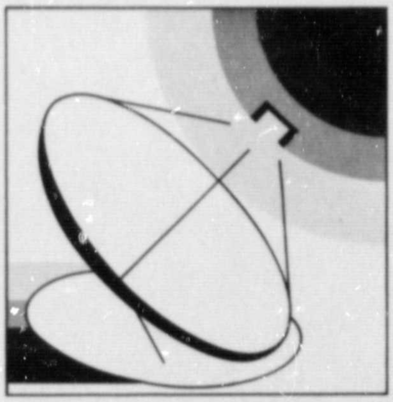
5105-87
Solar Thermal Power Systems Project
Parabolic Dish Systems Development

DOE/JPL-1060-47
Distribution Category UC-62b

The SYSGEN User Package

C. R. Carlson



March 15, 1981

Prepared for
U.S. Department of Energy
Through an agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

(JPL PUBLICATION 81-47)

5105-87
Solar Thermal Power Systems Project
Parabolic Dish Systems Development

DOE/JPL-1060-47
Distribution Category UC-62b

The SYSGEN User Package

C. R. Carlson

March 15, 1981

Prepared for
U.S. Department of Energy
Through an agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

(JPL PUBLICATION 81-47)

Prepared by the Jet Propulsion Laboratory, California Institute of Technology, for the U.S. Department of Energy through an agreement with the National Aeronautics and Space Administration.

The JPL Solar Thermal Power Systems Project is sponsored by the U.S. Department of Energy and forms a part of the Solar Thermal Program to develop low-cost solar thermal and electric power plants.

ABSTRACT

SYSGEN is a production costing and reliability model of electric utility systems. Hydro-electric, storage, and time-dependent generating units can be modeled in addition to conventional generating plants.

This user documentation describes the SYSGEN model and its links with other JPL simulations. Input variables, modeling options, output variables, and report formats are explained in detail and illustrated with examples. The appendixes contain sample computer output and instructions for running the program on an IBM batch system. SYSGEN also can be run interactively by using a program developed at JPL called FEPS (Front End Program for SYSGEN). A format for SYSGEN input variables which is designed for use with FEPS is presented.

FOREWORD

SYSGEN is a computer program which simulates the production costs and reliability of an electric utility system with and without time-dependent generating units. It is one of several simulations used at JPL for calculating the breakeven costs of photovoltaic and solar thermal electric systems in grid-connected applications.

JPL received SYSGEN in 1979 from the Massachusetts Institute of Technology (MIT). Significant modifications have been made in the SYSGEN program since then, based on the work of Dr. Donald Ebbeler and Dr. George Fox, both of JPL. These modifications, listed in Appendix C, do not affect the inputs to the model; thus, this user documentation may be used with both the MIT and JPL versions of SYSGEN.

ACKNOWLEDGMENT

This user package is based on the original SYSGEN documentation written by Dr. Susan Finger at the MIT Energy Laboratory. The original version required a rather sophisticated knowledge of computer programming and utility engineering. It is hoped that this package will allow a larger number of people to use the SYSGEN simulation easily and correctly.

This report benefitted greatly from the careful and thorough review done by Dr. Donald Ebbeler. The theoretical work on utility simulations done by both Dr. Ebbeler and Dr. George Fox has been the basis for all the corrections to and modifications of the SYSGEN program. Dr. Fox was also responsible for the unenviable task of translating the theoretical changes into software changes. Computer programming and execution of the SYSGEN code was competently performed by Michael Davisson, who has also provided invaluable general support throughout all the phases of writing this documentation.

Steven Bluhm, Dr. Susan Finger, Sandra Gutnecht, and Timothy Tutt all reviewed earlier drafts of this report and provided helpful suggestions and encouragement.

Peggy Panda was responsible for editing and publishing the report. The efforts of Jeanne Wadsworth, Susan Elrod, and Arlene Calvert in typing the many drafts of this report are appreciated.

CONTENTS

Tables

Figures

SECTION I

INTRODUCTION

A. THE USE OF COMPUTER SIMULATIONS IN THE BREAKEVEN COST CALCULATION

SYSGEN is one of several simulations used in the breakeven cost calculation for photovoltaic and solar thermal electric systems. Together, these simulations incorporate sufficient technological and financial detail to allow realistic estimation of the value and effects of solar generation to a grid system. The rest of this section explains how the JPL simulation models calculate these values.

Four major areas are modeled:

1) the lifetime cost and performance of the solar plant
2) the production cost and reliability of electric power generation by the utility, with and without the solar plant
3) optimal capacity expansion planning for the utility over time, with and without the solar plant
4) the financial structure and environment of the utility.

Electric power systems are assumed to operate to meet a fluctuating power demand at minimum cost.* The demand for electricity generally follows a predictable daily pattern, with peak periods occurring around noon and early evening. Utilities adjust their generating plant mix according to these changes in demand. Generating plants with low operating costs are run all the time to meet the minimum power demand and are called base loaded units.

* Utilities in reality are constrained by electric stability requirements imposed by the transmission network. However, a complete model of operating a power system would require detailed models and data for each generator and transmission line and would be far too complex for our purposes. Most production costing models, including the one used by JPL, do not consider transmission or stability constraints.

Plants with high operating costs but low capital costs are brought on line during the peak hours and are referred to as peak loaded units. Thus, as a utility increases its output, the marginal cost of generation also increases as more and more expensive units are brought on line to meet demand.

The value of a solar plant to a grid is defined in terms of fuel displacement and capacity displacement. Displaced fuel is fuel saved because solar generation is used to meet load instead of using an existing conventional plant. Capacity displacement occurs when the addition of new conventional capacity can be deferred or cancelled if a solar plant is added to the grid.

A utility can reduce its operating costs either by reducing the size of the peak loads (e.g., with time-of-day pricing) or by displacing expensive peak unit generation with cheaper limited energy sources, such as solar, storage, or hydro plants. It should be apparent that the value of a solar plant will depend upon what kinds of generating units it displaces. The value of the fuel displaced depends upon the correlation during the day between solar output and the load on the utility: If the bulk of solar output occurs during off-peak periods, then cheap base loaded plants are displaced rather than expensive peaking units. It is for this reason that utility and solar plant cost and performance simulations are done on an hourly basis rather than averaged over days or months. Averaged data will not correctly capture the difference between the value of peak and off-peak generation and thus will underestimate or overestimate the displaced fuel value attributed to the solar plant.

The lifetime cost and performance (LCP) simulation of a photovoltaic plant performs four functions: 1) it describes initial design and construction of the power plant, 2) simulates hourly photovoltaic system power output, 3) analyzes the long-term effects of exposure to an outdoor environment and operations/maintenance policies, and 4) finds the capital and recurring production costs of operating the system. The LCP model contains both deterministic and probabilistic characteristics: Module failure is modeled using transition probabilities; explicit time-dependent features are modeled deterministically.*

The cost and performance of solar thermal systems are estimated by the Solar Energy Simulation model (SES). The SES model comprises three programs which perform the following functions: 1) evaluation of collector field performance for specific insolation and temperatures, 2) calculation of the performance of a fixed-rated power plant with different collector and storage sizes, and 3) calculation of the minimum energy cost of the plant. These models are coupled with the SYSGEN utility grid simulation to determine the effects of the solar plant upon grid operating cost and reliability.

The value of the solar plant is also determined by the timing of its introduction to the grid system. The optimal time for bringing solar capacity on-line will be determined in part by future availability of fuels and costs of conventional power plants. JPL's simulation models allow the testing of different assumptions about the above factors. The production costing model (SYSGEN) can be run for up to a 35-year time period, incorporating different capacity expansion plans, cost escalation rates, and changes in customer demand. The results of these different production cost scenarios are then combined with investor specific financial and investment data to determine how the feasibility of investment in the solar plant changes over time.

Utilities plan their generation mix to meet a certain reliability requirement. One measure of reliability is called the loss of load probability

* C.S. Borden, "Computer Simulation of the Operations of Utility Grid Connected Photovoltaic Power Plants," paper presented at The National Computer Conference, May 19, 1980.

(LOLP), which may be defined as the probability that the utility cannot generate enough power to meet demand at any point in time, either because of a sudden surge in demand or an unexpected plant failure. On an hourly basis, the LOLP allowed is usually specified as a failure to meet load for one hour out of every ten years.* In order to meet this reliability criterion, utilities keep additional "unnecessary" units on spinning reserve, units which are running and can be connected to the grid immediately if needed. The production costing model uses a probabilistic method to incorporate uncertainty due to conventional plant failures and calculates the LOLP of the system. Because of this LOLP constraint, it is necessary to know the effect of a grid-connected solar plant on the reliability of the system. Solar plants differ from conventional units in that uncertainty in their performance is due not only to mechanical failure but also to the vagaries of the weather. Unfortunately, if scenarios are modeled using historical weather data (as they are at JPL), neither outages due to weather nor due to mechanical failure are included in the LOLP calculation for the grid system. This does not affect the estimates of the fuel displacement value for solar, but it presents some problems in planning capacity displacement.

One approach to this problem is to model both utility load and solar output as random variables, whose distributions are dependent on other measurable variables such as temperature, insolation, and time. This method would work particularly well in southern California, for example, where summer peak demand for electricity is highly dependent on the temperature because of the demand for air conditioning.

* More specifically, in a period of ten years, the expected number of hours for which there is a capacity deficiency to meet the hourly load demand is one.

The capacity displacement attributed to a solar plant is estimated with the optimal capacity expansion and the production costing/reliability models. The capacity expansion program (SCYLLA) uses a linear programming algorithm to minimize the cost of the generation mix for given changes in demand and production costs. Optimal changes in generation mix over time with and without solar plants are determined and are then tested for their reliability. If the addition of conventional capacity can be deferred when solar plants are added, then a capacity credit for the deferred capital costs is attributed to the solar plant.

The financial analysis model (APSEAM) incorporates 1) the estimated capital and production costs of both the solar plant and the utility, 2) the benefit stream to the utility in terms of fuel and capacity displacement over the lifetime of the solar plant, and 3) the optimal capacity expansion plan for the utility. These cost and benefit streams then can be tested in various financial environments, which include consideraton of inflation, escalation and interest rates, depreciation, and taxes to determine the net present value of an investment in the solar plant. The breakeven cost of the system is that cost which gives a net present value of zero for the investment.

Electric utilities use similar computer models for determining daily dispatch strategies and capacity expansion plans. Thus, our modeling procedures should be accepted as valid by the utility industry. The interfaces of the simulation programs are shown in Figure 1.

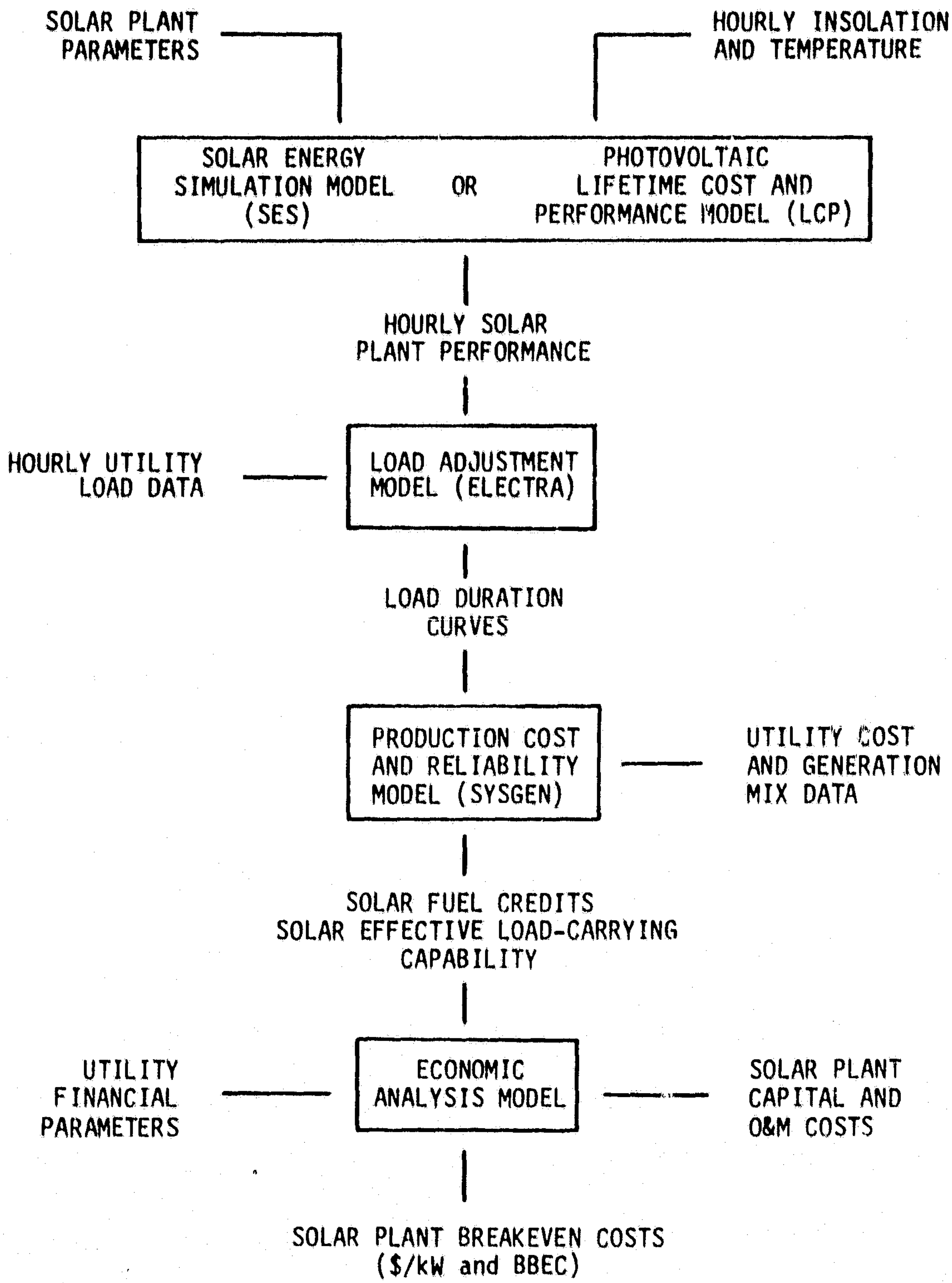


Figure 1. Methodology Overview

B. THE SYSGEN USER PACKAGE

The SYSGEN computer simulation is a production costing and reliability model of an electric power system. It may be used to study the effects of different assumptions about customer demand, fuel costs, or utility characteristics on system cost and reliability.

This package is designed for users who are not conversant with computer programming or utility engineering. Thus, descriptions of the actual modeling procedures are brief and necessarily general, and may not be detailed enough for some users. A complete list of the technical documentation for SYSGEN may be found in the references of this paper.

The model consists of three computer programs. The first, named ELECTRA, calculates a load duration curve (LDC) from hourly load curves, and models time-dependent power plants as increases or decreases in the net load on the system. Two LDCs are produced: one with the time-dependent generation and one without. The second program, SYSGEN, uses these LDCs and data describing the power plants in the system to calculate system cost and reliability with and without the time-dependent units. SCYLLA, the third program, uses these results to calculate the fuel and capacity credits of the time-dependent generation to the power system. The diagram in Figure 2 shows the program interactions.

Sections II through IV of this report explain the inputs, outputs, and modeling procedures used in the three computer programs. Section V contains worksheets which may be used to set up the inputs to the programs. These worksheets correspond directly to an interactive computer program named FEPS (Front End Program for SYSGEN). FEPS may be used to create computerized data bases for these simulations, and is explained below.

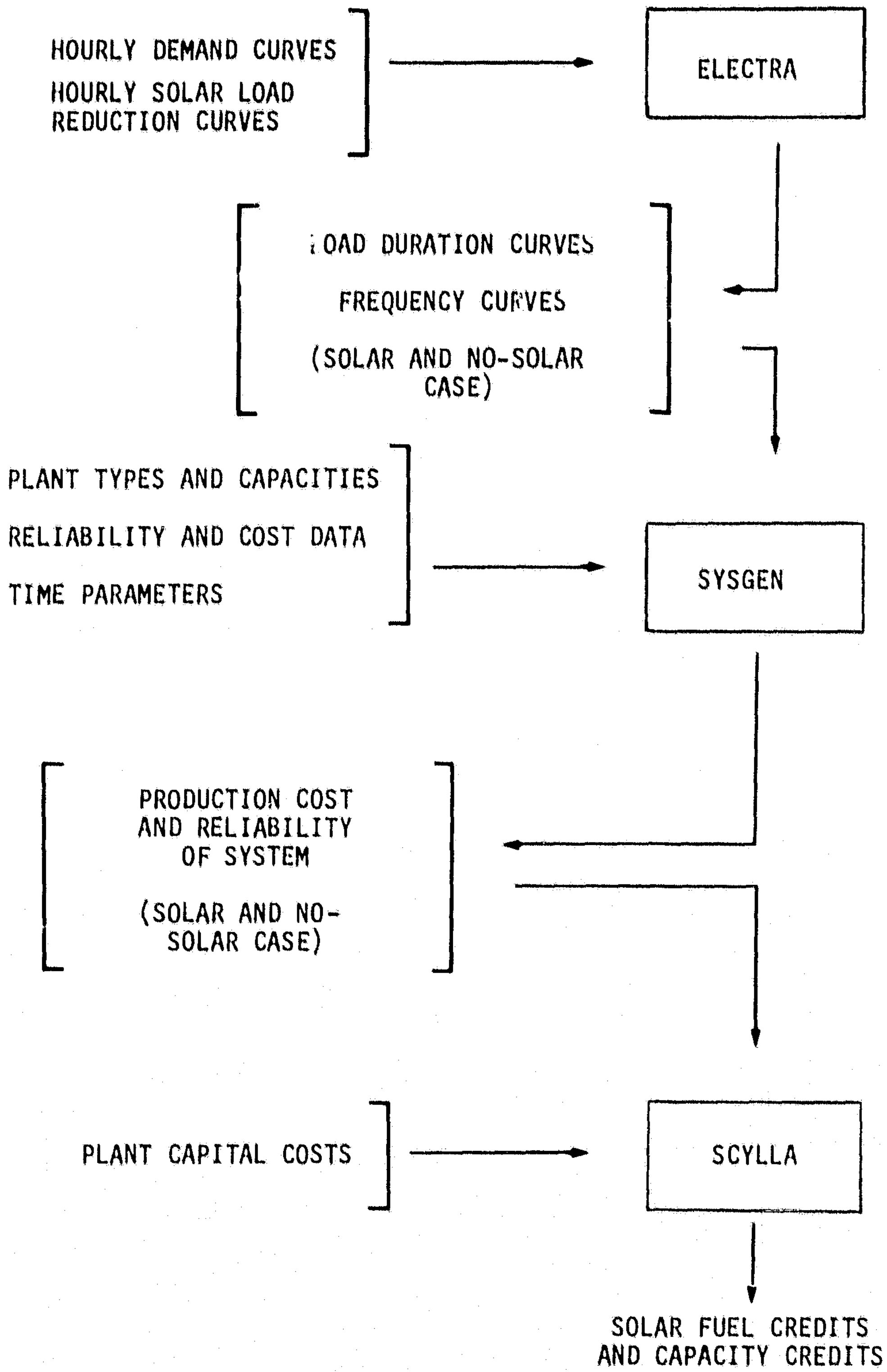


Figure 2. SYSGEN Model Overview

C. FEPS--THE FRONT END PROGRAM FOR SYSGEN

FEPS is an interactive computer program which may be used to create and modify data bases for SYSGEN simulations. The program transforms inputs into the proper format and files and adds the JCL (Job Control Language) necessary for SYSGEN, ELECTRA, and SCYLLA runs. It is presently set up on the California Institute of Technology (CIT) VAX time-sharing system, and may be accessed either from terminals at CIT or from remote terminals at JPL.

FEPS was written to be used in conjunction with this user package. Documentation for FEPS is available upon request. Data bases for SYSGEN still may be created from fixed format punched cards if so desired, and the JCL for running SYSGEN with card inputs is explained in Appendix B. The input formats for cards are fully described in the original MIT documentation for SYSGEN, also available upon request.

SECTION II

ELECTRA

A. THE LOAD CURVES

ELECTRA models time-dependent plants as decreases in the net load on the utility grid system. Up to four hourly load change curves may be input in addition to the original customer demand curve. The hourly load curves are converted into load duration curves that represent the net load with and without the time-dependent generation.

There may be up to 8,784 values in the customer demand curve and in each of the load modification curves. These values do not have to be hourly, but the values for demand and modification must match, i.e., they must start at the same point in time, the time interval used must be the same, there must be the same number of points in each curve, and the energy units must be the same (MW or kW).

The load duration curve is determined by the percent of time that load is greater than or equal to a percentage of peak load. Specifically, the dependent variable (Y axis) is the

percent of time demand $\geq X \cdot$ PEAK LOAD/n,

where $X = 1, 2, 3, \ldots, n$, and n = number of points in the load shape.

The "number of points in load shape" chosen determines the size of the MW intervals used in approximating the curve: The smaller the interval size, the more closely the true load duration curve is approximated. The user must specify the peak of each original load curve and the number of points in the load shape to be used in calculating the load duration curves. An example should be enlightening.

PRECEDING PAGE BLANK NOT FILMED

Suppose peak demand is 60 MW. We want to know the percent of time that the load is greater than or equal to Y MW, $0 \leq Y \leq 60$, where $Y = X \cdot 60/n$, with n and X defined as before. Table 1 illustrates the calculation of the load duration curve using three different values of n. (See also Figure 3.)

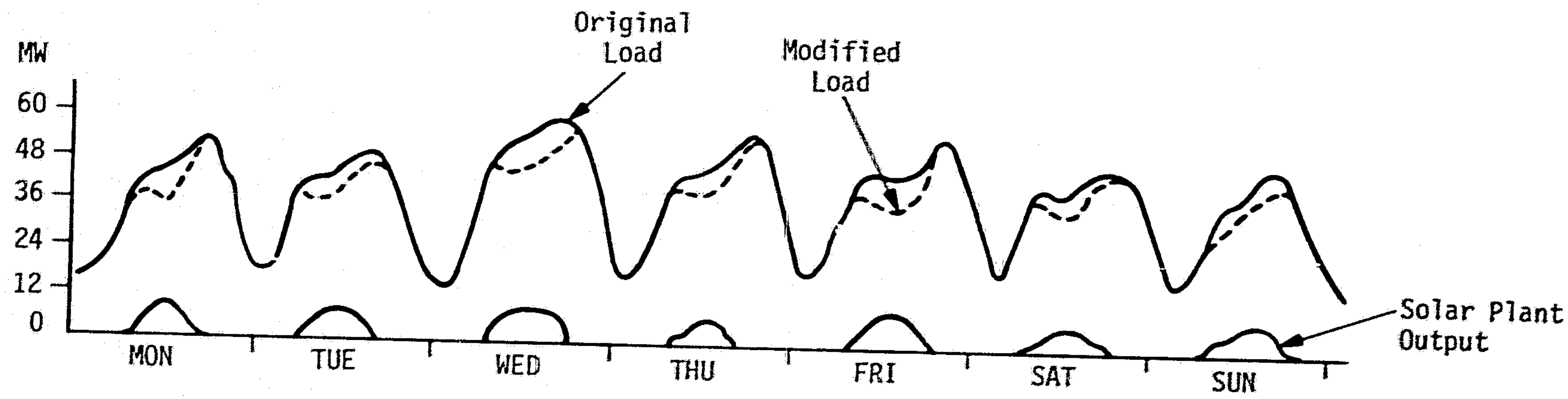
Table 1. Determining the Load Duration Curve

Number of Points in Load Shape		
5 Points	10 Points	20 Points
% of Time	% of Time	% of Time
Load is ≥ 1 X 60/5 = 12	Load is ≥ 1 X 60/10 = 6	Load is ≥ 1 X 60/20 = 3
2 X 60/5 = 24	2 X 60/10 = 12	2 X 60/20 = 6
3 X 60/5 = 36	3 X 60/10 = 18	3 X 60/20 = 9
4 X 60/5 = 48	⋮	⋮
5 X 60/5 = 60 MW	10 X 60/10 = 60 MW	20 X 60/20 = 60 MW

Thus, if there are 5 load shape points, the load interval will be 12 MW; 10 load shape points gives a 6 MW interval, and so on. It should be noted that the cost of ELECTRA runs increases almost exponentially as the number of points in the load shape goes above 40.

Frequency curves are also formed from the original and modified load curves. The frequency curve is determined by the number of times the load rises across a given MW level in time period T, normalized by the number of hours in T. The given MW levels are the same as those chosen for the load duration curve.

A. Time-Dependent Load Curves



B. Load Duration Curves

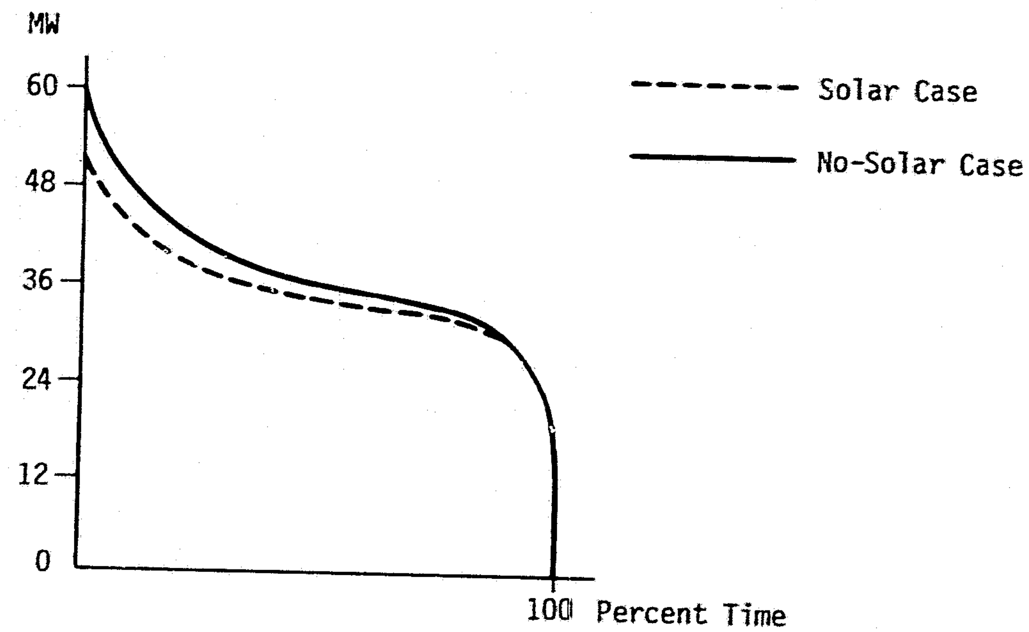


Figure 3. Transformation of Load Curves

Up to 52 frequency and load duration curves may be formed from the original load curve, e.g., given a year's worth of hourly load data, the user can model each week of that year separately (or each month or season). The number of curves desired and the number of hours in each must be specified by the user.

The reliability of the utility system is estimated by adjusting the load duration curve to account for possible plant failures. The adjusted LDC's are called equivalent load duration curves. These curves are actually calculated in SYSGEN, but their description here is a logical extension of the discussion of the load duration curve.

If a generating unit may be loaded incrementally (i.e., if it has valve points), then the unit may be treated as either a single increment or as multiple increments in the calculation of the equivalent load duration curve. If the former is chosen, then the unit is either all on or all off; if the latter is chosen, then partial outages may be modeled.

Figure 4 illustrates the simpler case of treating the unit as a single increment. Suppose two plants are being loaded. There is some probability that the first plant will fail and the second plant will be faced with the entire original load curve. If the first plant does not fail, then the second plant will be faced with the original load minus the capacity of the first plant. The equivalent load duration curve when the second plant is loaded is the sum of the curves weighted by their respective probabilities.

The equivalent LDC in Figure 4 was derived as follows. The first plant to be loaded has a capacity of 5 MW. Let S_1 be the state in which the 5 MW unit does not fail, and S_2 be the state in which the 5 MW unit does fail. The probability of S_1 occurring is 0.9; the probability of S_2 occurring is 0.1. From the figure it can be seen that a load level of 20 MW occurs 0% of the time in S_1, but in S_2 it occurs 50% of the time. Then the weighted

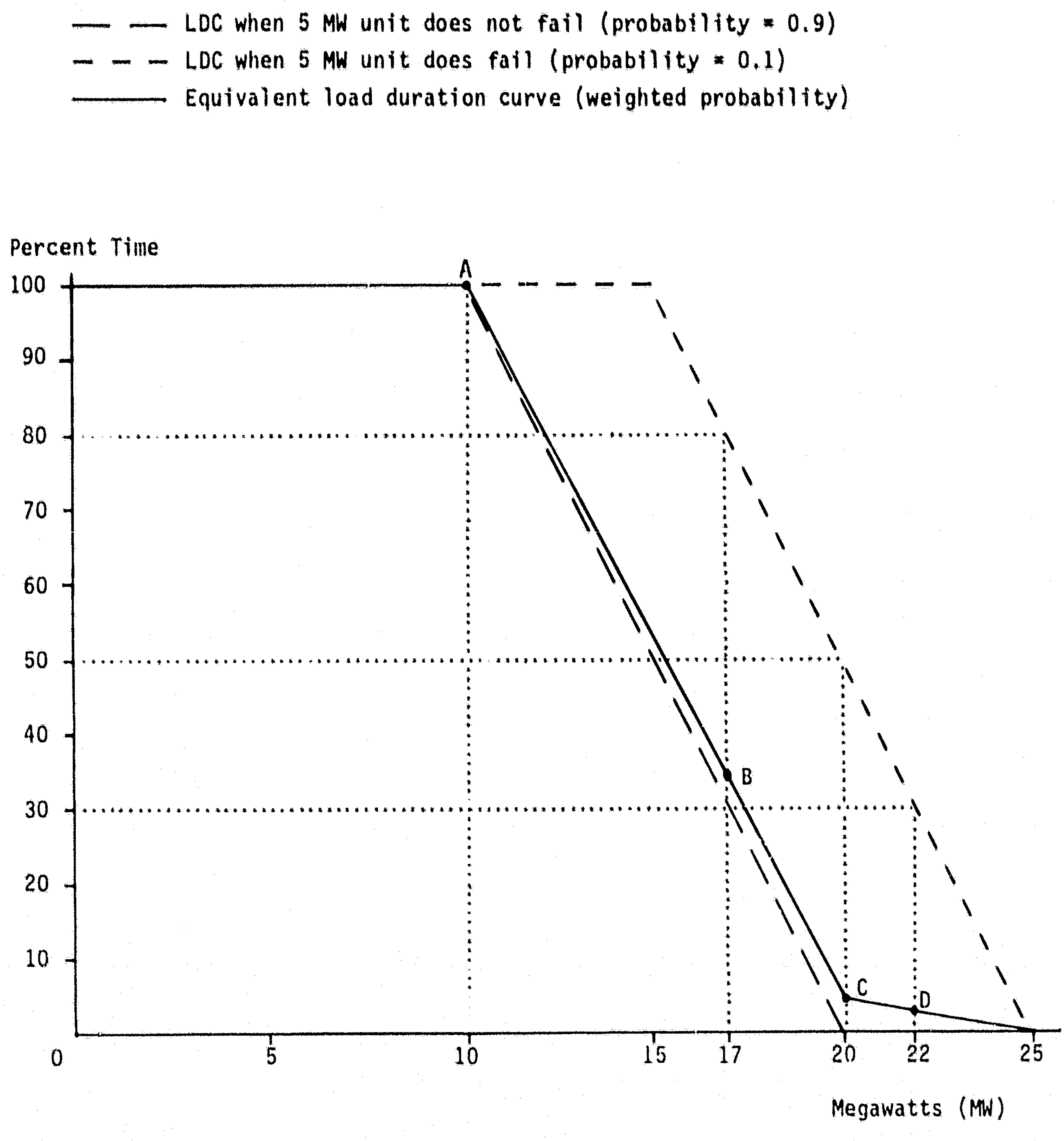


Figure 4. Equivalent Load Duration Curve

probability that a load of 20 MW occurs is: 0.9 (0%) + 0.1 (50%) = 5%. This is point C on the graph. A load of 10 MW occurs 100% of the time in both S_1 and S_2, so the weighted probability is 0.9 (100%) + 0.1 (100%) = 100%, giving us point A. The weighted probabilities of 17 and 22 MW loads were derived in the same fashion: For point B, we have 0.9 (30%) + 0.1 (80%) = 35%, and for point D it is 0.9 (0%) + 0.1 (30%) = 3%.

B. TIME PARAMETERS

SYSGEN's time parameters may be set to model many different situations. There are three basic units to specify: the number of periods, subperiods in a period, and weeks in a subperiod. A period is usually interpreted as a year, and a subperiod may represent a week, a month, or any fraction of a year. The time units to be specified are as follows:

NUMBER OF PERIODS	An integer value; $1 \leq P \leq 34$.
"HOURS" IN A TIME PERIOD	Each time period will have the same number of "hours"; this need not be an integer value; $1 \leq H \leq 8{,}784$.
SUBPERIODS	An integer value; $1 \leq SP \leq 52$. Each period will have the same number of subperiods.
"WEEKS"	An integer value; $1 \leq W \leq 99$. The number of "weeks" per subperiod <u>may be varied</u>.
"HOURS" IN A "WEEK"	Each "week" will have the same number of "hours"; this need not be an integer value.

To illustrate this, consider the following three examples:

1) a) number of periods = 10 (10 years)
   b) "hours" in a period = 8736 (24 hours x 364 days)
   c) number of subperiods = 4 (seasons)
   d) number of "weeks" in subperiod 1 = 5 (winter months)
      number of "weeks" in subperiod 2 = 2 (spring months)
      number of "weeks" in subperiod 3 = 3 (summer months)
      number of "weeks" in subperiod 4 = 2 (fall months)
   e) "hours" per "week" = 720 (24 hours x 30 days)

   NOTE THAT THE "WEEK" VARIABLE EQUALS A MONTH IN EXAMPLE 1

2) a) number of periods = 5 (5 years)
   b) "hours" in a period = 2,920 (data is measured at 3-hour intervals for 365 days)
   c) number of subperiods = 2 (winter and summer)
   d) number of "weeks" in subperiod 1 = 20 (20 "weeks" in winter)
      number of "weeks" in subperiod 2 = 32 (32 summer weeks)
   e) "hours" in a "week" = 56 (data measured at 3-hour intervals for one week)

3) a) number of periods = 12 (12 months)
   b) "hours" in a period = 672 (hours per 4-week month)
   c) number of subperiods = 4 (4 weeks per month)
   d) "weeks" in each subperiod = 7 (7 days per week)
   e) "hours" per "week" = 24 (24 hours per day)

These examples should show that practically any time frame may be used, as long as the variable values are internally consistent. Example 2 illustrates that the "hour" variable must correspond to the time value of the original load data: In this instance, one "hour" equals three hours. In examples 1 and 3, the "week" variable is equivalent to a month and a day, respectively. Please note that the assigned values of the "hour" and "week" variables will be used throughout the program. For example, a later input to the program is "the number of weeks per subperiod a generating plant is down for maintenance." Then if the "week" variable is one day and the unit will be down for 7 days, the "number of weeks per subperiod for maintenance" will be 7. Other variables which are input in "weekly" values are the weekly energy capacity of storage and hydro units and the installment and retirement weeks of generating units.

SECTION III

SYSGEN

The objective of this program is to find an operating schedule which minimizes production costs, and to estimate the frequency, duration, and probability of loss of load for a given mix of generation units and a given customer demand. The program uses a modified Booth-Baleriaux technique which treats plant outages as randomly occurring loads on other plants in the utility system.*

The input data required for SYSGEN are divided into the following sections:

A. Economic parameters

B. Program operation options (input options)

C. Transmission and distribution losses

D. Generating class data

E. Generating unit data

F. Loading order

G. Report options and outputs from SYSGEN

---

* This methodology is described in S. Finger, "Electric Power System Production Costing and Reliability Analysis Including Hydro-electric, Storage, and Time Dependent Power Plants," MIT Energy Lab Technical Report #MIT-EL-79-006, February 1979, and in D. H. Ebbeler, "Electric Power Generation Systems Probabilistic Production Costing and Reliability Analysis," (JPL working paper), April 1981.

A. ECONOMIC PARAMETERS

The production costs in each time period may be reported either as nominal or present values. The economic parameters used by SYSGEN are 1) the overall inflation rate, 2) the real discount rate, and 3) the nominal escalation rates for fuel and operations and maintenance (O&M) costs.* These values are entered as fractions, so a 10% discount rate is input as "0.10." The inflation and discount rates are assumed to be constant throughout the simulation. The escalation rates, however, may vary by time period. All rates are assumed to correspond to the designated time period length and are constant over the subperiods.

Escalation rates may be varied by generation class type, but not by individual plants. These input data are thus entered with the generating class data rather than with the other economic parameter data.

All input costs, such as fuel and cost per start-up, should be input in the same year's nominal dollars. The user may choose in what year's dollars the production costs will be reported. If present worth values are not desired, the user must set the discount rate to zero.

It is important to note that if the year the input costs are in is before the year the simulation is started, then all costs will be adjusted to start year nominal dollars using the general inflation rate, not the product-specific escalation rate. The easiest way to avoid confusion here is to input the costs in the start year's nominal dollars.

The following formulas are used to calculate the present worth factor and the escalation factors for fuel and O&M costs.

---

* An escalation rate is basically a product-specific inflation rate, e.g., a rise in fuel costs alone is designated by an escalation rate which, these days, is higher than the general inflation rate.

Let T = current time period

I = generating class

DR = discount rate

CPI = consumer price index

$ER_{OM}(I,T)$ = escalation rate for O&M costs for class I in time period T

$ER_F(I,T)$ = escalation rate for fuel costs for class I in time period T

CONVRT = conversion factor from input year nominal dollars to report year nominal dollars

C_{IN} = cost in the input year nominal dollars

PWF_T = present worth factor in time period T
$= (1 + DR)^{-T}$

then

$ESCOM_T\ (I)$ = escalation factor for O&M for class I at time period T

$$= \prod_{t=1}^{T} \left[1 + ER_{OM}\ (i,t)\right]$$

$ESCF_T\ (I)$ = escalation factor for fuel for class I at time period T

$$= \prod_{t=1}^{T} \left[1 + ER_F\ (i,t)\right]$$

and

C_T = present value in report year dollars of a cost incurred in time period T of the study

$$= C_{IN} \cdot \frac{CONVRT}{(1 + CPI)^T} \cdot ESC_T\ (I)\ /\ PWF_T$$

$$\text{where } ESC\ (I) = \begin{cases} ESCOM_T\ (I) \text{ for an O\&M cost} \\ ESCF_T(I) \text{ for a fuel cost} \end{cases}$$

B. INPUT OPTIONS

SYSGEN has a set of logical variables that can be used to control the level of detail in the simulation. These options will supersede any input parameters. For example, if the spinning reserve option is set to false and the spinning reserve requirement is set to 200 MW, no spinning reserve will be used in the simulation.

Not all of SYSGEN's input options are explained in this section. The options on hydro and storage dispatch, time-dependent plants, and loading order are explained in later sections as appropriate.

1. Spinning Reserve Option: MSPIN

The spinning reserve algorithm is implemented after the economic loading order is set up. The loading order is modified, if necessary, to meet the input spinning reserve requirement. Three variables are needed to specify spinning reserve:

1) The required reserve, stated in one of the following three ways:
   a) as a percent of peak load
   b) as an absolute MW value
   c) as a fraction of the largest unit on line.
2) The maximum percent of any unit to be credited to spinning reserve.
3) The maximum number of units to be displaced in the economic loading order to meet spinning reserve.

In reality, no utility ever loads its plants as SYSGEN does, i.e., starting cold with no energy generated and having to bring base units on-line. In a real utility, the base units are always running and the amount of capacity on spinning reserve is relatively constant. But as a computer model, SYSGEN does not see a unit as available for spinning reserve until it is partially loaded.

Thus, SYSGEN calculates the available reserves as the remaining capacity of units that have been partially loaded, up to the maximum percent of the unit specified in (2) above.* The following scenario should serve to illustrate this.

Suppose the loading will be started with two coal plants having capacities of 400 and 600 MW. Each coal plant has five loading increments, as follows.

Unit	Incremental Capacity	Unit	Incremental Capacity
Coal 400	100	Coal 600	150
	60		90
	80		120
	80		120
	80		120

The spinning reserve has been set to 300 MW. A maximum of 50% of any unit may be credited to spinning reserve. Further, assume that the economic loading order is to load all of the 600 MW unit and then the 400 MW unit. It can be seen, however, that if all of the 600 MW plant is loaded before the 400 MW plant, the available reserve will be less than 300 MW for some period of time. SYSGEN therefore will load the first two increments of the 600 MW unit, then load the first increment of the 400 MW unit. The "load/not load" decisions made by SYSGEN for the first few increments are shown in the table below. Note that the available reserve is not allowed to fall below 300 MW and that no more than 50% of a unit is ever credited to spinning reserve.

* This method of calculating the available spinning reserves is valid in the deterministic case, but it may not be appropriate when plants are modeled probabilistically since a zero forced outage rate is implicitly assumed for the plant when it is on spinning reserve.

Table 2. The Effect of a Spinning Reserve Requirement on Loading Order

Unit	Increment Number	Increment Capacity	Reserves Available	System Capacity	Load Decision
600	1	150	300	150	Yes
600	2	90	300	240	Yes
600	3	120	240		No
400	1	100	500	340	Yes
600	3	120	440	460	Yes
600	4	120	320	580	Yes
600	5	120	200		No
400	2	60	320	640	Yes

The loading order option (LORDOP, explained on p. 39) will supersede the spinning reserve requirement. For example, suppose the loading order option chosen required that all base units are loaded before any intermediate, and all intermediate units are loaded before any peak units. Then no intermediate units can be brought up to satisfy the spinning reserve requirement if not all base units have been loaded, no matter what value of spinning reserve is input.

2. Multiple Increment Option: MULT

MULT controls the multiple increment loading algorithms. If MULT is set to false, units are modeled as on/off variables (i.e., as a single increment). The single increment characteristics can be input or, if left blank, will be computed from the data for multiple increments. Note that if MULT is set to false, then MSPIN is automatically set to false by the program because of the method used to calculate spinning reserve.

3. Frequency Curves Option: MFREQ

MFREQ controls the frequency and duration algorithms. If MFREQ is set to false, no frequency curves are read in, and no frequency calculations, such as the expected number of startups, are made.

SYSGEN uses the average duration of each load level in calculating the amount of capacity available for spinning reserve. If MFREQ is set to false, but the spinning reserve option, MSPIN, is set to true, then the frequency of every load level will automatically be set to 1/number of "hours" in a day. This is a modification of the original MIT SYSGEN program. If MFREQ is false in the MIT version, then the frequency of every load level is assumed to be one.

C. TRANSMISSION AND DISTRIBUTION (T&D) LOSSES

T&D losses may be simulated for both conventional and time-dependent plants. Conventional plant losses are accounted for by dividing the energy output by a penalty factor specified by the user. Thus, a penalty factor of 1.0 will mean there are no T&D losses for that plant. (Note that the penalty factor cannot be less than 1.0.)

Time-dependent plant losses are modeled as decreases in the load reduction curves. The marginal losses in MW at up to ten load levels may be specified. The load levels are given as percentages of peak demand, and the intervals between demand levels do not have to be equal. Linear interpolation is used to find the intermediate losses.

D. GENERATING CLASS DATA

Each plant in SYSGEN must be assigned to a generating class, such as a hydro, diesel, or storage class. The input variables which are specified by class type are the cost escalation rates, the forced outage multipliers (explained below), and the generation type, i.e., base, intermediate, or peaking generation. Up to 34 class types may be created.

Hydro, storage, and time-dependent plants must be assigned to pre-specified SYSGEN class types:

1) All hydro plants must be assigned to class type "HYDO" when using FEPS, and to "CHY" when card input is used.
2) All storage plants must be assigned to class type "STOR" when using FEPS, and to "STO" when using cards.
3) All time-dependent plants must be assigned to class type "LDRD" (short for "load reduction") when using FEPS, and to "TDP" when using cards.

If these plants are not assigned to the proper classes, then SYSGEN will treat them as conventional units.

The forced outage rate of a plant is the percent of time the plant breaks down and is not operating (sometimes called "unscheduled maintenance"). A forced outage rate is input for each plant in the simulation. A variable called the "forced outage multiplier" may be used to increase a plant's forced outage rate during specific time periods. This multiplier would be used, for example, to account for variations in the reliability of a newly installed plant.

The forced outage multiplier is used as follows:

Let FOR_j = input forced outage rate for unit j.

$IFOR_{ij}$ = forced outage multipler for unit j in year i.

then F_{ij} = $FOR_j \times IFOR_{ij}$ = forced outage rate for unit j in year i used in SYSGEN calculations of LOLP.

Two things should be noted here. The first is that forced outage multipliers are assigned by generating class, not by plant. Thus, if you only want to vary the failure of one plant, you must create a new class for it. The second point is that SYSGEN includes the time a plant is out on scheduled maintenance in the calculation of the plant's effective capacity.* Thus, forced outage multipliers should not be used to account for time that the plant is down on scheduled maintenance.

The escalation rates and forced outage multipliers are entered in the form of "tables" (vectors, actually) with rates assigned by class type for one or more periods in the simulation. A maximum of 10 escalation and 10 outage tables for 10 periods (values) each may be specified. An example may be of use.

Suppose a simulation runs for three periods and has two plant classes: steam turbine and gas turbine. If the fuel and O&M costs for these classes all escalate at different rates, four escalation tables must be input. These might be

Class Type	One	Period Two	Three	Table Number
Steam Turbine				
Fuel	0.06	0.07	0.08	1
O&M	0.05	0.05	0.06	2
Gas Turbine				
Fuel	0.08	0.10	0.11	3
O&M	0.06	0.07	0.07	4

* The effective capacity of a plant is defined as the capacity that a 100%-reliable plant would have to have in order to generate an equal amount of power over the time period.

On the other hand, O&M costs for both classes might increase at the same rate. Then only three tables need be specified:

Class Type	Period One	Period Two	Period Three	Table Number
Steam Turbine Fuel	0.06	0.07	0.08	1
Gas Turbine Fuel	0.08	0.10	0.11	2
O&M	0.05	0.06	0.04	3

If the number of escalation values entered is less than the number of time periods in the study, the last value entered is assumed to hold true for the remaining time periods. Thus, if an escalation rate will be constant in the study, that value need only be entered once in the first time period.

Note that the same escalation rate table may be assigned to any number of classes and for either fuel or O&M costs.

The forced outage multipliers are set up in the same way, with one exception. If a value in the multiplier table for a given period is set to zero or left blank, the forced outage rate for plants in that class and time period will be calculated as zero (as can be seen from the equation on page 28: $F_{ij} = IFOR_{ij} \times FOR_j = 0$ if $IFOR_{ij}$ is 0). If the forced outage rate will not be altered for a class, a value of "1.0" should be entered in the multiplier table. Once a value of 1.0 has been found in that table, all subsequent periods in that table are assumed to have the value 1.0 unless other values are explicitly entered. Consider the following three multiplier tables:

Table	Period 1	Period 2	Period 3	Period 4
1	1.2	1.1	-	-
2	1.2	1.1	1.0	-
3	1.0	-	-	-

With Table 1, the forced outage rates calculated will be higher than originally set in time periods 1 and 2, but in time periods 3 and 4 the rates will be zero (thus simulating a totally reliable unit). Table 2 will cause the program to apply the original forced outage rate in time periods 3 and 4, with higher rates in the first two periods. If Table 3 is assigned to a class, no forced outage multiplier will be used, so the original forced outage rate is applied in all four time periods.

In summary, the generation class data required is

1) Number of generation classes in the mix (e.g., 2 nuclear plants, 4 coal fired, and 3 gas turbines = 3 generating classes)

2) Class name of each (e.g., COAL, HYDO)

3) Whether the class is base, intermediate, or peaking generation

4) Cost escalation tables for fuel and O&M

5) Forced outage multiplier tables

E. GENERATING UNITS

There are three special types of generating units in SYSGEN: hydro, storage, and time-dependent plants. All other generating plants are called conventional units.

The following list is a summary of the input data required for all types of generating units. Hydro, storage, and time-dependent plants require additional inputs which are explained at the end of this section.

1) The generation class to which the unit belongs
2) Incremental loading data, if relevant
3) Installment year and week (e.g., a unit installed on February 2, 1979, would be year = 1979, week = 5, if real weeks are used)
4) Retirement year and week (e.g., a unit retired on December 1, 1980, would be year = 1980, week = 48, as above)
5) Fuel cost for the unit ($/MBtu)
6) Variable O&M cost ($/MWh)
7) Cost per startup ($/startup)
8) Cost per MWh to keep unit as spinning reserve without generating power ($/MWh)
9) Mean time to repair after failure (hours)
10) Penalty factor, used to account for unit-specific transmission losses
11) Preventive maintenance data for each unit. It is important to note that the maintenance cycle is referenced to the installation date of the unit, not the start of the simulation.

It is assumed that maintenance is cyclically scheduled, and the cycle may be from one to ten periods long. Within each cycle, the subperiods during which maintenance is performed and the number of weeks in those subperiods the unit is unavailable due to maintenance must be specified. The number of weeks is an integer value which may vary by subperiod. If a plant is out more than one subperiod in a row, this must be entered explicitly.

Example: Simulation is started on January 1, 1988, and the unit is installed January 1, 1989. It is being put on a two-year maintenance cycle, with the following schedule:

June 20, 1989	1 week
December 10, 1989	2 weeks
June 15, 1990	2 weeks
December 11, 1990	3 weeks

Period length = 1 year, 12 subperiods (months) per period. Then cycle length = 2 and

	Subperiod	Weeks
Period 1:	6	1
	12	2
Period 2:	6	2
	12	3

12) Capacity, heat rate (MBtu/MWh), and forced outage rate (average for the plant and for each loading incrcment of the plant, if applicable)

For example, a 400 MW plant with four loading increments might have the following characteristics:

Increment	Cumulative Capacity	Heat Rate (MBtu/MWh)	Forced Outage Rate
1	80	16.9	0.03
2	160	12.2	0.0194
3	280	11.8	0.019
4	400	12.0	0.0279

The forced outage rate is actually a conditional probability. Each increment has an independent probability of failing, but increments must be loaded sequentially. Thus, the forced outage rate of increment i is the conditional probability that all increments before i have been loaded and increment i cannot be loaded. In the example above, each increment had the following independent probabilities of being loaded:

Increment	Probability of Failure	Probability of Success
1	0.03	0.97
2	0.02	0.98
3	0.02	0.98
4	0.03	0.97

The probability that cumulative capacity equals zero is simply the probability that the first increment fails, so the forced outage rate for the first increment is 0.03. In order for cumulative capacity to be exactly 80 MW, the first increment must be loaded and the second increment must fail. Then the forced outage rate for the second increment is (0.97)(0.02) = 0.0194, and so on.

In practice, the incremental probabilities are not available. The forced outage rates given are usually a total outage rate for the plant. In the example above, the total forced outage rate is 0.0963 (i.e., the plant will be be generating at full capacity 90.37% of the time). This total outage rate may be obtained two ways: 1) It is the sum of the incremental forced outage rates, or 2) it is one minus the product of the independent success probabilities.

1. Hydro Units

The only additional data required for a hydro unit is the "weekly" size of the hydro reservoir in each subperiod, expressed in megawatt hours.

Hydro power can be dispatched in two different ways. The first is to delay loading until the hydro unit can generate all its energy at full capacity. This delay is determined by the equivalent demand curve: The hydro unit will not be loaded until the remaining demand for energy is less than the available hydro energy. The second dispatch strategy is to simply load all hydro units first at a reduced capacity to generate all of their energy. If the input option MDLAY is set to true, then the first hydro dispatch is used. If MDLAY is set to false, then the hydro units will be loaded first as base generation, even if the hydro units are classed as peak or intermediate generators.

The first strategy is expected to give a more cost efficient use of the hydro energy than the second strategy, since more energy is removed from the peak when the hydro dispatch is delayed.*

A second dispatch option, MOVE, allows SYSGEN to interrupt the loading

* The first strategy is optimal in deterministic production costing, but may not be optimal for probabilistic production costing. See D. H. Ebbeler, "Electric Power Generation Systems Probabilistic Production Costing and Reliability Analysis," (JPL working paper), April 1981, and G. Fox, "A Stochastic Formulation of Electric Generation System Reliability Measures," (JPL working paper), January 1981.

of a conventional unit and back it off until the total energy demand exactly equals the hydro energy available. If MOVE is not true, then hydro units may only be loaded after increments of conventional plants have been fully loaded.

Purchased power can be modeled in SYSGEN as a hydro plant. The only difference is that the fuel cost in \$/MBtu should be set to the purchase price in \$/MWh, and the "heat rate" of the plant is set to 1.0.

2. Storage Units

Two distinct steps are involved in modeling storage units: charging the units with excess energy and then dispatching the stored energy. The following data are required for each storage unit:

1) The charging capacity, in megawatts
2) The forced outage rate for the charging cycle
3) The overall efficiency of the storage and generation process, measured by the product of the charging and discharging efficiencies (or equivalently, energy available from storage/energy generated to charge storage)
4) The reservoir size in megawatt hours available from storage in a "week." This value should be the most energy available from storage to meet demand when charging and discharging efficiencies are taken into account.

The input option MSTOR determines how storage is handled. If MSTOR is set to true, then the amount of energy stored is determined by the expected excess energy available from base units, expected storage plant failures, and the expected cost of the stored energy. If there is more than one storage unit, then they are ranked so that the largest ones are filled first. It should be pointed out that these storage algorithms are not optimal. The program assumes that the storage units will be filled, and then asks when they should be loaded, missing the question of how much energy should actually be stored, based on the marginal cost of adding energy to storage.

If MSTOR is set to false, then the energy available from storage is taken as the input storage size. The marginal cost of storage is similarly set to the average cost of base loaded energy.

The input options MDLAY and MOVE also control the dispatch of stored energy. As with the hydro dispatch, if MDLAY is false, then storage units are loaded at reduced capacity with conventional units by their marginal cost.* If MDLAY is true, then loading is delayed until all the stored energy can be discharged at full capacity. The MOVE option controls the storage dispatch exactly the same as HYDRO dispatch.

3. Time-Dependent Units

As stated previously, time-dependent generation is modeled as a reduction in the net load on the utility system. The plant itself is not modeled by SYSGEN, so no costs or energy generated are calculated by the program. In other words, SYSGEN treats the actual time-dependent plants and their output as exogenous inputs to the system.

The user can simulate increasing penetration levels by having SYSGEN multiply any given load reduction curve by integer values up to 99. For example, suppose a load reduction curve is the simulated output of a one-MWe solar plant, and the user wishes to simulate a system of 5 one-MWe plants. The user may specify that five time-dependent units are to be simulated, and the program will multiply the input load reduction curve by five.

SYSGEN is set up to run a base case using the original load curves, and then one or more solar cases using the modified load curves. Each set of

* See D. H. Ebbeler, "Electric Power Generation Systems Probabilistic Production Costing and Reliability Analysis," (JPL working paper), April 1981, for the appropriateness of interpreting this calculated cost as a marginal cost and for using that cost in both the hydro and storage dispatch algorithms.

cases can contain up to four load reduction curves, and there can be a total of twenty cases run at one time. The input data for time-dependent units are:

1) Total number of cases to be run. A base and one solar case would be a total of two cases, one base and two solar cases would be three cases, and so on.

2) The number of load reduction curves to be included in each case must be specified. The base case would normally use zero load reduction curves and a solar case would use from one to four reduction curves.

3) Each load reduction curve corresponds to one type or size of time-dependent unit. But as explained above, specifying more than one time-dependent unit will cause these curves to be increased appropriately. The user must input the number of units to go with each load reduction curve.

As an example of how this case structure may be used, suppose one wants to set up solar plants at two sites and there are three from which to choose. We can find the two that are the most complementary by running case sets on the three possible combinations of sites. Three load reduction curves, one for each site, would be generated by the appropriate solar plant simulation. SYSGEN would produce four cases: the base case without the solar output and one case for each site combination. Each solar case would include two load reduction curves. The best combination of sites would be the case with the highest fuel and/or capacity credit.

The input option MLRED (described on p. 38) is used to specify whether time-dependent units will be simulated. MLRED should be set to true if any load reduction curves will be used.

The following is a summary of the input options used to control hydro, storage, and time-dependent units.

4. Hydro and Storage Dispatch Options: MDLAY, MOVE

MDLAY controls the hydro and storage dispatch strategy. If MDLAY is set to false, then reservoir hydro units are always loaded first, at reduced capacity to generate all their energy. Storage units are loaded as soon as their marginal costs put them in the loading order.* If MDLAY is set to true, then hydro and storage units are delayed until they can generate all their energy at full capacity.

MOVE also controls the hydro and dispatch strategy. If MOVE is set to false, limited energy plants are loaded only at valve points of other units. That is, tests are made on the viability of bringing up a storage or hydro plant only after the previous increment has been completely loaded. If MOVE is true, then it is possible to split increments and load the hydro or storage unit at points other than the valve points of other units. Setting MOVE to true will result in more efficient use of hydro and storage energy, but the running time will be longer. If MDLAY is set to false, MOVE is automatically set to false.

5. Storage Cost Option: MSTOR

MSTOR controls the storage programs. If MSTOR is set to false, then the marginal cost of storage is set to the average cost of base loaded energy. The expected energy available is taken from the input reservoir size. An approximation of base load energy supplied is made on the basis of excess base load energy available, disregarding capacity constraints. If MSTOR is true, then the storage algorithms are implemented. The dispatch of the storage is controlled in either case by MDLAY and MOVE.

6. Load Reduction Option: MLRED

MLRED is used to determine if any load reduction curves will be used in the simulation. If MLRED is set to false, then no cases with time-dependent units will be run.

* Again, see D. H. Ebbeler, "Electric Power Generation Systems Probabilistic Production Costing and Reliability Analysis," (JPL working paper), April 1981, for the appropriateness of the non-delay option (i.e., setting MDLAY to false).

F. LOADING ORDER

SYSGEN will load units in order of increasing marginal cost, subject to the following constraints: 1) valve points of a unit must be loaded in order (the third valve point cannot be loaded until the first two have been loaded); 2) hydro and storage units will be interpolated where they can discharge all their energy to minimize costs, subject to two of the input options discussed previously, MDLAY and MOVE; and 3) the order may be modified to meet spinning reserve requirements, subject to the input option MSPIN. A modification due to the spinning reserve requirement is illustrated in the following example.

Suppose three coal plants called A, B, and C are being loaded. If the economic loading order is A, B, C, but the summed capacity of A and B did not meet the spinning reserve requirement, and the summed capacity of A and C did, then C would be loaded with or before B. The user may specify how far into the economic loading order the program may search to find a unit to meet spinning reserve (e.g., one unit down the line, two units, all units, etc.). There are two loading order options. The first option, LORDOP, is used to specify the loading order at the <u>group</u> level (i.e., base, intermediate, or peak), and the second, MLORD, is used to specify the entire loading order by unit or valve point.

1. Loading Option One: LORDOP

LORDOP is the only input option that is not a true/false input. This option will sort plants by marginal cost within groups, where the user specifies the order of the groups. For example, one may want all base units loaded, followed by intermediate and then peak. Or base and intermediate units can be sorted together, followed by peak. This is indicated by a three-digit number, XYZ, where: X position = base group

Y position = intermediate group

Z position = peak group $(1 \leq X, Y, Z \leq 3)$

and the values of X, Y, and Z determine when the group will be loaded.

For example,

XYZ = 123: base, intermediate, and peak units are sorted separately. All base units are loaded before any intermediate units, and all intermediate units are loaded before peak units.

XYZ = 112: base and intermediate units are sorted together and loaded before peak units.

XYZ = 321: base, intermediate and peak units are sorted separately. All peak units are loaded first, then all intermediate units, then the base units.

(Default Option: XYZ = 111)

2. Loading Option Two: MLORD

MLORD controls the loading order computation. If MLORD is set to false, the user determines the entire loading order instead of having it computed by the program. Only one loading order may be specified, and it is assumed to be the same for all time periods. If a plant is unavailable because it is on maintenance, retired, or not yet installed, then it is automatically skipped in the loading stack. The capacity of hydro plants and storage plants are adjusted so that they discharge as much energy as possible at their designated loading point. If MLORD is false and MSPIN is true, SYSGEN will compute the cost of keeping the necessary units on spinning reserve, but it will not change the loading order. If the units being loaded have valve points, the units may be partially loaded. For example, with two 5-valve point units, the first three valve points of unit A can be loaded, then the first two from B, then one from A, and so on. The only constraint is that in order to load the j^{th} valve point of a unit, all previous valve points must be loaded first.

G. OUTPUTS FROM SYSGEN

SYSGEN has seven report modules, described below. The user can control which modules are printed with the five report options explained at the end of this section.

1. Initial Plant and System Report

This is an echo print of the input data. (See pages A-1 to A-10 of the sample output file in Appendix A.)

2. Sorted Limited Energy Plant Report

The sorted limited energy plant report writes out conventional hydro and storage information showing the order in which they are considered for loading.

Variables in report:

Hydro/Storage load number (ID)	=	units' position in the loading stack, e.g., if STORAGE ID = 2, then that unit will be loaded only after the storage unit with ID = 1 has been loaded, if unit 1 is available.
Unit index	=	the unit's identifying number.
Hours per time period	=	the number of hours that the unit can generate at full capacity. (This is the reservoir size divided by the unit's capacity.) The hydro arrays are sorted by this number from greatest hours to smallest.
MWhs per time period	=	reservoir size of the unit.

3. Probability Curve Report

This report writes out information for the equivalent load demand curve. All values (except the area) are in MWs for the curve. (See, for example, page A-13 of the sample output file.)

Variables in report:

Load curve spacing	=	number of MWs between each array point on the curve printed beneath.
Minimum demand	=	minimum customer demand.

Maximum demand	=	maximum equivalent demand. For the initial demand curve, this is the peak demand. For the final demand curve, this is the peak demand plus installed capacity.
Equivalent demand area	=	area under the probability curve. For the initial demand curve, this is the energy demand on the system. For all other curves, this value does not have physical significance.
Demand curve	=	equivalent demand probability curve. These values are the probability that the equivalent demand will be greater than or equal to each demand level in the load duration curve. The first value on the curve is the probability that the demand is greater than one load curve spacing; the last value is the probability that the equivalent demand is greater than the maximum original demand.

4. <u>Plant Report</u>

The plant report gives the information on each unit after it is loaded. (See page A-11 in the sample output.)

<u>Variables in report</u>:

Unit index	=	input order of the unit (internal identification number).
Unit name	=	user identification for the unit.
Unit type	=	class name and loading type, e.g., coal, base.
Unit valve point	=	valve point of the unit currently being loaded.
MW added	=	capacity loaded in this step (MW).
Expected start-ups	=	expected number of times the unit is started up. Reported only for the first valve point.
Added expected energy	=	energy (MWh) expected to be generated by the current valve point to meet customer demand.

Fuel cost	=	present worth of the expected fuel cost in the time period for the current valve point (thousand $).
O&M cost	=	present worth of the expected O&M cost in the time period for the current valve point (thousand $).
Expected start-up cost	=	present worth of the expected cost of starting up the unit. Calculated only for the first valve point (thousand $).
Spinning reserve cost	=	present worth of cost of using the unit for spinning reserve. Reported with the values for the last valve point (thousand $).
Total cost	=	sum of fuel, O&M, start-up and spinning reserve costs (thousand $).
Total capacity factor	=	unit capacity factor. Capacity factor = total energy generated divided by the product of the MWs loaded and the number of hours in the time period.
Energy used for storage	=	energy generated for storage by the current valve point (MWh).
Capacity factor after storage	=	total capacity factor for a base loaded plant that is used for storage.

5. Subperiod Report

The system summary report prints out data on the system in each subperiod after all units have been loaded. (See page A-12 of the sample output file.) The first page of the summary report gives the total energy generated and total costs for each unit in a format similar to the plant report described above. In addition, the total system costs for the subperiod and the effective capacity of each unit are printed. The effective capacity of a unit is defined as the capacity of a 100%-reliable unit which would generate an equivalent amount of expected energy. If the input option MSTOR is true, a report on storage losses is written.

6. System Report

The system report prints the following variables for either a subperiod or for a time period (see page A-14 of the output):

Peak demand	=	peak customer demand (MW).
Customer energy demand	=	original customer energy demand (MWh).
Load factor	=	energy generated/(peak demand x hours).
Unserved energy demand	=	expected energy demand which cannot be met by the installed capacity (MWh).
Percent energy unserved	=	percent of original customer demand that cannot be met.
Loss-of-load probability	=	probability that the customer demand cannot be met or, equivalently, the percent of time customer demand cannot be met.
Magnitude of loss of load	=	expected magnitude of each loss of load (MW).
Frequency of loss of load	=	number of times in the subperiod or period that the load cannot be met.
Duration of loss of load	=	average duration of each loss of load.
Total expected energy generated	=	sum of the expected energy generated by each unit (MWh).
Fuel cost	=	total system expected fuel cost (million $).
O&M cost	=	total system expected O&M cost (million $).
Total cost	=	total system expected cost including fuel, O&M, start-up, and spinning reserve costs (million $).
GBtu consumed	=	expected input energy consumed by each class, reported only at the end of the time period (10^9 Btu).

7. Grid File

This file is generated by SYSGEN to be used as an input to SCYLLA. SCYLLA computes the worth of time-dependent units to the system using a static economic analysis. The following data are compiled for each subperiod:

Record	Description
1	load curve spacing loss of load frequency loss of load duration
2	loss of load probability
3	installed capacity for each class
4	energy generated by each class
5	fuel cost for each class
6	O&M cost for each class
7	equivalent demand curve (forty values centered on a zero loss-of-load probability)

For each time period, the total loss-of-load probability, frequency, and duration curves are written at the end of the file.

The following table shows the options used to control the reports printed in the computer output.

Table 3. SYSGEN Output Options

	Report Option				
Report	MMAXI	MAXI	MIDI	MINI	MGRID
1. Echo of Input Data	X				
2. Hydro/Storage	X				
3. Probability Curve	X				
4. Plant Loading	X	X			
5. Subperiod Summary	X	X	X		
6. System Summary	X	X	X	X	
7. SCYLLA Grid File					X

SECTION IV
SCYLLA

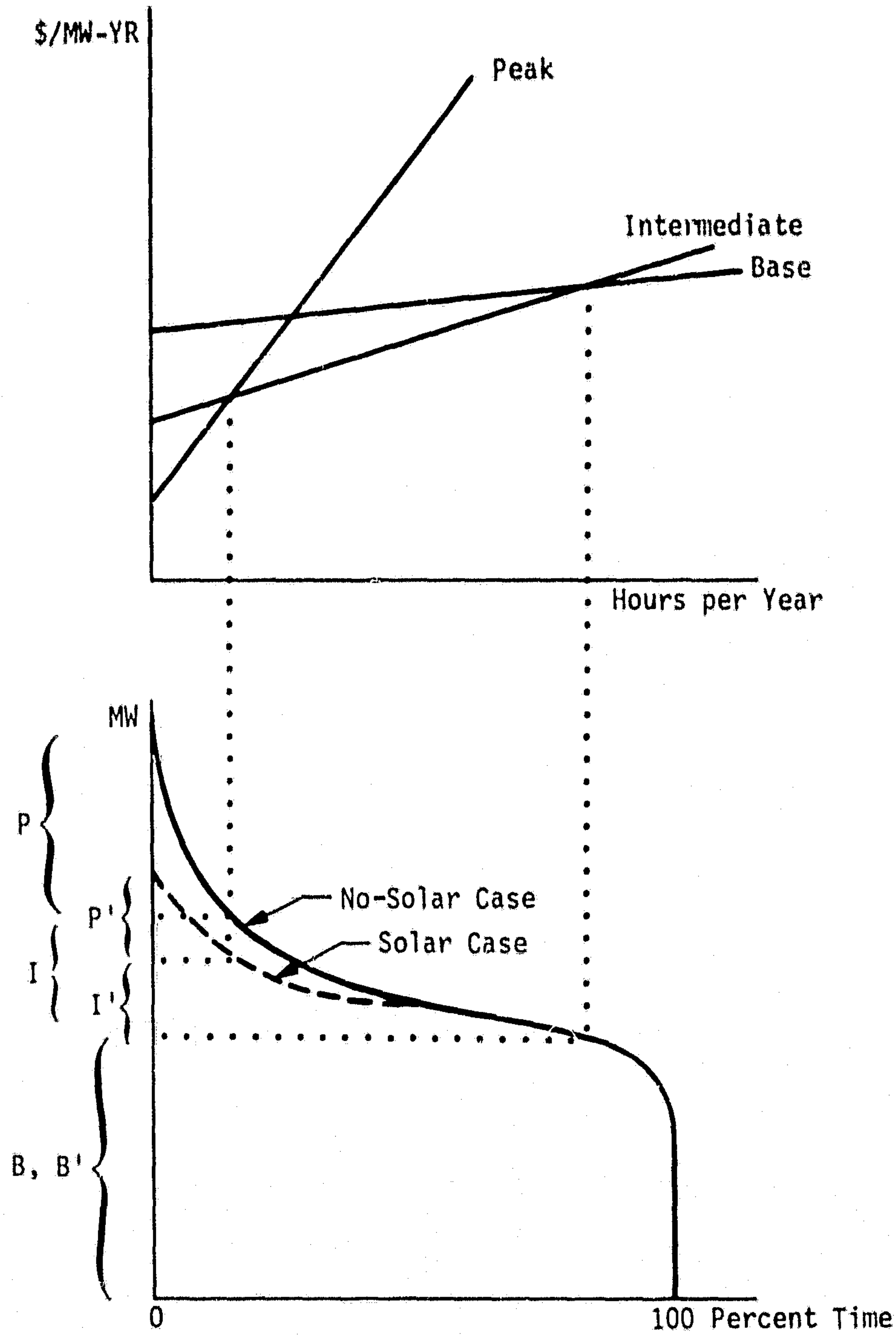
SCYLLA is a linear programming model which performs a static optimization of system generating capacity for the solar and no-solar cases. Optimal changes in capacity are determined by the equivalent load duration curves. Thus, the loss of load probability is held constant in determining the solar capacity credit.

Unfortunately, there are a few problems with this technique. Optimization is done by picking the cheapest base, intermediate, and peaking class types and then duplicating them to meet the load requirement. With this method existing capacity is not considered, and the individual plants in the simulation are not modeled. Further, in calculating the value of the solar generation, the solar plant should be credited for the capacity that was displaced and debited for the new installed capacity. Instead, the capacity credit calculated by SCYLLA is the difference between the solar and the no-solar optimal capacities. Revision of this methodology is being studied.

Most of SCYLLA's inputs are calculated by SYSGEN: class capacities, the amount and cost of energy generated by each class, and the equivalent demand curve for the system. The only exogenous inputs are capital costs and escalation rates by class type.

Figure 5 illustrates the calculation of the solar capacity credit. In the top graph, the y-intercepts are the capital costs in $/MW-year for each loading type. The slopes of the cost curves reflect the fuel and O&M costs. The bottom graph shows the equivalent load duration curves for the solar and no-solar cases. It can be seen that the solar capacity credit for each loading type is B - B', I - I', and P - P'.

PRECEDING PAGE BLANK NOT FILMED



P and I are the original no-solar case optimal capacities of peak and intermediate loading units. P' and I' are the new optimal capacities for the solar case. Optimal base loading capacity does not change.

Figure 5. Determination of Solar Capacity Credit

SECTION V

SYSGEN SIMULATION INPUT QUESTIONNAIRE

This questionnaire follows the same general order as Sections II through IV of this document and as the interactive input program, FEPS. See Appendix B for an explanation of how to set up a data base using batch card input.

It should be noted that the unit-specific questions, 44 through 61, will be repeated for each unit in the simulation.

A. TIME PARAMETERS

1) First year of the study (e.g., 1980): ________

2) Last year of the study (e.g., 2000): ________

3) Number of time periods in the study (note that this should be the last year minus the first year plus 1): ________

4) Number of subperiods in each period: ________

5) Number of "hours" in a time period: ________

6) Number of "hours" in each "week": ________

7) Value of the length of the "hour" variable (e.g., hourly, daily, etc.): ________

8) A four (4) character name for the length of the "week" variable (e.g., "MNTH" or "WEEK"): ________

9) Number of "weeks" in each subperiod:

Table 4. Weeks per Subperiod

Subperiod	Week	Subperiod	Week	Subperiod	Week
1	____	19	____	37	____
2	____	20	____	38	____
3	____	21	____	39	____
4	____	22	____	40	____
5	____	23	____	41	____
6	____	24	____	42	____
7	____	25	____	43	____
8	____	26	____	44	____
9	____	27	____	45	____
10	____	28	____	46	____
11	____	29	____	47	____
12	____	30	____	48	____
13	____	31	____	49	____
14	____	32	____	50	____
15	____	33	____	51	____
16	____	34	____	52	____
17	____	35	____		
18	____	36	____		

B. GENERAL AND ECONOMIC INPUTS

10) Title page heading: A title to appear at the beginning of the report which may be up to 120 characters long, including spaces.

____

____

____

____

____

11) Report heading: A title to appear at the top of each page of the report which may be up to 40 characters long, including spaces.

____

____

____

12) In what year's dollars are the input costs? (e.g., 1978) ________

13) In what year's dollars do you want the output costs to be reported? (e.g., 1980) ________

14) Conversion factor from input year nominal dollars (12) to report year nominal dollars (13): ________

15) Consumer price index over the planning period ($0 < CPI \leq 1.0$): ________

16) Discount rate (real, before tax) to be used in the present worth calculation ($0 < DR \leq 1.0$): ________

C. ORIGINAL LOAD AND LOAD REDUCTION DATA

The original load data are the values of electricity demand from which the load duration and frequency curves are formed. The load reduction data are normally the power output of a time-dependent plant, such as solar thermal, photovoltaic, wind or geothermal generation.

If these data are to be provided on cards, they should be readable on an IBM machine and in 12F5.0 format (12 data points per card, starting in column 21).*

If these data are to be provided on tape, the tape should have the following characteristics:

- standard IBM tape, 9 track
- 1600 BPI
- RECFM = fixed block
- LRECL = 80
- BLKSIZE = 3200
- data points in F5.0 format; 12 points per line
- no label on tape

Note again that the load data and the load reduction data must contain the same number of points, use the same time intervals, start at the same point in time, and be in the same units, e.g., MW or kW.

17) How many data points are in the original load curve? ________
    ($0 < \#$ points $\leq 8{,}784$)

18) How many load reduction curves are there? ________
    ($0 < \#$ curves ≤ 4)

19) How many load duration curves will be calculated?** ________
    ($0 < \#$ curves ≤ 52)

* Unless FEPS is being used to create the data base. With the appropriate commands, FEPS can transform original data in almost any format into a usable SYSGEN data base. For further information, see the FEPS User Documentation, JPL Working Paper, November 1980.

** Note that the number of load duration curves is equal to the number of subperiods in each period.

20) How many load shape points in the load duration curves do you want to use? $(0 \leq \#\text{ points} \leq 100)$ ______

21) ELECTRA automatically creates load duration curves which correspond to the subperiod structure of the simulation. Thus, load duration curves will be formed sequentially from the original load data, and there will be one LDC formed for each subperiod.

SYSGEN, however, allows the user to assign the LDC's to any subperiod desired. For example, a given LDC may be used in more than one subperiod, or the LDC assigned to a subperiod may vary by period.

In Table 5 on the following page, one should designate in which period and subperiod(s) each load duration curve is to be used. Please note that if the FEPS program is being used to create the data base, then this information is input in the ELECTRA mode.

Table 5. Specification of Load Duration Curves

LOAD DURATION CURVE	PERIOD	SUBPERIOD	LOAD DURATION CURVE	PERIOD	SUBPERIOD
1			27		
2			28		
3			29		
4			30		
5			31		
6			32		
7			33		
8			34		
9			35		
10			36		
11			37		
12			38		
13			39		
14			40		
15			41		
16			42		
17			43		
18			44		
19			45		
20			46		
21			47		
22			48		
23			49		
24			50		
25			51		
26			52		

D. INPUT OPTIONS

22) MSPIN = T F (circle one)

If MSPIN is false, skip questions 23 - 25.

23) Choose <u>one</u> of the three following methods of stating required reserve:

a) Required reserve is a percent of peak load: ________%

b) Required reserve is an absolute MW value: ________MW

c) Required reserve is a fraction of the largest unit on line ($0 \leq RR \leq 1$): ________

24) What is the maximum percent of any unit to be credited to spinning reserve? ________%

25) What is the maximum number of units to be displaced in the economic loading order in order to meet the spinning reserve requirement? (integer value) ________

26) MULT = T F (circle one)
(Note: If MULT is set to false, MSPIN is automatically set to false.)

27) MFREQ = T F (circle one)

28) MLORD = T F (circle one)

29) LORDOP = ______ (3 digit number designating base, intermediate, and peaking order)

30) MDLAY = T F (circle one)

31) MOVE = T F (circle one)

32) MSTOR = T F (circle one)

33) MLRED = T F (circle one)

E. GENERATION CLASS DATA

34) Number of generating classes $(1 \leq X \leq 34)$: ______

35) Class name of each (can be up to 4 characters long, including blanks), followed by class type, where B = base, I = intermediate, and P = peak; (e.g., 1. COAL, B, 2. HYDO, P).

Table 6. Designation of Generating Class Name and Type

Class Number	Class Name, Type	Class Number	Class Name, Type	Class Number	Class Name, Type
1	______	13	______	25	______
2	______	14	______	26	______
3	______	15	______	27	______
4	______	16	______	28	______
5	______	17	______	29	______
6	______	18	______	30	______
7	______	19	______	31	______
8	______	20	______	32	______
9	______	21	______	33	______
10	______	22	______	34	______
11	______	23	______		
12	______	24	______		

36) In the table below, indicate the capital cost in $/MW of a plant in each class type. Note that these inputs are not necessary if the user is not running SCYLLA.

Table 7. Capital Costs by Class

CLASS NUMBER	$/MW	CLASS NUMBER	$/MW
1		18	
2		19	
3		20	
4		21	
5		22	
6		23	
7		24	
8		25	
9		26	
10		27	
11		28	
12		29	
13		30	
14		31	
15		32	
16		33	
17		34	

37) How many cost escalation tables will be input?
($0 \leq \#$ tables ≤ 10) ________

38) How many forced outage multiplier tables will be input?
($0 \leq \#$ tables ≤ 10) ________

39) Tables 8, 9, and 10 are all used to assign the cost escalation rates and outage multipliers. In Tables 9 and 10, each set of rates and multipliers is identified by a table number from 1 to 10. These table numbers, or reference numbers, are put into Table 8 to assign the rates and multipliers to the appropriate class types.

Note that there can be only ten total fuel, O&M, and capital cost escalation rate tables.

Table 8. Table Reference Numbers for Cost Escalation Rates and Outage Multipliers

Class Number	O&M COST ESCALATION TABLE NUMBER	FUEL COST ESCALATION TABLE NUMBER	CAPITAL COST ESCALATION TABLE NUMBER	FORCED OUTAGE MULTIPLIER TABLE NUMBER
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				

Class Number	O&M COST ESCALATION TABLE NUMBER	FUEL COST ESCALATION TABLE NUMBER	CAPITAL COST ESCALATION TABLE NUMBER	FORCED OUTAGE MULTIPLIER TABLE NUMBER
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				

Table 9. Cost Escalation Rates

TIME PERIOD	TABLE NUMBER 1	2	3	4	5	6	7	8	9	10
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										

Table 10. Forced Outage Multipliers

TIME PERIOD	TABLE NUMBER 1	2	3	4	5	6	7	8	9	10
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										

F. TRANSMISSION AND DISTRIBUTION LOSSES

40) For how many load levels will time-dependent plant losses be specified? (1≤ # levels≤10) ______

41) In the table below, specify the load levels as fractions of the peak load and the marginal loss at each level.

Table 11. Transmission and Distribution Losses

LOAD LEVEL	PERCENT OF PEAK LOAD	MARGINAL LOSS (MW)
1	______	______
2	______	______
3	______	______
4	______	______
5	______	______
6	______	______
7	______	______
8	______	______
9	______	______
10	______	______

G. UNIT SPECIFIC DATA

If time-dependent units are being modeled, the following data are required.

42) How many cases will be run? ($1 \leq \#$ cases ≤ 20) ______

43) For each case, specify the total number of load reduction curves included, which ELECTRA curves they are (either curve 1, 2, 3, or 4 if it is a solar case), and the capacity multiplier for each curve (i.e., the number of units to be simulated.)

CASE	NUMBER OF CURVES INCLUDED	CURVE NUMBERS	NUMBER OF PLANTS
1	______	1	______
		2	______
		3	______
		4	______
2	______	1	______
		2	______
		3	______
		4	______
3	______	1	______
		2	______
		3	______
		4	______
4	______	1	______
		2	______
		3	______
		4	______
5	______	1	______
		2	______
		3	______
		4	______

CASE	NUMBER OF CURVES INCLUDED	CURVE NUMBERS	NUMBER OF PLANTS
6	______	1	______
		2	______
		3	______
		4	______
7	______	1	______
		2	______
		3	______
		4	______
8	______	1	______
		2	______
		3	______
		4	______
9	______	1	______
		2	______
		3	______
		4	______
10	______	1	______
		2	______
		3	______
		4	______
11	______	1	______
		2	______
		3	______
		4	______
12	______	1	______
		2	______
		3	______
		4	______
13	______	1	______
		2	______
		3	______
		4	______

CASE	NUMBER OF CURVES INCLUDED	CURVE NUMBERS	NUMBER OF PLANTS
14	______	1	______
		2	______
		3	______
		4	______
15	______	1	______
		2	______
		3	______
		4	______
16	______	1	______
		2	______
		3	______
		4	______
17	______	1	______
		2	______
		3	______
		4	______
18	______	1	______
		2	______
		3	______
		4	______
19	______	1	______
		2	______
		3	______
		4	______
20	______	1	______
		2	______
		3	______
		4	______

Unit Index ________

44) If this unit is a storage unit:

a) Charging capacity of storage unit (MW): ________

b) Forced outage rate for charging cycle $(0 \leq X \leq 1.0)$: ________

c) "Weekly" energy size of storage unit (MWh): ________

d) Generating/charging efficiency $(0 \leq X \leq 1.0)$: ________

Unit Index ________

45) If this unit is a conventional hydro plant, then the weekly MWh size of the reservoir in each subperiod is required. (Note that these figures will be constant over periods, e.g., if the "weekly" MWh size in subperiod 1 is X, then the first subperiod in each year will have MWh size X assigned to it.)

Table 12. Hydro Reservoir Size by Subperiod

SUBPERIOD	"WEEKLY" MWh	SUBPERIOD	"WEEKLY" MWh
1	________	27	________
2	________	28	________
3	________	29	________
4	________	30	________
5	________	31	________
6	________	32	________
7	________	33	________
8	________	34	________
9	________	35	________
10	________	36	________
11	________	37	________
12	________	38	________
13	________	39	________
14	________	40	________
15	________	41	________
16	________	42	________
17	________	43	________
18	________	44	________
19	________	45	________
20	________	46	________
21	________	47	________
22	________	48	________
23	________	49	________
24	________	50	________
25	________	51	________
26	________	52	________

The following questions must be completed for all conventional units and for the hydro, storage, and time-dependent units, as applicable.

Unit index ________

46) Unit name ______________ (up to 8 characters)*

47) Unit class ______________

(The class name must match one of the class names specified in the generation class data, previous section.)

48) Installment year ____________ Week ______________

49) Retirement year ____________ Week ______________

50) Fuel cost (\$/MBtu) ______________

51) O&M cost (\$/MWh) ______________

52) Cost per start-up (\$/start-up) ______________

53) Cost per MWh to keep unit as spinning reserve without generating power (\$/MWh) ______________

54) Mean time to repair after failure (hours) ______________

55) Transmission and distribution penalty factor (real # ≥ 1.0) ______________ (default = 1.0)

56) Total MW capacity of unit ______________

57) How many loading increments does this unit have? (If the unit is either all on or all off, or if MULT=F, then the number of loading increments is "1." There may be up to five loading increments.) ________

If the unit does not have multiple increments, indicate the average heat rate and forced outage rate below:

58) Average heat rate for unit (MBtu/MWh) ________

59) Forced outage rate for unit ($0 < X \leq 1.0$) ________

* Please note that if the unit names specified are unique, then it will be much easier to interpret the computer output.

60) Incremental loading data, if applicable:

Table 13. Incremental Loading Data

INCREMENT*	CAPACITY (MW)	INCREMENTAL HEAT RATE** (MBtu/MWh)	FORCED OUTAGE RATE
1	______	______	______
2	______	______	______
3	______	______	______
4	______	______	______
5	______	______	______

61) Maintenance schedule:

In the table on the following page, specify one complete maintenance cycle by indicating in which subperiods maintenance is scheduled and the number of "weeks" per subperiod the unit is unavailable. Please recall that the maintenance cycle is referenced to the period the unit was installed, not the first period of the simulation.

Number of years (periods) in the cycle
($1 \leq \#$ years ≤ 10): ______

---

* No unit may have more than 5 increments or valve points.

** This is the slope of the total heat rate curve.

Table 14. Maintenance Cycle

	# of Weeks Unit is Unavailable											# of Weeks Unit is Unavailable									
SUB-	PERIOD										SUB-	PERIOD									
PERIOD	1	2	3	4	5	6	7	8	9	10	PERIOD	1	2	3	4	5	6	7	8	9	10
1											27										
2											28										
3											29										
4											30										
5											31										
6											32										
7											33										
8											34										
9											35										
10											36										
11											37										
12											38										
13											39										
14											40										
15											41										
16											42										
17											43										
18											44										
19											45										
20											46										
21											47										
22											48										
23											49										
24											50										
25											51										
26											52										

H. LOADING ORDER

62) Loading order option MLORD; specifying entire loading order (optional):

Table 15. Loading Order Specification

LOADING ORDER	UNIT INDEX	UNIT NAME	VALVE POINT
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			

LOADING ORDER	UNIT INDEX	UNIT NAME	VALVE POINT
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			
51			
52			
53			
54			
55			
56			
57			
58			
59			
60			
61			
62			
63			
64			
65			

LOADING ORDER	UNIT INDEX	UNIT NAME	VALVE POINT
66			
67			
68			
69			
70			
71			
72			
73			
74			
75			
76			
77			
78			
79			
80			
81			
82			
83			
84			
85			
86			
87			
88			
89			
90			
91			
92			
93			
94			
95			
96			
97			
98			
99			
100*			

* This is not an upper bound. You may have up to 300 generating units with up to 5 valve points each.

I. REPORT OPTION DATA

63) If MGRID is true, then the Grid File Report for a SCYLLA simulation is written.

MGRID = T F (circle one)

64) If MINI is true, then the System Summary Report is printed for each subperiod and for each time period.

MINI = T F (circle one)

65) If MIDI is true, then all of MINI is printed and the Plant Subperiod and Time Period Reports are printed.

MIDI = T F (circle one)

66) If MAXI is true, then all of MIDI is printed plus the Plant Loading Report.

MAXI = T F (circle one)

67) If MMAXI is true, then all of MAXI is printed plus the Initial Plant Report, the Sorted Hydro Report, and the Probability Curve Report.

MMAXI = T F (circle one)

REFERENCES

Borden, C. S. "Computer Simulation of the Operations of Utility Grid Connected Photovoltaic Power Plants." Paper presented at The National Computer Conference, May 19, 1980.

Davis, R. B. "APSEAM Presentation." Talk presented at JPL, May 14, 1980.

Davisson, M. C. and J. W. Schlotter. "Front End Program for SYSGEN (FEPS) Documentation." Jet Propulsion Laboratory, November 1980. Working paper.

Ebbeler, D. H. "Electric Power Generation Systems Probabilistic Production Costing and Reliability Analysis." Jet Propulsion Laboratory, April 1981. Working paper.

Ebbeler, D. H. and G. Fox. "Summary of SYSGEN Changes." Jet Propulsion Laboratory, March 1981. Working paper.

Finger, S. "Electric Power System Production Costing and Reliability Analysis Including Hydro-Electric, Storage, and Time Dependent Power Plants." MIT Energy Laboratory Technical Report, #MIT-EL-79-006, February 1979.

Finger, S. "SYSGEN, Production Costing and Reliability Model User Documentation." MIT Energy Laboratory Technical Report, #MIT-EL-79-020, June 1980.

Finger, S. "ELECTRA, Time Dependent Power Generation Operation Model User Documentation." MIT Energy Laboratory Technical Report, #MIT-EL-79-025, August 1979.

Finger, S. "SCYLLA, Time Dependent Electric Power Generation Evaluation Model." MIT Energy Laboratory Technical Report, forthcoming.

Fox, G. "A Stochastic Formulation of Electric Generation System Reliability Measures." Jet Propulsion Laboratory, January 1981. Working paper.

<u>Electric Utility Systems and Practices</u>, 3rd ed. Schenectady, NY: General Electric, 1978.

MIT Energy Laboratory. SYSGEN, ELECTRA, and SCYLLA Source Codes.

APPENDIX A

SYSGEN SIMULATION SAMPLE OUTPUT

The Catalina Island study has been chosen to give a simple illustration of the SYSGEN computer model. Peak demand for power on this utility ranges from 2.3 to 3.2 MW over the year, with the highest load occurring during the summer tourist season. The utility has 5 diesel generators of from 1 MW to a little over 1.5 MW capacity. These generators all have the same heat rates, forced outage rates, and fuel and O&M costs.

The following section contains the first subperiod computer output of two SYSGEN runs. The first run is the "base case" simulation without solar generation; the second run includes a 100 kW solar thermal electric plant in the simulation. The energy output of the solar thermal plant was estimated with the SES computer model using 1978 insolation data from Barstow, CA.

The first ten pages of the base case are the echo print of the input data. The echo print is omitted from the second case. Please recall that the variables in the computer output are defined in Section III.G.

```
SYSGEN
PROBABILISTIC SIMULATION REPORT

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW
CATALINA CASE STUDY - SCE 1979 LOAD
1979 BARSTOW DIRECT NORMAL INSOLATION
BLACK AND VEATCH PDS SYSTEM 100KW

START YEAR: 1980                                END YEAR:   1980
PERIODS:      1                                 LENGTH(HR): 8736.
         DISCOUNT RATE:  20.000 %

                    G.E.M.
THE M.I.T. GENERATION EXPANSION MODEL
```

SYSGEN OPTIONS

LOADING ORDER OPTION - 122

OUTPUT OPTIONS

```
MGRID  -  F          MINI   -  T
MIDI   -  T          MAXI   -  T
MMAXI  -  T          MLCAP  -  F
MLRED  -  T
```

OPERATING OPTIONS

```
MULT   -  T          MFREQ  -  F
MLORD  -  T          MSPIN  -  F
MDLAY  -  F          MOVE   -  F
MSTOR  -  F          MAINT  -  F
MSUB   -  T
```

ECONOMIC CONVERSION FACTORS

INPUT IN 1980 DOLLARS
OUTPUT IN 1980 DOLLARS
CONVERSION FACTOR FROM INPUT TO OUTPUT DOLLARS = 1.000
CPI = 0.080

TIME PARAMETERS

```
PERIODS       -   1                     HOURS/WEEK   -   168.0
SUBPERIODS    -   3                     HOURS/PERIOD -  8736.0

WEEKS/PERIOD  -  52

SUB-PERIOD:      1   2   3
NO. OF WEEKS:   21  18  13
```

8 UNITS

INCLUDING
0 CONVENTIONAL HYDRO UNITS
0 STORAGE UNITS

SYSGEN

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

MODIFIED LOAD CURVES

CASE: 1

BASE CASE NO TIME DEPENDENT UNITS

LOAD DATA

NUMBER OF LOAD POINTS: 80

TIME PERIOD	SUB-PERIOD	PEAK LOAD (MW)	LOAD SHAPE
1	1	2557.0	1
	2	2862.0	2
	3	2354.0	3

LOAD SHAPES

LOAD SHAPE NO.	PERCENT OF TIME DEMAND EXCEEDS FRACTION OF PEAK LOAD				
1	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	0.99937171	0.99636364
	0.98601943	0.96794045	0.93546903	0.90094244	0.85966325
	0.81748605	0.79042727	0.76157212	0.73828322	0.72344190
	0.71206570	0.69433534	0.67761159	0.65783936	0.63303679
	0.60257781	0.57227767	0.52981430	0.48761535	0.44570601
	0.40490627	0.35642874	0.31515563	0.26690209	0.22414619
	0.18535089	0.14741004	0.11511052	0.08677733	0.06548834
	0.04875926	0.03682641	0.02745849	0.02147582	0.01602719
	0.01377335	0.01132223	0.00869098	0.00640210	0.00447471
	0.00380527	0.00298115	0.00189483	0.00103582	0.00091630
	0.00070327	0.00054141	0.00040818	0.00027495	0.0
2	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	0.99983943	0.99723202	0.99558377	0.99310011
	0.98862952	0.98379183	0.96990103	0.94863069	0.91693699
	0.87495035	0.84500927	0.81607890	0.79784155	0.77397484
	0.75637817	0.73357773	0.71869671	0.70294034	0.68661815
	0.66995358	0.65385467	0.63871157	0.62087876	0.59886211
	0.57618994	0.54734910	0.51667112	0.49100792	0.46603179
	0.44658488	0.42105204	0.39798754	0.36810547	0.33559901
	0.29917133	0.25850177	0.21992666	0.18638003	0.14050323
	0.10222107	0.07560651	0.05753243	0.04224109	0.02889674
	0.02257922	0.01430587	0.01045881	0.00759383	0.00333520
	0.00126230	0.00094421	0.00069610	0.00058855	0.0
3	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
	1.00000000	1.00000000	0.99944472	0.99734911	0.98562157
	0.95871544	0.92272162	0.88811290	0.84922349	0.82036966
	0.79374480	0.75910258	0.74194688	0.72575629	0.70610648
	0.69317997	0.68058532	0.66715258	0.65187657	0.63124400
	0.61277246	0.58958191	0.55840707	0.52181011	0.48676401
	0.44373941	0.39346385	0.35144776	0.29989076	0.24788612
	0.20911634	0.18078846	0.14654887	0.12310797	0.09664744
	0.07506424	0.06271631	0.05200553	0.04721113	0.03753598
	0.03063149	0.02502226	0.01981597	0.01359677	0.01152613
	0.01012628	0.00826378	0.00690264	0.00457165	0.0

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

GENERATION CLASS DATA

CLASS INDEX	CLASS NAME	CLASS TYPE	O&M ESCALATION TABLE	FUEL ESCALATION TABLE	IMMATURE FOR TABLE
1	DIES	BASE	1	1	1
2	DIES	INTR	2	2	1
3	LDRD	BASE	3	3	2

IMMATURE FORCED OUTAGE RATE TABLE

MULTIPLIER SET	MULTIPLIER FOR YEAR 1	2	3	4	5	6	7	8	9	10
1	1.00	1.00	1.00	1.00	1.00					
2	1.00	1.00	1.00	1.00	1.00					

ESCALATION RATE TABLE

ESCALATOR SET	ESCALATOR FOR YEAR 1	2	3	4	5	6	7	8	9	10
1	0.10									
2	0.10									
3	0.10									

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

PLANT DATA

UNIT INDEX	UNIT NAME	UNIT TYPE	INSTALL YEAR:WEEK	RETIRE YEAR:WEEK	FUEL COST ($/MBTU)	VAR O&M COST ($/MWH)	SPINNING RES COST ($/MWH)	STARTUP COST ($/START)	PENALTY FACTOR	VALVE POINT	CAPACITY (MW)	HEAT RATE (MBTU/MWH)	FORCED OUTAGE RATE	FORCED OUTAGE OCCURRENCE RATE
1	DIESL7	DIES INTR	-4: 1	18: 1	4.310	10.000	0.0	0.0	1.000	1	250.0	16.900	0.025	
										2	250.0	12.180	0.025	
										3	250.0	11.800	0.025	
										4	250.0	12.000	0.025	
										TOTAL	1000.0	13.220	0.062	0.00067
2	DIESL8	DIES BASE	-16: 1	7: 1	4.310	10.000	0.0	0.0	1.000	1	375.0	16.900	0.025	
										2	375.0	12.180	0.025	
										3	375.0	11.800	0.025	
										4	375.0	12.000	0.025	
										TOTAL	1500.0	13.220	0.062	0.00067
3	DIESL10	DIES BASE	-13: 1	9: 1	4.310	10.000	0.0	0.0	1.000	1	281.0	16.900	0.025	
										2	281.0	12.180	0.025	
										3	281.0	11.800	0.025	
										4	281.0	12.000	0.025	
										TOTAL	1124.0	13.220	0.062	0.00067
4	DIESL11	DIES BASE	-6: 1	16: 1	4.310	10.000	0.0	0.0	1.000	1	250.0	16.900	0.025	
										2	250.0	12.180	0.025	
										3	250.0	11.800	0.025	
										4	250.0	12.000	0.025	
										TOTAL	1000.0	13.220	0.062	0.00067
5	DIESL12	DIES BASE	-3: 1	19: 1	4.310	10.000	0.0	0.0	1.000	1	394.0	16.900	0.025	
										2	394.0	12.180	0.025	
										3	394.0	11.800	0.025	
										4	394.0	12.000	0.025	
										TOTAL	1576.0	13.220	0.062	0.00067
6	100KWPDS	LDRD BASE	0: 1	10: 1	0.0	0.0	0.0	0.0	1.000	1	100.0	0.0	0.025	0.25641
7	300KWPDS	LDRD BASE	0: 1	10: 1	0.0	0.0	0.0	0.0	1.000	1	300.0	0.0	0.025	0.25641
8	500KWPDS	LDRD BASE	0: 1	10: 1	0.0	0.0	0.0	0.0	1.000	1	500.0	0.0	0.025	0.25641

SYSGEN

CASE (1) 0KW (2) .1MW 3) .3MW (4) .5MW

PREVENTATIVE MAINTENANCE DATA

CYCLE STARTS FROM INSTALLMENT YEAR OF THE UNIT

PLANT INDEX	ID NO	YEARS IN CYCLE	SUB-PERIODS WITHIN CYCLE & CORRESPONDING WEEKS OF OUTAGE 1		2		3		4		5		6		7		8		9		10	
1	DIESL7	7	2	1	12	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	DIESL8	4	4	3	12	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	DIESL10	5	4	1	12	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	DIESL11	8	4	1	13	1	19	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	DIESL12	3	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	100KWPDS	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	300KWPDS	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	500KWPDS	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

INITIAL CUSTOMER LOAD DURATION CURVE

TIME PERIOD 1 SUB-PERIOD 1

LOAD CURVE SPACING (MW)	MINIMUM DEMAND (MW)	MAXIMUM DEMAND (MW)	EQUIVALENT DEMAND AREA (MWH)
31.96	894.95	2557.00	5341086.00

FRACTION OF TIME THAT THE EQUIVALENT DEMAND EXCEEDS THE ARRAY INDEX * SPACING:

1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	0.9993717074	0.9963636398	0.9860194325	0.9679404497
0.9354690315	0.9009424448	0.8596632481	0.8174860477	0.7904272676	0.7615721226	0.7382832170	0.7234418988
0.7120656967	0.6943353415	0.6776115894	0.6578393579	0.6330367923	0.6025778055	0.5722776651	0.5298143029
0.4876153467	0.4457060099	0.4049062729	0.3564287424	0.3151556253	0.2669020891	0.2241461873	0.1853508949
0.1474100351	0.1151105165	0.0867773294	0.0654883385	0.0487592593	0.0368264094	0.0274584889	0.0214758180
0.0160271893	0.0137733482	0.0113222264	0.0086909793	0.0064020976	0.0044747069	0.0038052700	0.0029811498
0.0018948293	0.0010358200	0.0009162999	0.0007032698	0.0005414099	0.0004081798	0.0002749499	0.0

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

TIME PERIOD 1 SUB-PERIOD 1

VALVE POINTS IN LOADING ORDER

UNIT INDEX	UNIT NAME	VALVE POINT	LOAD TYPE	MW ADDED	EXPECTED STARTUPS	MARGINAL COST ($/MWH)	EXPECTED ADDED ENERGY (MWHS)	FUEL COST (TH$)	O&M COST (TH$)	STARTUP COST (TH$)	SPINNING RESERVE COST (TH$)	TOTAL COST (TH$)	CAPACITY FACTOR	ENERGY TO STORAGE (MWH)	CAPACITY FACTOR AFTER STORAGE
5	DIESL12	1	BASE	394.0		82.84	1355280.0	98717.1	13552.8			112269.8	0.975		
5	DIESL12	2	BASE	394.0		62.50	1320529.0	69322.2	13205.3			82527.4	0.950		
5	DIESL12	3	BASE	394.0		60.86	1219281.0	62010.2	12192.8			74202.9	0.877		
5	DIESL12	4	BASE	394.0		61.72	822566.7	42543.1	8225.7			50768.8	0.592		
2	DIESL8	1	BASE	375.0		82.84	387460.1	28222.2	3874.6			32096.8	0.293		
2	DIESL8	2	BASE	375.0		62.50	108138.3	5676.8	1081.4			6758.2	0.032		
2	DIESL8	3	BASE	375.0		60.86	60570.9	3080.5	605.7			3686.2	0.046		
2	DIESL8	4	BASE	375.0		61.72	30707.5	1588.2	307.1			1895.3	0.023		
4	DIESL11	1	BASE	250.0		82.84	13322.2	1334.6	183.2			1517.8	0.021		
4	DIESL11	2	BASE	250.0		62.50	6742.4	353.9	67.4			421.4	0.008		
4	DIESL11	3	BASE	250.0		60.86	3015.0	153.3	30.1			183.5	0.003		
4	DIESL11	4	BASE	250.0		61.72	1723.1	89.1	17.2			106.4	0.002		
3	DIESL10	1	BASE	281.0		82.84	3958.5	288.3	39.6			327.9	0.004		
3	DIESL10	2	BASE	281.0		62.50	1474.2	77.4	14.7			92.1	0.001		
3	DIESL10	3	BASE	281.0		60.86	613.7	31.2	6.1			37.4	0.001		
3	DIESL10	4	BASE	281.0		61.72	263.8	13.6	2.6			16.3	0.000		
1	DIESL7	1	INTR	250.0		82.84	256.9	18.7	2.6			21.3	0.000		
1	DIESL7	2	INTR	250.0		62.50	111.5	5.9	1.1			7.0	0.000		
1	DIESL7	3	INTR	250.0		60.86	44.4	2.3	0.4			2.7	0.000		
1	DIESL7	4	INTR	250.0		61.72	15.9	0.8	0.2			1.0	0.000		

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

TIME PERIOD 1 SUB-PERIOD 1

UNIT TOTALS IN INDEX ORDER

UNIT INDEX	UNIT NAME	UNIT TYPE	MW TOTAL	EXPECTED STARTUPS	ENERGY (MWHS)	FUEL COST (TH$)	O&M COST (TH$)	STARTUP COST (TH$)	SPINNING RESERVE COST (TH$)	TOTAL COST (TH$)	CAPACITY FACTOR	ENERGY TO STORAGE (MWH)	CAPACITY FACTOR AFTER STORAGE	EFFECTIVE CAPACITY MW	EFFECTIVE CAPACITY %
1	DIESL7	DIES INTR	1000.0		428.7	27.6	4.3			31.9	0.000				
2	DIESL8	DIES BASE	1500.0		586876.8	38567.7	5868.8			44436.5	0.111				
3	DIESL10	DIES BASE	1124.0		6310.1	410.6	63.1			473.7	0.002				
4	DIESL11	DIES BASE	1000.0		29802.7	1931.0	298.0			2229.0	0.008				
5	DIESL12	DIES BASE	1576.0		4717656.0	272592.5	47176.6			319769.1	0.848				
SYSTEM TOTALS			6200.0		5341074.0	313529.4	53410.7			366940.1	0.244				

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

FINAL EQUIVALENT DEMAND CURVE

TIME PERIOD 1 SUB-PERIOD 1

LOAD CURVE SPACING (MW)	MINIMUM DEMAND (MW)	MAXIMUM DEMAND (MW)	EQUIVALENT DEMAND AREA (MWH)
31.96	894.95	8757.00	7023185.00

FRACTION OF TIME THAT THE EQUIVALENT DEMAND EXCEEDS THE ARRAY INDEX * SPACING:

1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	0.9996643329	0.9980572640	0.9925308413	0.9828720922
0.9655241427	0.9470782136	0.9250246829	0.9024880656	0.8879986458	0.8724379030	0.8595804392	0.8508587124
0.8434684233	0.8323403114	0.8213402317	0.8084266683	0.7928371666	0.7741140760	0.7552493242	0.7298340632
0.7046025557	0.6791719777	0.6541172588	0.6251243739	0.5999777471	0.5706292198	0.5439597688	0.5185587376
0.4928526501	0.4695343207	0.4478200847	0.4294193399	0.4133868891	0.3992996900	0.3861843168	0.3738643310
0.3613817513	0.3498629084	0.3379118486	0.3263792718	0.3150306653	0.3037911522	0.2938195797	0.2843813904
0.2746541342	0.2655255758	0.2568345887	0.2481359396	0.2390831567	0.2300170902	0.2202024874	0.2098696572
0.1995905893	0.1893856710	0.1786552144	0.1686684430	0.1585021846	0.1490803615	0.1402931682	0.1320001012
0.1239746493	0.1166996605	0.1098871694	0.1035989381	0.0978489735	0.0925044881	0.0875129596	0.0828573767
0.0785419545	0.0744436511	0.0704035861	0.0665570162	0.0626924993	0.0590780032	0.0555759541	0.0521369315
0.0489230692	0.0459436413	0.0432114777	0.0406667599	0.0383351055	0.0361670445	0.0341176079	0.0321598493
0.0303230841	0.0285037792	0.0267710057	0.0251056253	0.0235222069	0.0220443456	0.0206641584	0.0193376843
0.0181177659	0.0169664389	0.0158721164	0.0148400251	0.0138684896	0.0129312844	0.0120414830	0.0112048015
0.0104090956	0.0096487909	0.0089417767	0.0082602817	0.0076254038	0.0070288232	0.0064639466	0.0059340155
0.0054471608	0.0049960813	0.0045841484	0.0042135396	0.0038790518	0.0035808741	0.0033122560	0.0030720765
0.0028509447	0.0026466654	0.0024573477	0.0022776789	0.0021085120	0.0019489090	0.0017981193	0.0016579218
0.0015277661	0.0014073730	0.0012968422	0.0011963538	0.0011029132	0.0010156563	0.0009350243	0.0008595500
0.0007880093	0.0007218108	0.0006598117	0.0006019942	0.0005488666	0.0005004460	0.0004558067	0.0004151716
0.0003774107	0.0003425591	0.0003108260	0.0002816317	0.0002549125	0.0002307585	0.0002089632	0.0001891498
0.0001714310	0.0001556157	0.0001412175	0.0001279985	0.0001158219	0.0001046132	0.0000942446	0.0000846397
0.0000758468	0.0000679346	0.0000608985	0.0000546248	0.0000490593	0.0000441825	0.0000399062	0.0000360466
0.0000325960	0.0000295008	0.0000266267	0.0000239672	0.0000215674	0.0000194028	0.0000174330	0.0000156265
0.0000139854	0.0000125201	0.0000112073	0.0000100070	0.0000089156	0.0000079310	0.0000070279	0.0000062123
0.0000054910	0.0000048434	0.0000042586	0.0000037385	0.0000032809	0.0000028733	0.0000025077	0.0000021811
0.0000018918	0.0000016359	0.0000014086	0.0000012098	0.0000010398	0.0000008962	0.0000007740	0.0000006712
0.0000005862	0.0000005143	0.0000004507	0.0000003961	0.0000003493	0.0000003070	0.0000002685	0.0000002341
0.0000002045	0.0000001788	0.0000001560	0.0000001355	0.0000001177	0.0000001020	0.0000000880	0.0000000756
0.0000000646	0.0000000546	0.0000000458	0.0000000385	0.0000000323	0.0000000268	0.0000000222	0.0000000183
0.0000000149	0.0000000120	0.0000000095	0.0000000074	0.0000000057	0.0000000043	0.0000000032	0.0000000024
0.0000000018	0.0000000013	0.0000000010	0.0000000008	0.0000000006	0.0000000005	0.0000000004	0.0000000003
0.0000000002	0.0000000001	0.0000000001	0.0000000001	0.0000000000	0.0000000000	0.0000000000	0.0000000000
0.0000000000	0.0						

SYSTEM SUMMARY FOR TIME PERIOD 1 SUBPERIOD 1

PEAK DEMAND =	2557.0	MW
AVAILABLE CAPACITY =	6200.0	MW
CUSTOMER ENERGY DEMAND =	5341086.	MWHS
LOAD FACTOR =	59.21	%
SYSTEM CAPACITY FACTOR =	24.418	%
LOSS-OF-LOAD PROBABILITY =	0.000030	
UNSERVED ENERGY DEMAND =	29.	MWHS
PERCENT ENERGY UNSERVED =	0.0006	%
AVERAGE MAGNITUDE OF LOSS OF LOAD =	0.01	MWS
TOTAL ENERGY GENERATED INCLUDING ENERGY LOST IN STORAGE =	5341074.	MWHS
TOTAL ENERGY GENERATED TO MEET DEMAND =	5341074.	MWHS
SUB-PERIOD FUEL COST =	313529.375	THOUSAND DOLLARS
SUB-PERIOD O&M COST =	53410.723	THOUSAND DOLLARS
SUB-PERIOD TOTAL COST =	366940.063	THOUSAND DOLLARS
ERROR IN ENERGY CALCULATION =	0.000	%

PROBABILITY(AVAILABLE RESERVES < 1000. MW) =	0.000679
PROBABILITY(AVAILABLE RESERVES < 900. MW) =	0.000509
PROBABILITY(AVAILABLE RESERVES < 800. MW) =	0.000379
PROBABILITY(AVAILABLE RESERVES < 700. MW) =	0.000280
PROBABILITY(AVAILABLE RESERVES < 600. MW) =	0.000205
PROBABILITY(AVAILABLE RESERVES < 500. MW) =	0.000151
PROBABILITY(AVAILABLE RESERVES < 400. MW) =	0.000111
PROBABILITY(AVAILABLE RESERVES < 300. MW) =	0.000079
PROBABILITY(AVAILABLE RESERVES < 200. MW) =	0.000056
PROBABILITY(AVAILABLE RESERVES < 100. MW) =	0.000041
PROBABILITY(AVAILABLE RESERVES < 0. MW) =	0.000030
PROBABILITY(AVAILABLE RESERVES < -100. MW) =	0.000021
PROBABILITY(AVAILABLE RESERVES < -200. MW) =	0.000015
PROBABILITY(AVAILABLE RESERVES < -300. MW) =	0.000011
PROBABILITY(AVAILABLE RESERVES < -400. MW) =	0.000007
PROBABILITY(AVAILABLE RESERVES < -500. MW) =	0.000005
PROBABILITY(AVAILABLE RESERVES < -600. MW) =	0.000003
PROBABILITY(AVAILABLE RESERVES < -700. MW) =	0.000002
PROBABILITY(AVAILABLE RESERVES < -800. MW) =	0.000001
PROBABILITY(AVAILABLE RESERVES < -900. MW) =	0.000001
PROBABILITY(AVAILABLE RESERVES <-1000. MW) =	0.000001

SYSGEN
PROBABILISTIC SIMULATION REPORT

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW
CATALINA CASE STUDY - SCE 1979 LOAD
1979 BARSTOW DIRECT NORMAL INSOLATION
BLACK AND VEATCH PDS SYSTEM 100KW

START YEAR: 1980 END YEAR: 1980
PERIODS: 1 LENGTH(HR): 8736.
DISCOUNT RATE: 20.000 %

G.E.M.
THE M.I.T. GENERATION EXPANSION MODEL

SYSGEN OPTIONS

LOADING ORDER OPTION - 122

OUTPUT OPTIONS

MGRID	F	MINI	T
MIDI	T	MAXI	T
MMAXI	T	MLCAP	F
MLRED	T		

OPERATING OPTIONS

MULT	T	MFREQ	F
MLORD	T	MSPIN	F
MDLAY	F	MOVE	F
MSTOR	F	MAINT	F
MSUB	T		

ECONOMIC CONVERSION FACTORS

INPUT IN 1980 DOLLARS
OUTPUT IN 1980 DOLLARS
CONVERSION FACTOR FROM INPUT TO OUTPUT DOLLARS = 1.000
CPI = 0.080

TIME PARAMETERS

PERIODS - 1
SUBPERIODS - 3

HOURS/WEEK - 168.0
HOURS/PERIOD - 8736.0

WEEKS/PERIOD - 52

SUB-PERIOD:	1	2	3
NO. OF WEEKS:	21	18	13

8 UNITS

INCLUDING
0 CONVENTIONAL HYDRO UNITS
0 STORAGE UNITS

C-2

MODIFIED LOAD CURVES

CASE: 2

CURVES INCLUDE THE FOLLOWING TIME DEPENDENT UNITS:

UNIT INDEX	UNIT NAME	CAPACITY (MW)	NUMBER OF UNITS
6	100KWPDS	100.0	1

LOAD DATA

NUMBER OF LOAD POINTS: 80

TIME PERIOD	SUB-PERIOD	PEAK LOAD (MW)	LOAD SHAPE
1	1	2507.0	1
	2	2772.0	2
	3	2354.0	3

CASE (1) OKW (2) .1MW (3) .3MW (4) .5MW

INITIAL CUSTOMER LOAD DURATION CURVE

TIME PERIOD 1   SUB-PERIOD 1

LOAD CURVE SPACING (MW)	MINIMUM DEMAND (MW)	MAXIMUM DEMAND (MW)	EQUIVALENT DEMAND AREA (MWH)
31.34	846.11	2507.00	5245719.00

FRACTION OF TIME THAT THE EQUIVALENT DEMAND EXCEEDS THE ARRAY INDEX * SPACING:

1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	0.9997217655	0.9979301095	0.9868443608	0.9723280668	0.9509565830
0.9199131131	0.8828371167	0.8495423794	0.8095902205	0.7756253481	0.7530986667	0.7342671752	0.7152152061
0.7022995949	0.6898100972	0.6702285409	0.6530004740	0.6335736513	0.6090678573	0.5796334743	0.5457715392
0.5027486086	0.4592113495	0.4169929028	0.3765581250	0.3282590508	0.2876849174	0.2394626141	0.1989635825
0.1611864567	0.1272904277	0.1002720594	0.0766594410	0.0565235764	0.0414659195	0.0312654674	0.0239924788
0.0198286176	0.0155474991	0.0139288194	0.0103513896	0.0079870075	0.0056143478	0.0045880377	0.0034667698
0.0023780100	0.0013343799	0.0010385199	0.0005215998	0.0004769098	0.0003062098	0.0002239700	0.0

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

TIME PERIOD 1 SUB-PERIOD 1

VALVE POINTS IN LOADING ORDER

UNIT INDEX	UNIT NAME	VALVE POINT	LOAD TYPE	MW ADDED	EXPECTED STARTUPS	MARGINAL COST ($/MWH)	EXPECTED ADDED ENERGY (MWHS)	FUEL COST (TH$)	O&M COST (TH$)	STARTUP COST (TH$)	SPINNING RESERVE COST (TH$)	TOTAL COST (TH$)	CAPACITY FACTOR	ENERGY TO STORAGE (MWH)	CAPACITY FACTOR AFTER STORAGE
5	DIESL12	1	BASE	394.0		82.84	1355280.0	98717.1	13552.8			112269.8	0.975		
5	DIESL12	2	BASE	394.0		62.50	1320529.0	69322.2	13205.3			82527.4	0.950		
5	DIESL12	3	BASE	394.0		60.86	1192764.0	60661.6	11927.6			72589.2	0.858		
5	DIESL12	4	BASE	394.0		61.72	794696.1	41101.7	7947.0			49048.6	0.572		
2	DIESL8	1	BASE	375.0		82.84	357837.9	26064.5	3578.4			29642.9	0.270		
2	DIESL8	2	BASE	375.0		62.50	103288.6	5422.2	1032.9			6455.1	0.078		
2	DIESL8	3	BASE	375.0		60.86	58256.6	2962.8	582.6			3545.4	0.044		
2	DIESL8	4	BASE	375.0		61.72	29112.2	1505.7	291.1			1796.8	0.022		
4	DIESL11	1	BASE	250.0		82.84	17050.4	1241.9	170.5			1412.4	0.019		
4	DIESL11	2	BASE	250.0		62.50	6131.4	321.9	61.3			383.2	0.007		
4	DIESL11	3	BASE	250.0		60.86	2858.3	145.4	28.6			174.0	0.003		
4	DIESL11	4	BASE	250.0		61.72	1636.8	84.7	16.4			101.0	0.002		
3	DIESL10	1	BASE	281.0		82.84	3687.4	268.6	36.9			305.5	0.004		
3	DIESL10	2	BASE	281.0		62.50	1360.9	71.4	13.6			85.1	0.001		
3	DIESL10	3	BASE	281.0		60.86	572.9	29.1	5.7			34.9	0.001		
3	DIESL10	4	BASE	281.0		61.72	246.3	12.7	2.5			15.2	0.000		
1	DIESL7	1	INTR	250.0		82.84	239.2	17.4	2.4			19.8	0.000		
1	DIESL7	2	INTR	250.0		62.50	102.8	5.4	1.0			6.4	0.000		
1	DIESL7	3	INTR	250.0		60.86	40.7	2.1	0.4			2.5	0.000		
1	DIESL7	4	INTR	250.0		61.72	14.5	0.8	0.1			0.9	0.000		

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

TIME PERIOD 1 SUB-PERIOD 1

UNIT TOTALS IN INDEX ORDER

UNIT INDEX	UNIT NAME	UNIT TYPE	MW TOTAL	EXPECTED STARTUPS	ENERGY (MWHS)	FUEL COST (TH$)	O&M COST (TH$)	STARTUP COST (TH$)	SPINNING RESERVE COST (TH$)	TOTAL COST (TH$)	CAPACITY FACTOR	ENERGY TO STORAGE (MWH)	CAPACITY FACTOR AFTER STORAGE	EFFECTIVE CAPACITY MW	%
1	DIESL7	DIES INTR	1000.0		397.2	25.6	4.0			29.6	0.000				
2	DIESL8	DIES BASE	1500.0		548495.2	35955.2	5484.9			41440.2	0.104				
3	DIESL10	DIES BASE	1124.0		5867.5	381.9	58.7			440.6	0.001				
4	DIESL11	DIES BASE	1000.0		27676.9	1793.8	276.8			2070.6	0.008				
5	DIESL12	DIES BASE	1576.0		4663269.0	269802.5	46632.7			316435.1	0.839				
SYSTEM TOTALS			6200.0		5245705.0	307959.1	52457.0			360416.1	0.240	0.			

SYSGEN

CASE (1) 0KW (2) .1MW (3) .3MW (4) .5MW

FINAL EQUIVALENT DEMAND CURVE

TIME PERIOD 1   SUB-PERIOD 1

LOAD CURVE SPACING (MW)	MINIMUM DEMAND (MW)	MAXIMUM DEMAND (MW)	EQUIVALENT DEMAND AREA (MWH)
31.34	846.11	8707.00	6927819.00

FRACTION OF TIME THAT THE EQUIVALENT DEMAND EXCEEDS THE ARRAY INDEX * SPACING:

1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000	1.0000000000
1.0000000000	1.0000000000	1.0000000000	0.9998513524	0.9988941550	0.9929715616	0.9852161894	0.9737984121
0.9572133482	0.9374053895	0.9196173950	0.8982634399	0.8800533964	0.8676559893	0.8569934715	0.8459487284
0.8377562878	0.8292704083	0.8168624411	0.8053878008	0.7925093223	0.7768594288	0.7587277032	0.7378329143
0.7119462011	0.6858766437	0.6604237812	0.6356288019	0.6068355941	0.5818485598	0.5523121929	0.5264140796
0.5011716080	0.4772933942	0.4567880242	0.4376737168	0.4197376451	0.4041730922	0.3907947751	0.3783971298
0.3668177196	0.3546709087	0.3438219753	0.3314632050	0.3199498926	0.3093059098	0.2994255351	0.2895550484
0.2800345521	0.2708764030	0.2621011077	0.2536392557	0.2453066309	0.2367498996	0.2276742907	0.2181378478
0.2080145029	0.1977591356	0.1879335909	0.1779967946	0.1676158644	0.1581332850	0.1484365973	0.1397746633
0.1315617829	0.1239176892	0.1167529535	0.1101282473	0.1037436291	0.0980198347	0.0929178309	0.0881376101
0.0836215571	0.0792677428	0.0752274998	0.0711745134	0.0673043083	0.0636311971	0.0600152969	0.0565159509
0.0530794232	0.0498290463	0.0469007423	0.0441235598	0.0415684800	0.0391943154	0.0369716602	0.0348848823
0.0329648396	0.0311065818	0.0293771206	0.0276368206	0.0259575434	0.0243600120	0.0228533677	0.0214455341
0.0201189121	0.0188763969	0.0176757613	0.0165688440	0.0155162263	0.0145321171	0.0136058672	0.0127176546
0.0118544474	0.0110352394	0.0102705575	0.0095394702	0.0088493467	0.0082020269	0.0075686916	0.0069791528
0.0064229624	0.0059049234	0.0054322099	0.0049924352	0.0045863112	0.0042182459	0.0038887352	0.0035931159
0.0033341244	0.0030954327	0.0028786228	0.0026720734	0.0024848377	0.0023073002	0.0021415477	0.0019835964
0.0018342389	0.0016930463	0.0015615660	0.0014404110	0.0013311858	0.0012295602	0.0011345485	0.0010465544
0.0009648075	0.0008884698	0.0008183860	0.0007520897	0.0006901348	0.0006314816	0.0005763268	0.0005260757
0.0004805931	0.0004387432	0.0003996166	0.0003638451	0.0003304863	0.0003000111	0.0002724181	0.0002473229
0.0002247027	0.0002038606	0.0001848412	0.0001676512	0.0001526242	0.0001388689	0.0001261489	0.0001143381
0.0001033689	0.0000931071	0.0000837655	0.0000752426	0.0000676884	0.0000607754	0.0000545062	0.0000489881
0.0000442413	0.0000400030	0.0000362667	0.0000328763	0.0000298197	0.0000269486	0.0000243366	0.0000219540
0.0000198244	0.0000178503	0.0000160112	0.0000143651	0.0000128969	0.0000115593	0.0000103500	0.0000092580
0.0000082563	0.0000073355	0.0000065144	0.0000057750	0.0000051229	0.0000045277	0.0000039848	0.0000035024
0.0000030782	0.0000026959	0.0000023552	0.0000020532	0.0000017844	0.0000015415	0.0000013277	0.0000011433
0.0000009891	0.0000008546	0.0000007396	0.0000006430	0.0000005642	0.0000004952	0.0000004370	0.0000003858
0.0000003415	0.0000002999	0.0000002625	0.0000002298	0.0000002017	0.0000001766	0.0000001540	0.0000001342
0.0000001168	0.0000001012	0.0000000877	0.0000000757	0.0000000650	0.0000000552	0.0000000467	0.0000000394
0.0000000332	0.0000000277	0.0000000230	0.0000000190	0.0000000155	0.0000000125	0.0000000100	0.0000000079
0.0000000062	0.0000000047	0.0000000035	0.0000000025	0.0000000019	0.0000000014	0.0000000011	0.0000000009
0.0000000007	0.0000000005	0.0000000004	0.0000000003	0.0000000002	0.0000000002	0.0000000001	0.0000000001
0.0000000000	0.0000000000	0.0000000000	0.0000000000	0.0000000000	0.0		

SYSTEM SUMMARY FOR TIME PERIOD 1 SUBPERIOD 1

PEAK DEMAND =	2507.0	MW
AVAILABLE CAPACITY =	6200.0	MW
CUSTOMER ENERGY DEMAND =	5245719.	MWHS
LOAD FACTOR =	59.31	%
SYSTEM CAPACITY FACTOR =	23.982	%
LOSS-OF-LOAD PROBABILITY =	0.000027	
UNSERVED ENERGY DEMAND =	27.	MWHS
PERCENT ENERGY UNSERVED =	0.0005	%
AVERAGE MAGNITUDE OF LOSS OF LOAD =	0.01	MWS
TOTAL ENERGY GENERATED INCLUDING ENERGY LOST IN STORAGE =	5245705.	MWHS
TOTAL ENERGY GENERATED TO MEET DEMAND =	5245705.	MWHS
SUB-PERIOD FUEL COST =	307959.063	THOUSAND DOLLARS
SUB-PERIOD O&M COST =	52457.027	THOUSAND DOLLARS
SUB-PERIOD TOTAL COST =	360416.063	THOUSAND DOLLARS
ERROR IN ENERGY CALCULATION =	0.000	%

PROBABILITY(AVAILABLE RESERVES < 1000. MW) =	0.000635
PROBABILITY(AVAILABLE RESERVES < 900. MW) =	0.000475
PROBABILITY(AVAILABLE RESERVES < 800. MW) =	0.000353
PROBABILITY(AVAILABLE RESERVES < 700. MW) =	0.000260
PROBABILITY(AVAILABLE RESERVES < 600. MW) =	0.000191
PROBABILITY(AVAILABLE RESERVES < 500. MW) =	0.000140
PROBABILITY(AVAILABLE RESERVES < 400. MW) =	0.000103
PROBABILITY(AVAILABLE RESERVES < 300. MW) =	0.000073
PROBABILITY(AVAILABLE RESERVES < 200. MW) =	0.000052
PROBABILITY(AVAILABLE RESERVES < 100. MW) =	0.000038
PROBABILITY(AVAILABLE RESERVES < 0. MW) =	0.000027
PROBABILITY(AVAILABLE RESERVES < -100. MW) =	0.000020
PROBABILITY(AVAILABLE RESERVES < -200. MW) =	0.000014
PROBABILITY(AVAILABLE RESERVES < -300. MW) =	0.000010
PROBABILITY(AVAILABLE RESERVES < -400. MW) =	0.000007
PROBABILITY(AVAILABLE RESERVES < -500. MW) =	0.000005
PROBABILITY(AVAILABLE RESERVES < -600. MW) =	0.000003
PROBABILITY(AVAILABLE RESERVES < -700. MW) =	0.000002
PROBABILITY(AVAILABLE RESERVES < -800. MW) =	0.000001
PROBABILITY(AVAILABLE RESERVES < -900. MW) =	0.000001
PROBABILITY(AVAILABLE RESERVES <-1000. MW) =	0.000001

APPENDIX B

JCL FOR CARD INPUT

This appendix contains the JCL (Job Control Language) necessary to run the ELECTRA, SYSGEN, and SCYLLA simulations on the Caltech IBM computer using punched cards. The input formats of each card set are fully described in the original MIT documentations of the three programs; copies of the formats have been made and are available upon request.

A. ELECTRA

ELECTRA has 5 input files and 7 output files, which contain the following data:

INPUT FILE Number	CARD Set	Input Data
10	A,B	General, economic, and time parameters
11	C	Hourly load data
12	D	Hourly load reduction data
13	E	Transmission and distribution losses
30	F	Generating units data

OUTPUT FILE Number	Output Data
22	ELECTRA debug file
60	Base case (no-solar) load duration curve
61	Solar case load duration curve
70	Base case frequency curve
71	Solar case frequency curve
80	Base case load-generation correlation matrix
81	Solar case load-generation correlation matrix

The input card sets are punched exactly as described in the input format section. The card order for an ELECTRA run is:

```
//'run name' JOB ('account number'),'programmer name',CLASS=K
//STEP1 EXEC PGM=NEWELCT
//STEPLIB DD DSN=ACS342.SDDL.LOAD,DISP=SHR
//FT06F001 DD SYSOUT=B
//FT10F001 DD *
   card set A
   card set B
//FT11F001 DD *
   card set C
//FT12F001 DD *
   card set D
//FT13F001 DD *
   card set E
//FT30F001 DD *
   card set F
//FT60F001 DD SYSOUT=B
//FT70F001 DD SYSOUT=B
//FT80F001 DD SYSOUT=B
//FT61F001 DD SYSOUT=B
//FT71F001 DD SYSOUT=B
//FT81F001 DD SYSOUT=B
//
```

The 'SYSOUT=B' statement has the output put onto punched cards. If you want printed output instead, replace all the 'SYSOUT=B' with 'SYSOUT=A'.

B. SYSGEN

SYSGEN has 7 input files, of which 2 are output files from ELECTRA. Note that the SYSGEN card sets A, B, and F are similar to the ELECTRA A, B, and F sets, but they are not identical. Thus, those inputs cannot simply be transferred from one program to the other.

Recall that SYSGEN must be run twice if load reduction curves are being used. The first run with the unmodified load curve is called the base case, and uses ELECTRA output files 60 and 70. The second run with the modified load is called the solar case, and ELECTRA output files 61 and 71 are used as the input files.

INPUT FILE Number	CARD Set	Input Data
10	A,B	General, economic, and time parameters
15	C/1,2	SYSGEN load data variables
	C/3	ELECTRA output file 60 for base case run or 61 for solar case run
20	D	ELECTRA output file 70 for base case run or 71 for solar case run
25	E	Generation class data
30	F	Generating units data
35	G	Preventative maintenance data
40	H	Loading order specification (input only if the entire loading order is being specified)

SYSGEN only has two output files. The content of the first file is determined by the report options specified in the intput data (MINI, MIDI, etc., in card set A). The second file contains the grid file for a SCYLLA run. If SYSGEN is run twice, then there will be four output files total: two for each run.

Again, the input cards are punched exactly as described in the SYSGEN input format section. The card order for the two SYSGEN runs is as follows:

Base Case (Run 1)

```
//'run name' JOB ('account number'), 'programmer name',CLASS=K
//STEP1 EXEC PGM=NEWSYG
//STEPLIB DD DSN=ACS342.SDDL.LOAD,DISP=SHR
//FT06F001 DD SYSOUT=A
//FT10F001 DD *
   card set A
   card set B
//FT15F001 DD *
   card set C, using ELECTRA output file 60
//FT20F001 DD *
   card set D, using ELECTRA output file 70
//FT25F001 DD *
   card set E
//FT30F001 DD *
   card set F
//FT35F001 DD *
   card set G
//FT40F001 DD *              Used only if loading order
   card set H                is specified
//FT45F001 DD SYSOUT=A,DCB=(RECFM=FBA,LRECL=133,BLKSIZE=133)
//FT50F001 DD SYSOUT=B
//
```

Solar Case (Run 2)

```
//'run name' JOB ('account number'), 'programmer name',CLASS=K
//STEP1 EXEC PGM=NEWSYG
//STEPLIB DD DSN=ACS342.SDDL.LOAD,DISP=SHR
//FT06F001 DD SYSOUT=A
//FT10F001 DD *
   card set A
   card set B
//FT15D01 DD *
   card set C, using ELECTRA output file 61
//FT20F001 DD *
   card set D, using ELECTRA output file 71
//FT25F001 DD *
   card set E
//FT30F001 DD *
   card set F
//FT35F001 DD *
   card set G
//FT40F001 DD *              Used only if loading
   card set H                order is specified
//FT45F001 DD SYSOUT=A,DCB=(RECFM=FBA,LRECL=133,BLKSIZE=133)
//FT50F001 DD SYSOUT=B
//
```

C. SCYLLA

SCYLLA's input files comprise the input card sets A through F for SYSGEN (and H if necessary), and the base and solar case grid files output from the two SYSGEN runs.

INPUT FILE Number	CARD Set	Input Data
10	A,B	Identical to SYSGEN
25	E	Identical to SYSGEN
30	F	Identical to SYSGEN
40	H	Identical to SYSGEN
60	C	Identical to SYSGEN
61	D	Identical to SYSGEN
80		Base case grid file output from SYSGEN
81		Solar case grid file output from SYSGEN

The card order to a SCYLLA run is:

```
//'run name' JOB ('account number'), 'programmer name',CLASS=K
//STEP1 EXEC PGM=NEWSLL
//STEPLIB DD DSN=ACS342.SDDL.LOAD,DISP=SHR
//FT06F001 DD SYSOUT=A
//FT10F001 DD *
   card set A
   card set B
//FT25F001 DD *
   card set E
//FT30F001 DD *
   card set F
//FT40F001 DD *        Used only if loading order
   card set H          is specified by user
//FT60F001 DD *
   ELECTRA output file 60
//FT61F001 DD *
   ELECTRA output file 61
//FT80F001 DD *
   SYSGEN output file 50, base case grid file
//FT81F001 DD *
   SYSGEN output file 50, solar case grid file
//FT45F001 DD SYSOUT=A,DCB=(RECFM=FBA,LRECL=133,BLKSIZE=133)
//FT50F001 DD SYSOUT=A
//FT55F001 DD SYSOUT=A
//
```

In summary, the simulation programs have the following inputs and outputs:

1) ELECTRA inputs are the card sets A, B, C, D, E, and F specified in the ELECTRA input format. ELECTRA output--files 60, 61, 70, and 71--are in the form of punched cards, and comprise the load duration and frequency curves for the base and solar cases.

2) SYSGEN inputs are the card sets A, B, C, D, E, F, G, and H specified in the SYSGEN input format. Card sets C and D contain the ELECTRA output of punched cards. SYSGEN output is in two forms: printed output and punched cards. The printed output will contain the production costing and reliability results of the simulation. The punched cards will be the grid file for the SCYLLA program. There will be one printed output and one set of punched cards for each SYSGEN run.

3) SCYLLA inputs are the card sets A, B, C, D, E, and F specified in the SYSGEN input format, plus the grid files on the card output from SYSGEN. The output of a SCYLLA run is printed.

APPENDIX C

JPL MODIFICATIONS TO SYSGEN CODE

JPL has identified several problems with the MIT SYSGEN model involving both the theoretical foundations of the model and the implementation of the theory in the software. Conceptual and descriptive errors in the MIT technical documentation are detailed in a JPL working paper by Dr. D. Ebbeler, "Electric Power Generation System Probabilistic Production Costing and Reliability Analysis." Dr. Ebbeler's findings are based in part on another JPL working paper by Dr. G. Fox, "A Stochastic Formulation of Electric Generation System Reliability Measures."

Listed below are the areas in which Ebbeler and Fox have identified problems.* As of this report's publication, not all of these problems have been corrected, but the corrections that have been made are noted. A separate report is being prepared in which errors in and suggested corrections to algorithms and formulas are presented explicitly and illustrated with test case results.

1) The interpolation formula for converting load profiles to load duration curves is incorrect. JPL has replaced the algorithm by simple linear interpolation.

2) The deconvolution algorithm is inefficient and unstable for unit availability parameters less than 0.5. JPL has replaced this with an efficient stable algorithm for those cases. The original deconvolution algorithm was also modified to correct for a numerical inaccuracy which occurs when deconvolving sufficiently small units.

---

* Ebbeler, D. H. and G. Fox, "Summary of SYSGEN Changes," Jet Propulsion Laboratory, Working paper, March 1981.

3) The method used by the convolution algorithm to guarantee that the sum of expected energies served by the loaded plants and the expected unserved energy be fixed at each iteration results in an incorrect computation of all expected energies by distorting the peak demand level at each iteration. JPL has modified this algorithm to assure a correct peak demand level at each iteration.

4) The algorithm for computing spinning reserve operating costs is incorrect. JPL has not made corrections.

5) The algorithm for optimal dispatching of a charged conventional reservoir hydro-electric plant was derived in the deterministic framework. JPL has not made changes for the probabilistic framework.

6) The storage charging algorithm is suboptimal in both the deterministic and probabilistic frameworks. The algorithm for dispatching a charged storage plant using average cost is incorrect. The algorithm for optimal dispatching of a charged storage plant was derived in the deterministic framework. JPL has not corrected the charging-discharging problem in the probabilistic framework.

7) The treatment of intermittent generator output as ergodic is inappropriate. In the absence of a stochastic model of intermittent generator output, JPL models such output as a deterministic reduction of customer demand.