AN APPLICATION OF LINEAR PROGRAMMING TO DECISION RULES FOR OPERATING ELECTRIC POWER SYSTEMS

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PREFACE

This report presents results adapted from a masters' thesis prepared by Mr. Emile Snidjers and supported by the National Regulatory Research Institute (NRRI). Mr. Snidjers was a graduate research associate with NRRI from 1977 until August 1979 when he received an M.B.A. and an M.S. (Nuclear Engineering) from The Ohio State University. More detailed discussion of the computer models can be found in his thesis, Decision Rules For Operating Electric Power Systems, Including Hydro-pumped Storage, OSU, August 1979. The opinions expressed herein are solely those of the author and do not necessarily reflect the opinions nor the policies of the NRRI.

The NRRI is making this report available to those concerned with state regulatory issues since the subject matter presented here is believed to be of interest to regulatory agencies and to others concerned with utilities' regulation.

Douglas N. Jones
Director

EXECUTIVE SUMMARY

This report examines optimum capacities and hourly generation decision rules through the use of linear programming and chance-constrained programming. A framework is developed to derive these capacities and generation rules, and they are tested for a specific utility's capacity and load data, namely, the Virginia Electric Power Company (VEPCO).

The report shows that, if the yearly load duration curve is used to optimize capacity, then basic information is lost which is viable to generation planning. Therefore, the actual hour to hour utility loads, with a certain degree of uncertainty, were used to optimize the system.

The general results of this study, based on VEPCO information and 1978 cost data, are shown below.

A. Given any 1978 daily load:

(1) pumped storage is cost effective for all days considered in the study;
(2) both storage pumping and overall reservoir capacities can be satisfactorily explained by maximum and average loads, whereas their load leveling effect makes the capacities of the generating systems depend completely on the average load;
(3) in the optimum configuration storage pumping capacity is highly correlated with overall reservoir capacity;
(4) generation is performed in the standard economic loading order, and the storage reservoir is filled during the first seven to nine hours of the day and emptied during the peak-load period(s).

B. Given a stochastically determined daily load profile:

(1) pumped storage again is cost-effective for all cases considered;

(2) the load uncertainty results in increases in both storage and reservoir capacities corresponding to approximately 2-4 and 3-7 times the size of their deterministic counterparts, for reliability levels ranging from 85 to 99%;
(3) generating costs and capital costs for an optimum system increase non-linearly with the reliability of the system, i.e. the probability of meeting a stochastic demand pattern;
(4) zero-order decision rules can be established with respect to generation scheduling and capacity determination.

C. The linear programming approach for the determination of both capacities and generation levels does yield solutions which can incorporate dynamic aspects of electricity supply (such as plant loading rates, etc.). However, the derived decision rules do need additional adjustments since they were obtained through daily optimizations, which necessarily lead to some suboptimization when these daily time units are aggregated over longer periods.

The recommendations focus on possible future extensions of this approach, involving the following aspects:

A. An extension of the model to allow for technical and economic information of individual plants.

B. Extensions to optimize a total yearly period, opposed to the performed daily sub-optimizations.

C. The probabilistic formulation of the hourly loads so that:

(1) the uncertainty related to these loads can be diminished, and
(2) the stochastic decision rules can be improved by accounting for updated information.

D. The scheduling of maintenance and unforeseen breakdowns in a longer-term overall optimization framework. In this case a purchased power option is to be included in the system.

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LIST OF SYMBOLS

Symbol	Definition
AMAX	maximum power output fraction
α	column vector of probability
β	index denoting a system's component
C	zero-order decision on generation, 1000 MW
CA	zero-order decision on capacity, 1000 MW
CAP	capacity, 1000 MW
CAPMAX	maximum capacity, 1000 MW
CC	daily capacity cost, $/1000 MW
CP	fuel cost, $/1000 MWh
D	system load, 1000 MW
$\overline{D}$	average system load, 1000 MW
DCR	discharging ratio
e	efficiency, %
GEFF	efficiency of storage in generating mode, fraction
I	input, MMBTU
L	output, MMWh
LR	loading rate, 1000 MW/hour
N	normally distributed random variable
NSF	net storage flow, 1000 MW
PEFF	efficiency of storage in pumping mode, fraction

LIST OF SYMBOLS (Continued)

Symbol	Definition
SD	standard deviation, 1000 MW
STOREF	storage efficiency
t	hourly time index
TC	total cost, $
X	generation, 1000 MW
Z	value of normal variable

CHAPTER 1

INTRODUCTION

This research was undertaken to gain a better understanding of the relationships governing generating capacities and power generation. By using a "simple" linear programming approach, a framework is developed which can be of timely interest to regulatory agencies and to others concerned with utilities' regulation.

Although the report focuses heavily on energy storage, one gains insight into the large uncertainties which are associated with both long and short-term utility planning. It is this increased understanding which should be of interest to those involved with utilities' regulation.

Energy Storage and the Utilities

Utilities are required by law to supply power on demand, matching the output of their generators to the aggregate demands of their customers. The Public Utility Regulatory Policies Act of 1978 [29], commonly known as "PURPA," establishes as one of its purposes "the optimization of the efficiency of use of facilities and resources by electric utilities." One of its provisions requires the state regulatory authority or nonregulated utilities to determine a cost-effective load management technique. This method is defined as cost-effective if:

"(1) such technique is likely to reduce maximum kilowatt demand on the electric utility, or (2) the long-run cost-savings to the utility of such reduction are likely to exceed the long-run costs to the utility associated with implementation of such technique."

Several such techniques have been investigated. Among them are various energy storage methods for load leveling, and methods to reduce peak loads through selective pricing [4, 6, 8, 11]. Each technique, however, depends largely on the specifics of the situation. This report focuses on the historically proven method of pumped hydro storage [8] to level the utility's load. Examination of the daily/weekly variation of electricity demand shows that there is a steady component which is present throughout the day/week and a highly variable component which is affected by daily changes in load, statistical changes in weather, the specific day of the week, and the price of electricity to the consumer [6, 21, 30]. These daily, weekly and seasonal load variations on utility systems result in a typical annual system load factor ranging between 40 and 80% [1].

Utilities purchase generating capacity to meet annual peak load requirements with a specific degree of reliability. Because of the marked variations in the daily load profile, a portion of the generation capacity has the capability of generating additional power at low-load periods; this is the least expensive energy available in the utility system. Availability of this low-cost, off-peak energy makes the concept of storage attractive and economically feasible [27]. The amount of energy which can be effectively stored on a particular electric utility system depends on many factors including the utilities load characteristics, the amount of installed base-load generation and its energy storage capabilities.

The benefits which accrue from energy storage are a result of improved supply management [2]. These benefits include, but may not be limited to:

(1) Improvement in baseload plant capacity factor

(2) Production cost savings

(3) Use as spinning reserve

(4) Improved reliability

(5) More efficient load following

In the short run, the most important impact could be an improvement of the capacity factor of baseload plants. Currently, there is a difference of almost 15 absolute percent between the availability and the actual utilization of nuclear power plant capacity. Studies by EPRI's Nuclear Division suggest that about 1/3 of this difference is due to lack of load -- which means that plant capacity factors could be increased by an average of 5 absolute percent if sufficient energy storage were available today [8].

As early as the 1920's, storage was recognized as a valuable tool in managing energy, but it is only recently, as the cost differential between peaking fuels and baseload energy has grown, that energy storage has been identified as a major benefit to the utility industry. The ability to shift consumption from the expensive or more scarce fossil-fuels to the more plentiful and lower cost coal and nuclear fuels is the primary economic force propelling the development of storage technology.

Energy storage in combination with coal and nuclear power plants will be able to supply a significant part of future peaking and cycling energy requirements. This will permit the displacement of oil-fired generating capacity and the substitution of coal or nuclear derived energy for oil. As other technologies develop, coal and nuclear energy may be displaced gradually by resources such as solar and fusion; storage will prove to be self-modernizing as this technique can readily utilize energy derived from any source.

Energy storage devices and systems can effectively contribute to a power system's spinning reserve. One impact of this use would be the increased power system efficiency. Spinning reserve is presently provided by running gas turbines and by operating some power plants at 5-10% below their rated capacity which results in reduced efficiency. If energy storage can recoup this efficiency, then significant savings can be achieved.

Energy storage systems are likely to have a higher reliability than conventional generating devices [22]. If this proves to be true, then power systems which have significant amounts of energy storage available could get by with a lower reserve margin and still maintain the required security of supply. A reduction in reserve margin translates into a capital cost credit for the energy storage system.

Load following by means of energy storage would smooth the need for cycling individual power plants. Power plants would still cycle, but more slowly. The resultant lowering of thermal stress would almost certainly increase reliability and reduce maintenance costs. This use will no doubt become much more important as older cycling plants are being phased out and replaced with more highly stressed, modern equipment.

In our optimism for energy storage, it is important to recognize that the value and potential benefits which can be derived from energy storage requires the availability of low cost energy at periods of low demand. Energy storage is <u>not</u> an energy source, rather it is part of a strategy for managing energy supply. For energy storage to be successful, utilities must continue to build and operate baseload coal and nuclear generating stations today. In future years, these conventional sources may be replaced by solar or fusion energy; but for today, and for the immediate future, reliance must be placed on energy resources which are currently available.

Research Objectives and Methods

The objectives of this study have been to determine:

(1) the optimum capacities of the nuclear, coal and oil-fired generating systems and of the pumped storage system -- in terms of reservoir and pumping capacity, -- and

(2) hourly generation decision rules for each system, yielding minimum operating and investment costs as well as a high reliability of supply.

A framework was developed to derive these capacities and generation rules, as well as to test them for a specific utility's capacity and load data (The Virginia Electric Power Company [15]).

Two distinct approaches can be used to optimize both capacity and generation. One method focuses on the yearly load duration curve [3, 9, 31, 32]. In using this load duration curve some basic information is lost since it represents the aggregated load profiles for one year. Although some progress has been made in incorporating some basic information in the load duration curve -- such as probabilistic effects [30] -- it still does not, and cannot contain the dynamics of hourly load changing effects for each day. Since energy storage is largely dependent on these specific hour to hour load changes, a direct approach has to be used which does represent the actual load situation [3, 13].

Since this study focuses on the actual load situation a trade-off was made between the computationally infeasible situation of optimizing 365 periods of 24 hours each, and a sub-optimization based on the peak day during the year. In this study, it is assumed that the utility must meet this peak load, and that external power purchases are excluded. Figure 1.1 shows an overview of the methods by which the objectives of this study were met. A set of basic capacity and operating information is used to optimize the generation patterns and capacities for a typical electric power generation system, such as VEPCO.

For the optimization two cost minimization approaches were used. The first uses a linear programming method in which all inputs (costs, loads, technological factors) are known with complete certainty. Due to the uncertainty in the demand for electricity a second method was developed which uses chance-constrained linear programming. The latter derives zero-order decision rules, both for hourly generation and for capacities. Storage flows become randomized decision functions, depending upon actual demand. A simulation of utility operations is performed with these decision rules to investigate their reliability over time-spans longer than a day.

Chapter 2 introduces the system as modelled in the study, whereas Chapters 3 and 4 describe and develop the mathematical approach used in this study. Chapter 5 then shows some of the study results, with the general conclusions and recommendations listed in Chapter 6.

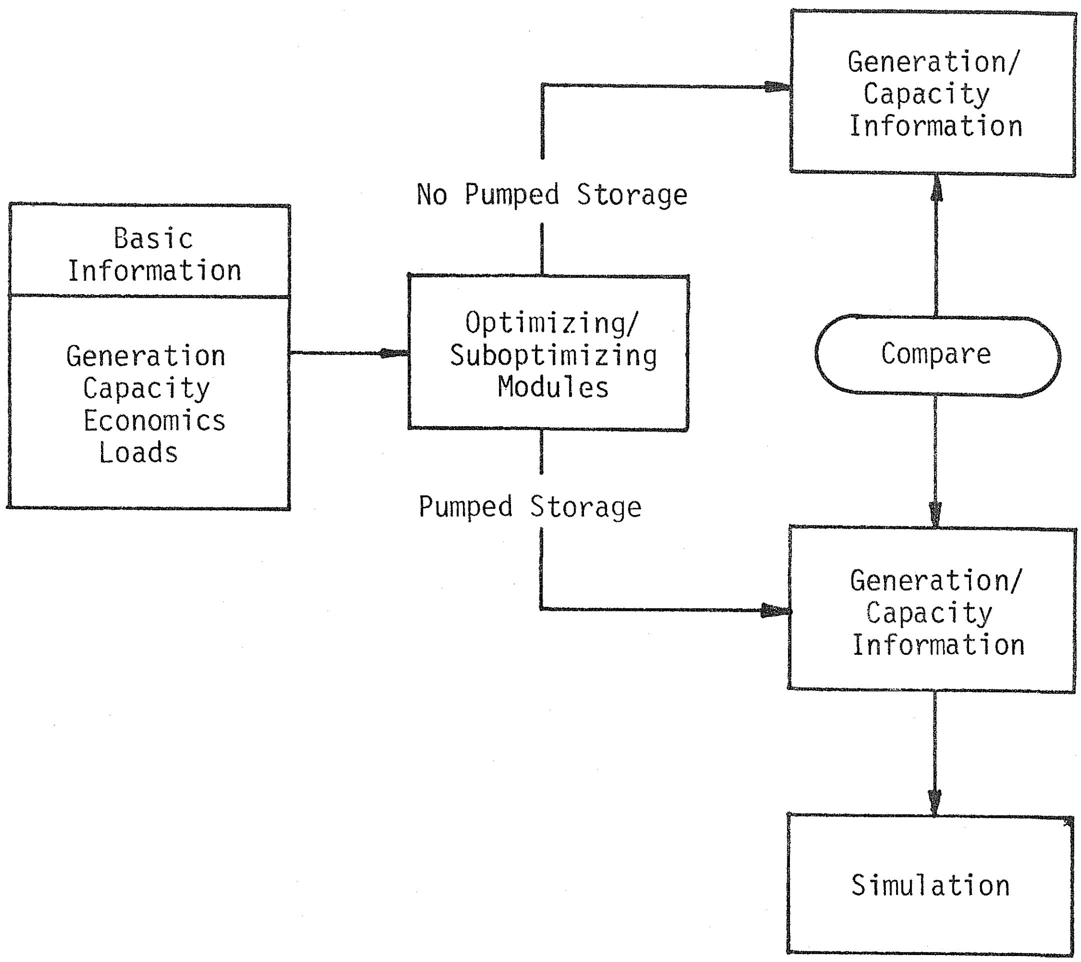

Figure 1.1 Overview of Basic Methods Used in this Study

CHAPTER 2

SYSTEM MODELING

This chapter introduces the system as modeled in this study, as well as technical and economic information on electricity generating stations and pumped storage.

System Overview

Figure 2.1 shows the system model. The utility's load is supplied by the generating plants, and by the pumped storage plant if this unit is in the generating mode. If the latter is in the pumping mode, then some of the generated power -- to be determined by an optimization procedure--is stored for later use.

The components of the system, however, have their own technological and cost characteristics. In order to optimize the design and operations of the total system it is necessary to include all the relevant constraints and costs for each part of the system.

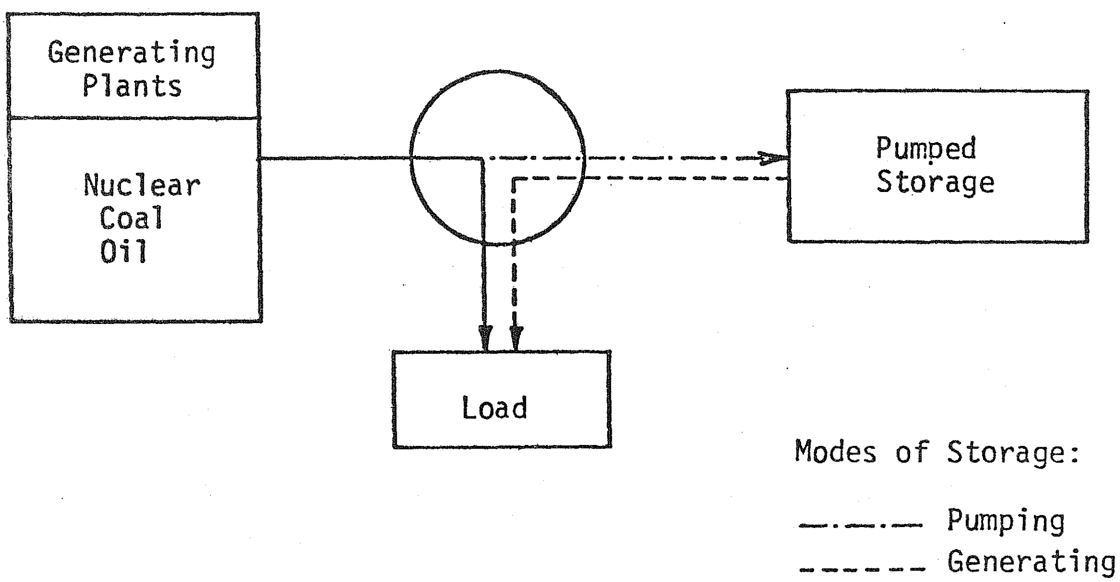

Figure 2.1 System Model

General Plants

Technical Considerations

Station performance is most precisely determined by input-output curves derived from tests on individual equipment. Figure 2.2a shows the general trend of this curve, which follows the general polynomial form

$$I = a + bL + cL^2 + \ldots + nL^r , \qquad (2\text{-}1)$$

where

I = fuel input in MBtu's,

L = output in MWh.

From the basic input-output curve the more familiar efficiency curve (Figure 2.2b) and the heat-rate curve (Figure 2.2c) may be derived [26]. The efficiency (e) curve is derived from the formula

$$e = \frac{3.413L}{I} \times 100 \text{ percent} \qquad (2\text{-}2)$$

and the heat-rate (HR) curve from the formula

$$HR = \frac{I}{L} \left(\text{in } {}^{\text{Btu's}}/_{\text{KWh}} \right) \qquad (2\text{-}3)$$

From a systems modeling viewpoint, these curves contain all necessary information for evaluating differences among nuclear, coal and oil-fired generating stations at a constant power output.

Several differences do, however, exist from a dynamic standpoint. The loading rate (LR) expresses the rate by which the power output (P) of a station can be increased, or

$$LR = \frac{dP}{dt} . \qquad (2\text{-}4)$$

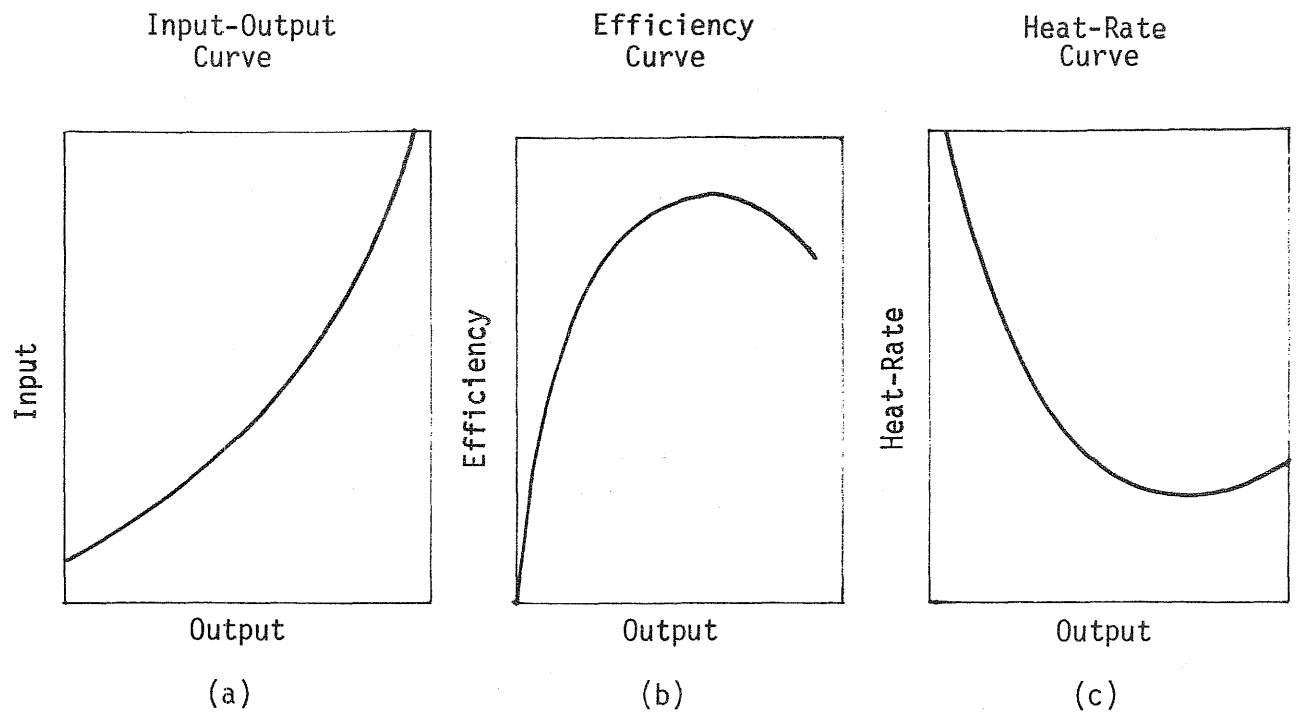

Figure 2.2 Input-Output, Efficiency and Heat-Rate Curves

Thermodynamic considerations normally limit these loading rates. (They also place upper and lower bounds on total power output). A constant loading rate is often assumed sufficient for calculations involving slight power changes [7, 23].

Economic Considerations

The relevant costs for generating stations comprise [17, 20]:

1. Fixed Costs, including
   a. Capital Costs (annualized)
   b. Fixed Operating and Maintenance Expenses
2. Variable Costs, including
   a. Fuel Costs
   b. Variable Operating and Maintenance Costs

Pumped Storage

Description

Hydro pumped storage is distinguished from all other energy storage methods suitable for utility application in that it has already reached a mature state of development. Plants have been built and their costs and characteristics are known. The use of pumped storage in the United States has, however, been limited. More storage could now be used to advantage,and expected future loads, generation mixes and fuel costs point to an expanded role for several possible energy storage methods.

In a hydro pumped storage system, energy is stored by pumping water from a lower to a higher elevation. The energy is recovered for utility use by passing the water from the higher to the lower elevation through a hydro turbine driving an electric generator. Pumping and generation is accomplished by a reversible pump/turbine connected to a generator/motor, shown schematically in Figure 2.3. It was the introduction of this reversible unit, coupled with changing economic conditions, that contributed substantially to the accelerated interest and development of pumped storage since the 1960's.

The reservoirs of existing hydro plants or of water storgae systems can be specially constructed surface reservoirs, underground caverns, or combinations of these. The pumping-generating plant is connected to the two reservoirs by appropriate waterways. The power house itself may be either on the surface or underground -- underground construction has sometimes been found economically and environmentally desirable, even where the reservoirs are on the surface [8].

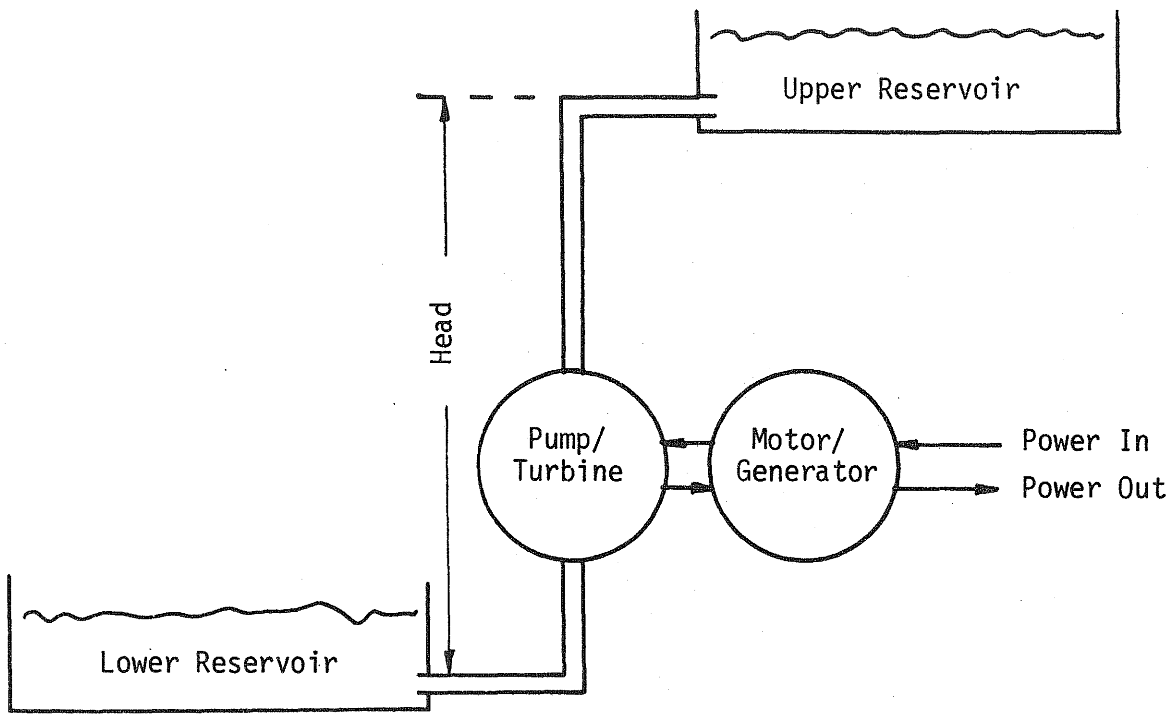

Figure 2.3 Hydro Pumped Storage System

Most of the pumped storage capacity now in service can be classified as "pure" pumped storage, i.e, units built only for the storage of off-peak energy [5]. However, several constructed plants have additional purposes, including the development of conventional hydroelectric output from natural flow into the upper storage reservoir, and storage for irregation. In fact, wherever there is a need to either move or store water, there may be an economic incentive to develop this into a hydro pumped storage system.

The necessity of storing relatively large volumes of water in two reservoirs, separated by several hundred feet of head, requires a topography that is not available everywhere. Consequently, the developed and planned pumped storage systems are confined to certain sections of the country [1]. It has, however, been estimated that aboveground pumped storage could be built, if needed and economically justified, to serve the peaking requirements of the systems which supply about 70% of the total electric load in the United States [2].

Technical Considerations

Size and Head:

The unit size suitable for utility application will generally be larger than 200 MW. Smaller units have been built, mostly for specific applications. Plant size can be any multiple of unit size, although total plant size is frequently limited by the available reservoir capacity; and if this is not the limitation, it will usually be the size that fits the utility system needs.

The heads that have been found economical, in the absence of special conditions, have been above 300 feet. There are indications that heads of up to 2500 feet are feasible for single stage reversible units. For still higher heads, it will be necessary to consider multi-stage units, units in series, or separate pumps and turbines. During pumping, the lower reservoir is emptied and the upper one is filled; the gross head is increased. This results in a change of input, but generally there is a small decrease in pumping load as the head increases.

Efficiency:

Demonstrated over-all efficiencies have been increased from 66% to 75% [8]. These higher efficiencies have been the result of improvements in pump/turbine design and of a more liberal design of water passages. Because over-all efficiency is the product of the separate pump, motor, generator, transformer (used twice), turbine and waterway (used twice) efficiencies, and because each efficiency is close to its practical limit, the maximum theoretical efficiency is approximately 80%.

Charge/Discharge Ratio:

The charge/discharge ratio is measured by the relation of power input (average pumping load in MW) to power output (rated capacity in MW). Most constructed plants have ratios in the range of 1.0 to 1.3.

The importance of this ratio is its effect on available generating time. For example, if the ratio is 1.15 and the overall efficiency is 80%, then the duration of generation available from 1 hour of pumping will be 0.92 hours (= 1.15 * 0.80). These ratios are within the control of the plant designer with higher ratios obtainable at higher cost.

Reliability and Availability:

An average availability of about 90% can be established for pumped hydro systems. (Based on limited historical experience; yielding a forced outage rate of 4%, and a total 5 weeks of maintenance per year.)

Turn-Around Time and Load Regulating Ability:

A pumped storage plant cannot switch instantaneously from the pumping mode to the generating mode. A definite time interval is required due to mechanical and hydraulic inertias. However, 15 minute time intervals are feasible for each unit in the system.

Load following can be accomplished to a limited extent, but generally its effect on efficiency and on maintenance requirements will be considered prohibitive in the case of fast load transients.

Economic Considerations

Useful Life:

Hydro units and plants are inherently long-lived property. Although pumped storage plants are subject to more severe service requirements than conventional hydro units because of reversals in the waterflow direction, maintenance and design do take this into account, making their life comparable to regular hydro units. For tax-accounting purposes the Internal Revenue Service allows a life of 50 years for all hydro property.

Costs:

Reservoir capital costs (in \$/MWh) and pumping plant costs (in \$/MW) have to be considered separately in an economic analysis. Other fixed costs include minimal operation and maintenance expenses and negligable costs such as license fees payable to the Federal Power Commission, now FERC. Variable costs are virtually nonexistent, due to the low variable operations and maintenance costs and the absence of fuel costs.

CHAPTER 3

OPTIMIZATION METHODS

Introduction

There are several optimization techniques that can be applied to the problem of scheduling hourly generation loads and determining overall capacities simultaneously. Available optimization techniques include linear, integer, dynamic, and nonlinear programming.

Of these techniques, classical calculus methods are of limited use due to the large number of variables involved. However, dynamic, non-linear, and integer programming are possible alternatives to the standard linear programming technique.

Direct or exhaustive search is an optimization method which enumerates all the possible combinations of variables [19]. After completion of all the enumerations, the selection of the optimal combination of decision variables is possible. A major disadvantage is the number of enumerations that must be done.

Dynamic programming is an optimization technique which can markedly decrease the computational requirements of a large system optimization [18, 19, 31, 32]. The reduction in computation is achieved by transforming a sequential decision process with interrelated variables into a series of single-state decision processes involving only a few variables. This means the stages must be decoupled from each other and that no past decisions affect future decisions and vice versa. However, future decisions can affect the optimality of past decisions because of the coupling of stages. Since the storage system, especially the reservoir, depends on past and future information it is not possible to decouple the stages.

Non-linear programming can handle various types of objective functions. Some development of algorithms dealing with quadratic objective functions has been done, but the development of non-linear algorithms has been limited to a few special applications. This technique is of very limited value because of the large number of steps required to reach an optimum solution, which consequently increases the computational time tremendously.

Linear Programming

Linear programming is a standard, well-known, technique which has been used extensively in optimization problems [3, 13, 16, 25]. The standard formulation is described as:

$$\text{Maximize} \quad Z = cx, \tag{3-1}$$

$$\text{Subject to} \quad Ax \leq b, \tag{3-2}$$

$$x \geq 0, \tag{3-3}$$

where:

Z is the objective function,

$Ax \leq b$ are the constraints,

c is a row vector with n elements,

x is a column vector with n elements,

A is a $m \times n$ matrix, and

b is a column vector of size m.

The problem is solved by means of the "simplex" method, which (through an iterative procedure) finds the value of the x vector producing the optimum in the objective function (Z). The major drawback of this approach is of course that all the parameters (c, A, b) have to be known with certainty. Obviously any random parameter, such as the load on an electricity generating system, does present problems for this approach. Several methods of mathematical programming have consequently been developed to account for these problems. The method most applicable to probabilistic parameters is known as chance-constrained programming and will be described in the following section.

Chance-Constrained Programming

The standard formulation of chance-constrained programming may be described as [16, 20]:

$$\text{Maximize} \quad f(cx) \tag{3-4}$$

$$\text{Subject to} \quad P(Ax \leq b) \geq \alpha \tag{3-5}$$

where P denotes "probability," and c and A are a non-random vector and matrix. The vector α contains a set of constants that are probability measures of the extent to which constraint violations are permitted. Assuming a normally distributed random variable b, with mean μ and variance σ^2, it is possible to transform the probabilistic constraint into a deterministic equivalent. Defining by F(z) the probability that a standardized normal variable will take on a value between 0 and z, i.e.:

$$F(z) = \frac{1}{\sqrt{2\pi}} \int_0^z e^{-\frac{1}{2}t^2} dt, \tag{3-6}$$

then each of the equations in the probabilistic constraint set (3-5) can be stated as

$$\sum_{j=1}^{j=n} a_{ij}x_j \leq \mu - F^{-1}(\alpha - \tfrac{1}{2}) * \sigma \tag{3-7}$$

Once all constraints have been transformed in this fashion, it is possible to solve the model for a given exogenous vector of risks $\alpha = (\alpha_1, \ldots, \alpha_m)$ and to derive the associated optimum value of the decision variable vector $x = (x_1, \ldots, x_m)$. If the values of the x_i's are determined before observing the values of the random variables, then zero-order decision rules have been established [16, 24].

CHAPTER 4

MODEL SET-UP

This chapter will describe (a) the general set-up of the optimization models in this study, (b) the deterministic and stochastic approaches, (c) an overview of the required input data, and (d) the simulation model designed to evaluate the derived stochastic decision rules.

General Description

The general linear programming set-up (see equations 3-1 through 3-3, and Figure 4.1) can be specified to include the following functional groups:

Minimize TC = (Fuel Cost for each System) (Fuel Use)
+ (Capacity Cost) (Installed Capacity) (4-1)

Subject to the following constraints;

a) Unit Hourly Power Output of Generating Systems and Storage $\leq$ Unit Capacity of Each System (4-2)

b) Unit Loading Rates $\leq$ Maximum Unit Loading Rates (4-3)

c) Storage Hourly Outflows $\leq$ Available Energy in Reservoir (4-4)

d) Available Energy in Reservoir $\leq$ Reservoir Capacity
and
Available Energy in Reservoir $\geq$ 0 (4-6)

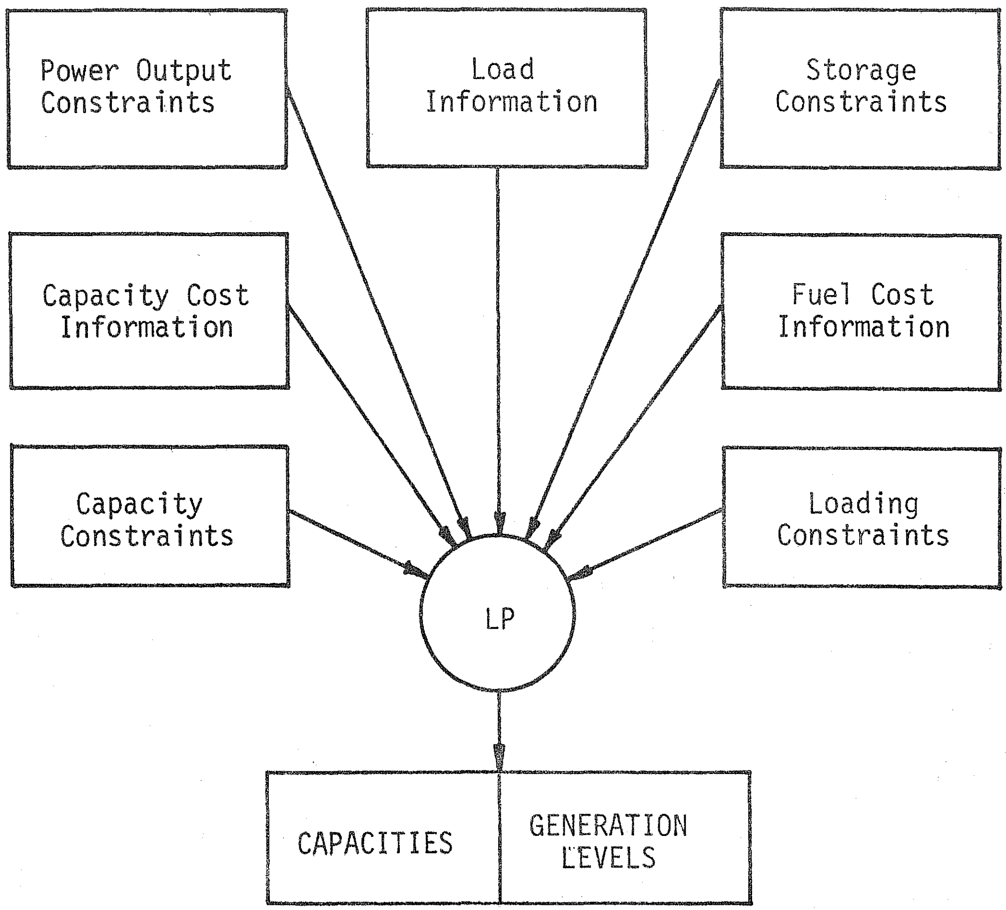

Figure 4.1 General Linear Programming Set-Up

and finally,

e) Total Hourly Generation + Net Hourly Storage Flow + Required Power Purchases = Hourly Load (4-7)

The unknowns in this model -- i.e., the hourly outputs from the nuclear, coal and oil generation systems, the hourly inflows and outflows to and from the pumped storage, and the capacities of the generating systems of the reversible storage turbine/pump and of the storage reservoir --will be determined by the simplex method. It is essential to include external power purchases if circumstances such as unforeseen equipment breakdowns and scheduled maintenance outages are included in the model. The present approach deals with specific days during which full power availability is assumed. The resulting minimum cost scenario of capacities and hourly generations is sufficient to exclude the purchased power option.

This study contains eight different analyses. Based on 1978 load data, provided by the Virginia Electric Power Company, a deterministic model was built. This model was run for all VEPCO's daily load profiles in 1978. Figure 4.2 shows the different cases that were considered for this deterministic approach; namely:

a) Pumped storage excluded, and no upper limits on the capacities of the generating systems (yielding model LP1)

b) Same as a) but with VEPCO's total plant capacities (model LP1V)

c) Pumped storage included, and no upper limits on the capacities of the system's components (model LP2)

d) Same as c) but with VEPCO's total plant capacities (model LP2V)

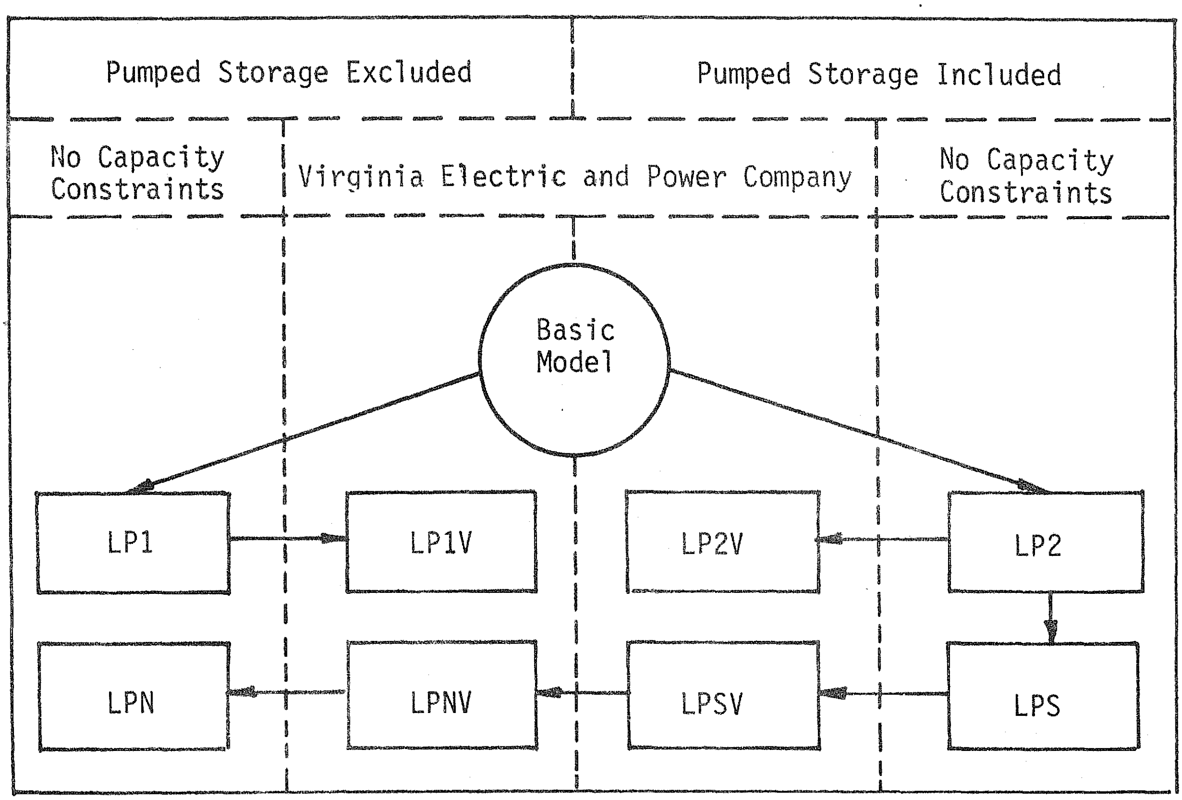

Figure 4.2 Computer Models in the Study

For each of these cases the month and type of day was selected which resulted in the maximum cost scenario for the system. In the LP2V model the storage and reservoir capacities of this worst case were "installed" in the system and their financial repercussions investigated for different load profiles. In the LP2 model all capacities were again determined by the maximum cost day. The detrimental effects of different generating system mixes again was considered.

Four stochastic models (LPS, LPSV, LPNV, LPN) were built analogous to the previous approach. Since the uncertainty of the loads in these models introduces the additional dimension of reliability, this approach was only investigated for the peak month. Again, the capacities for the maximum cost days were considered binding and their effects were checked for the other days of the peak month. The resulting generation decision rules and these above capacities were used in a simulation to provide a basis for determining the long-term effects of this sub-optimization. In the computer programs, each model builds the required vectors and matrices. These programs are then linked to the optimization code "LINPRO" which was developed by Dr. Clarence H. Martin, Department of Industrial and Systems Engineering, The Ohio State University. The programs are not listed in this paper since they are assumed "standard".

The Deterministic Model

In order to mathematically formulate the optimization model we will first describe the symbols that will be used. The following sub and superscripts are defined:

t = time index for hourly intervals (1 through 24)

β = index denoting a system's component, i.e.,

$\beta = 1$: nuclear

$\beta = 2$: coal

$\beta = 3$: oil

$\beta = 4$: storage input

$\beta = 5$: storage output

The model contains the following unknowns:

X_t^β = power output of system part β during hour t

CAP^β = capacity of system part β, where

$\beta = 1 \rightarrow 3$: as before

$\beta = 4$: storage pumping capacity

$\beta = 5$: reservoir capacity

The cost vector, c, contains the following elements:

CP_β = fuel cost in $/1000 MWh for system part β

CC_β = daily capacity cost in $/1000 MW for part β

Other constants included are defined as:

$AMAX_\beta$ = maximum output for system part β as a fraction of 100% capacity (set equal to 1 in this study).

STOREF = storage efficiency

DCR = discharging ratio

PEFF = overall pumping efficiency of storage system

GEFF = overall generating efficiency of storage system

D_t = system load in 1000 MW during hour t, adjusted for loads continuously supplied by sources not considered in this analysis

$CAPMAX^{\beta}$ = maximum capacity considered for system part β

Figure 4.3 shows the set-up of the generation and storage system. Note that the losses in the storage system, related to its efficiency and its charge/discharge ratio, were assumed evenly distributed over the pumping and the generation mode, i.e.,

$$PEFF = \sqrt{STOREF * DCR} \tag{4-8}$$

= overall pumping efficiency, and

$$GEFF = \sqrt{STOREF * DCR} \tag{4-9}$$

= overall generating efficiency

Chapter 2, Figure 2.2a, presented the input-output curve for generating stations. It is shown later that it is realistic to assume a linear curve for which power output is a linear function of fuel input.

The Model is now set up as:

$$\text{Minimize} \quad TC = \sum_{t=1}^{t=24} \sum_{\beta=1}^{\beta=3} \left(CP_{\beta} * X_t^{\beta} \right) + \sum_{\beta=1}^{\beta=5} CC_{\beta} * CAP^{\beta} \tag{4-10}$$

Subject to:

1. Maximum capacity constraints

$$X_t^{\beta} - AMAX_{\beta} * CAP^{\beta} \leq 0 \qquad \forall \begin{cases} t = 1 \rightarrow 24 \\ \beta = 1 \rightarrow 4 \end{cases}$$

and,

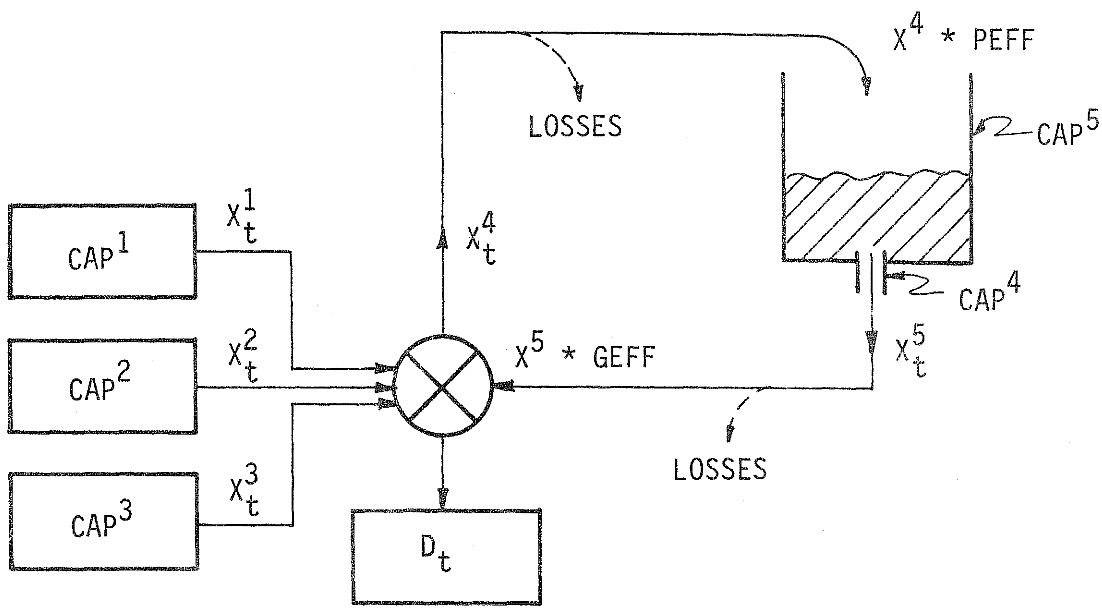

Figure 4.3 Model of Generation and Storage System During Hour t

$$X_t^5 - AMAX_4 * CAP^4 \leq 0 \qquad \forall \quad t = 1 \rightarrow 24 \qquad (4\text{-}11)$$

2. Storage outflows

$$X_1^4 \leq 0 \qquad (4\text{-}12)$$

$$X_t^\beta - \sum_{\tau=1}^{\tau=t-1} (X_\tau^5 * PEFF - X_\tau^4) \leq 0 \qquad \forall \quad t = 2 \rightarrow 24 \qquad (4\text{-}13)$$

3. Reservoir constraints

$$\sum_{\tau=1}^{\tau=t} (X_\tau^5 * PEFF - X_\tau^4) - CAP^5 \leq 0 \qquad \forall \quad t = 1 \rightarrow 24 \qquad (4\text{-}14)$$

and,

$$\sum_{\tau=1}^{\tau=t} (X_\tau^4 - X_\tau^5 * PEFF) \leq 0 \qquad \forall \quad t = 1 \rightarrow 24 \qquad (4\text{-}15)$$

4. Demand constraints

$$\left(\sum_{\beta=1}^{\beta=3} X_t^\beta \right) + X_t^4 * GEFF - X_t^5 = D_t \qquad \forall \quad t = 1 \rightarrow 24 \qquad (4\text{-}16)$$

5. Capacity constraints

$$CAP^\beta \leq CAPMAX^\beta \qquad \forall \quad \beta = 1 \rightarrow 5 \qquad (4\text{-}17)$$

The previous set-up contains 5 * 24 = 120 generation variables and 5 capacity variables, thus a total of 125 unknowns, as well as 221 constraint equations. The computer algorithm has to calculate inverses of matrices of approximately 150 by 230 elements. It is easily seen that any extension of this basic model requires much care since increasing the size of the matrix to be inverted increases the computational time -- especially because several iterations are required. The resulting deterministic model is labeled LP2 or LP2V, depending upon the specific data input.

The loading rate constraints as introduced in equation (4-3) were a priori deleted from the model as a result of these computational problems. The justification for dropping these constraints is the assumption that economic load leveling will occur wherever possible (an inherent characteristic of linear programming). Several tests have, however, been performed in which loading rates constraints for selected periods were included. The results have shown that extensions in this direction are feasible.

If hydro pumped storage is not to be considered, then simply constraints 2 and 3 (equations 4-12 through 4-15) are dropped, as well as the unknowns X_t^β ($\forall$ $t = 1 \rightarrow 24$, $\beta = 4 \rightarrow 5$) and CAP^β ($\beta = 4 \rightarrow 5$). The result is model LP1 or LP1V, depending on whether or not the capacities of the Virginia Electric and Power Company are considered binding.

The Stochastic Model

To account for the statistical variations in the load of the system a chance-constrained programming approach is introduced. We will assume that the hourly system load is a normally distributed variable with mean $\overline{D}_t$ and standard deviation SD_t. Zero-order decision rules are established as:

$$X_t^{\beta} = C_t^{\beta} \qquad \forall \begin{cases} t = 1 \rightarrow 24 \\ \beta = 1 \rightarrow 3 \end{cases} \tag{4-18}$$

$$CAP^{\beta} = CA^{\beta} \qquad \forall \quad \beta = 1 \rightarrow 5 \tag{4-19}$$

Note that the storage inflows and outflows have been dropped from the model; they are intrinsically determined. For convenience sake we will define a net storage flow during time t (NSF_t) as:

NSF_t = Storage Inflows_t - Storage Outflows_t, or,

$$NSF_t = \left(\sum_{\beta=1}^{\beta=3} C_t^{\beta}\right) - D_t \qquad \forall \quad t = 1 \rightarrow 24 \tag{4-20}$$

In this approach losses in the storage system have to be neglected because they have different effects on storage inflows and outflows whereas it is a priori unknown whether NSF_t represents either. A possible solution to this drawback is to select periods in which only inflows are allowed, with negative NSF_t's defined for the remaining periods. However, the simplest approach has been retained in the present study.

The mathematical formulation of the objective function is now:

$$\text{Minimize } E(TC) = E\left\{\sum_{t=1}^{t=24}\sum_{\beta=1}^{\beta=3}\left(CP_\beta * C_t^\beta\right)\right\} + E\left\{\sum_{\beta=1}^{\beta=5}\left(CC_\beta * CA^\beta\right)\right\}$$

$$= \sum_{t=1}^{t=24}\sum_{\beta=1}^{\beta=3}\left(CP_\beta * C_t^\beta\right) + \sum_{\beta=1}^{\beta=5}\left(CC_\beta * CA^\beta\right), \qquad (4\text{-}21)$$

where E is the expected value operator which of course can be dropped from the right hand side of the equation since no random variables are present there. The minimization of this objective function is subject to the following constraints:

1. Maximum output constraints

$$P\left\{C_t^\beta - AMAX_\beta * CA^\beta \leq 0\right\} \geq \alpha \qquad \forall \begin{cases} t = 1 \rightarrow 24 \\ \beta = 1 \rightarrow 3 \end{cases}$$

$$P\left\{\left|NSF_t\right| - AMAX_\beta * CA^\beta \leq 0\right\} \geq \alpha \qquad \forall \begin{cases} t = 1 \rightarrow 24 \\ \beta = 4 \end{cases}$$

The first constraint is purely deterministic and is therefore rewritten as:

$$C_t^\beta - AMAX_\beta * CA^\beta \leq 0 \qquad \forall \begin{cases} t = 1 \rightarrow 24 \\ \beta = 1 \rightarrow 3 \end{cases} \qquad (4\text{-}22)$$

The second one is transformed into two separate constraints:

$$\left(\sum_{\beta=1}^{\beta=3} C_t^\beta\right) - CA^4 \leq \overline{D}_t - SD_t * Z(\alpha)$$

and:

$$-\left(\sum_{\beta=1}^{\beta=3} C_t^\beta\right) - CA^4 \leq -\overline{D}_t - SD_t * Z(\alpha), \qquad \forall \; t = 1 \rightarrow 24 \qquad (4\text{-}23)$$

where $Z(\alpha)$ is the value of the normal variable Z, such that $P(Z < Z(\alpha)) = \alpha$.

2. Storage flow constraints

$$P\left\{\sum_{\tau=1}^{\tau=t-1} NSF_\tau + NSF_t \geq 0\right\} \geq \alpha \qquad \forall \quad t = 1 \rightarrow 24$$

$$\text{or} \quad -\sum_{\tau=1}^{\tau=t}\sum_{\beta=1}^{\beta=3} C_\tau^\beta \leq -\sum_{\tau=1}^{\tau=t} (\overline{D}_\tau + SD_\tau * Z(\alpha))$$

$$\forall \quad t = 1 \rightarrow 24 \qquad (4\text{-}24)$$

3. Reservoir constraints

$$P\left\{\sum_{\tau=1}^{\tau=t} NSF_\tau - CA^5 \leq 0\right\} \geq \alpha \qquad \forall \quad t = 1 \rightarrow 24$$

$$P\left\{\sum_{\tau=1}^{\tau=t} NSF_\tau \geq 0\right\} \geq \alpha \qquad \forall \quad t = 1 \rightarrow 24$$

which are transformed into:

$$\sum_{\tau=1}^{\tau=t}\sum_{\beta=1}^{\beta=3} C_\tau^\beta - CA^5 \leq \sum_{\tau=1}^{\tau=t} (\overline{D}_\tau - SD_\tau * Z(\alpha)) \qquad (4\text{-}25)$$

$$\forall \quad t = 1 \rightarrow 24$$

and:

$$-\sum_{\tau=1}^{\tau=t}\sum_{\beta=1}^{\beta=3} C_\tau^\beta \leq -\sum_{\tau=1}^{\tau=t} (\overline{D}_\tau + SD_\tau * Z(\alpha)) \qquad \forall \quad t = 1 \rightarrow 24 \qquad (4\text{-}27)$$

The demand constraints are satisfied automatically due to the setup of the model involving the net storage flow definition. The last constraint, regarding maximum considered capacities, remains deterministic as before, i.e.:

5. Maximum capacity constraints

$$P\left\{ CA^{\beta} \leq CAPMAX^{\beta} \right\} \geq \alpha \text{ , or}$$

$$CA^{\beta} \leq CAPMAX^{\beta} \qquad \forall \quad t = 1 \rightarrow 5 \qquad (4\text{-}28)$$

Again, we can distinguish among four different models, depending upon whether storage is included or excluded -- in the latter case CAPMAX for storage is set equal to zero -- and depending upon the specific upper limits of the maximum capacities.

Data Inputs

This section will briefly describe the input data used to drive both the deterministic and the stochastic models. For more in-depth information the reader is referred to Appendix A.

Loads

Hourly load profiles were obtained from VEPCO for the year 1978. These data were aggregated by type of day (Monday, Tuesday, etc.) for each month separately, the corresponding means and standard deviations were computed, and the hypothesis of a normal distribution was tested. Figure 4.4 shows this process. Figure 4.5 shows VEPCO's 1978 load profiles for all Mondays in August (before aggregation). These profiles display the same general form, and their general height is primarily determined by outside temperature, which control electric air conditioning requirements. It was assumed that the temperature factor has a uniform influence. However, in addition to that factor, other random phenomena modify the load profile, hence the interreactions between some of the profiles. Since no information was available on temperature data and on these other random phenomena it was assumed that each hourly load is normally distributed and that the values of the normal variables Z(0, 1) describing these distributions are the source for all the hourly loads of a given day. Chi-square tests support this normality hypothesis at a moderate confidence levels.

Figures 4.6 and 4.7 show selected loads for types of days in August, and in January.

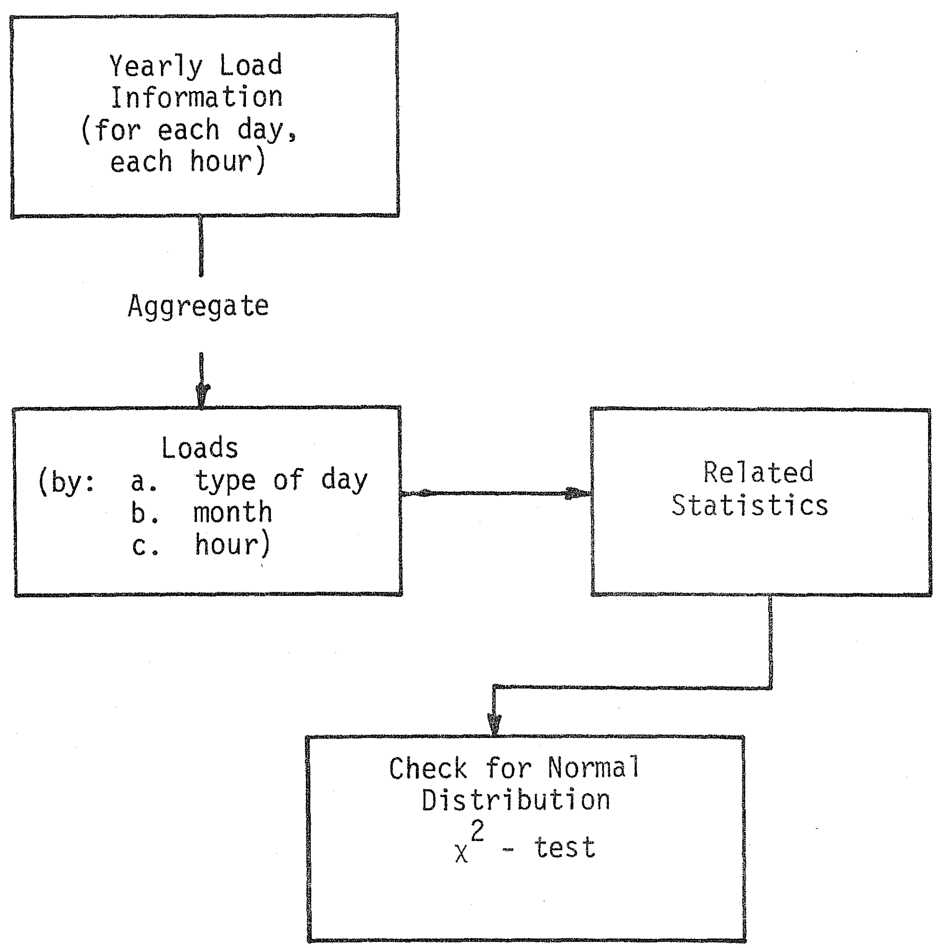

Figure 4.4 Load Data Set-Up

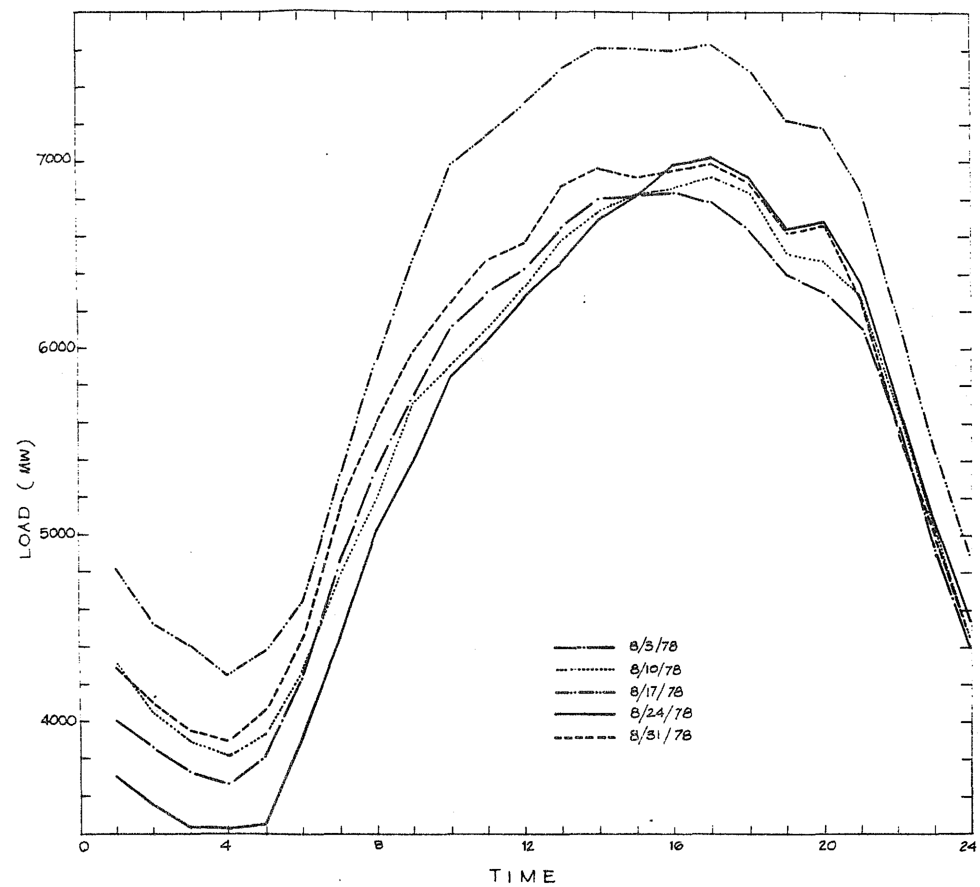

Figure 4.5 Selected Loads for Specific Days in August

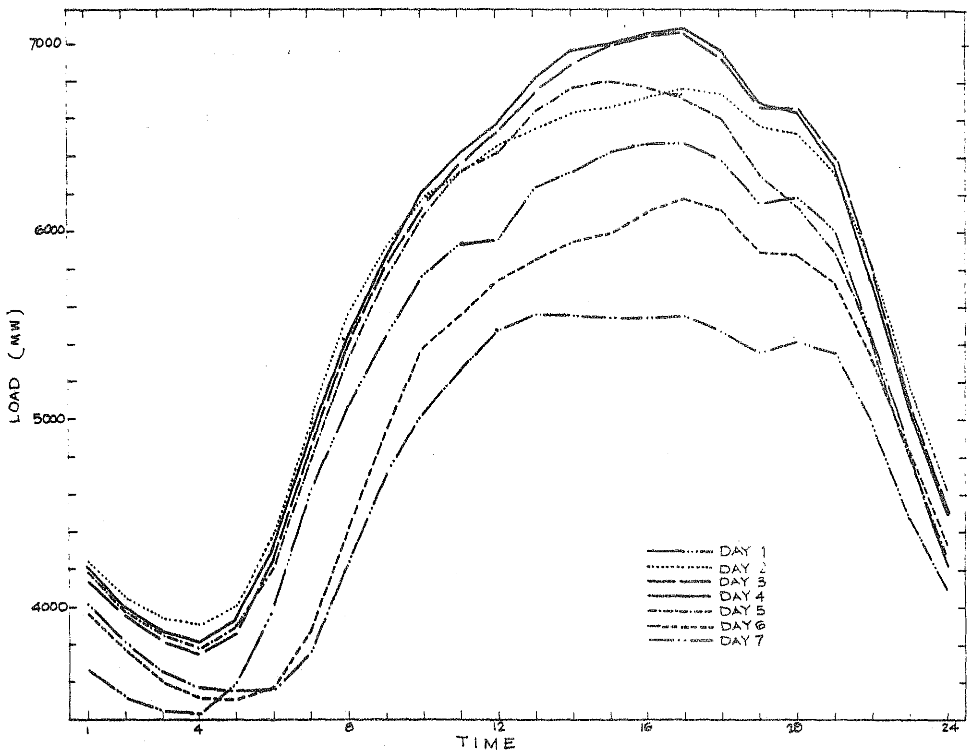

Figure 4.6 Selected Loads for Types of Days in August

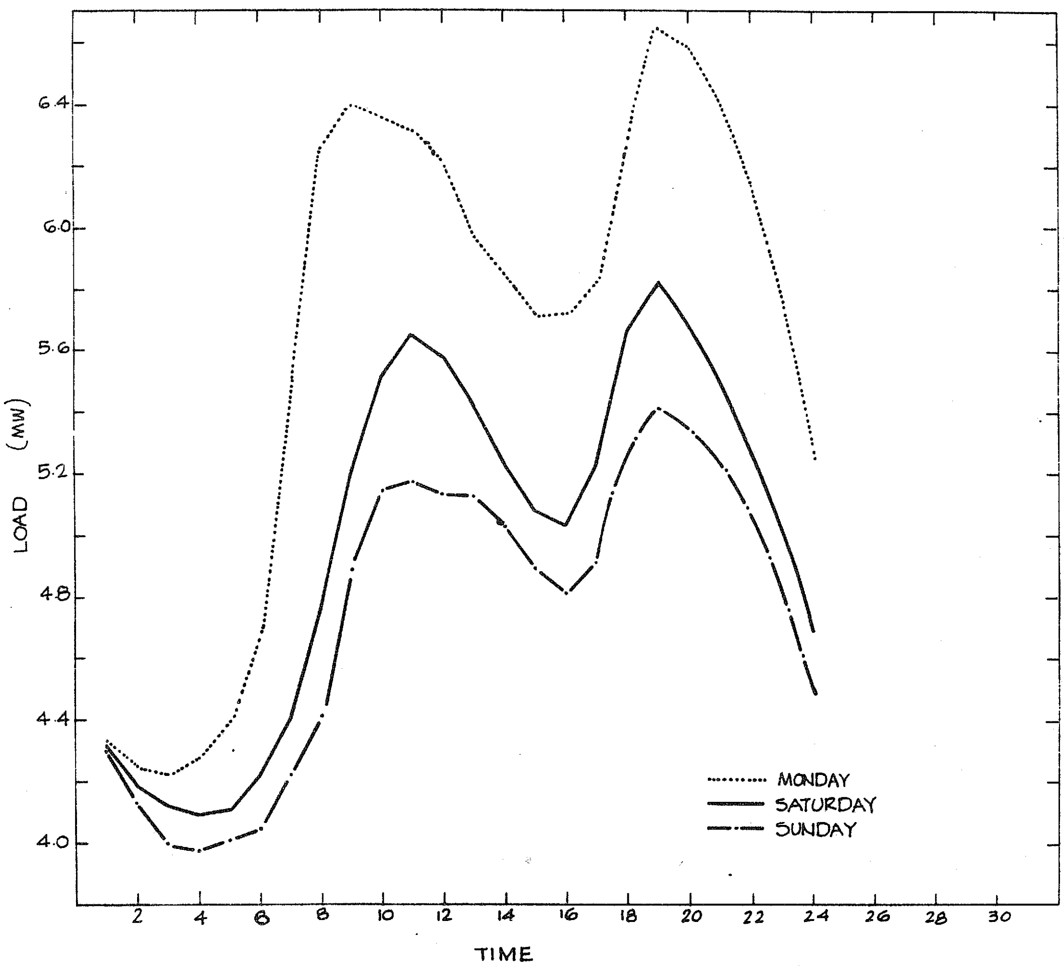

Figure 4.7 Selected Loads for Types of Days in January

Generating and Pumped Storage Stations - Generating Stations Technical Specifications

An analysis was made of the generating units in the Virginia Electric and Power System as of 1978. From the aggregated heat-rate specifications (at 1/2, 3/4, and full power) for its nuclear, coal and oil units, the heat-rate curves were determined, as shown in Figure 4.8. Estimated efficiency curves (Figure 4.9) and input-output curves (Figure 4.10) were derived from these heat-rate specifications.

The derived input-output curves contain two linear segments; one from zero to 3/4 of full capacity output, and the second segment from 3/4 to full power. To capture this information the computer models could be transformed to include the following fuel input formulation:

$$X_o^\beta + \sum_{j=1}^{j=2} S_{\beta j} * X_t^{\beta j} \qquad (4\text{-}29)$$

where the previous power output variable X_t^β, is decomposed into two power components $(X_t^{\beta 1}, X_t^{\beta 2})$. These components, multiplied by their respective slopes $(S_{\beta 1}, S_{\beta 2})$, and with the addition of the zero-power fuel input X_o^β, yield the total necessary fuel input for a power output $X_t^{\beta 1} + X_t^{\beta 2}$. It is also necessary to add the following constraints:

$$X_t^{\beta 1} - 3/4 * CAP^\beta \leq 0 \qquad \forall \begin{cases} t = 1 \rightarrow 24 \\ \beta = 1 \rightarrow 3 \end{cases} \qquad (4\text{-}30)$$

and,

$$\sum_{j=1}^{j=2} X_t^{\beta j} - CAP^\beta \leq 0 \qquad \forall \begin{cases} t = 1 \rightarrow 24 \\ \beta = 1 \rightarrow 3 \end{cases} \qquad (4\text{-}31)$$

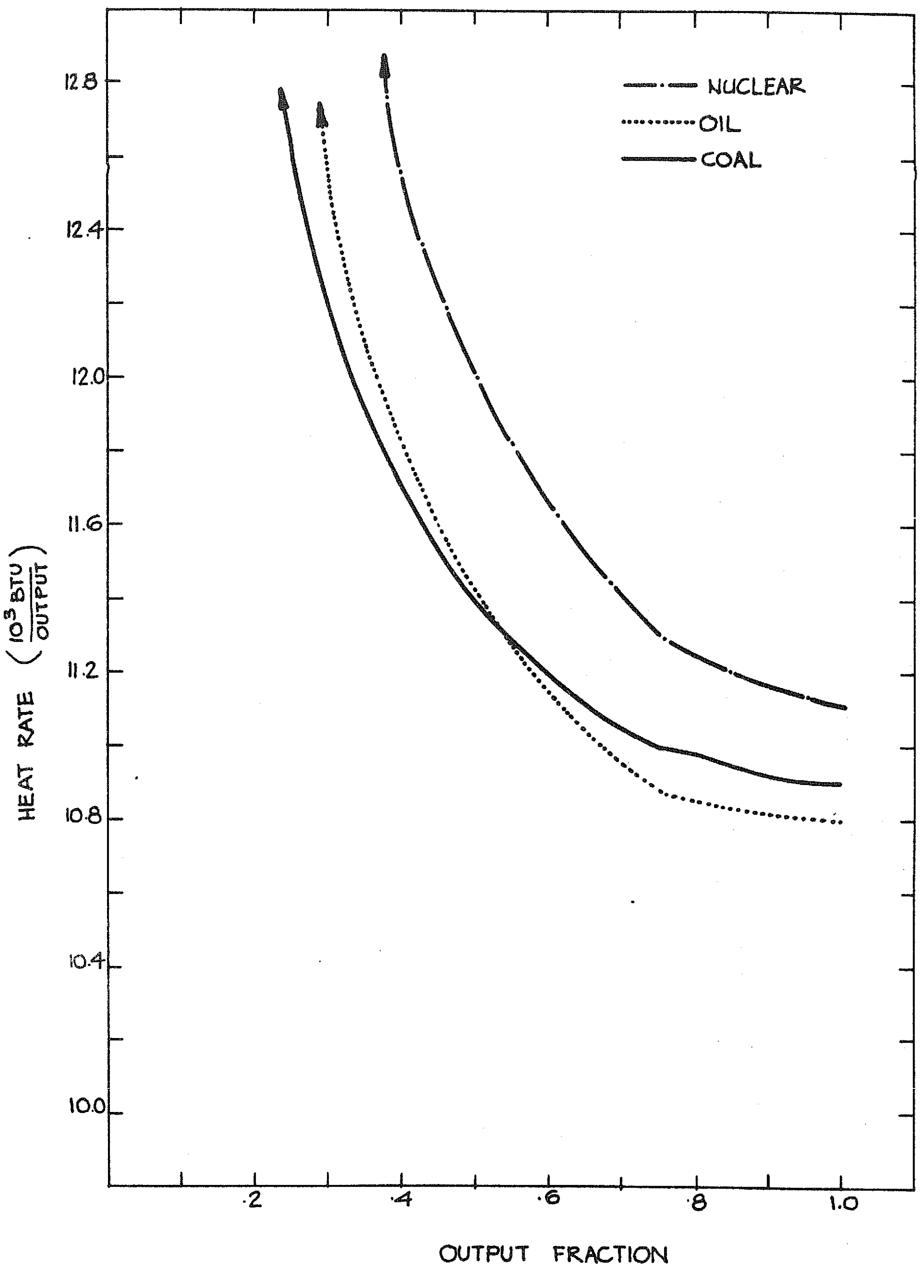

Figure 4.8 VEPCO System Heat-Rate Curves

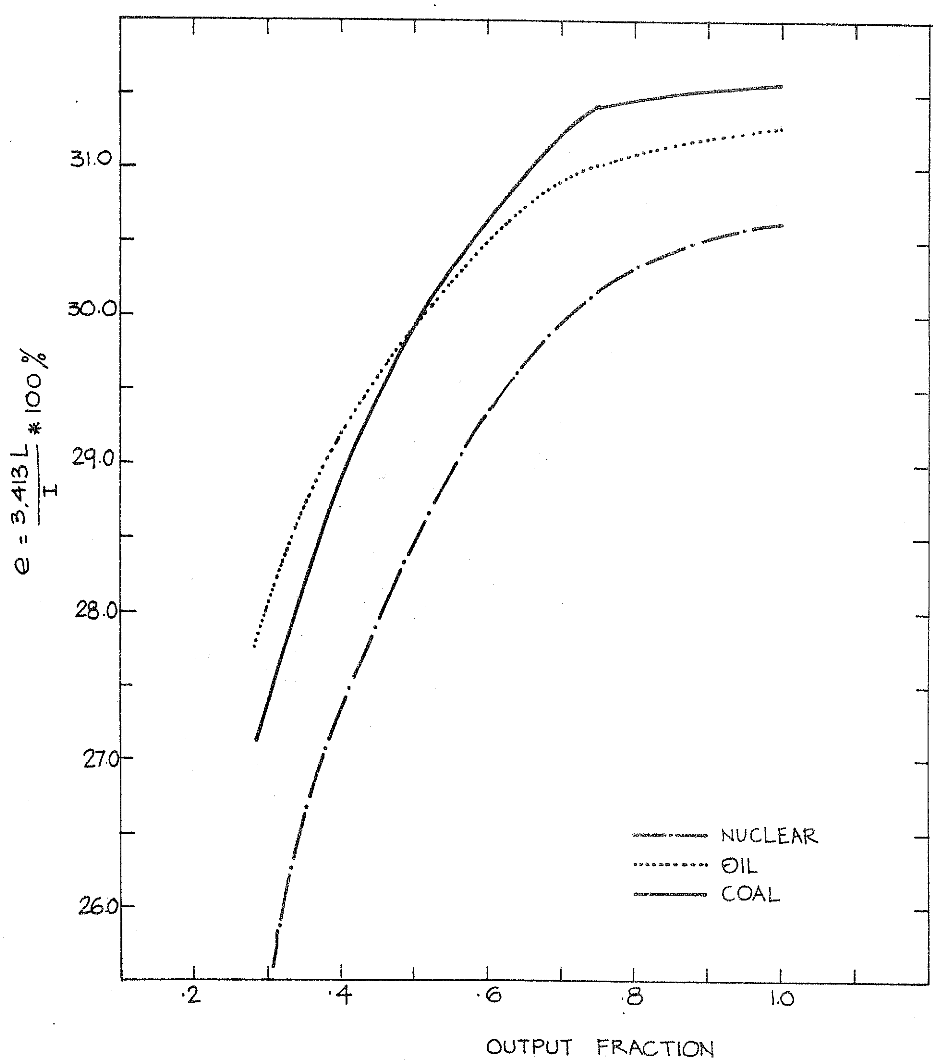

Figure 4.9 VEPCO System Efficiency Curves

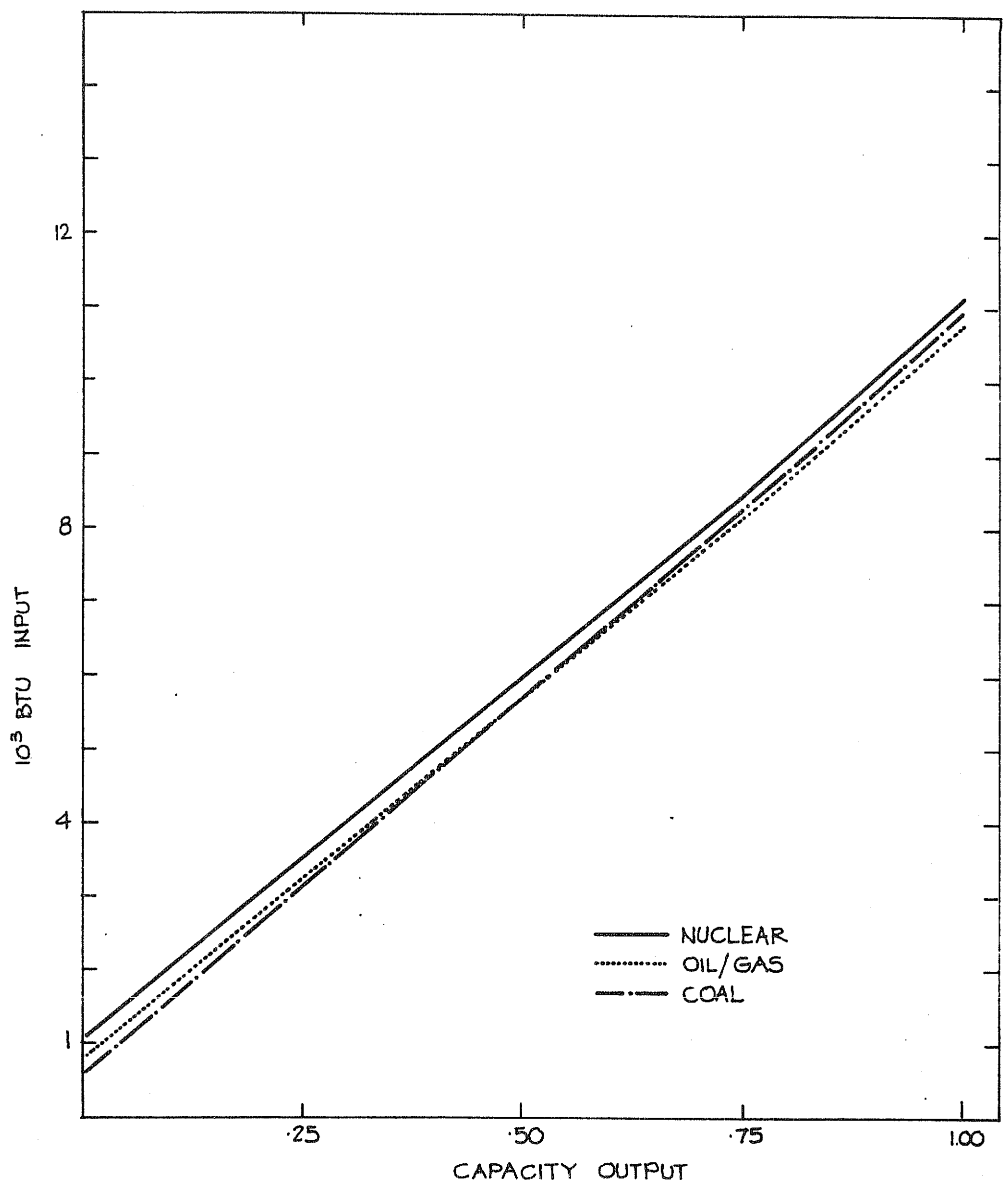

Figure 4.10 VEPCO System Input-Output Curves

This would yield a deterministic model with 245 unknowns and 461 constraints. The increased precision would however, be minimal due to the near-linearity of the input-output curves. Therefore the simpler approach, as developed previously, was retained.

Using a simpler approach, we can introduce a constant loading rate, or

$$X_t^\beta - X_{t-1}^\beta \leq k_\beta * CAP^\beta \, , \qquad \forall \begin{cases} \beta = 1, 3 \\ t = 1, 24 \end{cases} \qquad (4\text{-}32)$$

where k denotes a system constant. The computational costs of adding another 3 x 24 = 72 constraints outweigh, however, the benefits derived from the increased precision reached by accounting for this constraint.

Pumped Storage Technical Specifications

An average efficiency of 72% and a charge/discharge rate of 1.25 was used for the pumped storage system in the deterministic models. Obviously, these parameters are within the control of the plant designer, but they do represent acceptable benchmarks.

Cost Information

Table 4.1 contains the cost data used in this study. For additional information the reader is referred to Appendix A. Note that no economies of scale have been introduced in the capital cost data since this again would create computational inefficiencies without significant benefits.

Table 4.1 Costs Used in Optimization Models*[1]

System	FIXED COSTS		
	Capital Cost ($/KW)	Fixed O&M ($/KW Year)	Total Fixed Costs ($/1000 MW day)
Nuclear	$795.00	$2.73	$194,410.96
Coal	690.00	2.50	169,068.49
Oil	440.00	1.85	108,520.55
Storage (pump/ turbine)	180.26	2.18	43,013.70
Reservoir (in kWh)	8.16	0.00	1,918.39

System	Heat-Rate (BTu/kWh)	VARIABLE COSTS		
		Fuel ($/ 10^6BTu)	O&M (mills/kWh)	Total Variable Cost ($/1000 MWh)
Nuclear	10,400	$0.583	0.69 mills	$ 6,753.20
Coal	10,100	1.000	1.61	11,710.00
Oil	9,500	2.730	0.30	26,235.00
Storage	-	-	-	0.00 *[2]
Reservoir	-	-	-	0.00 *[2]

*[1] see Appendix A for detailed information and sources of data.

*[2] assumed negligable in comparision with other costs.

Simulation

To investigate the feasibility of the decision rules related to capacity and generation loads determined by the LPS model at given reliability levels, a simulation approach was developed. This program calculates any deviations from the decision rules that are required when a normally distributed load is introduced randomly. These deviations occur when the physical constraints on storage and reservoir capacities are exceeded.

Figure 4.11 shows the general approach to this simulation. The time frames that were investigated included (a) a repetitive simulation of the peak day, (b) a week made up of the typical days of the peak month, and (c) a repetitive simulation of (b).

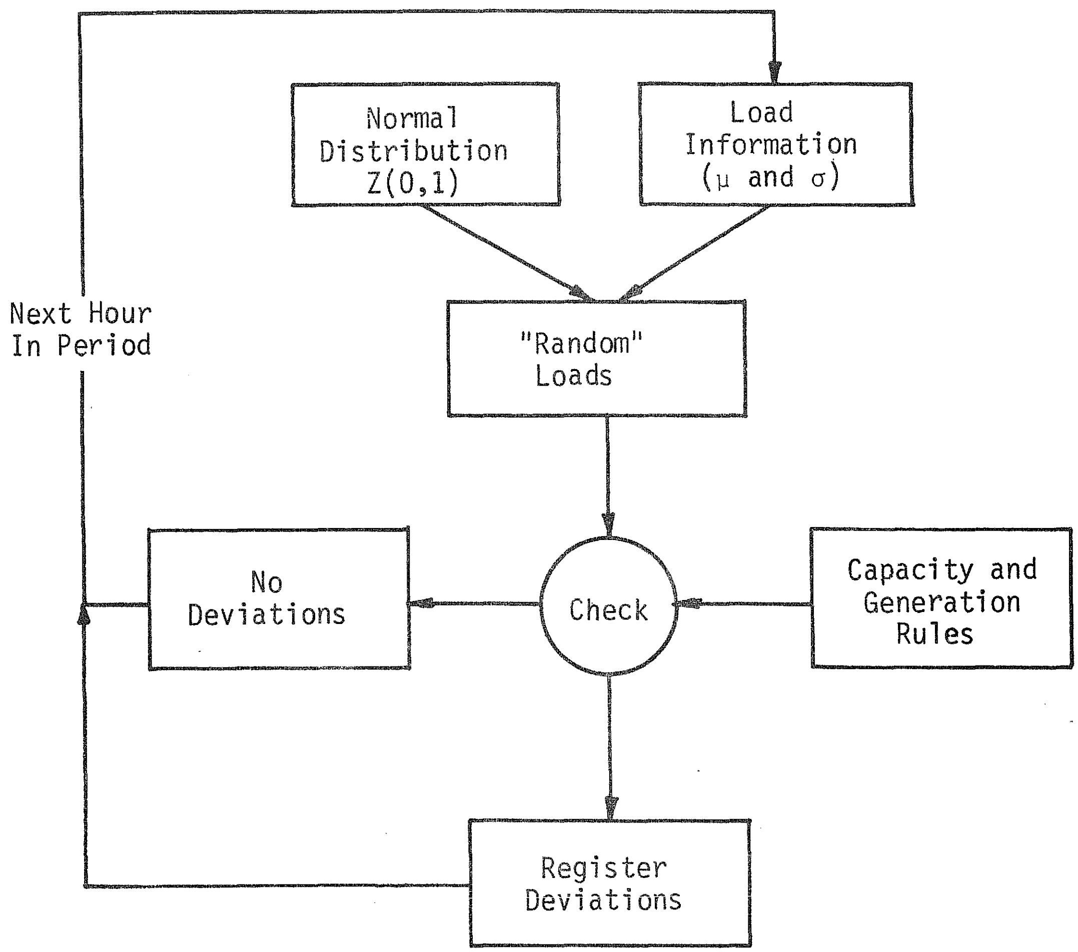

Figure 4.11 Simulation Approach

CHAPTER 5

RESULTS

This chapter describes and compares the results of the model applications. To recapitulate the models applied in this study, Table 5.1 lists each computer code with its corresponding features. The deterministic models were applied with average load profiles of each type of day and for each month. The load profile leading to the highest cost, i.e., the "worst" day, was further investigated with respect to storage and reservoir capacities. The first section presents the details of these analyses.

The month including the "worst day" and characterized by seven types of days was selected for the stochastic model applications. Again, the maximum cost day was determined among these seven days, on the basis of normally distributed loads. The system capacities derived on this "worst" day were then assumed "installed" in the system, and generation decision rules were derived for the other types of days in this month. The second section presents the details of this approach.

Finally, these decision rules were used in a simulation to analyze their feasibility since they were obtained through daily optimizations, which necessarily leads to some suboptimization when these daily time units are aggregated over a longer period.

Table 5.1 Model Features

Model	Storage System		Capacities		Deter-ministic	Stochas-tic
	Included	Excluded	Unlimited	VEPCO		
LP1		x	x		x	
LPN		x	x			x
LP2	x		x		x	
LPS	x		x			x
LP1V		x		x	x	
LPNV		x		x		x
LP2V	x			x	x	
LPSV	x			x		x

Deterministic Models

The LP1 and LP2 models were run for all seven types of days in each of the twelve months. For both the worst day encountered was $8/\overline{4}$*, i.e., Thursdays in August. For the LP1 model, which excludes storage, this selection is intuitively obvious since (a) the maximum load in the study period occurs during the $8/\overline{4}$ days, and (b) installed capacity has to be available to meet this demand. If storage is included then the maximum cost case depends on the complete load profile, since the peak loads can be met by energy in storage derived from generation at hours with excess capacity. However, both "worst" cases did coincide.

Deterministic Models Without Storage

The LP1 and LP1V models only differ in that the latter one contains upper limits on its system capacities corresponding to the 1978 VEPCO data. The LP1 model of course is not restricted in its selection of generation mix capacities.

LP1:

Table 5.2 contains an overview of the results obtained by the LP1 with respect to capacities and costs. Figures 5.1 and 5.2 respectively show the daily generation profiles obtained with LP1 for the days with the highest load ($8/\overline{4}$) and the lowest load ($10/\overline{7}$).

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* The notation $8/\overline{4}$ corresponds to month 8 and type of day 4, to distinguish it from August 4 (8/4). The types of days used are indexed by $\overline{1}, \ldots, \overline{7}$ corresponding to Mondays through Sundays.

Table 5.2 Overview of LP1 Results

Highest Cost Case	Day*	System			
		Nuclear	Coal	Oil	Total
Capacity (10^3MW)	8/$\overline{4}$	6.657	0.152	0.115	
Capacity Cost ($)		1,294,252.	25,664.	12,501.	1,332,418
Operating Cost ($)		890,114.	8,887.	6,459.	905,461
Total Cost ($)		2,184,366.	34,552.	18,960.	2,237,879
Lowest Cost Case					
Capacity (10^3MW)	10/$\overline{7}$	3.616	0.047	0.274	
Capacity Cost ($)		703,010.	7,980	29,734.	740,724
Operating Cost ($)		523,867.	2,763	15,914.	542,544
Total Cost ($)		1,226,876.	10,743.	45,649.	1,283,268

* notation: month/$\overline{\text{type of day}}$; where $\overline{1}$, ..., $\overline{7}$ correspond to Mondays, ..., Sundays.

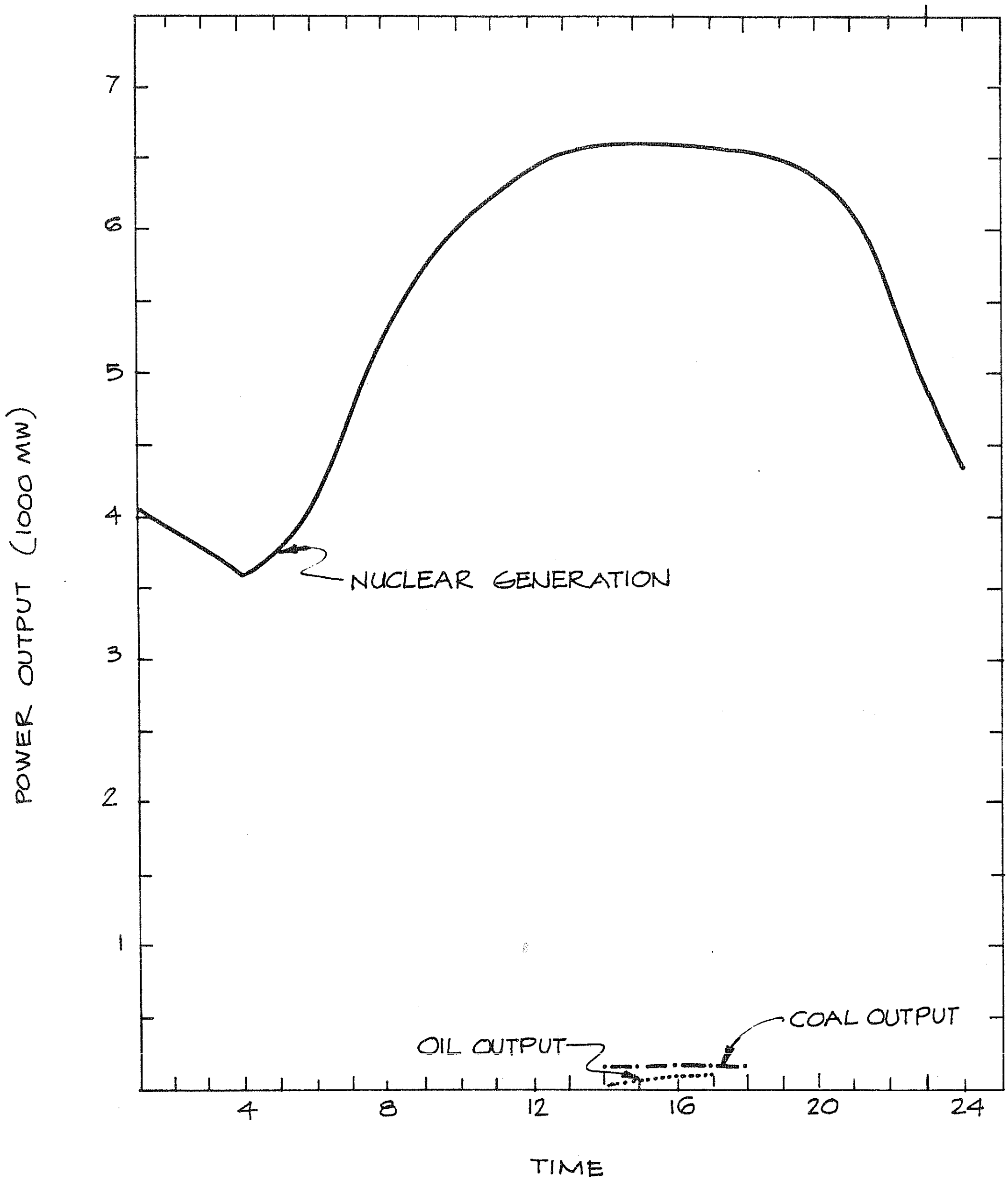

Figure 5.1 LP1 Generation Results for 8/$\overline{4}$

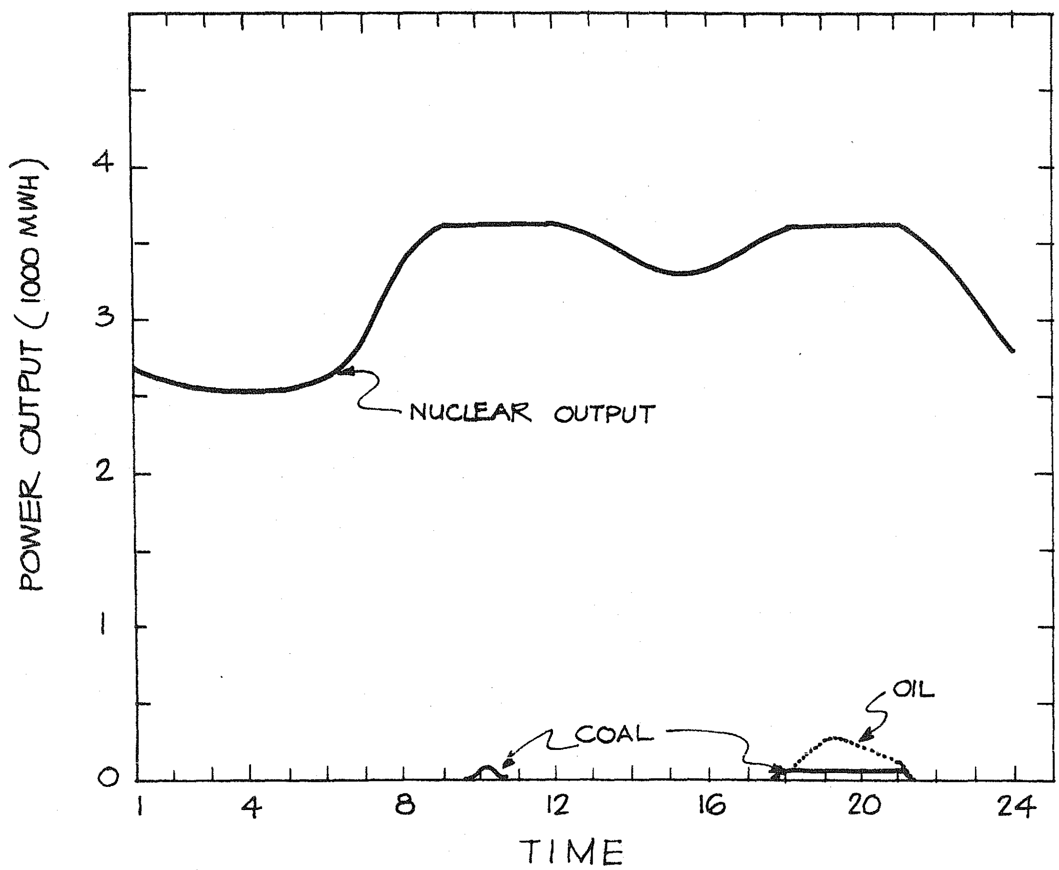

Figure 5.2 LP1 Generation Results for 10/7̄

A regression analysis applied to the optimal capacities obtained for each type of day in the 1978 period shows that the maximum daily load explains 98.7% of the capacity variations for the nuclear system, i.e.,

$$\begin{pmatrix}\text{Nuclear} \\ \text{Capacity in} \\ \text{1000 MW}\end{pmatrix} = -.111 + .9817 \begin{pmatrix}\text{Maximum} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix}, \quad R^2_{adj} = .987 \qquad (5\text{-}1)$$

Other variables, such as average daily load, do not improve the above regression equation. The coal and oil capacities were also regressed on maximum and average daily loads, but no satisfactory fit could be found. This implies that they depend upon other characteristics of the daily load profiles.

It should be noted that the load following with nuclear plants, as illustrated in Figures 5.1 and 5.2, may be infeasible because of Federal regulations and uneconomic due to to resulting increases in maintenance costs and equipment breakdowns.

This case does, however, correspond to the absolute minimum cost case that is "feasible" without pumped storage.

LP1V :

The LP1V results show that the most economical generation procedure is loading in the order (a) nuclear, (b) coal, and (c) oil. Obviously this is the incremental cost loading which is expected. Figure 5.3 shows the optimal generation schedule for $8/\overline{4}$, given the VEPCO maximum capacities of 2.457 (1000 MW Nuclear), 3.288 (1000 MW) Coal, and 3.469 (1000 MW) Oil.

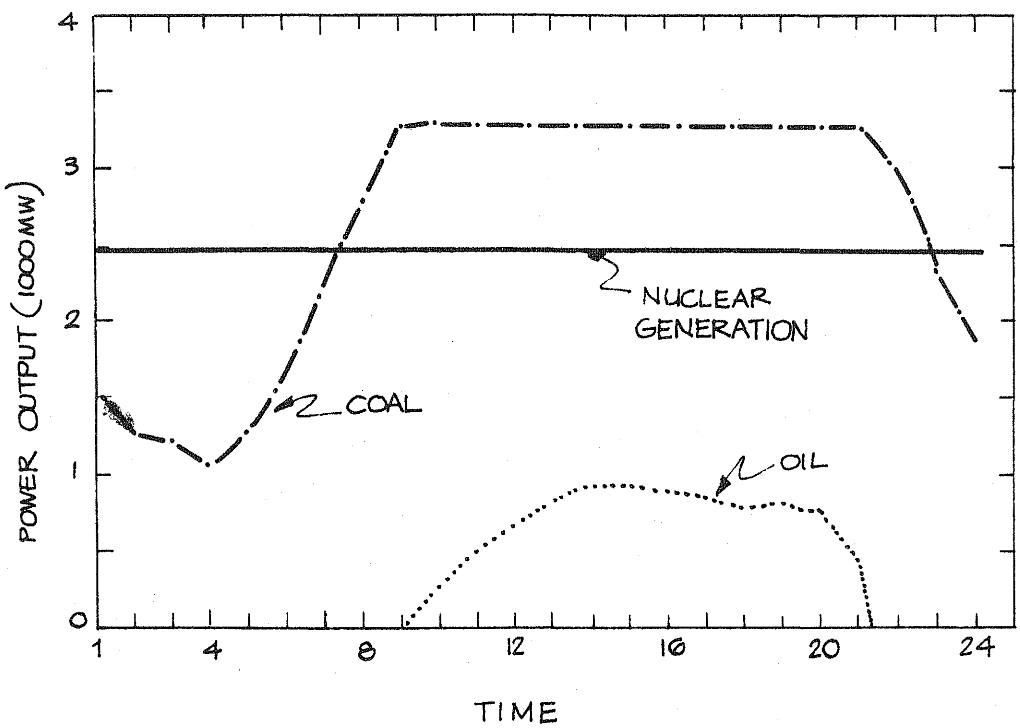

Figure 5.3 LP1V Generation Results for 8/4

Deterministic Models With Storage

The deterministic LP2 and LP2V models incorporate the hydro-pumped storage system by the addition of hourly storage inflow and outflow variables, as well as storage pumping and reservoir capacity variables. The capacities are unlimited in the LP2 model, whereas the LP2V model is constrained by the VEPCO generating capacities for 1978. A sensitivity analysis was performed on LP2 results for $8/\overline{4}$.

LP2:

Introducing hydro-pumped storage in the generation system results in an extremely levelized nuclear production and zero-power outputs from both coal and oil generating systems, for all types of days throughout 1978. Figures 5.4 and 5.5 present the optimum generation patterns for the peak load type of day ($8/\overline{4}$) and for a typical winter day ($1/\overline{1}$). Note that the dual peak requirements on winter days are supplied by the storage system; not by increases/decreases in the nuclear power output. A total cost comparison between LP2 and LP1 for the peak day shows a savings of $127,414 in favor of the system with the pumped storage. This is equivalent to an average savings of approximately 0.096¢/kWh to the consumer. Table 5.3 lists an overview of the LP2 results. It appears that the nuclear units now exhibit very good base loading featuers.

Regressions on the optimum nuclear capacities for each type of day of the study period show that they are, at a rate of 99.6%, explained by the average daily load -- not by the maximum load as for LP1. The

Table 5.3 Overview of LP2 Results

Highest Cost Case	Day	System					
		Nuclear	Coal	Oil	Storage	Reservoir*	Total
Capacity (10^3MW)	8/$\overline{4}$	5.732	0.0	0.0	1.652	10.720	
Capacity Cost ($)		1,114,315	0.0	0.0	71,052.	20,565.	1,205,932.
Power Cost ($)		904,533.	0.0	0.0	0.0	0.0	904,533.
Total Cost ($)		2,018,848.	0.0	0.0	71,052.	20,565.	2,110,465.

* Reservoir capacities in 10^3 MWh.

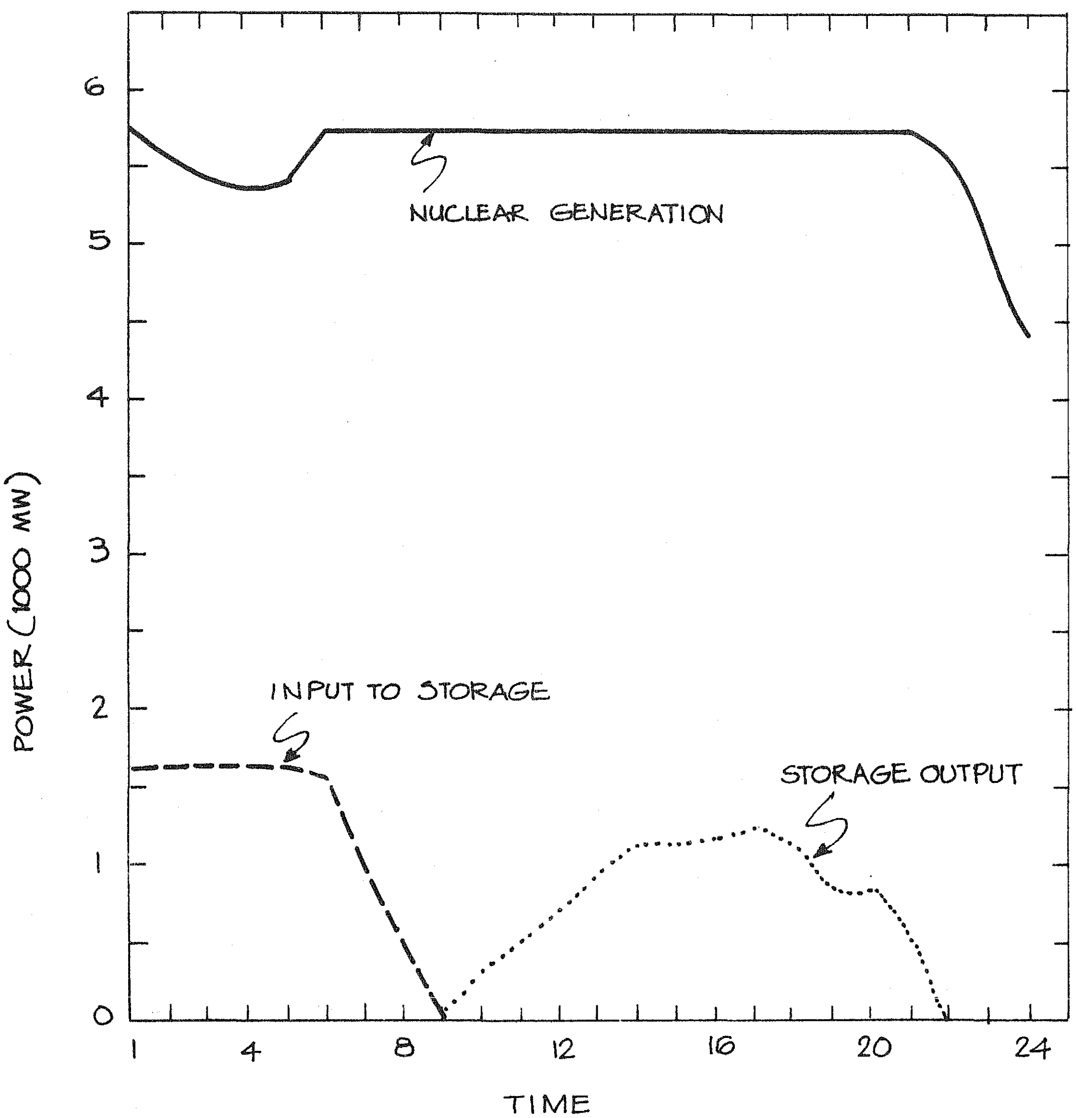

Figure 5.4 LP2 Generation and Storage Schedules for 8/$\overline{4}$

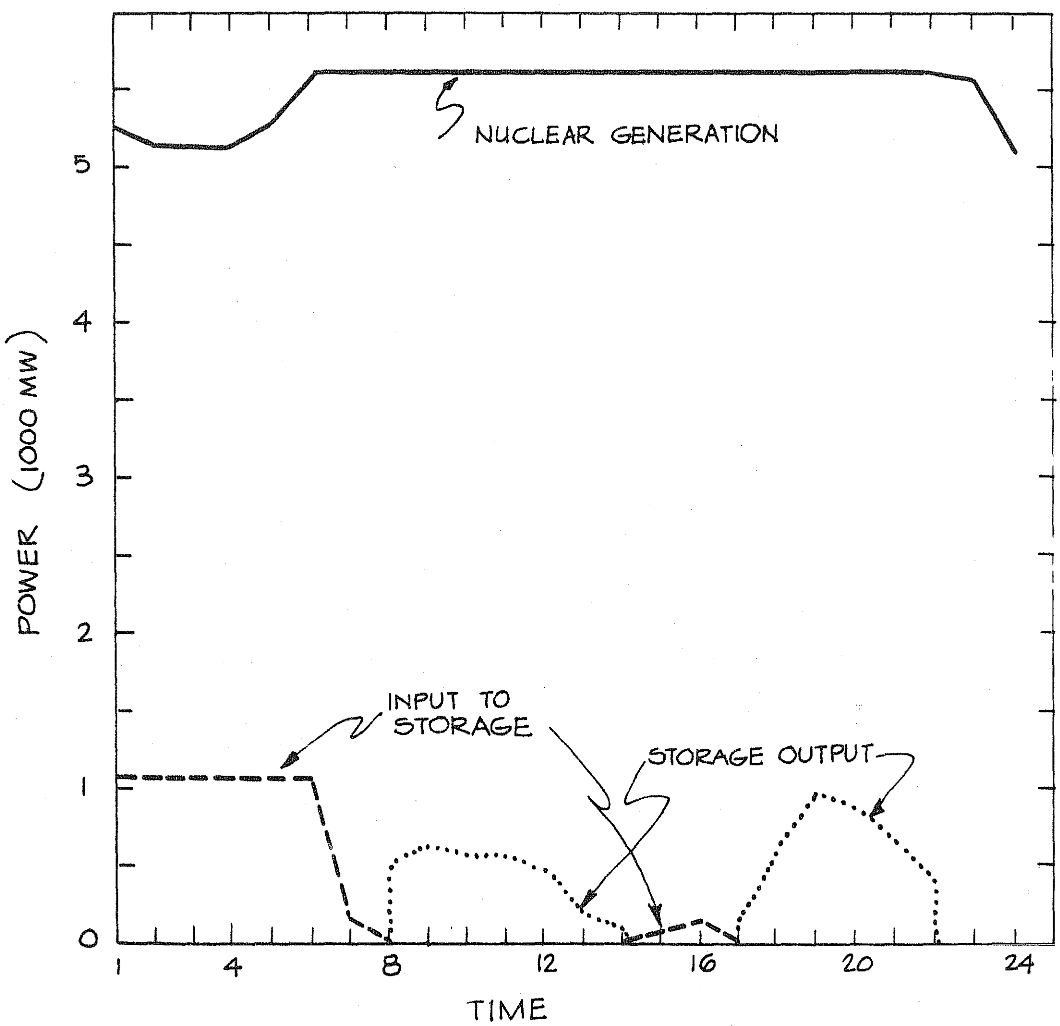

Figure 5.5 LP2 Generation and Storage Schedules for 1/$\overline{I}$

regression fit with the average load only is:

$$\begin{pmatrix}\text{Nuclear} \\ \text{Capacity in} \\ \text{1000 MW}\end{pmatrix} = -.038 + 1.035 \begin{pmatrix}\text{Average} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix}, \quad R^2_{adj} = .996 \qquad (5\text{-}2)$$

and, when adding the maximum load, the fit is slightly improved, with:

$$\begin{pmatrix}\text{Nuclear} \\ \text{Capacity in} \\ \text{1000 MW}\end{pmatrix} = -.030 + 0.901 \begin{pmatrix}\text{Average} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix} + .112 \begin{pmatrix}\text{Maximum} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix},$$

$$R^2_{adj} = .997 \qquad (5\text{-}3)$$

Both the optimum storage and reservoir capacities, obtained for the study period, are dependent upon the maximum and average daily load, i.e.:

$$\begin{pmatrix}\text{Storage} \\ \text{Capacity in} \\ \text{1000 MW}\end{pmatrix} = .170 + 1.333 \begin{pmatrix}\text{Maximum} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix} - 1.393 \begin{pmatrix}\text{Average} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix},$$

$$R^2_{adj} = .612 \qquad (5\text{-}4)$$

and,

$$\begin{pmatrix}\text{Reservoir} \\ \text{Capacity in} \\ \text{1000 MWh}\end{pmatrix} = .881 + 9.522 \begin{pmatrix}\text{Maximum} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix} - 10.149 \begin{pmatrix}\text{Average} \\ \text{Load in} \\ \text{1000 MW}\end{pmatrix},$$

$$R^2_{adj} = .763 \qquad (5\text{-}5)$$

LP2V:

The LP2V results for the total study period indicate that VEPCO's nuclear and coal capacity is always sufficient to serve its system demand. Nuclear output is completely flat at 2457 MW and coal-fired generation follows the load profile whenever necessary. Oil is never used in the optimal solutions. A sample generation pattern is shown for day 8/$\overline{4}$ in Figure 5.6. All the storage flow patterns are similar to those obtained in the LP2 applications.

Pumped Storage Analysis

The previous results indicate that substantial savings are possible by introducing pumped storage facilities in the system. Since site characteristics may constitute major constraints on feasible reservoir capacity, sensitivity analyses were performed by varying the maximum reservoir capacity and the relationship between storage and reservoir capacity was investigated. These analyses were made for the 8/$\overline{4}$ day.

Figure 5.7 represents the relationship between the optimal storage and the reservoir capacities when the maximum reservoir capacity is varied continuously. Note that this relationship becomes linear when the reservoir capacity is larger than 8000 MWh. The storage pumping capacity (in MW) is approximately 1/7th of the size of the reservoir capacity (in MWh). The regression fit is:

$$\begin{pmatrix}\text{Storage} \\ \text{Capacity in} \\ \text{1000 MW}\end{pmatrix} = 0.020 + 0.1389 \begin{pmatrix}\text{Reservoir} \\ \text{Capacity in} \\ \text{1000 MWh}\end{pmatrix}, \quad R^2_{adj} = 0.940 \tag{5-6}$$

The daily system costs are shown in Figure 5.8. Given the daily system cost without storage ($2,237,879; see LP1) the average daily cost savings by introducing pumped storage are $21 per MWh of installed reservoir capacity (with the corresponding storage facilities). Of course these savings are increasing at a diminishing rate with larger reservoir sizes.

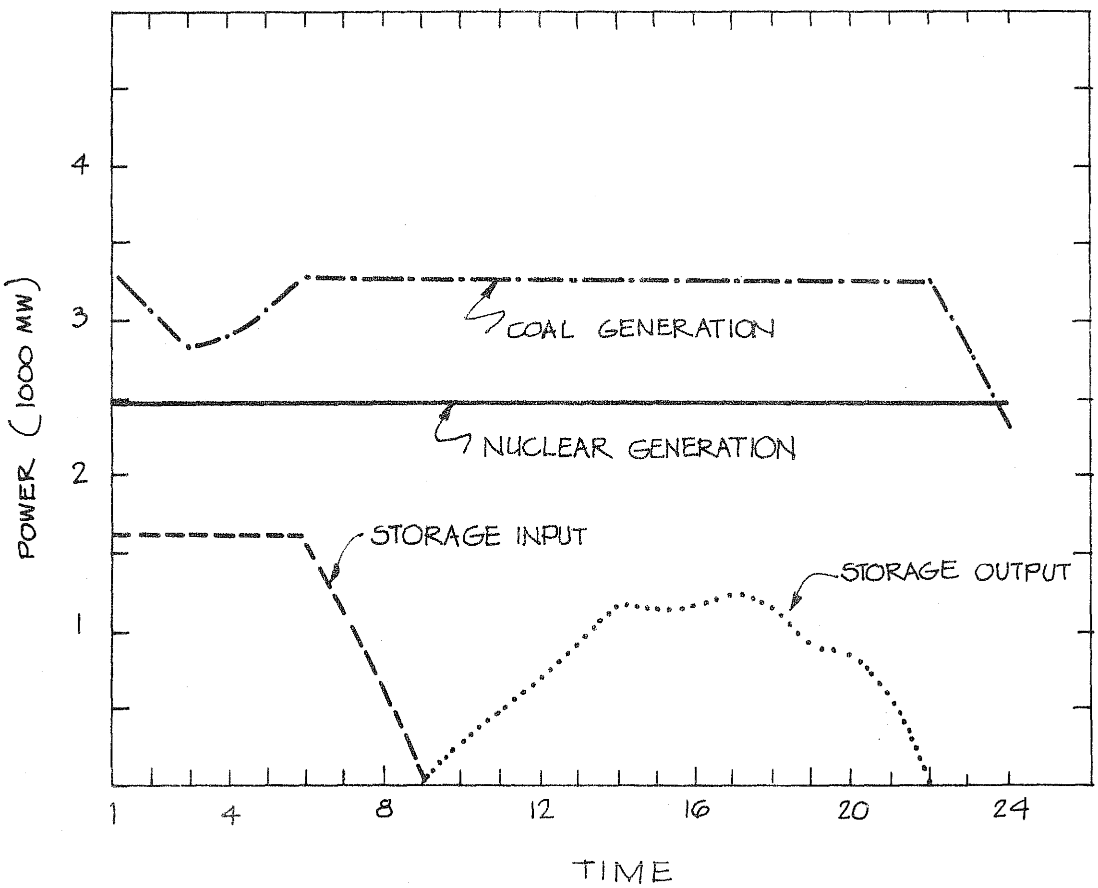

Figure 5.6 LP2V Generation Results for 8/$\overline{4}$

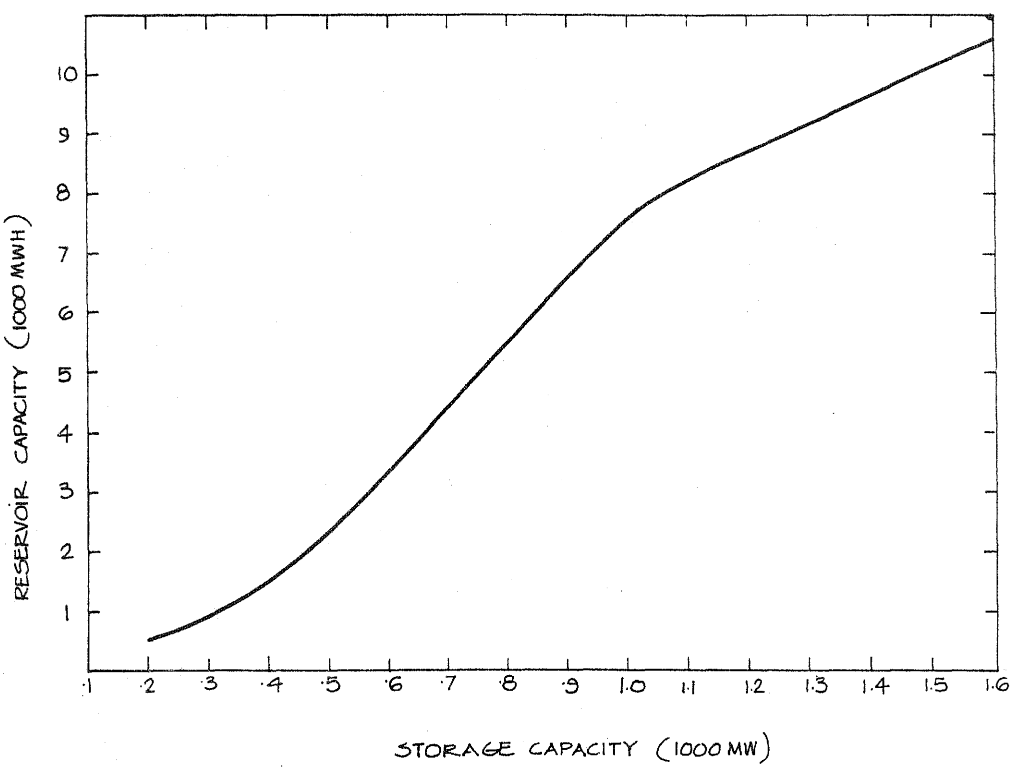

Figure 5.7 Optimum Storage versus Reservoir Capacity

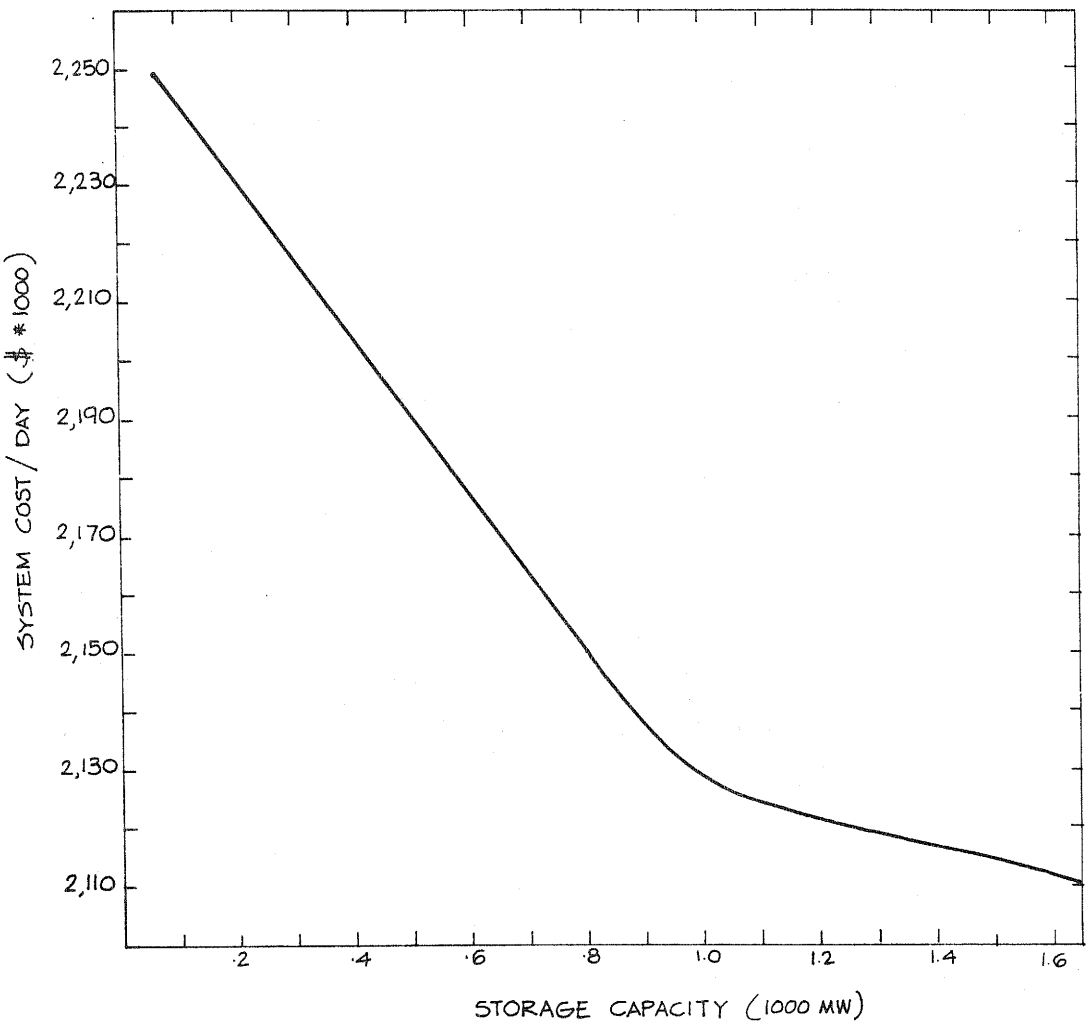

Figure 5.8 Total Daily System Cost versus Storage Capacity

Stochastic Models

Given the "worst" month as determined by the previous models, the maximum cost stochastic case was found as $8/\overline{1}$. Although this day is neither the highest average load or maximum load day, the combined effect of the load profile and its large hourly variations resulted in this selection. The optimum LPS capacity and generation costs for this day are shown in Figure 5.9 as a function of reliability. A similar curve is presented in Figure 5.10 for the LPSV case.

The uncertainty in the hourly load yields extreme increases in the sizes of both storage and reservoir capacities. Comparing Figure 5.11, which shows the optimum reservoir sizes as a function of the reliability level, with the "worst" day deterministic solution of 10,720 MWh, we see that the load uncertainty increases the reservoir size 4.4 times (reliability level of 85%; 47,324 MWh) to 7.9 times (99%; 84,682 MWh). The deterministic storage capacity (1,652 MW) now ranges from 3,273 to 4.524 MW for the investigated reliability range (2.0 to 2.7 its previous size).

From a systems viewpoint these increases are realistic since the storage facilities provide the "buffer" for all expected load deviations. It is however questionable whether reservoirs of this size are always available within the utilities territory. It is also questionable whether this size is optimum for a longer period, say a week, since it was derived from the "worst" day case.

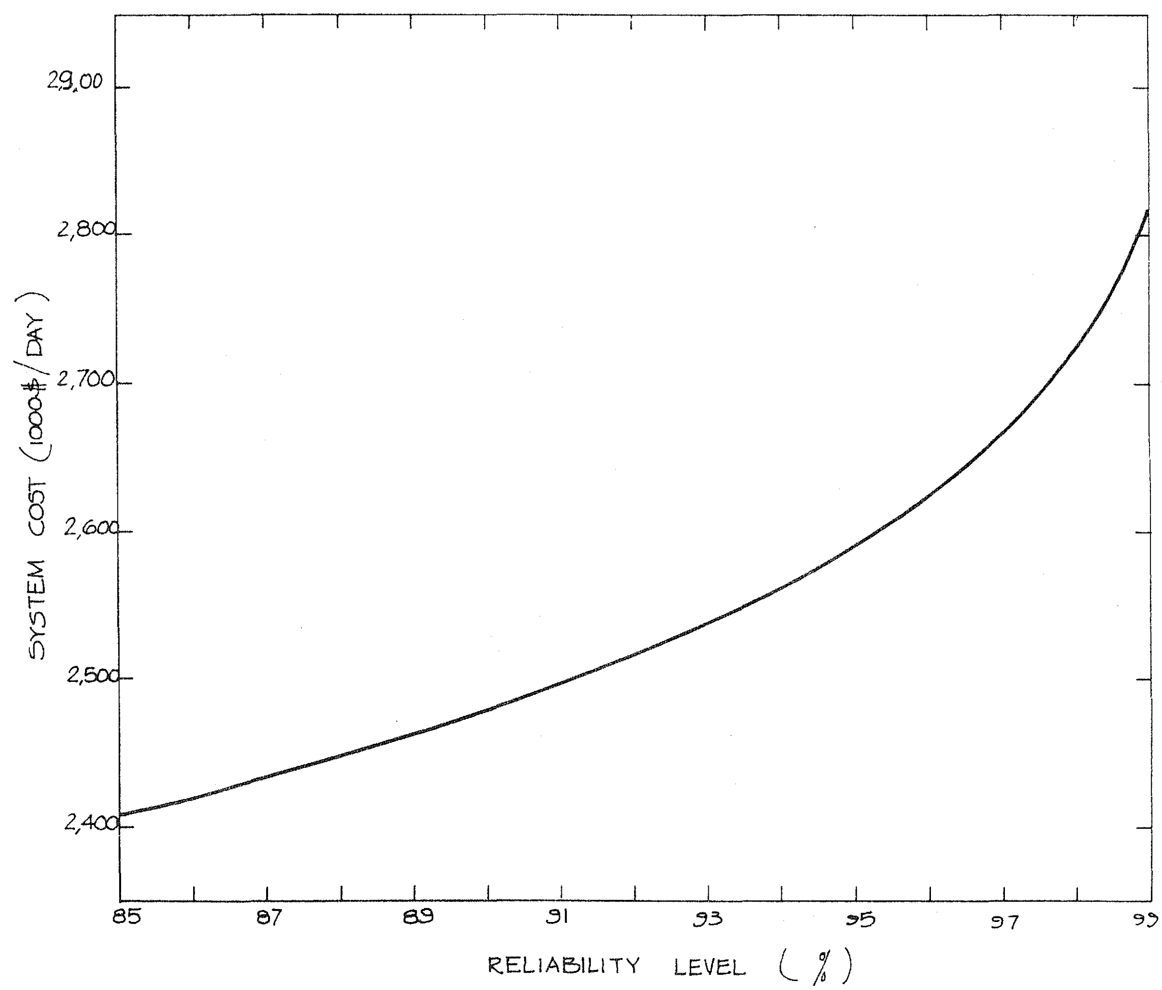

Figure 5.9 Optimum System Cost versus Reliability Level

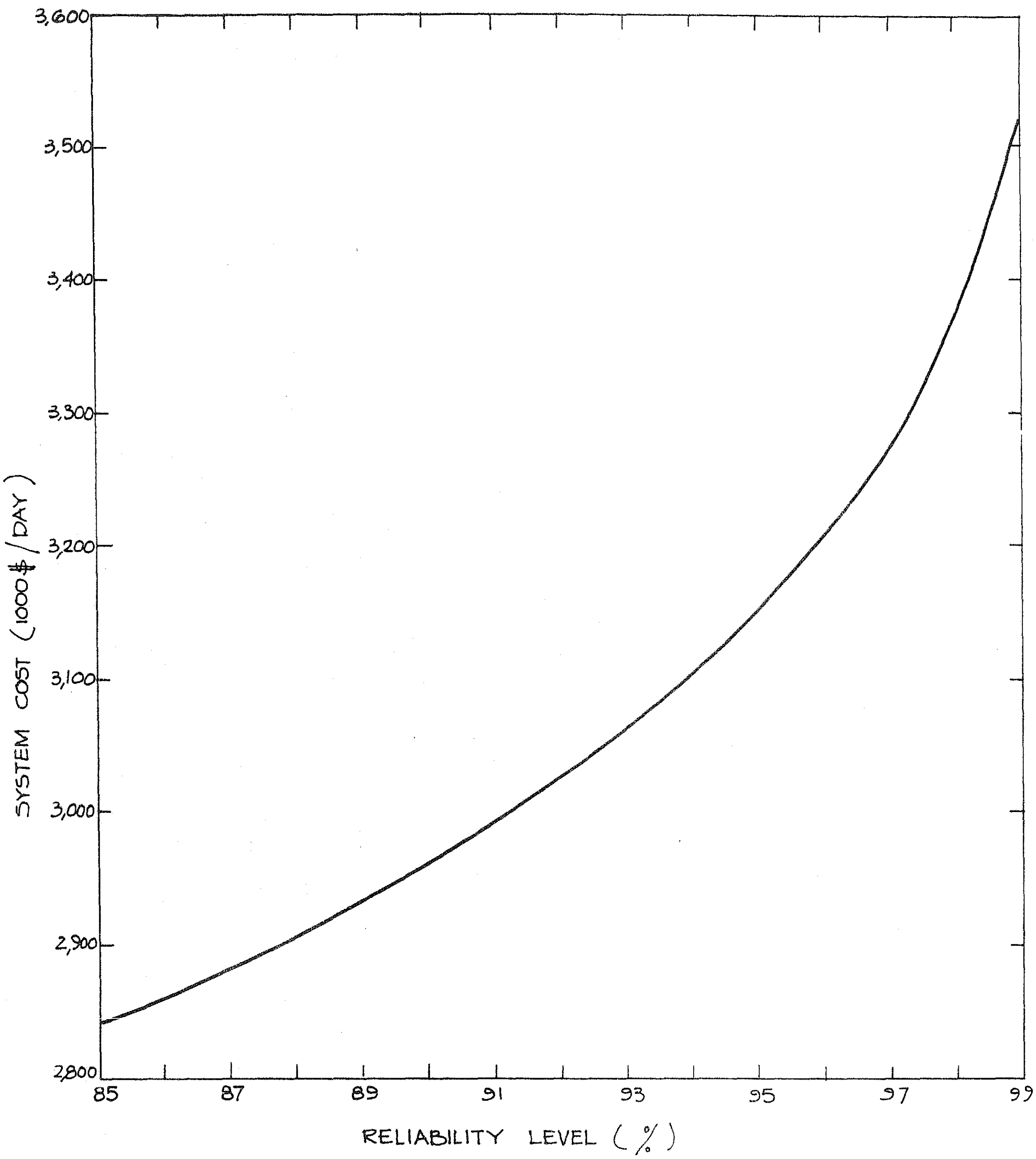

Figure 5.10 VEPCO Optimum System Cost versus Reliability Level

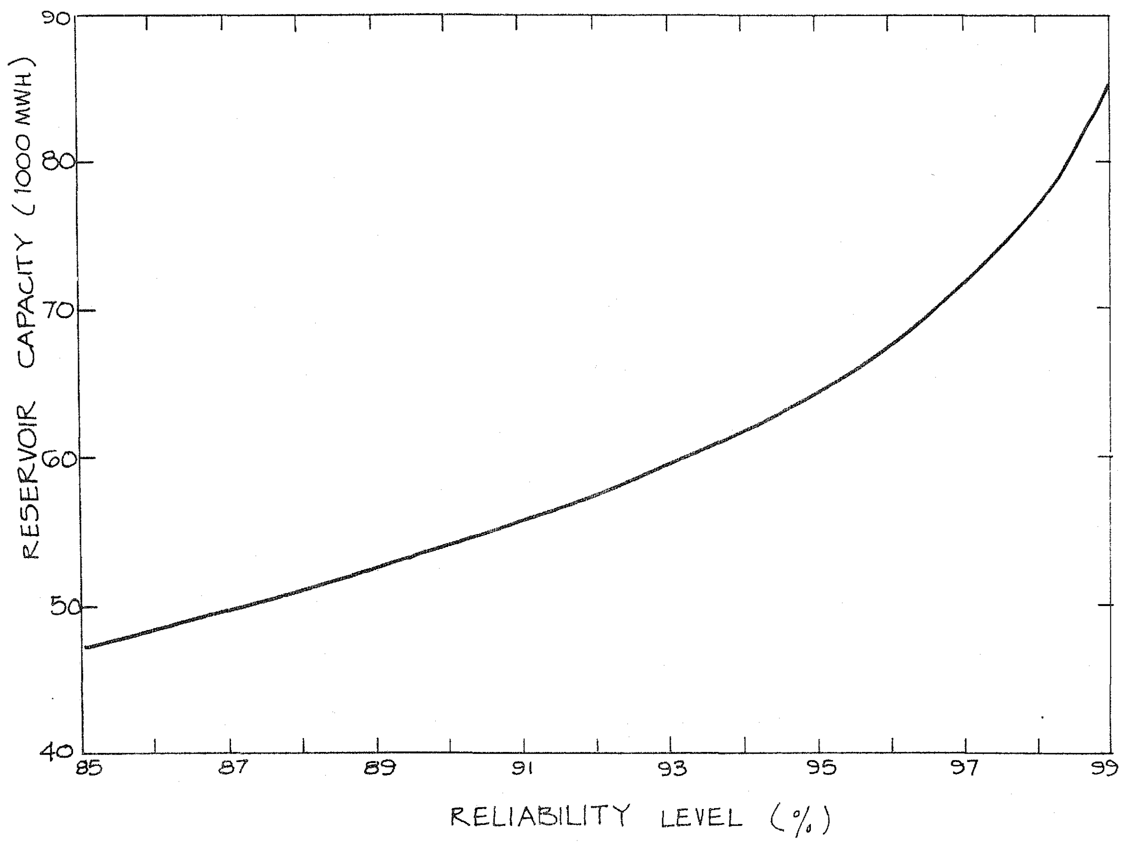

Figure 5.11 Optimum Reservoir Size versus Reliability Level

The cost versus reliability curves indicated that benchmarks can be reasonably established at the 95% and 99% levels. All further analyses of the stochastic models is therefore made at those levels.

Stochastic Models Excluding Storage

LPN:

Figures 5.12 and 5.13 show the power production levels for the two reliability levels. Both plots are similar to the deterministic generation pattern of LP1 (Figure 5.1). The only differences are the higher production levels due to the added load uncertainty. Of course the nuclear load following again seems excessive, but it can be established as the cheapest production scenario for the most demanding day. Table 5.4 presents an overview of the LPN results.

LPNV:

The traditional economic loading rules are applicable in the VEPCO case without storage. The generation pattern for day $8/\overline{1}$ is shown in Figure 5.14. The total cost of this pattern is \$3,172,870, showing a penalty (or trade-off cost) of \$275,125/day as compared to the LPN generation mix.

Stochastic Models Including Storage

LPS:

Table 5.5 lists the financial highlights for the LPS maximum cost scenario. The capacities, which were determined by this $8/\overline{1}$ configuration, were assumed fixed within the system, and LPS was applied to each

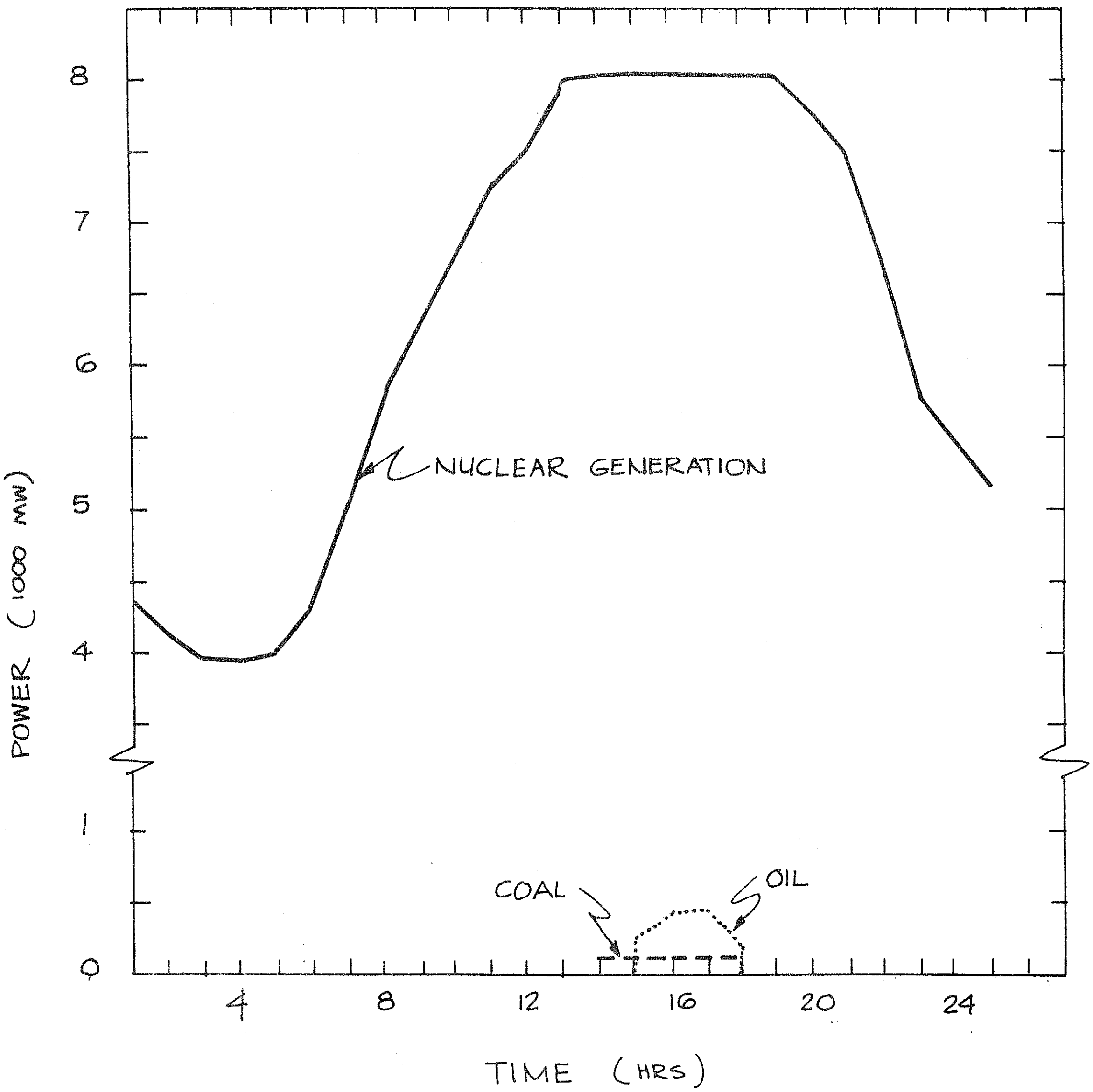

Figure 5.12 LPN Generation Results for 8/$\overline{1}$
at a 95% Reliability Level

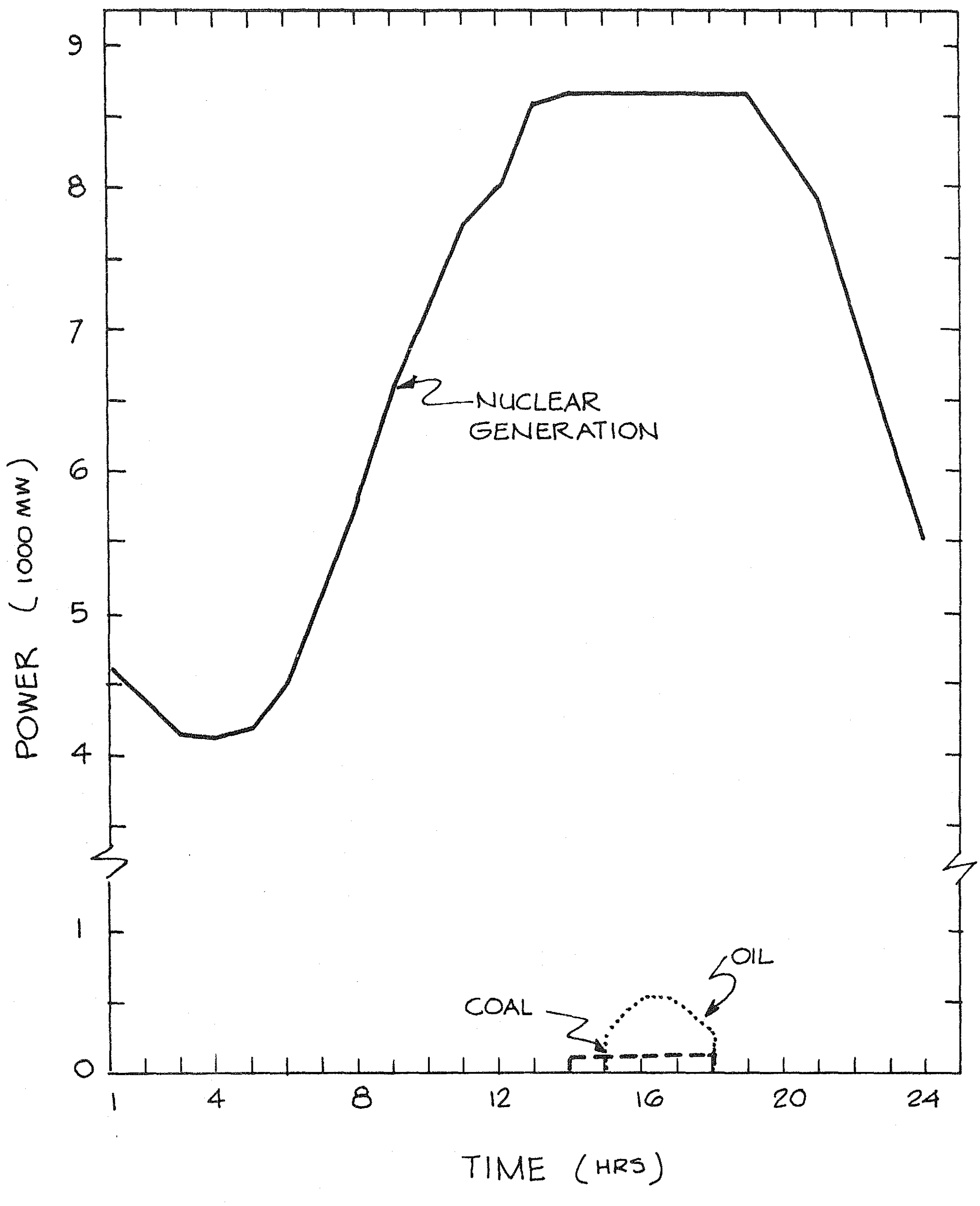

Figure 5.13 LPN Generation Results for 8/$\overline{1}$
at a 99% Reliability Level

Table 5.4 Overview of LPN Results

Highest Cost Case	Day	System at 99% Reliability Level			
		Nuclear	Coal	Oil	Total
Capacity (10^3MW)	8/$\overline{1}$	8.669	0.098	0.506	
Capacity Cost ($)		1,685,278.	16,501.	54,958.	1,756,738.
Power Cost ($)		1,095,060.	5,714.	40,232.	1,141,007.
Total Cost ($)		2,780,338.	22,216.	95,190.	2,897,745.
		System at 95% Reliability Level			
Capacity (10^3MW)		8.032	0.112	0.425	
Capacity Cost ($)		1,561,428.	18,866.	46,122.	1,626,416.
Power Cost ($)		1,027,965.	6,533.	33,751.	1,068,250.
Total Cost ($)		2,589,393.	25,400.	79,874.	2,694,667

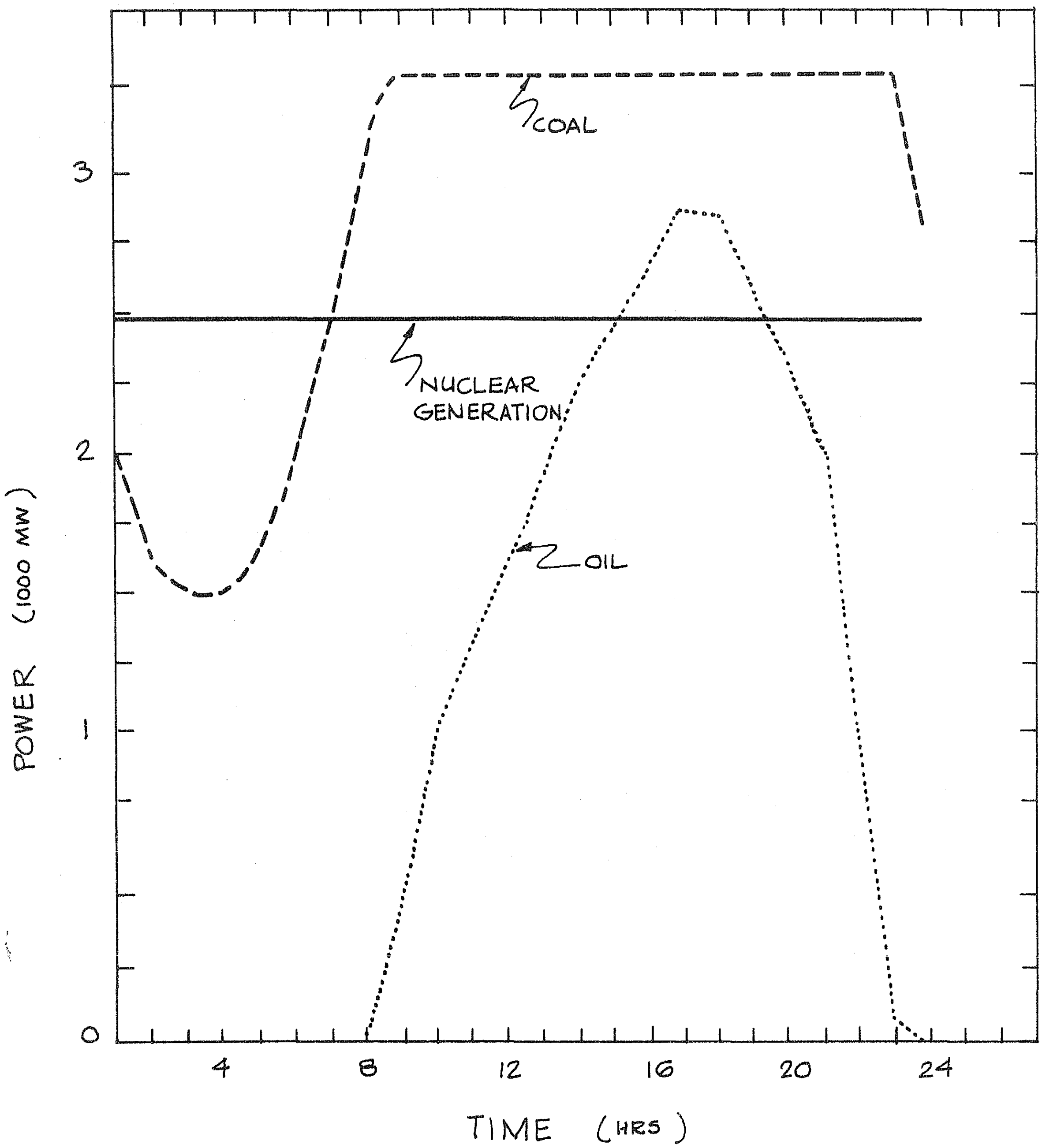

Figure 5.14 LPNV Generation Results for 8/$\overline{1}$ at a 99% Reliability Level

Table 5.5 Overview of LPS Results

95% Reliability Case	Day	System			
		Nuclear	Storage	Reservoir	Total
Capacity (10^3MW)	8/$\overline{1}$	6.619	3,857	64.457	
Capacity Cost ($)		1,286,884.	165,291.	123,654.	1,576,460.
Operating Cost ($)		1,040,421	0.	0.	1,040,421.
Total Cost ($)		2,327,305	165,921	123,654	2,616,880.
99% Reliability Case					
Capacity (10^3MW)	8/$\overline{1}$	6.953	4.524	84.683	
Capacity Cost ($)		1,351,739.	194,594.	162,454.	1,708,787
Operating Cost ($)		1,108,711.	0.	0.	1,108,711
Total Cost ($)		2,460,450.	194,594.	162,454	2,817,499

type of day in August, leading to optimum generation rules within these given capacities. Table 5.6 lists the resulting costs for August. It should be noted that this is not a complete system optimization.

Figure 5.15 presents the nuclear generation pattern and the net storage flows for day $8/\overline{1}$ at a reliability level of 99%. The generation levels for day $8/\overline{1}$ at the lower 95% reliability level are extremely similar.

One should note that in all stochastic versions of the model, a decision is first made on generation, and the storage pool regulates the differences between this production and the actual demand encountered. The net storage flows presented in the figures are the result of the generation decisions, and a demand corresponding to either the 95% or 99% reliability level.

In all cases the decision on generation is almost set at the maximum available capacity for the major part of the day. The storage facilities are able to absorb additional energy flows as they never reach their critical limits. The large decreases in generation during the latter parts of the day -- because the reservoir can supply all necessary power -- do, however, create problems concerning day to day oeprations. This should be adjusted if a longer-term optimization is considered.

LPSV Final Results:

Analgous to the LPS approach, the August costs are listed in Table 5.7. The generation pattern for $8/\overline{1}$ shown in Figure 5-16 for the 99% reliability level and in Figure 5-17 for the 95% level.

Table 5.7 LPSV Costs for August for the VEPCO System* at 99% Reliability

Type of Day	Production Cost ($)	Total Cost ($)
$\overline{1}$	2,015,085	3,740,992
$\overline{2}$	2,014,939	3,740,846
$\overline{3}$	1,880,160	3,606,067
$\overline{4}$	1,711,004	3,436,911
$\overline{5}$	1,459,985	3,185,892
$\overline{6}$	1,254,164	2,980,071
$\overline{7}$	1,103,365	2,829,272

* Capacities: Nuclear - 2,457 MW
Coal - 3,288 MW
Oil - 3,469 MW
Storage - 3.567 MW
Reservoir - 84.683 MWh

Capital Cost: $1,725,907/day.

Table 5.6 LPS Costs for August with Fixed Capacities* at 99% Reliability

Type of Day	Production Cost ($)	Total Cost ($)
$\overline{1}$	1,108,711.	2,817,499.
$\overline{2}$	1,106,201.	2,814,989.
$\overline{3}$	1,073,135.	2,781,923.
$\overline{4}$	1,026,423.	2,735,211.
$\overline{5}$	961,051.	2,669,838.
$\overline{6}$	891,827.	2,600,615.
$\overline{7}$	804,864.	2,513,651.

* Capacities: Nuclear - 6.953 MW
Coal - 0 MW
Oil - 0 MW
Storage - 4.524 MW
Reservoir - 84.623 MW

Capital Cost: $1,708,787/day.

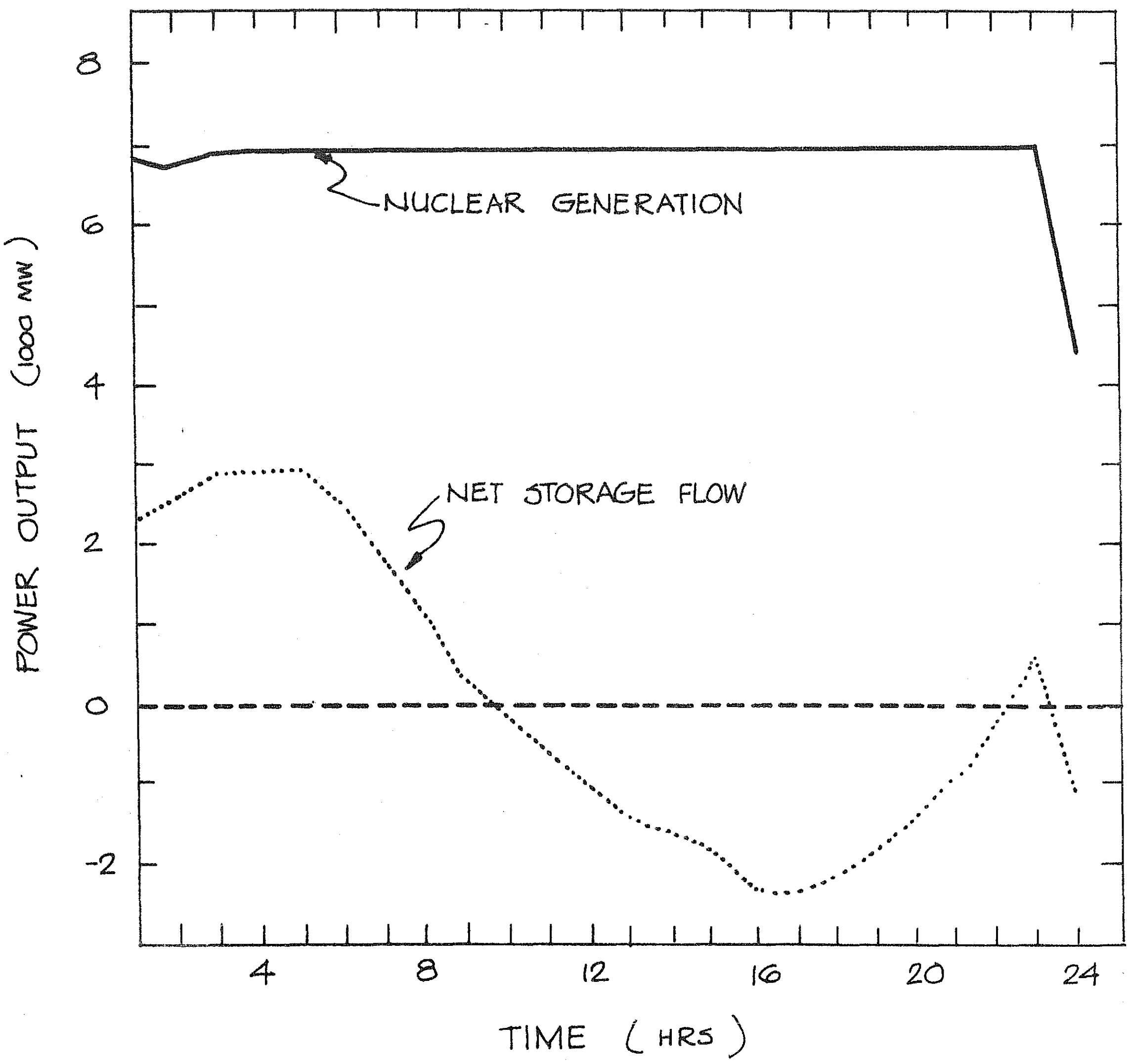

Figure 5-15 LPS Generation Results for 8/T at a 99% Reliability Level

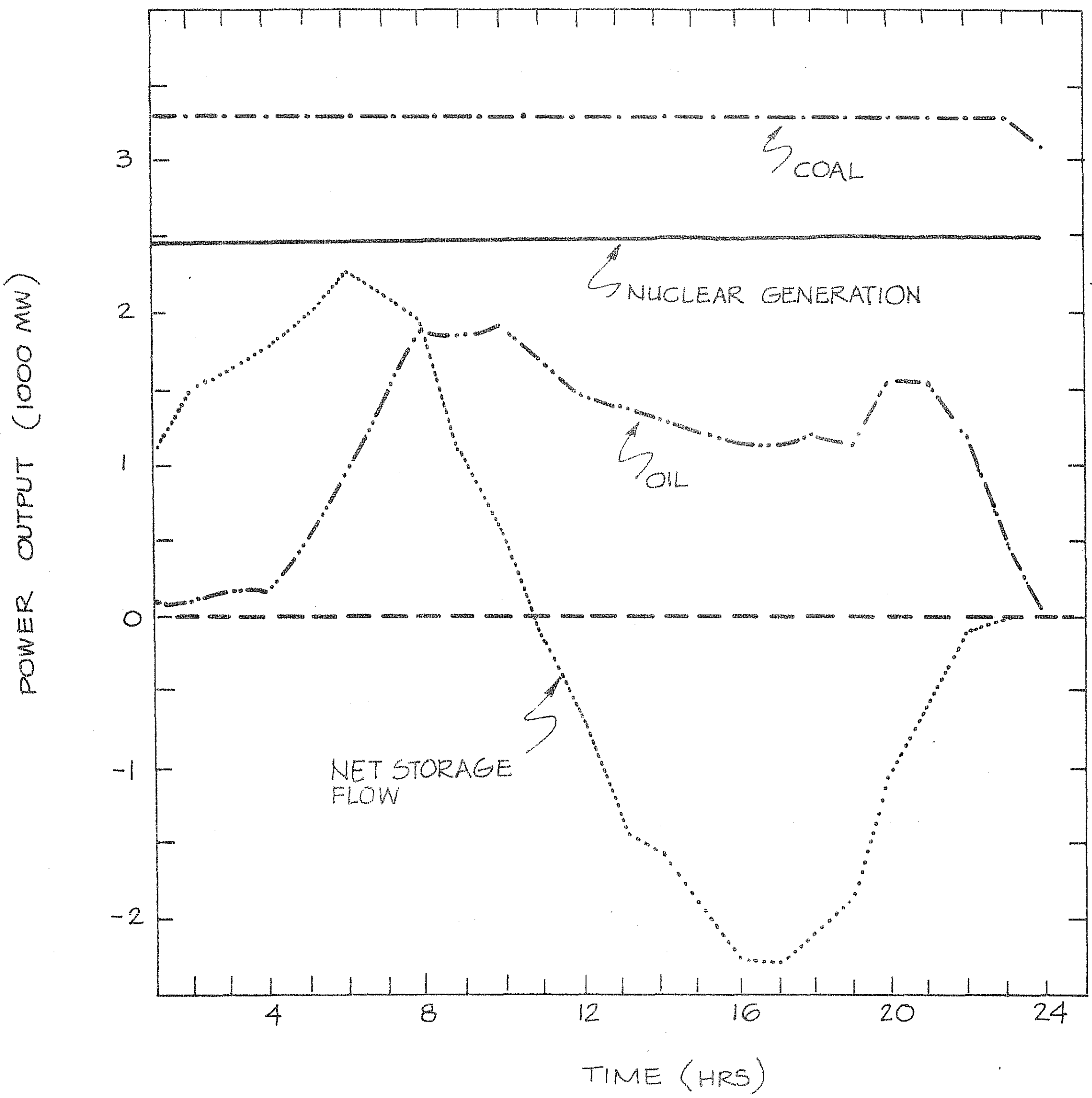

Figure 5-16 LPSV Generation Results for 8/1 at a 99% Reliability Level

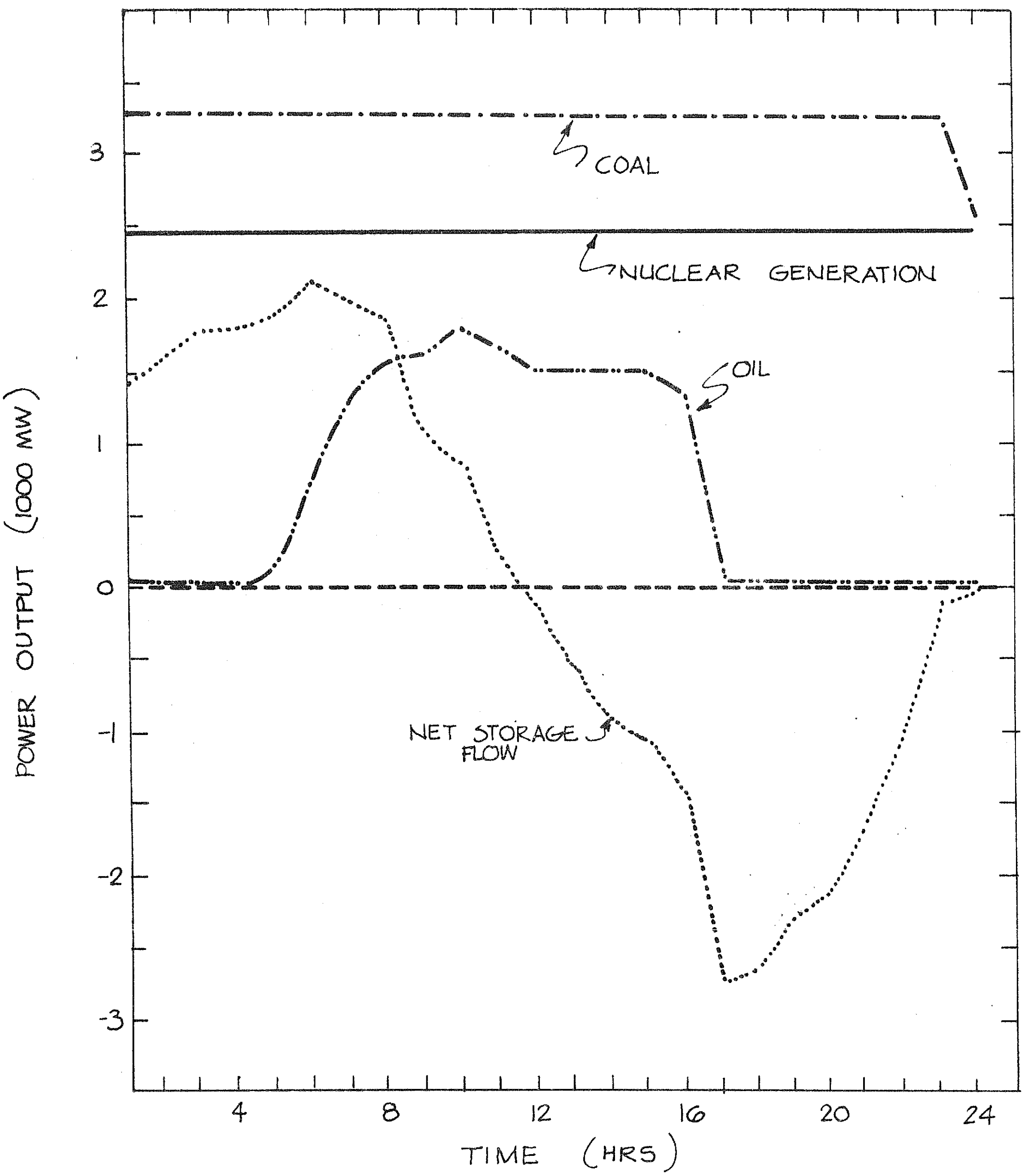

Figure 5-17 LPSV Generation Results for 8/$\overline{1}$ at a 95% Reliability Level

Simulation

The simulation approach focused on the applicability of the decision rules as derived in the LPS model for reliability levels of 95 and 99%. Given the decisions on capacity and on hourly generation for days $8/\overline{1}$ through $8/\overline{7}$, comparisons were made between the planned power outputs and a constructed random demand. When the net storage flow exceeded the storage capacity or the reservoir capacity, "lost power" deviations were registered, denoted by P_{sto}^{loss}, and P_{res}^{loss}.

Three different scenarios were investigated, namely:

(1) a long-term simulation focusing on the peak day $8/\overline{1}$, i.e., 300 successive $8/\overline{1}$ days;

(2) a simulation involving 300 successive $8/\overline{1}$ through $8/\overline{7}$ weeks, in which the energy existing in the reservoir after hour 24 of each day is transferred to the next day;

(3) a simulation involving 300 successive $8/\overline{1}$ through $8/\overline{5}$ working day weeks, with the same approach as in (2).

Table 5.8 shows the results of these simulations. To summarize this table one should note that:

(a) for the peak-day period, the observed reliabilities are higher than those used to specify the model's constraints;

(b) for a total week problems do exist because of the accumulation of energy in the reservoir, and

Table 5.8 Simulation Results

Number of Runs	Period	Reliability Level	Required Deviations from Planned Generation (in 1000 MW)			
			P_{sto}^{loss}	(in %)*	P_{res}^{loss}	(in %)*
300	$8/\overline{1}$	95%	2.25	.1600	112.7	.31
		99%	.34	.0010	29.8	.08
300	$8/\overline{1}$-$8/\overline{7}$	95%	13.98	.0050	38,437.7	14.69
		99%	.95	.0004	47,612.3	18.19
300	$8/\overline{1}$-$8/\overline{5}$	95%	8.74	.0050	19,732.8	10.18
		99%	.59	.0003	23,912.2	.66

* % deviation represents deviation from the average hourly load level L_{avg}, where:

$$L_{avg}(8/\overline{1}) = 5{,}076.6 \text{ MW},$$

$$L_{avg}(8/\overline{1} \rightarrow 8/\overline{7}) = 5{,}193.5 \text{ MW, and}$$

$$L_{avg}(8/\overline{1} \rightarrow 8/\overline{5}) = 5{,}384.8 \text{ MW}$$

(c) these problems are mostly due to the low level demand days, Saturday and Sunday.

The conclusion from the previous analysis is that the decision rules should be modified if a week or a longer period is considered in the optimization models.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

The objectives of this study have been to determine

(1) the optimum capacities of the nuclear, coal and oil-fired generating systems and of the pumped storage system -- in terms of reservoir and pumping capacity, and

(2) hourly generation decision rules for each system, yielding minimum operating and investment costs as well as high reliability of supply.

A framework was developed to derive these capacities and generation rules, as well as to test them for a specific utility's capacity and load data (the Virginia Electric Power Company). The following sections summarize the conclusions that can be drawn from this work, and list recommendations for improvements and possible further research.

Conclusions

The general results of this study, based on VEPCO information and 1978 cost data, are shown below.

A. Given any 1978 daily load profile:

(1) pumped storage is cost effective for all days considered in the study;

(2) both storage and reservoir capacities can be satisfactorily explained by maximum and average loads, whereas their load leveling effect makes the capacities of the generating systems depend completely on the average load;

(3) in the optimum configuration storage capacity is highly correlated with reservoir capacity;

(4) generation is performed in the standard economic loading order, and the storage reservoir is filled during the first seven to nine hours of the day and emptied during the peak load period(s).

B. Given a stochastically determined daily load profile:

(1) pumped storage again is cost-effective for all cases considered;

(2) the load uncertainty results in increases in both storage and reservoir capacities corresponding to approximately 2-4 and 3-7 times the size of their deterministic counterparts, for reliability levels ranging from 85 to 99%,

(3) generating costs and capital costs for an optimum system are increasing non-linearly with the reliability of the system, i.e. the probability of meeting a stochastic demand pattern;

(4) zero-order decision rules can be established with respect to generation scheduling and capacity determination.

C. The linear programming approach for the determination of both capacities and generation levels produces realistic solutions which can incorporate dynamic aspects of electricity supply (such as plant loading rates, etc.). However, the derived decision rules do need additional adjustments since they were obtained through daily optimizations, which necessarily lead to some suboptimization when these daily time units are aggregated over longer periods.

Recommendations

Recommendations for extensions of the existing models, and on possible future improvements, are given here.

Concerning the extensions, it is recommended that:

A. Technical information, such as plant loading rates, be incorporated in the models to avoid severe power increases/decreases that appeared in some outputs.

B. Losses in the pumped storage system be included in the stochastic models to present the actual situation more realistically.

C. More detailed input-output curves be used in all models.

Possible future improvements might focus on:

A. System optimizations over periods longer than the peak-day.

B. The probabilistic formulation of the hourly loads so that:

  (1) the uncertainty related to these loads can be diminished, and

  (2) the stochastic decision rules can be improved by accounting for up-dated information.

C. The scheduling of maintenance and unforeseen breakdowns in a longer-term overall optimization framework. In this case a purchased power option is to be included in the system.

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APPENDIX A

BASIC DATA

A-1 Load Data

This study used the 1978 hourly load data of the Virginia Electric Power Company. The hourly loads and standard deviations for the cases described in the report are listed with the program output in Appendix B.

In order to test the hypothesis of a normal distribution for the hourly loads a Chi-square goodness-of-fit test was performed. The postulated relation for the load distribution was:

$$\mathrm{LOAD}(D,t) = \overline{\mathrm{LOAD}}(D,t) + N(0,1) * SD(D,t) \qquad \text{(A-1)}$$

where:

$\mathrm{LOAD}(D,t)$ = load on the system during type of day, D, and hour t,

$\overline{\mathrm{LOAD}}(D,t)$ = average load during (D,t),

$N(0,1)$ = normally distributed variable with mean 0 and variance 1.

$SD(D,t)$ = standard deviation of the load during (D,t).

A more precise relationship could be expressed as

$$\mathrm{LOAD}(D,t) = f(D,t,T) + N(0,\sigma) \qquad \text{(A-2)}$$

where $f(D,t,T)$ = load function depending on D,t, and on the temperature T.

This approach, however, was abandoned because:

(a) no temperature data were available, and

(b) the modeling approach would have become more complex since obviously the temperatures of successive hours are related.

The Chi-square test values show that the normal distribution assumption for hourly loads is acceptable within an error risk of 5%.

A-2 Generating Station Data

Tables A-1 through A-3 respectively show VEPCO's specifications for their nuclear, coal and oil-fired plants. The capital cost data shown reflect the costs as they were perceived by VEPCO in 1978. Since almost all these capital cost estimates contain non-updated historical costs, they are useless with respect to evaluating actual 1978 costs.

Table A-1 VEPCO Nuclear Unit Specifications

Unit Name	Capacity (MW)	Heat Rates (BTU/KWh)				Fuel Cost (¢/MMBTU) 1/79
		Half	3/4	Full	Avg.	
North Anna 1	907	12,000	11,400	11,300	11,675	40.80
Surry 1	775	12,000	11,250	11,000	11,562	33.98
Surry 2	775	12,000	11,250	11,000	11,562	43.03
North Anna 2 (not on-line till 8/79)	779	12,000	11,400	11,300	11,675	n.a.

Summary of Nuclear Capability as of 12/78

Total Capacity	:	2457 MW
Combined Heat Rates	:	12,000 BTU/KWH at 50% power
		11,305 BTU/KWH at 75% power
		11,110 BTU/KWH at full power
Weighted Fuel Cost	:	39.35 ¢/MMBTU
Available Capacity	:	1,486.1 MW (or 60.48%)
Average Heat Rate	:	11,604.7 BTU/KWH
Weighted Capacity Cost	:	281.24 $/KW
Annual Cost*	:	24.133 $/KW-year
Daily Cost**	:	$66,118.76 per 1000 MW-day

* @ 7%, 25 years: annuity factor 0.08581

** Annual Cost/365

Table A-2 VEPCO Coal Unit Specifications

Unit Name		Capacity (MW)	Heat Rates (BTU/KWH) Half	3/4	Full	Avg.	Fuel Cost (¢/MMBTU) 1/79
Mt. Storm	1	553	11,400	10,700	10,600	11,025	113.00
Mt. Storm	2	553	11,400	10,700	10,600	11,025	113.00
Mt. Storm	3	560	11,200	10,500	10,400	10,825	113.00
Bremo	3	72	12,560	12,140	12,160	12,401	156.00
Bremo	4	164	10,375	9,730	9,640	10,031	156.00
Chesterfield	1	56	16,800	16,000	15,900	16,382	184.00
Chesterfield	2	73	15,200	14,500	14,600	14,882	184.00
Chesterfield	3	100	11,600	11,050	10,950	11,308	184.00
Chesterfield	4	166	10,600	10,400	10,300	10,490	184.00
Chesterfield	5	333	11,500	11,100	11,100	11,302	184.00
Chesterfield	6	658	11,000	10,800	10,700	10,878	184.00

Summary of Fossil Capability:

Total Capacity : 3288 MW
Combined Heat Rates : 11,412 BTU/KWH at 50% power,
10,880 BTU/KWH at 75% power
10,797 BTU/KWH at full power
Weighted Fuel Cost : 146.02 ¢/MMBTU
Available Capacity : 2428.3 MW (or 73.854%)
Average Heat Rate : 11,128.6 BTU/KWH
Weighted Capacity Cost: 149.80 $/KW
Annual Cost : 12.854 $/KW-year
Daily Cost : $35,216.61 per 1000 MW-day

Table A.3 VEPCO Oil/Gas Unit Specifications

Unit Name		Capacity (MW)	Heat Rates (BTU/KWH)				Fuel Costs (¢/MMBTU) 1/79
			Half	3/4	Full	Avg.	
Yorktown	1	166	10,400	10,000	9,950	10,190	198.00
Yorktown	2	170	11,300	11,100	11,000	11,183	198.00
Yorktown	3	818	10,390	9,940	9,830	10,145	198.00
Portsmouth	1	101	11,700	11,100	11,000	11,383	181.00
Portsmouth	2	101	11,435	10,820	10,750	11,119	181.00
Portsmouth	3	162	10,180	9,795	9,900	10,029	181.00
Portsmouth	4	233	10,800	9,900	9,800	10,393	181.00
Possum Pt.	1	74	13,200	13,000	13,100	13,127	175.00
Possum Pt.	2	69	13,000	12,900	13,000	13,027	175.00
Possum Pt.	3	101	11,000	10,350	10,250	10,658	175.00
Possum Pt. Icen.	1-6	78	15,683	15,683	15,683	15,683	299.00
Portsmouth	1,3,4,6	60	17,463	17,463	17,463	17,463	298.00
Portsmouth Icen.	7-10	84	17,463	17,463	17,463	17,463	299.00
Kitty Hawk Icen.	1,2	41	17,735	17,735	17,735	17,735	299.00
Possum Pt.	4	233	10,400	9,900	9,900	10,155	175.00
Possum Pt.	5	805	10,200	9,800	9,600	9,979	244.00
Lowmoor Icen.	1-4	60	16,049	16,049	16,049	16,049	293.00

Table A.3 VEPCO Oil/Gas Unit Specifications (Continued)

Unit Name		Capacity (MW)	Heat Rates (BTU/KWH) Half	3/4	Full	Avg.	Fuel Costs (¢/MMBTU) 1/79
Northern	1-4	64	16,191	16,191	16,191	16,191	299.00
Surry Icen.	1,2	37	16,601	16,601	16,601	16,601	299.00
Mt. Storm Icen.	1	12	18,327	18,327	18,327	18,327	364.00

Summary of Oil/Gas Capability:

Total Capacity	:	3,469 MW.
Combined Heat Rates	:	11,401 BTU/KWH at 50% power
		10,998 BTU/KWH at 75% power
		10,912 BTU/KWH at full power.
Weighted Fuel Cost	:	215.38 ¢/MMBTU
Available Capacity	:	2,819.95 MW (or 81.290%)
Average Heat Rate	:	11,200.5 BTU/KWH
Weighted Capacity Cost	:	163.43 $/KW
Annual Cost	:	$ 14.024/KW-year
Daily Cost	:	$38,421.62 per 1000 MW-day

A-3 Cost Data

After examination of approximately 25 sources on cost information, five were retained as realistic -- based on discussions with utility executives and utility consultants. Four of these, and their cost estimates, are presented in Table A-4. The actually used estimates, plus the fifth source concerning hydro pumped storage and reservoir, are presented in Table A-5.

Table A-4 Considered Cost Estimates

	Capital Cost ($/Kw)				Fuel Costs			
System	1*	2*	3*	4*	1* ($/MMBTU)	2* ($/MWH)	3* ($/MWH)	4* ($/MMBTU)
Nuclear	795.	700.	779.	719-	.583	7.3	4.2	.49-.63
Coal	690	625.	315-475.	605-721	1.000	17.0	11.0	.83-1.07
Oil	440.	424.	334.	n.a.	2.730	29.6	20.7	n.a.
Pumped Storage	250.	319.	185-1120.	n.a.	0.000	0.0	0.0	n.a

1* National Power Grid Study (NRRI) 1977 year-end $. (12/78)

2* Evaluation & Classification of Load Management Equipment (6/77), 1981 $.

3* Progress in Optimal Scheduling (9/77)

4* EPRI Journal (10/77); 1976 $.

Table A-4 Considered Cost Estimates (Continued)

System	Fixed O&M ($/kW-year) 1*	Fixed O&M ($/kW-year) 2*	Fixed O&M ($/kW-year) 3*	Variable O&M mills/kWh 1*	Variable O&M mills/kWh 2*	Variable O&M mills/kWh 3*	Heat Rates (BTU/KWh) VEPCO Avg.	Heat Rates (BTU/KWh) 1*
Nuclear	2.73	11.04	.990	.69	n.a.	0.0	11,605	10,400
Coal	2.50	9.94	1.200	1.61	n.a.	0.0	11,129	10,100
Oil	1.85	.72	.670	0.30	n.a.	0.0	11,200	9,500
Pumped Storage	1.00	1.95	.325	0.00	n.a.	0.0	11,200	9,500

1* National Power Grid Study (NRRI) 1977 year-end $. (12/78)

2* Evaluation & Classification of Load Management Equipment (6/77), 1981 $.

3* Progress in Optimal Scheduling (9/77)

4* EPRI Journal (10/77); 1976$.

Table A-5 Cost Estimates Used in Study

	Capital Cost $/kW	Capital Cost *3 $/kW-year	Fixed O&M $/kW-year	Total Fixed Costs $/kW-year	Total Fixed Costs $/10^3 MW-day
Nuclear[*1]	795.	68.23	2.73	70.96	194,410.96
Coal[*1]	690.	59.21	2.50	61.71	109,068.49
Oil[*1]	440.	37.76	1.85	39.61	108,520.55
Storage[*2]	180.16	13.52[*4]	2.18	15.70	43,013.70
Reservoir[*2]	8.16[*5]	0.70	0.00	0.70	1,918.39

*1: National Power Grid Study; 12/78

*2: EPRI-EM 264

*3: @25 years; 7%

*4: @40 years; 7%

*5: in $/kWh

All costs are expressed in 1978 dollars.

OUTPUT FOR MONTH 8 , AND DAY 4
SENSITIVITY ANALYSIS

TIME	POWER OUTPUTS (1000 MWH)							
	NUCLEAR	COAL	OIL	STO.OUT	STO.INPUT	STO.POWER	RESERVOIR	DEMAND
1	2.457	1.623	0.0	0.0	0.0	0.0	0.0	4.080
2	2.457	1.402	0.0	0.0	0.0	0.0	0.0	3.659
3	2.457	1.273	0.0	0.0	0.0	0.0	0.0	3.730
4	2.457	1.202	0.0	0.0	0.0	0.0	0.0	3.659
5	2.457	1.320	0.0	0.0	0.0	0.0	0.0	3.777
6	2.457	1.692	0.0	0.0	0.0	0.0	0.0	4.149
7	2.457	2.308	0.0	0.0	0.0	0.0	0.0	4.765
8	2.457	2.810	0.0	0.0	0.0	0.0	0.0	5.267
9	2.457	3.249	0.0	0.0	0.0	0.0	0.0	5.706
10	2.457	3.288	0.307	0.0	0.0	0.0	0.0	6.052
11	2.457	3.288	0.511	0.0	0.0	0.0	0.0	6.256
12	2.457	3.288	0.686	0.0	0.0	0.0	0.0	6.431
13	2.457	3.288	0.912	0.0	0.0	0.0	0.0	6.657
14	2.457	3.288	1.068	0.0	0.0	0.0	0.0	6.813
15	2.457	3.288	1.101	0.0	0.0	0.0	0.0	6.846
16	2.457	3.288	1.154	0.0	0.0	0.0	0.0	6.899
17	2.457	3.288	1.179	0.0	0.0	0.0	0.0	6.924
18	2.457	3.288	1.064	0.0	0.0	0.0	0.0	6.809
19	2.457	3.288	0.794	0.0	0.0	0.0	0.0	6.529
20	2.457	3.288	0.765	0.0	0.0	0.0	0.0	6.510
21	2.457	3.288	0.480	0.0	0.0	0.0	0.0	6.225
22	2.457	3.135	0.0	0.0	0.0	0.0	0.0	5.592
23	2.457	2.476	0.0	0.0	0.0	0.0	0.0	4.933
24	2.457	1.892	0.0	0.0	0.0	0.0	0.0	4.349
CAPACITY 1000 MW:	2.457	3.288	1.179		0.0		0.0	(1000 MWH)

OUTPUT FOR MONTH 8 , AND DAY 4
SENSITIVITY ANALYSIS

TIME	POWER COSTS ($/1000 MWH), AND % OF TOTAL						
	NUCLEAR		COAL		OIL		TOTAL
1	16592.12	(46.6%)	19004.16	(53.4%)	0.0	(0.0%)	35596.28
2	16592.12	(50.3%)	16420.94	(49.7%)	0.0	(0.0%)	33013.06
3	16592.12	(52.7%)	14900.98	(47.3%)	0.0	(0.0%)	31493.10
4	16592.12	(54.1%)	14076.59	(45.9%)	0.0	(0.0%)	30668.71
5	16592.12	(51.8%)	15456.03	(48.2%)	0.0	(0.0%)	32048.15
6	16592.12	(45.6%)	19812.15	(54.4%)	0.0	(0.0%)	36404.27
7	16592.12	(38.0%)	27030.20	(62.0%)	0.0	(0.0%)	43622.32
8	16592.12	(33.5%)	32899.25	(66.5%)	0.0	(0.0%)	49491.37
9	16592.12	(30.4%)	38039.94	(69.6%)	0.0	(0.0%)	54632.06
10	16592.12	(26.3%)	38502.48	(61.0%)	8046.28	(12.7%)	63140.88
11	16592.12	(24.2%)	38502.48	(56.2%)	13398.22	(19.6%)	68492.82
12	16592.12	(22.7%)	38502.48	(52.7%)	17994.59	(24.6%)	73089.19
13	16592.12	(21.0%)	38502.48	(48.7%)	23934.19	(30.3%)	79028.79
14	16592.12	(20.0%)	38502.48	(46.3%)	28021.61	(33.7%)	83116.21
15	16592.12	(19.8%)	38502.48	(45.8%)	28882.11	(34.4%)	83976.72
16	16592.12	(19.4%)	38502.48	(45.1%)	30283.06	(35.5%)	85377.66
17	16592.12	(19.3%)	38502.48	(44.8%)	30938.94	(36.0%)	86033.54
18	16592.12	(20.0%)	38502.48	(46.4%)	27916.67	(33.6%)	83011.27
19	16592.12	(21.9%)	38502.48	(50.9%)	20565.62	(27.2%)	75660.22
20	16592.12	(22.1%)	38502.48	(51.2%)	20061.91	(26.7%)	75156.51
21	16592.12	(24.5%)	38502.48	(56.9%)	12595.43	(18.6%)	67690.03
22	16592.12	(31.1%)	36707.34	(68.9%)	0.0	(0.0%)	53299.46
23	16592.12	(36.4%)	28988.11	(63.6%)	0.0	(0.0%)	45580.23
24	16592.12	(42.8%)	22158.84	(57.2%)	0.0	(0.0%)	38750.96
TOTALS	398210.87		747524.29		262639.62		1408373.78

APPENDIX B

SELECTED OUTPUT

B-1 LP1 Output

SYSTEM DATA INPUT INFORMATION

	NUCLEAR	COAL	OIL	STORAGE
MAX. OUTPUT FRACTION:	1.00	1.00	1.00	1.00
POWER COSTS ($/1000 MWH):	6753.00	11710.00	26235.00	0.0
STORAGE				
(EFFICIENCY):				0.72
(CHARGE RATE):				1.25
OBJECTIVE FUNCTION COSTS:				
(FUEL):	6753.00	11710.00	26235.00	0.0
(CAPACITY):	194410.96	169068.49	108520.55	43013.70
(RESERVOIR):				1918.39

DEMAND INFORMATION

MONTH	DAY	LOADS FOR 1 TO 24 HRS. IN MW.							
8	4	4234.60	4014.00	3884.20	3813.80	3931.60	4303.60	4920.00	5421.20
		5860.20	6206.40	6410.40	6585.60	6812.00	6967.80	7000.60	7054.00
		7079.00	6963.80	6683.60	6664.40	6379.80	5746.40	5087.20	4504.00

LOAD INFORMATION (1000 MW)

TIME	TOTAL LOAD	MAX.LOAD	AVG.LOAD	LOAD FACTOR
DAY	132.815	6.924	5.534	0.799

SYSTEM DATA INPUT INFORMATION

	NUCLEAR	COAL	OIL	STORAGE
MAX. OUTPUT FRACTION:	1.00	1.00	1.00	1.00
POWER COSTS ($/1000 MWH):	6753.00	11710.00	26235.00	0.0
STORAGE				
(EFFICIENCY):				0.72
(CHARGE RATE):				1.25
OBJECTIVE FUNCTION COSTS:				
(FUEL):	6753.00	11710.00	26235.00	0.0
(CAPACITY):	194410.96	169068.49	108520.55	43013.70
(RESERVOIR):				1918.39

DEMAND INFORMATION

MONTH	DAY	LOADS FOR 1 TO 24 HRS. IN MW.							
8	4	4234.60	4014.00	3884.20	3813.80	3931.60	4303.60	4920.00	5421.20
		5860.20	6206.40	6410.40	6585.60	6812.00	6967.80	7000.60	7054.00
		7079.00	6963.80	6683.60	6664.40	6379.80	5746.40	5087.20	4504.00

LOAD INFORMATION (1000 MW)

TIME	TOTAL LOAD	MAX.LOAD	AVG.LOAD	LOAD FACTOR
DAY	132.815	6.924	5.534	0.799

OUTPUT FOR MONTH 8 , AND DAY 4
SENSITIVITY ANALYSIS

TIME	POWER OUTPUTS (1000 MWH)							
	NUCLEAR	COAL	OIL	STO.OUT	STO.INPUT	STO.POWER	RESERVOIR	DEMAND
1	2.457	3.229	0.0	0.0	1.606	0.0	1.523	4.080
2	2.457	3.008	0.0	0.0	1.606	0.0	3.047	3.859
3	2.457	2.878	0.0	0.0	1.606	0.0	4.570	3.730
4	2.457	2.808	0.0	0.0	1.606	0.0	6.094	3.659
5	2.457	2.926	0.0	0.0	1.606	0.0	7.617	3.777
6	2.457	3.289	0.0	0.0	1.596	0.0	9.132	4.149
7	2.457	3.288	0.0	0.0	0.980	0.0	10.061	4.765
8	2.457	3.288	0.0	0.0	0.478	0.0	10.515	5.267
9	2.457	3.288	0.0	0.0	0.039	0.0	10.553	5.706
10	2.457	3.288	0.0	0.323	0.0	0.307	10.229	6.052
11	2.457	3.288	0.0	0.539	0.0	0.511	9.691	6.256
12	2.457	3.288	0.0	0.723	0.0	0.686	8.969	6.431
13	2.457	3.288	0.0	0.962	0.0	0.912	8.006	6.657
14	2.457	3.288	0.0	1.126	0.0	1.068	6.880	6.813
15	2.457	3.289	0.0	1.160	0.0	1.101	5.720	6.846
16	2.457	3.289	0.0	1.217	0.0	1.154	4.503	6.399
17	2.457	3.288	0.0	1.243	0.0	1.179	3.260	6.924
18	2.457	3.288	0.0	1.122	0.0	1.064	2.138	6.809
19	2.457	3.288	0.0	0.826	0.0	0.784	1.312	6.529
20	2.457	3.288	0.0	0.806	0.0	0.765	0.506	6.510
21	2.457	3.289	0.0	0.506	0.0	0.480	0.000	6.225
22	2.457	3.135	0.0	0.0	0.0	0.0	0.000	5.592
23	2.457	2.476	0.0	0.0	0.0	0.0	0.000	4.933
24	2.457	1.892	0.0	0.0	0.0	0.0	0.000	4.349
CAPACITY 1000 MW:	2.457	3.288	0.0		1.606		10.553 (1000 MWH)	

OUTPUT FOR MONTH 8 , AND DAY 4
SENSITIVITY ANALYSIS

TIME	POWER COSTS ($/1000 MWH), AND % OF TOTAL						
	NUCLEAR		COAL		OIL		TOTAL
1	16592.12	(30.5%)	37809.33	(69.5%)	0.0	(0.0%)	54401.45
2	16592.12	(32.0%)	35226.11	(68.0%)	0.0	(0.0%)	51818.23
3	16592.12	(33.0%)	33706.15	(67.0%)	0.0	(0.0%)	50298.27
4	16592.12	(33.5%)	32881.77	(66.5%)	0.0	(0.0%)	49473.88
5	16592.12	(32.6%)	34261.20	(67.4%)	0.0	(0.0%)	50853.32
6	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
7	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
8	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
9	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
10	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
11	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
12	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
13	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
14	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
15	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
16	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
17	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
18	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
19	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
20	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
21	16592.12	(30.1%)	38502.48	(69.9%)	0.0	(0.0%)	55094.60
22	16592.12	(31.1%)	36707.34	(68.9%)	0.0	(0.0%)	53299.46
23	16592.12	(36.4%)	28988.11	(63.6%)	0.0	(0.0%)	45580.23
24	16592.12	(42.8%)	22158.84	(57.2%)	0.0	(0.0%)	38750.96
TOTALS	398210.87		877778.54		0.0		1275989.41

OUTPUT FOR MONTH 8 , AND DAY 4
SENSITIVITY ANALYSIS

COST SUMMARY;ALL IN $

	POWER COST	CAP. COST	TOTAL COST
NUCLEAR	398210.87	477667.69	875878.55
COAL	877778.54	555897.21	1433675.76
OIL	0.0	0.0	0.0
STORAGE(IN)	0.0	69076.01	69076.01
STORAGE(OUT)	0.0		0.0
RESERVOIR		20243.85	20243.85
TOTALS	1275989.41	1122884.76	2398874.17

SYSTEM DATA INPUT INFORMATION

	NUCLEAR	COAL	OIL	STORAGE
MAX. OUTPUT FRACTION:	1.00	1.00	1.00	1.00
POWER COSTS ($/1000 MWH):	6753.00	11710.00	26235.00	0.0
STORAGE				
(EFFICIENCY):				0.72
(CHARGE RATE):				1.25
OBJECTIVE FUNCTION COSTS:				
(FUEL):	6753.00	11710.00	26235.00	0.0
(CAPACITY):	194410.96	169068.49	108520.55	43013.70
(RESERVOIR):				1918.39

DEMAND INFORMATION

MONTH DAY LOADS FOR 1 TO 24 HRS. IN MW.

MONTH	DAY								
8	1	3666.67	3530.83	3453.83	3431.50	3607.17	4008.17	4632.66	5085.33
		5438.83	5755.50	5923.16	5972.66	6243.50	6312.16	6414.83	6477.66
		6470.50	6384.83	6156.00	6191.50	5999.66	5410.50	4765.16	4219.50

STANDARD DEVIATIONS IN MW.

MONTH	DAY								
8	1	440.32	392.37	347.60	337.93	303.05	243.42	282.32	333.89
		497.41	586.90	745.66	839.74	969.21	1013.12	1078.13	1145.52
		1143.27	1087.26	1035.86	889.97	803.29	720.97	628.87	577.13

LOAD INFORMATION (1000 MW)

TIME	TOTAL LOAD	MAX.LOAD	AVG.LOAD	LOAD FACTOR
DAY	121.839	6.323	5.077	0.803

OUTPUT FOR MONTH 8 , AND DAY 1 ;STOCHASTIC ANALYSIS WITH RELIABILITY LEVEL OF 95 %

TIME	POWER OUTPUTS (1000 MWH)						
	NUCLEAR	COAL	OIL	NSF	RESERVOIR	DEMAND	DEVIATION
1	6.506	0.0	0.0	2.131	2.131	3.512	0.863
2	6.464	0.0	0.0	2.319	4.451	3.376	0.769
3	6.475	0.0	0.0	2.495	6.945	3.299	0.681
4	6.472	0.0	0.0	2.533	9.478	3.277	0.662
5	6.619	0.0	0.0	2.573	12.051	3.452	0.594
6	6.619	0.0	0.0	2.289	14.340	3.853	0.477
7	6.619	0.0	0.0	1.588	15.928	4.478	0.553
8	6.619	0.0	0.0	1.034	16.962	4.931	0.654
9	6.619	0.0	0.0	0.360	17.323	5.284	0.975
10	6.619	0.0	0.0	-0.132	17.191	5.601	1.150
11	6.619	0.0	0.0	-0.611	16.580	5.768	1.461
12	6.619	0.0	0.0	-0.844	15.736	5.818	1.646
13	6.619	0.0	0.0	-1.369	14.367	6.089	1.900
14	6.619	0.0	0.0	-1.524	12.843	6.157	1.986
15	6.619	0.0	0.0	-1.754	11.089	6.260	2.113
16	6.619	0.0	0.0	-1.949	9.141	6.323	2.245
17	6.619	0.0	0.0	-1.937	7.203	6.316	2.241
18	6.619	0.0	0.0	-1.742	5.462	6.230	2.131
19	6.619	0.0	0.0	-1.412	4.049	6.001	2.030
20	6.619	0.0	0.0	-1.162	2.888	6.037	1.744
21	6.619	0.0	0.0	-0.800	2.088	5.845	1.574
22	6.619	0.0	0.0	-0.050	2.038	5.256	1.413
23	6.067	0.0	0.0	0.224	2.262	4.610	1.233
24	2.934	0.0	0.0	-2.262	-0.000	4.065	1.131
CAPACITY 1000 MW:	6.619	0.0	0.0	3.857	64.458	(1000 MWH.)	

OUTPUT FOR MONTH 8 , AND DAY 1 ;STOCHASTIC ANALYSIS WITH RELIABILITY LEVEL OF 95 %

TIME	POWER COSTS ($/1000 MWH), AND % OF TOTAL						
	NUCLEAR		COAL		OIL		TOTAL
1	43937.33	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	43937.33
2	43654.67	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	43654.67
3	43727.25	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	43727.25
4	43704.45	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	43704.45
5	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
6	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
7	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
8	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
9	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
10	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
11	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
12	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
13	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
14	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
15	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
16	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
17	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
18	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
19	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
20	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
21	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
22	44700.81	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	44700.81
23	40973.01	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	40973.01
24	19809.95	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	19809.95
TOTALS	1040421.22		0.0		0.0		1040421.22

OUTPUT FOR MONTH 8 , AND DAY 1 ;STOCHASTIC ANALYSIS WITH RELIABILITY LEVEL OF 95 %

COST SUMMARY;ALL IN $

	POWER COST	CAP. COST	TOTAL COST
NUCLEAR	1040421.22	1286883.91	2327305.13
COAL	0.0	0.0	0.0
OIL	0.0	0.0	0.0
STORAGE	0.0	165921.04	165921.04
RESERVOIR		123654.63	123654.63
TOTALS	1040421.22	1576459.59	2616880.8C

SYSTEM DATA INPUT INFORMATION

	NUCLEAR	COAL	OIL	STORAGE
MAX. OUTPUT FRACTION:	1.00	1.00	1.00	1.00
POWER COSTS ($/1000 MWH):	6753.00	11710.00	26235.00	0.0
STORAGE				
(EFFICIENCY):				0.72
(CHARGE RATE):				1.25
OBJECTIVE FUNCTION COSTS:				
(FUEL):	6753.00	11710.00	26235.00	0.0
(CAPACITY):	194410.96	169068.49	108520.55	43013.70
(RESERVOIR):				1918.39

DEMAND INFORMATION

LOADS FOR 1 TO 24 HRS. IN MW.

MONTH	DAY								
8	1	3666.67	3530.83	3453.83	3431.50	3607.17	4008.17	4632.66	5085.33
		5438.83	5755.50	5923.16	5972.66	6243.50	6312.16	6414.83	6477.66
		6470.50	6384.83	6156.00	6191.50	5999.66	5410.50	4765.16	4219.50

STANDARD DEVIATIONS IN MW.

MONTH	DAY								
8	1	440.32	392.37	347.60	337.93	303.05	243.42	282.32	333.89
		497.41	586.90	745.66	839.74	969.21	1013.12	1078.13	1145.52
		1143.27	1087.26	1035.86	889.97	803.29	720.97	628.87	577.13

LOAD INFORMATION (1000 MW)

TIME	TOTAL LOAD	MAX.LOAD	AVG.LOAD	LOAD FACTOR
DAY	121.839	6.323	5.077	0.803

OUTPUT FOR MONTH 8 , AND DAY 1 :STOCHASTIC ANALYSIS WITH RELIABILITY LEVEL OF 99 %

TIME	POWER OUTPUTS (1000 MWH)						
	NUCLEAR	COAL	OIL	NSF	RESERVOIR	DEMAND	DEVIATION
1	6.902	0.0	0.0	2.256	2.256	3.512	1.134
2	6.890	0.0	0.0	2.503	4.760	3.376	1.010
3	6.928	0.0	0.0	2.734	7.494	3.299	0.895
4	6.931	0.0	0.0	2.784	10.277	3.277	0.870
5	6.953	0.0	0.0	2.720	12.997	3.452	0.780
6	6.953	0.0	0.0	2.473	15.470	3.853	0.627
7	6.953	0.0	0.0	1.748	17.218	4.478	0.727
8	6.953	0.0	0.0	1.163	18.381	4.931	0.860
9	6.953	0.0	0.0	0.388	18.769	5.284	1.281
10	6.953	0.0	0.0	-0.159	18.610	5.601	1.511
11	6.953	0.0	0.0	-0.736	17.874	5.768	1.920
12	6.953	0.0	0.0	-1.027	16.847	5.818	2.162
13	6.953	0.0	0.0	-1.632	15.215	6.089	2.496
14	6.953	0.0	0.0	-1.813	13.402	6.157	2.609
15	6.953	0.0	0.0	-2.083	11.319	6.260	2.776
16	6.953	0.0	0.0	-2.320	8.999	6.323	2.950
17	6.953	0.0	0.0	-2.307	6.692	6.316	2.944
18	6.953	0.0	0.0	-2.077	4.616	6.230	2.800
19	6.953	0.0	0.0	-1.716	2.900	6.001	2.667
20	6.953	0.0	0.0	-1.375	1.524	6.037	2.292
21	6.953	0.0	0.0	-0.960	0.564	5.845	2.068
22	6.953	0.0	0.0	-0.159	0.405	5.256	1.856
23	6.953	0.0	0.0	0.723	1.128	4.610	1.619
24	4.423	0.0	0.0	-1.128	-0.000	4.065	1.486
CAPACITY 1000 MW:	6.953	0.0	0.0	4.524	84.683	(1000 MWH.)	

OUTPUT FOR MONTH 8 , AND DAY 1 ;STOCHASTIC ANALYSIS WITH RELIABILITY LEVEL OF 99 %

TIME POWER COSTS ($/1000 MWH), AND % OF TOTAL

	NUCLEAR		COAL		OIL		TOTAL
1	46610.19	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46610.19
2	46526.67	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46526.67
3	46785.19	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46785.19
4	46802.55	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46802.55
5	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
6	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
7	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
8	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
9	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
10	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
11	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
12	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
13	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
14	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
15	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
16	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
17	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
18	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
19	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
20	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
21	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
22	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
23	46953.61	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	46953.61
24	29868.25	(100.0%)	0.0	(0.0%)	0.0	(0.0%)	29868.25
TOTALS	1108711.43		0.0		0.0		1108711.43

OUTPUT FOR MONTH 8 , AND DAY 1 ;STOCHASTIC ANALYSIS WITH RELIABILITY LEVEL OF 99 %

COST SUMMARY:ALL IN $

	POWER COST	CAP. COST	TOTAL COST
NUCLEAR	1108711.43	1351739.42	2460450.85
COAL	0.0	0.0	0.0
OIL	0.0	0.0	0.0
STORAGE	0.0	194593.99	194593.99
RESERVOIR		162454.26	162454.26
TOTALS	1108711.43	1708787.66	2817499.09