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SUSITNA HYDROELECTRIC PROJECT
ECONOMIC ANALYSIS PACKAGE

MEETING JANUARY 14 AND 15, 1982

BELLEVUE, WASHINGTON

ACRES

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ACRES

December 29, 1981
P5700.00

Mr. Dennis Rohan
SRI International
333 Ravenwood Avenue
Merlo Park, CA 94205

Dear Mr. Rohan:

Susitna Hydroelectric Project

The purpose of this letter is to transmit information in preparation for your briefing on the subject, January 14 and January 15 in Bellevue, Washington. Mr. Robert Mohn of APA has previously outlined the meeting topics in his letter of December 7, to you.

These materials are related to the Susitna study, Economic Analysis Methodology and Preliminary Results and the Risk Analysis. Background material for Acres' third area of briefing responsibility, Financial Analysis, are being sent under separate cover.

Enclosed are separate briefing packages for the economics and risk analysis topics. As you will note, at this time, we are getting into the middle of each task's scope of work. As a result, the information presented here is oriented towards methodology rather than results. We hope to have more on the results side to present at the meetings.

The Economic Analysis package includes six sections:

1 - A Scope of Work for the generation planning update work. This work builds on the work done about one year ago for the Development Selection Report.

2 - A draft memorandum of a coordination meeting held between Acres and Battelle to review the respective studies and identify and resolve conflicts where possible.

3 - An explanation of the economic analysis methodology which uses the generation model production costs as a basis. The end product of the economic analysis is a benefit-to-cost ratio.

4 - Preliminary results of the "with" and "without" Susitna, Railbelt plans.

5 - Load Projections as supplied by Battelle, December 21, 1981.

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6 - A summary of the Generation Planning Model, OGP, written and published by General Electric, Schenectady, New York.

The Risk Analysis package contains the following:

1 - The scope of work for the Risk Analysis

2 - A list of risk and construction activities

3 - Risk analysis

4 - Progress status of work scope

We hope that these packages provide you with sufficient background for our briefings. If you have any questions on this material, please contact me or Phil Hoover in Columbia (301-992-5300).

Very truly yours,

John Lawrence
Project Manager

JL/pb

Enclosures

ITEM 1 - SCOPE OF WORK

Item 1

DETAILED WORK PLAN - SUBTASK 6.37/6.38 - UPDATE GENERATION PLAN 11/10/81

Objective:

Update results of the generation planning studies based on detailed information available to the study from the Battelle Power Alternatives Study and the latest information on the Susitna Hydroelectric Project. The primary tool to be used in this analysis is the General Electric Optimized Generation Planning model.

Methodology:

The generation planning portion of the study Subtasks 04, 05, 06 and 07 will follow this general methodology:

1. Pre-Susitna base system under economic parameters (low, medium and high load forecasts).
2. Study period (1993-2010) without Susitna case with economic parameters, medium load forecast.
3. Study period with Susitna case with economic parameters, medium load forecast.
4. Repeat for high and low load forecasts.
5. Test medium load forecast case using financial parameters.
6. Conduct sensitivity analysis on medium load case with the Susitna project.

See Figure 1 for diagram of analysis.

Schedule:

This outline assumes an initial target start date of November 9 and a completion date of January 22 based on the availability of information for each of the Subtasks listed below. See Table 1 for a summary and schedule.

Subtask.01: Update Load Models

Based on information provided by Battelle/ISER and WCC derived load shapes (Task 2) regarding load forecasts; medium, high and low forecasts for energy (GWh) and peak (MW) for net generation demand (not just utility sales) will be revised in the OGP-5 Load Model program routine. ISER has, in the past, presented projections for load in terms of utility sales. Generation plans are developed based on sales plus transmission and distribution losses or net generation. Also, since Battelle is using an probabilistic model without a high, medium or low forecast per se, it may be necessary to revise information from Battelle/ISER to conform with our high, medium and low load forecast format, concentrating on the medium case.

This subtask is completed.

Subtask.02: Update Generation Model

According to March 1981 (Task 4) Report by Battelle, check existing generation system planned additions and retirements for consistency, revise if necessary.

Subtask.03: Update Alternatives Data

Review results of alternatives' cost and availabilities, as well as other parameters, outages (forced and planned) and O&M costs. Data on fuel costs and escalation patterns is also necessary from Battelle Task 1 fuel reports. Update OGP-5 model and check initial data preparation output.

At this point a second coordination meeting with Battelle will be necessary. Some additional points discussed:

- escalation from 1980 - Jan. 1982 price level
- utility sales conversion to generation demand assumptions (note; Battelle + 8 percent)
- intertie cost assumptions with respect to thermal and Susitna development plans
- consistency of capital cost assumptions
- preliminary reserve margin figures from Battelle
- clarification of other points which may arise during the review of alternatives data
- planning parameters.

The alternatives selected by Battelle for use in the Susitna study generation planning update are:

- coal-fired steam electric at Nenana and Beluga
- gas-fired combined cycle plants at Anchorage or Fairbanks
- gas-fired combustion turbines at Anchorage or Fairbanks
- Chackachamna Hydro project

Subtask.04: Generation Plan Without Susitna (Economic Parameters)

Based on system reliability criteria or reserve margins (if available) from Battelle, a "without" case, medium load forecast will be run, allowing the program to optimize new generation production costs using economic parameters.

The following assumptions will be made provided they are consistent with Battelle and Acres transmission team assumptions.

- No limit in natural gas use.
- Economic parameters as specified by APA (0% escalation; 3% interest)

- Costs of transmission for initial Beluga and Nenena plants will be added in.
- Alternatives available under Battelle's Plans I & II will be available to the system and staged as necessary.
- Fuel escalation as specified by Battelle will be used.

Similar OGP-5 runs will be made for the high and low forecasts. These runs will be comparable with Battelle Plans I and potentially IV and V.

Subtask.05: Generation Plan With Susitna (Economic) Parameters

A number of OGP-5 runs will be made under this task to confirm a "with" Susitna plan under the medium, high and low load forecasts for comparison with Battelle Plan II results.

Three key points are:

- Economic parameters will be used as specified by APA (10/29/81)
- The only Susitna plan is Watana/Devil Canyon (in that order)
- Susitna data (energy and cost) used in this task identical to that provided to Battelle

For the medium load forecast, staging will be optimized using economic parameters. Definition of a plan under the high load forecast similar to the medium case including later unit additions of Susitna. The low forecast plan will also resemble the base case, utilizing cheaper alternatives for peak during intermediate years. The first coal units will be assessed for transmission cost to the existing Willow to Healy 345 kV line provided this is consistent with assumptions in Subtask 04.

Subtask 06: Financial Analysis

Based on the plans for the middle load forecast defined in the Subtask 04 and 05 work; the systems for the with and without cases will be run under the financial parameters.

Subtask.07: Sensitivity Analysis

The methdology for sensitivity analysis is as follows:

- Identify areas of uncertainty
- For each topic identify the range of variability
- Test sensitivity
- Discuss the variability.

Several topics have already been identified and tested in the 6.36 work:

Loads - As part of both Tasks 04 05 and 05, high, medium and low loads will be addressed. Intrinsic to these loads are assumptions of economic activity, state spending, per capita use in each consumptive sector. The variability of the with and without plan within the range of load forecasts has been treated before and will be updated.

Economic/Financial Inflation/Discount Rates - Under this revised scope of work economic (0% inflation, 3% cost of money) and financial (to be identified by APA) parameters are to be tested in Subtasks 04, 05 and 06. Similarly, the conclusions drawn in the Task 6.36 (DSR) work would be extended in this phase. At this time, we propose to wait until the results of the previous tasks are completed to define a range of variability of discount rate. However, assuming that Susitna is still economic, the approach would be to seek the case where Susitna becomes unacceptable in economic terms, rather than review the entire range of greater economic feasibility; i.e., higher rather than lower real interest rates will be used.

Period of Analysis - The planning period for modeling purposes extends to 2010. This is considered to be the outer limit for load forecasting and economic cost projections. However, the Susitna project is entered into the system in the 1993-2005 timeframe (Watana/Devil Canyon separate stages). Thus, the production cost model will assess the value of the Susitna stages from a maximum of 17 years, to as little as 5 years. Given that the life of the Susitna project is approximated as 50 years, several assumptions must be made to extend the period of analysis.

In order to assess the economics of the project, the last year of production cost modeling will be assumed to re-occur annually for a period of time equal to 50 years after the last Susitna installation. This assumes no load growth and no actual escalation of any costs. It is believed that this approach provides a slightly conservative edge to the non-Susitna plan. This approach is discussed in more detail in the B/C methodology section.

Sensitivity of this approach could be performed only if the economics of Susitna are not within the acceptable range. The sensitivity would be to find the period of analysis where Susitna is feasibile/unfeasibile.

Project life for the generation alternatives have been mutually agreed upon by Acres and Battelle and are within accepted ranges for the industry. Results of the study are not highly sensitive to a ± change of 5 years or less to these values.

Capital Costs - A considerable amount of analysis and reiteration of capital costs of thermal alternatives has been already completed in the 1981 sensitivity analysis. Additionally, Battelle/Ebasco has devoted a significant level of effort into estimating capital costs of alternatives. Nonetheless, there is concern that the estimates produced (particularly for the coal-fired steam alternative) and a level of confidence lower than the Susitna project. The sensitivity of the capital costs will be approached in two ways.

First, the alternative capital costs will be checked against the Susitna base plan using 90 percent and 120 percent of the Ebasco estimate. The selected alternative plan (units and staging) will remain constant. These percentages will be varied somewhat in an effort to determine the "breakeven point" for the Susitna project.

Second, using the medium forecast plans, real escalation of construction and operation costs will be entered. These escalation values will be adopted from those included by Ebasco in their Railbelt capital cost studies. These values are not being used in the base plans at this time.

Construction Period - An upward variance (longer) in the construction period will be considered. It is expected that this possibility will not have a major impact on results since 3 percent, interest during construction is minimal.

Fuel Cost and Escalation - As defined in the DSR senstivity analysis, fuel cost and fuel cost escalation plays an extremely important role in the planning procedure. Sensitivity should be geared towards defining the fuel/cost escalation rate combination for alternatives at which Susitna becomes unattractive. In the financial analysis of the Susitna study, exception has been taken to the coal escalation rates. One case will be analyzed using the base plans and the Acres' escalation estimates.

Construction Period and Online Dates - This sensitivity is essentially accomplished under the definition of the plans under financial parameters. Constraints on construction period are factored into the earliest possible online date and the high contingency values.

O & M Costs - Although a factor in the production cost model it would appear that due to the lack of historic data and the consistency of application, it is doubtful that the sensitivity of this parameter would result in different recommendations and will not be further addressed.

System Reliability - A system loss of load probability of one day in ten years has been used in system modeling. Variance of this factor would cause the system to add more or less capacity, thus potentially changing the staging of alternatives. Additionally, the Battelle study in using a probabilistic approach to the load forecast may result in a reserve margin higher than that planned with a single forecast input. For sensitivity we would propose to conduct our study planning Subtasks 04, 05, and 06 using Battelles' reserve margins (if available) and then checking sensitivity with LOLP. Thus further model runs should not be needed.

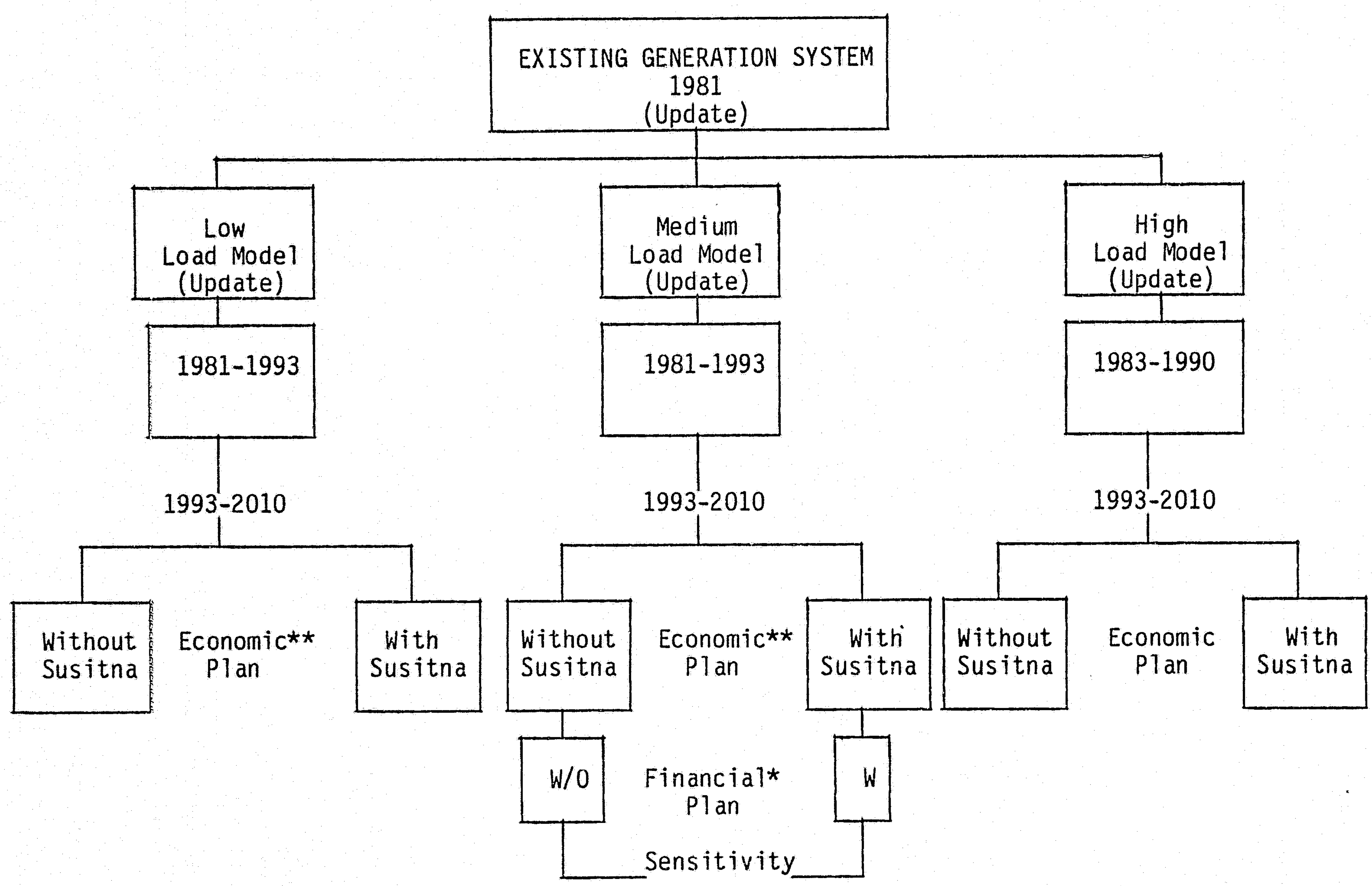
These represent a most of the potential sensitivity runs that can be accomplished. Given the results of the sensitivity checks, combinations of parameter variance will be checked, if they appear critical.

Figure 2 outlines assumptions and potential sensitivity tests.

Subtask.08: Document Results

Document results of the above tasks in a format consistent with the proposed outline of the Feasibility Report (dated October 12, 1981)

It is our understanding at this time that Section 8.8 will document the DSR Task 6.36 studies and remain intact. The 6.37/6.38 Tasks will provide a portion of the financial and economic evaluation of new Section 16. OGP-5 data will be summaraized in Appendix (A1).



SYSTEM PLANNING METHODOLOGY

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* Using parameters defined by APA (10/29/81).

** Using 0%, 3% parameters.

FIGURE 1

ASSUMPTIONS			SENSITIVITY
Appliance Saturation Turnover of Housing	Residential Commercial Industrial	Economic Activity State Spending Per Capita Use	LOAD FORECASTS
		Analysis Period Discount Rate Inflation Rate Construction Cost Escalation Rate	ECONOMIC ANALYSIS PARAMETERS
	1982 Cost Fuel Char. Esc. Rate	Fuel Cost/Escalation	COST OF THERMAL GENERATION
		Construction Period O&M Costs	
	Alaskan Factor Env. Protection Base Costs	Capital Costs	
		O&M Costs Construction Period	COST OF SUSITNA GENERATION
	Contingencies Risk Cost	Capital Costs	

Potential Sensitivity Tests.

FIGURE 2

ITEM 2 - MEMORANDUM OF BATTELLE/ACRES MEETING

Item 2

Memo of Meeting
December 14 and 15, 1981
Battelle PNL
Richland, Washington

December 17, 1981

Subject: Susitna Generation Planning and Railbelt Alternatives Studies

Purpose:

The purpose of the meeting was to review the study progress to date and identify and reconcile, if possible, differences.

Attendance:

Jay Jacobson, Battelle; Mary Ann Hosko and Phil Hoover, Acres

Agenda

1. Discuss status of progress of the individual studies, including work remaining.

2. Review and compare preliminary input/output of the Railbelt Generation Planning models, OGP (Acres) and EPRI Over/Under-AREEP Version (Battelle).

3. Discuss and resolve specific issues and differences between studies identified.

4. Unresolved issues

Meeting Notes

1. Phil Hoover reviewed the Acres' scope of work for the 6.37/.38 efforts and provided a copy of the work scope. This scope provides for a breakout of the effort into eight subtasks:

   - Update Load Models (input)
   - Update Generation Model (input)
   - Alternatives Data
   - Generation Plan without Susitna
   - Generation Plan with Susitna
   - Financial Analysis
   - Sensitivity Analysis
   - Documentation

   Jay Jacobson reviewed Battelle's effort which consists of essentially five tasks:

   (a) Fuel cost estimating: (Lead - Tom Sechrest) This task is essentially complete. One area which is being reviewed is the availability of North Slope Gas in Fairbanks given recent developments in the gas pipeline.

   (b) Demand Forecasting: (Lead - Mike Scott) The forecast provided 12/9 has been invalidated due to an internal error in program data. New forecasts were being developed during the meeting. Anchorage and Fairbanks are assumed to have a 97 percent coincident peak.

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It appears that the medium load forecast, when completed, will be fairly close to the forecast used in previous DSR Acres' studies. All three forecasts will probably be available during the December 16-18 time period. The forecasting team is confident that the errors are ironed out of the forecast.

(c) Evaluation of Generation and Conservation Alternative: (Lead - Jeff King) This task is also nearly complete. From the initial exhaustive list of alternatives, there remains 17; eight or nine are hydro and the rest are coal and natural gas. The plans to be developed in Battalle Plans 1A and 1B will use coal-fired steam, combined cycle and gas turbine plants, located in both Anchorage and Fairbanks.

(d) System Integration: (Lead - Jay Jacobson) The primary tool to be used in this task is the EPRI Over/Under Model, AREEP Version. Using this model, Battelle will develop plans with scheduled plant additions and cost. Also to be done is a sensitivity analysis consisting of:

- Higher and lower fuel costs. The base case is set with world markets forcing real escalation of 2 percent on oil prices. Sensitivity will be done on price forecasts with world oil escalating at 1 and 3 percent.

- Capital costs will be varied on a $\pm$ 20% basis. Variance will be limited to one alternative at a time. All capital costs will be recovered in the generation planning study.

- Effect on demand of SB25,"capital cost grant" interpretation. For example, if consumers did not have to repay the costs of Susitna in their rates, what effect would the low cost energy have on demand.

(e) Implementation Strategy - This will be defined for each Generation Plan identified. This task will address the possibilities for financing, strategy and institutional arrangements needed for plan implementation, including cautionary notes on assumptions.

The actual completion date for the draft report in January 30. This will include plans, cost of plans, environmental impacts, other precautions. No recommendations are anticipated.

2. Mary Ann Hosko reviewed in detail a printout of a preliminary OGP output. The input data was discussed in detail. In general, there is a high degree of consistency between Acres and Battelle's basic data.

The load model used by OGP will be annually matched to the Battelle forecast; however, the monthly/daily characteristics will remain based on the 1980 Woodward-Clyde studies. The load model is a significant difference between AREEP and OGP as the former operates on a yearly load duration curve while the latter varys by month and day. AREEP will use a constant shape of load duration curve throughout the 30-year period of analysis.

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Acres has adopted the most recent Battelle information on existing and committed units. We will include the Copper Valley/Glennallen resources and load in the study, as Battelle has been directed to do so. In the OGP model, heat rates are specified to units, thus the existing units have a much higher heat rate than the available new alternatives. AREEP allows only a single heat rate for each type unit. Therefore, the OGP model will have higher fuel costs associated with use of existing generation units.

It was noted that Battelle is assuming no interactive energy flows between Anchorage and Fairbanks can take place prior to 1984. In 1985-89, energy transfer is limited to the planned intertie, 260 GHW annually. In the post-1990 period, energy transfers are unlimited. Acres, in focusing in the post Susitna period (1993-2010) has full exchange potential but also in costs to account for the more intertie capability.

Acres is currently using one cost level each for coal, gas and oil. Battelle is differentiating between coal in Anchorage (Beluga) and Fairbanks (Nenana), and old and new gas in CEA and AML&PD. It was decided that Acres would make the necessary changes in their Railbelt model to enact the cost difference. This change will probably have a small impact on results.

Battelle is reviewing cost projections of North Slope gas available to Fairbanks. This is consistent with the economic scenario assumption of the completion of the TAPS gasline. It is interesting that this gas decreases in real price through time, due to the back out price from the lower 48 sales.

Battelle is using two coal plants at the separate prices at Beluga and Nenana, as compared to the Acres' all Beluga development. Since the costs developed by Ebasco are nearly equal for the two sites, the prior decision that it would be much less expensive to upgrade the intertie and keep development at Beluga may be remiss. Acres will give consideration to the shifting of some of the Beluga units to the Nenanna fields. This could enact savings to the all-thermal plan, as it would have lower transmission costs (currently $500 million).

At this time, 200 MW units are the standard size being used by Battelle for coal and combined cycle units. Acres will adopt this size. The retirement policies on the units will be from published Battelle work paper 4.1.

The AREEP model calculates interest during construction on capital costs, given a constant annual cash flow during the construction period. The OGP model does not calculate IDC so it is input as part of the capital costs. Acres is using an "S" curve formula for this calculation. These differences should not be significant.

Start up time as defined on Battelle's information sheets is not consistent with the Acres' definition of immature unit time. The Battelle definition is time which would be added on to the construction period for unit commissioning. The Acres' definition is that time that the unit suffers a higher forced and planned outage rate, due to "bugs" in the plant which must be worked out. Acres will revert to using the previous immature time periods instead of the new Battelle start-up times. Battelle does not have the capability for expressing immature outage rates.

Battelle is using several factors in AREEP, not used in the Acres' model. These include a rate base for plants in service, and a cost for distibution and overhead. Battelle is using 8.13 mills/kWh for general administration and overhead. The rate base was supplied by the Alaska-PUC. A copy was given to Acres. It is depreciated by Battelle on a declining balance method at 10 percent per year.

The AREEP model develops a generation plan based on a desired long term mix goal and an upper limit on capacities specified by the operator. Thus, the mix is controlled somewhat by the operator. The program, when capacity is needed, reviews the existing system mix and compares it to the long term desired plan. Units are then selected to make the existing balance as close as possible with the plan. Currently, the all-thermal long term mix is approximately 40% Beluga coal units, 18% combined cycle, 8% gas turbines, 14% Fairabnks (Nenana) coal and 20% hydro.

Spinning reserve requirements are not addressed by the AREEP model. The OGP model operates plants as necessary on a hot spinning reserve mode. Thus, the fuel costs in the Acres model will be higher for the same amount of generation.

The output of the AREEP model are in three categories of price Jan. 1981, mills/kWh: total, electrical requirements, delivered energy, and conservation. The latter is calculated by Battelle's RED (Railbelt Electric Demand) model. The delivered category corresponds to the Acres' planning since conservation is taken into account by the forecasts provided by Battelle.

It was concluded from the close comparison of the two models that the outputs will not be directly comparable on an absolute number basis. The generation plans are expected to be similiar with the relative merits of each plan shown to be the same. The following are major differences in methodology/model capability:

(a) Dispatch: The daily unit dispatch modeling in the OGP model results in greater use of more expensive units than the AREEP model, which dispatches units on an annual basis. This will result in higher fuel costs in the OGP model.

(b) Heat Rates: The AREEP model uses only one heat rate per unit type. The Acres' model was specific rates for each existing unit. This fuel costs for operating existing units will be significantly higher in the Acres' model.

(c) Overhead and Sunk Costs: The Battelle AREEP model has included cost for distribution systems and utility overhead. These have not been included in the Acres' model since relative costs between plans is desired rather than an absolute customer cost. Thus, the production cost value from the OGP model is not equivalent to the AREEP consumer cost. The AREEP model also includes an annual cost for existing plant in service which is depreciated over time.

3. <u>Other issues discussed:</u>

(a) Hydro alternative: Battelle has cost and energy information from both Bechtel and Ebasco on the Chackachamna project. It was agreed that the primary Chackachamna alternative would be Case B from the Bechtel Study. Battelle will check the Ebasco costs and project in sensitivity analyses.

Other hydro alternatives to be used are Grant Lake (7 MW in 1988) and Allison Creek (7MW in 1992) based on Acres-DSR costs (escalated to January 1982 level by 7 percent) and energies.

(b) Socio-economic data which is the basis of ISER's forecast was provided to Acres in report form.

(c) The revised medium forecast, as well as the high and low forecast, will be available by December 18. The high and low will bracket the range of reasonable economic futures.

(d) No analysis of a resultant reserve margin which would be dependent on forecast uncertainty has been completed. At this time Battelle is doing their analysis on a 40 percent reserve goal. Acres is planning to a loss of load probability of one day in ten years.

(e) A copy of Acres' final report on Cook Inlet Tidal Power will be sent to Battelle.

(f) Acres will adjust its model to differentiate between fuel costs in the different load centers. This will be consistant with the AREEP model. Additionally, to be consistent with Battelle's findings, a limited number of coal plants will be sited in Nenana to balance demand and generating resources.

(g) The period of analysis for the study was discussed. Acres is making the assumption of a 40-year extension of the last year (2010) of modeling in order to make some measure of the long term relative benefits of the with and without Susitna plans. While Battelle has no specific objections to the methods, they will not be doing the same, unless directed.

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(h) Susitna development was discussed, and it was pointd out that the development could be formulated as follows:

				Energy
Watana	1	4	170 MW units = 680	3385 GWh
	2	2	170 MW units = 340	0
			1020 MW	GWh
Devil Canyon	1	3	150 MW units = 450	3264 GWh
	2	1	150 MW units = 150	0
			600 MW	6649 GWh

Addition of second stage at Watana delays $41 million expenditure.

4. Unresolved Issues:

(a) The escalation of O&M and capital costs proposed by Ebasco have not been accepted yet by Battelle. They have requested that Ebasco substantiate the figures. At this time the values are not being used.

(b) The Acres' concern with regard to coal prices was discussed including: the zero real escalation of Nenana coal, the relationship between the coal and oil prices, and the probability of the opening of the Beluga fields in light of low coal value. This issue will be pursued at a later date.

(c) An additional concern with regard to level of confidence of estimates was discussed. The Susitna estimate, made with detailed studies, takes into account the specific problems of the site. The alternative estimates, on the other hand, may have a lower confidence level and may actually be a center point forecast, subject to a cost increase. Battelle will discuss the level of confidence of the estimates with Ebasco.

(d) Transmission line costs for Susitna development have included a reliable assessment of transmission line update and capability. A similar assumption and associated costs must be made for the thermal alternative, to be added to the cost of the "without" Susitna case.

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ITEM 3 - BENEFIT TO COST RATIO METHODOLOGY

Susitna Hydroelectric Project Economic Analysis

Benefit to Cost Ratio Calculation

The primary method of comparing with and without Susitna alternative scenarios is total system costs. The planning model provides output from a computer of the total production costs of these alternative models on a year by year basis. These total costs for the period of modeling include all costs of fuel and operation and maintenance of all generating units included as part of the system. In addition, the production cost include the annualized investment costs of any production plants added during the period of study. Factors which contribute to the ultimate cost to the consumer of power which are not included in this model are: all investment cost to plants in service prior to 1993, costs of the transmission and distribution facilities in service and administrative cost of utilities for providing electric service to the public. These costs are common to all scenarios and have been omitted from the study, as having no impact on generation plant decisions.

Thus, the production costs modeled are only a portion of ultimate consumer costs and in effect are only a portion, albeit major, of total costs. The sum of the costs is an effective relative indicator of the measure of cost of following one plan compared to another.

In order to compare costs, all annual costs from 1993-2010 production simulation have been converted to a present worth to 1982. These present worths for all scenarios considered are shown in tabular form in two amounts. The first is the 1982 PW of the 18 years of model study from 1993-2010. The second value is an estimated long term PW of system costs which will be discussed later.

To illustrate this discussion, the with and without Susitna plans of the medium load forecast will be compared. Considering the without Susitna Plan (Case D in Item 4 of this package) the 1982 PW of 1993-2010 production costs is $3141 X 10^6. This total is the theoretical amount of cash (not including those items noted) needed in 1982 to meet electrical production costs in the Railbelt for the period 1993-2010, given scenario assumptions.

The second cumulative PW value is the long term (2100-2051) PW estimate of production costs. In considering the value of the addition of a hydropower plant, which has a useful life of approximately 50 years, the study period is inadequately short. A plant which is added in 1993 or 2002 would accrue PW benefits or penalties for only 17 or nine years respectively in the PW measure.

It is also true that modeling the system for an additional 50 years, assuming loads and generation alternatives, is well beyond the realm of any prudent projections. For this reason, the final study year (2010) production costs were assumed to reoccur for an additional 41 years, and added to the 18 year PW, to sum a relative measure of long term cost differences between alternative methods of power generation.

It should be noted that the long term PW is not by any means an absolute number but is a relative measure of alternative scenarios production costs. For this reason, a benefit-to-cost ratio for a Susitna alternative cannot be calculated by taking one 20 year or long term PW divided by another. What can be estimated is a long term benefit of utilizing one alternative compared to another, by examining the difference in PW totals. For example, there would be a production cost savings over the long term of $1022.4 million by pursuing the with Susitna Plan ($8069.8 million), compared to the non-Susitna system ($7047.5 million). Since the costs of these hydro alternatives are built into the production costs, this is a net benefit.

In order to compare the Susitna alternatives in terms of both net benefits and costs, it is desirable to estimate a benefit-to-cost ratio for the alternative developments based on system cost estimates. The first impulse would be to divide the total long term PW of one system by another, yielding a system with/without comparison. However, as previously noted, the PW total is not an absolute figure by itself, but does contain some system-common factors. Additionally, both the numerator and denominator contain substantial portions of system costs common to both systems, masking the costs and benefits under scrutiny.

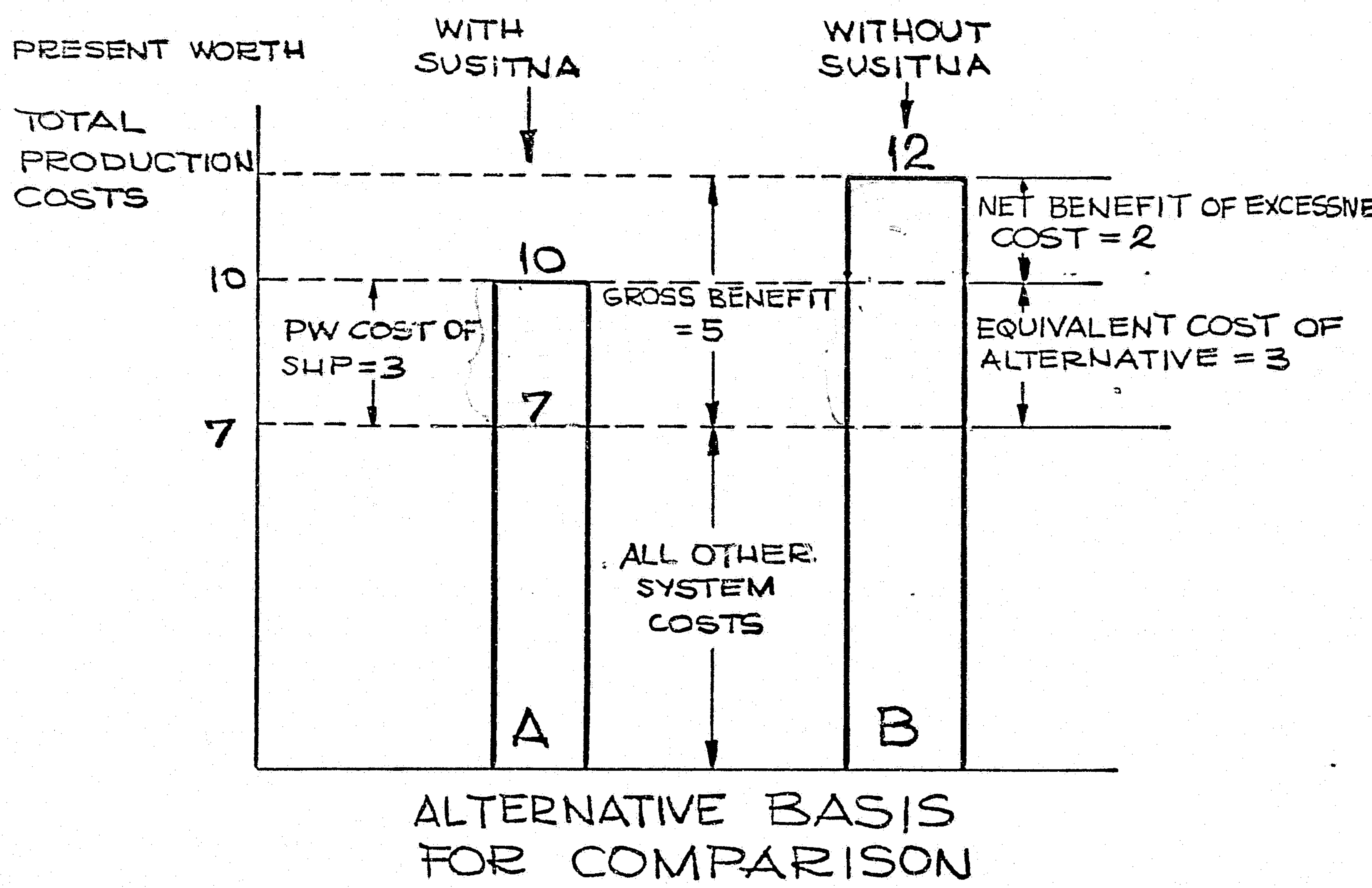
The following benefit-to-cost methodology was used. It is readily seen that the net benefits of a plan are defined as the production system cost savings or penalties of the plan as compared to the basis. Additionally, the present worth of the alternatives investment cost would be in the denominator of the ratio.

The measure of net benefits is inadequate however, in computing a complete benefit-to-cost ratio. Inherent to the non-Susitna plan is a portion of basic costs of generating which are equal to the cost of the Susitna alternative. These costs must be included with the net benefits to yield a total benefit for an alternative. Figure 1 illustrates this discussion. In that illustration, the ratio would be equal to the PW of gross system benefits divided by the PW of the alternative cost.

The basis used for calculating the B/C ratios is the non-Susitna plan. This plan has a long term PW of 7047.5 Since the Susitna plan has a lower production cost, the B/C ratio is 1.2. Should any plan in sensitivity analysis have a higher production cost than the non-Susitna plan, it would then have a B/C less than 1.

$$B/C = \frac{\text{Cost} + B}{\text{Cost}}$$

$$B/C = 1 + \frac{B}{\text{Cost}}$$



$$\frac{B}{C} = \frac{\text{BENEFIT}}{\text{COST}} = \frac{\text{ALL COSTS OR GROSS BENEFITS}}{\text{COST OF A}} = \frac{\text{EQUIV. B + EXCESS B}}{\text{COST OF A}}$$

BENEFIT TO COST RATIO METHODOLOGY

FIGURE 1

ACRES

ITEM 4 - PRELIMINARY RESULTS

Item 4

Preliminary Results - Economic Analysis

The following pages present preliminary results of the economic analysis discussed in other items in this package. The first two pages are calculations based on output from the production cost model using different development plans. The following pages are direct output from the model describing those plans. To interpret the output, the final item of the package (OGP summary) should be consulted.

Five plans have been developed to date:

A. Without Susitna, all Thermal Alternatives - using Battelle figures
B. Without Susitna, Thermal plus Chackachamna - using Battelle figures
C. With Susitna - using Battelle figures
D. Without Susitna, all Thermal Alternatives - using Battelle figures except for coal prices, including real escalation on capital costs and O&M.
E. With Susitna - using Battelle figures except for coal prices, including real escalation on capital costs and O&M

As concluded from the work sheets, in comparing Cases D and E, the Susitna project has a benefit to cost ratio (B/C) of 1.21 to 1. In comparing Case C to Case A, Susitna has a B/C of 1.16 to 1. In comparing Case C to Case B the B/C is 1.11 to 1.

Note that these are preliminary results. Several minor adjustments to model input need to be made. These include the estimate on O&M for Susitna and the calculation of interest during construction in Cases D and E. These changes may raise the B/C for Susitna to a small degree.

ACRES

Calculations

SUBJECT: LONG TERM PW

JOB NUMBER P5700.06
FILE NUMBER P5700.14.06
SHEET 1 OF 2
BY RM DATE 1/81
APP DATE

@ 3%

Factors

P/A_{41} $\frac{(1.03)^{41}-1}{(0.3)(1.03)^{41}} = \frac{2.36}{0.1008} = 23.4124$

Years 2011-2051 inclusive to 2010

$P/F_{28} = .4371$
1982 ← 2010

Total factor for last year (23.4124)(.4371) = 10.234

PW 1982 ($\$ \times 10^6$)

CASE	RUN #	1993-2010	2010	(2010-2141)	1993-2141
A Without/all therm	L749	2476.3	361.6	3700	6176.3
B Without/Chack included	L7K5	2387.3	353.7	3619.6	6006.9
~~With (Prelim)~~	~~L3L1~~	~~2545.2~~	~~309.3~~	~~3165.2~~	~~5710.4~~
C With Susitna	L7V1	2502.3	299.5	3065.10	5567.1
D Without - esc	L709	3141.1	481.8	4928.8	8069.9
E With - esc	L7V7	3095.6	386.3	3951.8	7047.5

Without - No Susitna

FORM NO. 152 REV. 1

ACRES

Calculations

SUBJECT:

JOB NUMBER P5700,06
FILE NUMBER P5700.14.06
SHEET 2 OF 2
BY pmtt DATE 1/82
APP DATE

B/C @ Chadcachama

PW Net Benefit = ~~7448.3 - 7250.7 = 197.6 m~~
6176.3 - 6006.9 = 169.4

PW Cost = P/F 11 × 1.45 × 10^9 = .7224(1.45 × 10^9) = 1047

$B/C = \frac{1047 + 169.4}{1047} = 1.16.$

(B) Sus vs Therm (check)

PW Net Bene = ~~7251 - 6778 = 453~~ 6006.9 - 5567.1 = 439.8

PW cost = 3860

$B/C \; \frac{3860 + 439.8}{3860} = 1.11$

(C) Sus vs All Therm

~~7448 - 6798 = 650~~ 6176.3 - 5567.1 = 609.2

PW cost = 3860

$B/C = \frac{3860 + 609.2}{3860} = 1.16.$

(D) Sus vs Therm - esc

Net benefit 8069.9 - 7047.5 = 1022.4

	PW		esc		
WAT	1982 \$ 4094 m	×	1.219 × .7224	=	3605
O.C.	\$ 1631 m	×	1.457 × .5537	=	1316
					4920

$\frac{1022.4 + 4920}{4920} = 1.21$

FORM NO. 152 REV. 1

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML749 12/30/81
****

GENERATION SYSTEM

	NUKE	COAL	NGASGT	OIL GT	DIESEL	COMCYC	TYPES	
TYPE	1	2	3	4	5	6	7-10	
OPTMZING	0	1993	1993	0	0	1993	***	
PCT TRIM	0	0	0	0	0	0		
1992 MW	0	59	452	141	67	317	155	SUM= 1190

****

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	****** ****
93		1X 200						1373
94		200*						1542
95								1495
96		200*						1624
97			70*					1620
98			70*					1635
99								1635
0								1591
1			70*					1661
2								1608
3			1X 70					1625
4		200*						1825
5			70*					1807
6			70*					1854
7			70*					1924
8		200*						2098
9								2097
10								2097

****
****

MW ADD	0	1000	490	0	0	0	0	SUM= 1490
MW RET	0	-46	-335	-141	-61	0	0	SUM= -583
******	******	******	******	******	******	******	****	***********
2010	0	1013	606	0	6	317	155	SUM= 2097
PCT TOT	0.	48.3	28.9	0.	0.3	15.1	7.4	SUM=100 PCT

****

AUTO	0	200	70	0	0	0	0	SUM= 270
PCT TOT	0.	74.1	25.9	0.	0.	0.	0.	SUM=100 PCT

* COMMITTED MW

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML749 12/30/81
****

YEAR	LOAD	TOTAL CAPABILITY (INCLUDING TIES) YEAR END	TIME OF PEAK	PCT. RES.	LOSS OF LOAD PROBABILITY D/Y	H/Y	COST IN MILLION $ YEARLY COST	CUM. PW TOTAL
****	*****	*****	*****	****	******	******	*******	*******
1993	947	1373	1373	45.0	0.063	0.	141.8	102.4
1994	965	1542	1542	59.8	0.027	0.	165.1	218.2
1995	983	1495	1495	52.0	0.077	0.	170.0	334.0
1996	1003	1624	1624	61.9	0.059	0.	203.6	468.6
1997	1023	1620	1620	58.4	0.084	0.	210.7	603.8
1998	1044	1635	1635	56.6	0.092	0.	218.8	740.2
1999	1064	1635	1635	53.6	0.055	0.	222.7	875.0
2000	1084	1591	1591	46.8	0.059	0.	226.7	1008.1
2001	1121	1661	1661	48.2	0.038	0.	237.8	1143.7
2002	1158	1608	1608	38.9	0.062	0.	242.7	1278.1
2003	1196	1625	1625	35.9	0.087	0.	256.1	1415.8
2004	1233	1825	1825	48.0	0.029	0.	272.1	1557.8
2005	1270	1807	1807	42.3	0.062	0.	287.4	1703.4
2006	1323	1854	1854	40.2	0.064	0.	302.3	1852.1
2007	1377	1924	1924	39.7	0.057	0.	318.1	2004.1
2008	1430	2098	2098	46.7	0.033	0.	337.5	2160.5
2009	1484	2097	2097	41.3	0.063	0.	350.3	2318.3
2010	1537	2097	2097	36.4	0.060	0.	361.6	2476.3

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML749 12/30/81
****

YR	POOL PEAK (MW)	TOTAL ENERGY (GWH)	LOAD FACTOR	TOTAL COSTS (MIL.$)	YEARLY $/MWH INV.	FUEL	O+M	N.I.	TOTAL
**	******	*******	******	******	*****	*****	*****	*****	******
93	947	4736	57.09	142	5.07	21.23	3.64	0.	29.93
94	965	4829	57.12	165	12.46	17.96	3.76	0.	34.18
95	983	4922	57.16	170	12.22	18.60	3.72	0.	34.55
96	1003	5031	57.10	204	18.14	18.32	4.02	0.	40.47
97	1023	5141	57.37	211	18.21	18.81	3.96	0.	40.99
98	1044	5250	57.40	219	18.29	19.47	3.93	0.	41.69
99	1064	5360	57.51	223	17.91	19.78	3.85	0.	41.55
0	1084	5469	57.44	227	17.56	20.17	3.72	0.	41.45
1	1121	5661	57.65	238	17.38	20.94	3.68	0.	42.01
2	1158	5853	57.70	243	16.81	21.10	3.56	0.	41.46
3	1196	6044	57.69	256	16.68	22.18	3.52	0.	42.38
4	1233	6236	57.58	272	20.01	19.80	3.82	0.	43.63
5	1270	6428	57.78	287	19.78	21.21	3.73	0.	44.72
6	1323	6701	57.82	302	19.33	22.13	3.66	0.	45.12
7	1377	6973	57.81	318	18.92	23.08	3.62	0.	45.62
8	1430	7246	57.69	338	21.52	21.21	3.85	0.	46.58
9	1484	7518	57.83	350	20.74	22.09	3.77	0.	46.60
10	1537	7791	57.86	362	20.01	22.73	3.67	0.	46.41

***** END OF NAMELIST DATA CHECKING ******

4/6

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ID # L7K5

w/o Sus.
with crack
Battelle fuel esc
No esc on Cons. or O&M

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7K5 12/30/81
****

GENERATION SYSTEM

	NUKE	COAL	NGASGT	OIL GT	DIESEL	COMCYC	TYPES	
TYPE	1	2	3	4	5	6	7-10	
OPTMZING	0	1993	1993	0	0	1993	***	
PCT TRIM	0	0	0	0	0	0		
1992 MW	0	59	452	141	67	317	155	SUM= 1190

****

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	****** ****
93							330*	1503
94								1472
95								1424
96								1354
97		200*						1480
98			70*					1495
99								1495
0		200*						1651
1								1651
2			70*					1668
3			70*					1685
4								1685
5		200*						1797
6								1774
7			70*					1844
8			70*					1888
9			70*					1957
10		200*						2157

****
****

MW ADD	0	800	420	0	0	0	330	SUM= 1550
MW RET	0	-46	-335	-141	-61	0	0	SUM= -583
******	******	******	******	******	******	******	****	***********
2010	0	813	536	0	6	~~317~~	485	SUM= 2157
~~PCT TOT~~	~~0.~~	~~37.7~~	~~24.9~~	~~0.~~	~~0.3~~	~~14.7~~	~~22.5~~	~~SUM=100 PCT~~

****

AUTO	0	0	0	0	0	0	0	SUM= 0
PCT TOT	0.	0.	0.	0.	0.	0.	0.	SUM= 0 PCT

* COMMITTED MW

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% -.3%
JOB NUMBER 2ML7K5 12/30/81
****

00234

OT 0. 0. 0. 0. SUM= 0 PCT

5/6

MITTED MW

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

KA RAILBELT
% - 3%
~~UMBER 2ML7K5 12/30/81~~
****

		TOTAL CAPABILITY (INCLUDING TIES)			LOSS OF LOAD PROBABILITY		COST IN MILLION $	
	LOAD	YEAR END	TIME OF PEAK	PCT. RES.	D/Y	H/Y	YEARLY COST	CUM. PW TOTAL
	*****	*****	*****	****	******	******	*******	*******
3	947	1503	1503	58.7	0.000	0.	146.5	105.8
	965	1472	1472	52.5	0.000	0.	151.8	212.3
	983	1424	1424	44.9	0.002	0.	158.3	320.1
6	1003	1354	1354	35.0	0.019	0.	187.8	444.3
	1023	1480	1480	44.7	0.024	0.	192.6	567.9
	1044	1495	1495	43.2	0.030	0.	201.2	693.2
9	1064	1495	1495	40.5	0.044	0.	207.6	818.8
00	1084	1651	1651	52.3	0.024	0.	228.6	953.1
	1121	1651	1651	47.3	0.043	0.	236.8	1088.2
02	1158	1668	1668	44.1	0.065	0.	248.1	1225.5
03	1196	1685	1685	40.9	0.040	0.	255.5	1362.9
	1233	1685	1685	36.7	0.067	0.	264.8	1501.1
0	1270	1797	1797	41.5	0.073	0.	280.6	1643.2
06	1323	1774	1774	34.1	0.095	0.	290.0	1785.9
0	1377	1844	1844	33.9	0.083	0.	304.9	1931.5
0	1430	1888	1888	32.0	0.097	0.	321.1	2080.5
09	1484	1957	1957	31.9	0.087	0.	338.2	2232.7
10	1537	2157	2157	40.3	0.038	0.	353.7	2387.3

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

SKA RAILBELT
% - 3%
B NUMBER 2ML7K5 12/30/81
****

	EXCESS (MW)	DAYS/YEAR	JAN. JULY	FEB. AUG.	MARCH SEPT.	APRIL OCT.	MAY NOV.	JUNE DEC.
			************ LOSS OF LOAD	PROBABILITY	************			
	******	********	********	********	********	********	********	********
3	247.	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	205.	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
			0.0000	0.0000	0.0000	0.0000	0.0000	0.0002
5	148.	0.0018	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
			0.0000	0.0000	0.0000	0.0000	0.0002	0.0015
6	68.	0.0186	0.0017	0.0005	0.0001	0.0000	0.0000	0.0000
			0.0000	0.0000	0.0000	0.0000	0.0020	0.0140
9	66.	0.0240	0.0029	0.0007	0.0004	0.0002	0.0002	0.0002
			0.0002	0.0002	0.0002	0.0002	0.0030	0.0158
8	56.	0.0302	0.0036	0.0009	0.0005	0.0002	0.0002	0.0002
			0.0003	0.0002	0.0002	0.0002	0.0039	0.0197

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

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ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7K5 12/30/81
****

YR	POOL PEAK (MW)	TOTAL ENERGY (GWH)	LOAD FACTOR	TOTAL COSTS (MIL.$)	YEARLY $/MWH INV.	FUEL	O+M	N.I.	TOTAL
**	******	*******	******	******	*****	*****	*****	*****	******
93	947	4736	57.09	146	12.22	15.29	3.42	0.	30.93
94	965	4829	57.13	152	11.98	16.07	3.39	0.	31.44
95	983	4922	57.16	158	11.75	17.01	3.38	0.	32.15
96	1003	5031	57.10	188	11.50	22.50	3.34	0.	37.34
97	1023	5141	57.37	193	17.30	16.72	3.43	0.	37.46
98	1044	5250	57.41	201	17.40	17.50	3.42	0.	38.32
99	1064	5360	57.51	208	17.04	18.29	3.40	0.	38.72
0	1084	5469	57.43	229	23.32	14.85	3.64	0.	41.81
1	1121	5661	57.65	237	22.52	15.73	3.57	0.	41.83
2	1158	5853	57.70	248	22.19	16.67	3.53	0.	42.39
3	1196	6044	57.69	255	21.88	16.95	3.44	0.	42.27
4	1233	6236	57.58	265	21.21	17.86	3.39	0.	42.46
5	1270	6428	57.78	281	24.31	15.72	3.62	0.	43.66
6	1323	6701	57.82	290	23.32	16.46	3.51	0.	43.28
7	1377	6973	57.81	305	22.75	17.52	3.46	0.	43.73
8	1430	7246	57.69	321	22.22	18.69	3.41	0.	44.32
9	1484	7518	57.83	338	21.74	19.86	3.38	0.	44.98
10	1537	7791	57.87	354	24.05	17.75	3.60	0.	45.40

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7K5 12/30/81
****

GENERATION SYSTEM TYPE	1	2	3	4	5	6	7	8	9	10	SUM
92	0	59	452	141	67	317	155	0	0	0	1191

****

YR	YEARLY PERCENT MIX										TOTAL CAPAB.
**											
93	0.	3.9	29.5	9.3	3.9	21.1	32.3	0.	0.	0.	1503
94	0.	4.0	28.0	9.5	3.9	21.5	32.9	0.	0.	0.	1472
95	0.	4.1	28.0	9.4	2.2	22.3	34.0	0.	0.	0.	1424
96	0.	4.4	29.5	4.8	2.1	23.4	35.8	0.	0.	0.	1354
97	0.	17.5	26.7	0.	1.6	21.4	32.8	0.	0.	0.	1480
~~98~~	~~0.~~	~~17.3~~	~~27.8~~	~~0.~~	~~1.2~~	~~21.2~~	~~32.4~~	~~0.~~	~~0.~~	~~0.~~	~~1495~~
99	0.	17.3	27.8	0.	1.2	21.2	32.4	0.	0.	0.	1495
0	0.	26.3	24.1	0.	1.0	19.2	29.4	0.	0.	0.	1651
1	0.	26.3	24.1	0.	1.0	19.2	29.4	0.	0.	0.	1651
2	0.	26.0	25.0	0.	0.9	19.0	29.1	0.	0.	0.	1668
3	0.	25.8	25.7	0.	0.9	18.8	28.8	0.	0.	0.	1685
4	0.	25.8	25.7	0.	0.9	18.8	28.8	0.	0.	0.	1685
5	0.	34.1	20.9	0.	0.4	17.6	27.0	0.	0.	0.	1797
[illegible]	0.	34.6	19.9	0.	0.4	17.9	27.3	0.	0.	0.	1774
											1844

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7V1 12/31/81
****

GENERATION SYSTEM

	NUKE	COAL	NGASGT	OIL GT	DIESEL	COMCYC	TYPES	
TYPE	1	2	3	4	5	6	7-10	
OPTMZING	0	1993	1993	0	0	1993	***	
PCT TRIM	0	0	0	0	0	0		
1992 MW	0	59	452	141	67	317	155	SUM= 1190

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES	
**	*******	*******	*******	*******	*******	*******	*****	******	****
93							680*	1853	
94								1822	
95								1774	
96								1704	
97								1630	
98								1575	
99								1575	
0								1531	
1								1531	
2							601*	2079	
3								2026	
4							1*	2027	
5								1939	
6							1*	1917	
7			1X 70					1987	
8			1X 70				1*	2032	
9								2031	
10			1X 70				1*	2102	

MW ADD	0	0	210	0	0	0	1285	SUM= 1495
MW RET	0	-46	-335	-141	-61	0	0	SUM= -583
****** ******	******	******	******	******	******	******	****	***********
2010	0	13	326	0	6	317	1440	SUM= 2102
PCT TOT	0.	0.6	15.5	0.	0.3	15.1	68.5	SUM=100 PCT
AUTO	0	0	210	0	0	0	0	SUM= 210
PCT TOT	0.	0.	100.0	0.	0.	0.	0.	SUM=100 PCT

* COMMITTED MW

GENERAL·ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7V1 12/31/81
****

YEAR	LOAD	TOTAL CAPABILITY (INCLUDING TIES) YEAR END	TIME OF PEAK	PCT. RES.	LOSS OF LOAD PROBABILITY D/Y	H/Y	COST IN MILLION $ YEARLY COST	CUM. PW TOTAL
****	*****	*****	*****	****	******	******	*******	*******
1993	947	1853	1853	95.7	0.000	0.	203.8	147.2
1994	965	1822	1822	88.8	0.000	0.	209.0	293.8
1995	983	1774	1774	80.5	0.000	0.	211.9	438.1
1996	1003	1704	1704	69.9	0.000	0.	222.2	585.0
1997	1023	1630	1630	59.4	0.000	0.	225.4	729.7
1998	1044	1575	1575	50.8	0.001	0.	229.7	872.8
1999	1064	1575	1575	48.0	0.002	0.	234.6	1014.8
2000	1084	1531	1531	41.2	0.015	0.	244.0	1158.1
2001	1121	1531	1531	36.6	0.032	0.	253.4	1302.6
2002	1158	2079	2079	79.5	0.000	0.	250.7	1441.4
2003	1196	2026	2026	69.4	0.001	0.	268.2	1585.6
2004	1233	2027	2027	64.4	0.001	0.	250.6	1716.3
2005	1270	1939	1939	52.7	0.017	0.	266.9	1851.6
2006	1323	1917	1917	44.9	0.068	0.	254.9	1976.9
2007	1377	1987	1987	44.3	0.025	0.	278.4	2109.9
2008	1430	2032	2032	42.1	0.029	0.	276.7	2238.2
2009	1484	2031	2031	36.9	0.050	0.	296.0	2371.4
2010	1537	2102	2102	36.8	0.025	0.	299.5	2502.3

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7V1 12/31/81
****

YR	POOL PEAK (MW)	TOTAL ENERGY (GWH)	LOAD FACTOR	TOTAL COSTS (MIL.$)	YEARLY $/MWH INV.	FUEL	O+M	N.I.	TOTAL
**	******	*******	******	******	*****	*****	*****	*****	******
93	947	4736	57.09	204	34.49	4.99	3.54	0.	43.02
94	965	4829	57.12	209	33.83	5.95	3.50	0.	43.28
95	983	4922	57.16	212	33.19	6.42	3.44	0.	43.05
96	1003	5031	57.10	222	32.47	8.35	3.35	0.	44.17
97	1023	5141	57.37	225	31.78	8.80	3.27	0.	43.84
98	1044	5250	57.41	230	31.12	9.43	3.21	0.	43.76
99	1064	5360	57.51	235	30.48	10.11	3.18	0.	43.76
0	1084	5469	57.44	244	29.87	11.63	3.12	0.	44.62
1	1121	5661	57.65	253	28.86	12.81	3.09	0.	44.76
2	1158	6352	62.61	251	35.96	0.	3.51	0.	39.47
3	1196	6455	61.61	268	35.39	2.66	3.50	0.	41.54
4	1233	6599	60.92	251	34.62	0.	3.36	0.	37.97
5	1270	6698	60.21	267	34.10	2.44	3.29	0.	39.84
6	1323	6880	59.36	255	33.20	0.69	3.15	0.	37.04
7	1377	7079	58.69	278	32.60	3.56	3.16	0.	39.32
8	1430	7310	58.20	277	31.90	2.89	3.07	0.	37.85
9	1484	7551	58.08	296	30.88	5.28	3.04	0.	39.20
10	1537	7827	58.14	300	30.10	5.21	2.96	0.	38.26

Gar

BEGIN FILE - L7090207

SNUMB = ML709, ACTIVITY # = 02, REPORT CODE = 07, RECORD COUNT = 000349

GENERAL ELECTRIC COMPANY, OGP-5 GENERATION PLANNING PROGRAM 1/6
JOB NUMBER 2ML709 12/31/81

ID # L709 1/6

NAMELIST DATA RECORD 1 HAS BEEN READ
NAMELIST DATA RECORD 2 HAS BEEN READ

w/o Susitna or Chak

Acres- esc on fuel

Ebasco - esc on Cons., O&M

****** END OF NAMELIST DATA CHECKING ******

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML709 12/31/81
****

GENERATION SYSTEM

	NUKE	COAL	NGASGT	OIL GT	DIESEL	COMCYC	TYPES		
TYPE	1	2	3	4	5	6	7-10		
OPTMZING	0	1993	1993	0	0	1993	***		
PCT TRIM	0	0	0	0	0	0			
1992 MW	0	59	452	141	67	317	155	SUM=	1190

****

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	****** ****
93		200*						1373
94		1X 200						1542
95								1495
96		200*						1624
97			70*					1620
98			70*					1635
99								1635
0								1591
1			70*					1661
2								1608
3			70*					1625
4		200*						1825
5			70*					1807
6			70*					1854
7			70*					1924
8		200*						2098
9								2097
10								2097

****
****

MW ADD	0	1000	490	0	0	0	0	SUM=	1490
MW RET	0	-46	-335	-141	-61	0	0	SUM=	-583
******	******	******	******	******	******	******	****	***********	
2010	0	1013	606	0	6	317	155	SUM=	2097
PCT TOT	0.	48.3	28.9	0.	0.3	15.1	7.4	SUM=100 PCT	
AUTO	0	200	0	0	0	0	0	SUM=	200
PCT TOT	0.	100.0	0.	0.	0.	0.	0.	SUM=100 PCT	

9	2097	1484	0.0627
10	2097	1537	0.0603

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*****************************************************************************
*****************************************************************************
MW ADD    1490        0         0         0         0   SUM=     1490
MW RET    -583        0         0         0         0   SUM=     -583
****** ******    ******    ******    ******    ******   ************
2010      1942      155         0         0         0   SUM=     2097
PCT TOT   92.6      7.4        0.        0.        0.   SUM= 100 PCT
*****************************************************************************
AUTO       200                  0         0         0   SUM=      200
PCT TOT  100.0                 0.        0.        0.   SUM= 100 PCT
```

2/6

* COMMITTED MW

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML709 12/31/81
****

YEAR	LOAD	TOTAL CAPABILITY (INCLUDING TIES) YEAR END	TIME OF PEAK	PCT. RES.	LOSS OF LOAD PROBABILITY D/Y	H/Y	COST IN MILLION $ YEARLY COST	CUM. PW TOTAL
****	*****	*****	*****	****	******	******	*******	*******
1993	947	1373	1373	45.0	0.063	0.	171.3	123.8
1994	965	1542	1542	59.8	0.027	0.	194.7	260.4
1995	983	1495	1495	52.0	0.077	0.	201.0	397.3
1996	1003	1624	1624	61.9	0.059	0.	250.6	563.0
1997	1023	1620	1620	58.4	0.084	0.	261.2	730.6
1998	1044	1635	1635	56.6	0.092	0.	271.6	899.9
1999	1064	1635	1635	53.6	0.055	0.	278.5	1068.4
2000	1084	1591	1591	46.8	0.059	0.	285.0	1235.8
2001	1121	1661	1661	48.2	0.038	0.	296.9	1405.1
2002	1158	1608	1608	38.9	0.062	0.	305.3	1574.1
2003	1196	1625	1625	35.9	0.087	0.	320.1	1746.2
2004	1233	1825	1825	48.0	0.029	0.	356.5	1932.3
2005	1270	1807	1807	42.3	0.062	0.	373.1	2121.3
2006	1323	1854	1854	40.2	0.064	0.	391.2	2313.7
2007	1377	1924	1924	39.7	0.057	0.	410.2	2509.6
2008	1430	2098	2098	46.7	0.033	0.	453.3	2719.8
2009	1484	2097	2097	41.3	0.063	0.	468.0	2930.5
2010	1537	2097	2097	36.4	0.060	0.	481.8	3141.1

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML709 12/31/81
****

YEAR	EXCESS (MW)	DAYS/YEAR	JAN. JULY	FEB. AUG.	MARCH SEPT.	APRIL OCT.	MAY NOV.	JUNE DEC.
****	******	********	******	******	******	******	******	******

ZERO% - 3%
JOB NUMBER 2ML709 12/31/81
****

3/6

YR	POOL PEAK (MW)	TOTAL ENERGY (GWH)	LOAD FACTOR	TOTAL COSTS (MIL.$)	YEARLY $/MWH INV.	FUEL	O+M	N.I.	TOTAL
93	947	4736	57.09	171	9.31	22.43	4.43	0.	36.18
94	965	4829	57.12	195	15.31	20.35	4.67	0.	40.33
95	983	4922	57.16	201	15.02	21.11	4.71	0.	40.84
96	1003	5031	57.10	251	22.69	21.92	5.21	0.	49.82
97	1023	5141	57.37	261	22.82	22.74	5.26	0.	50.82
98	1044	5250	57.40	272	22.96	23.46	5.31	0.	51.73
99	1064	5360	57.51	278	22.48	24.15	5.32	0.	51.96
0	1084	5469	57.44	285	22.04	24.84	5.24	0.	52.12
1	1121	5661	57.65	297	21.89	25.26	5.29	0.	52.44
2	1158	5853	57.70	305	21.17	25.76	5.23	0.	52.16
3	1196	6044	57.69	320	21.09	26.61	5.27	0.	52.97
4	1233	6236	57.58	356	26.27	25.06	5.83	0.	57.16
5	1270	6428	57.78	373	26.06	26.19	5.79	0.	58.04
6	1323	6701	57.82	391	25.56	27.01	5.80	0.	58.37
7	1377	6973	57.81	410	25.11	27.86	5.85	0.	58.82
8	1430	7246	57.69	453	29.60	26.61	6.35	0.	62.56
9	1484	7518	57.83	468	28.53	27.39	6.33	0.	62.25
10	1537	7791	57.86	482	27.53	28.03	6.29	0.	61.85

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML709 12/31/81
****

GENERATION SYSTEM

TYPE	1	2	3	4	5	6	7	8	9	10	SUM
92	0	59	452	141	67	317	155	0	0	0	1191

YR	YEARLY PERCENT MIX										TOTAL CAPAB.
93	0.	18.9	32.3	10.2	4.3	23.1	11.3	0.	0.	0.	1373
94	0.	29.8	26.8	9.1	3.7	20.6	10.1	0.	0.	0.	1542
95	0.	30.7	26.7	8.9	2.1	21.2	10.4	0.	0.	0.	1495
96	0.	40.6	24.6	4.0	1.8	19.5	9.5	0.	0.	0.	1624
97	0.	40.7	28.8	0.	1.4	19.6	9.6	0.	0.	0.	1620
98	0.	40.3	29.7	0.	1.1	19.4	9.5	0.	0.	0.	1635
99	0.	40.3	29.7	0.	1.1	19.4	9.5	0.	0.	0.	1635
0	0.	39.8	29.4	0.	1.1	19.9	9.7	0.	0.	0.	1591
1	0.	38.2	32.4	0.	1.0	19.1	9.3	0.	0.	0.	1661
2	0.	39.4	30.3	0.	0.9	19.7	9.6	0.	0.	0.	1608
3	0.	39.0	31.0	0.	0.9	19.5	9.5	0.	0.	0.	1625
4	0.	45.7	27.6	0.	0.8	17.4	8.5	0.	0.	0.	1825
5	0.	45.0	28.5	0.	0.4	17.5	8.6	0.	0.	0.	1807
6	0.	43.8	30.4	0.	0.3	17.1	8.4	0.	0.	0.	1854
7	0.	42.3	32.9	0.	0.3	16.5	8.1	0.	0.	0.	1924
8	0.	48.3	28.9	0.	0.3	15.1	7.4	0.	0.	0.	2098
9	0.	48.3	28.9	0.	0.3	15.1	7.4	0.	0.	0.	2097
10	0.	48.3	28.9	0.	0.3	15.1	7.4	0.	0.	0.	2097

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OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7V7 12/31/81
****

GENERATION SYSTEM

	NUKE	COAL	NGASGT	OIL GT	DIESEL	COMCYC	TYPES		
TYPE	1	2	3	4	5	6	7-10		
OPTMZING	0	1993	1993	0	0	1993	***		
PCT TRIM	0	0	0	0	0	0			
1992 MW	0	59	452	141	67	317	155	SUM=	1190

****

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES	
**	*******	*******	*******	*******	*******	*******	*****	******	****
93							680*	1853	
94								1822	
95								1774	
96								1704	
97								1630	
98								1575	
99								1575	
0								1531	
1								1531	
2							601*	2079	
3								2026	
4							1*	2027	
5								1939	
6							1*	1917	
7								1987	
8			70*				1*	2032	
9			70*					2031	
10			70*				1*	2102	

****

MW ADD	0	0	210	0	0	0	1285	SUM=	1495
MW RET	0	-46	-335	-141	-61	0	0	SUM=	-583
******	******	******	******	******	******	******	****	***********	
2010	0	13	326	0	6	317	1440	SUM=	2102
PCT TOT	0.	0.6	15.5	0.	0.3	15.1	68.5	SUM=100 PCT	
AUTO	0	0	0	0	0	0	0	SUM=	0
PCT TOT	0.	0.	0.	0.	0.	0.	0.	SUM=	0 PCT

* COMMITTED MW

GENERAL ELECTRIC COMPANY

OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT

****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7V7 12/31/81
****

YR	POOL PEAK (MW)	TOTAL ENERGY (GWH)	LOAD FACTOR	TOTAL COSTS (MIL.$)	YEARLY $/MWH INV.	FUEL	O+M	N.I.	TOTAL
93	947	4736	57.09	243	42.05	4.99	4.32	0.	51.36
94	965	4829	57.12	249	41.24	5.95	4.35	0.	51.55
95	983	4922	57.16	252	40.46	6.33	4.36	0.	51.16
96	1003	5031	57.10	263	39.59	8.35	4.35	0.	52.28
97	1023	5141	57.37	267	38.74	8.80	4.33	0.	51.87
98	1044	5250	57.41	271	37.94	9.43	4.34	0.	51.71
99	1064	5360	57.51	277	37.16	10.11	4.39	0.	51.65
0	1084	5469	57.44	287	36.42	11.72	4.40	0.	52.54
1	1121	5661	57.65	297	35.18	12.81	4.44	0.	52.43
2	1158	6352	62.61	327	46.28	0.	5.14	0.	51.42
3	1196	6455	61.61	345	45.54	2.66	5.23	0.	53.42
4	1233	6599	60.92	328	44.55	0.	5.11	0.	49.66
5	1270	6698	60.21	345	43.89	2.44	5.12	0.	51.45
6	1323	6880	58.36	333	42.73	0.69	5.00	0.	48.41
7	1377	7079	58.69	359	42.07	3.56	5.12	0.	50.74
8	1430	7310	58.20	360	41.27	2.89	5.05	0.	49.21
9	1484	7551	58.08	380	39.96	5.28	5.11	0.	50.34
10	1537	7827	58.14	386	39.07	5.21	5.08	0.	49.35

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

ALASKA RAILBELT
ZERO% - 3%
JOB NUMBER 2ML7V7 12/31/81
****

		TOTAL CAPABILITY (INCLUDING TIES)			LOSS OF LOAD PROBABILITY		COST IN MILLION $	
YEAR	LOAD	YEAR END	TIME OF PEAK	PCT. RES.	D/Y	H/Y	YEARLY COST	CUM. PW TOTAL
****	*****	*****	*****	****	******	******	*******	*******
1993	947	1853	1853	95.7	0.000	0.	243.3	175.7
1994	965	1822	1822	88.8	0.000	0.	248.9	350.3
1995	983	1774	1774	80.5	0.000	0.	251.8	521.8
1996	1003	1704	1704	69.9	0.000	0.	263.0	695.7
1997	1023	1630	1630	59.4	0.000	0.	266.7	866.9
1998	1044	1575	1575	50.8	0.001	0.	271.5	1036.0
1999	1064	1575	1575	48.0	0.002	0.	276.8	1203.5
2000	1084	1531	1531	41.2	0.015	0.	287.3	1372.3
2001	1121	1531	1531	36.6	0.032	0.	296.8	1541.6
2002	1158	2079	2079	79.5	0.000	0.	326.6	1722.4
2003	1196	2026	2026	69.4	0.001	0.	344.9	1907.8
2004	1233	2027	2027	64.4	0.001	0.	327.7	2078.8
2005	1270	1939	1939	52.7	0.017	0.	344.6	2253.4
2006	1323	1917	1917	44.9	0.068	0.	333.1	2417.3
2007	1377	1987	1987	44.3	0.025	0.	359.2	2588.8
2008	1430	2032	2032	42.1	0.029	0.	359.8	2755.6
2009	1484	2031	2031	36.9	0.050	0.	380.1	2926.8
2010	1537	2102	2102	36.8	0.025	0.	386.3	3095.6

ITEM 5 - LOAD PROJECTIONS

Item 5

ACRES AMERICAN INC., COLUMBIA MD., 21044
ALASKA RAILBELT BATTELLE MEDIUM FORECAST

YEAR	(MW) POOL PEAK	(MWH) TOTAL ENERGY	LOAD FACTOR
1981	574.	2893000.	57.54
1982	601.	3027000.	57.50
1983	626.	3162000.	57.66
1984	652.	3296000.	57.55
1985	678.	3431000.	57.77
1986	721.	3636000.	57.57
1987	764.	3841000.	57.39
1988	806.	4046000.	57.15
1989	849.	4251000.	57.16
1990	892.	4456000.	57.03
1991	910.	4549000.	57.07
1992	928.	4642000.	56.95
1993	947.	4736000.	57.09
1994	965.	4829000.	57.12
1995	983.	4922000.	57.16
1996	1003.	5031000.	57.10
1997	1023.	5141000.	57.37
1998	1044.	5250000.	57.41
1999	1064.	5360000.	57.51
2000	1084.	5469000.	57.44
2001	1121.	5661000.	57.65
2002	1158.	5853000.	57.70
2003	1196.	6044000.	57.69
2004	1233.	6236000.	57.58
2005	1270.	6428000.	57.78
2006	1323.	6701000.	57.82
2007	1377.	6973000.	57.81
2008	1430.	7246000.	57.69
2009	1484.	7518000.	57.83
2010	1537.	7791000.	57.86

ACRES AMERICAN INC., COLUMBIA MD., 21044
ALASKA RAILBELT
BATTELLE LOW FORECAST

YEAR	(MW) POOL PEAK	(MWH) TOTAL ENERGY	LOAD FACTOR
1981	568.	2853000.	57.34
1982	586.	2948000.	57.43
1983	605.	3044000.	57.44
1984	623.	3139000.	57.36
1985	642.	3234000.	57.50
1986	674.	3387000.	57.37
1987	706.	3540000.	57.24
1988	738.	3693000.	56.97
1989	770.	3846000.	57.02
1990	802.	3999000.	56.92
1991	811.	4047000.	56.97
1992	821.	4095000.	56.78
1993	830.	4144000.	57.00
1994	840.	4192000.	56.97
1995	849.	4240000.	57.01
1996	863.	4320000.	56.99
1997	878.	4400000.	57.21
1998	892.	4481000.	57.35
1999	907.	4561000.	57.40
2000	921.	4641000.	57.37
2001	950.	4784000.	57.49
2002	979.	4928000.	57.46
2003	1008.	5071000.	57.43
2004	1037.	5215000.	57.25
2005	1066.	5358000.	57.38
2006	1102.	5547000.	57.46
2007	1138.	5736000.	57.54
2008	1173.	5925000.	57.50
2009	1209.	6114000.	57.73
2010	1245.	6303000.	57.79

0 0 2 3 4

JOB NUMBER 1ML4V5 12/30/81

ACRES AMERICAN INC., COLUMBIA MD., 21044
ALASKA RAILBELT
BATTELLE HIGH FORECAST

YEAR	(MW) POOL PEAK	(MWH) TOTAL ENERGY	LOAD FACTOR
1981	598.	3053000.	58.28
1982	647.	3347000.	59.05
1983	696.	3642000.	59.73
1984	745.	3936000.	60.15
1985	794.	4231000.	60.83
1986	855.	4525000.	60.42
1987	916.	4820000.	60.07
1988	976.	5114000.	59.65
1989	1037.	5409000.	59.54
1990	1098.	5703000.	59.29
1991	1128.	5855000.	59.25
1992	1158.	6007000.	59.06
1993	1188.	6160000.	59.19
1994	1218.	6312000.	59.16
1995	1248.	6464000.	59.13
1996	1286.	6663000.	58.98
1997	1324.	6861000.	59.16
1998	1363.	7060000.	59.13
1999	1401.	7258000.	59.14
2000	1439.	7457000.	58.99
2001	1505.	7795000.	59.13
2002	1571.	8133000.	59.10
2003	1637.	8472000.	59.08
2004	1703.	8810000.	58.89
2005	1769.	9148000.	59.03
2006	1848.	9605000.	59.33
2007	1927.	10063000.	59.61
2008	2007.	10520000.	59.67
2009	2086.	10978000.	60.08
2010	2165.	11435000.	60.29

ITEM 6 - SUMMARY - GE OGP MODEL

Item 6

ELECTRIC UTILITY SYSTEMS ENGINEERING DEPARTMENT

OPTIMIZED GENERATION PLANNING PROGRAM

PROGRAM DESCRIPTION

MARCH 1979

GENERAL ELECTRIC COMPANY
1 RIVER ROAD
SCHENECTADY, N.Y. 12345

Table of Contents

OPTIMIZED GENERATION PLANNING (OGP) PROGRAM

The OGP program was developed over ten years ago to combine the three main elements of generation expansion planning (system reliability, operating and investment costs) and automate generation addition decision analysis.

The first calculation in selecting the generating capacity to install in a future year is the reliability evaluation using either percent installed reserves or loss-of-load probability (LOLP). This answers the questions of "how much" capacity to add and "when" it should be installed. A production costing simulation is also done to determine the operating costs for the generating system with the given unit additions. Finally, an investment cost analysis of the capital costs of the unit additions is performed. The operating and investment costs help to answer the question of "what kind" of generation to add to the system.

The next three sections review the elements of these computations.

Reliability Evaluation

Historically, electric utility system planners measured generation system reliability with a percent reserves index. This planning design criterion compared the total installed generating capacity to the annual peak load demand. However, this approach proved to be a relatively insensitive indicator of system reliability, particularly when comparing alternative units whose size and forced outage rate varied.

Since its introduction in 1946, the measure that has gradually gained widest acceptance in the industry is the "loss-of-load probability." The LOLP method is a probabilistic determination of the expected number of days per year on which the demand exceeds the available capacity. It factors into the reliability calculation the forced and planned outage rates of the units on the system as well as their sizes.

Computing LOLP requires an identification of all outage events possible (in a system with n units, this means 2^n events) and then a determination of the probability of each outage event. However, since LOLP is concerned with system capacity outages and not so much with particular unit outages, the probability of a given total amount of capacity on outage is calculated. This information can be presented as a "cumulative capacity outage table" as shown in Figure 1.

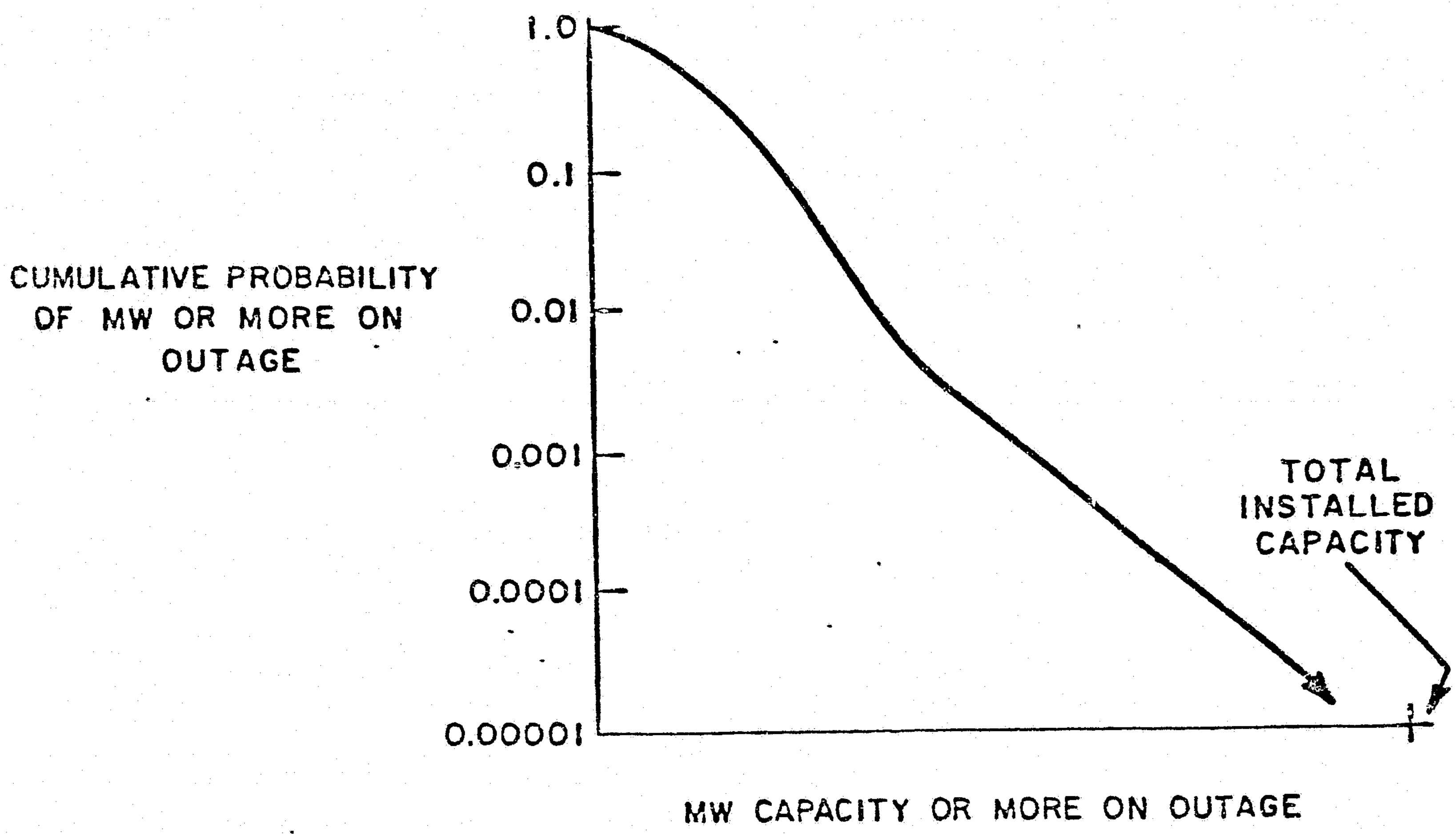

Figure 1. Cumulative Capacity Outage Table

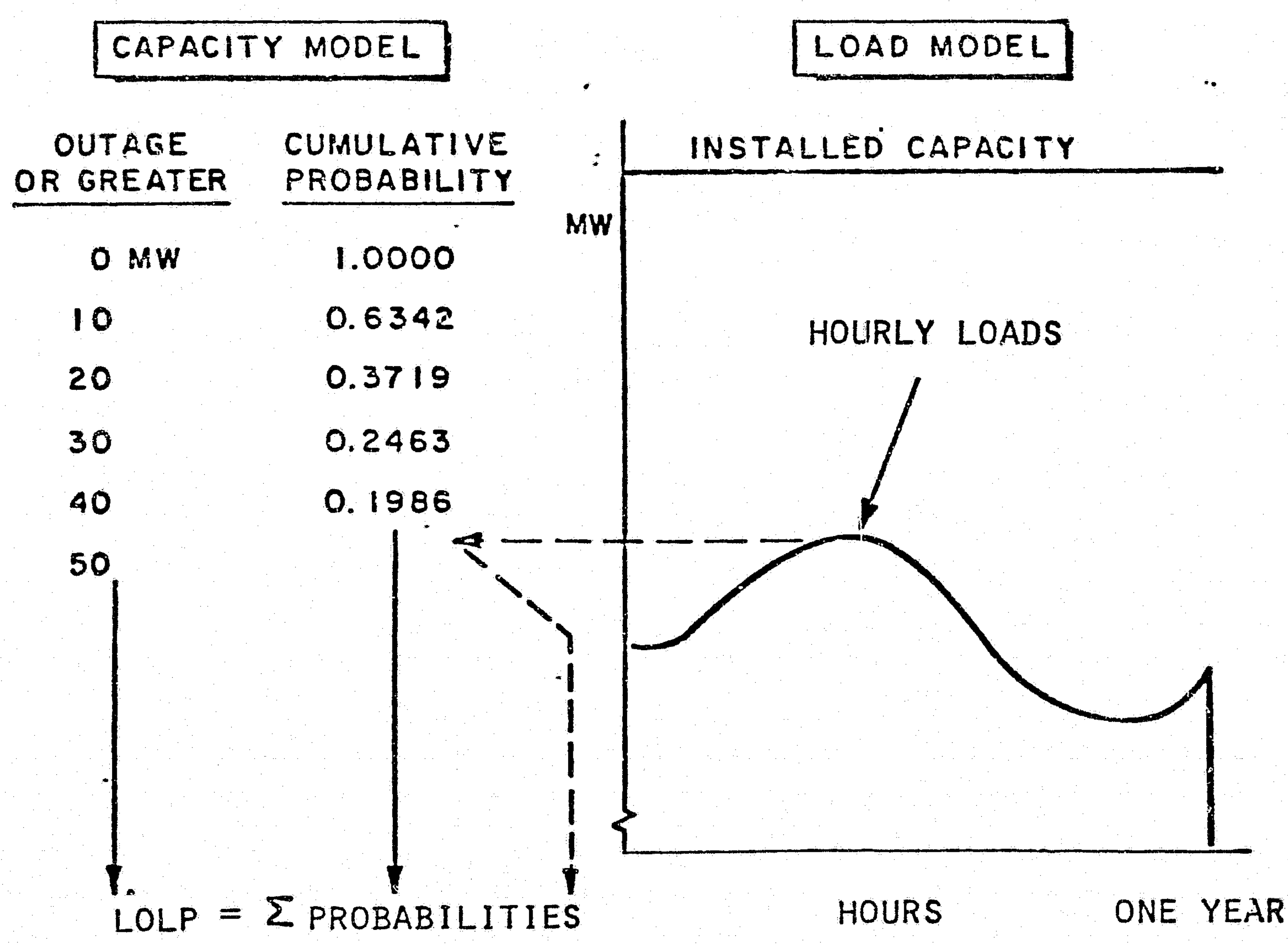

Figure 2. LOLP Calculation Procedure

Utilizing a highly efficient recursive computer technique, these capacity outage tables are calculated directly from a list of unit ratings and forced outage rates.

The LOLP for a particular hour is calculated based on the demand and installed capacity for that hour. The reserves are given by capacity minus demand. On this basis, a deficiency in available capacity (i.e., loss of load) occurs if the capacity on forced outage exceeds the reserves. The probability of this happening is read directly from the cumulative outage table and is the LOLP for a single hour as shown in Figure 2.

In addition to calculating the percent installed reserves, OGP can also calculate a daily LOLP (days/year) and an hourly value (hours/year). The daily LOLP is determined by summing the probabilities of not meeting the peak demand for each weekday in the year. The hourly LOLP is calculated by summing the probabilities of not meeting the load for all the hours in the year. These two values are not related by a factor of 24 because a deficiency for the peak hour of the day does not necessarily imply a deficiency for the entire day.

The discussion above proceeded on the assumption that the hourly demand was specified deterministically. The inclusion of load forecasting uncertainty can also be important and has been integrated into the OGP computational procedure. At each demand point in the uncertainty distribution, the LOLP is calculated. The equivalent is then determined by weighting the LOLP result at each demand point by the probability distribution value.

Utilizing this technique, generation planners can design the generation system to a specified level of reliability. As the demand grows through time, generation additions are automatically timed by OGP such that the LOLP does not exceed the design criterion.

Figure 3 plots LOLP versus the annual peak load for a specific generation system. As the graph indicates, LOLP varies exponentially with load changes. The design criterion in this case is 0.1 days/year. For the 1985 peak load indicated on the graph, the generation system is at a level of reliability better than 0.1 days/year. Therefore, no additional capacity is required.

In 1986, the annual peak has increased to a point where the generation system cannot maintain the desired 0.1 days/year LOLP. In anticipation of this, a unit addition would

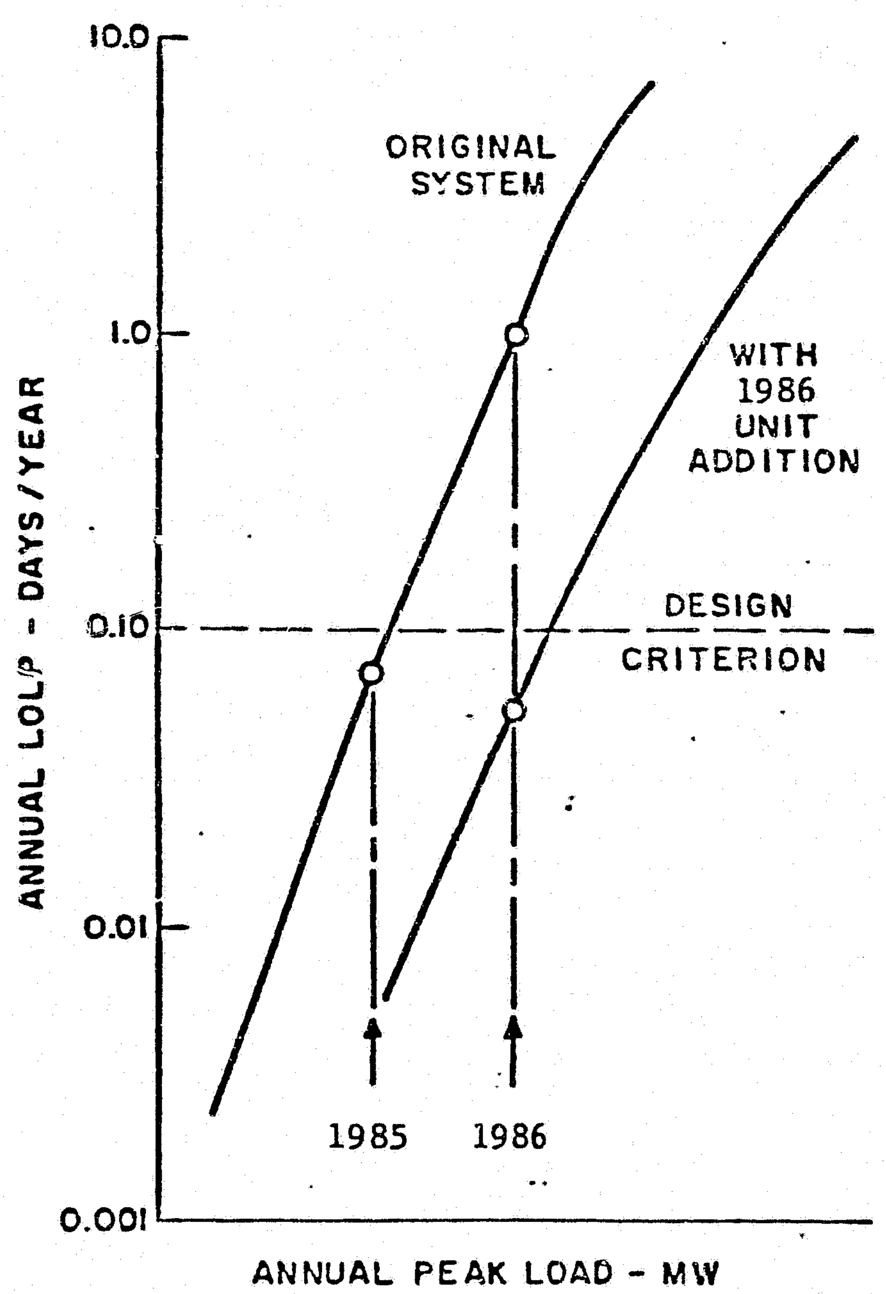

Figure 3. LOLP vs. Annual Peak Load

be scheduled for 1986. What happens to the LOLP versus peak load curve?

With the new unit addition installed, the curve shifts to the right as in Figure 3. In 1986, the LOLP has decreased from 1.0 days/year to about 0.05 days/year because of the unit addition. This is below the desired 0.1 days/year criterion established by the utility system planner and hence the unit addition process is completed in that year.

Production Simulation

Once a system with sufficient generating capacity has been determined by the reliability evaluation, the fuel and related operating and maintenance (O&M) costs of the system must be calculated. OGP does this by an hourly simulation of system operation.

The program commits and dispatches generation based on economics so as to minimize costs. However, the user has the option of biasing or overriding the normal economic operation of the system. This can be accomplished in two ways. The user may specify weighting factors for various environmentally related quantities such that the program will operate those units to minimize their impact. The user may also limit, on a monthly basis, the number of hours that units may run or the amounts of different fuels that may be consumed.

The production simulation in OGP is performed in six steps: load modification based on recognition of contractual purchases and sales; conventional hydro scheduling and its associated load modification; monthly thermal unit maintenance scheduling based on planned outage rates; pumped storage hydro or other energy storage scheduling; thermal unit commitment for the remaining loads based on economics and/or environmental factors, spinning reserve rules, and unit cycling capabilities; and unit dispatch based on incremental production costs and environmental emissions. The production simulation is for a single utility system or pool. Unrestrained power transfer capability is assumed between areas or companies internal to the pool represented.

Purchases and Sales

The OGP production cost load model is an hour-by-hour model of a typical weekday and weekend day for each month, arranged in monotonically decreasing order. These hourly loads are modified to reflect the firm purchases and sales between the area being studied and entities outside that area. Each contract has associated with it a demand charge ($/kW/yr) and an energy charge ($/MWh).

Conventional Hydro Scheduling

Hydro energy generally has a very small incremental variable cost and, therefore, in OGP it is used as much as possible so as to minimize system operating costs. There are two types of conventional hydro. First, run of river hydro is typically an installation which has a low head and minimal storage. These units tend to be base loaded since the river and dam characteristics dictate that the unit must be running most of the time. The second form of conventional hydro is pondage hydro, characterized by a significant volume of storage. Pondage hydro units are usually scheduled during peak load time periods because it is during these periods that the system's incremental fuel cost is at its highest. Thus, the pondage hydro is scheduled to shave peaks. In scheduling conventional hydro, attention must be given to the fact that hydro capability is affected by seasonal conditions. This is handled in OGP by specifying data on a monthly basis.

Thermal Unit Maintenance

On a utility system, the planned maintenance of individual units is usually performed on a monthly basis. During these periods, the units are unavailable for energy production. Maintenance scheduling is normally done so as to minimize the effect on both system reliability and system operating costs. A common strategy for scheduling maintenance, and the method used in OGP, is the levelized reserves approach. Basically, the monthly peak loads are examined throughout the year and incremental amounts of generating capacity maintenance scheduled to try and levelize the peak load plus capacity on maintenance throughout the year.

Increased maintenance levels which might be required during the first few years of a unit's operation are modeled using an immaturity multiplier. OGP also allows the user to annually input a predetermined maintenance schedule for units for which this information is available.

Energy Storage Scheduling

Although very often applied to studies of pumped storage hydro, OGP may also be used to study other types of energy storage on electric utility systems such as batteries, thermal storage, and compressed air storage.

Recognizing losses in the cycle, generating and charging energy is scheduled to maximize the savings in system production costs on a weekly basis. Energy storage units are assumed to be fully charged at the beginning of the week. Incremental amounts of generation are balanced by enough charging to fully recharge the unit by the start of the next week. Because of the nonlinearity in system operating costs, the energy storage units can operate so as to decrease costs despite a cycle efficiency less than 100%.

Thermal Unit Commitment

After modifications for contracts, hydro, unit maintenance, and energy storage, the remaining loads must be served by the thermal units on the system. In OGP, the units can be committed to minimize either the operating costs, as is usually done, or some combination of user specified environmental factors and operating costs. The operating costs are calculated from the fuel and variable O&M costs and input-output curve for each unit. Fixed O&M costs do not effect the order in which units are committed, but are included in the total production cost.

Figure 4 illustrates the type of input-output representation used by OGP to model the thermal characteristics of generating units. This model specifies the fuel input in Btu per hour as a function of the electric power output in megawatts. However, performance economics are dictated not only by the heat input but also the price ($/MBtu) of the fuel used by the generating unit. Therefore, the cost characteristic relating fuel cost per hour to power output is simply the product of the heat input characteristic and the fuel price. In addition to the fuel input versus power output specification, the maximum and minimum output are specified as operating limits.

The environmental quantities that OGP can factor into the operation of the system along with the operating costs are: heat rejection into the atmosphere, heat rejection into the cooling medium, SO_2 emissions, NO_x emissions, CO emissions, particulate emissions, and water consumption. Figure 5 shows that these characteristics are modeled much like the unit heat rate.

The unit commitment logic determines how many units will be on-line each hour and also attempts to provide an adequate level of operating reliability while minimizing the system operating costs and/or environmental emissions. The operating reliability requirement is met by committing sufficient generation to meet the load plus a user specified

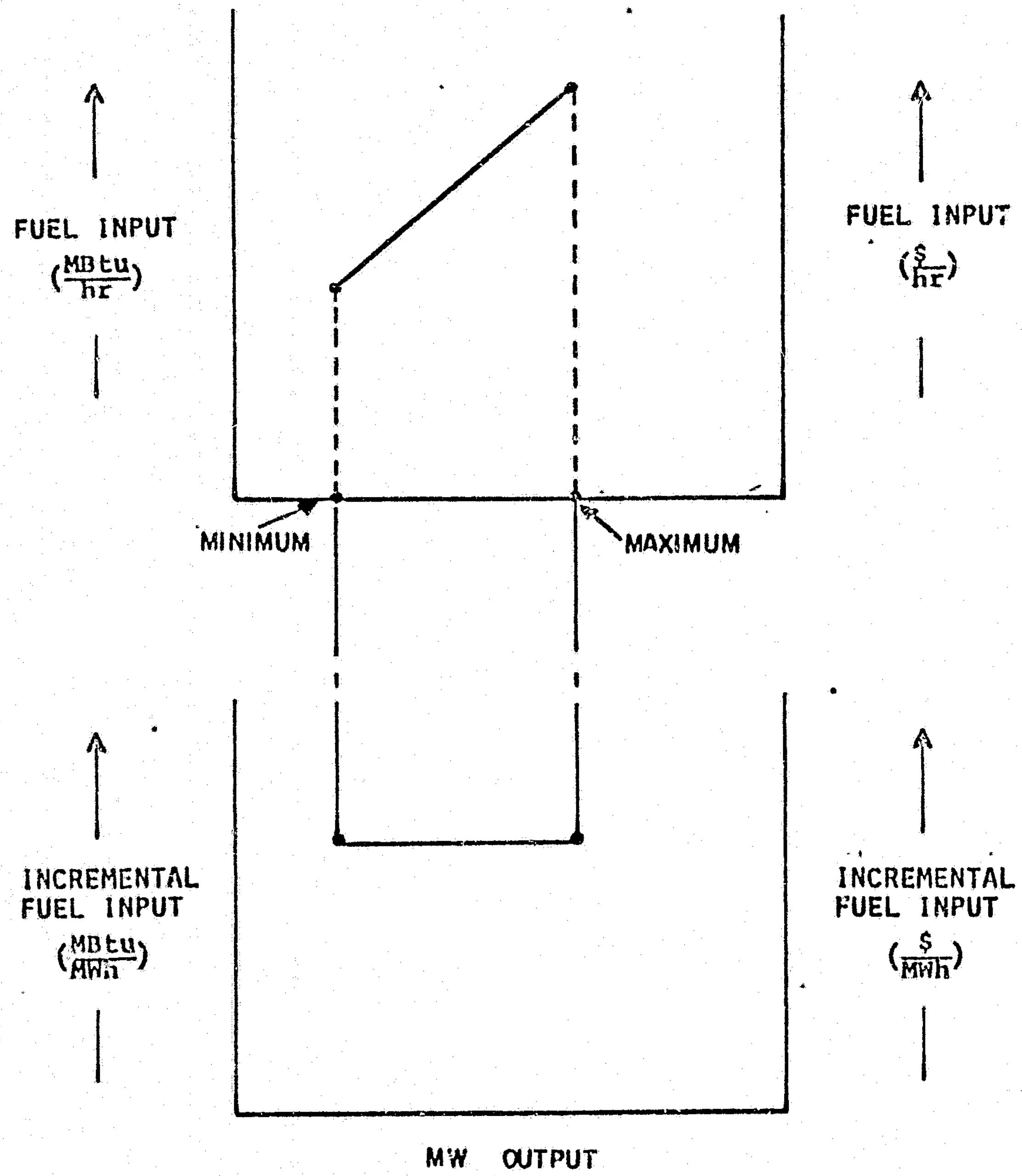

Figure 4. Generating Unit Input-Output Representation

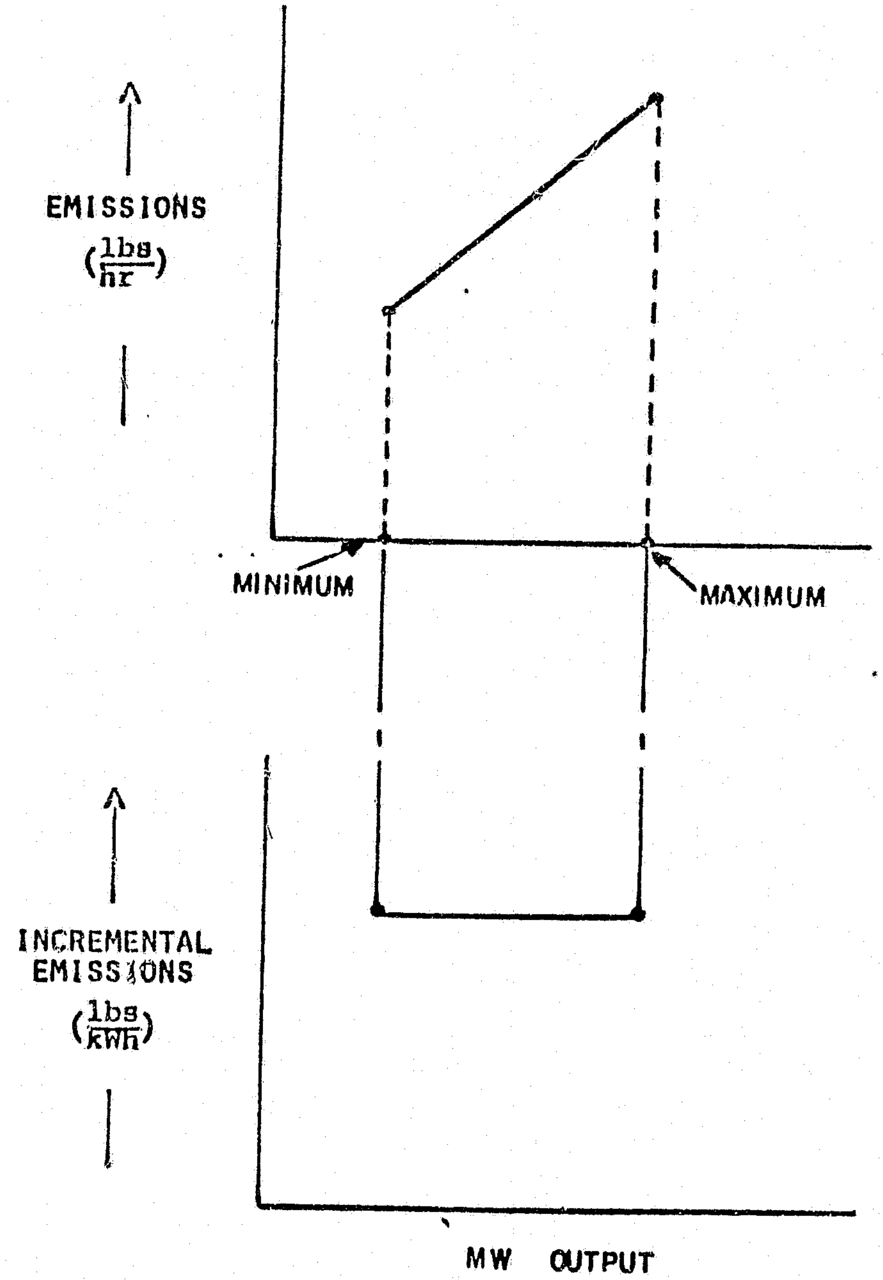

Figure 5. Generating Unit Emissions Output Representation

spinning reserve margin. Units are committed in order of their full load energy costs or emissions, starting with the least expensive.

This commitment is then reviewed to determine if the thermal cycling capability of any units is being violated. If so, this preliminary commitment will be modified to keep such units on line as may be dictated by their cycling restrictions.

Thermal Unit Dispatch

If a unit is committed, the unit's minimum loading level requires that its output be at that level or higher. When the final commitment has been established, each unit will be loaded to at least it's minimum. Typically the sum of the minimums does not equal the load. Additional load will be served by the units' incremental loading sections. The dispatching function in the OGP production simulation loads the incremental sections of the units committed in a manner which serves the demand at minimum system fuel cost or emissions. This dispatch technique is the equal incremental cost approach.

Figures 4 and 5 also show the incremental fuel cost and environmental emissions models used in dispatching the incremental loading sections to serve the load.

OGP can model the forced outages of units either deterministically, by extending the planned maintenance period, or stochastically. In the stochastic dispatch, the program recognizes that units will be out of service in each zone of constant commitment for a period of time proportional to the forced outage rate. The load previously served by these units will be transferred to higher cost units. This usually requires the commitment of additional generating units. If additional units are not available, emergency tie energy will be supplied at a cost input by the user.

Fuel and Energy Limitations

OGP has the option of performing the production simulation subject to additional constraints. The amount of energy to be generated each month by each unit or the quantities of the different fuels consumed in a month may be limited. If any limits are reached, other, less economic units will be committed and dispatched as needed.

Investment Costing

The investment cost analysis in OGP calculates the annual carrying charges for each generating unit added to the system. This is computed based on a $/kW installed cost, a kW nameplate rating, and an annual levelized fixed charge rate.

OGP Optimization Procedure

Figure 6 outlines the procedure used by OGP to determine an optimum generation expansion plan.

For the year under study, a reliability evaluation is performed. This determines the need for additional generating capacity. If the capacity is sufficient, the program calculates the annual production and investment costs, prints these values, and proceeds to the next year.

If additional capacity is needed, the program will add units from a list of available additions until the reliability index is met. This list can contain up to six thermal types and three types of energy storage units. These units can be added both by themselves and in combinations with other types of generation.

For each combination of units added to the system, OGP does a production simulation and investment cost calculation for the year under study. The program uses the information gained from the cost calculations to logically step through the different combinations of units to add, eliminating from consideration combinations that would produce higher annual costs than previously found. This process continues until the expansion giving the lowest annual costs is found. The selected units are added to the system, and the program proceeds to the next year of the study.

In cases where operating cost inflation and/or time variation in unit outage rates are present, the OGP optimization logic utilizes a "look-ahead" feature. The look-ahead feature develops levelized fuel and O&M costs and mature outage rates for use in the economic evaluation. As part of the output information available, the user obtains documentation of the relative costs of all the alternatives examined. After the generating unit selection, the reliability and costing calculations are repeated for the chosen alternative so that the expansion report available for the user contains the correct annual values.

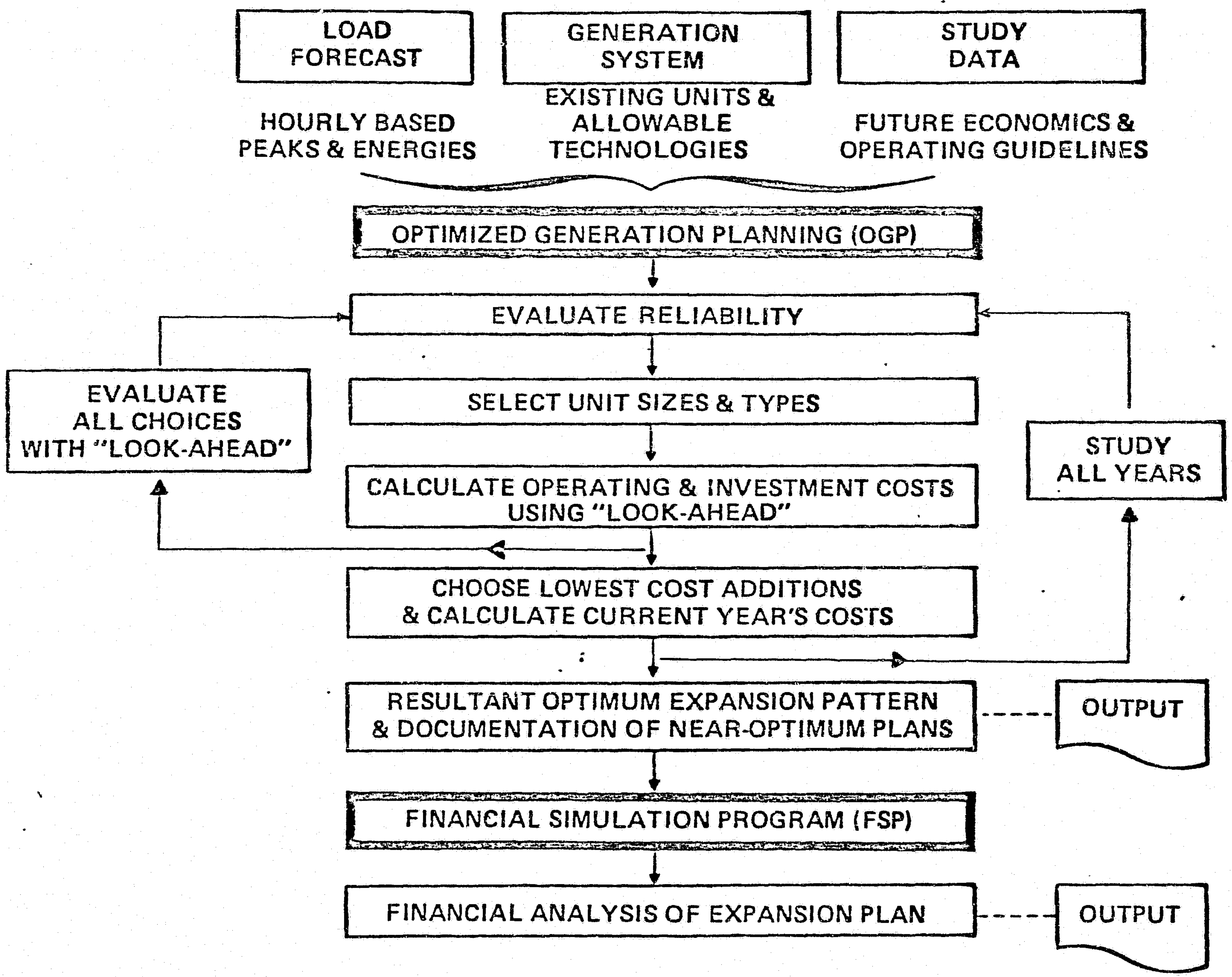

Figure 6. Optimized Generation Planning (OGP) Program

Sample Output Results

The "bottom line" result from the OGP program is the annual summary of additions. Figures 7 and 8 present the annual capacity additions by type (nuclear, coal, gas turbine, etc.). For example, in year 1995, the OGP program added in this sample run one 1300 MW nuclear unit and two 300 MW blocks of gas turbines as well as 500 MW of pumped storage hydro. The generating units indicated with an asterisk (*) are those units which have been previously committed for service. For example, in 1984, a 1200 MW nuclear unit and a 500 MW battery storage unit are committed for service.

At the bottom of the additions report, a summary is provided. The first row is the sum of megawatt additions and retirements (MW ADD and MW RET) during the period. The second row is the capacity in service in 1998 (end of the study). The third row is the MW additions that were added automatically (AUTO) by the OGP program (total additions less committed additions).

Other summaries are also provided by the program. Figure 9 presents the load, capacity, reserve, LOLP and cost summary. Figure 10 presents a more detailed cost summary both on a yearly basis and also on a cumulative present worth basis.

OGP also makes available more detailed yearly and even monthly results. One of these results is illustrated in Figure 11. This is the annual production cost summary and illustrates the annual history of each generating unit's maintenance period, hours on line, capacity factor, fuel cost, etc.

At the bottom of the page, the energy output, capacity factor, and fuel cost results are summarized by generating plant type (nuclear, coal, gas turbine, etc.).

Other summaries are also available including annual fuel consumption by fuel type (nuclear, coal, oil #2, oil #6, natural gas, etc.), and annual environmental summaries (water consumption, SO_2, and NO_x emmissions, etc.).

While these summaries are examples of OGP program output, a complete printout would include a formatted listing of the input parameters and other useful displays of information.

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT

OGP-5 ELECTRIC SYSTEM
USERS MANUAL EXAMPLE
JOB NUMBER 24939S 03/14/79

GENERATION SYSTEM

	NUCL.	F-COAL	G.T.	STAG	C-COAL	F-OIL	TYPES	
TYPE	1	2	3	4	5	6	7-10	
OPTMZING	1989	1987	1979	1984	1984	1987	***	
PCT TRIM	25	25	0	25	25	25		
1978 MW	5005	4781	702	600	300	4792	934	SUM= 17114

YR	YEARLY		MW		ADDITIONS			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	****** ****
79		225*	2X 150					18367
80	1200*		2X 150					19844
81		750*	2X 150					20804
82	1200*			400*				22289
83	1200*		1X 150					23514
84	1200*						500*	25214
85							500	25584
86							500*	
							500	26584
87			2X 300				600	27609
88							1300	28778
89			1X 300	2X 400			500	30378
90			1X 300	3X 400			100	31863
91		2X1300						34348
92		2X1300						36848
93			3X 300				300	37902
94			1X 300	3X 400			300	39410
95	1X1300		2X 300				500	41647
96		2X1300	2X 300				100	44627
97	1X1300		1X 300	1X 400			300	46777
98		2X1300	2X 300				100	49761

MW ADD	7400	11375	5550	4000	0	0	6100	SUM= 34425
MW RET	0	-1455	0	0	0	-1373	0	SUM= -2828
******	******	******	******	******	******	******	****	***********
1998	12405	14701	6252	4600	300	3419	7034	SUM= 48711
PCT TOT	25.5	30.2	12.8	9.4	0.6	7.0	14.4	SUM=100 PCT
AUTO	2600	10400	5550	3600	0	0	5100	SUM= 27250
PCT TOT	9.5	38.2	20.4	13.2	0.	0.	18.7	SUM=100 PCT

* COMMITTED MW

Figure 7. Annual Capacity Additions by Type

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT

OGP-5 ELECTRIC SYSTEM
USERS MANUAL EXAMPLE
JOB NUMBER 24939S 03/14/79

GENERATION SYSTEM

	THERMAL	HYDRO	PSH	BATRES	COMPAR		
TYPE	1-6	7	8	9	10		
OPTMZING		***	1984	1984	1984		
PCT TRIM			0	0	0		
1978 MW	16130	310	624	0	0	SUM=	17114

YR	YEARLY	MW	ADDITIONS			TOTAL CAPAB. +TIES	LOAD MW	LOLP D/Y
**	******	******	******	******	******	******	*****	*******
79	525					18367	14091	0.4153
80	1500					19844	14866	0.3813
81	1050					20804	15684	0.4021
82	1600					22289	16546	0.3362
83	1350					23514	17456	0.4551
84	1200			500*		25214	18416	0.2454
85			5X 100			25584	19429	0.4728
86			5X 100		500*	26584	20498	0.4290
87	600		6X 100			27509	21625	0.4926
88			13X 100			28778	22814	0.4830
89	1100		5X 100			30378	24069	0.3391
90	1500		1X 100			31863	25393	0.3360
91	2600					34348	26790	0.4140
92	2500					36848	28263	0.3910
93	900		3X 100			37902	29818	0.4784
94	1500		3X 100			39410	31453	0.4695
95	1900		5X 100			41647	33188	0.4498
96	3200		1X 100			44627	35013	0.4217
97	2000		3X 100			46777	36939	0.4551
98	3200		1X 100			49761	38970	0.4303

MW ADD	28325	0	5100	500	500	SUM=	34425
MW RET	-2828	0	0	0	0	SUM=	-2828
******	******	******	******	******	******	************	
1998	41677	310	5724	500	500	SUM=	48711
PCT TOT	85.6	0.6	11.8	1.0	1.0	SUM=	100 PCT
AUTO	22150		5100	0	0	SUM=	27250
PCT TOT	81.3		18.7	0.	0.	SUM=	100 PCT

* COMMITTED MW

Figure 8. Annual Capacity Additions by Type

GENERAL ELECTRIC COMPANY
OGP-5 GENERATION PLANNING PROGRAM-SUMMARY OUTPUT
****

OGP-5 ELECTRIC SYSTEM
USERS MANUAL EXAMPLE
JOB NUMBER 24939S 03/14/79

		TOTAL CAPABILITY (INCLUDING TIES)			LOSS OF LOAD PROBABILITY		COST IN MILLION $	
YEAR	LOAD	YEAR END	TIME OF PEAK	PCT. RES.	D/Y	H/Y	YEARLY COST	CUM. PW TOTAL
1979	14091	18422	18367	30.3	0.415	0.53	1207.8	1098.0
1980	14866	19884	19844	33.5	0.381	0.48	1547.0	2376.5
1981	15684	20844	20604	32.6	0.402	0.51	1827.6	3749.6
1982	16546	22329	22289	34.7	0.336	0.42	2236.2	5277.0
1983	17456	23554	23514	34.7	0.455	0.58	2652.9	6924.2
1984	18416	25254	25214	36.9	0.245	0.31	3146.7	8700.4
1985	19429	25624	25584	31.7	0.473	0.59	3398.3	10444.2
1986	20498	26624	26584	29.7	0.429	0.52	3754.7	12195.8
1987	21625	27649	27609	27.7	0.493	0.58	4184.1	13970.3
1988	22814	28918	28778	26.1	0.483	0.56	4731.3	15794.4
1989	24069	30418	30378	26.2	0.339	0.38	5364.5	17674.6
1990	25393	31903	31863	25.5	0.338	0.37	6099.1	19613.0
1991	26790	34388	34348	28.2	0.414	0.47	7233.1	21713.2
1992	28263	36988	35648	30.4	0.391	0.45	8391.6	23922.9
1993	29818	37942	37902	27.1	0.478	0.54	9308.6	26151.3
1994	31458	39450	39410	25.3	0.470	0.52	10453.8	28427.7
1995	33188	41687	41647	25.5	0.450	0.49	12023.4	30806.5
1996	35013	44667	44627	27.5	0.422	0.46	13760.1	33281.4
1997	36939	46817	46777	26.6	0.455	0.50	15577.5	35828.4
1998	38970	49801	49761	27.7	0.430	0.47	17695.6	38458.7

Figure 9. Summary of Load, Capacity, Reserve, LOLP, and Cost

OGP-5 ELECTRIC SYSTEM 249398
USERS MANUAL EXAMPLE 03/14/79

YEAR	POOL PEAK (MW)	TOTAL ENERGY (GWH)	LOAD FACTOR	YEARLY COSTS (MILLION $) INVEST.	FUEL	O+M	NUC INV	TOTAL	YEARLY COSTS ($/MWH) INV.	FUEL	O+M	N.I.	TOTAL
1979	14091.	74061.4	60.00	24.5	997.0	156.2	30.0	1207.8	0.3	13.5	2.1	0.4	16.3
1980	14866.	78348.9	60.00	246.1	1085.0	176.2	39.6	1547.0	3.1	13.8	2.2	0.5	19.7
1981	15684.	82432.5	60.00	364.4	1228.3	192.7	42.2	1827.6	4.4	14.9	2.3	0.5	22.2
1982	16546.	86966.0	60.00	633.8	1333.6	218.0	53.7	2236.2	7.3	15.3	2.5	0.6	25.7
1983	17456.	91749.6	60.00	896.0	1451.2	239.2	66.4	2652.9	9.8	15.8	2.6	0.7	28.9
1984	18416.	97061.3	60.00	1235.2	1563.3	267.5	80.6	3146.7	12.7	16.1	2.8	0.8	32.4
1985	19429.	102120.2	60.00	1272.8	1769.1	280.6	85.8	3398.3	12.5	17.2	2.7	0.8	33.3
1986	20498.	107735.4	60.00	1352.7	2012.7	297.9	91.4	3754.7	12.6	18.7	2.8	0.8	34.9
1987	21625.	113662.2	60.00	1427.6	2345.2	313.9	97.4	4184.1	12.6	20.6	2.8	0.9	36.8
1988	22814.	120241.6	60.00	1539.8	2754.4	333.4	103.7	4731.3	12.8	22.9	2.8	0.9	39.3
1989	24069.	126508.6	60.00	1677.1	3214.2	362.8	110.4	5364.5	13.3	25.4	2.9	0.9	42.4
1990	25393.	133466.2	60.00	1827.9	3756.4	397.2	117.6	6099.1	13.7	28.1	3.0	0.9	45.7
1991	26790.	140806.2	60.00	2435.3	4229.4	443.2	125.3	7233.1	17.3	30.0	3.1	0.9	51.4
1992	28263.	148958.2	60.00	3056.6	4711.3	490.3	133.4	8391.6	20.5	31.6	3.3	0.9	56.3
1993	29818.	156722.0	60.00	3145.2	5490.7	530.6	142.1	9308.6	20.1	35.0	3.4	0.9	59.4
1994	31458.	165341.3	60.00	3352.2	6381.1	575.2	151.3	10459.8	20.3	38.6	3.5	0.9	63.3
	33188.	174434.9	60.00	4028.5	7173.2	639.2	182.5	12023.4	23.1	41.1	3.7	1.0	68.9
	35013.	184533.4	60.00	4866.8	7990.0	708.9	194.4	13760.1	26.4	43.3	3.8	1.1	74.6
	36939.	194150.6	60.00	5642.6	8920.6	783.1	231.2	15577.5	29.1	45.9	4.0	1.2	80.2
	38970.	204828.5	60.00	6583.5	10005.5	860.3	246.3	17695.6	32.1	48.8	4.2	1.2	86.4

CUMULATIVE PRESENT WORTH (MILLION $)

YEAR	INVEST.	FUEL	O+M	NUC INV	TOTAL
1979	22.3	906.4	142.0	27.3	1098.0
1980	225.7	1803.1	287.6	60.1	2376.5
1981	499.5	2725.9	432.4	91.8	3749.6
1982	932.4	3636.8	579.3	128.5	5277.0
1983	1488.7	4537.9	727.9	169.7	6924.2
1984	2186.0	5420.4	878.9	215.2	8700.4
1985	2839.1	6323.1	1022.8	259.2	10444.2
1986	3470.2	7262.0	1161.8	301.9	12195.8
1987	4075.6	8256.6	1294.9	343.2	13970.3
1988	4669.3	9318.5	1423.5	383.2	15794.4
1989	5257.1	10445.1	1550.6	421.9	17674.6
1990	5839.5	11642.0	1677.2	459.3	19618.0
1991	6544.9	12867.1	1805.6	495.6	21713.2
1992	7349.8	14107.7	1934.7	530.7	23922.9
1993	8102.8	15422.1	2061.7	564.8	26151.3
1994	8832.3	16810.9	2186.9	597.7	28427.7
1995	9629.3	18230.0	2313.3	633.8	30806.5
1996	10504.6	19667.1	2440.8	668.8	33281.4
1997	11427.3	21125.7	2568.9	706.6	35828.4
1998	12405.9	22613.0	2696.8	743.2	38458.7

Figure 10. Detailed Summary of Costs

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OGP-5 ELECTRIC SYSTEM 25855K
USERS MANUAL EXAMPLE 01/25/79

OPTIMUM

G.T. PSH
1987 YEARLY PRODUCTION COST SUMMARY
COSTS IN THOUSANDS OF DOLLARS

TERRITORY PEAK 21625. MW THERMAL PEAK 18050. MW
SPINNING RESERVE 1200. MW

UNIT ID	STATION NAME	CO. IDENT.	UNIT TYPE	FUEL TYPE	RATING MW	PTRN.	MAINTENANCE MONTHS	MIN. UP RULE	ENERGY OUTPUT MWH	HRS. ON LINE	CAPACTY FACTOR	FUEL COST	OPER.+ MAINT. COSTS	FUEL INVT. COSTS	FORCED OUTAGE RATE	PLANNED OUTAGE RATE	FUEL PRICE $/MBTU
19	NEWTON 01	EDISON	2	2	705.0	2		-1	4857865.	7359.	0.754	113602.	9509.	0.	0.082	0.113	2.698
48	SEASHORE 02	EDISON	1	1	960.0	4		1	6799910.	7083.	0.809	77088.	14815.	9533.	0.119	0.120	1.134
23	SEASHORE 01	EDISON	1	1	960.0	3		1	6170665.	6428.	0.734	69955.	14815.	9533.	0.119	0.120	1.134
43	EAST PT 02	PUBSER	1	1	960.0	0	MARCH	1	6779612.	7062.	0.806	76858.	14815.	9533.	0.119	0.120	1.134
44	EAST PT 01	PUBSER	1	1	925.0	0	APRIL MAY	1	5952442.	6435.	0.735	67481.	14447.	9185.	0.118	0.120	1.134
57	SEASHORE 05	PUBSER	1	1	1200.0	0	MAY	1	8372475.	6990.	0.796	97776.	17235.	11916.	0.128	0.120	1.134
55	EAST PT 03	PUBSER	1	1	1200.0	0	APRIL MAY	1	7550164.	6362.	0.718	88228.	17235.	11916.	0.128	0.120	1.134
60	SEASHORE 06	EDISON	1	1	1200.0	0	APRIL	1	8413056.	7011.	0.800	98238.	17235.	11916.	0.128	0.120	1.134
49	SEASHORE 03	EDISON	1	1	1200.0	5		1	8140938.	6990.	0.774	114303.	17235.	11916.	0.128	0.120	1.134
50	SEASHORE 04	EDISON	1	1	1200.0	0	OCT.	1	7383211.	6990.	0.702	104393.	17235.	11916.	0.128	0.120	1.134
13	STATE 02	EDISON	2	2	210.0	0	MARCH	2	1380801.	7607.	0.751	34297.	4882.	0.	0.051	0.100	2.698
9	LINCOLN 02	EDISON	2	2	170.0	0	JUNE	2	1126980.	7638.	0.757	28079.	4136.	0.	0.050	0.100	2.698
10	WATERSIDE 01	EDISON	2	2	163.0	0	MARCH APRIL	2	940472.	6931.	0.659	23478.	4038.	0.	0.050	0.100	2.698
8	LINCOLN 01	EDISON	2	2	150.0	0	JULY	2	971314.	7615.	0.739	24223.	3546.	0.	0.050	0.100	2.698
12	STATE 01	EDISON	2	2	125.0	0	JULY	2	803247.	7615.	0.734	20039.	3457.	0.	0.050	0.100	2.698
11	WATERSIDE 02	EDISON	2	2	117.0	0	MAY	2	738958.	7615.	0.721	18450.	3326.	0.	0.050	0.100	2.698
51	BLUE LAKE 05	PUBSER	5	2	300.0	0	APRIL	2	1770432.	7509.	0.674	44431.	6507.	0.	0.066	0.103	2.698
4	HARBOR 01	EDISON	2	2	131.0	0	NOV.	2	810908.	7638.	0.707	20976.	3553.	0.	0.050	0.100	2.698
56	NEWTON 02	EDISON	2	2	750.0	1		2	4008005.	6727.	0.510	106291.	9860.	0.	0.084	0.114	2.698
40	FRONTIER 02	PUBSER	2	3	621.0	0	FEB.	2	3466765.	7473.	0.637	113424.	8829.	0.	0.078	0.111	3.575
38	FRONTIER 01	PUBSER	2	3	320.0	0	JAN. FEB.	2	1567920.	6925.	0.539	51735.	5591.	0.	0.057	0.103	3.575
46	BLUE LAKE 04	PUBSER	2	3	210.0	0	JULY	2	1129133.	7607.	0.614	37546.	4682.	0.	0.051	0.100	3.575
34	BLUE LAKE 03	PUBSER	2	3	146.0	0	AUG. SEPT.	2	711534.	6931.	0.556	23770.	3786.	0.	0.050	0.100	3.575
37	RIVERSIDE 05	PUBSER	2	3	105.0	0	AUG.	2	550508.	7615.	0.599	18443.	3122.	0.	0.050	0.100	3.575
31	BLUE LAKE 02	PUBSER	2	3	146.0	0	MARCH	2	743207.	7615.	0.581	25483.	3786.	0.	0.050	0.100	3.575
30	RIVERSIDE 04	PUBSER	2	3	100.0	0	NOV.	2	510525.	7638.	0.583	17628.	3034.	0.	0.050	0.100	3.575
58	NEWTON 01	PUBSER	2	3	750.0	0	JULY	2	3633448.	7343.	0.553	128988.	9860.	0.	0.084	0.114	3.575
52	FRONTIER 03	PUBSER	2	3	225.0	0	AUG. SEPT.	2	954453.	6917.	0.484	34036.	4875.	0.	0.052	0.101	3.575
45	BAY VIEW 04	EDISON	6	4	550.0	0	OCT.	2	2543014.	7599.	0.528	91126.	4885.	0.	0.052	0.089	3.862
39	LOON MT 03	PUBSER	6	4	550.0	0	SEPT.	2	2435598.	7531.	0.506	87473.	4885.	0.	0.052	0.089	3.862
36	LOON MT 02	PUBSER	6	4	117.0	0	JAN. FEB.	2	454710.	7016.	0.444	16642.	1975.	0.	0.030	0.080	3.862
33	LOON MT 01	PUBSER	6	4	150.0	0	JUNE	2	644428.	7799.	0.490	23648.	2284.	0.	0.030	0.080	3.862
17	STATE 03	EDISON	6	4	527.0	0	MARCH	2	2069569.	7511.	0.448	79335.	4764.	0.	0.050	0.068	3.862
18	STATE 04	EDISON	6	4	527.0	0	AUG.	2	1971254.	7365.	0.427	75727.	4764.	0.	0.050	0.068	3.862
16	HARBOR 03	EDISON	6	4	456.0	0	MAY	2	1504738.	6947.	0.377	58260.	4378.	0.	0.046	0.086	3.862
15	HARBOR 02	EDISON	6	4	209.0	0	JAN.	2	633113.	6543.	0.346	24564.	2774.	0.	0.031	0.080	3.862
70	GAS TURBINE	EDISON	3	5	150.0	0	JAN.	3	5724.	395.	0.004	939.	305.	0.	0.060	0.040	4.730
70	GAS TURBINE	EDISON	3	5	150.0	0		3	5299.	386.	0.004	870.	295.	0.	0.060	0.040	4.730
70	GAS TURBINE	EDISON	3	5	150.0	0	OCT.	3	3827.	283.	0.003	660.	266.	0.	0.060	0.040	4.730
70	GAS TURBINE	EDISON	3	5	150.0	0		3	2881.	229.	0.002	525.	247.	0.	0.060	0.040	4.730
22	HARBOR-GT 02	EDISON	3	5	150.0	0	FEB.	3	2101.	181.	0.002	502.	230.	0.	0.060	0.040	4.730
42	G.T. LUMP 3	PUBSER	3	5	100.0	0		3	1225.	153.	0.001	290.	147.	0.	0.067	0.040	4.730
21	UPTOWN-GT 02	EDISON	3	5	100.0	0	APRIL	3	906.	121.	0.001	227.	140.	0.	0.067	0.040	4.730
61	G.T. LUMP 4	EDISON	3	5	94.0	0		3	690.	100.	0.001	178.	127.	0.	0.067	0.040	4.730
20	G.T. LUMP 1	EDISON	3	5	128.0	0	JUNE	3	727.	79.	0.001	193.	166.	0.	0.063	0.040	4.730
41	G.T. LUMP 2	PUBSER	3	5	130.0	0		3	707.	80.	0.001	200.	168.	0.	0.063	0.040	4.730
	TIE ENERGY								369.			51.					
	TOTAL THERMAL				23025.0				112437672.			2315974.	305529.	97363.			
	CONV. HYDRO				310.0				2208000.				466.				
	PUMPED HYDRO				2224.0				-1148989.			0.	4946.				
	BATTERIES				500.0				-56827.			0.	1923.				
	COMPRESD AIR				500.0				-88074.			6278.	1185.				
	PURCHASE + SALES				1050.0				310200.			22968.					
	SYSTEM TOTALS				27609.0				113661962.			2345219.	314026.	97363.			

TYPE	RATING MW	ENERGY OUTPUT MWH	CAPACITY FACTOR,	FUEL COST THOUSAND $	O + M THOUSAND $	THERMAL $/MWH
1 NUCL.	9805.	65562474.	0.7633	794321.	145068.	14.33
2 F-COAL	5144.	28706043.	0.6370	840487.	94373.	32.57
3 G.T.	2352.	160786.	0.0076	20133.	5203.	157.55
4 STAG	1000.	699970.	0.0799	28597.	4447.	47.21
5 C-COAL	300.	1770432.	0.6737	44431.	6507.	28.77
6 F-OIL	4424.	15537602.	0.4009	567955.	49931.	41.05
TIENG		369.		51.		139.33
TOTAL	23025.	112437672.		2315974.	305529.	23.32

* * * *MANUAL MAINTENANCE PATTERNS* * * *

PTRN	J	F	M	A	M	J	J	A	S	O	N	D
1	1	1	0	0	0	0	0	0	0	0	0	0
2	0	0	1	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	1	1	0	0
4	0	0	0	0	0	0	0	0	0	0	1	0
5	0	0	0	0	0	0	0	0	0	0	0	1

NOTE WHEN USED, PATTERNS OVERRIDE THE COMPUTED P.O.R.-A 1 INDICATES SCHEDULED MAINTENANCE.

Figure 11. Annual Production Cost Summary