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AN OVERVIEW OF RELCOMP, THE RELIABILITY AND COST MODEL FOR ELECTRICAL GENERATION PLANNING

November 1979

by

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The authors would like to acknowledge several individuals who made key contributions to the development and application of RELCOMP. Craig Huber prepared a set of computer programs and coupled them with RELCOMP to allow analysis of intermittent power sources, such as wind (documentation is forthcoming). Ken Mullen developed several new procedures for RELCOMP, such as the maintenance scheduler and the spinning reserve calculations, and modified several others, such as the energy allocation subroutine. Karen Guziel provided general assistance, including several modifications to the model, and prepared the input description. Judy Andrews added some frequency and duration calculations and prepared an earlier input description.

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AN OVERVIEW OF RELCOMP, THE RELIABILITY AND COST MODEL FOR ELECTRICAL GENERATION PLANNING

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ABSTRACT

RELCOMP is a system planning tool that can be used to assess the reliability and economic performance of alternative expansion patterns of electric utility generating systems. Given input information such as capacity, forced outage rate, number of weeks of annual scheduled maintenance, and economic data for individual units along with the expected utility load characteristics, the nonoptimizing model calculates a system maintenance schedule, the loss-of-load probability, unserved demand for energy, mean time between system failures to meet the load, required reserve to meet a specified system failure rate, expected energy generation from each unit, and system energy cost. Emergency interties and firm purchases can be included in the analysis.

The calculation can be broken down into five distinct categories: maintenance scheduling, system reliability, capacity requirement, energy allocation, and energy cost. This brief description of the program is intended to serve as preliminary documentation for RELCOMP until a more complete document is prepared. In addition to this documentation, a sample problem and a detailed input description are available from the authors.

1 INTRODUCTION

The purpose of this document is to provide an overview of the capabilities of the Reliability and Cost Model for Electrical Generation Planning, RELCOMP. The framework for RELCOMP was derived from a generating system reliability model, SYSREL, developed at Argonne National Laboratory in the early 1970s.* The improvements and additions to SYSREL have resulted in a new model, RELCOMP, with greatly expanded capabilities but no documentation prior to this report. In these few pages the basic features of the improved model are presented without extensive numerical examples. A more complete report on RELCOMP is expected to be available in mid-1980.

RELCOMP is a nonoptimizing computer program that determines the expected reliability and cost of electrical utility generating system configurations. The model is oriented toward use by system planners and indivi-

*Hub, K.A., et al., *Electrical Utility Generating System Reliability Analysis Code, SYSREL*, ANL/AA-4 (Sept. 1975).

duals interested in reasonably accurate reliability representations of utility generating systems. Comparisons of alternative configurations of a generating system usually are made on the basis of equivalent generating system reliability, often measured in terms of an index such as loss-of-load probability. Cost comparisons not normalized with respect to reliability can yield misleading and incorrect results. RELCOMP can be used to analyze short-term problems, such as the effect of load management on generating cost and reliability, as well as long-run expansion alternatives. A separate set of procedures has been developed and coupled with RELCOMP to allow analysis of intermittent power sources, such as wind (documentation is forthcoming).

The time period analyzed by RELCOMP can range from 1 to 20 years. The calculations are generally performed on a biweekly basis (26 periods per year) in order to properly represent scheduled maintenance and to provide information on the generating system's performance during specific time periods of a year as well as annually. The primary input to RELCOMP includes:

1. Expected electricity demand over time (periodic load duration curves and peak loads),
2. The generating system configuration over time,
3. Characteristics for each generating unit (forced outage rate, average repair time, scheduled maintenance per year, heat rates, fuel type, spinning reserve capability, capital cost, operating and maintenance (O&M) cost),
4. Fuel prices,
5. Firm purchases or sales,
6. Emergency interties, and
7. Spinning reserve goals (if any).

The primary output from RELCOMP includes the following:

1. A maintenance schedule for the system,
2. Reliability performance of the generating system, as measured by loss-of-load probability (LOLP), the frequency of failures to meet the load, the average duration of failures to meet the load, the mean time between failures (MTBF) to meet the load, the expected unserved energy, and the loss-of-energy probability. All of these results are available on a biweekly basis and as annual averages. In addition, the effect of emergency interties on LOLP and unserved energy is determined for each period as well as for each year.
3. The amount of dependable capacity that should be added (the reserve deficit) or subtracted from the generating system to meet a specified LOLP or MTBF,
4. The expected generation in kilowatt-hours (kWh) from each generating unit for each period and for each year,

5. The quantity of each fuel used,

6. The expected generating system energy cost in mills/kWh, and all the component costs, i.e., capital, O&M, fuel, and firm purchases or sales,

7. The operating costs for each generating unit, and

8. The present value of the costs over several years, discounted to the first year of the study.

An overview of RELCOMP's key input and key output is shown in Fig. 1.1. As shown in the figure, the main sectors of the program schedule maintenance and calculate generating system reliability, energy allocation, and generating system cost. A fifth sector, the reserve deficit calculation, is discussed separately in the following pages because it is unique to RELCOMP and because it has proved especially useful in some studies that required reliability normalization.

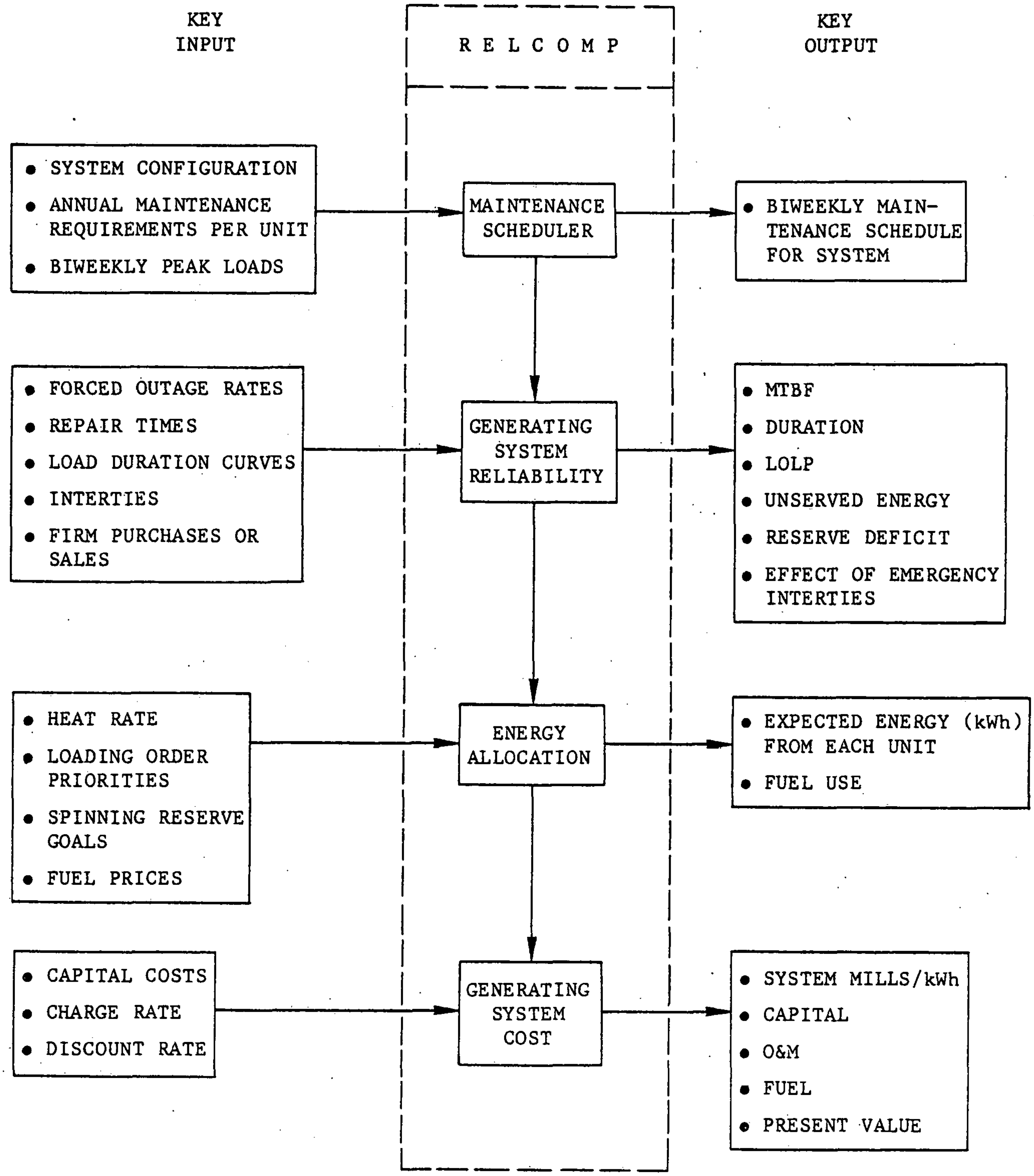

Fig. 1.1. Characteristics of the Reliability and Cost Model for Electrical Generation Planning (RELCOMP)

2 MAINTENANCE SCHEDULING

The objective of the maintenance schedule is to schedule downtime approximately for those periods when, from a reliability perspective, the system least needs the generating unit. For each generating unit the number of weeks of scheduled downtime in each year can be specified. A particular downtime for any unit can be prespecified if desired, e.g., for nuclear refueling. An entire system maintenance schedule can be input if it is already known.

The schedule maintenance is assumed to occur in consecutive periods for any generating unit. That is, two separate maintenance periods in a single year for a particular generating unit are not allowed except when the maintenance period extends beyond the end of the year. In that case, period 1 is assumed to follow period 26 when two-week periods are used. For example, if a generating unit required three periods (six weeks) of maintenance and the start of maintenance is period 25, then the final maintenance period for that unit would be period 1.

When the RELCOMP maintenance scheduler is responsible for the scheduling, the following approach is used. The peak load for each period is adjusted for any firm purchases or sales. Firm purchases would reduce the effective load, and firm sales would increase the effective load. All generating units to be scheduled are ordered according to the annual megawatt-weeks of maintenance required. The scheduler then proceeds to schedule the unit requiring the most megawatt-weeks such that the minimum expected reserve margin for any period is maximized. This procedure is repeated until all units are scheduled. Expected reserve margin is defined by Eq. 1:

$$E_j = [\sum_{i=1}^{n} C_{ij}(1 - F_i) - P_j]/P_j \tag{1}$$

where:

E_j = expected reserve margin (fraction) for period j,

C_{ij} = capacity of the ith unit scheduled to be available in the jth period (MWe),

F_i = forced outage rate (fraction) for unit i, and

P_j = peak load for period j adjusted for firm purchase or sale agreements (MWe).

This definition of reserve margin differs from the usual one by taking into account the forced outage rates of the units scheduled to be available. The expected reserve margin is not necessarily positive for all periods. Expected reserve margin was used instead of reserve margin because tests of the scheduling procedure showed that improved system reliability is more likely when one uses expected reserve margin.

The system schedule, unit by unit, is given in the RELCOMP output. A summary table of results, such as in Table 2.1, is also available in the

Table 2.1. Maintenance Summary for a Typical RELCOMP Problem (Annual Summary with 26 Biweekly Periods)

Period Number	Period Load (MWe)	Buy/ Sell (MWe)	Scheduled Capacity (MWe)	Scheduled Mainte-nance (MWe)	Period Reserve[a]	Expected Capacity (MWe)	Expected Reserve[a]
1	8,360	0	11,000	1,150	0.3158	9,321.5	0.1150
2	8,360	0	11,000	1,150	0.3158	9,321.5	0.1150
3	8,360	0	11,000	1,150	0.3158	9,321.5	0.1150
4	8,360	0	10,950	1,200	0.3098	9,333.0	0.1164
5	7,315	0	9,550	2,600	0.3055	8,185.2	0.1190
6	7,315	0	9,550	2,600	0.3055	8,185.2	0.1190
7	7,315	0	9,550	2,600	0.3055	8,185.2	0.1190
8	7,315	0	9,550	2,600	0.3055	8,185.2	0.1190
9	7,315	0	9,550	2,600	0.3055	8,185.2	0.1190
10	7,315	0	9,550	2,600	0.3055	8,185.2	0.1190
11	7,315	0	9,600	2,550	0.3124	8,213.9	0.1229
12	9,500	0	12,150	0	0.2789	10,339.1	0.0883
13	9,500	0	12,150	0	0.2789	10,339.1	0.0883
14	9,500	0	12,150	0	0.2789	10,339.1	0.0883
15	9,500	0	12,150	0	0.2789	10,339.1	0.0883
16	9,500	0	12,150	0	0.2789	10,339.1	0.0883
17	9,500	0	12,150	0	0.2789	10,339.1	0.0883
18	8,170	0	10,700	1,450	0.3097	9,138.8	0.1186
19	8,170	0	10,700	1,450	0.3097	9,138.8	0.1186
20	8,170	0	10,700	1,450	0.3097	9,140.0	0.1187
21	8,170	0	10,700	1,450	0.3097	9,117.6	0.1160
22	8,170	0	10,750	1,400	0.3158	9,136.2	0.1183
23	8,170	0	10,750	1,400	0.3158	9,136.2	0.1183
24	8,170	0	10,850	1,300	0.3280	9,196.9	0.1257
25	8,360	0	11,050	1,100	0.3218	9,359.5	0.1196
26	8,360	0	11,100	1,050	0.3278	9,409.4	0.1255

[a]Fraction of load.

RELCOMP output.* The typical example in Table 2.1 shows that no maintenance was scheduled in the summer periods, when the annual peak load was expected. If a 50-MWe gas turbine with two weeks of required maintenance were added to this system, the maintenance would be scheduled for period 24 because the expected reserve margin is largest for that period.

*Expected capacity in Table 2.1 is just $\sum_{i=1}^{n} C_{ij} (1 - F_i)$, as given in Eq. 1.

3 SYSTEM RELIABILITY: STATE PROBABILITY, DURATION OF OUTAGE, AND CAPACITY FORCED OUT

For each biweekly period, the model determines the frequency of combined forced outages on the basis of their probability and duration. Only the fundamentals of the probabilistic approach used in RELCOMP are given here.

Generating units are grouped according to capacities, forced outage rates, and repair rates. Each group of units is sequentially examined for a biweekly period. Each possible outage combination for the group is estimated, and three pieces of information are associated with an outage:

1. The probability of occurrence,
2. The expected duration if it were to occur, and
3. The capacity forced out.

In the calculations for a single group consisting of n identical units, the probability (P_r) of r units being forced out at a single time is given by:

$$P_r = \frac{n!}{r!\,(n - r)!} f^r (1 - f)^{n-r} \tag{2}$$

where f is the forced-outage rate, or the probability of finding the unit in a failed state at any time that it is called upon to operate. The factorial coefficient represents the number of combinations of n things taken r at a time, or the number of ways of choosing r components out of n components.

The average duration of an r-fold outage, T_r, is:

$$T_r = \frac{T(1 - f)}{r + f(n - 2r)} \tag{3}$$

where T is the average time to repair a single unit. This is the average time for transition from a state with r units forced out to a state with either r + 1 or r - 1 units forced out.

The third piece of information associated with each state is the megawatt outage; that is, r times the megawatts per unit in the group.

After calculating all possible states for two groups, a meshing procedure is carried out to reduce the information to a single data set. The number of megawatts on forced outage associated with the meshed point (M_{AB}) is the sum of the megawatts forced out associated with the data point from Group A (M_A) plus the megawatts forced out associated with the data point from Group B (M_B):

$$M_{AB} = M_A + M_B \tag{4}$$

The probability of occurrence of the meshed point is the probability of occurrence for the situation from Group A times the probability of occurrence for the data point from Group B:

$$P_{AB} = P_A P_B \tag{5}$$

The average outage duration for data point AB is:

$$T_{AB} = \frac{T_A T_B}{T_A + T_B} \tag{6}$$

The meshing procedure is repeated until all groups have been condensed to a single data set representing the possible outage states.

The frequency (F) of occurrence for an outage combination is the ratio of the probability of occurrence and the duration:

$$F = P/T \tag{7}$$

This frequency is for an outage of magnitude equal to the number of megawatts forced out, associated with P and T.

The number of megawatts forced out for each outage possibility is compared with the critical megawatts, namely the system capacity less scheduled maintenance less the period peak load. If the megawatts forced out are larger than the critical megawatts, the period load duration curve is examined to determine the fraction of time that the outage state would cause a system failure to meet the load. If the megawatts forced out are less than the critical megawatts, that outage state does not contribute to the system failure frequency. Each point is examined, and the sum of the frequencies for all possible states yields the failure frequency for the period. If emergency interties are available, the critical megawatts are adjusted upward accordingly.

In addition to the frequency of failure to meet the load in the period, the average duration of failure is determined. An approximate period LOLP is also obtained in this section of the model, although a more accurate LOLP calculation and other reliability indices are determined in the energy allocation calculation, to be discussed later.

The annual summary of results includes the mean time between system failures to meet the load, which is just the inverse of the annual failure frequency:

$$MTBF = 1/F \tag{8}$$

Of course, calculations such as those outlined above do not need to be carried out for every possible outage combination for large generating systems. For example, Table 3.1 shows a typical generating system of 10 groups with a total of 79 generating units. The possible outage states in a period with no scheduled maintenance total 160,056,000. RELCOMP uses three techniques to trim these extensive calculations without significant loss of accuracy. First, when more than 100 states have been examined, all states with probabilities of less than an input parameter (CRITER) times the average probability for all possible states are dropped from memory. Second, there is no need to consider the possibility of 18 units, each having a forced outage rate of 2.7%, being all forced out at the same time, as in group 6 in Table 3.1. From Equation 2, the probability of such an event is 5.8×10^{-29}. Thus, a second input parameter (EPSIL) is used to eliminate remote possibilities within a single group. The third calculation trimmer is an automatic procedure that is used when the number of states in memory exceeds 3,000. All outage states are sorted according to the number of megawatts forced out, and outage states that fall within certain limits of megawatts are combined into a single data point. For example, in Table 3.1, after group 6 was included, the number of states was 4,584. The number of states in memory drops to 332 after including group 7 because the procedure was used. The typical results in Table 3.1 demonstrate that the calculations for a large utility system can be trimmed to reasonable size.

Table 3.1. Example of Calculation Trimmers

Group Number	Number of Units	Forced Outage Rate	Total States After Group Meshing	Total States Used
1	5	0.290	6	6
2	2	0.150	18	18
3	4	0.210	90	90
4	3	0.130	360	282
5	9	0.074	3,600	1,182
6	18	0.027	68,400	4,584
7	2	0.130	205,200	332
8	2	0.074	615,600	962
9	9	0.027	6,156,000	3,538
10	25	0.240	160,056,000	49,532

4 ADDITIONAL RESERVE REQUIREMENT (RESERVE DEFICIT)

The amount of capacity required to meet a specified reliability criterion is estimated by an empirical equation, which has acceptable accuracy over reasonable ranges of parameter variations. If the system needs additional capacity to meet the reliability standard, a reserve deficit exists. If the system has more capacity than necessary to meet the standard, excess capacity or a negative reserve deficit exists. The following equation presents the relationship used in the calculations when a particular MTBF is specified:

$$\text{DELMEG} = 0.7\ (\text{CAPAC} - \text{ADEQL})\ [(\text{T1}/\text{TIME})^{1/\text{BB}} - 1] \tag{9}$$

RELCOMP estimates DELMEG, the quantity of dependable capacity, which if added to the system would cause the calculated MTBF (variable TIME in Eq. 9) to equal the input MTBF reliability criterion (variable T1 in Eq. 9). A positive DELMEG indicates a capacity shortage. CAPAC is the installed capacity and ADEQL is the average of biweekly peak loads adjusted for firm power purchases and sales, scheduled maintenance, and emergency intertie power. BB is a system dependent program constant used for calculation; typical values are in the range of 5 to 8. By making several runs for the system, with varying capacity, the investigator can find an appropriate value of BB. The accuracy of the DELMEG estimate can be checked by making another run with the appropriate capacity added to the system. A useful feature of this approach is that a reserve deficit is calculated without iteration once the parameter BB has been specified.

DELMEG is dependable capacity, unadjusted for forced outage of actual capacity that would be added to the system. Therefore, a good test for DELMEG is to adjust emergency interties upward or downward and observe the change in reliability and reserve deficit. If DELMEG is +50 MWe, indicating a need of an additional 50 MWe to meet the reliability criterion, it is unlikely that the addition of a single 50-MWe unit will satisfy the need because of the forced outages and scheduled maintenance associated with the actual generating unit.

If an LOLP is the specified reliability criterion instead of MTBF, an adjusted Eq. 9 is used to find the additional capacity needed to meet the specified LOLP. The LOLP may be approximated as the frequency times the average duration of outages, or the average duration divided by mean time between failures. However, the LOLP used in the calculation of reserve deficit is the more accurate LOLP determined in the energy allocation subroutine, described in the next section.

5 ENERGY ALLOCATION

After the reliability calculations have been carried out for a biweekly period, subroutine ENCALC is called to ascertain the energy generated by each unit scheduled to be in operation for the biweekly period. The energy allocation is based on an extension of the loss-of-load probability analysis which uses probabilistic simulation.

The loss-of-load method requires calculation of two probability curves versus capacity. One curve is the incremental-load probability, i.e., the probability that the load will fall in a particular range of megawatts. The second curve is the probability that a particular number of megawatts will be forced out at any time. An equivalent-load curve is then found by convoluting the two curves; the resultant curve is compared to the available capacity for generation.

With some units already loaded, the energy that is expected to be generated by the next particular unit to be loaded is determined by preparing a cumulative-probability curve from the incremental equivalent-load curve. The average value of the probability that corresponds to the appropriate range of capacity in the equivalent load is the fraction of time that the unit will be called upon to operate.

The calculations for an actual system have many complicating factors. One of these is that the units are not always 100% on or off at any given time. This particular dilemma can be partially accounted for in the loss-of-load analysis by splitting the units into blocks of capacity that have different positions in the loading order. The block that is further down in the loading order might represent the load-following portion of the unit's capacity. Breaking the generating units into blocks does not totally eliminate the difficulty, but does produce more realistic capacity factors in most cases.

A generating unit is either available or not available because of scheduled maintenance in any period. The loading order for the available generating units is determined in one of three ways:

1. Input by the user,
2. Automatically, by ordering the units according to variable cost (sum of fuel and variable O&M cost), and
3. Same as 2 except a spinning reserve goal overrides the economics. The spinning reserve goal for the system is an input multiple of the capacity for the largest operating unit and an input multiple of the period peak load. If the spinning reserve goal is satisfied, the economic loading order is followed.

The loading order is an important factor in determining fuel use and system energy costs.

Loss-of-load probability, loss of energy (unserved demand), and loss-of-energy probability (unserved energy divided by energy demand), are calculated for the system with and without emergency interties for every period and on an annual basis.

6 ENERGY COST

The energy cost subroutine, ECOST, utilizes the energy generation calculations and input cost data to determine annual and cumulative generation costs. The cost data required for each unit are:

1. Capital cost in dollars per kWe,
2. Fuel cost in cents per 10^6 Btu,
3. Variable operation and maintenance cost in mills per kWh,
4. Fixed operation and maintenance cost (in addition to the variable cost) in dollars per kilowatt-year, and
5. For each block of capacity in the unit, the expected heat rate for the mode of operation in thousands of Btu per kWh.

An annual capital charge rate is input to allow calculation of annual generation costs. This capital charge rate includes factors such as a weighted average cost of money, depreciation, federal income tax, state and local taxes, interim replacements, and property insurance.

Each generating unit is represented in RELCOMP by one to three blocks of capacity. Each block has its own average heat rate and loading order position. The costs of generating power for each block of capacity as well as for the units are calculated. For the blocks, the fuel cost in mills per kWh are calculated on the basis of an average heat rate for the block. The incremental portion of the O&M cost is added to the fuel cost for each block to determine the variable cost of operation for each block. The annualized capital costs and fixed O&M costs are added to the variable costs to obtain the total costs for each generating unit. The total yearly cost for the system is the sum of the generating unit costs plus any firm purchase or sale and reserve costs.

A present-value estimate is made through the use of an input discount factor. The discounting of costs is performed by referencing the costs to the first day of the first year; an assumption is made that the annual costs occur at midyear. This present-value approach is especially useful when studying multiyear expansion plans. The present value of the power costs for the plan is given at the end of the last year.

The calculated capacity required to meet the reliability criterion can be included in the annual and cumulative generation cost by providing values for each of the five cost factors listed above and the expected capacity factor for the additional capacity requirement. Firm purchase costs and firm sale revenues are identified separately in the cost calculations. Benefits and costs of emergency interties with neighboring utilities are assumed to balance; however, the expected energy demanded from those interties is calculated.

A separate cost routine has recently been developed in order to vary economic parameters without recalculating the reliability results. Subroutine ECOST uses a single set of economic parameters.