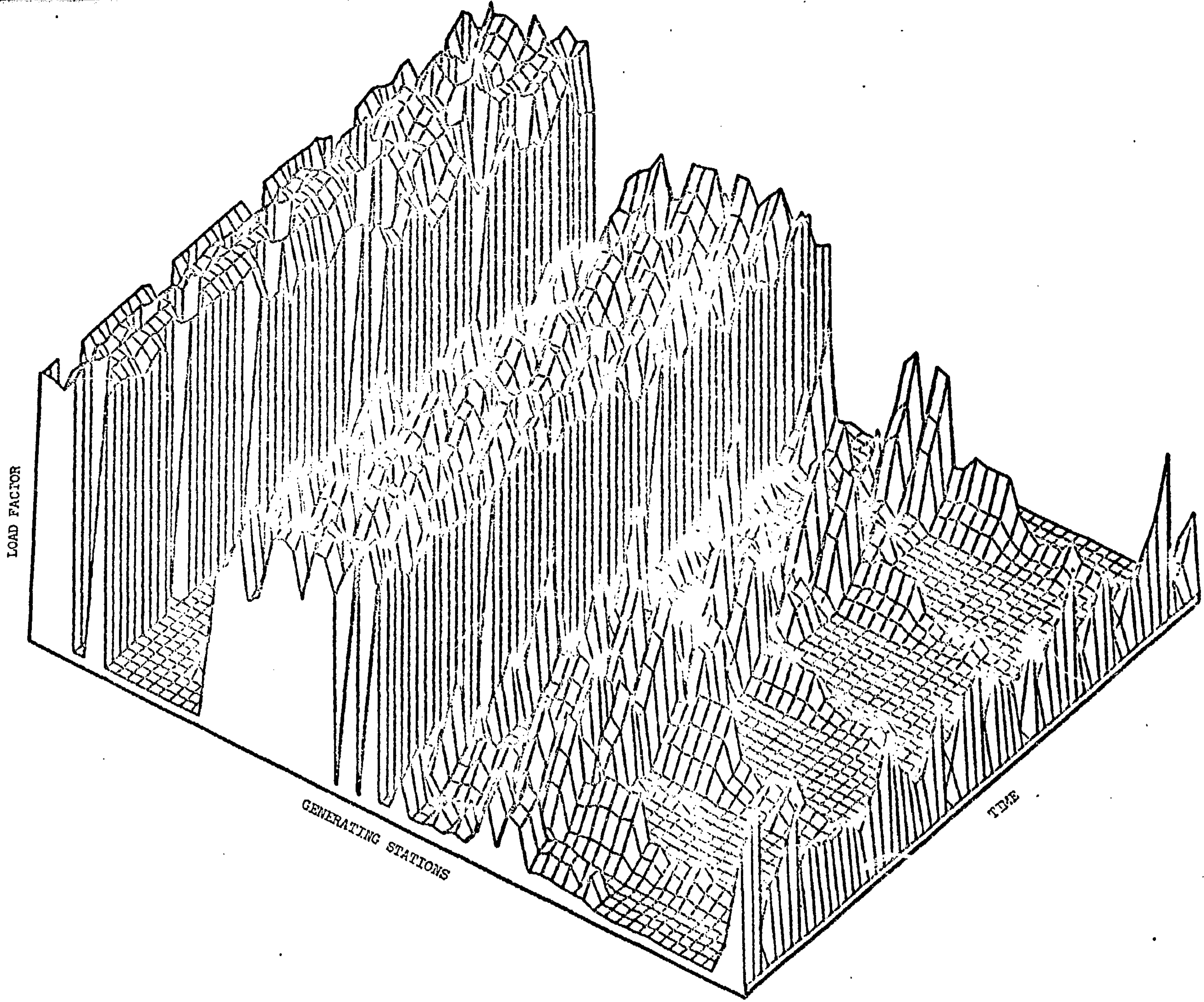

Fig. 4b. Perspective Plot of Load Factor
Refueling Schedule of Table 2b

This optimization and costing capability of ORSIM makes it useful for deriving operating strategies and costs for alternative situations that the utility may encounter. Examples include,

1. Evaluation of alternative plant addition schedules to meet system growth.
2. Evaluation of cost effects of construction delays, nuclear plant deratings, and changes in refueling schedules.
3. Assessment of economics of using off-peak power for hydrogen production or pumping energy.
4. Assessment of costs and operational changes produced by pollution abatement requirements; evaluate effluent cleanup versus clean fuels.
5. Assessment of proposed fuel policy changes on utility costs; fuel availability vs prices; LNG, coal gasification, etc.

It seems clear that the ORSIM code could play a role in such studies, and others not included in this "back-of-the-envelope" list. ORSIM can be run for alternative cases, or it could serve as the system simulation and costing module in an overall energy assessment code.

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Appendix A

Although the chronological sequence of loads has been lost, the area under the load duration curve (Fig. A-1a) is the total energy requirement imposed on the system. In this curve, the abscissa represents the number of hours during which the system load equals or exceeds the value of associated power on the ordinate. By normalizing the time variable, the value at any point on the abscissa becomes the fraction of the entire period for which the load equals or exceeds the associated power. Carrying this logic a step further, the abscissa can be considered to represent the probability that a particular value of the system load will be equaled or exceeded.

It is more convenient to work with the load duration curve in a slightly different form by reversing the ordinate and abscissa, Fig. A-1b. The "inverted" load duration curve can be used to estimate the loadings of the various generation units by plotting the units on the curve as shown in Fig. A-2a, and integrating the curve between the proper limits

$$E_i = T \int_{a_i}^{b_i} L\,(x)\,dx \tag{A-1}$$

where E_i = expected generation of ith unit;

T = time period represented by load duration curve;

$L(x)$ = load duration curve;

a_i = system capacity for units 1, 2, ..., i-1;

b_i = system capacity for units 1, 2, ..., i.

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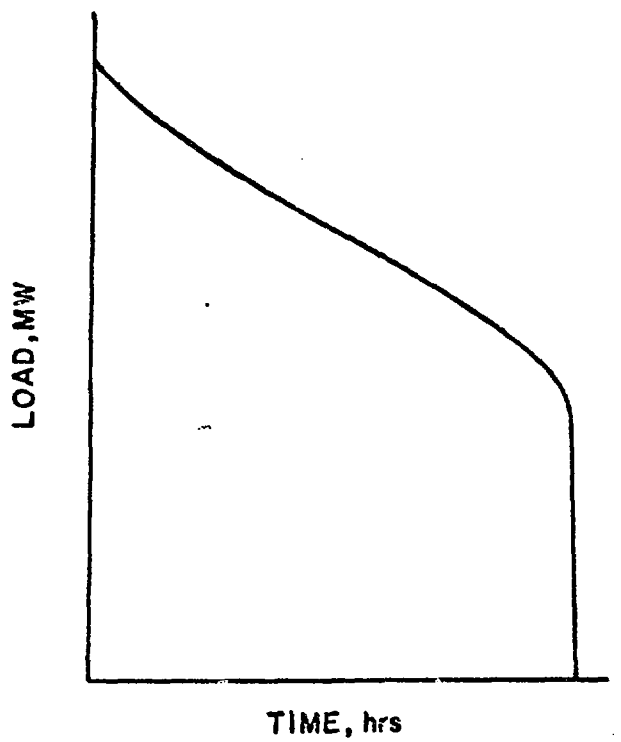

Fig. A-1a. Load Duration Curve

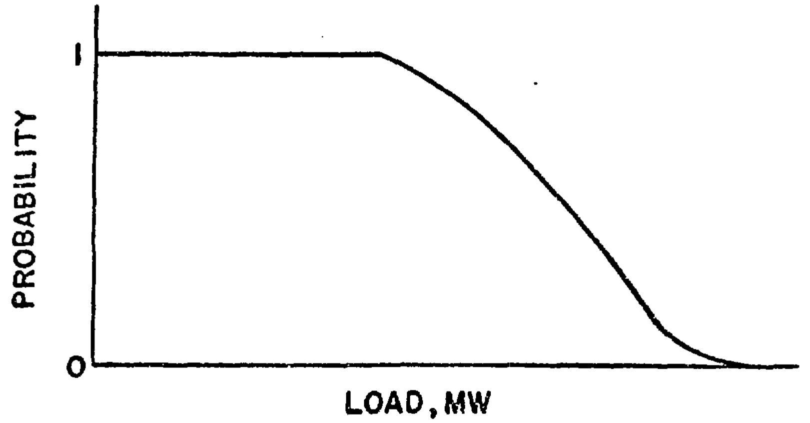

Fig. A-1b. "Inverted" Load Duration Curve

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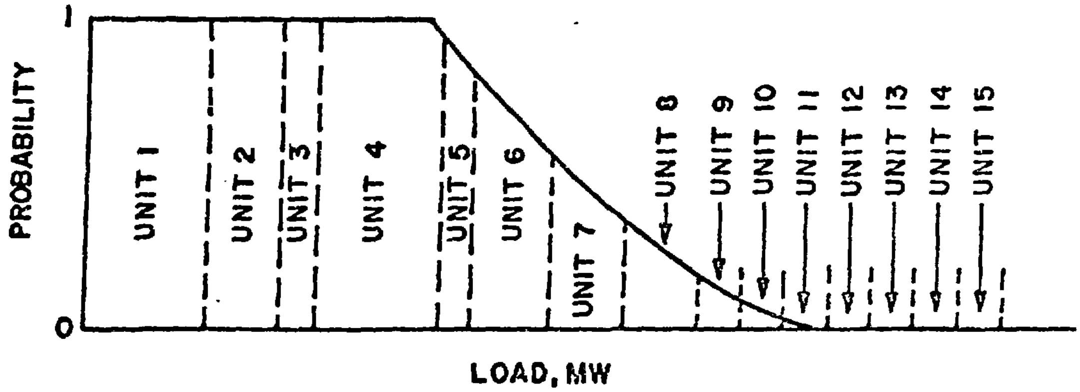

Fig. A-2a. Estimating Unit Loadings via an Inverted Load Duration Curve

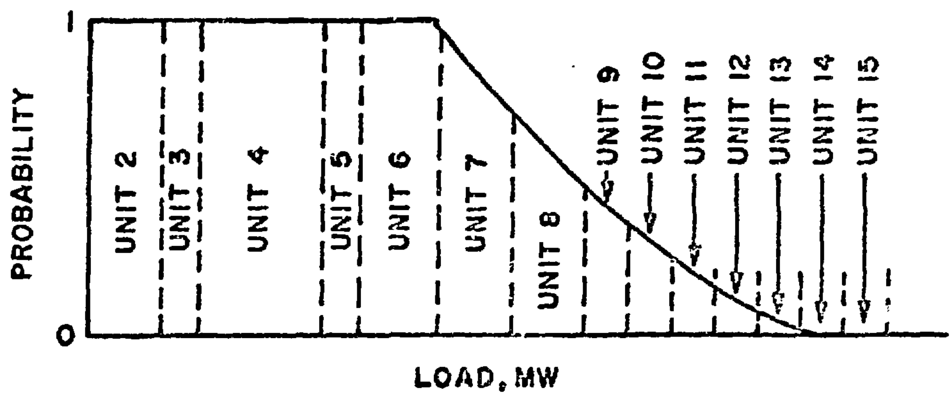

Fig. A-2b. Estimating Unit Loadings via an Inverted Load Duration Curve with Unit 1 not Available

In order to perform this calculation the order in which the units are to be loaded (i.e., the loading order) must be specified. This technique would accurately estimate the expected generation of each unit if all units were available for generation 100% of the time.

Unfortunately, all generating units are subject to random outages, the occurence and duration of which are unpredictable. The simplest stochastic model for treating unit reliability is to define two possible states for each unit. The unit is either available and capable of full power generation, or the unit is not available and is unable to deliver any power. Associated with each state is a probability of the unit being in that state. Let p_i be the probability of unit i being available and let q_i be the probability of the unit not being available. Since the unit must be in one of the two states

$$p_i + q_i = 1.0 \quad \text{(A-2)}$$

The probability q_i is normally referred to as the expected forced-outage rate and is frequently expressed as a percentage rather than as a fraction.

The major problem in using a load duration curve to estimate the unit loadings is that the order in which the units are plotted under the load duration curve changes when one or more units suffer a forced-outage. The order in which the units are plotted in Figure A-2b is representative of how the system would be operated when unit 1 is not available. Comparing Figures A-2a and A-2b, it is obvious that all units have been shifted to the left by the capacity of unit 1. It is important to notice that there has been a significant change in the expected generation of some of the units, particularly the units in the region of the maximum system load (units 9-14).

How much energy would unit 1 be expected to generate? If unit 1 is available, the amount of energy it would be required to generate would be equal to the area under the load duration curve L (Fig. A-2a). If unit 1 is not available, it is not capable of generating any energy. Therefore, the expected generation for unit 1 would be that calculated from load duration curve L times the probability of the unit being available.

$$E_1 = p_1 \, T \int_{a_1}^{b_1} L\,(x)\,dx \qquad \text{(A-3)}$$

Outages of other units in the system do not have any effect on unit 1 since the position of unit 1 under the curve L does not change when other units are removed from the system.

The operation of unit 2 is directly effected by any outage of unit 1. but not effected by outages of units 3, 4, etc. When unit 2 is available (probability P_2), it would be loaded according to Figure A-2a if unit 1 is available, and according to Figure A-2b if unit 1 is not available. When unit 2 is unavailable (probability q_2), it would not be capable of generating any energy. Therefore, the expected generation of unit 2 would be

$$E_2 = p_2 \, T \left[p_1 \int_{a_2}^{b_2} L(x)dx + q_1 \int_{\alpha_2}^{\beta_2} L(x)dx \right] \qquad \text{(A-4)}$$

where a_2, b_2 are integration limits for Fig. A-2a

α_2, β_2 are integration limits for Fig. A-2b

Instead of considering two separate loading positions, an alternative and equivalent representation of an outage of unit 1 would be to leave unit 1 in its original position and shift the inverted load duration curve to the right by the capacity of unit 1, Fig. A-3. Again let L represent the original inverted load duration curve and let L´ be the shifted curve. From examination of Fig. A-3, it becomes apparent that

$$L'(x) = L(x - MW_1) \qquad \text{(A-5)}$$

where

$$MW_1 = \text{capacity of Unit 1}$$

and hence

$$\int_{\alpha_2}^{\beta_2} L(x)\,dx = \int_{a_2}^{b_2} L(x - MW_1)\,dx. \qquad \text{(A-6)}$$

The probability that unit 2 would be loaded by curve L is p_1 and the probability that unit 2 would be loaded by curve L´ is q_1. By substituting Eq. (A-6) into Eq. (A-4) and rearranging, the expected generation of unit 2 would be calculated by

$$E_2 = p_2 T \left\{ \int_{a_2}^{b_2} \left[p_1 L(x) + q_1 L(x - MW_1) \right] dx \right\} \qquad \text{(A-7)}$$

Equation (A-7) suggests that the effect of forced outages can be combined with the system load in a single variable, the equivalent load. The equivalent load is defined as

$$EL_{i-1} = L + O_i \qquad \text{(A-8)}$$

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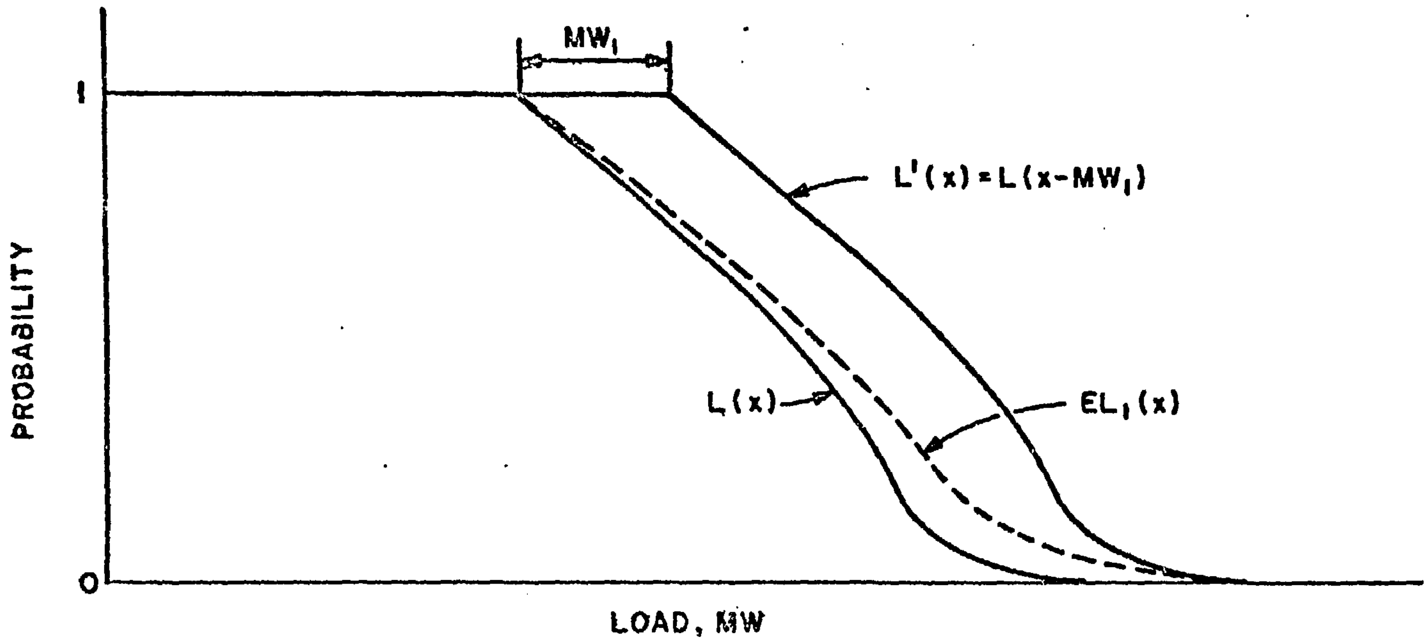

Fig. A-3. Representation of Equivalent Load where

EL_{i-1} = equivalent load considering outages of units before unit i in the loading order, units 1, 2,..., i-1;

L = system load duration curve;

O_i = additional operation required of unit i by outages of units before unit i in the loading order, units 1, 2,..., i-1.

For unit 2 the system load would be determined from the original inverted load duration curve (L).

$$L = L\ (x).$$

The operation of unit 2 caused by an outage of unit 1 would be represented by the difference between curves L $(x - MW_1)$ and L (x)

$$O_i = \left[L\ (x - MW_1) - L\ (x) \right] .$$

The equivalent load curve for unit 2 (EL_1) would be evaluated by multiplying the additional load by the probability of having to serve the additional load

$$EL_1 = L\ (x) + q_1\ [L\ (x - MW_1) - L\ (x)]$$

which by substitution of Eq. (A-2) becomes

$$EL_1 = p_1\ L\ (x) + q_1\ L\ (x - MW_1)\ . \qquad \text{(A-9)}$$

This curve is shown as the dashed curve in Fig. A-3. Substituting Eq. (A-9) into Eq. (A-7) yields

$$E_2 = p_2 T \int_{a_2}^{b_2} EL_1\ (x)\ dx. \qquad \text{(A-10)}$$

In order to evaluate the expected generation of unit 3, the effects of outages in both units 1 and 2 must be considered. The equivalent load curve (EL_1) incorporates the effect of forced outages for unit 1. Unit 3 is loaded according to this curve if unit 2 is available. If unit 2 is not available, the equivalent load curve would be shifted to the right by the capacity of unit 2 (MW_2). Again these two curves can be combined into a single equivalent load curve (EL_2) by using Eq. (A-9) and replacing L with EL_1.

The Probabilistic Simulation method calculates the expected loadings for the units by first generating the proper equivalent load curve and then integrating this curve between the proper limits. Although there exists several different algorithms designed to perform this function; one may, in general, view the equivalent load curve for the first unit as simply the load duration curve.

$$EL_{m-1} = L_{m-1} \text{ with } m = 1 \tag{A-11}$$

Then, for successive units the equivalent load curve is

$$EL_m = p_m \quad EL_{m-1}(x) + q_m \quad EL_{m-1}(x - MW_m) \tag{A-12}$$

and the expected generation for each unit is

$$E_m = p_m T \int_{a_m}^{b_m} EL_{m-1}(x)\, dx \tag{A-13}$$

Additional information about the system can be obtained from the equivalent load curve which results from applying Equation A-12 recursively to all the units in the system. Figure A-4 shows this curve with the total system capacity, $\overline{X}_N$, also being plotted. Referring to the definition of equivalent load, it is evident that P* is the probability of having an equivalent load equal to or greater than the system capacity. Since the generating system would not be able to supply loads greater than the system capacity, P* is the generating system's probability of loss of load. In order to estimate total system reliability, the value of P* must be increased to include the reliability of the transmission and distribution system.

The area under the equivalent load curve to the right of the $\overline{X}_N$ (shaded area in Fig. A-4) represents the expected energy demand that the generating system would not be able to serve

$$U = T \int_{\overline{X}_N}^{\infty} EL_N(x)\,dx \quad . \qquad \text{(A-14)}$$

Recall now that the loading order concept was introduced during the discussion of the calculation of expected generations for each unit. The basic model assumes that a unit would be completely loaded before the next unit was loaded. A much more realistic simulation of a utility system can be obtained by defining two blocks of capacity for each unit. The individual blocks may then be placed in nonadjacent positions of the loading order. This technique is known as the "two-block representation" and in the ORSIM code the user has the option of defining each unit as a one block or two block unit.

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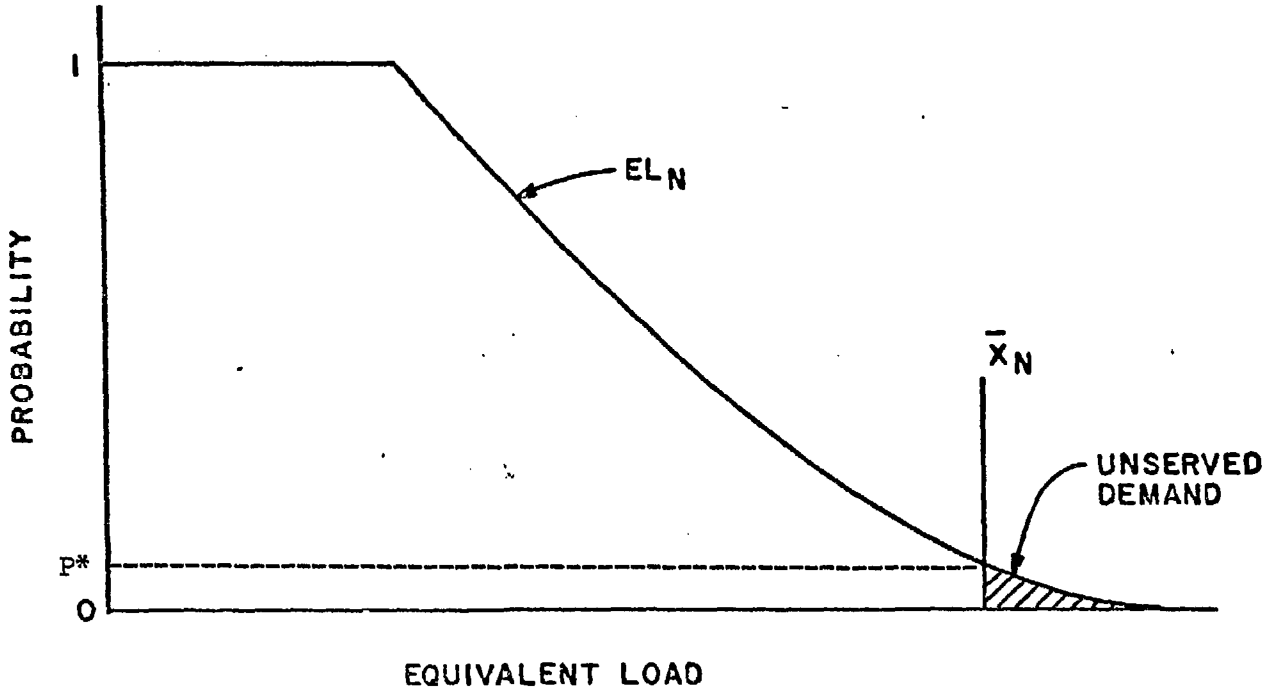

Fig. A-4. Equivalent Load Curve for Entire System and Unserved Energy Demand

The probabilistic simulation model used in ORSIM is also capable of simulating hydroelectric, pumped storage, and energy-fixed nuclear units. Because of reservoir constraints, hydroelectric units may only be able to generate a fixed amount of energy. Hence it is desirable to utilize the hydroelectric energy in the most economical manner. In order to simulate the effect of hydroelectric units, the optimum amount of energy to be generated in each subinterval of the planning horizon must therefore be calculated. The probabilistic simulator then decides which of the more expensive thermal units will be off-loaded by the hydro unit, and what the resulting load factor for these units will be.

Similarly, for the energy-fixed nuclear units, the amount of energy to be generated in each subinterval must be calculated. Given this information, the probabilistic simulation makes economic off-loading decisions.

Pumped-storage units are also simulated in a manner quite similar to that used for simulating hydroelectric units; however, it is not necessary to specify an energy allocation in the case of pumped-storage units. During periods of reduced load, energy at low incremental cost is employed to pump water into the pumped-storage reservoir This water is later used during periods of high system load to replace high-cost thermal generation In the simulator, the amount of energy to be generated by the pumped storage unit is calculated from an economic interchange of energy through the pumped storage reservoir.

In summary, the probabilistic model is designed to incorporate the effect of random events in estimating the operation of a series of thermal generating units. The capacity, forced-outage rate, operating cost, and position in the loading order must be specified for each unit in the system. The capacity of any thermal unit may be divided into blocks, which can be placed in non-adjacent positions in the loading order.

The amount of energy to be generated by hydroelectric and energy-fixed nuclear units, the pumping capacity and efficiency of the pumped-storage facility, and the load duration curve are additional items required as input information. The model will calculate an expected generation of each thermal unit and the pumped-storage unit. The expected hours of operation for each unit, the expected operating costs, the probability of loss of load, and the expected unserved energy are also calculated.