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WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP) — AN ELECTRIC UTILITY OPTIMAL GENERATION EXPANSION PLANNING COMPUTER CODE

R. T. Jenkins
D. S. Joy

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Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22151
Price: Printed Copy $5.45; Microfiche $1.45

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ORNL-4945
UC-32 — Mathematics and Computers

Contract No. W-7405-eng-26

CHEMICAL TECHNOLOGY DIVISION

WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP) — AN ELECTRIC UTILITY OPTIMAL GENERATION EXPANSION PLANNING COMPUTER CODE

by

R. T. Jenkins
(Tennessee Valley Authority, Chattanooga, Tenn.)

and

D. S. Joy
(Oak Ridge National Laboratory)

Studies and Evaluations Program
L. L. Bennett, Director

JULY 1974

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WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP) – AN ELECTRIC UTILITY OPTIMAL GENERATION EXPANSION PLANNING COMPUTER CODE

R. T. Jenkins* and D. S. Joy

ABSTRACT

The Wien Automatic System Planning Package (WASP) is designed to find the optimal generation expansion policy for an electric utility system. A dynamic programming algorithm is used in the optimization. A Probabilistic Simulation Model is used to evaluate the operating costs.

The WASP package evolved from the Tennessee Valley Authority's System Analysis Generation Expansion (SAGE) program and was specifically designed in its present form for the International Atomic Energy Agency's Market Survey for Nuclear Power in Developing Countries. The package is composed of six computer programs which can be run either independently or in series. The structure of the WASP package encourages a user-machine interface for monitoring intermediate results.

The major features of the package are:

1. New units can be automatically selected from a user-supplied list of expansion candidates.

2. The candidate list can contain hydroelectric and pumped-storage projects.

3. The existing system is modeled, including specified additions to and/or retirements from the existing system.

4. A Probabilistic Simulation Model is used to calculate production costs for all allowable configurations. The model includes the effect of unit forced outages and the maintenance schedule.

5. The user can supply restrictions for limiting generation configurations to an area of economic interest.

*Tennessee Valley Authority, Chattanooga, Tennessee

6. The Optimization Program reports whether the restrictions acted as a constraint on the solution.

7. The discount rate and the escalation rate are treated separately for each expansion candidate.

8. The discount rate and the escalation rate are treated separately for each fuel type.

9. All expenditures are separated into local and foreign accounts, and a weighting factor can be applied to foreign expenditures.

10. All expanded configurations are required to pass a user-supplied reliability restriction.

11. Study periods of up to 30 years are permitted.

The WASP package is designed to run on relatively small computers. The maximum core memory required is 30,000 words or 120 K bytes on an IBM computer. The code uses magnetic disk files to preserve information from iteration to iteration, thus avoiding repetition of calculations.

---

1. INTRODUCTION

Historically, the electric utility demand in developed countries has increased exponentially, with a doubling time of approximately 10 years. In the recent past, the planning of expansion policies to supply this demand required the consideration of a relatively small number of options. In some systems, the planner had to choose between hydroelectric and thermal additions. Within the thermal classification, the fuel was generally clearly defined and the major decisions involved the capacity of new units. Generating units were steadily improving in efficiency, and the planner normally specified an expansion using base-loaded units which would gradually be moved up the loading order as newer, more efficient units were added to the system. The planners were concerned with the size, timing, and determination of the special features that should be added to the thermal units.

Traditionally, the planner would generate a limited set of competitive expansion plans and calculate the cash flow associated with each plan. The computations were made by hand and, in more recent years, with computer assistance. Such a study required many hours of the planner's time, even though the alternatives examined were extremely limited.

Increased motivation for utilizing more-sophisticated techniques of evaluating utility expansion policies has developed during the past decade. The types of available generation capacity have multiplied, and the choice of alternatives has become more complicated because the assumption that new capacity should be base-loaded is no longer valid. Nuclear, gas turbine, combined cycle, base or intermediate fossil, hydroelectric, and pumped-storage units must now be considered as possible expansion candidates. The use of more-refined techniques for evaluating competitive system expansion schemes has increased significantly. Anderson's[1] survey paper discusses the application of various optimization techniques to the utility expansion problem. Among the optimization techniques available, dynamic programming has proved to be a powerful tool.

Also, a significant evolution has taken place in the method of estimating the production cost of a utility system. Previously, the operating costs for extended time periods were calculated with the aid of a load duration curve or by estimating the maximum load factors of the various units as a function of time. In the past few years the probabilistic simulation method[2] of estimating the expected operating costs has gained increasing acceptance. The method is capable of simulating the effects of random unit forced outages and also predicts the load factor for each unit in the system.

Booth[3] developed a utility expansion program which incorporates the probabilistic simulation method within a dynamic programming framework. The WASP package also utilizes both the Probabilistic Simulation Model and dynamic programming, but in a radically different program structure. The WASP package has the facility of allowing the planner to direct or constrain the area of study to configurations which he believes most economic. The user can modify his constraints and, without repeating all the previous calculations, can determine the value of the constraint relaxation. This

process can be repeated as many times as is necessary to find an optimal path free of user-imposed constraints.

While the WASP package was especially developed for the needs of the IAEA Market Survey for Nuclear Power in Developing Countries,[4] it is also an extensive revision of an earlier Systems Analysis Generation Expansion program (SAGE) developed by and for the Tennessee Valley Authority (TVA).

Acknowledgments. — The authors would like to thank Dr. R. R. Booth of the State Electricity Commission of Victoria, Australia, for introducing us to the probabilistic simulation method and providing the TVA with early versions of his simulation and dynamic programming system expansion model. We would also like to acknowledge the work of Katherine McQueen and T. R. Jackson, of TVA, for their intensive effort in developing and applying the Systems Analysis Generation Expansion Model. The improvements discussed in this report are largely a result of their experience. Finally, gratitude is expressed to Peter Heinrich of the IAEA's Computing Center Staff for his contributions relative to the debugging and implementation of the WASP code on the IAEA computer.

2. GENERAL STRUCTURE AND PHILOSOPHY OF THE WIEN AUTOMATIC SYSTEM PLANNING PACKAGE

The WASP package is composed of six program modules. The main advantage in using a modular concept is to allow the use of man-machine interaction. Each program prints a separate report, and the user can analyze his results from step to step. Thus, any errors in data can be corrected before large amounts of computer time are wasted in simulating and optimizing with erroneous data. A second advantage is that the amount of memory required at any one time can be minimized, allowing the use of relatively small computers. The maximum core storage required for the WASP package is only 30,000 words or 120 K bytes on an IBM computer. Another feature of the WASP package is that data can be saved from previous iterations, thus significantly reducing the computational effort required to arrive at a solution. The general structure of the WASP package is presented in this section. A brief description of the individual programs

is also included. A detailed description of each program can be found in later sections. Logical flowcharts of the programs are presented in Appendixes C through H.

2.1 Brief Description of Programs

2.1.1 Fixed System Program (FIXSYS)

The Fixed System Program describes the state of the existing power system at the start of the study. The required data for each generating station in the system include: number of identical units, minimum and maximum operating capacities, heat rates associated with these capacities, type of fuel, fuel cost, forced-outage rate, and maintenance requirements. Any firmly committed additions and/or unit retirements are also specified in this program. Committed additions are described in the same manner as for existing plants with the exception that the first year of operation must also be specified. The date of retirement must be specified for unit retirements.

2.1.2 Variable System Program (VARSYS)

The Variable System Program defines the type of units that will be used to expand the system during the study period. Each particular unit whose type and capacity are defined becomes an expansion candidate. For example, a 600-MW nuclear unit and a 1000-MW nuclear unit would constitute different expansion candidates. Hydroelectric and/or pumped storage projects can also be included as expansion candidates. The data required to define a particular candidate are identical to those used in the Fixed System Program.

2.1.3 Load Description Program (LOADSY)

The Load Description Program defines the generation requirements in each period of the study. The study is nominally divided into years; however, each year may be subdivided into a number of periods. The forecasted peak loads and shape of the load duration curve are defined for each period in this program.

2.1.4 Expansion Configuration Generator Program (CONGEN)

The Expansion Configuration Generator Program gives the system planner the ability to direct the area of study to expansion configurations that he believes to be most economic. This can be accomplished by specifying minimum and maximum reserve requirements, thus constraining the system capacity. Any expansion configuration whose capacity would fall outside the reserve requirements would not be considered as a feasible state. Limits can also be placed on the minimum and maximum number of units of a particular expansion candidate that can be installed in any given year. The CONGEN program forms a list of all allowable system configurations (or states) for each year in the study.

2.1.5 Merge and Simulate Program (MERSIM)

This program calculates the operating cost for each of the configurations generated by the CONGEN program. A Probabilistic Simulation Model[5] is used to calculate the unit loadings and the system operating cost. The reliability of the generating system is also estimated by calculating the probability that the generating system will not be able to meet the system load and the probable amount of unserved energy. In addition to calculating the total operating cost, the MERSIM program calculates the cumulative expenditure with separate accounting in local and foreign currency.

2.1.6 Optimization Program (DYNPRO)

The DYNPRO program uses a dynamic programming algorithm to determine the optimal system expansion policy from the states defined in the CONGEN program. All the economic calculations, including the escalation of fuel prices, penalty on foreign expenditures, and present-worth calculations, are performed in the program.

A critical loss-of-load probability can be defined for any year of the study. Any configuration having a poorer reliability than the critical value is not considered as a feasible state and is omitted from the optimization calculations. After the optimum expansion schedule has been

calculated, the DYNPRO program will tell the user if any of the restrictions used in the CONGEN program acted as a constraint on the solution.

2.2 Flow of Information Between Programs

The WASP program was developed as a series of separate programs to allow the user to monitor his results as he proceeds with the analysis. Each of the programs can be run as a "stand-alone" program, or any number of the programs can be run sequentially as a single job.

Information is passed from program to program by data files which are stored on disks. The first three programs are data gathering programs, and each generates a separate data file (Fig. 1). The CONGEN program uses the files generated by the FIXSYS, VARSYS, and LOADSY programs, along with additional card input, and generates two additional data files (Fig. 2). These are the EXPANALT file, which is used by the MERSIM program, and the EXPACONT file, which is used by the DYNPRO program. The MERSIM program uses the files from the previous program and generates a file (SIMULXXX) for use in the DYNPRO program (Fig. 3). The DYNPRO program uses the FIXPLANT, VARPLANT, EXPACONT, and SIMULXXX files. Since this is the last step in the calculational process, DYNPRO does not generate any additional files.

2.3 Organization of Calculations

The WASP package allows the user to monitor his results after each step if he desires. The first three programs are completely independent of any other program. Most of the errors associated with input data will occur in these programs; therefore, it is recommended that the results from each be carefully checked before the remaining programs are used. Any errors that are found in the data can be corrected by rerunning the particular program involved and will thus save large amounts of computer time by avoiding runs of MERSIM and DYNPRO with erroneous data.

The dynamic programming algorithm used in DYNPRO is a powerful tool for solving utility expansion problems. Unfortunately, the unrestricted choice of all possible expansion configurations which would satisfy the

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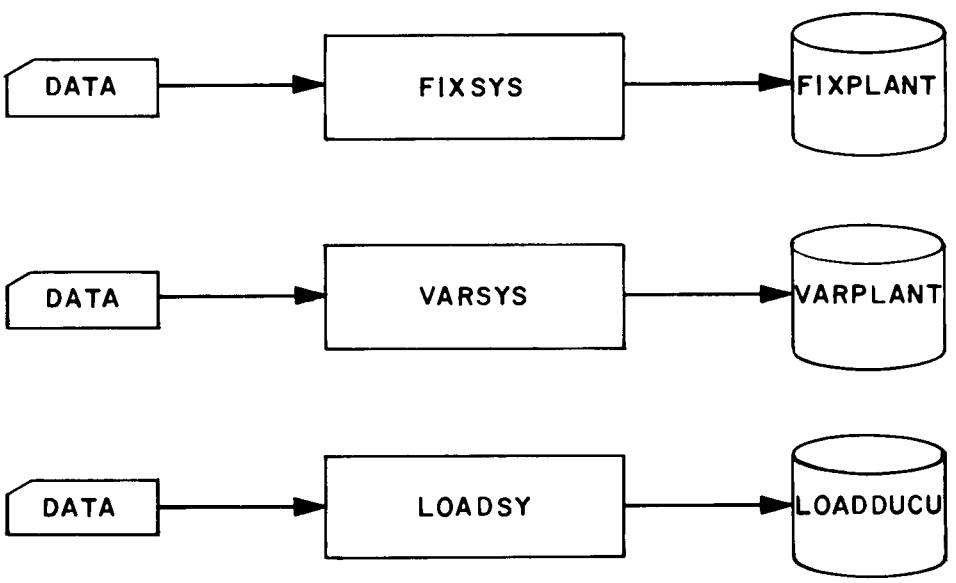

Fig. 1. Information Flow in FIXSYS, VARSYS, and LOADSY Programs.

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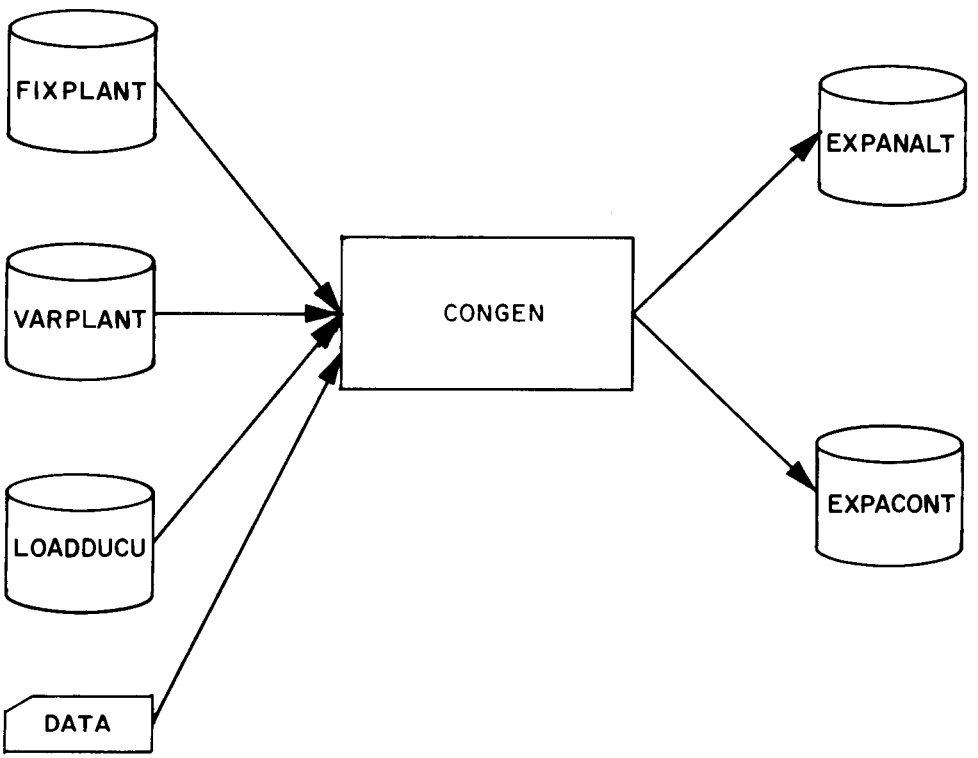

Fig. 2. Information Flow in the EXPALT Program.

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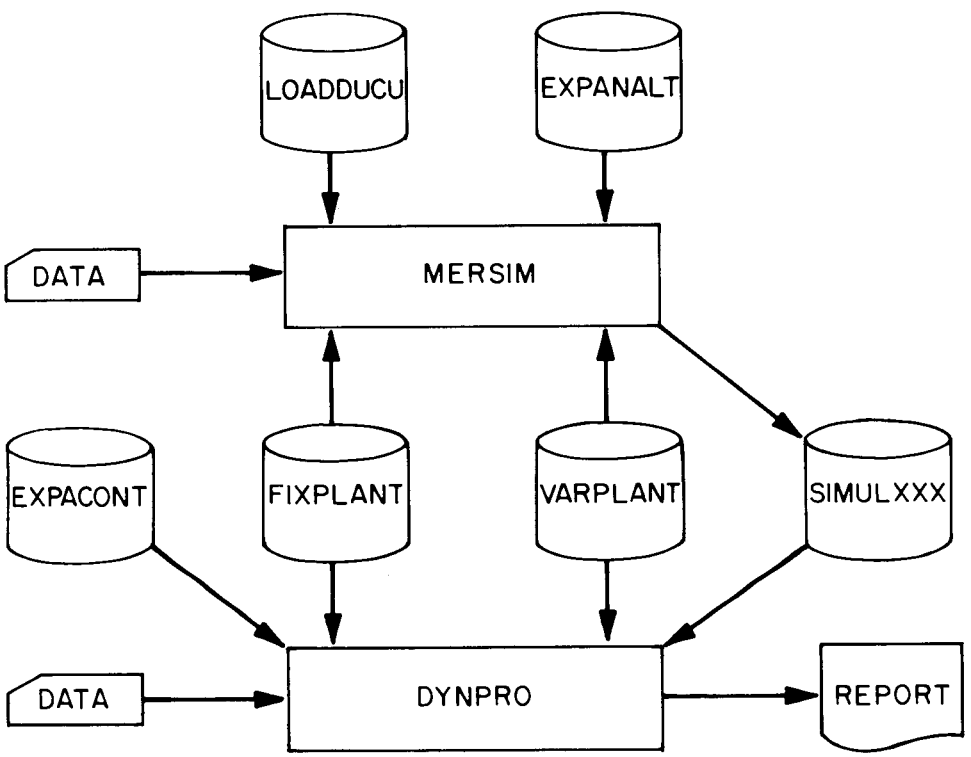

Fig. 3. Information Flow in the MERSIM and DYNPRO Programs.

load requirements leads to such a large number of states that the computational requirements become infeasible. In order to overcome this difficulty, the WASP package allows the user to direct the area of study to configurations (states) which he believes to be most economic. This is accomplished by specifying the reserve margins and limits on the number of units for each expansion candidate in the CONGEN program. The DYNPRO program will inform the user whether his restrictions acted as a constraint on the solution. The user may then modify his area of study and find a new optimal expansion policy without repeating all of the previous calculations. The MERSIM program has the capability of utilizing simulations from previous runs by adding only the new configurations to the data file. This is a very important feature since the program does not have to resimulate the system operation for any state encountered in a previous iteration. The iterative process of adjusting the area of study could be repeated until an optimal path free of any user-imposed constraints is found. Figure 4 is a flowchart of this procedure, in which a symbol indicates the appropriate points for user-machine interaction.

The WASP package can also be used to evaluate any specific expansion schedule. If the user explicitly defines the number of units for each expansion candidate that are to be added to the system in each year of the study, the EXPALT program will generate only a single state in any given year. In this case, the DYNPRO program simply degenerates to a cash flow program. This procedure could be used to evaluate a number of expansion patterns to select a favorable area as a starting point in full-scale optimization runs.

3. UNITS

The units adopted for this report are those commonly used throughout the United States. However, any consistent set of units can be used. Capacity units such as megawatts or kilowatts always refer to electrical units and not thermal units. In the metric system, the heat rate is expressed in kilocalories per kilowatt-hour, which is equivalent to 0.252 Btu/kWhr; the fuel costs are expressed as ¢/Mkcal,* which is equivalent to 3968 ¢/MMBtu.**

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*Mkcal = 10^3 kilocalories.

**MMBtu = 10^6 Btu.

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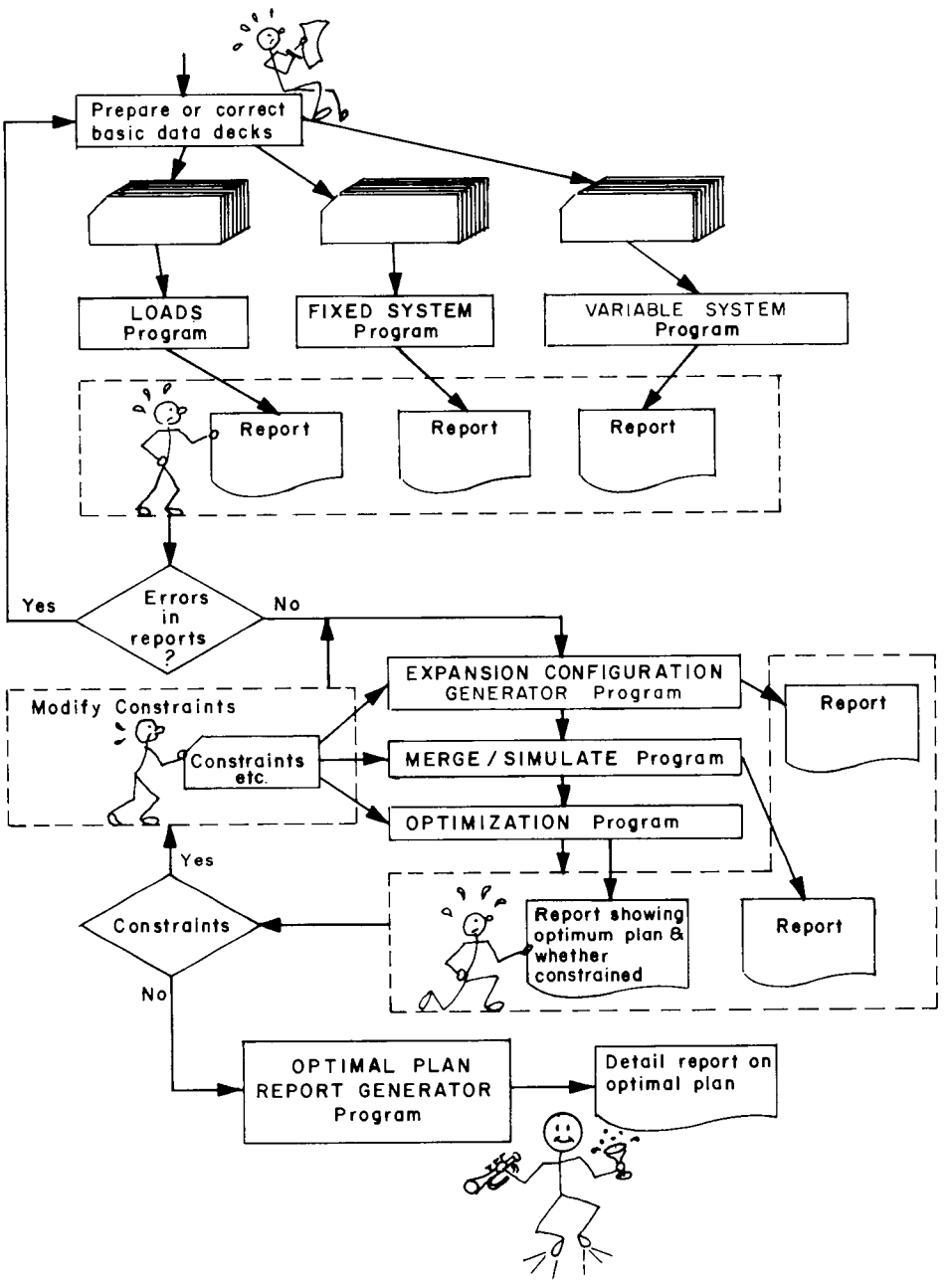

Fig. 4. Man-Machine Interaction in Use of the WASP Program.

All expenditures are expressed in terms of United States dollars. However, any currency could be used by applying the appropriate rate of exchange to all cost data.

4. DESCRIPTION OF WASP PROGRAMS

The remainder of this report will describe, in detail, the separate programs comprising the WASP package. A description of the Probabilistic Simulation Subprogram, which is used to calculate system reliability and production costs, will be given first. An understanding of the Probabilistic Simulation Model is a prerequisite for a discussion of the WASP package since the major purpose of several of the programs is to prepare data for the simulation program. A discussion of the assumptions used to simulate any hydroelectric and/or pumped-storage units will also be presented.

4.1 Probabilistic Simulation Subprogram

The concept of using a probabilistic simulation for estimating the operating cost of generating plants within an electrical utility was first introduced in 1967[2] and has recently been gaining acceptance throughout the United States and Europe.[5-10] In general, the probabilistic simulation technique develops the cost of operating a utility system over an extended period of time by forecasting the expected amount of power to be generated by each plant. The basic model for this technique requires the following information: system load duration curve, loading order of units, generating unit characteristics, fuel costs, and energy supplied by energy-limited units such as hydroelectric units. The major advantage of this technique is its capability to simulate the effects of random events such as unit forced outages.

4.1.1 Basic Concepts

A load duration curve (Fig. 5) is commonly used to represent the system load over an extended period of time. As with a chronological

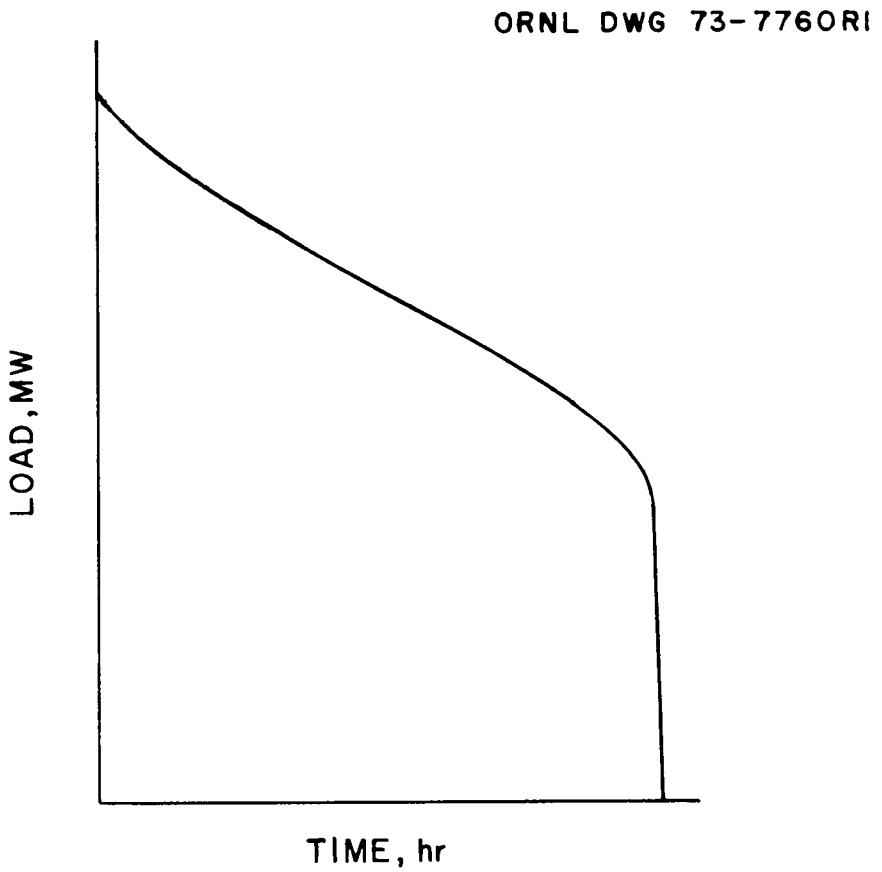

Fig. 5. Typical Load Duration Curve.

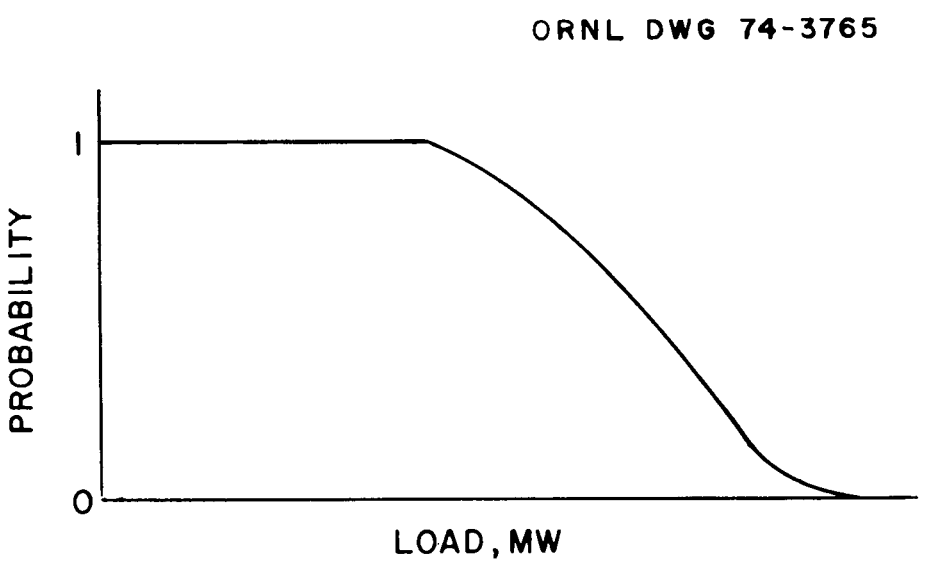

Fig. 6. Typical "Inverted" Load Duration Curve.

hourly load curve, the area under the load duration curve represents the total system energy requirement; however, the chronological sequence of loads has been lost. In the load duration curve, the abscissa represents the number of hours during which the system load equals or exceeds the associated amount of 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 in probabilistic simulation work to use the load duration curve with the ordinate and abscissa reversed (see Fig. 6). This form of the curve (called an "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. 7a, and integrating the curve between the proper limits:

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

where

E_i = expected generation of ith unit;

T = time period represented by load duration curve;

$L(x)$ = inverted load duration curve;

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

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

In order to perform this calculation, the order in which the units are to be loaded must be specified. This technique would accurately estimate the expected generation by each unit if all units were available for generation 100% of the time. Unfortunately, all generating units are subject to random outages, the occurrence and duration of which are unpredictable. In the simplest stochastic model for treating unit reliability, two possible states are defined for each unit. The unit is

either available and capable of full power generation, or it is unavailable and 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 that unit i is available, and let q_i be the probability that the unit is not available. Since the unit must be in one of the two states,

$$p_i + q_i = 1.0 \ . \tag{2}$$

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

The major difficulty encountered in using a load duration curve to estimate the unit loadings is that the position of operating units in relation to the load duration curve changes when any units suffer a forced outage. The order in which the units are plotted in Fig. 7b shows how the system would be operated when Unit 1 is not available. Comparing Figs. 7a and 7b, it is obvious that all units have been shifted to the left by an amount equivalent to the capacity of Unit 1. It is important to notice that a significant change has occurred in the expected generation of some of the units, particularly with regard to 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 its area under the load duration curve, L (Fig. 7a). If Unit 1 is unavailable, it is not capable of generating any energy. Therefore, the expected average generation for Unit 1 would be calculated by multiplying the area under curve L by the probability that this unit will be available:

$$E_1 = p_1 T \int_{a_1}^{b_1} L(x)\ dx \ . \tag{3}$$

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.

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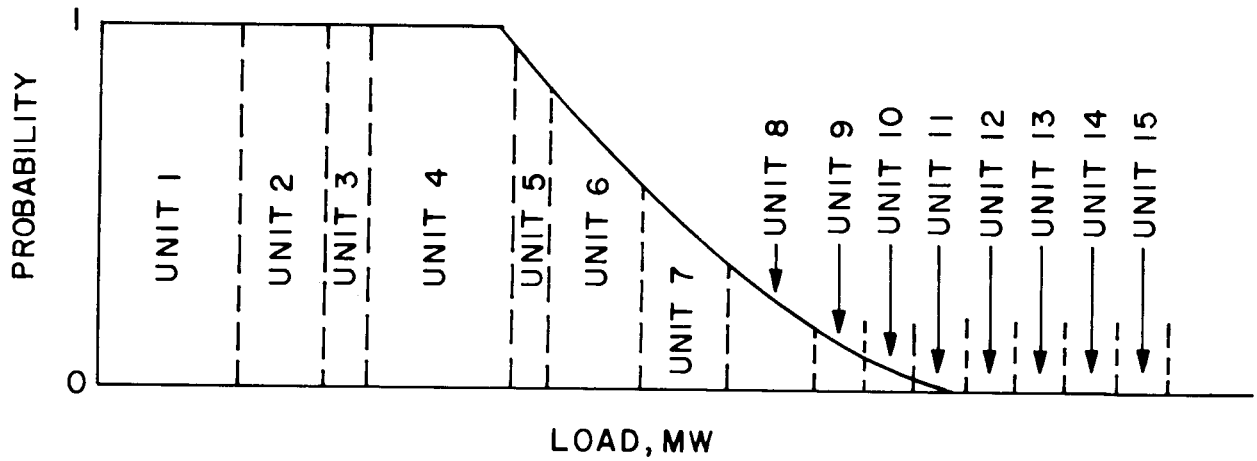

Fig. 7a. Unit Loading When All Units Are 100% Available.

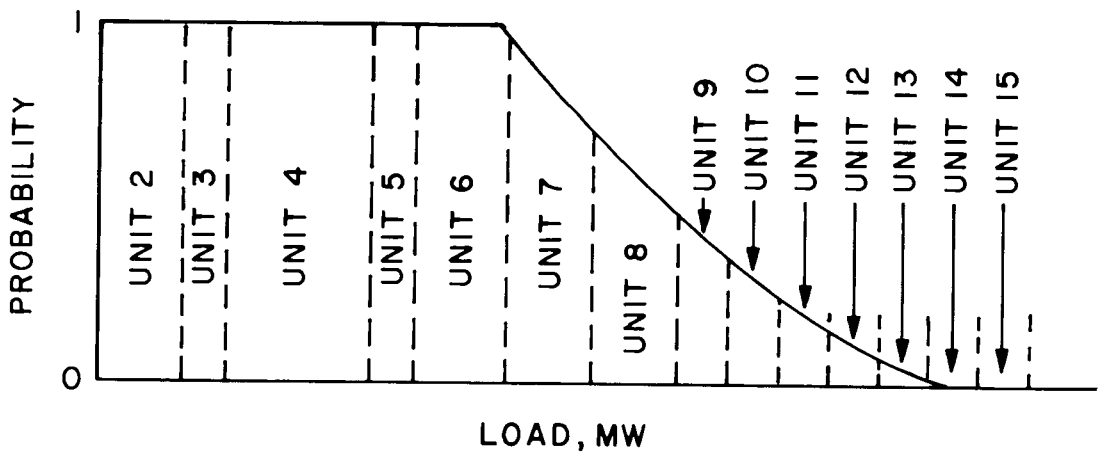

Fig. 7b. Unit Loading When Unit 1 Is Not Available.

The operation of Unit 2 is directly affected by any outage of Unit 1 but is not affected by outages of Units 3, 4, etc. When Unit 2 is available (probability p_2), it would be loaded according to Fig. 7a if Unit 1 is available, and according to Fig. 7b if Unit 1 is unavailable. 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:

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

where

a_2, b_2 = are integration limits based on the type of loading shown in Fig. 7a;

α_2, β_2 = are integration limits based on the type of loading shown in Fig. 7b.

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 (see Fig. 8). Let L represent the original inverted load duration curve, and let L' be the shifted curve. From an examination of Fig. 8, it becomes apparent that

$$L'(x) = L(x - MW_1) , \tag{5}$$

where

MW_1 = the capacity of Unit 1

and hence

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

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. (6) into Eq. (4) and rearranging, the expected generation of Unit 2 would be calculated by:

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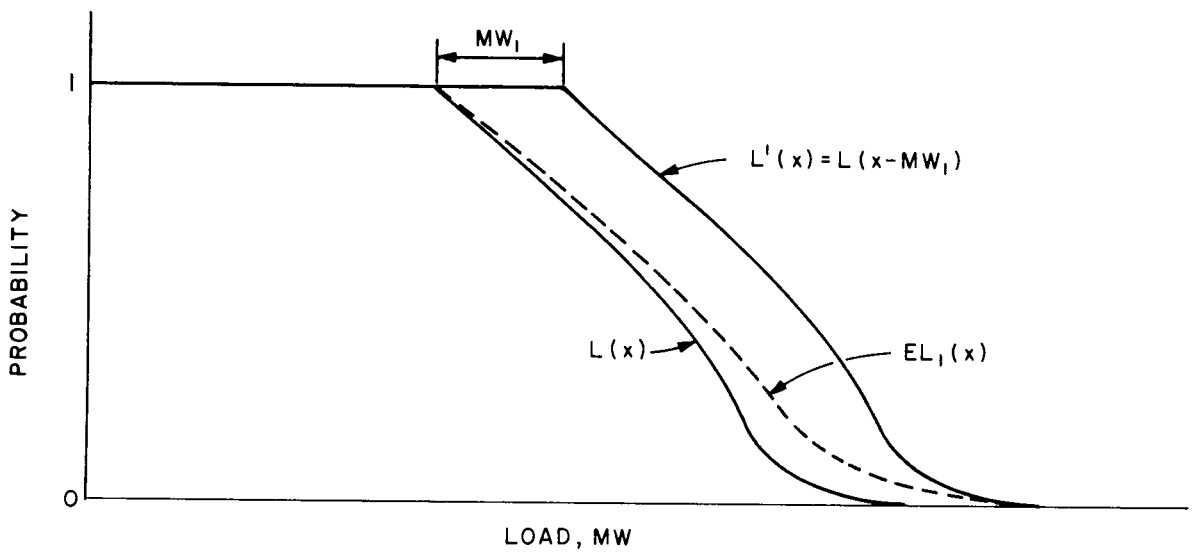

Fig. 8. Representation of Equivalent Load.

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

Equation (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:

$$EL_{i-1} = L + O_i \ , \tag{8}$$

where

EL_{i-1} = equivalent load considering outages of units before Unit i to be 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 prior to 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) as:

$$L = L(x).$$

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,

$$EL_1 = L(x) + q_1 \, [L(x - Ma_1) - L(x)],$$

which, on substitution of Eq. (2), becomes:

$$EL_1 = p_1 \, L(x) + q_1 \, L(x - MW_1) \ . \tag{9}$$

This is the dashed curve shown in Fig. 8. Substituting Eq. (9) into Eq. (7) yields

$$E_2 = p_2 T \int_{a_2}^{b_2} EL_1(x) \, dx \ . \tag{10}$$

The effects of outages in both Units 1 and 2 must be considered in order to evaluate the expected generation of Unit 3. 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 an amount equal to the capacity of Unit 2 (MW_2). These two curves can be combined into a single equivalent load curve (EL_2) by using Eq. (9) and replacing L with EL_1 (see Appendix A).

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. The equivalent load curve for the first unit is simply the inverted load duration curve

$$EL_o = L \ . \tag{11}$$

For successive units the equivalent load curve is:

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

and the expected generation for each unit is:

$$E_n = p_n T \int_{a_n}^{b_n} EL_{n-1}(x) \ dx \ . \tag{13}$$

This procedure is repeated until all units have been considered and the resulting equivalent load curve includes the forced outage effects of all units. Additional information about the system can be obtained from the final equivalent load curve. Figure 9 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 loss-of-load probability for the generating system. In order to estimate the system reliability, the value of P^* must be adjusted 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. 9) represents the expected energy demand that the generating system would not be able to serve:

$$U = T \int_{\overline{X}}^{\infty} EL_N(x) \ dx \ . \tag{14}$$

(See Appendix B for details.)

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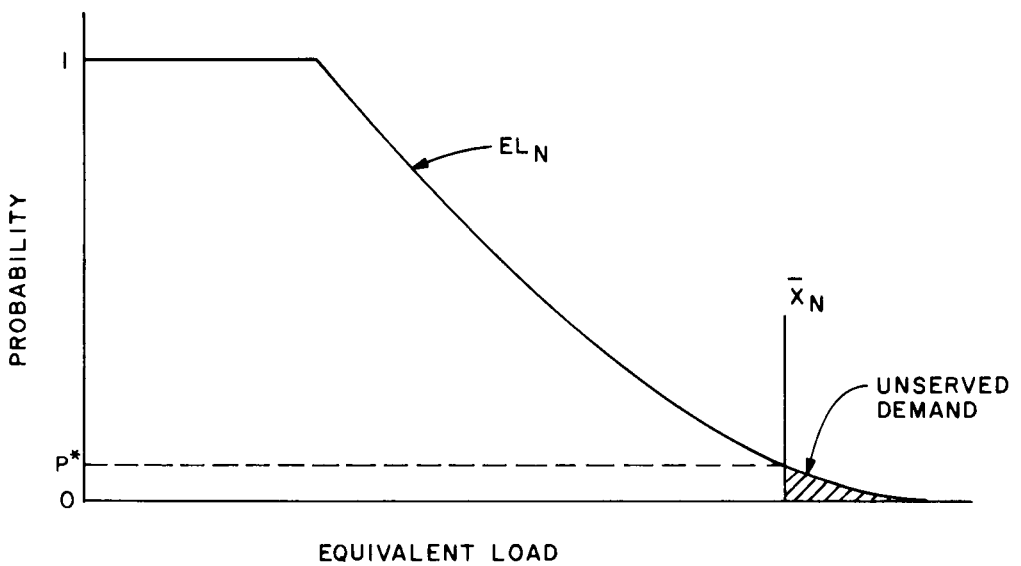

Fig. 9. Equivalent Load Curve for Entire System and Unserved Energy Demand.

4.1.2 Representation of Generating Units

The above discussion describes the basic Probabilistic Simulation Model. Some extensions of this model are briefly discussed below. Additional information is available in Ref. 5.

The loading-order concept was introduced during the discussion of the calculation of expected energy generation by each unit. The basic model assumes that a unit would be completely loaded prior to the loading of the next unit. A much more realistic simulation of a utility system can be obtained by defining two blocks of capacity, e.g., a base load and peak load block, for each thermal unit. The individual blocks may then be placed in nonadjacent positions of the loading order. This technique, known as two-block representation, gives the WASP package user the option of defining each unit as either a one-block or a two-block unit.

The Probabilistic Simulation Model is capable of simulating hydroelectric units. In the WASP package it was not considered necessary to simulate all hydroelectric units in detail. Hence, the individual hydroelectric projects are combined into a single pseudo unit whose capacity is equal to the sum of the project capacities:

$$MW_H = \sum_{i=1}^{m} (MW_h)_i \ , \tag{15}$$

where

MW_H = capacity of pseudo-hydroelectric unit,

$(MW_h)_i$ = capacity of individual hydroelectric projects,

m = number of hydroelectric projects.

Hydroelectric units are usually not able to generate energy to the limit of their availability. Therefore, the amount of energy to be generated by each hydroelectric project must be specified, and the energy generated by the pseudo-hydroelectric unit is defined as the sum of the energy generations of the individual projects, as follows:

$$E_H = \sum_{i=1}^{m} (E_h)_i \ , \tag{16}$$

where

E_H = energy to be generated by pseudo-hydroelectric unit,

$(E_h)_i$ = energy to be generated by individual hydroelectric projects.

The total capacity of the pseudo-hydroelectric unit can be divided into two capacity blocks. The base block represents the amount of capacity that will be continuously on-stream (i.e., run-of-the-river hydroelectric). The remaining capacity is assumed to be available for peak-shaving duty. The amount of energy that would be generated by the base block is deducted from the total energy specified, and the remainder is assigned to the peak-shaving portion of the pseudo-hydroelectric unit.

The base part of the pseudo-hydroelectric unit is placed in the first position in the loading order. The remaining hydroelectric capability, which is used to shave the system peak load (see Fig. 10), is not included in the Probabilistic Simulation Model. This is obviously not the best representation of a hydroelectric unit. It is anticipated that a model which includes a rigorous treatment of multiple hydroelectric units might be incorporated into the WASP package in the near future.

The Probabilistic Simulation Model is also capable of simulating a single pumped-storage unit. If the system under consideration contains multiple pumped-storage projects, these will be combined into a single pseudo unit. The amount of energy to be generated by the pumped-storage unit depends on an economic interchange of energy through the pumped-storage reservoir. However, to reflect any reservoir limitations, the user must specify the maximum amount of energy that the pumped-storage unit is capable of generating. The reservoir operation will be balanced over the time period represented by the load duration curve. The pseudo-pumped-storage unit, like the pseudo-hydroelectric unit, is assumed to have a capacity equal to the sum of the capacities of the individual projects and a maximum generation limit equal to the sum of the limits of the individual projects. The cycle efficiency of the pseudo-pumped-storage unit is the weighted average of the efficiencies of the individual projects.

In normal operation a pumped-storage unit withdraws water from the upper reservoir during the hours of peak load to generate energy which would

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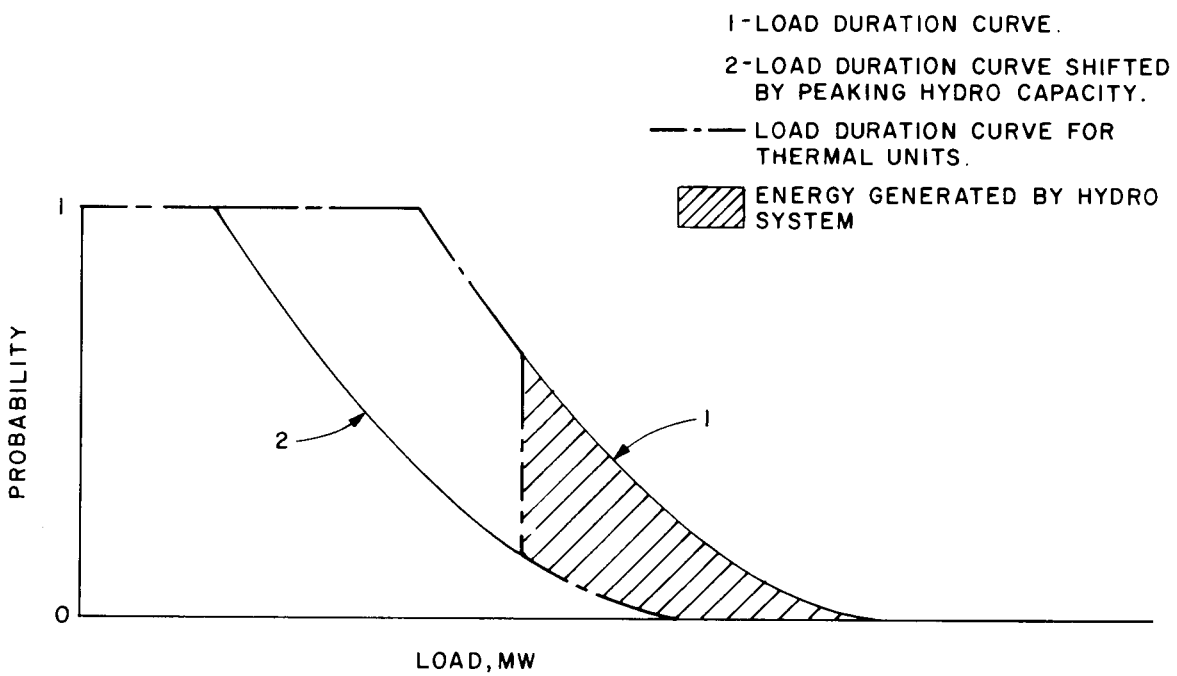

Fig. 10. Treatment of Peak-Shaving Hydroelectric Capability.

otherwise have to be generated by high-cost peaking units. During low load periods, such as nighttime and weekends, the lower-cost base load units are used to pump water back into the pumped-storage reservoir. Hence, the operation of the pumped-storage unit shaves the peak of the load duration curve and adds an additional load to the region of the minimum system load as shown in Fig. 11.

4.2 Fixed System Program

The Fixed System Program defines the state of the existing power system at the start of the study and describes any firmly scheduled additions and/or retirements.

Assumptions made for the WASP package are that the study period is divided into a number of stages and that each stage corresponds to a year. The user can subdivide a year into a number of equal periods, with a maximum of 12 periods being allowed. The period is the basic unit of simulation, and the number of periods used should be chosen to adequately represent seasonal characteristics such as load shape, hydroelectric characteristics, and scheduled maintenance for generating units.

The generating plants that exist at the start of the study are described in this program. A maximum of 100 stations can be defined. The type of station is identified by assigning the appropriate value from Table 1 to the variable NTYPE.

Table 1. Plant Type Definitions

NTYPE	Definition
0	Nuclear station
1,2,3, or 4	Fossil-fired station
5	Hydroelectric system
6	Pumped-storage system
-1	Emergency hydroelectric system

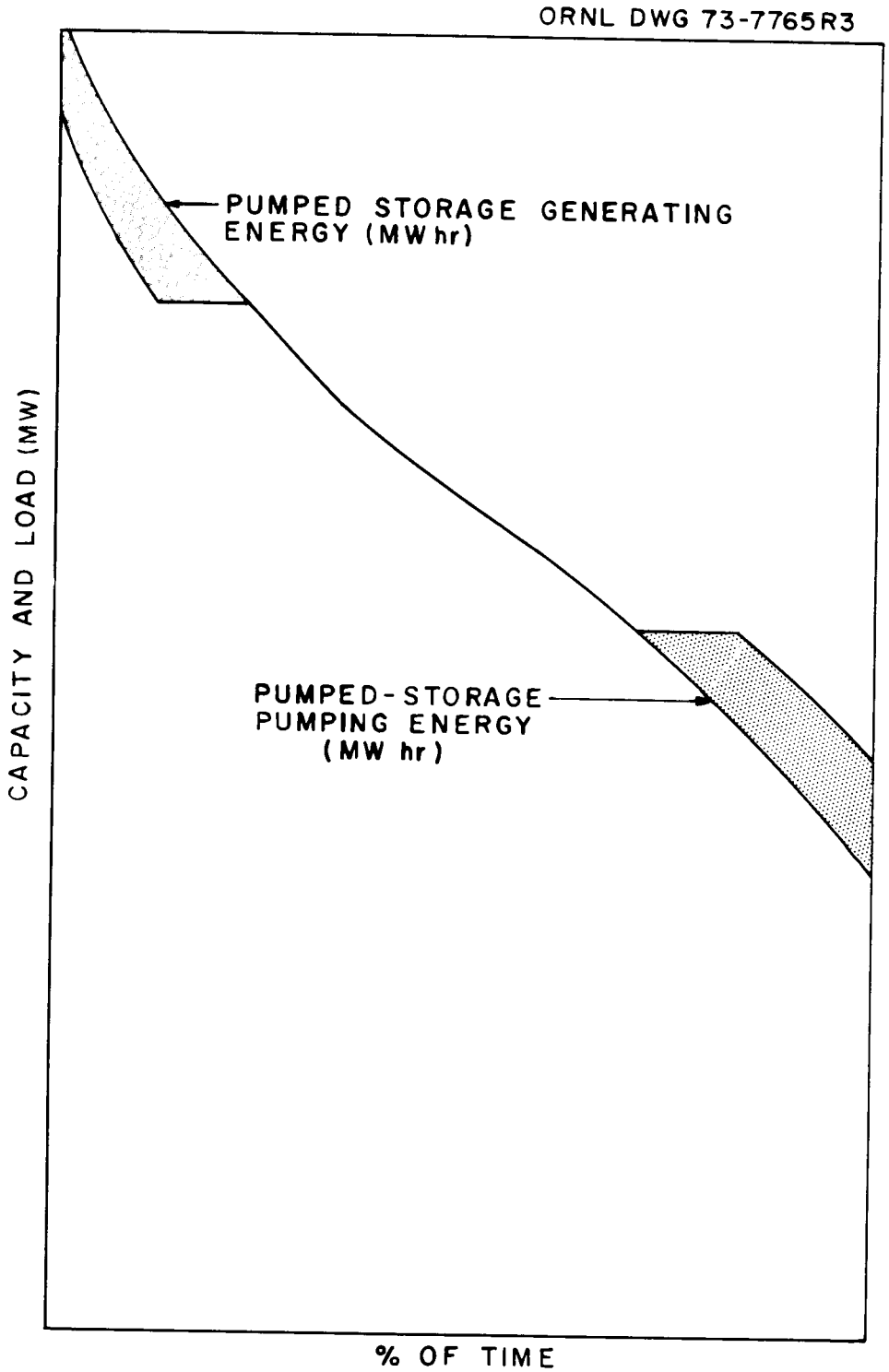

Fig. 11. Idealized Representation of Pumped-Storage Operation.

The fossil-fueled plant classification can be further subdivided by using one of the four values for NTYPE. For example, the following definitions might be used:

1 = oil-fired unit
2 = diesel or gas turbine
3 = lignite-fired unit
4 = coal-fired unit

The definitions of the subdivisions are left to the user. By specifying the fuel, different escalation rates can be applied to each type of fuel.

4.2.1 Definition of Thermal Units

A thermal station is defined as an aggregate of identical generating units operating at the same fuel cost. All existing thermal stations (nuclear and fossil-fueled stations) must be described by the data listed in Table 2. If a particular station is not part of the system at the beginning of the study but will be added as a firmly scheduled addition after the first year, it must also be defined. In this case the number of units (NSETS) must be set equal to zero.

In the probablistic simulation, a thermal unit can be considered to have two blocks of capacity, a base block and a load following or peaking block. The variable MWC is the total capacity of the unit, and MWB is the capacity of the base block. The remaining capacity (MWC - MWB) is the capacity of the load following block. If the user wishes to define the unit as a single block of capacity, then MWC and MWB must be equal. Generally, base-loaded and intermediate units are defined to have two capacity blocks while peaking units are defined to have a single block of capacity. A heat rate must be defined for each capacity block. BHRT is the heat rate for the base block, and CRMHRT is the average incremental heat rate for the load following block.

The only other input parameter listed in Table 2 which is not self-explanatory is the maintenance class capacity, MAINCL. This capacity will be used in the maintenance scheduling algorithm (Sect. 4.6). It is recommended that a maximum of seven maintenance classes be used. All units which have nearly, but not exactly, the same rated capacity should be

Table 2. Data Required for Definition of Thermal Stations

Variable	Definition
NAME	Name of station
NSETS	Number of identical units in station at start of study
MWB	Base capacity for each unit, MW
MWC	Total rated capacity of each unit, MW
BHRT	Heat rate for base block of capacity, Btu/kWhr
CRMHRT	Average incremental heat rate for remaining capacity, MWC - MWB, Btu/kWhr
FCST	Domestic fuel cost, ¢/MMBtu
FCSTF	Foreign fuel cost, ¢/MMBtu
FOR	Forced-outage rate, %
MAINT	Average time the unit is required to be out of service for maintenance, days/year
MAINCL	Maintenance class capacity, MW
OMA	Fixed nonfuel operating and maintenance cost, $ per kW per month
OMB	Variable nonfuel operating and maintenance cost, $/MWhr

placed in the same maintenance class by defining the same value of the maintenance class for all units.

4.2.2 Definition of the Hydroelectric System

Since it was not considered necessary to simulate all hydroelectric projects in detail, the individual hydroelectric projects are combined into a single pseudo system. Most hydroelectric projects are designed to operate at less than 100% capacity factor and, in the WASP package, are considered to be divided into two separate systems: a normal hydroelectric system, and an emergency hydroelectric system.

The normal hydroelectric system, which will be referred to as "the hydroelectric system," represents the capacity that is normally used for everyday service. This includes capacity which is continuously on-stream (i.e., "run-of-river" capacity) and capacity which is used for peak-shaving duty. The amount of energy generated by a hydroelectric system is limited by the supply of water as well as by various reservoir constraints. Hydroelectric generation is distributed throughout the year to make optimal use of the hydroelectric resources by minimizing fuel costs of the thermal system. Normally, no energy cost is assigned to the hydroelectric systems.

The emergency hydroelectric category is used to describe any hydroelectric capacity that is used as reserve. This capacity is available for maintaining system reliability and is brought into service only when other units are forced out of service. When used, hydroelectric energy that would have been saved for a future time period is expended. Therefore, there is a penalty associated with the operation of this system.

4.2.3 The Normal Hydroelectric System

The existing power system is assumed to contain only a single hydroelectric system. If more than one hydroelectric system actually exists, it is necessary to define a composite unit or system. The data required for defining a hydroelectric system are given in Table 3. In the event that the existing system does not contain any hydroelectric units and the

user wishes to consider hydroelectric projects as expansion candidates, or if hydroelectric projects are to be added as firmly scheduled additions, a dummy hydroelectric unit whose capacity is equal to zero must be defined.

The hydroelectric system can have two separate capacities: total capacity (MWC), and "run-of-the-river" capacity (MWB). The "run-of-the-river" capacity is the level at which the unit must run at all times. The remaining capacity (MWC - MWB) is that which is available for peak-shaving duty.

Table 3. Data Required for Definition of the Normal Hydroelectric System

Variable	Definition
NAME	Name of station
NSETS	Number of units (must = 1)
MWC	Nominal total capacity, MW
MWB	Nominal "run-of-the-river" capacity, MW
ENERGY	Energy expected to be generated by the hydroelectric system each year, GWhr
OMA, OMB	Same as for thermal units
	Period-dependent Parameters
$(HYDFAC)_i$	Multipliers of total capacity
$(HYDFAB)_i$	Multipliers of "run-of-the-river" capacity
$(HENPRP)_i$	Distribution of annual energy

Since the capacity and the expected energy generation of a hydroelectric system can vary significantly from period to period, capacity multipliers must also be defined if the year is to be subdivided into periods. Generally, maintenance requirements for hydroelectric systems are not specified since any maintenance can be included in the period capacity multipliers. The actual hydroelectric capacity available in each period is:

$$(MWC)_i = (HYDFAC)_i \cdot MWC, \tag{17}$$

$$(MWB)_i = (HYDFAB)_i \cdot MWB \ . \tag{18}$$

The distribution of the annual generation (ENERGY) must also be defined, and the amount of energy to be generated by the hydroelectric system in each period is:

$$(ENERGY)_i = (HENPRP)_i \cdot ENERGY \ . \tag{19}$$

The sum of the energy distribution must equal 1.0; thus

$$\sum_i (HENPRP)_i = 1.0 \ . \tag{20}$$

If the entire year is represented by a single load duration curve (not subdivided into periods), then the capacity multipliers and energy distribution are not required.

4.2.4 Emergency Hydroelectric System

As with conventional hydroelectric units, all emergency hydroelectric projects are combined into a single composite system. When the expansion candidates include hydroelectric projects, an emergency hydroelectric system must be defined even if no emergency hydroelectric capacity is present in the initial system.

The data required to define an emergency hydroelectric system are listed in Table 4. A heat rate and a fuel cost are assigned for this system. Although these variables do not have any physical meaning, they are used to calculate the desired penalty for operating this unit. It is strongly recommended that a large penalty cost be defined since,

otherwise, the optimization program would try to utilize a block of free energy and give unrealistic results. If the year is subdivided into periods, a multiplier of the emergency hydroelectric capacity must also be defined (HYDFAE).

Table 4. Data Required for Definition of the Emergency Hydroelectric System

Variable	Definition
NAME	Name of station
NSETS	Number of units (must = 1)
MWC	Total capacity, MW
BHRT	Hypothetical heat rate, Btu/kWhr
FCST	Hypothetical fuel cost, local currency, ¢/MMBtu
FCSTF	Hypothetical fuel cost, foreign currency, ¢/MMBtu
OMA, OMB	Same as for thermal units
	Period-dependent Parameters
$(HYDFAE)_i$	Multipliers of capacity

4.2.5 Definition of the Pumped-Storage System

Only a single pumped-storage system is allowed; therefore, if the system contains multiple pumped-storage units at the start of the study, they must be combined into a single composite unit. If no pumped-storage units exist in the system at the start of the study but such units are to be added either as a firmly committed expansion or as an expansion candidate, a pumped-storage unit must be defined with zero capacity. The data required to define a pumped-storage system are listed in Table 5.

Table 5. Data Required for Definition of the Pumped-Storage System

Variable	Definition
NAME	Name of unit
NSETS	Number of units (must = 1)
MWB	Electrical load imposed by pumps, MW
MWC	Generating capacity, MW
ENERGY	Maximum feasible energy which could be generated in one period, GWhr
OMA, OMB	Same as for thermal units
PEF	Efficiency of pumps expressed as a fraction
GEF	Generation efficiency expressed as a fraction

4.2.6 Additions to, or Retirements from, Existing System

Any firmly scheduled additions to, or retirements from, the existing system can be incorporated into the program. For thermal units the user must simply specify the station, number of units added or deleted, and the proper year. The program assumes that any changes occur at the beginning of the year. A station is identified by an index which is assigned in the same order that the stations were defined.

Any changes in the hydroelectric, emergency hydroelectric, or pumped-storage system must include the added or deleted capacity, change in energy specification, efficiencies, and period variational parameters. The changes in capacity and energy are added to the existing capacity and energy. A capacity-weighted average is calculated for the parameters defining pumped-storage efficiencies and the period-by-period variation of hydroelectric capacity and energy, as follows:

$$(VAR)_c = \frac{(VAR)_o\ (CAP)_o + (VAR)_n\ (CAP)_n}{(CAP)_o + (CAP)_n}\ , \qquad (21)$$

where

$(VAR)_c$ = period multiplier of new composite unit,

$(VAR)_o$ = period multiplier of existing composite unit,

$(VAR)_n$ = period multipliers for new project,

$(CAP)_o$ = capacity, MW, of existing composite unit,

$(CAP)_n$ = capacity, MW, of new project.

4.2.7 Fixed System Calculations

The main purpose of the Fixed System Program is to assemble data concerning the state of the existing power system. A few additional calculations are performed in the program so that the user can check the validity of his input data. A full load heat rate is calculated for each thermal unit:

$$FLHTRT = \frac{(BHRT)(MWB) + (CRMHRT)(MWC - MWB)}{MWC} , \qquad (22)$$

where FLHTRT = full-load heat rate.

Both local and foreign expenditures are calculated for each block of capacity defined for thermal and emergency hydroelectric units. The base heat rate is used to calculate the cost of operating the base capacity block, and the full-load heat rate is used to calculate the cost of operating the unit at full load. The general equation used to calculate the fuel portion of operating cost is:

$$OC = 10^{-5} (HR)(FC) , \qquad (23)$$

where

OC = operating cost, \$/MWhr,

HR = appropriate heat rate, Btu/kWhr,

FC = appropriate fuel cost, ¢/MMBtu.

4.3 Variable System Program

The Variable System Program describes the units that are to be considered for system expansion. The data required to describe expansion

candidates are identical to those used to describe the fixed system (see Tables 2-5). All candidate types (a maximum of 20 is permitted) must be described in this program even if they are identical to units already described in the Fixed System Program.

Hydroelectric and pumped-storage candidates are special cases. If hydroelectric or pumped-storage projects are to be added, they are merged with the existing system into a composite hydroelectric or pumped-storage system and simulated as a single entity. Since hydroelectric and pumped-storage projects are generally unique, the various seasonal capacity and energy parameters to describe them may be input for each project. If hydroelectric is to be included as a candidate type, as many as 20 individual projects may be included within that single candidate type. Similarly, a maximum of 20 individual pumped-storage projects may be included within a single pumped-storage candidate type.

The optimization program is able to determine the optimum installation date for each nonthermal project but must consider the projects in the order defined. It is not capable of reordering the list of projects for the purpose of finding a lower-cost expansion policy.

It is not possible to retire any units defined by this program once they have been added to the system. Hence, units with very short life expectancy should not be considered as expansion alternatives. Since most expansion studies cover a period from 10 to 20 years and generating units generally have a 25- to 30-year life, the inability to retire these units should not be a restriction.

The Variable System Program can be considered as describing the independent variables of the expansion problem, while the Fixed System Program defines the initial conditions.

4.4 Load Description Program

The Load Description Program defines the forecasted capacity demand and energy requirements that will be imposed on the system during the study. The loads for the various periods are represented by load duration curves (see typical curve in Fig. 5). By normalization of both the ordinate

and abscissa, the shape of the load duration curve can be represented as a fifth-order polynomial which is independent of peak load:

$$y = a_o + a_1x + a_2x^2 + a_3x^3 + a_4x^4 + a_5x^5 , \tag{24}$$

where

y = fraction of peak load,

x = fraction of time,

$a_o,\ldots,a_5$ = load duration curve coefficients.

As long as the shape of the load duration curve does not change, any number of periods can be specified by a single equation. However, if the forecast shows a change in projected load shape, it is necessary to modify the coefficients.

A peak load must be specified for each year of the study. If a year is subdivided into periods, the peak load for each period is designated in terms of a fraction of the annual peak.

For use in the Probabilistic Simulation Model, the load duration curve must be converted from a continuous curve to a discrete function and the axes must be reversed. The main function of the Load Description Program is to generate a discrete inverted load duration curve for each period in the study. The number of discrete points to be used must be specified in order to perform this operation. The user does this by specifying the capacity to be associated with each discrete point (DM). Some judgment and experience are required in the specification of DM. If a very small value of DM is used, the discrete function will make an excellent approximation of the continuous load duration curve; however, this will greatly increase both the storage requirements and computation time. On the other hand, if an excessively large value of DM is chosen, the discrete function will be a poorer approximation of the load duration curve and could result in distorted estimations of unit loadings. Hence a tradeoff has to be made between accuracy and computational requirements. While it is not possible to specify the optimal value of DM, some guidelines can be specified. The minimum value of DM must be greater than the maximum installed capacity (during the study) divided by 590:

$$DM > \frac{(ICAP)_{MAX}}{590} . \tag{25}$$

DM should be less than 2% of the minimum system installed capacity if this does not violate Eq. (25). The number of points in the discrete curve can be estimated by Eq. (26):

$$N = \frac{(ICAP)}{DM} . \tag{26}$$

It is recommended that approximately 100 to 350 discrete points be used to represent the load curves over the study period and then the corresponding value of DM be rounded off to the nearest 25 MW.

The load description program also calculates a load factor for each period and an annual load factor; in addition, it generates a file of inverted load duration curves for each period for use in the Probabilistic Simulation Subroutine.

4.5 Expansion Configuration Generator Program (CONGEN)

The Expansion Configuration Generator Program defines the possible states of the expanded power system for each year in the study. Expressing it another way, this program defines permissible values of the independent variables during the optimization calculations. An expansion state is defined as a particular configuration of generating units in the system for one year. In this program, the system planner can exercise his skill and judgment by controlling the states generated, and thereby prevent the computer from examining all sorts of absurd configurations.

A simple example will help illustrate the usefulness of this capability. Let an existing power system, as defined by the Fixed System Program, be designated by the letter B. Assume that only three expansion candidates are under consideration, namely: 1000-MW nuclear units (N), 500-MW coal-fired units (C), and 100-MW gas-fired peaking units (P). Table 6 lists the 74 possible expansion configurations having capacities between B and B+2000 MW. If this table were extended to include larger system reserves or a larger number of alternative types for expansion, it would have to contain an extremely large number of entries.

Table 6. Possible Expansion States

Capacity (MW)	States								
B	B								
B+100	B+P								
B+200	B+2P								
B+300	B+3P								
B+400	B+4P								
B+500	B+5P	B+C							
B+600	B+6P	B+C+P							
B+700	B+7P	B+C+2P							
B+800	B+8P	B+C+3P							
B+900	B+9P	B+C+4P							
B+1000	B+10P	B+C+5P	B+2C	B+N					
B+1100	B+11P	B+C+6P	B+2C+P	B+N+P					
B+1200	B+12P	B+C+7P	B+2C+2P	B+N+2P					
B+1300	B+13P	B+C+8P	B+2C+3P	B+N+3P					
B+1400	B+14P	B+C+9P	B+2C+4P	B+N+4P					
B+1500	B+15P	B+C+10P	B+2C+5P	B+N+5P	B+3C	B+C+N			
B+1600	B+16P	B+C+11P	B+2C+6P	B+N+6P	B+3C+P	B+C+N+P			
B+1700	B+17P	B+C+12P	B+2C+7P	B+N+7P	B+3C+2P	B+C+N+2P			
B+1800	B+18P	B+C+13P	B+2C+8P	B+N+8P	B+3C+3P	B+C+N+3P			
B+1900	B+19P	B+C+14P	B+2C+9P	B+N+9P	B+3C+4P	B+C+N+4P			
B+2000	B+20P	B+C+15P	B+2C+10P	B+N+10P	B+3C+5P	B+C+N+5P	B+4C	B+2C+N	B+2N

In general, the reliability of a power generation system to produce the required demand is a function of the size and reliability of the individual items of generating equipment. For the same total capacity, many small components will produce a more reliable system than a few large ones, even if both sizes have the same individual reliability. This is true because the amount of capacity lost as a result of outage with small equipment will be more evenly distributed with regard to time. Analysis of system reliability on a fairly rigorous basis, taking into account size and component reliability, is made in a later program; however, for purposes of roughly estimating which configuration should be considered, the CONGEN program permits the planner to set a minimum reserve requirement. For a configuration to be acceptable, its capacity in the critical period must satisfy Eq. (27):

$$SCAP \geq \left[1.0 + (RSV)_{MIN}\right] \cdot MWPEAK, \tag{27}$$

where

SCAP = capacity of state, MW;

$(RSV)_{MIN}$ = minimum reserve margin expressed as a fraction;

MWPEAK = maximum expected load in critical period, MW.

The critical period is defined as that period during which the difference between the system load and the capacity of the fixed system plus expansion candidates forced into the system is a maximum.

It is also apparent that, from an economic standpoint, a grossly overexpanded power system is undesirable. Hence any state having an excessive capacity can be eliminated from consideration. The probability of such a state forming part of the optimum expansion policy is exceedingly small. Therefore, the planner may also set a maximum reserve constraint for the critical period:

$$SCAP \leq \left[1.0 + (RSV)_{MAX}\right] \cdot MWPEAK, \tag{28}$$

where $(RSV)_{MAX}$ = maximum reserve margin expressed as a fraction.

Equations (27) and (28) can be used as constraints to limit the number of states that must be considered in any given year. Any state with a capacity outside this range will be considered as infeasible and will be omitted from further consideration. Continuing with the simple example, assume that the selected minimum and maximum reserve requirements correspond to a capacity range from B+500 to B+1500 MW. This constraint reduces the number of acceptable states shown in Table 6 (i.e., 74) to 36.

The user can further reduce the number of states by placing constraints on the allowable number of units for each expansion candidate each year. These constraints are called "tunnels":

$$(MIN)_i \leq N_i \leq (MAX)_i \ , \tag{29}$$

where

$(MIN)_i$ = minimum number of units allowed for expansion candidate i for given year,

N_i = number of units for expansion candidate i,

$(MAX)_i$ = maximum number of units allowed for expansion candidate i for given year.

The restriction allows the user to direct the optimization program away from obviously uneconomic states. In the example, the user might reason that it would not be economical to include more than four peaking units, two coal units, or a single nuclear unit in the year of interest. The program then would not consider any state containing five or more peaking units, three or more coal units, or more than one nuclear unit. The restrictions on the maximum number of units, coupled with the reserve requirements, would result in the 16 states shown in Table 7. The user can also specify the minimum number of units that must be included in any state. If the user judges that a coal-fired unit must be included, any alternative that does not contain a coal unit would be considered as an infeasible state. This would further reduce the number of allowable states to 11 by excluding the five states enclosed by the heavy lines in Table 7.

Table 7. Allowable Expansion States

Capacity (MW)	States			
B+500	B+C			
B+600	B+C+P			
B+700	B+C+2P			
B+800	B+C+3P			
B+900	B+C+4P			
B+1000		B+2C	B+N	
B+1100		B+2C+P	B+N+P	
B+1200		B+2C+2P	B+N+2P	
B+1300		B+2C+3P	B+N+3P	
B+1400		B+2C+4P	B+N+4P	
B+1500				B+C+N

In summary, the Expansion Configuration Generator Program allows the user to put restrictions on the range of values that the independent variables can assume in the optimization program. By employing these restrictions, the user can greatly reduce the computational requirements during the optimization calculations and save a significant amount of computer time by not considering obviously uneconomic states. In our example, the user-imposed restrictions were:

$$B+500 \leq SCAP \leq B+1500 \tag{30}$$

$$0 \leq N \leq 1 \tag{31}$$

$$1 \leq C \leq 2 \tag{32}$$

$$0 \leq P \leq 4 \tag{33}$$

The optimization program will tell the user if any of the restrictions Eqs. (30)-(33) acted as a constraint on the solution. If this is the case, the user can simply redefine his restrictions and perform a new optimization. This procedure would continue until he found a solution which was free of user-imposed constraints.

4.6 Merge and Simulate Program

The primary task of the Merge and Simulate Program is to calculate the operating cost associated with each state generated by the Expansion Configuration Generator Program. The Merge and Simulate Program reads the files generated by the preceding programs and compiles a complete description of each state for use in the Probabilistic Simulation Subprogram.

Prior to performing actual production costing, an estimated maintenance schedule must be prepared since it will affect equipment availability in each of the time periods. It is not reasonable to ignore maintenance since the maintenance of units has a significant effect on the system's operating cost. To a large extent, the maintenance of generation equipment can be scheduled at times when system capacity reserves are greatest. Batch-loaded nuclear reactor refueling requires a shutdown which is treated as a maintenance outage. The time requirements for scheduled maintenance outages depend on the type and size of unit. A reasonable procedure is to schedule maintenance for the largest items of equipment when the reserves are greatest,

schedule maintenance for the next largest items of equipment when the remaining reserves are greatest, etc. This procedure tends to levelize the operable equipment reserves for the system during the year. Ideally, one should schedule maintenance by examining expected weekly reserves throughout the year; however, to include such detail in an expansion optimization algorithm would be computationally infeasible. To approximate the situation, allocation of maintenance can be based on seasonal reserves; and the maintenance assigned to a season may be considered random within the season, whereas in reality it is a discrete outage.

The maintenance scheduling algorithm in the WASP package begins by calculating the minimum reserve for each period:

$$MNRSV_i = INSTCP_i - MAXLD_i \ , \tag{34}$$

where

$MNRSV_i$ = minimum reserve in period i, MW;

$INSTCP_i$ = installed capacity in period i, MW;

$MAXLD_i$ = maximum system load in period i, MW.

Maintenance space is defined as the minimum reserve minus any previously scheduled maintenance during that period:

$$MAINSP_i = MNRSV_i - PSMAIN_i \ , \tag{35}$$

where

$MAINSP_i$ = maintenance space in period i, MW;

$PSMAIN_i$ = previously scheduled maintenance in period i, MW.

In Fig. 12, the installed capacity and maximum system load are plotted for each period. The variation in the installed capacity is caused by the variation of hydroelectric capacity from period to period. Each thermal unit is assigned to a maintenance class, the value of which approximates the capacity of the unit. For purposes of meeting capacity restraints, each unit in a particular class is assumed to have the same capacity. The total maintenance requirement for a particular class is calculated by:

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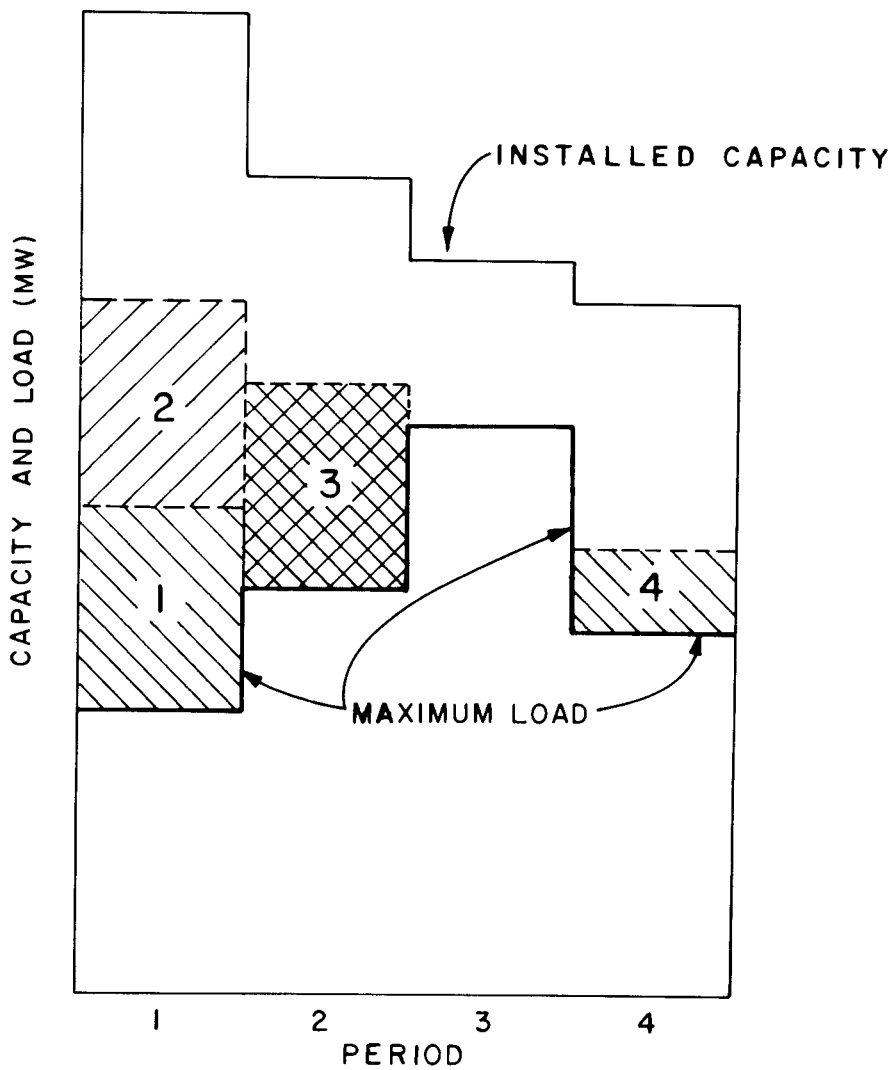

Fig. 12. Estimation of Maintenance for Largest Maintenance Class.

$$MWDAYS = \sum_i (MWC)_i \cdot (MAINT)_i \cdot (NOSETS)_i \ , \tag{36}$$

where

MWDAYS = total maintenance requirement of maintenance class, MWd/year;

$(MWC)_i$ = actual capacity of unit, MW;

$(MAINT)_i$ = maintenance requirement for each unit in station i, days/year;

$(NOSETS)_i$ = number of identical units at station;

i = index of stations in maintenance class.

The maintenance classes are considered in order of decreasing size; that is, the class with the largest capacity is considered first, the next largest capacity second, etc. A maintenance block represents the amount of maintenance that could be performed by the removal of a specific capacity for the entire period:

$$MAINBK = (MAINCL) \cdot (T_p) \ , \tag{37}$$

where

MAINBK = maintenance space available in a maintenance block, MWd;

MAINCL = capacity of maintenance class, MW;

T_p = length of period, days.

The number of blocks required for each maintenance class is calculated as

$$NO = \frac{MWDAYS}{MAINBK} \ , \tag{38}$$

and the blocks are sequentially assigned to the period that has the largest maintenance space. Figure 12 shows the scheduling of three maintenance blocks as the shaded areas labeled 1, 2, and 3. The first block (area 1) is assigned to the first period since this period has the largest available maintenance space. The effect of scheduling the maintenance can be considered equivalent to increasing the system load by the capacity of the particular maintenance class. This concept is identical to that of equivalent load, which was used in the discussion of the Probabilistic Simulation

Subprogram since the maintenance block represents a scheduled outage of a block of capacity. The second block was also scheduled during the first period since the remaining maintenance space in period 1 is still larger than the available maintenance space in the other periods. After scheduling the first two blocks, the second period has the largest available maintenance space; thus the third block would be assigned to this period.

An approximation must be made for a fractional block. It is not possible to subdivide a period in the Probabilistic Simulation. Therefore, for any remaining maintenance, the class size must be adjusted to allow the maintenance to extend over the entire period, as shown in the shaded area 4. The capacity of the fractional block is calculated as:

$$MCLL = \frac{REMAIN}{T_p}, \tag{39}$$

where

MCLL = estimated capacity for fractional maintenance block, MW;
REMAIN = maintenance requirement for fractional maintenance block, MWD;
T_p = length of period, days.

This interpolation preserves the proper maintenance requirement (MWD) but distorts the amount of capacity that is removed from the system. For this reason, it is recommended that the number of maintenance classes be limited to 7. Although more maintenance classes could be defined, the additional interpolations could bias the operating cost for some expansion policies.

A probability distribution of performing maintenance for a particular maintenance class is calculated as the number of maintenance blocks scheduled in a given period, divided by the total number of maintenance blocks required:

$$P_i = \frac{N_i}{NO}, \tag{40}$$

where

P_i = probability of performing maintenance for class in period i,

N_i = number of maintenance blocks scheduled in period i,

NO = total number of maintenance blocks.

The maintenance distribution for the particular maintenance class, as based on the schedule shown in Fig. 12, is listed in Table 8. The maintenance for each unit in the class is assumed to be distributed in the same manner. Hence the expected number of days each unit will be out of service during each period is:

$$D_i = (\text{MAINT})_i \cdot P_i \ , \tag{41}$$

where

D_i = expected number of days the unit will undergo maintenance during period i.

Table 8. Maintenance Schedule and Availability of a Typical Unit

Period	Maintenance Blocks[a]	Probability of Performing Maintenance for Class	Unit Maintenance Data[b]		
			Days	Expected Outage Rate	Availability
1	2	0.5882	35.29	0.3867	0.5520
2	1	0.2941	17.65	0.1934	0.7259
3	0	0.0	0.0	0.0	0.9000
4	0.4	0.1176	7.06	0.0774	0.8303
Total	3.4	1.0000	60.0		

[a]Calculated for case shown in Fig. 12.

[b]Unit data: maintenance requirement, 60 days/year; expected forced-outage rate, 10%.

Table 8 also shows the distribution, by periods, of the number of days of maintenance for a unit requiring a total of 60 days maintenance annually. If the number of maintenance days per period is divided by the number of days in a period, the expected outage rate for maintenance can be calculated:

$$(Pm)_i = \frac{D_i}{T_p} \ . \tag{42}$$

The maintenance scheduling continues in a sequential manner until all maintenance classes have been assigned to appropriate periods. Before the simulation of any period, the probability that the unit will require maintenance during the period must be combined with the forced-outage probability of that unit to give a unit availability. The total unit availability is defined as the fraction of time that the unit is available to generate energy if called upon to do so:

$$A_i = (1 - Pm_i)(1 - FOR), \tag{43}$$

where

A_i = availability of unit in period i,

FOR = expected forced-outage rate of unit expressed as a fraction.

The maintenance probability and the availability for a unit with an expected forced-outage rate of 10% are shown in Table 8.

It is realized that the maintenance scheduling algorithm produces an approximation to actual utility operation. As the number of periods in a year is increased, the maintenance schedule generated by this program will become a more accurate approximation of actual operation. However, the user must balance accuracy against computational effort. Experience has shown that the use of a four-period year (each period corresponding to a season) gives reasonable results while holding the computational requirements to a manageable level.

After the unit availabilities for each period have been evaluated, the corresponding operating costs are calculated using the Probabilistic Simulation Subprogram. As discussed previously, this model also calculates the generating system's loss-of-load probability, the expected energy generation, and hours of operation for each unit. The local fuel expenditure for each unit is calculated from

$$CST = (ENGB \cdot BHRT + ENGP \cdot CRMHRT) \cdot FCST \cdot 10^{-2}, \tag{44}$$

where

CST = local fuel expenditure, $;

ENGB = expected generation of base portion of unit, GWhr;

BHRT = heat rate of base portion of unit, Btu/kWhr;

ENGP = expected generation of remaining capacity of unit, GWhr;

CRMHRT = incremental heat rate for remaining unit capacity, Btu/kWhr;

FCST = local fuel cost, ¢/MMBtu.

The foreign fuel expenditure (CSTF) is calculated from Eq. (44) by replacing the local fuel cost (FCST) with the foreign fuel cost (FCSTF). The nonfuel expenditure for each unit is calculated from:

$$\text{NFCST} = \text{OMA}\left(\frac{12}{\text{NPER}}\right) \cdot \text{MWC} \cdot \text{NOSETS} \cdot 10^3 + \text{OMB} \cdot (\text{ENGB}+\text{ENGP}) \cdot 10^3 , \tag{45}$$

where

NFCST = nonfuel expenditures for operation of unit, $;

OMA = fixed operating and maintenance cost, $ per kW per month;

NPER = number of periods in year;

MWC = capacity of unit, MW;

NOSETS = number of identical units;

OMB = variable operating and maintenance cost, $/MWhr.

The operating expenditures for each period are summed according to type of fuel and type of expenditures (local or foreign). All of the simulation results are saved on a file for possible future use.

One of the features of the WASP package is the option of allowing the user to specify the area of interest. This was accomplished by allowing the user to specify various restrictions in the Expansion Configuration Generator Program. It is probable that a large portion of the system configurations generated with the modified restrictions will be identical to configurations that have already been simulated. When operated in the "MERGE" mode, the Merge and Simulate Program simply copies the results when it finds a configuration that has already been simulated. Therefore, it is only necessary to simulate any new configurations that result from modification of the restrictions. This feature leads to a significant reduction in the computational effort expended during a study.

4.6.1 Recovery of Simulation Files for Aborted Runs

The results from a Merge and Simulate run can be easily recovered if the run is terminated before completion. Most terminations are caused by underestimation of the computational time required, or by exhaustion of the available space on the output file where the simulations are stored. Such partially completed runs may represent a considerable investment in computer time. It is usually desirable to recover as much information as possible from the simulation output file.

The RECSIM program was designed to correct the files so that the Merge and Simulate program can be rerun with a minimum number of resimulations. This is done by copying all of the records for the completed years onto another file. Only the records for the incomplete year, the year for which states were being simulated when the run was terminated, are lost. If the aborted run was a merge run, the RECSIM program will add the records for the partially completed year and any succeeding years to the newly created file. This file then becomes the input file for the next Merge and Simulate run. Thus, very little computation time is lost since a short run of MERSIM will normally complete the originally intended work.

4.7 Optimization Program

The purpose of the Optimization Program is to find the "best" expansion policy for the power systems. The "best" policy is interpreted to mean that policy which results in a system of desired reliability with minimum discounted cash flow expenditures over the study period. A dynamic programming algorithm is used to calculate the best expansion policy.

A simplified discussion of the principles of dynamic programming will be considered first. The study period is divided into a number of subdivisions or "stages." In the WASP package, each stage is assumed to correspond to a year. Between stages a decision must be made as to whether a particular type of unit should be added to the system, and this decision must be made for each expansion candidate. Let the vector $D(t)$ represent the decision made between stage $t-1$ and stage t. Any decision to add units will change the configuration of generating units in the power system or,

expressing it in another way, will change the "state" of the power system. Let the vector X(t) represent the state of the power system in stage t. The value of the state variable in stage t is a function of the state variable in stage t-1 and the decision made between stages t-1 and t:

$$X(t) = X(t-1) + D(t) \ . \tag{46}$$

Equation (46) may be applied successively to give:

$$X(t) = X(0) + \sum_{j=1}^{t} D(j), \tag{47}$$

where

X(0) = initial state or configuration of the power system.

Equation (47) simply says that the state of the system in stage t is equal to the initial state of the system as defined in the Fixed System Program plus the sum of all the decisions made prior to stage t.

The effects of the various decisions must be evaluated in order to determine whether one decision is better than another. This is accomplished by defining a performance criterion or an objective function. Each decision in the system expansion problem affects the capital and operating costs. Hence, for purposes of this initial discussion, a convenient objective function can be defined as the present-worth discounted summation of the capital costs, operating costs, and salvage value. Obviously, the value of the objective function at a particular state in stage t is a function of the decisions made prior to stage t. The capital costs are a direct function of the decisions since these represent additions to the system. The operating costs depend on the kinds of capacity added and, therefore, depend on preceding states. Hence the objective function can be represented as:

$$L(X) = \sum_{j=1}^{t} C_j + O_j \ , \tag{48}$$

where

L(X) = value of objective function for reaching stage X in stage t,

C_j = present worth of capital costs associated with the decisions between stage j-1 and stage j, corrected for salvage value at end of study,

O_j = present worth of operating cost in stage j for the state associated with the decisions prior to stage j.

Any number of possible sets of decisions could lead from state X(0) to state X(t), and it is necessary to find the particular set that will minimize the value of the objective function for reaching state X(t) at stage t.

Dynamic programming is based on Bellman's principle of optimality.[11,12] This principle will be illustrated by a simple example which was previously presented by Larson.[13] Assume that the solid line between points A and C in Fig. 13 is the optimal path between these points. Let B be any intermediate point on the optimal trajectory. The portion of the solid line from A to B must also be the optimal path between these points. Otherwise, there must be some other path between points A and B which results in a lower cost than the solid line. Let the dashed line be such a path. However, the existence of the dashed line violates the original assumption since a lower-cost path from A to C could be obtained by following the dashed line from A to B and then the solid line from B to C. Thus, in order to find the optimal path from point A to point C, one simply needs to determine the optimal path from point A to each intermediate point on the optimal trajectory between points A and C.

To find the optimal path from point A to point C, we can apply the principle of optimality by finding the optimal trajectory to every state in each stage. The state in the previous stage that lies on the optimal trajectory to the state under consideration is saved. To find the optimum path to any state in stage j, one only needs to know the optimum paths to all states in stage j-1 with their associated values of the objective function and the cost of going from each of these states to the state under consideration in stage j. By recursive application of this principle, one can determine the optimal path to any state in any stage. The global optimum over the study period is associated with that state in the final stage which has the lowest value of the final objective function, and the optimal trajectory is determined by tracing backward to the initial condition.

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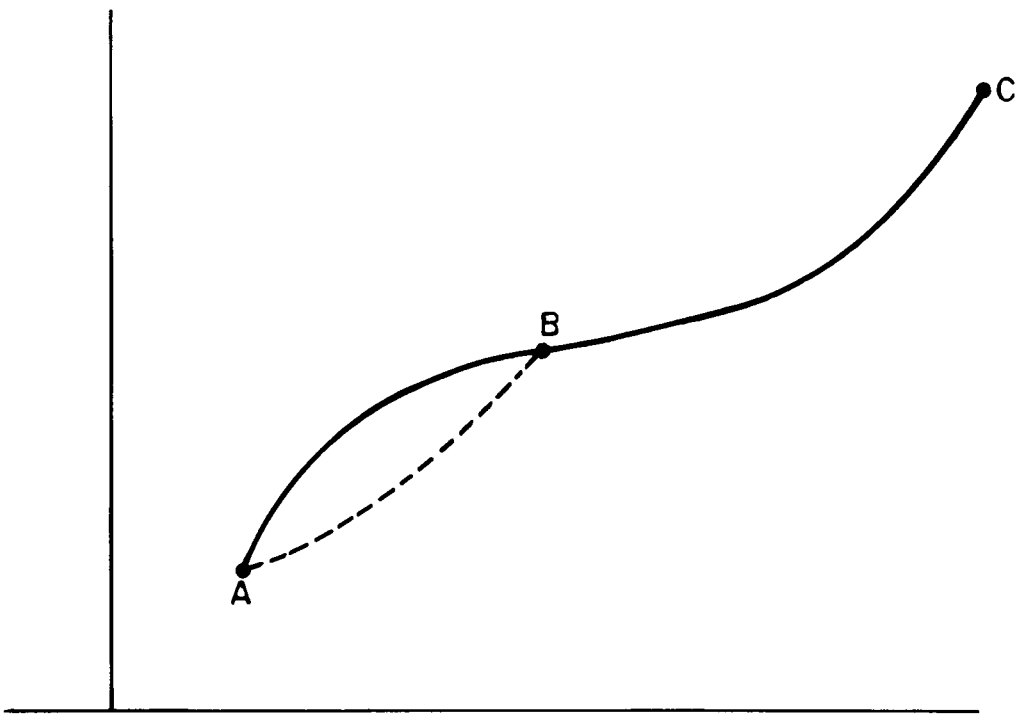

Fig. 13. Illustration of Principle of Optimality.

The calculational technique will be further demonstrated by a simple example consisting of three stages as shown in Fig. 14. No choices are involved in choosing optimum paths from the initial state to states 1 and 2 in stage 1. The associated cost functions are I(1) and I(2) respectively.

In going from stage 1 to stage 2, four possible paths exist: two to state 3, and two to state 4. Considering state 3, it is seen that one path to this state comes from state 1 and the other comes from state 2. The values of the objective functions for the paths arriving at state 3 are then:

$$L_1 = C(3 - 1) + I(1), \tag{49}$$

$$L_2 = C(3 - 2) + I(2),$$

where

$C(3 - 1)$ = cost of going from state 1 to state 3,

$C(3 - 2)$ = cost of going from state 2 to state 3.

L_1 and L_2 are compared, and the path resulting in the lower value is retained as the optimal path to state 3. If we assume that the path from state 1 to state 3 resulted in the lower value of the objective function, then the minimum cost function for state 3 is:

$$I(3) = L_1 \ . \tag{50}$$

The path from state 2 to state 3 is discarded as being uneconomical and is not included in any further consideration involving state 3. Figure 15 illustrates the two possible paths for arriving at state 3, with the optimal and the nonoptimal decisions being shown as a solid line and a dotted line respectively. The same analysis is repeated for state 4, and again only the optimal decision is retained. In the third stage one may proceed from states 3 or 4 to states 5, 6, or 7. The same logic is applied to this set of decisions. Figure 15 shows the optimal paths to each of the states in the final stage. At this point the optimal end state and the optimal trajectory can be determined by selecting the final objective function as:

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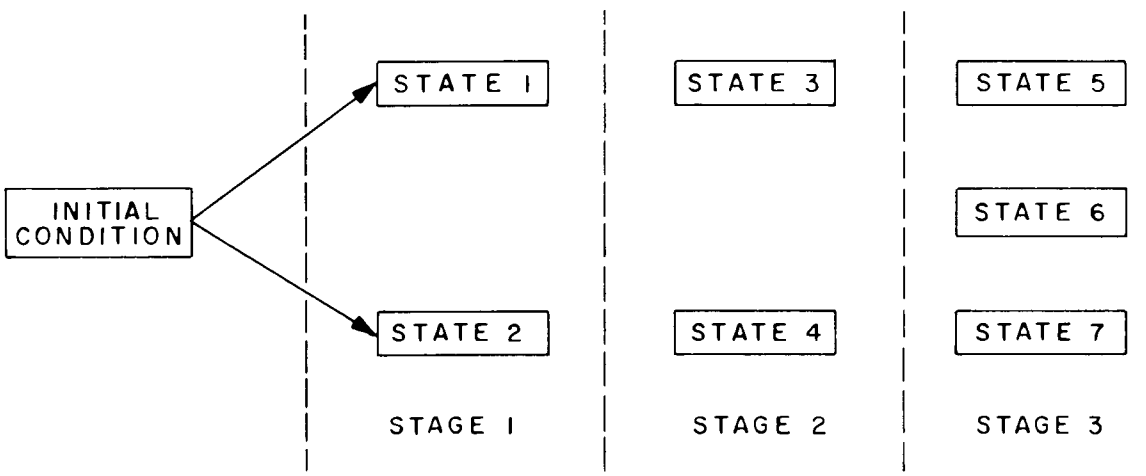

Fig. 14. Sample State Space for Three-Stage Dynamic Programming.

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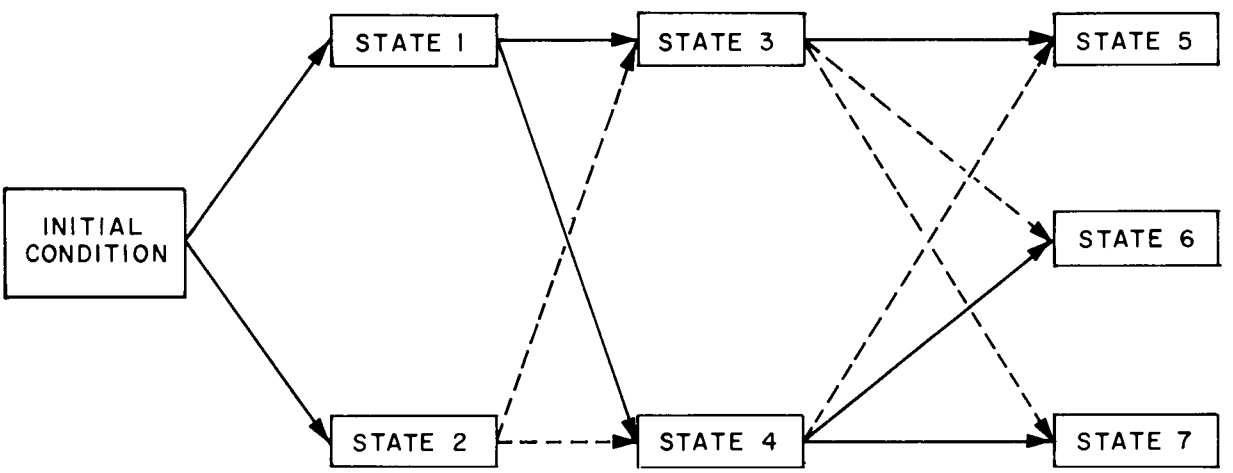

Fig. 15. Sample Dynamic Programming Problem.

$$I = \text{Min}\ [I(5),\ I(6),\ I(7)]. \tag{51}$$

Assume that state 6 resulted in the minimum value of the total objective function. The optimal path from stage 6 is traced backward to the initial condition showing that states 1, 4, and 6 formed the optimal expansion policy. Note that no decision is made as to which state formed part of the optimal policy until all of the states in every stage have been considered.

The previously discussed programs of the WASP package are designed to assemble data and to define the necessary information for the Optimization Program. The initial state is defined in the Fixed System Program. The states to be considered and any user-imposed limitations on the decisions are defined in the Expansion Configuration Generator Program. The operating costs associated with any state are calculated in the Merge and Simulate Program.

In Eq. (48), the objective function is defined as the sum of the appropriate capital and operating expenditures. All expenditures are present-worth values and may be escalated as the study progresses. For capital expenditures, the escalation and present-worth factors may be combined into a single factor

$$Q_{k,j} = \frac{(1 + m_k)^p}{(1 + i_k)^n}, \tag{52}$$

where

$Q_{k,j}$ = combined present-worth and escalation factor for expansion candidate k in year of study j;

m_k = escalation rate for kth candidate;

i_k = present-worth discount rate for kth candidate;

n = number of years from present-worth base year, which may differ from first year of study;

p = number of years from escalation base year.

Both local and foreign capital costs for each expansion candidate must be defined. The installation of a new plant and its associated cash flow

are assumed to occur at the beginning of a year or stage. A different discount rate may be applied to each candidate and to each type of expenditure (local or foreign). A foreign exchange weighting factor can also be defined to influence the use of foreign capital. Therefore, the capital charge for any decision between year j-1 and year j is:

$$C_j = \sum_k \left[QL_{k,j} \cdot IL_k + FF_j \cdot QF_{k,j} \cdot IF_k \right] \cdot MWC_k \cdot N_k \cdot 10^3 , \qquad (53)$$

where

C_j is the present-worth value of the capital expenditure for year j,

k = the index of the expansion candidate,

$QL_{k,j}$ = the combined present-worth and escalation factor in the year j for local capital required to build candidate k,

$QF_{k,j}$ = the combined present-worth and escalation factor in the year j for foreign capital required to build candidate k,

IL_k = the unit local capital cost for expansion candidate k for the base year, \$/kW,

IF_k = the unit foreign capital cost for expansion candidate k for the base year, \$/kW,

FF_j = a factor to weight foreign capital expenditure in the year j,

MWC_k = the capacity of expansion candidate k, MW,

N_k = the number of units of expansion candidate k added to system at start of year j.

Any generating equipment added to the systems during the study period will have further usefulness in the years following the study period. A credit is given as a salvage value for the unused portion of the unit life. The credit for the salvage value of the unit is taken when the unit is installed, but its present-worth value must be discounted from the study horizon since the actual cash flow occurs at that time. Therefore,

$$R_j = \sum_k P_{k,nyr} \, S_{k,j} , \qquad (54)$$

where

R_j = credit to objective function for all unit additions in year j,

$P_{k,nyr}$ = present-worth factor at the study horizon, $P_{k,nyr} = (1 + i_k)^{-nyr}$;

nyr = number of years from present-worth base year to end of study;

$S_{k,j}$ = computed salvage value for all units of expansion candidate k added in year j.

The actual salvage value for any unit is based on the escalated but undiscounted cost ($C'_{k,j}$) in the year j:

$$C'_{k,j} = \left[(1 + m_k)^p \, IL_k + FF_j \, (1 + m'_k)^p \, IF_k\right] \cdot MWC_k \cdot N_k \cdot 10^3 , \qquad (55)$$

where

$C'_{k,j}$ = undiscounted capital cost for expansion candidate k, escalated to year j, \$;

m_k = escalation rate for local expenditures;

IL_k = the local capital cost for expansion candidate k for the base year, \$/kW;

FF_j = factor to weight foreign capital expenditure in year j;

m'_k = escalation rate for foreign expenditures;

p = number of years from escalation base year;

IF_k = the foreign capital cost for expansion candidate k for the base year, \$/kW;

MWC_k = the capacity of expansion candidate k, MW;

N_k = the number of units of expansion candidate k added to system at start of year j.

This salvage value is calculated using either a straight-line depreciation

$$S_{k,j} = \left[1 - \frac{y_k}{L_k}\right] C'_{k,j} , \qquad (56)$$

where

L_k = economic life of candidate, years;

y_k = portion of candidate life in study period, years;

or a sinking fund depreciation

$$S_{k,j} = \left[1 - \frac{1 - (1 + i_k)^{-L_k + y_k}}{1 - (1 + i_k)^{-L_k}}\right] C'_{k,j} , \tag{57}$$

where

i_k = discount rate for capital expenditures.

The total operating cost for any year is calculated by summing up the costs for each fuel type. The code allows for the escalation of fuel prices, permits a different interest rate to be applied to each type of fuel, and separates the fuel expenditures into local and foreign categories. All operating costs are assumed to be paid in the middle of the year. Again, the escalation rate and present-worth factors are combined into a single factor:

$$Q_{\ell,j} = \frac{(1 + m_\ell)^n}{(1 + i_\ell)^{m + 1/2}} , \tag{58}$$

where

$Q_{\ell,j}$ = combined present-worth and escalation factor for operating costs for fuel type ℓ in year j,

m_ℓ = appropriate escalation rate for expenditures on fuel ℓ.

i_ℓ = appropriate discount rate for expenditures on fuel ℓ.

The program assumes that the fuel price remains constant throughout the entire year and only changes by a discrete amount from year to year. Therefore, the operating cost for a given year is:

$$O_j = \Sigma\left[QL_{\ell,j}(CST_\ell + NFCST_\ell) + QF_{\ell,j} \cdot FF_j \cdot FCST_\ell\right] , \tag{59}$$

where

O_j = total operating cost for a state in year j, \$;

$QL_{\ell,j}$ = local combined present-worth and escalation factor for fuel expenditure;

CST_ℓ = local fuel expenditures for fuel type ℓ;

$NFCST_\ell$ = local nonfuel operating expenditures for plants operating on fuel type ℓ;

$QF_{\ell,j}$ = foreign combined present-worth and escalation factor for fuel expenditures;

FF_j = factor to weight foreign expenditure in year j;

$FCST_\ell$ = foreign fuel expenditures for fuel type ℓ .

Hence the total objective function for any state, X, would be calculated as

$$L(X) = \left[\sum_{j=1}^{t} C_j - R_j + O_j \right], \tag{60}$$

where C_j, R_j, and O_j are evaluated in Eqs. (53), (54), and (56) respectively. The total objective function for the optimum plan would, of course, be the lowest value of L(X) found in the final stage.

Starting with the optimum final state, the program traces back through the stage-by-stage optimal decisions. During the traceback process, it examines the restrictions that were defined in the Expansion Configuration Generator Program and identifies the states on the optimal trajectory that are coincident with the restrictions. Figure 16 illustrates this condition. The user would examine this solution and modify the restrictions for his next run. The new optimal solution might resemble that shown in Fig. 17. The solution is unchanged through year 4, although additional units were permitted during years 3 and 4. Increasing the upper restrictions from four to five in year 5 is insufficient, and the limit of five units in year 6 (which previously did not constrain the solution) has now become a constraint. Successive runs with restriction modifications permit one to ultimately reach an unconstrained solution. Each run made for this purpose should require only a few additional simulations.

A further constraint can be imposed during the optimization calculations. At the time that the configurations are generated, minimum reserve margins are used to restrict the configurations to systems which are

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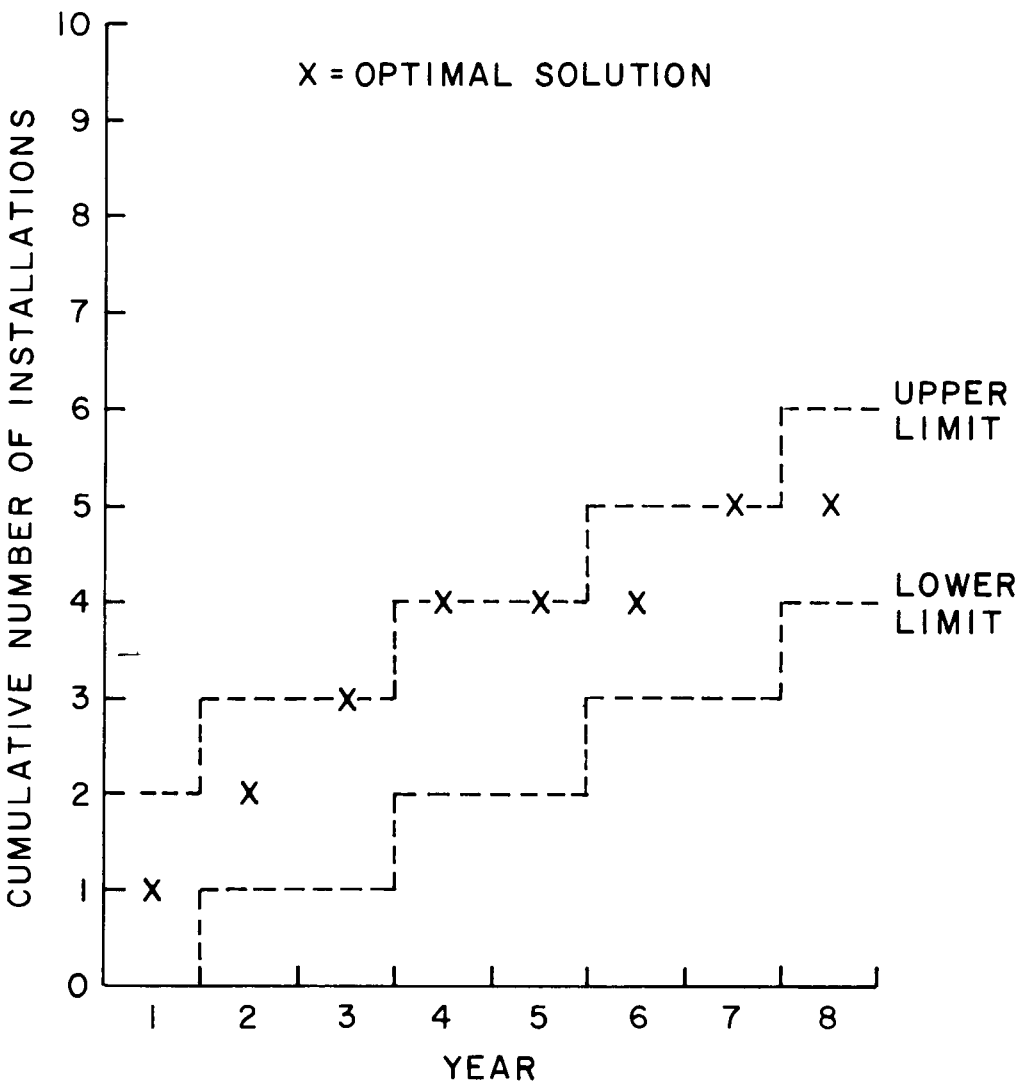

Fig. 16. Optimization Solution for One Candidate Showing Tunnel Restrictions.

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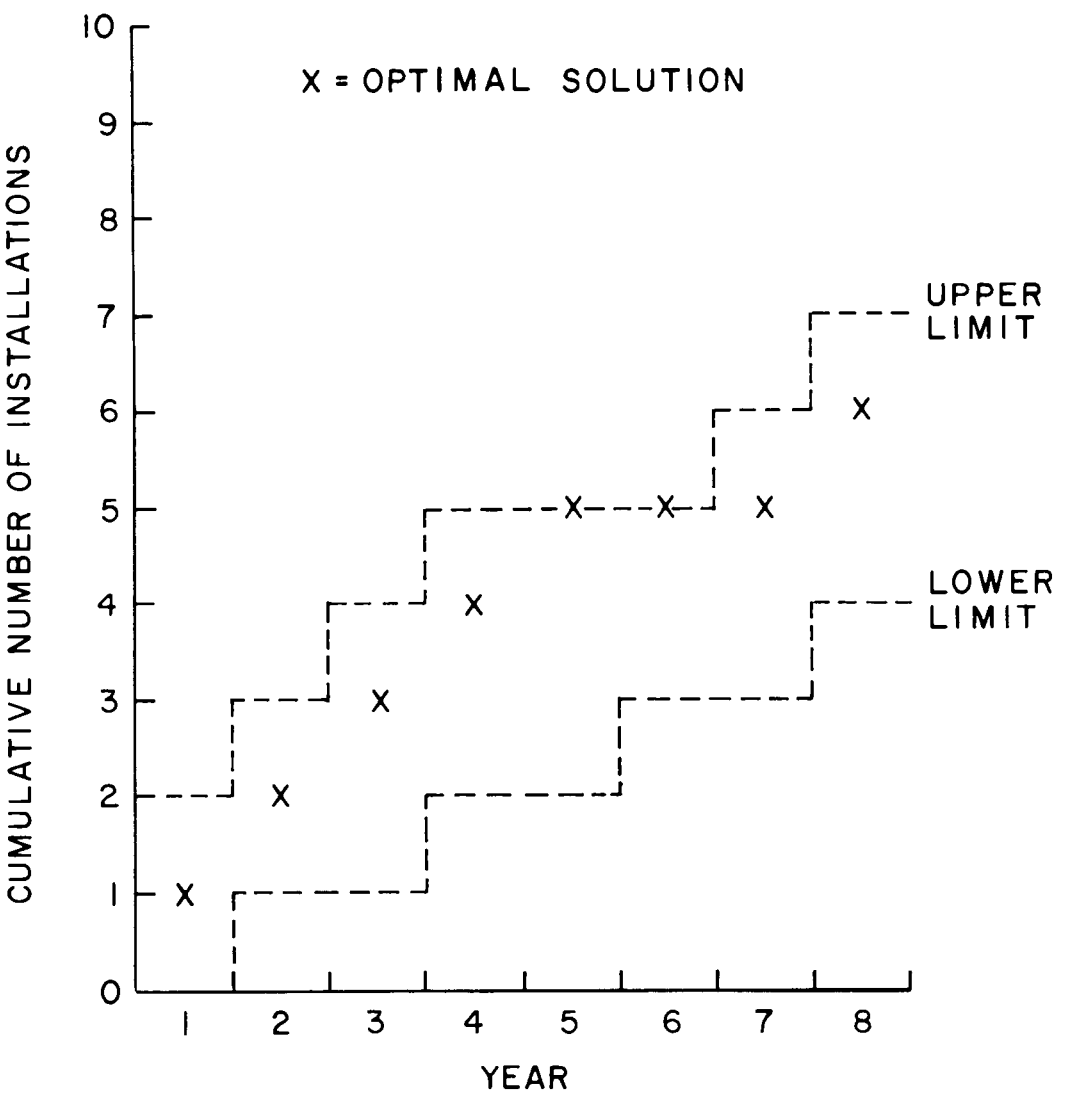

Fig. 17. New Optimal Solution for One Candidate for Modified Tunnel Restrictions.

probably reliable. The MERSIM Program calculates the reliability of the generating system. The Optimization Program compares the computed system reliability with a user-controlled critical value, and configurations that do not meet the reliability standards are rejected and excluded from further consideration by the Optimization Program.

The computer available at the IAEA Headquarters in Vienna required that each program operate in less than 120 K of core. This imposed restrictions on the size of a problem that could be analyzed in a single run. The number of configurations in the Expansion Configuration Generator Program is limited to 200 per year. The Dynamic Programming Program requires the total number of configurations over the entire study period to be less than 2000; also, the study period cannot exceed 30 years. There is no limit on the number of simulations that can be stored on the simulation files.

4.8 Sensitivity Studies

Sensitivity studies can be made to evaluate the effects of various economic parameters on the optimal expansion study by simply rerunning the Optimization Program. These studies are easy to conduct, particularly if the new values for the parameters do not cause the optimal solution to move against the tunnel boundaries. If the solution does move against the tunnel boundary, a few new simulations may be required to find a new constraint-free optimum.

The economic parameters that may be studied include:

(1) unit capital cost,
(2) capital cost escalation factors,
(3) capital cost discount rates, and
(4) system reliability requirement (critical loss-of-load probability).

The economic parameters that affect the fuel prices may also be varied in sensitivity studies. However, some care must be taken to ensure that the changes in these parameters would not cause a change in the loading order used for the simulations. Also, if the system contains a pumped-storage system, any modification of its operation is considered to have a

negligible effect on the system operating costs. Hence, sensitivity runs can be made for reasonable perturbations of the following variables:

(1) fuel cost escalation factors,
(2) fuel cost discount rates, and
(3) penalty factor on foreign expenditures.

If it is desired to make large changes in these variables, which would violate the restrictions mentioned above, sensitivity studies could still be made; however, in this case, the operating costs for all states used in the Optimization Program would have to be recalculated.

5. PROPOSED IMPROVEMENTS TO THE WASP PACKAGE

Several modifications that would make the WASP package more usable are listed below. The order in which they are presented does not imply any order of preference. All of them employ well-defined methods which could be included in the package with little or no further research effort.

1. Incorporate a rapid, rigorous reliability calculation in the Expansion Configuration Generator Program. Only the configurations that meet a user-specified reliability standard would be saved for simulation. This modification would place a greater emphasis on the specification of a realistic critical loss-of-load probability but would avoid simulating unreliable configurations.

2. Include the uncertainty in the load forecast and hydroelectric capacity in calculations involving the system's reliability. This procedure would require assignment of probabilities to describe the uncertainties associated with these two variables.

3. Include an option which would permit expansion configurations to be limited to those just exceeding a specified reliability criterion. Under this option, any configuration which represents an additional expansion over a reliable configuration would not be permitted. This option would significantly reduce the number of configurations to be simulated and would simplify the search

for an optimum expansion policy. Once an optimum path is found, the user could allow overinstallation to ascertain whether additional cost savings could be realized.

4. Modify the Probabilistic Simulation Subprogram to include a more accurate representation of hydroelectric operation. The present model in the WASP package removes the peaking portion of hydroelectric energy directly from the original, inverted load duration curve. This ignores the hydroelectric system's ability to cover forced outages of thermal units.

5. Incorporate a recently developed version of the Probabilistic Simulation Model in which an analytical function is utilized to represent the load duration curve. The current model uses a discrete function to represent the load curves. The analytical approach would eliminate the need for defining a step size (DM). Also, it would probably run somewhat faster and require less computer core memory.

6. Utilize peripheral equipment (i.e., magnetic disks) so that temporary files can be reserved for storage of the data for the final traceback of the optimal solution. In this way the maximum number of configurations in the Optimization Program for any year could be increased from 200 to perhaps 2000 without increasing the core memory requirements. This would avoid the necessity for specifying very restrictive tunnel limits when many alternative types of capacity are being considered. While this improvement would not affect the computational requirements, it would allow the user to employ broader tunnel limits during the search for an optimum and in subsequent sensitivity studies.

7. Improve the method used in the Optimization Program to gather information from the Simulation File. This would allow the user more freedom in changing his restrictions in the Expansion Configuration Generator Program and would be required if modifications (1) or (3) were implemented.

8. Develop a report program. This program would generate a complete cash flow report for the optimal trajectory. The Optimization Program could punch a data deck describing the optimal solution that is suitable for use in the Expansion Configuration Generator Program. The only configurations allowed would be the states that formed the optimal trajectory. The Merge and Simulate and the Optimization Programs would be rerun to obtain a complete summary of the system operation and cash flow. The only modifications required in these programs would be format specifications.

6. REFERENCES

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11. R. Bellman, Dynamic Programming, Princeton University Press, Princeton, N.J., 1957.

12. R. Bellman and S. E. Dreyfus, Applied Dynamic Programming, Princeton University Press, Princeton, N.J., 1962.

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7. APPENDIXES

Appendix A: Derivation of General Equivalent Load Curves and Expected Generation Equations

Consider that the loading of Unit 3 is subject to forced outages of Units 1 and 2. Four different cases must be considered:

(1) Units 1 and 2 both available, probability $p_1 p_2$.

(2) Unit 1 available and Unit 2 unavailable, probability $p_1 q_2$.

(3) Unit 1 unavailable and Unit 2 available, probability $q_1 p_2$.

(4) Units 1 and 2 both unavailable, probability $q_1 q_2$.

For case 1, Unit 3 would be loaded according to the inverted load duration curve L(x). In Eq. (6) we have shown that an outage of a unit can be represented by shifting the load duration curve to the right by an amount equivalent to the capacity of the unit out of service. Therefore, Unit 3 would be loaded for case 2 by curve $L(x - MW_2)$, for case 3 by $L(x - MW_1)$, and finally by $L(x - MW_1 - MW_2)$ for case 4. Now the expected energy for Unit 3 would be:

$$E_3 = p_3 T_p \Big[p_1 p_2 \int_a^b L(x)\, dx + p_1 q_2 \int_a^b L(x - MW_2)\, dx$$

$$+ q_1 p_2 \int_a^b L(x - MW_1)\, dx + q_1 q_2 \int_a^b L(x - MW_1 - MW_2)\, dx \Big]. \quad \text{(A-1)}$$

The first and third terms in Eq. (A-1) can be rewritten as:

$$p_2 \int_a^b \Big[p_1 L(x) + q_1 L(x - MW_1) \Big]\, dx \ .$$

Referring to Eq. (9) the term inside the brackets is seen to be simply the definition of the equivalent load curve (EL_1) incorporating an outage of Unit 1.

$$E_3 = p_3 T_p \Big[p_2 \int_a^b EL_1(x)\, dx + p_1 q_2 \int_a^b L(x - MW_2)\, dx$$

$$+ q_1 q_2 \int_a^b L(x - MW_1 - MW_2)\, dx \Big]. \quad \text{(A-2)}$$

Let $y = x - MW_2$; then, noting that $dx = dy$, the last two terms in Eq. (A-2) become:

$$q_2 \int_a^b \left[p_1 \; L(y) + q_1 L(y - MW_1)\right] dy \; .$$

Referring to Eq. (9), this is simply the equivalent load curve for y, $EL_1(y)$, when the outage of Unit 1 is incorporated. Therefore,

$$E_3 = p_3 T_p \left[p_2 \int_a^b EL_1(x) \; dx + q_2 \int_a^b EL_1 \; (y) \; dy\right] . \tag{A-3}$$

Now, replacing y with $x - MW_2$ and rearranging Eq. (A-3) yields

$$E_3 = p_3 T_p \int_a^b \left[p_2 EL_1(x) + q_2 EL_1 \; (x - MW_2)\right] dx \; . \tag{A-4}$$

Hence the energy to be generated by Unit 3 would be calculated from a new equivalent load curve which is formed by incorporating the effect of outages of Unit 2 into the original equivalent load curve:

$$E_3 = p_3 T_p \int_a^b EL_2(x) \; dx \; , \tag{A-5}$$

where

$$EL_2(x) = p_2 EL_1(x) + q_2 EL_1(x - MW_2) \; . \tag{A-6}$$

An equivalent load curve can be generated to include forced outages of any number of units by successively applying Eq. (A-6). The general form of the equation is:

$$EL_n = p_n EL_{n-1}(x) + q_n EL_{n-1}(x - MW_n) \; . \tag{A-7}$$

The expected energy generation of any unit is:

$$E_n = p_n T_p \int_a^b EL_{n-1}(x) \; dx \; . \tag{A-8}$$

Appendix B: Calculation of Unserved Energy

During the discussion of the Probabilistic Simulation Subprogram, it was stated that there is a probability that the equivalent load will exceed the installed capacity. Also, it was shown in Fig. 9 that an outage of a generation unit would be represented as an increased capacity demand by shifting the inverted load duration curve to the right by the capacity of that particular unit. Let K represent the original peak system load. As shown in Fig. 9, the shifted curve L' and the equivalent load curve EL_1 have a maximum value of $K + MW_1$ (the capacity of Unit 1). If all generating units have a forced-outage rate (all $q_1 > 0$), then the maximum system load would be equal to K + ICAP, where ICAP represents the total generation capacity, since there is a finite probability that all the generating units would fail simultaneously. Although one would hope such a probability would be extremely small, it is apparent that the probability of having an equivalent system load exceed the system capacity is greater than zero.

Associated with the probability (p^*) there is an energy demand being placed on the system which the system would not be able to serve. In order to calculate the demand, one only needs to consider adding a fictitious unit to the system with the following characteristics:

(1) infinite capacity ($MW = \infty$),

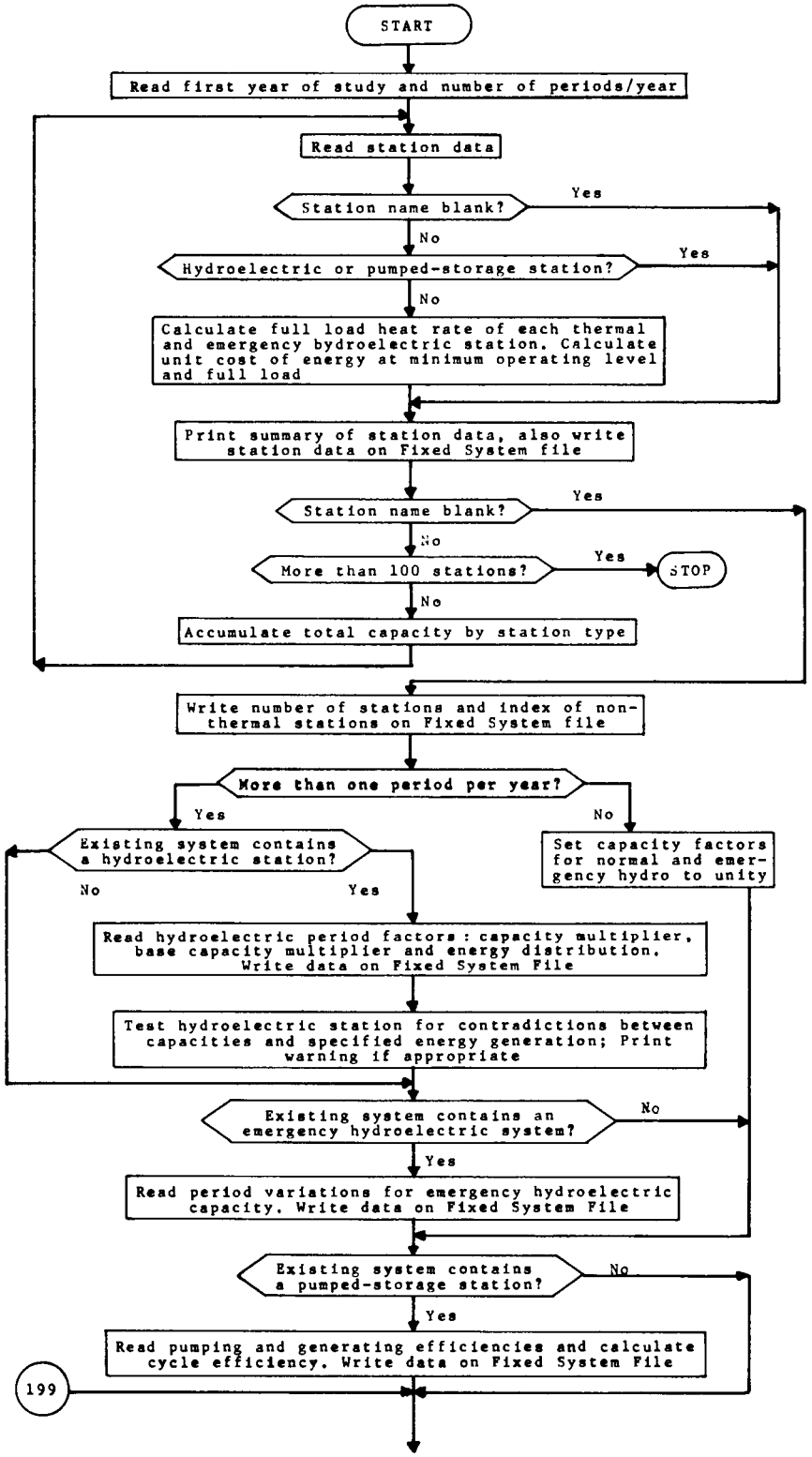
(2) a forced-outage rate of zero ($q = 0$).

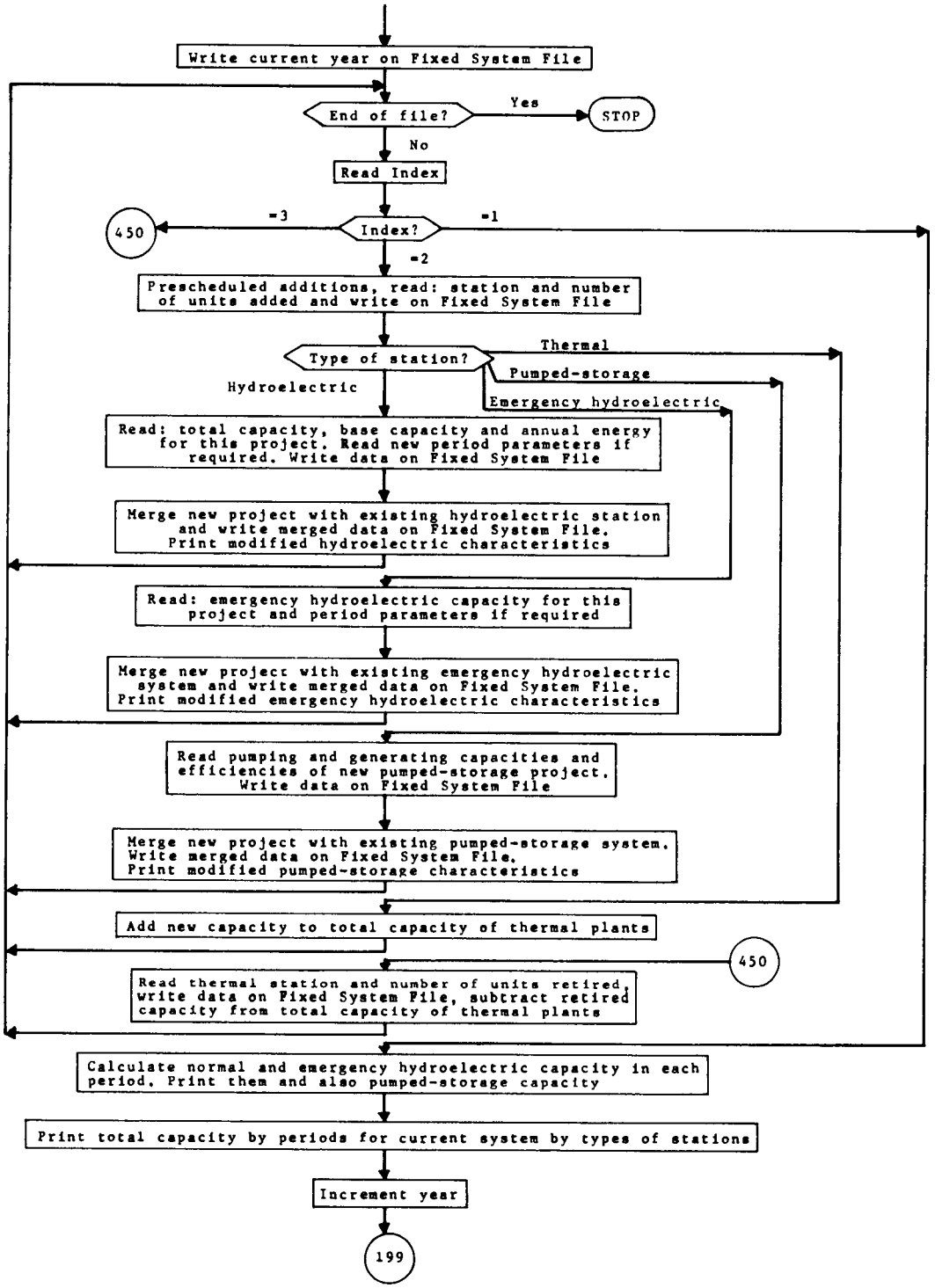
Following Eq. (13) the expected generation of this fictitious unit would be:

$$E_{m+1} = \tau \int_{b_{m+1}}^{\infty} EL_m(x)\, dx \,, \qquad \text{(B-1)}$$

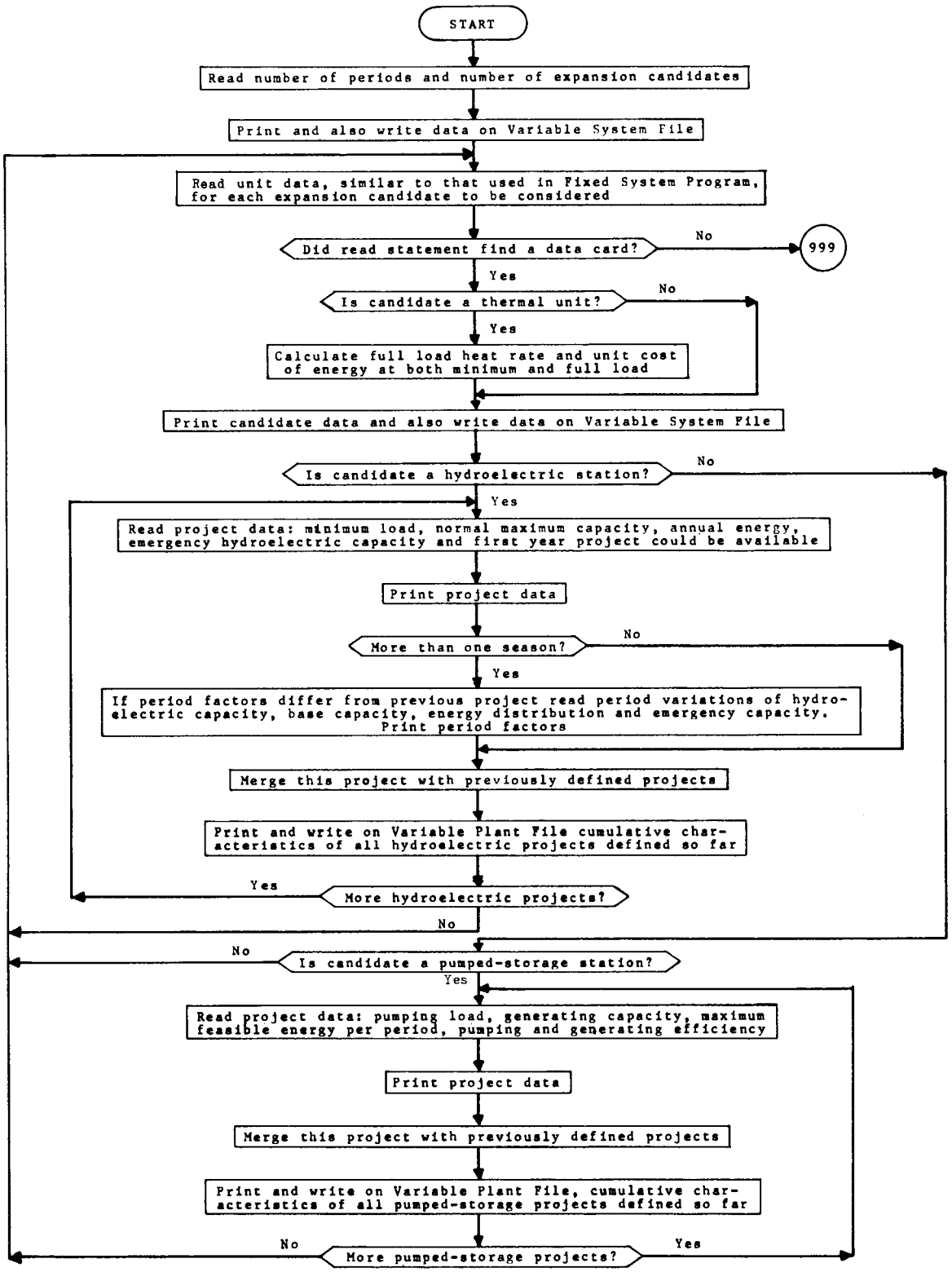
where b_{m+1} = the system capacity without unit m + 1 or the installed capacity.

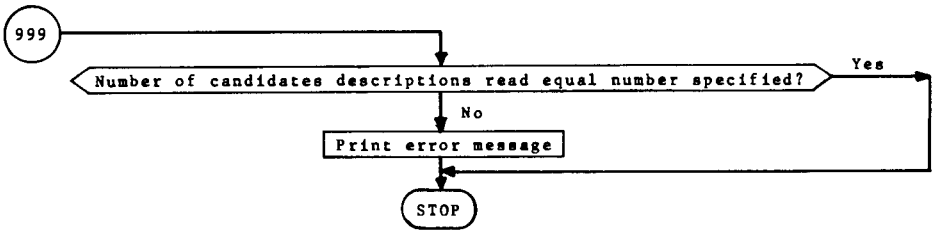
Appendix C: Flow Chart of Fixed System Program


START
Read first year of study and number of periods/year
Read station data
Station name blank?
Yes
No
Hydroelectric or pumped-storage station?
Yes
No
Calculate full load heat rate of each thermal and emergency hydroelectric station. Calculate unit cost of energy at minimum operating level and full load
Print summary of station data, also write station data on Fixed System file
Station name blank?
Yes
No
More than 100 stations?
Yes
STOP
No
Accumulate total capacity by station type
Write number of stations and index of non-thermal stations on Fixed System file
More than one period per year?
Yes
No
Existing system contains a hydroelectric station?
No
Yes
Set capacity factors for normal and emergency hydro to unity
Read hydroelectric period factors : capacity multiplier, base capacity multiplier and energy distribution. Write data on Fixed System File
Test hydroelectric station for contradictions between capacities and specified energy generation; Print warning if appropriate
Existing system contains an emergency hydroelectric system?
No
Yes
Read period variations for emergency hydroelectric capacity. Write data on Fixed System File
Existing system contains a pumped-storage station?
No
Yes
Read pumping and generating efficiencies and calculate cycle efficiency. Write data on Fixed System File
199

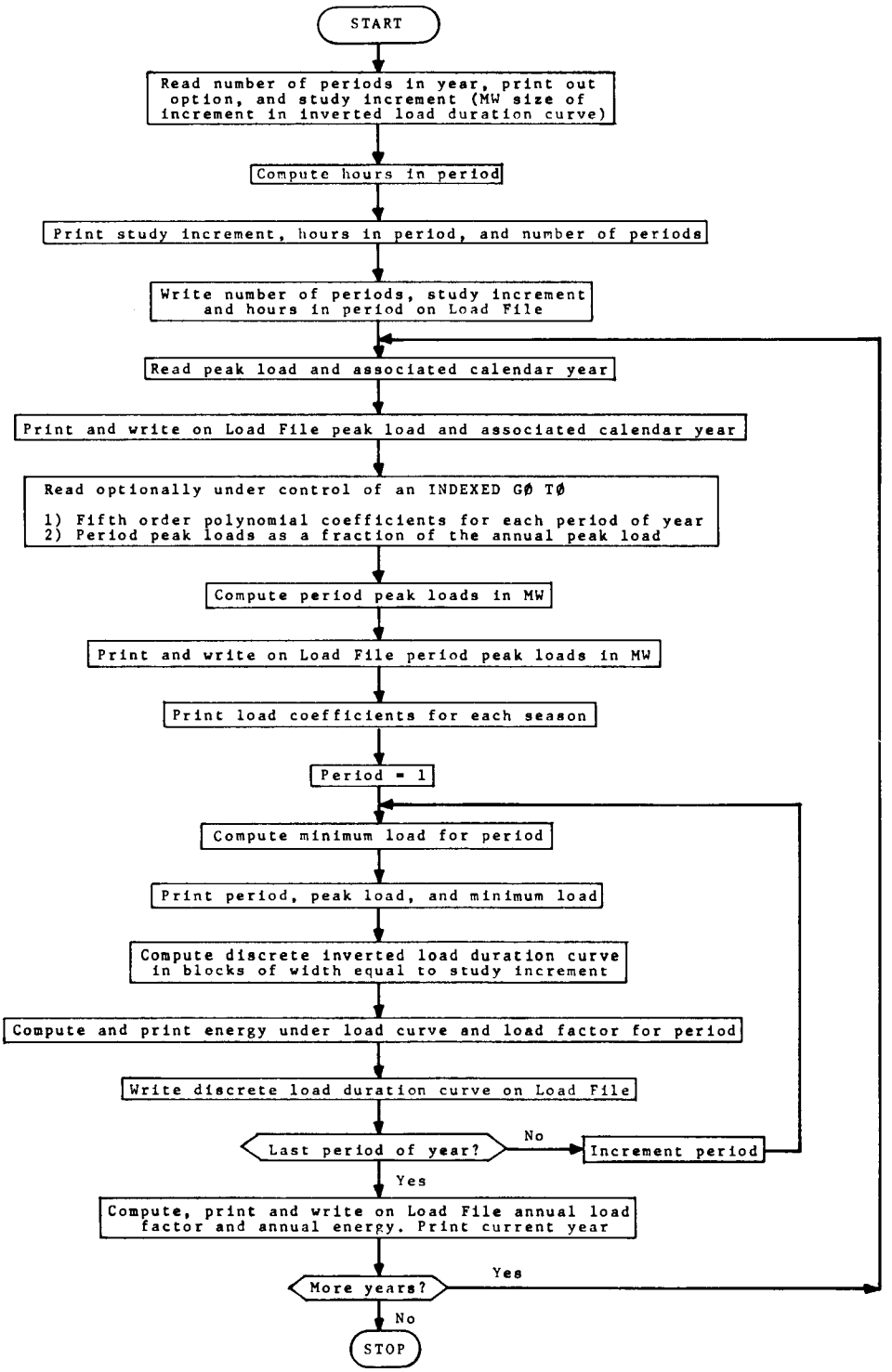

Write current year on Fixed System File
End of file?
Yes
STOP
No
Read Index
Index?
=3
450
=1
=2
Prescheduled additions, read: station and number of units added and write on Fixed System File
Type of station?
Thermal
Pumped-storage
Hydroelectric
Emergency hydroelectric
Read: total capacity, base capacity and annual energy for this project. Read new period parameters if required. Write data on Fixed System File
Merge new project with existing hydroelectric station and write merged data on Fixed System File. Print modified hydroelectric characteristics
Read: emergency hydroelectric capacity for this project and period parameters if required
Merge new project with existing emergency hydroelectric system and write merged data on Fixed System File. Print modified emergency hydroelectric characteristics
Read pumping and generating capacities and efficiencies of new pumped-storage project. Write data on Fixed System File
Merge new project with existing pumped-storage system. Write merged data on Fixed System File. Print modified pumped-storage characteristics
Add new capacity to total capacity of thermal plants
450
Read thermal station and number of units retired, write data on Fixed System File, subtract retired capacity from total capacity of thermal plants
Calculate normal and emergency hydroelectric capacity in each period. Print them and also pumped-storage capacity
Print total capacity by periods for current system by types of stations
Increment year
199

Appendix D: Flow Chart of Variable System Program

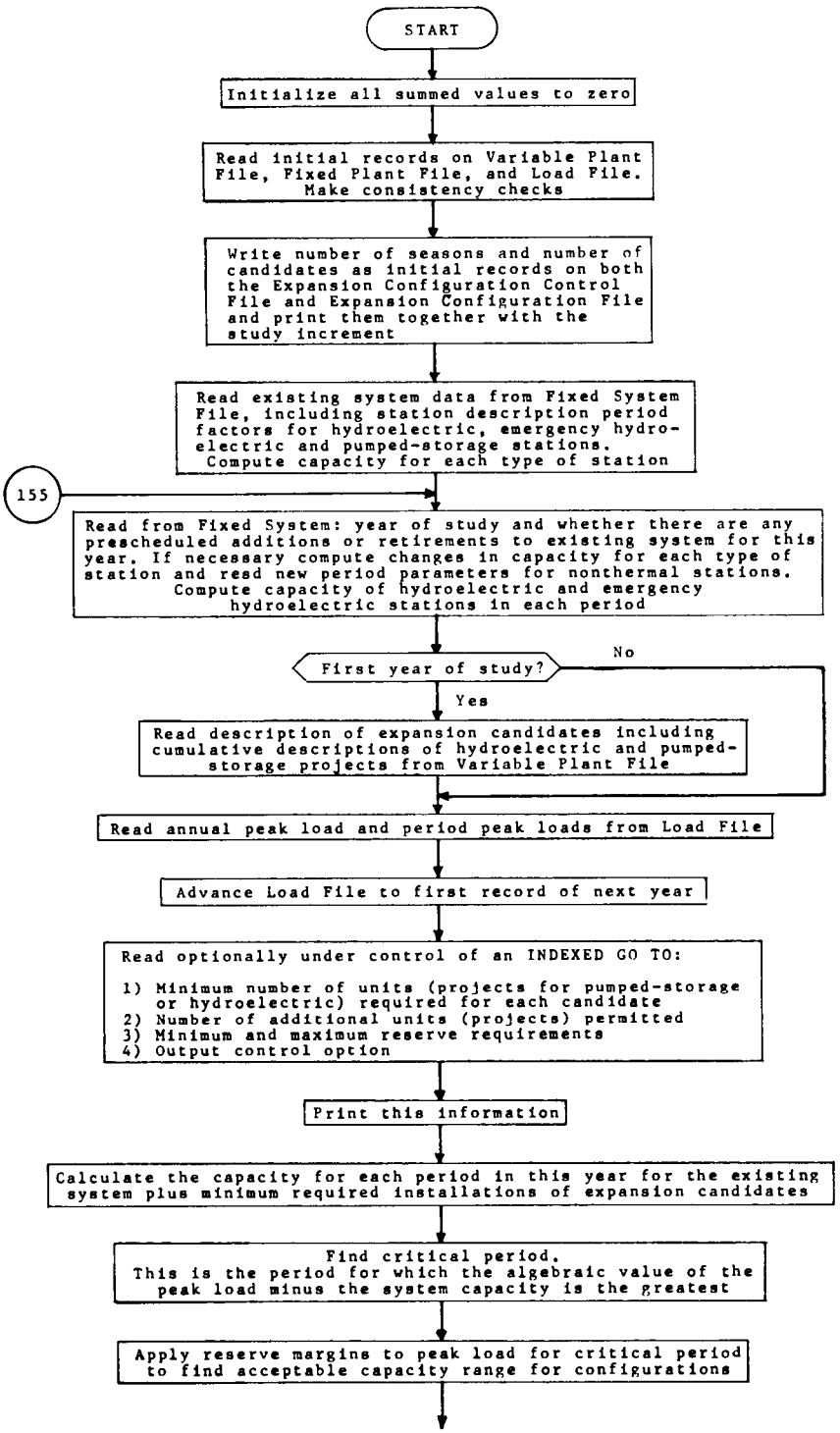

START
Read number of periods and number of expansion candidates
Print and also write data on Variable System File
Read unit data, similar to that used in Fixed System Program, for each expansion candidate to be considered
Did read statement find a data card?
No
999
Yes
Is candidate a thermal unit?
No
Yes
Calculate full load heat rate and unit cost of energy at both minimum and full load
Print candidate data and also write data on Variable System File
Is candidate a hydroelectric station?
No
Yes
Read project data: minimum load, normal maximum capacity, annual energy, emergency hydroelectric capacity and first year project could be available
Print project data
More than one season?
No
Yes
If period factors differ from previous project read period variations of hydroelectric capacity, base capacity, energy distribution and emergency capacity. Print period factors
Merge this project with previously defined projects
Print and write on Variable Plant File cumulative characteristics of all hydroelectric projects defined so far
Yes
More hydroelectric projects?
No
No
Is candidate a pumped-storage station?
Yes
Read project data: pumping load, generating capacity, maximum feasible energy per period, pumping and generating efficiency
Print project data
Merge this project with previously defined projects
Print and write on Variable Plant File, cumulative characteristics of all pumped-storage projects defined so far
No
More pumped-storage projects?
Yes

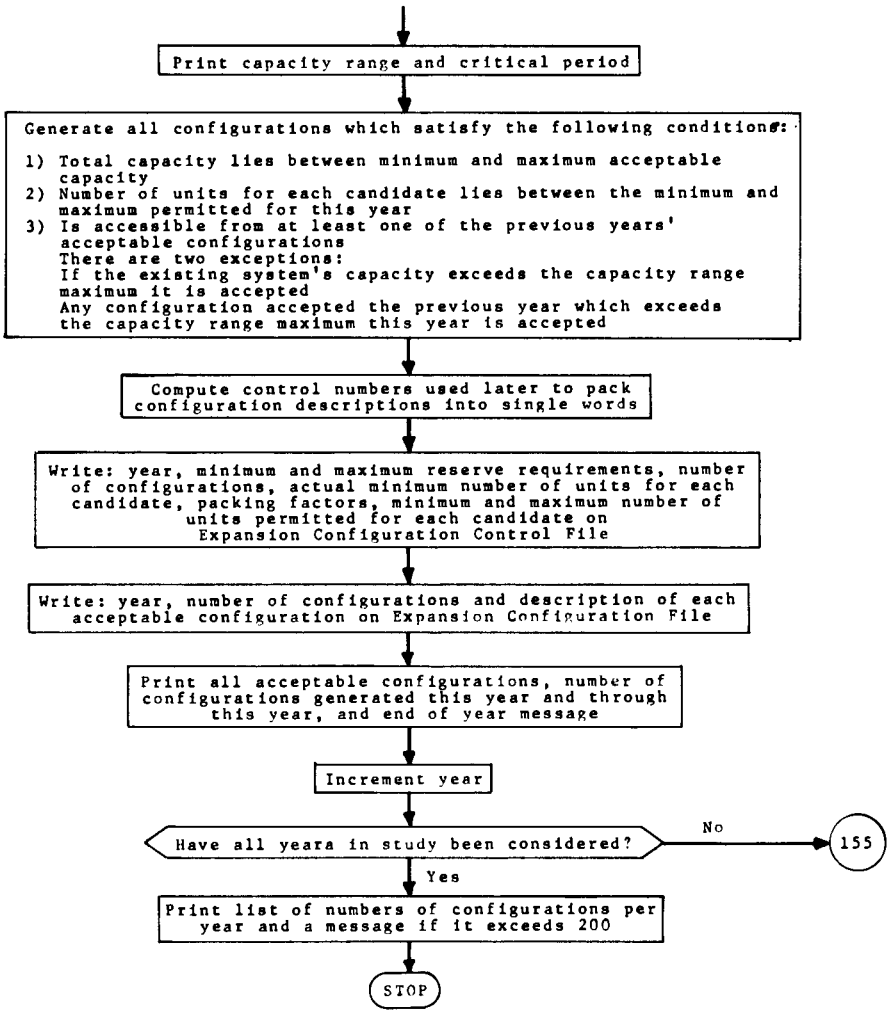

999
Number of candidates descriptions read equal number specified?
Yes
No
Print error message
STOP

Appendix E: Flow Chart of Load Program

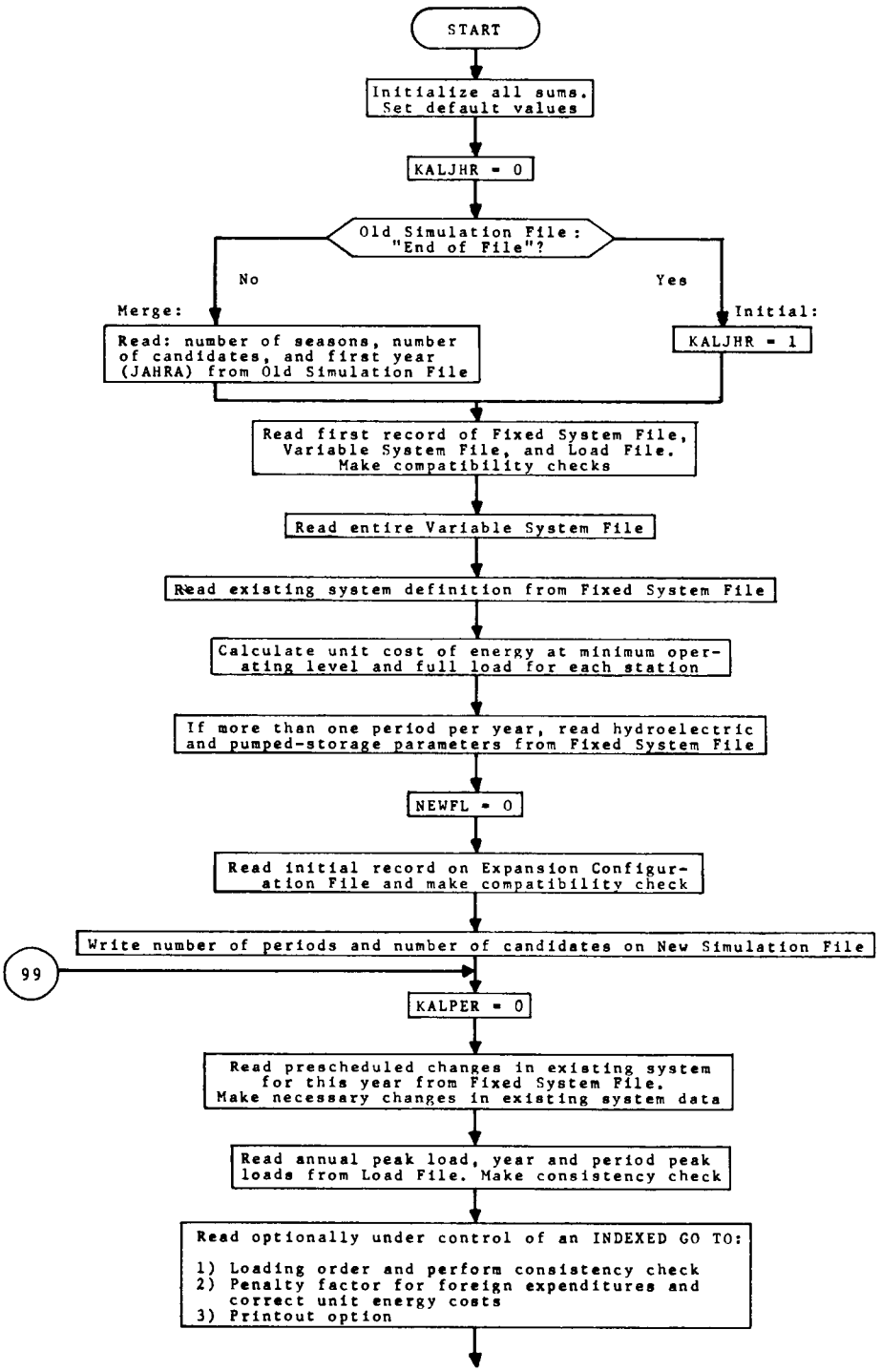

START
Read number of periods in year, print out option, and study increment (MW size of increment in inverted load duration curve)
Compute hours in period
Print study increment, hours in period, and number of periods
Write number of periods, study increment and hours in period on Load File
Read peak load and associated calendar year
Print and write on Load File peak load and associated calendar year
Read optionally under control of an INDEXED GØ TØ
1) Fifth order polynomial coefficients for each period of year
2) Period peak loads as a fraction of the annual peak load
Compute period peak loads in MW
Print and write on Load File period peak loads in MW
Print load coefficients for each season
Period = 1
Compute minimum load for period
Print period, peak load, and minimum load
Compute discrete inverted load duration curve in blocks of width equal to study increment
Compute and print energy under load curve and load factor for period
Write discrete load duration curve on Load File
Last period of year?
No
Increment period
Yes
Compute, print and write on Load File annual load factor and annual energy. Print current year
More years?
Yes
No
STOP

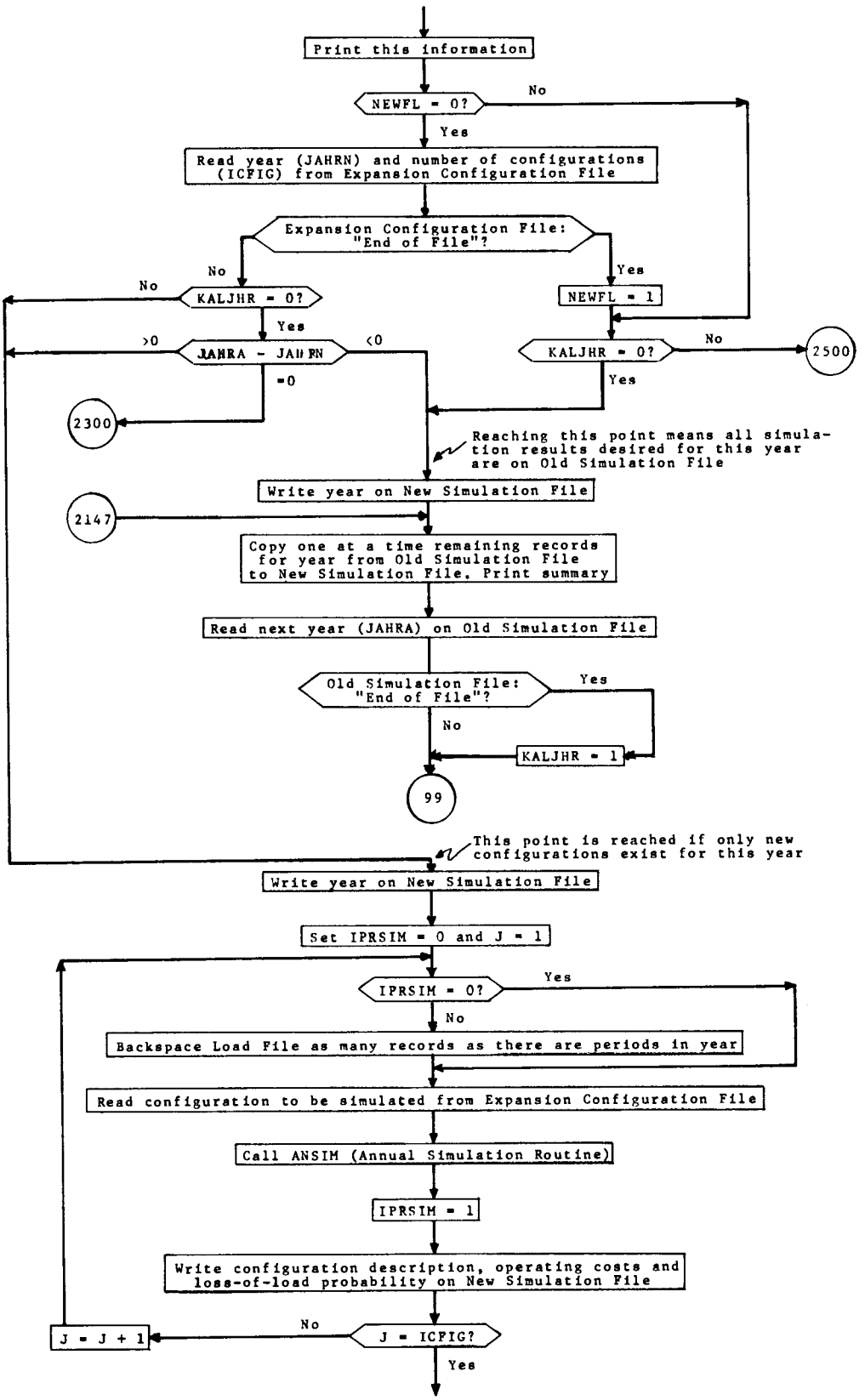
Appendix F: Flow Chart of Expansion Configuration Generator Program

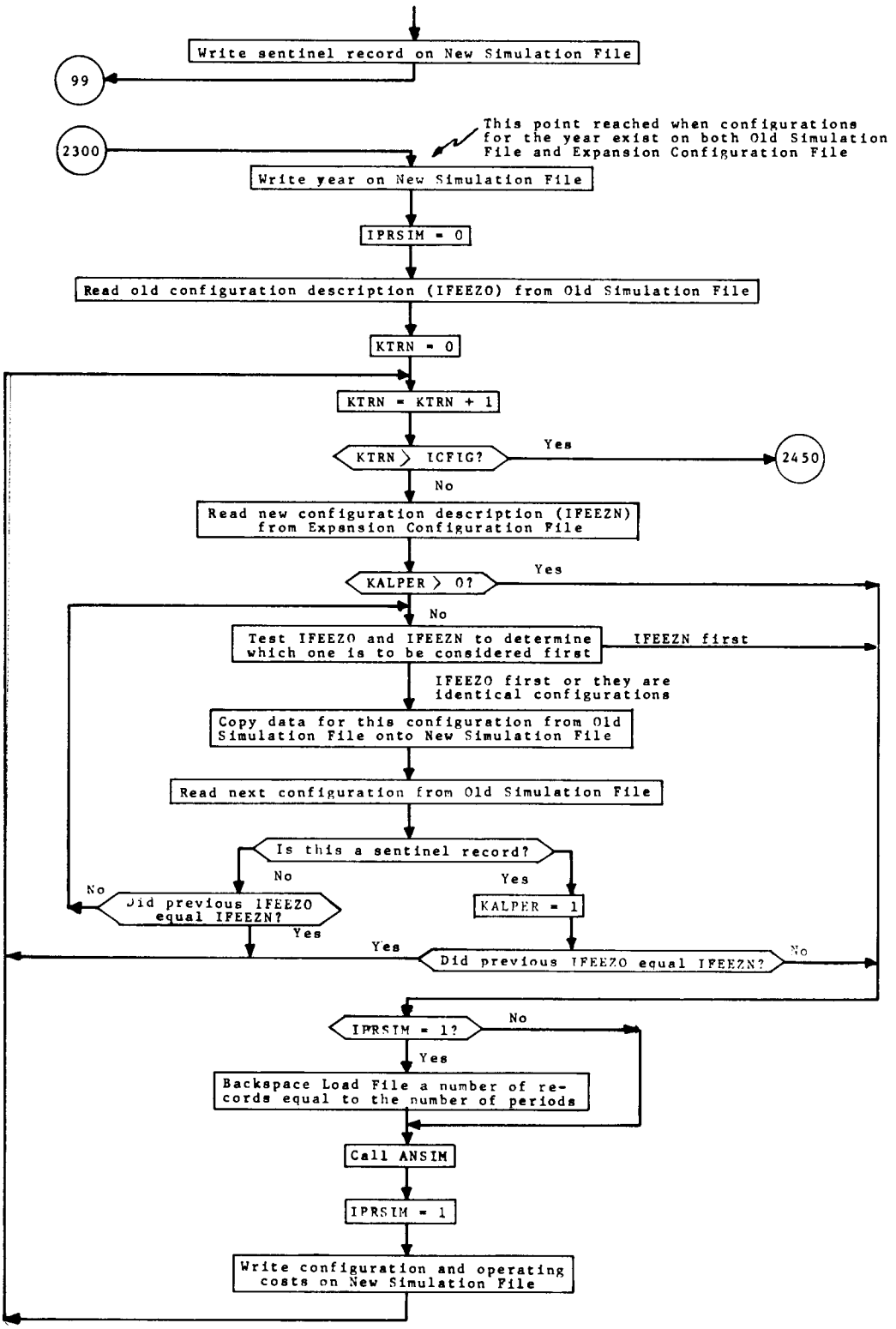

START
Initialize all summed values to zero
Read initial records on Variable Plant File, Fixed Plant File, and Load File. Make consistency checks
Write number of seasons and number of candidates as initial records on both the Expansion Configuration Control File and Expansion Configuration File and print them together with the study increment
Read existing system data from Fixed System File, including station description period factors for hydroelectric, emergency hydro-electric and pumped-storage stations. Compute capacity for each type of station
155
Read from Fixed System: year of study and whether there are any prescheduled additions or retirements to existing system for this year. If necessary compute changes in capacity for each type of station and read new period parameters for nonthermal stations. Compute capacity of hydroelectric and emergency hydroelectric stations in each period
First year of study?
No
Yes
Read description of expansion candidates including cumulative descriptions of hydroelectric and pumped-storage projects from Variable Plant File
Read annual peak load and period peak loads from Load File
Advance Load File to first record of next year
Read optionally under control of an INDEXED GO TO:
1) Minimum number of units (projects for pumped-storage or hydroelectric) required for each candidate
2) Number of additional units (projects) permitted
3) Minimum and maximum reserve requirements
4) Output control option
Print this information
Calculate the capacity for each period in this year for the existing system plus minimum required installations of expansion candidates
Find critical period. This is the period for which the algebraic value of the peak load minus the system capacity is the greatest
Apply reserve margins to peak load for critical period to find acceptable capacity range for configurations

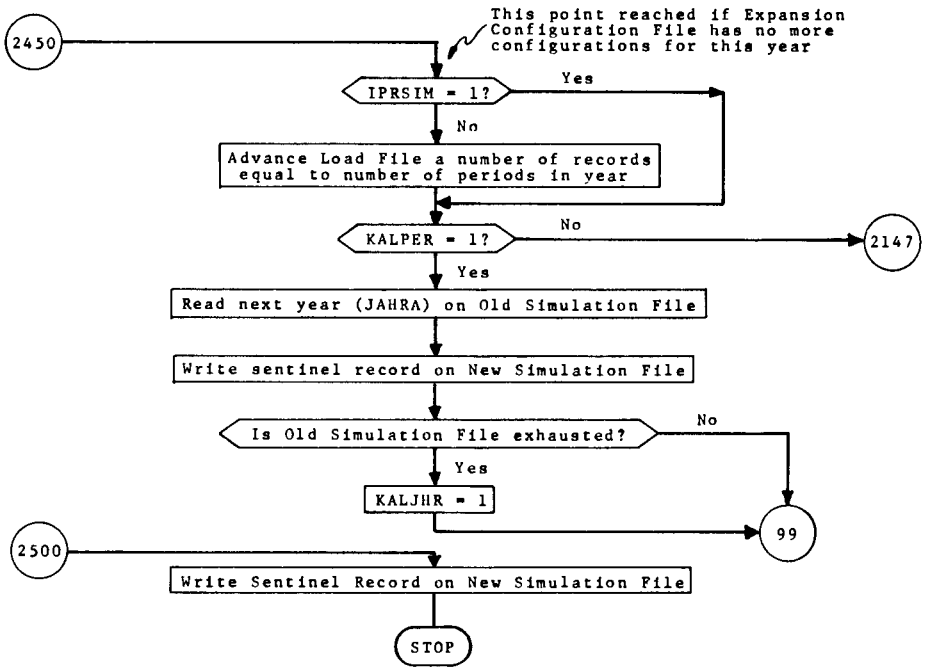

Print capacity range and critical period
Generate all configurations which satisfy the following conditions:
1) Total capacity lies between minimum and maximum acceptable capacity
2) Number of units for each candidate lies between the minimum and maximum permitted for this year
3) Is accessible from at least one of the previous years' acceptable configurations
There are two exceptions:
If the existing system's capacity exceeds the capacity range maximum it is accepted
Any configuration accepted the previous year which exceeds the capacity range maximum this year is accepted
Compute control numbers used later to pack configuration descriptions into single words
Write: year, minimum and maximum reserve requirements, number of configurations, actual minimum number of units for each candidate, packing factors, minimum and maximum number of units permitted for each candidate on Expansion Configuration Control File
Write: year, number of configurations and description of each acceptable configuration on Expansion Configuration File
Print all acceptable configurations, number of configurations generated this year and through this year, and end of year message
Increment year
Have all years in study been considered?
No
155
Yes
Print list of numbers of configurations per year and a message if it exceeds 200
STOP

Appendix G: Flow Chart of Merge and Simulation Program

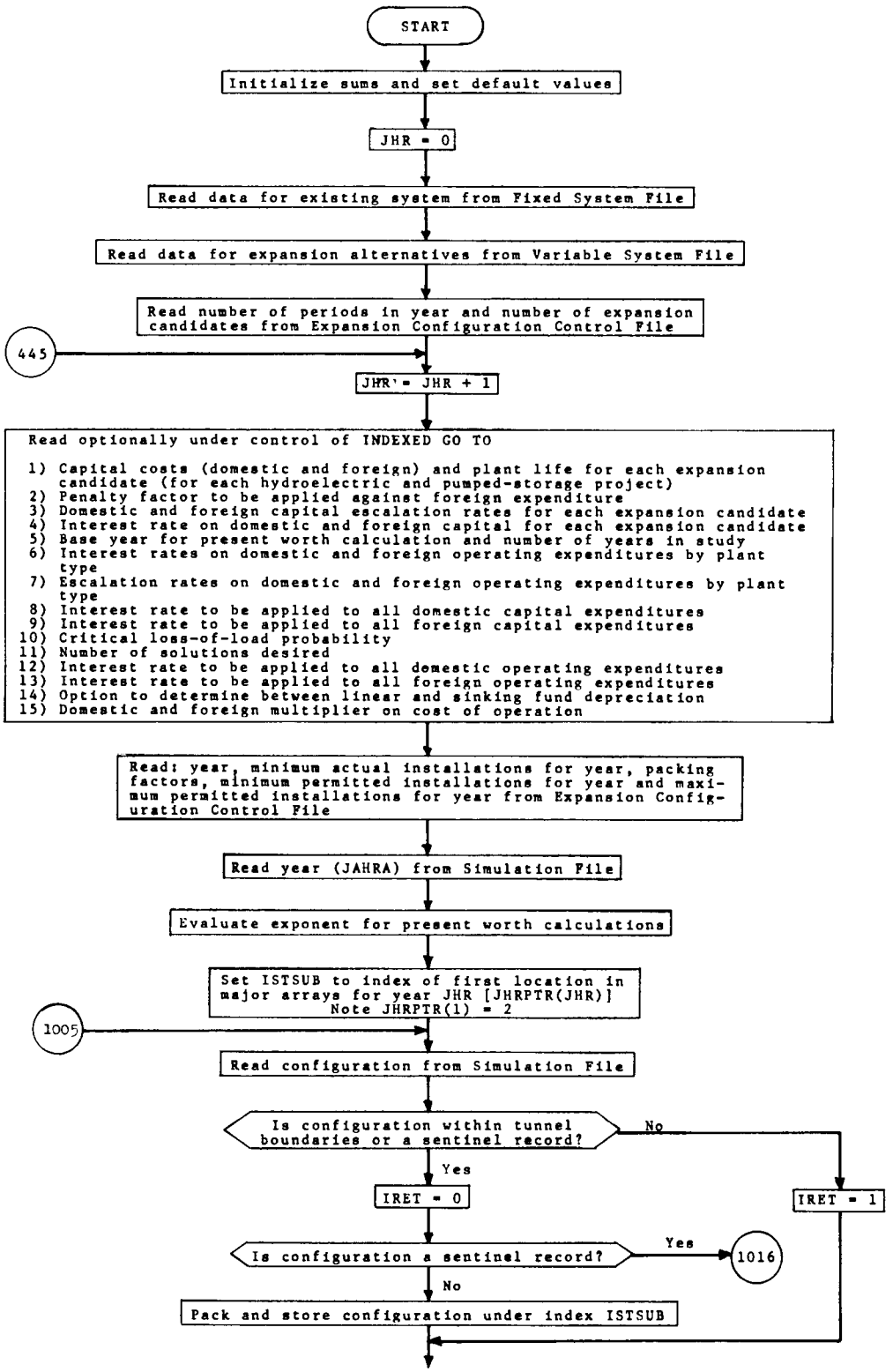

START
Initialize all sums. Set default values
KALJHR = 0
Old Simulation File: "End of File"?
No
Yes
Merge:
Initial:
Read: number of seasons, number of candidates, and first year (JAHRA) from Old Simulation File
KALJHR = 1
Read first record of Fixed System File, Variable System File, and Load File. Make compatibility checks
Read entire Variable System File
Read existing system definition from Fixed System File
Calculate unit cost of energy at minimum operating level and full load for each station
If more than one period per year, read hydroelectric and pumped-storage parameters from Fixed System File
NEWFL = 0
Read initial record on Expansion Configuration File and make compatibility check
Write number of periods and number of candidates on New Simulation File
99
KALPER = 0
Read prescheduled changes in existing system for this year from Fixed System File. Make necessary changes in existing system data
Read annual peak load, year and period peak loads from Load File. Make consistency check
Read optionally under control of an INDEXED GO TO:
1) Loading order and perform consistency check
2) Penalty factor for foreign expenditures and correct unit energy costs
3) Printout option

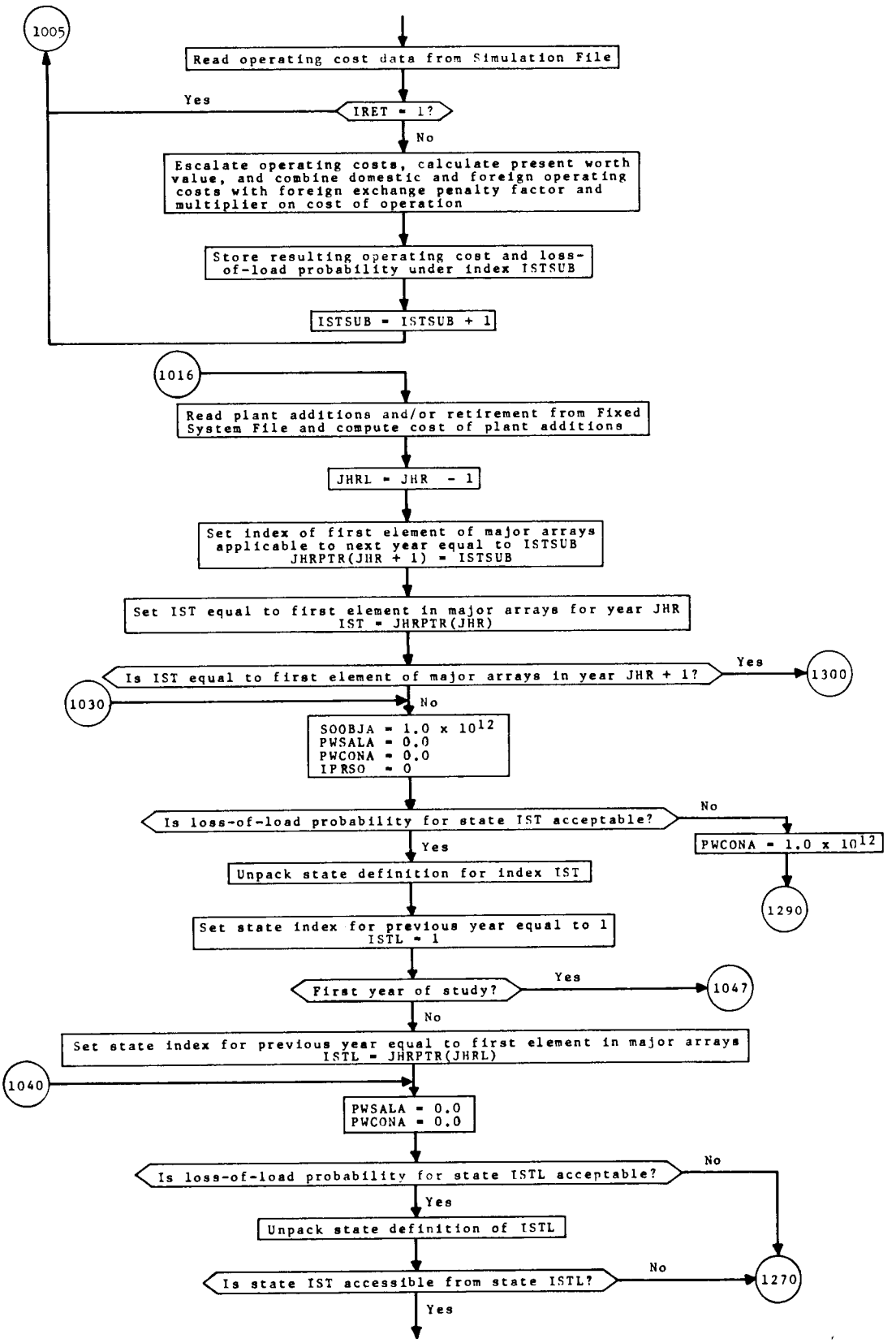

Print this information
NEWFL = 0?
No
Yes
Read year (JAHRN) and number of configurations (ICFIG) from Expansion Configuration File
Expansion Configuration File: "End of File"?
No
Yes
NEWFL = 1
KALJHR = 0?
No
Yes
JAHRA - JAHRN
>0
<0
=0
KALJHR = 0?
No
Yes
2500
2300
Reaching this point means all simulation results desired for this year are on Old Simulation File
Write year on New Simulation File
2147
Copy one at a time remaining records for year from Old Simulation File to New Simulation File. Print summary
Read next year (JAHRA) on Old Simulation File
Old Simulation File: "End of File"?
Yes
No
KALJHR = 1
99
This point is reached if only new configurations exist for this year
Write year on New Simulation File
Set IPRSIM = 0 and J = 1
IPRSIM = 0?
Yes
No
Backspace Load File as many records as there are periods in year
Read configuration to be simulated from Expansion Configuration File
Call ANSIM (Annual Simulation Routine)
IPRSIM = 1
Write configuration description, operating costs and loss-of-load probability on New Simulation File
J = ICFIG?
No
J = J + 1
Yes

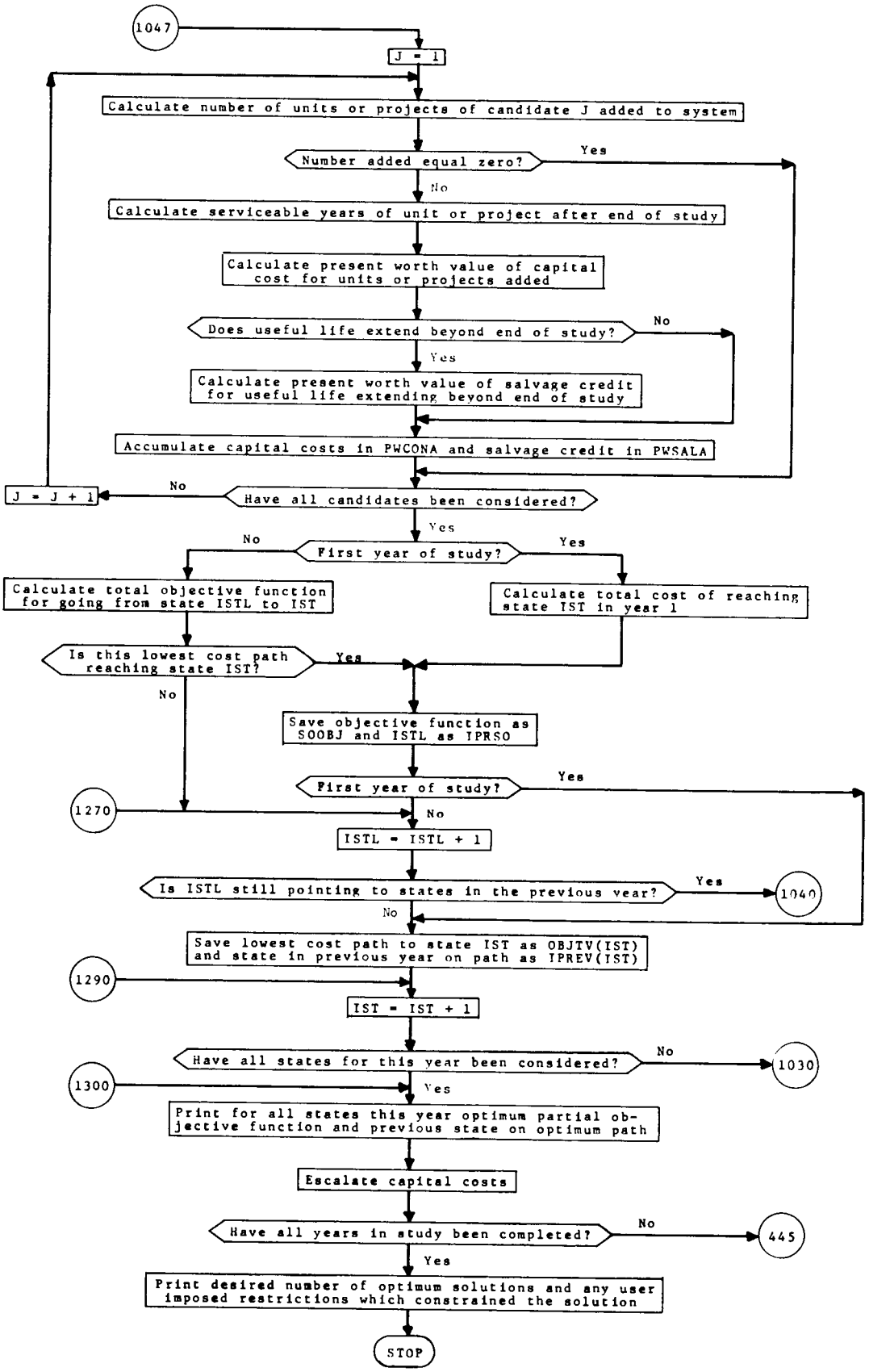

Write sentinel record on New Simulation File
99
2300
This point reached when configurations for the year exist on both Old Simulation File and Expansion Configuration File
Write year on New Simulation File
IPRSIM = 0
Read old configuration description (IFEEZO) from Old Simulation File
KTRN = 0
KTRN = KTRN + 1
KTRN > ICFIG?
Yes
2450
No
Read new configuration description (IFEEZN) from Expansion Configuration File
KALPER > 0?
Yes
No
Test IFEEZO and IFEEZN to determine which one is to be considered first
IFEEZN first
IFEEZO first or they are identical configurations
Copy data for this configuration from Old Simulation File onto New Simulation File
Read next configuration from Old Simulation File
Is this a sentinel record?
No
Yes
No
Did previous IFEEZO equal IFEEZN?
KALPER = 1
Yes
Yes
Did previous IFEEZO equal IFEEZN?
No
IPRSIM = 1?
No
Yes
Backspace Load File a number of records equal to the number of periods
Call ANSIM
IPRSIM = 1
Write configuration and operating costs on New Simulation File


This point reached if Expansion Configuration File has no more configurations for this year
2450
IPRSIM = 1?
Yes
No
Advance Load File a number of records equal to number of periods in year
KALPER = 1?
No
2147
Yes
Read next year (JAHRA) on Old Simulation File
Write sentinel record on New Simulation File
Is Old Simulation File exhausted?
No
Yes
KALJHR = 1
99
2500
Write Sentinel Record on New Simulation File
STOP

Appendix H: Flow Chart of Optimization Program


START
Initialize sums and set default values
JHR = 0
Read data for existing system from Fixed System File
Read data for expansion alternatives from Variable System File
Read number of periods in year and number of expansion candidates from Expansion Configuration Control File
445
JHR = JHR + 1
Read optionally under control of INDEXED GO TO
1) Capital costs (domestic and foreign) and plant life for each expansion candidate (for each hydroelectric and pumped-storage project)
2) Penalty factor to be applied against foreign expenditure
3) Domestic and foreign capital escalation rates for each expansion candidate
4) Interest rate on domestic and foreign capital for each expansion candidate
5) Base year for present worth calculation and number of years in study
6) Interest rates on domestic and foreign operating expenditures by plant type
7) Escalation rates on domestic and foreign operating expenditures by plant type
8) Interest rate to be applied to all domestic capital expenditures
9) Interest rate to be applied to all foreign capital expenditures
10) Critical loss-of-load probability
11) Number of solutions desired
12) Interest rate to be applied to all domestic operating expenditures
13) Interest rate to be applied to all foreign operating expenditures
14) Option to determine between linear and sinking fund depreciation
15) Domestic and foreign multiplier on cost of operation
Read: year, minimum actual installations for year, packing factors, minimum permitted installations for year and maximum permitted installations for year from Expansion Configuration Control File
Read year (JAHRA) from Simulation File
Evaluate exponent for present worth calculations
Set ISTSUB to index of first location in major arrays for year JHR [JHRPTR(JHR)]
Note JHRPTR(1) = 2
1005
Read configuration from Simulation File
Is configuration within tunnel boundaries or a sentinel record?
No
Yes
IRET = 0
IRET = 1
Is configuration a sentinel record?
Yes
1016
No
Pack and store configuration under index ISTSUB


1005
Read operating cost data from Simulation File
Yes
IRET = 1?
No
Escalate operating costs, calculate present worth value, and combine domestic and foreign operating costs with foreign exchange penalty factor and multiplier on cost of operation
Store resulting operating cost and loss-of-load probability under index ISTSUB
ISTSUB = ISTSUB + 1
1016
Read plant additions and/or retirement from Fixed System File and compute cost of plant additions
JHRL = JHR - 1
Set index of first element of major arrays applicable to next year equal to ISTSUB
JHRPTR(JHR + 1) = ISTSUB
Set IST equal to first element in major arrays for year JHR
IST = JHRPTR(JHR)
Is IST equal to first element of major arrays in year JHR + 1?
Yes
1300
1030
No
SOOBJA = 1.0 x 10^12
PWSALA = 0.0
PWCONA = 0.0
IPRSO = 0
Is loss-of-load probability for state IST acceptable?
No
PWCONA = 1.0 x 10^12
1290
Yes
Unpack state definition for index IST
Set state index for previous year equal to 1
ISTL = 1
First year of study?
Yes
1047
No
Set state index for previous year equal to first element in major arrays
ISTL = JHRPTR(JHRL)
1040
PWSALA = 0.0
PWCONA = 0.0
Is loss-of-load probability for state ISTL acceptable?
No
Yes
Unpack state definition of ISTL
Is state IST accessible from state ISTL?
No
1270
Yes


1047
J = 1
Calculate number of units or projects of candidate J added to system
Number added equal zero?
Yes
No
Calculate serviceable years of unit or project after end of study
Calculate present worth value of capital cost for units or projects added
Does useful life extend beyond end of study?
No
Yes
Calculate present worth value of salvage credit for useful life extending beyond end of study
Accumulate capital costs in PWCONA and salvage credit in PWSALA
J = J + 1
No
Have all candidates been considered?
Yes
No
First year of study?
Yes
Calculate total objective function for going from state ISTL to IST
Calculate total cost of reaching state IST in year 1
Is this lowest cost path reaching state IST?
Yes
No
Save objective function as SOOBJ and ISTL as IPRSO
First year of study?
Yes
1270
No
ISTL = ISTL + 1
Is ISTL still pointing to states in the previous year?
Yes
1040
No
Save lowest cost path to state IST as OBJTV(IST) and state in previous year on path as IPREV(IST)
1290
IST = IST + 1
Have all states for this year been considered?
No
1030
1300
Yes
Print for all states this year optimum partial objective function and previous state on optimum path
Escalate capital costs
Have all years in study been completed?
No
445
Yes
Print desired number of optimum solutions and any user imposed restrictions which constrained the solution
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