Impact of Electric Space Heating on an Electric Utility's Generation Expansion Plan
Case Study of the New Brunswick Electric Power System

by

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ABSTRACT

The potential shortages and higher prices of oil and natural gas can result in a dramatic increase in electric space heating demand. On the other hand, increases in electricity costs, energy conservation and improved insulation standards and practices, could result in a substantial decrease in electric space heating demand. Thus, the resulting benefits and penalties of electric space heating remain uncertain. This thesis presents a quantitative analysis of the long-term implications and impact of electric space heating on an electric utility. A three stage model for the evaluation of this impact of electric space heating is presented. The model is then applied to the New Brunswick electric power system to calculate the generation and primary fuel requirements for electric space heating during the 1981 to 2010 planning period. The results of the evaluation are presented and analysed in terms of time-dependent system demand, primary fuel requirements, central electric generating capacity requirements and total utility generation system costs.

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GLOSSARY OF TERMS

Available Capacity: The installed capacity of the system minus the forced and scheduled outage capacities.

Annual Peak Load: The maximum of the hourly average loads during a year.

Baseload Units: Generating units that supply most or all of the power needed to meet the demand base, i.e., the level below which demand rarely falls. Baseload units operate at full power most of the time. Their annual capacity factor is usually greater than 50 %.

Capacity: The net power output for which a generating unit is designed.

Capacity Factor: The amount of energy generated by a unit in a specified time period divided by the amount it would have generated if operated at full capacity.

Chronological Load Curve: A curve showing the magnitude of the demand as a function of time; the time scale may be in hours, days, months or years.

Conductance: The heat-flow characteristic of a building component, expressed in terms of the amount of energy that would travel from interior of the building to the exterior through a unit area of the component in a unit time if pushed by a temperature difference of one degree.

Degree Days: The total annual degree days is the sum of the differences between 18°C and the mean temperatures in °C of every day in the year when the mean temperature is below 18°C.

Demand Energy Unit: It is any generating unit which serves customer load upon demand - provided the unit is available to do so and the dispatcher calls on it to operate. Thus, the energy served by a demand energy unit is limited only by its generating capacity and availability.

Discount Rate: The annual rate that is used to take into account inflation and the potential earning power of money between two points in time, so that dollar amounts from different period can be compared in terms of their values at some specific point in time.

Escalation Rate: The annual rate of increase of a cost.

Fixed Costs: The annual costs that must be paid whether or not a generating unit operates, generally includes capital costs and some fixed operating and maintenance costs.

Forced Outage: A forced outage is an outage that results from emergency conditions directly associated with a component to be taken out of service immediately, either automatically or as soon as switching operation can be performed, or an outage caused by improper operation of equipment or human error.

Forced Outage Rate: The fraction of time that a generating unit will not function when it is called upon to generate, excluding scheduled maintenance time and idle time.

Forecast Demand: Total system load which will most probably have to be supplied.

Generating Capability: Output power which can be provided from existing (in-service), committed (under construction), and planned (future commitments) generating units or stations.

Heat Rate: The amount of thermal energy (BTU, joules or kcal) needed to produce a unit of electrical energy (KWh).

Incremental Fuel Cost: Mathematically, the incremental fuel costs of a generating unit for any given power output can be defined as the limit of the ratio of the increase in cost of fuel input in dollars per hour to the corresponding increase in power output in megawatts as the increase in power output approaches zero.

Intermediate Load Units: Generating units operated as needed to meet daily variations in demand, their annual capacity factor is usually in the range of 20 % to 50 %.

Load Duration Curve: A graph derived from a chronological load curve that shows, for each level of load, the amount of time that a particular load level was equalled or exceeded.

Load Factor: The ratio of the average load over a designated period of time to the period load occuring in that period.

Loss of Load Probability: The probability that the demand (usually peak demand) will exceed the available capacity of the system.

Merit Order of Loading: To achieve minimum operating cost, generating units are committed in the order of their incremental fuel cost, with the least expensive unit first.

Optimal Generation Expansion Plan: Expansion for an electric utility that satisfies given levels of loss of load probability and reserve capacity margin and minimizes the present worth of the total capital and operating costs minus a salvage value.

Outage: Describes the state of a component when it is not available to perform its intended function.

Peaking Units: Generating units usually used to meet additional load when all available base and intermediate units are already operating, expected annual capacity factors are less than 20 %.

Penetration Level: Installed capacity or demand increase of a particular unit or option.

Planned or Scheduled Outage: A scheduled outage is an outage that results when a component is taken out of service at a selected time, usually for a purpose of construction, preventive maintenance or repair.

Present Worth: A process to convert the cash flow to a single equivalent amount (usually the present value) based on the duration of the study period and interest rate.

Reliability: Mathematically, it can be defined as the probability of a system performing its purpose adequately for the period of time intended under the operating conditions encountered.

Reserve Capacity Margin: The excess of available generating capacity over peak load; usually expressed as a percentage of the peak load.

Variable Costs: The costs that are proportional to a generating unit's output (GWh), generally includes fuel and some operating and maintenance costs.

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INTRODUCTION

1.1 BACKGROUND AND MOTIVATION

In Canada today, oil and natural gas are by far the most commonly used fuels for residential space heating. In 1976, oil and gas heating systems were installed in 85 per cent of the existing housing stock [29]. Electric heating of one form or another accounted for only 13 per cent [29], about the same proportion as their introduction in the late 1950's. In spite of a relatively low initial cost when compared with gas and oil heating equipment, electric heating was and still is expensive from an operating-cost point of view. In many regions of the country today, however, the differential between conventional fossil-fuel and electricity prices is narrowing and electricity is being used to a greater extent than in the past. As crude oil prices in Canada are moved towards world level, higher heating oil prices are expected. Electric utilities are forecasting increased penetrations of electric heating as a result of potential shortages and higher prices of heating oil and natural gas.

As has been repeatedly stated by electric utilities in Canada and US during the past couple of years, the days of relatively cheap and abundant quantities of energy are over. There is a growing shortage of conventional crude oil supplies and that is a crucial component of the current energy mix. As a recent report by the Department of Energy, Mines and Resources [22] pointed out, there is a change from historic utilization patterns of energy. The trend is one containing a marked increase in the use of electrical energy as other forms become more expensive and harder to obtain. This potential shift toward electrical energy, however, poses many additional problems and uncertainties for electric utilities, not the least of which is the accurate forecasting of future capacity and energy requirements.

In the Province of New Brunswick (NB), for instant, the New Brunswick Electric Power Commission (N.B.E.P.C.) is now paying $15 per barrel of heavy oil including the subsidy from the Federal Government. However, as Federal subsidies are reduced in the future, oil prices could well be in the $50 to $60 per barrel range. With the current uncertainties in world events, the price of oil will certainly reach higher levels in the future.

This increase in the cost of oil has put a lot of pressure on electric utilities to change their planning strategies. Plans for building oil-fired units are no longer contemplated. In fact, most utilities are contemplating modifications to existing oil-fired facilities to burn coal or an oil-coal mixture, or even mothballing inefficient oil burning stations. As indicated in the recently published National Energy Program [37]:

> The high cost of energy in the Atlantic region is largely due to the region's heavy reliance on oil for electrical generation. An immediate priority is to replace existing oil-fired capacity with lower-cost alternatives ... The key to these efforts is increased regional co-operation, which the Government of Canada will encourage through generous financial assistance.
>
> An Utility Off-Oil Fund will be established, with funding over the initial four years of $175 million to finance on a grant basis up to 75 per cent of the cost of environmentally acceptable conversions of oil-fired electricity plants to coal.

The potential benefits and penalties associated with electric space heating are often described qualitatively but are usually not quantified. The potential benefits include the possibility of substituting coal and nuclear for the more limited oil and gas fuels. The potential penalties associated with electric space heating include the increased generation requirements, the possible deterioration of the system load factor and as well as increased primary fuel requirements. The need to develop a credible computational procedure suitable for use by electric utilities to evaluate quantitatively the long-term implications and impact of electric space heating is the very incentive for the work as undertaken and described in this thesis.

1.2 APPROACH

Long term planning for electrical energy generation is a very difficult task due to the many unknowns and complex factors which must be predicted for a planning period which may end some 25 to 30 years in the future. Because of the uncertainties and complexities involved, it is important to be able to quantify any of these factors which may have a significant impact on future electrical demand patterns and subsequently on generation capacity and operating strategies. A complete system evaluation of the problem involves identifying the various factors and constraints, modelling their effects on demand patterns, projecting these effects over the planning period, calculating the resulting electric generation expansion and operating schedule and finally calculating the incremental impact on elements of interest such as fuel consumption and capital requirements.

1.2.1 Model Description

The three stage model for the evaluation of the impact of electric heating is shown in Figure 1. Stage 1 is the electric heating demand model which calculates the electric demand forecast as a function of the amount, weather conditions, type and insulation standards of electrically heated customers for the housing stock considered. This calculation is performed by an analytical procedure that employs a reference peak demand forecast, and the embedded reference forecast of numbers, type and insulation levels of electrically heated customers along with hourly demand and hourly weather for a recent historic one year period.

Stage 2 is the generation expansion model which calculates the optimal generation expansion schedule. The basic tool used in the analysis of the various alternative system expansion plans is the Wien Automatic System Planning (WASP) [1, 2, 3, 4, 6, 9] package. This state-of-the-art computer model uses the Baleriaux-Booth [15, 16] method to probabilistically simulate the operation of the power stations on a monthly basis, evaluates the operating costs for each plant, calculates the present-worth value of these operating costs and of the capital costs associated with all plant additions during the study period, and determines the total present-worth value of these costs up to the study horizon. The optimization technique employs dynamic programming with the objective function defined as minimization of the present worthed sum of capital and operating costs minus a salvage value at the end of the planning horizon. The optimal expansion plans must satisfy given levels of reliability, in terms of loss of load probability (LOLP) and reserve capacity margin.

Stage 3 is the total impact model which calculates the increment of total system demand, total system costs, generation and primary fuel requirements for electric heating by a method [8, 10, 11, 12] that compares the input and output of a reference case with the input and output of a case that represents an electric heating policy variation relative to the reference.

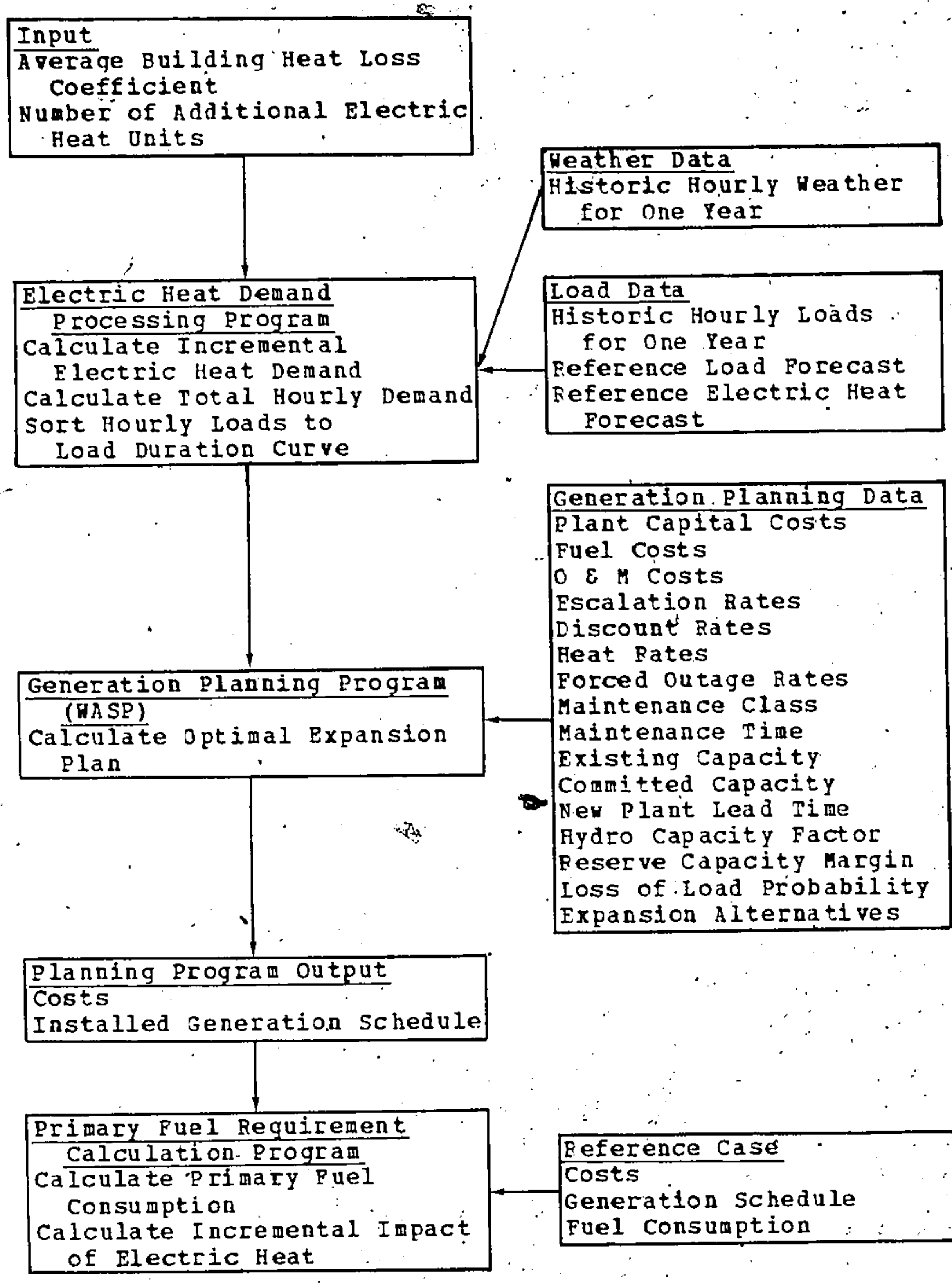

Figure 1: Conceptual Model for Evaluating the Impact of Electric Space Heating

1.3 OUTLINE OF THE THESIS

In this thesis, a credible computational procedure suitable for use by electric utilities to evaluate the long-term implications and impact of electric heating is developed. The technique and procedure are demonstrated by performing a series of case studies over the 1981 to 2010 planning period. The New Brunswick electric power system is selected for the analysis. The following studies are made:

1. Evaluation of a base case optimal generation expansion plan including presently installed and committed units and considering viable expansion alternatives for generation during the 1981 to 2010 study period.

2. Evaluation of the impact of increasing penetration levels of electric space heating in the residential sector on system demand, energy and load factor and determination of optimal generation plans.

In addition, as a way of finding out the effects of the assumptions made, this study also includes a sensitivity analysis of the key parameters used. Parameters such as construction costs, discount rates, fuel cost escalation rates and the load growth rate are varied and their effects on the final results are examined. Finally, evaluations in terms of system demand, installed generation, fuel and financial requirements are made.

In the second chapter, a short review of power system expansion planning is given. The general approach to planning generation is discussed. Also in this chapter, current generation planning models are discussed.

In Chapter three, the methodology and the technical details of the three stage model are given. The electric heating demand model, the generation planning model and the total impact model for the assumed housing stock are presented.

In Chapter four, the results of the evaluation are presented. Reasons for the results obtained are also given. The last chapter of the thesis deals with areas that require further investigation and elaboration. A brief description of the WASP package, the New Brunswick electric power system and the computer programs are given in the Appendix.

Chapter II

REVIEW OF POWER SYSTEM EXPANSION PLANNING

2.1 INTRODUCTION

The purpose of an electric power system is to supply a geographical region with the electric power and energy needed for its homes, industries, farms and institutions at a predetermined level of reliability and at the cheapest cost consistent with sound economic and technical practices with minimum or acceptable ill effects to the environment. The planner of such a system has the task of defining as explicitly as possible the optimal strategy for its development, so that the costs and the benefits of a service of a desired quality are in balance.

Relative to past practice, energy planning now involves many more options, existing or projected, and many more uncertainties. Planning has to be more extensive and careful to permit a realistic evaluation of implications of a variety of plausible assumptions about the future course of events with regard to the amount and character of energy requirements, strategies to meet these requirements, and costs and environmental impacts associated with implementing these strategies. The questions the planner must address, and find answers to, in the context of the new generation, transmission, and distribution facilities, are the size and the number of generating units of each fuel category, the availability of generating sites, the lead time required for construction and operation of generating facilities. While a myriad of all possible combinations are possible, the planners must restrict their choice to some selected combinations of unit sizes, location and fuel mix. The planner must exercise good judgement and have a good knowledge of sound planning practices to carry out this selection process.

2.2 THE CHANGING PLANNING ENVIRONMENT

In the days of steady growth in demand and short lead times, the task of system planning was comparative simple. The inflation rate was low, fuel supply and sound financing were regarded as assured, and cost estimates were assumed by planners to be reliable. The environmental impact of electric power production and supply had not yet become a social issue, and thus the acquistion of land for generating stations and transmission rights of way was not a major problem. The load forecaster gave his projections to the system planner, whose time was spent mainly on immediate capacity additions rather on system plans for 15 to 20 years ahead.

However, this situation changed dramatically in the 1970s, For example, the forecast made in 1971 for peak demand in New Brunswick in 1977 was about 13 % lower than the actual demand. Other factors that have altered many of the traditional concepts of system planning are:

1. The impact of alternative technologies.

2. The uncertainty concerning fuel and capital availability.

3. The unforeseen plant shut-downs.

4. Environmetal restrictions.

Alternative technologies such as co-generation, heat pumps, solar heating, biomass and wind energy will have their influence, but their precise eventual role is difficult to foresee. Most large-scale conventional generating plants cost hundreds of millions of dollars. The size of the investment, combined with long lead-times, makes the financing of such plants a major undertaking. Before a plant is built, the supply of fuel over the plants service life (normally 30 years) must be reasonably assured. Plants may be shut down for extended periods by regulatory agencies of the government or by the utility itself, for safety or environmental reasons.

These uncertainties may culminate in either an excess or a shortfall in the capacity of the electric power system. In either case, the result will be to increase the cost of power to the customer. The largest single component of the cost of excess capacity is the interest on the capital borrowed to finance the construction of the capacity. Other charges, such as depreciation and operations and maintenance costs, depend on whether the capacity is in service or "mothballed". Thus, long term planning for electrical energy generation is becoming more complex and difficult.

2.3 THE GENERAL APPROACH TO PLANNING GENERATION

The first element in the methodology for planning the addition of new generating facilities is a long range load forecast for 15 to 20 years in the future. This forecast includes not only the peak demand but also the amount of energy that will have to be supplied from year to year and possible changes in future load characteristics.

In determining the amount of new generating capacity that will be needed, two more factors are significant. In order to meet the peak demand conditions in some future years at a specified level of reliability, a certain amount of reserve capacity is required for protection against forced and scheduled plant shut-downs and deratings. While the actual amount of reserve capacity that will be required depends on the configuration of the system, an initial estimate may be made in the form of a percentage based on experience and judgement, e.g. 30 to 50 % for the New Brunswick system. In addition, it will be necessary to replace existing capacity after it has completed its useful life. Thus, the expected growth in load, the associated reserve margin, and an allowance for plant retirement provide the system planner with an estimate of the total amount of new generating capacity that will be required over the generating period.

The next step is to determine which one of the alternative forms of generation should be used to meet the new capacity requirement. This involves an economic study of these alternatives to determine their suitability for supplying loads of various durations, taken into account the operating characteristics of the alternatives. With this information, along with the data on generating capacity, existing and under construction, the system planner is able to formulate some broad guidelines for the expansion of the generating system. Starting with these guidelines, the planner develops a number of feasible alternative plans with a view to discovering the "optimum" plan. Considerations that may restrict the number of feasible alternatives are capital, fuel, site and manpower availability. Each alternative plan is evaluated in conjunction with the load forecast, to obtain estimates of capital requirements, fuel requirements, operating costs, reliability etc. The plan with the minimun cost that also satisfy the reliability and other constraints is selected as the basis for system expansion.

2.4 CURRENT GENERATION PLANNING MODELS

The application of probabilistic methods by electric utilities to plan the generation requirements and to predict the costs of generation has been evident since 1933 in a paper by Lyman [13]. Calabrese [14] introduced the loss of load probability (LOLP) approach which evaluates the probability that the available capacity, of a system of generating units, was insufficient to meet the demand. A recursive technique discussed in Billinton [35] is commonly employed to obtain this LOLP.

The basic technique for the probabilistic simulation of a system of generating units supplying a load, for production costing, is based on the Baleriaux [15] formulation. It was further improved by Booth [16]. Basically, the method evaluates the expected energy generated by each generating unit as it is called to meet the demand, according to a predetermined loading order. This is done by convolving the probability density function (PDF) of forced outage capacity of a generating unit with the load probability distribution. This procedure gives rise to an equivalent load curve [34] which includes the outage capacity of the generating unit which have already been committed. More recently, Rau and Schenk [17] have considered the Gram-Charlier expansion and the Method of Moments to efficiently evaluate LOLP and production costs.

These probabilistic methods have been incorporated in many production costing and reliability computer models [1, 18, 19, 20] to estimate the cost of operating the electrical generators and to determine the optimal mix of generation satisfying a specified loss of load probability and reserve capacity margin criteria. One of the state-of-the-art computer model is the Wien Automatic System Planning (WASP) [1, 2, 3, 4, 6, 9] package. This computer model is the basic tool used in this thesis to analyse the various alternative system expansion plans. Some details on WASP are given in Appendix A.

Chapter III

METHODOLOGY

3.1 INTRODUCTION

This chapter presents the technical details of the three stage model used to evaluate the benefits and penalties of electric space heating. Stage 1 is the electric heating demand model. The output of this model is the resulting total hourly system demand forecast for electric heating. Stage 2 is the generation expansion model. The ultimate output of this model is the optimal generation expansion schedule. Stage 3 is the total impact model which calculates the increment of total system demand, total system costs, generation and primary fuel requirements for the assumed penetration of electric heating.

3.2 ELECTRIC HEATING DEMAND MODEL

The purpose of the electric heating demand model is to calculate the electric demand forecast as a function of the amount, weather conditions, type and insulation standards of electrically heated customers. To accomplish this purpose, the model must fulfill two major requirements. First, it must represent the essential physical features of the losses and gains of heat in the entire housing stock in sufficient detail to permit accurate computation of the present energy consumption for space heating without being too unwieldy nor requiring excessive computer time or storage capacity. Second, it must permit the investigation of energy-saving options (e.g. the addition of below grade insulation in basements) in sufficient details to enable realistic forecasts to be made.

To fulfill these requirements, it was necessary (i) to define a manageable but realistic representation of the present housing stock, with respect to its form, size and thermal characteristics and (ii) to establish equations representing the heat losses and gains of this stock in a realistic manner. The conceptual framework of the electric heating demand model is shown in Figure 2.

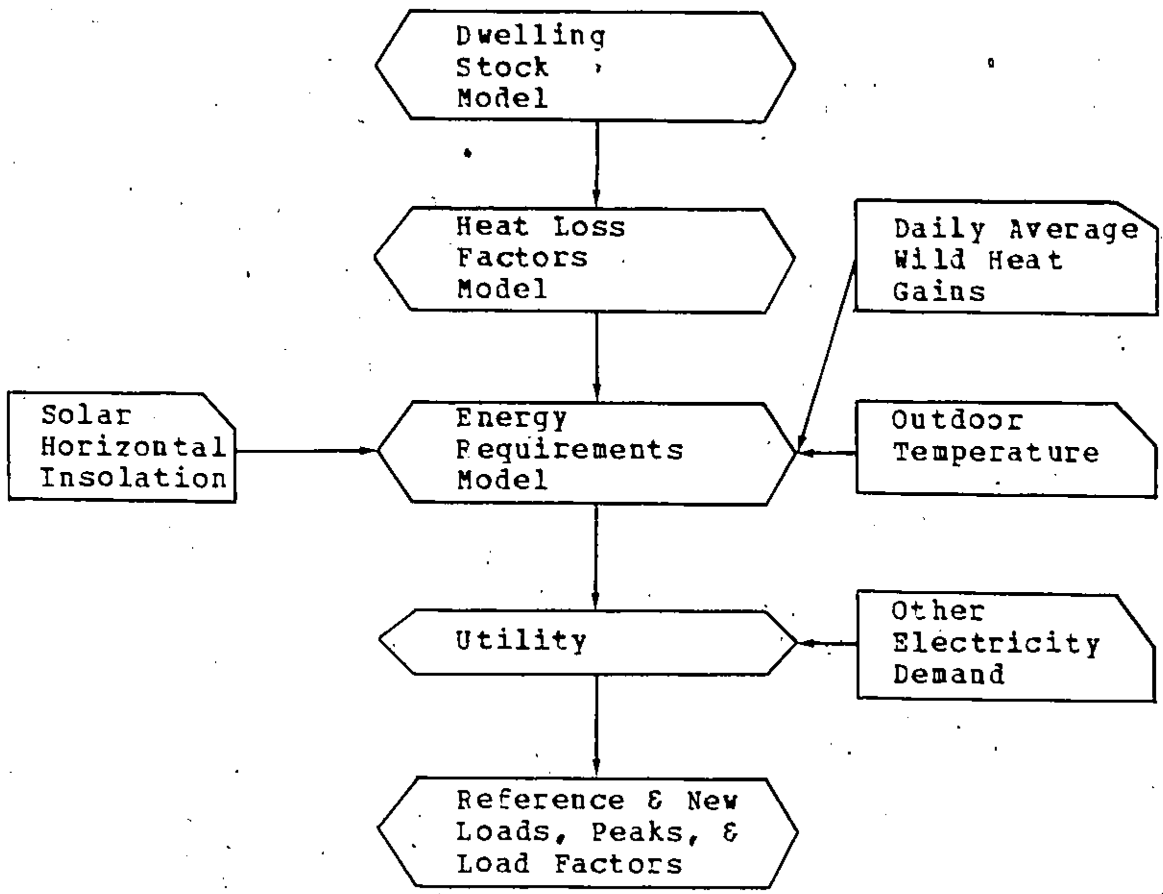

Figure 2: The Electric Heating Demand Model Description

3.2.1. Dwelling Stock Model

The energy requirements of a dwelling are determined to some extent by its form and size. Obviously, a detached dwelling, such as a single-family house, will generate different demands for heating and cooling than a dwelling unit that is part of a larger structure, such as an apartment. Therefore, the purpose of the dwelling stock model is to represent the present housing stock, with respect to its form and size.

3.2.1.1 Form of Dwelling

In April 1977, single detached dwelling units were by far the most common form of housing in Canada comprising 4 500 000 units or 60 percent of the total housing stock [29] as compared with 2 550 150 apartment units (33 percent of the total), 295 914 semi-attached dwellings (4 percent of the total) and 221 936 row houses (3 percent of the total). Although it has been suggested that the single detached dwelling is declining in popularity as a preferred form of housing. In view of the existing stock, however, and the number of new units of this type that are appearing on the market each year, it seems that it will be some time before there is a significant change in the current pattern. For this reason, the percentage distribution of the different types of dwelling is assumed to remain unchanged for the duration of the study period. Table 1 gives the distribution of housing types used in the study.

TABLE 1

Percentage Distribution of Different Dwellings by Types

Type of Dwellings	Percentage Distribution
Single Detached	60
Semi Attached	4
Row House	3
Apartment	33

3.2.1.2 Size of Dwelling

For each type of dwellings listed in Table 1, sizes and typical building layouts were established [24]. The areas of the various major components of the four dwelling types are given in Table 2. For the present study, it was assumed that the same component areas will apply to future electric dwellings. It should be noted that the component areas represent weighted-average values for a variety of dwellings.

TABLE 2

Areas of Different Construction Components for Dwellings*

Description of Component	Units	Single-Detached 1	Semi-Detached & Duplex 2	Row House 3	Apartment 4
Ceiling	m^2	106.0	74.3	52.0	35.8
Exterior Wall	m^2	118.0	84.8	55.4	30.7
Foundation Wall	m^2	116.0	70.5	32.8	7.4
Windows	m^2	19.9	13.4	10.1	3.8
Doors	m^2	3.6	3.6	3.6	3.6
Basement Slab	m^2	83.6	70.4	42.3	14.9
Basement Wall Above Grade**	m^2	16.6	10.1	4.7	1.1
Basement Wall Below Grade	m^2	99.4	60.4	28.1	6.4
House Volume	m^3	529.0	477.9	469.4	293.6

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* Calculated from 1969 CMHC Housebuilders' Survey [24]. This survey covers a representative sample of housing stock built in 1969. It does not restrict itself to NHA housing.

** Exposed 300 mm above grade.

3.2.2 Overall Heat Transfer Coefficient Model

It is a basic principle of physics that heat flows from matter at one temperature to surrounding matter or space at a lower temperature. The transfer of heat occurs by conduction, convection, and radiation.

Heat flows through a building's enclosing structure (the building envelope) mainly by conduction through materials. (For a well insulated house, the effects of convection and radiation may be neglected.) The rate of flow depends on the difference in temperature between the interior surface and the exterior surface, and the capacity of the enclosure to resist or prevent heat loss.

The heat flow characteristic of a component of the building envelope (such as a wall, a window, or the roof) is known as its thermal conductance. Thermal conductance is defined as the amount of heat energy conducted through a unit area (from one surface to the other) in a unit time with a unit temperature difference between the two surfaces. When the surface-to-air and air-to-surface conductances are added, the resultant figure is known as the "U value". The U value is expressed in watts per square metre degree Celsius or $W/(m^2\ ^oC)$. The higher the U value, the greater the heat loss from the enclosed space.

The resistance, or R value, of a building component is a measure of the component's insulating properties and is simply the reciprocal of its U value.

The heat that is transferred from or to a building via transmission through walls, roofs and basement is referred to as the fabric heat transfer.

Heat loss is also caused by direct air leakage that occurs from the interior to the exterior through intentional and unintentional openings in the building envelope. This factor is completely separate from the U and R of the building components. This kind of heat transmission is known as infiltration heat transfer.

The fabric heat transfer is calculated by considering the following building components:

Component	Identification
Basement wall below grade	1
Basement wall above grade	2
Basement slab	3
External walls	4
Ceiling	5
Windows	6
Doors	7

The identification numbers are used as subscripts on the variables to identify building components.

3.2.2.1 Basement Wall Below Grade Heat Transfer

The thermal conductances of basement walls below grade are given by Latta [36]. These conductances are based on the overall temperature difference from the interior air to the ambient air and are expressed for each incremental foot of depth below grade, as given in Table 3.

TABLE 3

Basement Wall Below Grade Conductances

Depth Below Grade Feet	Metres	Conductance $W/m^2\ ^{\circ}C$
1	0.305	2.33
2	0.610	1.25
3	0.915	0.88
4	1.220	0.68
5	1.525	0.54
6	1.830	0.45
7	2.135	0.39

These overall conductances for each incremental foot below grade allow for typical thermal conductivities of soil and an effective heat flow path length through the soil. The overall conductances in the above table are each normalized to a one-foot incremental depth of wall.

To establish the overall conductance of an insulated basement wall below grade, the overall conductance of each incremental foot is calculated by adding the thermal resistance corresponding to the conductance in question in the above table to the thermal resistance of the insulation R_{i1}, and then adding the resulting overall conductances for each incremental foot, since each incremental foot acts in parallel for heat flow from the basement through the ground to the ambient air, and then dividing by m, the number of incremental feet making the wall below grade.

That is

$$U_1 = \frac{1}{m} \sum_{j=1}^{m} \frac{1}{\frac{1}{U_{1j}} + R_{i1}} \qquad (3.1)$$

3.2.2.2 Basement Wall Above Grade Heat Transfer

The thermal conductance of the basement wall above grade is calculated by adding the thermal resistance of the building component in question to the thermal resistance of the insulation R_{i2}. The thermal resistance of basement wall above grade is taken from [23], as follows:

Component	Thermal Resistance ($m^2\,^{o}C/W$)
Exterior film boundary layer	0.030
8" concrete	0.196
Interior film boundary layer	0.120
Total:	0.346

Allowing for the effect of the insulation, the overall thermal conductance of the basement wall above grade is given by:

$$U_2 = \frac{1}{0.346 + R_{i2}} \tag{3.2}$$

3.2.2.3 Basement Slab Heat Transfer

The effective conductance of the floor slab, again based on the overall temperature difference between the interior air and ambient air, and thus allowing for a typical soil conductivity and an effective heat flow path through the soil, is taken from Latta [36]. The effective conductance is a function of the width of the floor slab and its depth below grade. For a slab of about 1.8 metres, the effective conductance is given in Table 4.

TABLE 4

Basement Slab Conductances

Slab Width Feet	Slab Width Metres	Conductance $W/m^2\ {}^oC$
20	6.1	0.170
24	7.3	0.153
28	8.5	0.141
35	9.8	0.125

3.2.2.4 External Wall Heat Transfer

The thermal conductance of the external wall is calculated by adding the thermal resistance of the building component in question to the thermal resistance of the insulation R_{i4}. However, for components to which insulation is added between studs, joists or rafters, allowance must be made for the thermal resistance of these elements in parallel with the insulation. The thermal resistance of the external wall as taken from [23] is:

Component	Thermal Resistance (m^2 °C/W)
Exterior film boundary layer	0.030
Face brick siding	0.074
Building paper	0.010
7/16" fibreboard	0.183
Air space	0.171
1/2" gypsum wallboard	0.079
Interior film boundary layer	0.120
Total:	0.667

By assuming that the studs, joists or rafters elements occupying 15 percent of the total area of the component, the overall thermal conductance of the external wall is given by:

$$U_4 = \frac{0.85}{0.667 + R_{i4}} + \frac{0.15}{0.667 + R_{w4}} \tag{3.3}$$

where R_{w4} = thermal resistance of the rafter in m^2 °C/W.

For a 2" by 6" rafter (actual depth 5 1/2"), the value of R_{w4} is:

$$R_{w4} = 1.21 \ (m^2 \ ^oC/W)$$

3.2.2.5 Ceiling Heat Transfer

The thermal conductance of the ceiling is calculated by adding the thermal resistance of the ceiling to the thermal resistance of the insulation R_{i5}. Again, allowance must be made for insulation in parallel with the rafters elements. The thermal resistance of the ceiling as taken from [23] is:

Component	Thermal Resistance ($m^2 \ ^oC/W$)
Attic film boundary layer	0.044
1/2" gypsum wallboard	0.079
Interior film boundary layer	0.107
Total:	0.230

By assuming that the rafters elements occupying 15 percent of the total area of the component, the overall conductance of the ceiling is given by:

$$U_5 = \frac{0.85}{0.23 + R_{i5}} + \frac{0.15}{0.23 + R_{w5}} \tag{3.4}$$

Once again, the value of R_{w5} is the same as that for R_{w4}.

3.2.2.6 Windows Heat Transfer

All windows are assumed to be double-glazed. The effective conductance of double-glazed windows, from Latta [36], is:

$$U_6 = 3.33 \ (W/m^2 \ ^oC)$$

3.2.2.7 Doors Heat Transfer

All doors are assumed to be 45 mm solid wood door. The effective conductance of the door, from Latta [36], is:

$$U_7 = 2.00 \ (W/m^2 \ ^oC)$$

3.2.2.8 Fabric Heat Transfer Coefficient

The total fabric heat transfer coefficient is given by the sum of the component coefficients.
Thus

$$h_F = \sum_{j=1}^{7} U_j A_j \tag{3.5}$$

where U_j = overall thermal conductance of component j in $W/m^2 \ ^oC$.

A_j = area of building component j in m^2.

3.2.2.9 Infiltration Heat Transfer Coefficient

When warm air escapes from the interior of a building, it is replaced by cooler outdoor air. For each degree Celsius of difference between the indoor and the outdoor temperature, each cubic metre of air exchanged causes a loss of 1206 joule in heat energy [23]. The infiltration heat loss coefficient is therefore given by:

$$h_I = 1206 \cdot V \cdot n \tag{3.6}$$

where V = volume of house in m^3.

n = number of air changes per hour.

If the result is to be given in watts per degree Celsius or $W/^{o}C$, then (3.6) must be divided by 3600, i.e.

$$h_I = 0.335 \cdot V \cdot n \tag{3.7}$$

The greatest uncertainty in determining the infiltration heat loss coefficient is the number of air changes per hour, n. This depends on many factors including window and door crack lengths, types of windows and doors, dwelling structure, wind velocity and direction, internal to external temperature differences, existence or not of fireplaces, ventilation fan operation and habits of residents [25, 26, 27, 28].

The value used for n in the study was 0.5 air changes per hour, which should be a conservative value for a well-built structure. The use of a constant value of n in the analysis is, of course, an approximation to reality since the infiltration rate must vary with time as a function of such factors as household activity, wind conditions, fire places and fan operation and out-door temperature. Nevertheless, a constant value was used in the analysis since:

1. There are no authoritative studies which establish infiltration as a function of the above variables with the degree of certainty that would be meaningful within our model framework.

2. The model represents a large stock of houses with diversity in location and household activity, which tend to produce much less variation in infiltration in the model as a whole than in individual dwellings.

3. Infiltration heat loss ranges between 15 and 25 percent of total heat losses depending on the type of dwelling [25, 26, 27, 28], so that even significant variations in the average value of n will not affect the results greatly.

3.2.2.10 Overall Heat Transfer Coefficient

The overall heat transfer coefficient including both fabric and infiltration heat transfer coefficients is given by:

$$G = h_F + h_I$$
$$= \sum_{j=1}^{7} (U_j \ A_j) + 0.335 \cdot V \cdot n \qquad (3.8)$$

The overall heat transfer coefficient is used in the energy requirements model to calculate the space heating energy requirements.

3.2.2.11 Thermal Insulation of Housing Components

The insulation levels assumed for dwellings are those proposed by Canada Mortgage and Housing Corporation [23]. The proposed insulation requirements (R-values) as a function of conventional degree-days are shown in Figure 3. The degree-days for several cities are also included in Figure 3. From Figure 3, the required insulation levels (R-values) for walls, roofs and basement walls may be established.

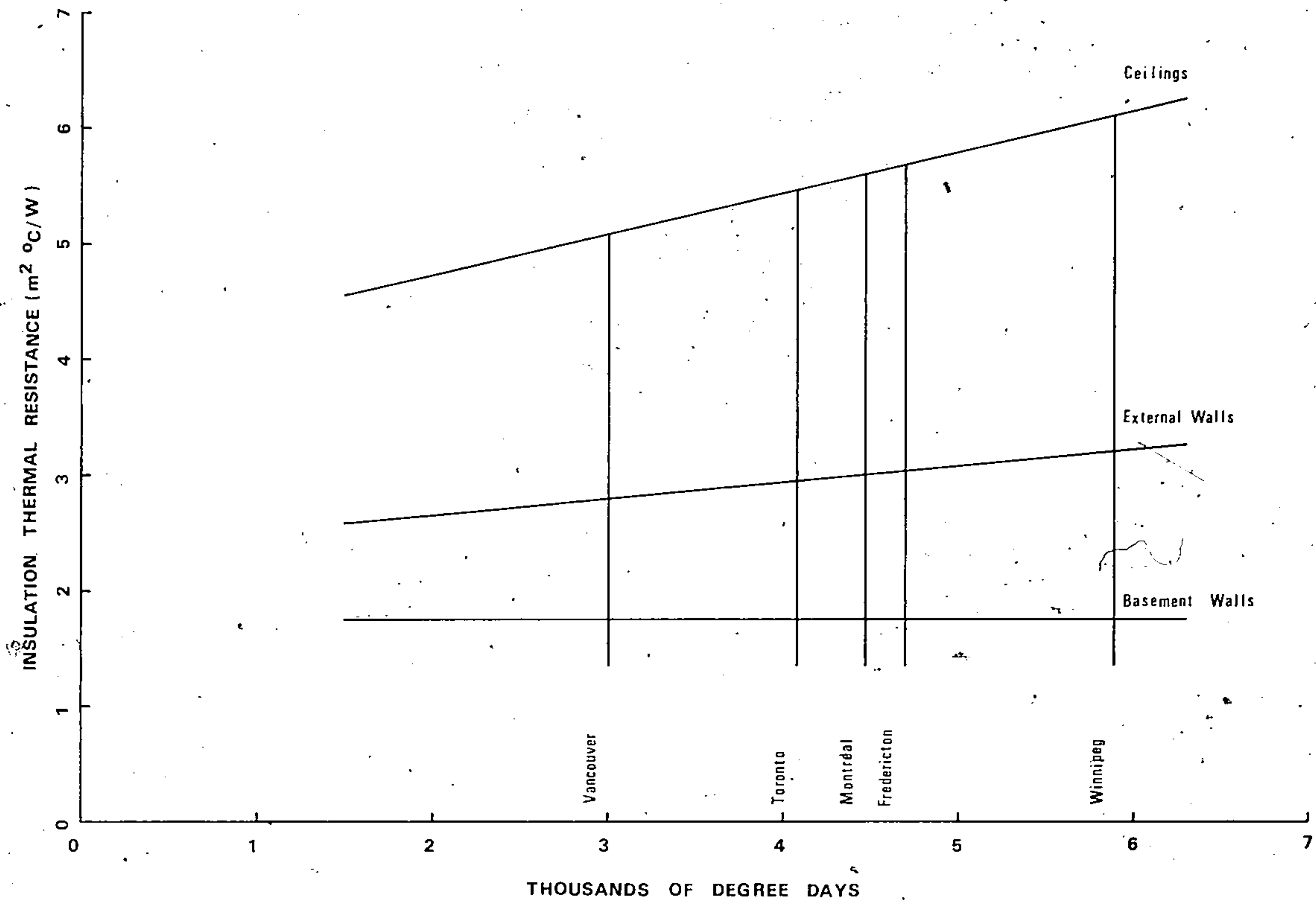


Figure 3: Proposed Standards for Household Insulation

3.2.3 Energy Requirements Model

To maintain a constant temperature, the basic requirement is that heat must be added to the dwelling at the same rate as the rate of heat loss. The total heat loss from a building does not, however, represent the actual load on the building's heating system. Some heat is replaced from other sources: solar radiation, the occupants themselves, electrical appliances and hot water consumed in the dwelling. This is sometimes called the "wild heat". Thus the heating load is calculated as the total heat loss less the wild heat. Obviously, the heating system operates only when the heat loss is greater than the wild heat gain.

The amount of wild heat varies from dwelling to dwelling depending on such parameters as the amount of insulation, the number and orientation of the windows and the living habits of the occupants. The purpose of the energy requirements model is therefore to determine the space heating requirements on an hour-by-hour basis in the various types of dwellings taken into account the effect of passive solar heat gains and "wild heat" gains from appliances, equipments and occupants. From these requirements, the total hourly system demand for electric space heating can be calculated.

3.2.3.1 Heat Losses

The heat loss rate of a dwelling in watts at any given time is calculated by:

$$P_L = G\ (T_i - T_o) \tag{3.9}$$

where G = overall heat transfer coefficient of dwelling in W/°C.

T_i = design inside temperature in °C.

T_o = ambient temperature in °C.

3.2.3.2 Passive Solar Heat Gains

Solar radiation is a source of heat energy. Direct sunlight falling on an opaque surface, through the window, is converted to sensible heat, generally at the point of contact. Solar heat is also absorbed by the exterior surface of the dwelling and, depending upon the effectiveness of its insulation, may be transmitted to the interior space. However, passive solar heat gains through walls and roofs are not very significant [31], therefore, their effects are ignored in the model. It is assumed that all solar heat gains occur through windows.

In the approach used here, the total windows areas for different dwelling types were first established. As in the dwelling stock model, it was assumed that a sufficient number of dwellings are considered so that the proportion of windows areas in all directions will be equal. For calculation purposes, eight directions (N, NE, E, SE, S, SW, W and NW) were assumed.

The next step required the determination of the actual solar insolation on a horizontal surface on an hour-by-hour basis and the conversion of this insolation to insolation incident on the randomly oriented window glass. From tables of clear-day solar heat gain factors [39], a relationship was established between the daily solar intensity on windows averaged over the eight directions to the daily insolation on a horizontal surface as a function of the day of the year. The relationship can be closely approximated by a sine function [26] as follows:

$$\Omega = 1.38 - 0.97 \, \text{Sin}\left\{\frac{\pi d}{365} + 0.0274\pi\right\} \tag{3.10}$$

where d = day of the year.

Using (3.10), the incident solar insolation on the collective windows of a dwelling may be estimated from the measured hour-by-hour solar insolation on a horizontal surface.

An allowance must also be made for the presence of blinds or curtains on the windows. Of course, there is no way of actually determining the number of windows in the housing stock that will be equipped with blinds or curtains nor the percentage of time during the heating season that the blinds and curtains will be closed. Therefore, there is no justification for attempting to develop a very elaborate model for windows. It was thus assumed that one-third of the windows would have closed blinds or curtains at any one time, so that the correction factor for the daily solar intensity factor was estimated to be 0.667. Therefore, the rate of solar heat gains in watts at any given time is given by:

$$P_s = 0.667 \cdot \Omega \cdot H \cdot A_w \tag{3.11}$$

where H = solar insolation on a horizontal surface in W/m^2.

A_w = window area in m^2.

3.2.3.3 Wild Heat Gains

Heat is also generated by appliances, equipments and occupants of the dwelling. This is sometimes called the 'wild heat' gain. The heating season average wild heat gain for dwellings was established as 22.6 kWh per day for all building types except apartments [25]. For apartments, the heating season average wild heat gain was estimated as 19.2 kWh per day [25], which does not allow for water heater inefficiency, as the hot water tank is part of a central heating system, remote from individual units. These estimates accounted for the most common electrical appliances, including lighting, the average capacities and usages. An allowance for the heat generated by occupants is also included in the wild heat contribution.

Although it is apparent that there will be a seasonal variation in wild heat gains, no reliable information was available on this question and it was assumed that there was no variation in the daily-average of wild heat gains.

Information on the hourly variation in wild heat generation was available from [40]. This variation is a result of a survey of a small sample and therefore does not properly account for load diversity. ~~To~~ develop a more realistic hourly wild heat gain model, the following procedure was used. Recognizing that most of the wild heat gain originates from electrical appliances and water heaters [25], it was assumed that a typical electrical utility load profile on a Sunday, being mainly a result of residential use, would approximate the wild heat gain profile. If the hourly electric demand on a Sunday is given by:

$$D_{HR}, \quad HR = 1, 2, 3, \ldots 24$$

and assuming that the minimum wild heat gain for any hour is approximately 0.35 percent of the daily-average wild heat gain, then the hourly wild heat gain as a fraction of the daily-average wild heat gain is given by:

$$W_{HR} = \frac{0.916 \, (D_{HR} - D_{MIN})}{\left(D_T - 24 \cdot D_{MIN} \right.} + 0.0035 \qquad (3.12)$$

where $D_{MIN} = \mathrm{Min}\ \{D_{HR}\}$

$$D_T = \sum_{HR=1}^{24} D_{HR}$$

The hourly wild heat gain is therefore:

$$P_w = W_{HR} \cdot Q_w \qquad (3.13)$$

where Q_w = daily-average wild heat gain in Wh.

A typical wild heat gain profile is shown in Figure 4.

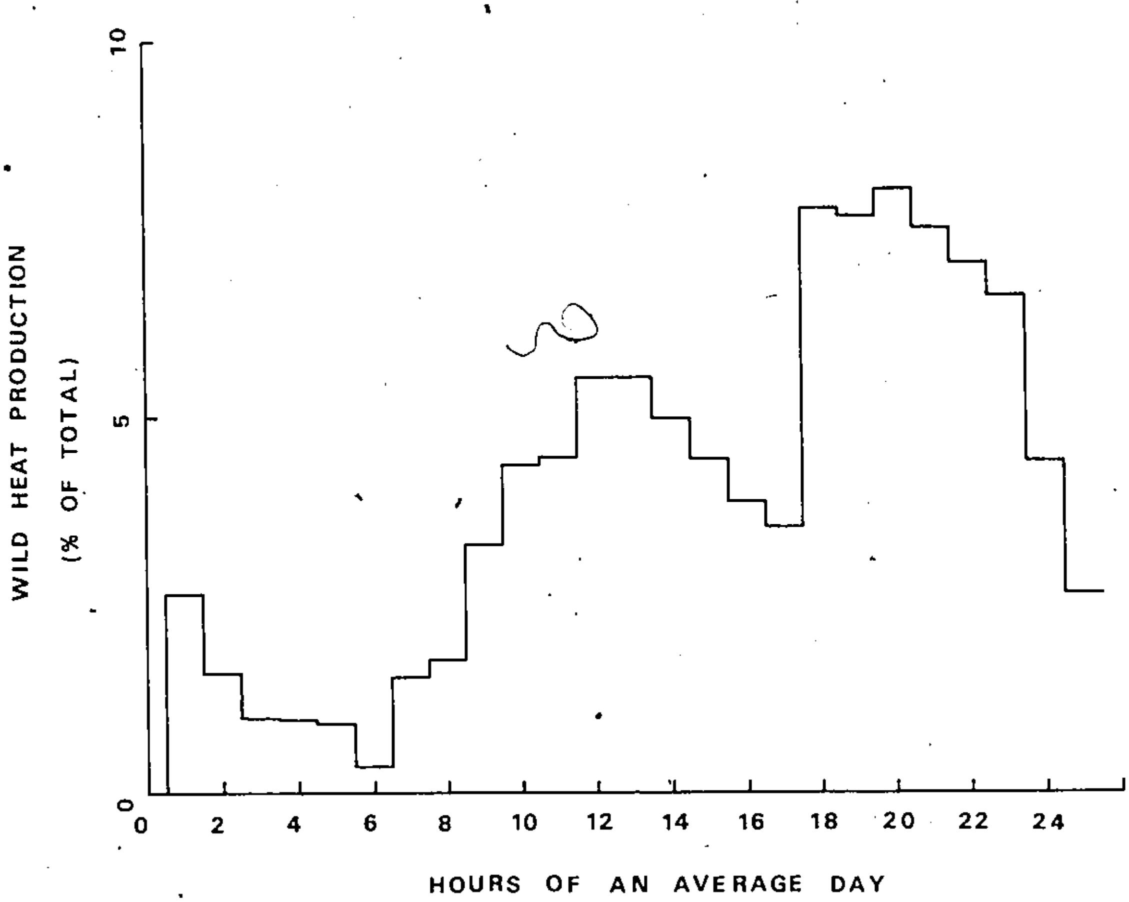


Figure 4: Hourly Variation of Wild Heat Generation

3.2.3.4 Power Requirements for Electric Heating

The on-demand power requirements for electric heating are readily determined for each dwelling types in any city knowing the dwelling heat loss factors, the indoor design temperature, the ambient temperature, the solar radiation on a horizontal surface and the daily-average wild heat gains. Assuming that the electric heaters are 100 percent efficient in converting electric energy to heat, the power requirements for electric heating at any hour is given by:

$$P_T = P_L - (P_S + P_W) \qquad (3.14)$$

3.2.4 The Computer Program Description

The various component models have been integrated using a computer program. The computer program was developed to calculate the power requirements for electric heating and to manage the information produced from these models so as to determine the effects of increased penetration level of electric heating on the electric utility. A flow chart for the program is given in Figure 5.

The logic of the program is described in the following paragraphs. For a given metropolitan area, the overall heat loss factors are calculated for each dwelling types by the overall heat transfer coefficient model. From these calculations, the electric heating demand for each of the four dwelling types is found for each hour of the year by the energy requirements model. For a given assumed penetration of electric dwellings, the individual demands are multiplied by the number of dwellings of each type, for the given distribution of types for the city in question, and the total demands for each dwelling type are summed. The result is the total hourly demand for electric space heating. These loads are added to the reference hourly electric loads for the city to produce a new hourly load curve.

The computer program then sorts the hourly data and converts the modified hourly loads to an load duration curve and generates an output file for input to the generation planning program. The program also produces graphical results which include the sample week hourly load curves and the monthly load duration curves.

A complete listing of the program is given in Appendix C.

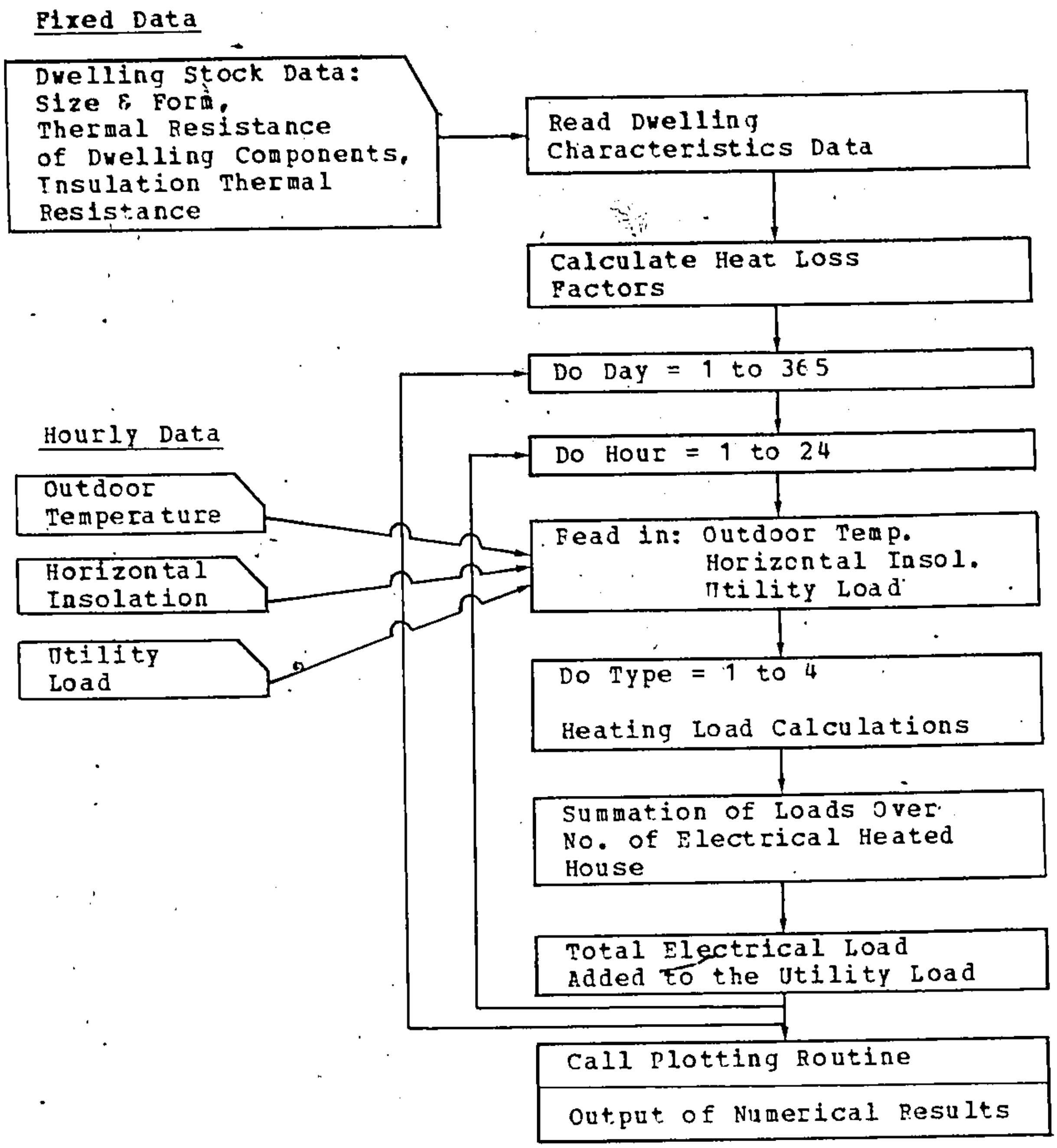


Figure 5: Flow Chart of the Computer Program to Determine the Power Requirements for Electric Heating

3.3 GENERATION EXPANSION MODEL

In system expansion planning involving choice between alternatives, the least cost investment that meets the demand for power with a given reliability level, is the one that is selected. Production costing and reliability models of power systems are used to estimate the costs of operating the electrical generators and to estimate the probability that there will not be enough power to meet the customer demand. With these models, the effect on system costs and reliability due to different assumptions about customer demand, fuel costs, or generator characteristics can be studied. The purpose of the generation expansion model is thus to calculate the most cost effective generation expansion schedule subject to reliability and reserve capacity margin constraints.

Two major factors affecting system operating costs are uncertainties in demand and random failures of plants. There are several models available that take these factors into account. The simplest is a deterministic model with heuristic calibration coefficients added to account for plant failures. More complicated is a method developed by Baleriaux and Jamoulle [15] which combines the probability distributions of customer demand and of plant failures to find the expected value of the energy produced by each plant and the probability that the customer demand will not be met. This method was further improved by Booth [16] which includes the treatment of reservoir hydro electric energy. The model described in this section is the combined method of Baleriaux and Booth.

The main difference between the deterministic model and the probabilistic model is that electrical demand and electrical generation are treated as random variables in the probabilistic model. In the deterministic model, a plant's capacity is derated to reflect random outages of the plant during its operating period. This assumes that the plant is always available at its derated capacity, or equivalently, that it has a forced outage rate of zero at its derated capacity. In fact, the plant is not always available. When a plant fails, more expensive generation must be brought on line to replace it. Since the deterministic model assumes that units never fail, the energy supplied by the more expensive plants is underestimated. The deterministic model also assumes that the electrical demand is fixed. In the probabilistic model, uncertainty in demand can be included in its probability distribution.

In the probabilistic model, the electrical demand and power plant failures are modelled as random variables. That is, a power plant has a probability of failure and the electrical demand has a probability of being at a given demand level.

3.3.1 Load Model

The most often used load model is the load duration curve (LDC). The LDC is a function which relates the customer's load level to the duration of time that each load level is equalled or exceeded. The data required to develop such a model are readily available, since continuous readings of system demand and energy are usually obtained on a routine basis by electric utilities. If a recording of instantaneous demands were plotted for a particular historical month, a curve such as depicted in Figure 6 might result. From this curve, the load duration curve as shown in Figure 7 is easily constructed. The load duration curve is created by determining what percentage of time the demand exceeded a particular level, where percent time is shown on the x-axis and demand level on the y-axis. Although detail is lost in the conversion, the load duration curve is easier to work with for time periods longer than a day and for time periods for which there is not enough information to create hourly curves.

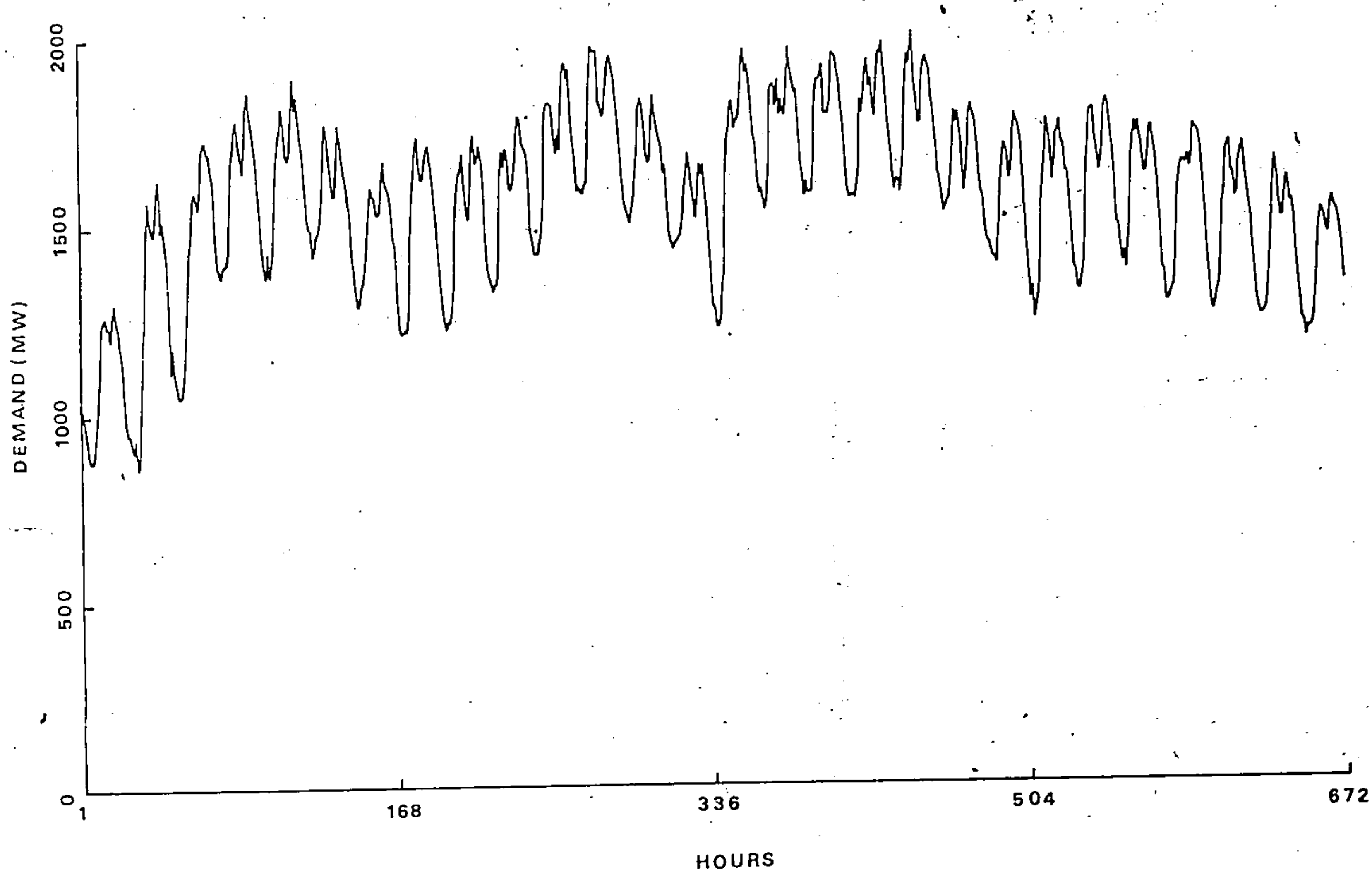


Figure 6: Time Dependent Load Curve for a Typical Month

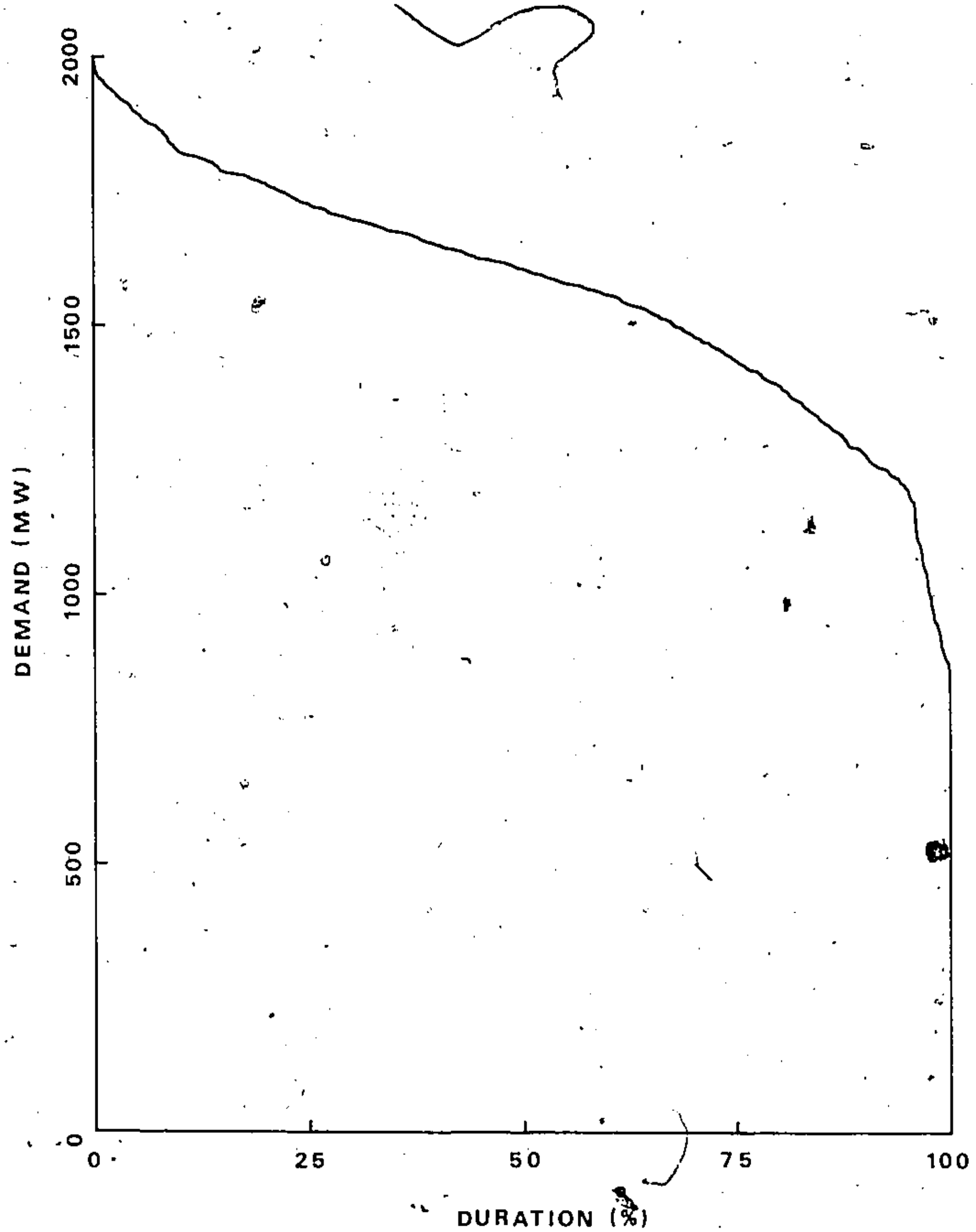


Figure 7: Load Duration Curve of Figure 6

3.3.1.1 Load Probability Distribution

The load probability distribution for the electrical demand can be created by equating the cumulative distribution function with the load duration curve. This is done by rotating the axes of the load duration curve and normalizing the time period so that the vertical axis gives the percent of time that the demand level is exceeded. The resulting load probability distribution is as shown in Figure 8. For example, there is a probability of 1.0 that the load will be greater than the minimum load at any given time, or equivalently the minimum load is exceeded 100 percent of the time. Further, there is a probability of zero that the load will be greater than the maximum load at any given time.

The customer demand, D_C is a random variable and $f_C(L_c)$ is its probability density function. By definition:

$$f_C(L_c)\, dL_c = \text{Probability}\left[L_c \leqslant D_C \leqslant L_c + dL_c \right] \tag{3.15}$$

Thus the cumulative probability distribution function is:

$$G_C(L_c) = \text{Probability}\left[D_C \leqslant L_c \right] = \int_0^{L_c} f_C(\theta)\, d\theta \tag{3.16}$$

The reverse cumulative probability distribution function is:

$$F_C(L_c) = 1 - G_C(L_c) = \text{Prob}\left[D_C \geqslant L_c \right] = \int_{L_c}^{\infty} f_C(\theta)\, d\theta \tag{3.17}$$

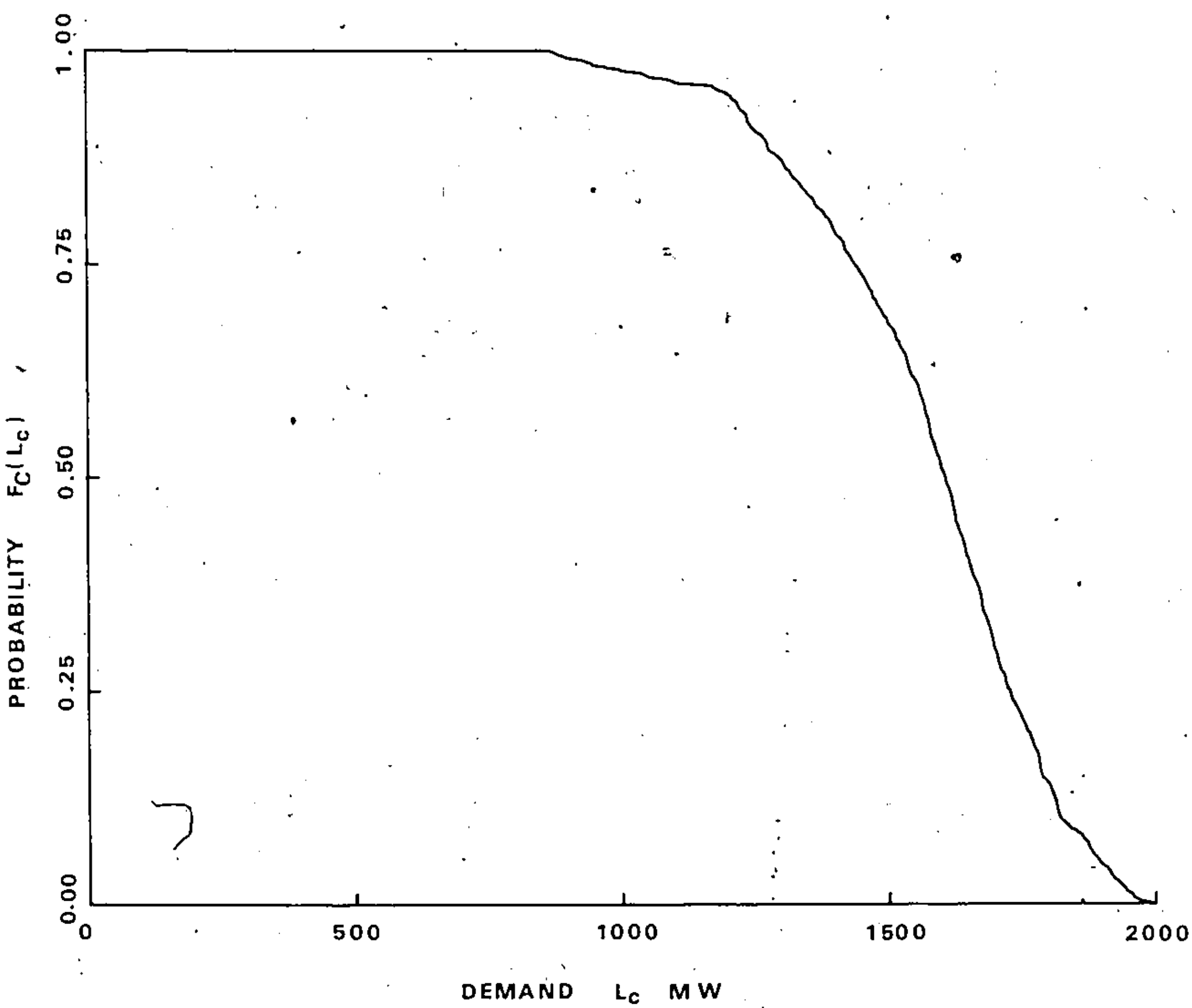


Figure 8: Load Probability Distribution of Figure 6

3.3.2 Generating Unit Model

Because the reliability of a power system depends on the reliability of its generation system, which often consists of many different types of generating units that are randomly forced off-line by technical problems, a method to model the random availability of a generating unit must be developed.

To account for the random outage or availability of a generating unit, it is necessary to determine the probability density function that describes the probability that a unit will be forced off-line or will be available during its normal period of operation. For example, assume on the basis of historical data, that the availability of the generating capacity is a Run-Fail-Repair-Run cycle as shown in Figure 9.

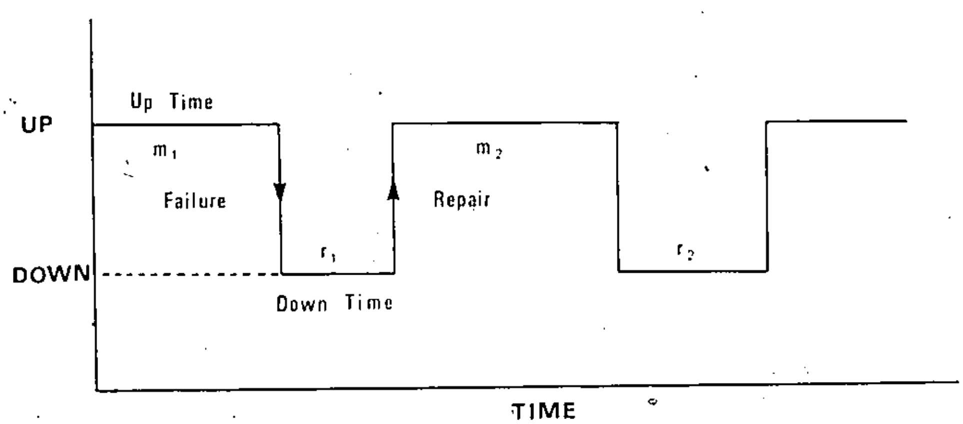


Figure 9: Run-Fail-Repair-Run Cycle for a Generating Unit

The system alternates between an operating state, or UP state, followed by a failed state, or DOWN state, in which repair is effected.

For the i-th cycle let

$$m_i = \text{UP time}$$

$$r_i = \text{DOWN time}$$

The random unit history may be represented in terms of an average UP time and an average DOWN time as follows:

$$m = \text{mean UP time} = \frac{1}{N}\sum_{i=1}^{N} m_i$$

$$r = \text{mean DOWN time} = \frac{1}{N}\sum_{i=1}^{N} r_i$$

Let

$$\lambda = \text{unit failure rate} = \frac{1}{m}$$

$$\mu = \text{unit repair rate} = \frac{1}{r}$$

This conveys the idea that random failure and repair of a unit can be defined as a two-state stochastic process, where a stochastic process is defined as a process that develops in time in a manner controlled by probabilistic law. The so called generating unit state-space diagram for the stochastic process, shown in Figure 10, tell us that a unit may be in UP state (state 1) and then randomly transfer to the DOWN state (state 2) and vice versa.

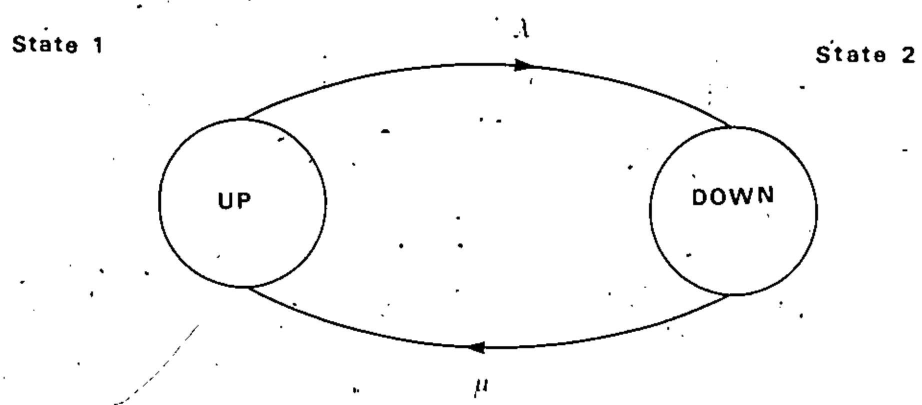


Figure 10: Generating Unit State Space Diagram

To obtain an expression for the long-term availablity of the generating capacity of a unit, it is necessary to recognize the stochastic process that is being considered is a zeroth order, discrete state, continuous transition Markov process. This process is characteristized by a lack of memory: the future of the process is completely defined by the immediate future. That is, the 'future' is independent of the 'past'. A Markov process is described by a transition probability function $P(E,t|X,t_0)$ which represents the conditional probability that the state of the system at time t belong to the set E, given that at time t_0 $(t_0 < t)$ the system is in state X.

Assume that:

1. Changes of state are possible.
2. The probability of departure from a state depends only on the current state and is independent of time.
3. The probability of more than one change of state during a small interval t is negligible.

Let

$P_1(t+\Delta t)$ = probability that the unit will be in state 1 at time $t+\Delta t$.

$P_2(t+\Delta t)$ = probability of being in state 1 at time t and not leaving that state during interval Δt. + probability of being in state 2 at time t and moving to state 1 during interval Δt.

If the probability of a unit can be described by an exponential distribution, then

$e^{-\lambda t}$ = probability of unit being available up to time t.

$$= 1 - \lambda\Delta t + \frac{\lambda^2\Delta t}{2} + \ \ldots$$

$$\sim 1 - \lambda\Delta t \qquad (3.18)$$

= probability of unit being available up to time Δt.

where

$\lambda\Delta t$ = probability of transferring from state 1 to state 2 in time Δt.

Similarly,

$e^{-\mu t}$ = probability of unit being unavailable up to time t.

$$\sim 1 - \mu\Delta t \qquad (3.19)$$

= probability of unit being unavailable in time Δt.

where

$\mu\Delta t$ = probability of transferring from state 2 to state 1 in time Δt.

Hence,

$$P_1(t+\Delta t) = P_1(t)(1-\lambda \Delta t) + P_2(t)\mu \Delta t + O(\Delta t) \qquad (3.20)$$

Similarly,

$$P_2(t+\Delta t) = P_1(t)(1-\mu \Delta t) + P_2(t)\lambda \Delta t + O(\Delta t) \qquad (3.21)$$

Upon rearranging these two equations, we have

$$\frac{P_1(t+\Delta t) - P_1(t)}{\Delta t} = -\lambda P_1(t) + \mu P_2(t) + \frac{O(\Delta t)}{\Delta t} \qquad (3.22)$$

$$\frac{P_2(t+\Delta t) - P_2(t)}{\Delta t} = \lambda P_1(t) - \mu P_2(t) + \frac{O(\Delta t)}{\Delta t} \qquad (3.23)$$

As $\Delta t \to 0$, one obtains the system of differential equations

$$\frac{dP_1(t)}{dt} = -\lambda P_1(t) + \mu P_2(t) \qquad (3.24)$$

$$\frac{dP_2(t)}{dt} = \lambda P_1(t) - \mu P_2(t) \qquad (3.25)$$

The solution is simply

$$P_1(t) = \frac{\mu}{\lambda+\mu} + \frac{\lambda e^{-(\lambda+\mu)t}}{\lambda+\mu} \qquad (3.26)$$

$$P_2(t) = \frac{\lambda}{\lambda+\mu} + \frac{\lambda e^{-(\lambda+\mu)t}}{\lambda+\mu} \qquad (3.27)$$

As the long-term (steady state) probability are of interest, then by setting $t \to \infty$ one gets

$$P_1(\infty) = \frac{\mu}{\lambda + \mu} = p \qquad (3.28)$$

$$P_2(\infty) = \frac{\lambda}{\lambda + \mu} = q \qquad (3.29)$$

which are the expression used to define the availability p and forced outage q of a generating unit.

A generating unit power output can be probabilistically represented as a forced outage capacity density function as shown in Figure 11. Figure 11 gives the simplist probabilistic model of this form.

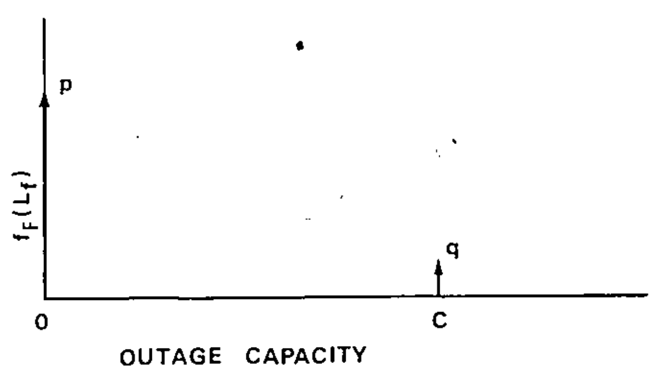


Figure 11: Forced Outage Probability Density Function of a Generating Unit

The PDF of forced outage capacity may be expressed as:

$$f_F(L_f) = p\delta(L_f) + q\ \delta(L_f - C) \tag{3.30}$$

where $\delta(\cdot)$ = dirac-delta function.

p = availability of the unit.

q = forced outage rate of the unit.

C = capacity of the unit.

Often experienced failure of auxiliary components such as valves, reheaters, pumps, fans, boilers, bearing oil etc, call for a more detailed model for the generating unit. This is accomplished with the multi-state model [17]. In the derated state, a portion of the capacity may be out of service randomly due to aforementioned reasons which reduced the capacity of the unit. A probability value is assigned to the existence of that capacity state. For planning purposes, a two state representation would be sufficient.

3.3.3 Reliability Model

The most widely used measures for estimating the reliability of generation systems is the loss of load probability (LOLP), or, as it has more recently and perhaps more correctly been termed, the loss of load expectation. The LOLP index provides a consistent and sensitive measure of generation systems reliability. The LOLP, as used in planning, is not a probability as such but a probabilistic measurement of the expected number of days per year in which the available capacity cannot meet the peak demand. Among utilities using the LOLP index for planning generation, a commonly accepted value is 0.1 days per year or one day in ten years. This means that sufficient generation capacity must be installed so that the expected number of loss of load days in a given future year will be no more than 0.1.

3.3.3.1 Equivalent Demand

In the probabilistic model, the equivalent demand on a generating unit is defined to be the sum of the demand due to customers plus the demand due to the random failures of generating units already dispatched. Suppose it has been determined that generating unit i will be loaded only after the first i-1 units have been committed. Then the equivalent demand on the i-th unit, $D_E^{(i)}$ is the sum of the two random variables:

$$D_E^{(i)} = D_C + D_T \qquad (3.31)$$

where D_C is the direct customer demand and D_T is the demand due to forced outages of the first i-1 units already dispatched. From probability theory, the cumulative distribution for the sum of the two random variables is given by:

$$G_E^{(i)}(L_e) = \int_0^{L_e} \int^{L_e-L_t} f_{C,T}(L_c,L_t)\ dL_c\ dL_t \quad (3.32)$$

The function $f_{C,T}(L_c,L_t)$ is the joint probability density function of the customer demand, D_C, and the forced outage demand of the first i-1 committed units, D_T.

Since these two random variables are independent, this implies that:

$$f_{C,T}(L_c,L_t) = f_C(L_c) \cdot f_T(L_t) \quad (3.33)$$

Using equation (3.33), equation (3.32) can be simplified to:

$$G_E^{(i)}(L_e) = \int_0^{L_e} f_T(L_t) \int_0^{L_e-L_t} f_C(L_c)\ dL_c\ dL_t \quad (3.34)$$

From the definition of the cumulative distribution function for the customer demand given in equation (3.16), equation (3.34) becomes:

$$G_E^{(i)}(L_e) = \int_0^{L_e} f_T(L_t)\ G_C(L_e-L_t)\ dL_t \quad (3.35)$$

$$= \text{Prob}\left[\text{Load} + \text{Outage} \leqslant L_e\right]$$

3.3.3.2 Probability Distribution of the Equivalent Demand

With the basic equation derived in Section 3.3.3.1, the probabilistic analysis proceeds in the following manner. Generating units are loaded starting at the left of the inverted load duration curve. The equivalent demand on the first loaded unit to be brought up is the entire customer demand since there are no outages from previous units, so

$$D_E^{(1)} = D_C \tag{3.36}$$

where $D_E^{(1)}$ = equivalent demand on the first unit.

D_C = customer demand.

Thus

$$G_E^{(1)}(L_e) = G_C(L_e) \tag{3.37}$$

Since $G_E = 1 - F_E$

$$F_E^{(1)}(L_e) = F_C(L_e) \tag{3.38}$$

Equation (3.38) gives the new equivalent demand curve.

The equivalent demand on the second unit to be brought up is the customer demand plus the demand due to the outages of the first unit:

$$D_E^{(2)} = D_C + D_{F_1} \tag{3.39}$$

Thus the probability distribution of the equivalent demand on the second unit is:

$$G_E^{(2)}(L_e) = \int_0^{L_e} f_{F_1}(L_f) \quad G_C(L_e - L_f)\, dL_f \tag{3.40}$$

For the case in which in forced outage rate of the first unit is a discrete random variable, the integral over the probability density function $f_{F_1}(L_f)$, can be replaced by the sum over the probability mass function. That is:

$$G_E^{(2)}(L_e) = p_1\, G_C(L_e) + q_1\, G_C(L_e - C_1) \tag{3.41}$$

since $p_1 + q_1 = 1$ and $G_E = 1 - F_E$

$$F_E^{(2)}(L_e) = p_1\, F_C(L_e) + q_1\, F_C(L_e - C_1) \tag{3.42}$$

but

$$F_E^{(1)}(L_e) = F_C(L_e)$$

we get a recursive relationship:

$$F_E^{(2)}(L_e) = p_1\, F_E^{(1)}(L_e) + q_1\, F_E^{(1)}(L_e - C_1) \tag{3.43}$$

Figure 12 illustrates graphically how this convolution is performed.

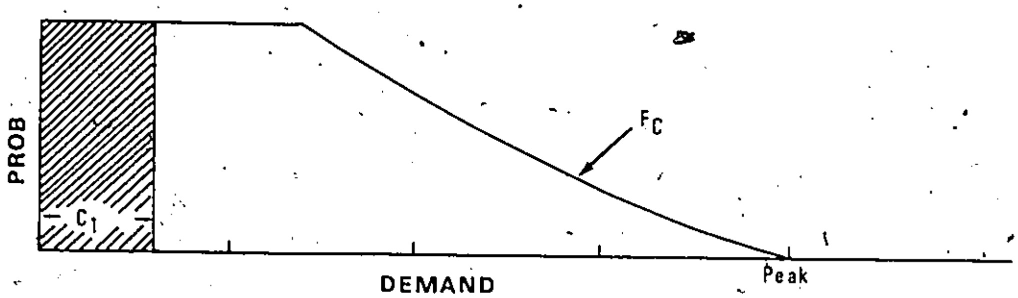


Figure 12a: Loading of a generating unit of capacity C_1 MW with probability p_1.
Expected capacity (shaded area) = C_1 MW.

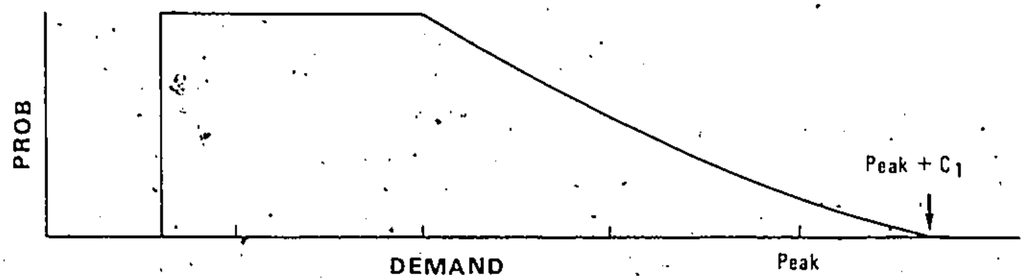


Figure 12b: If the first unit fails, the second units sees the original customer curve. The event has a probability of q_1 (= $1-p_1$).

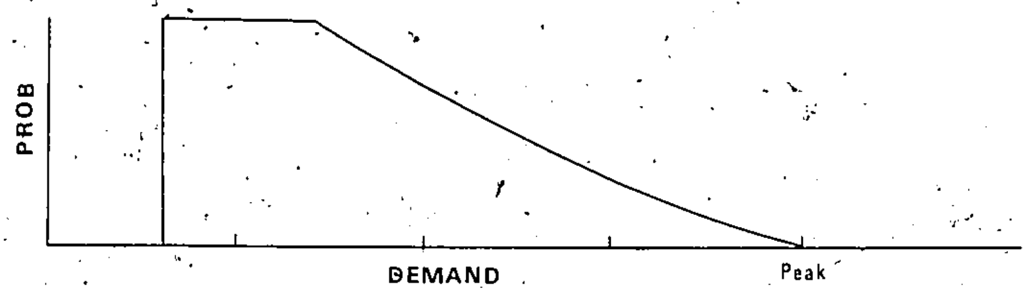


Figure 12c: If the first unit operates the second unit does not see the first C_1 MW of customer demand. This event has a probability of p_1.

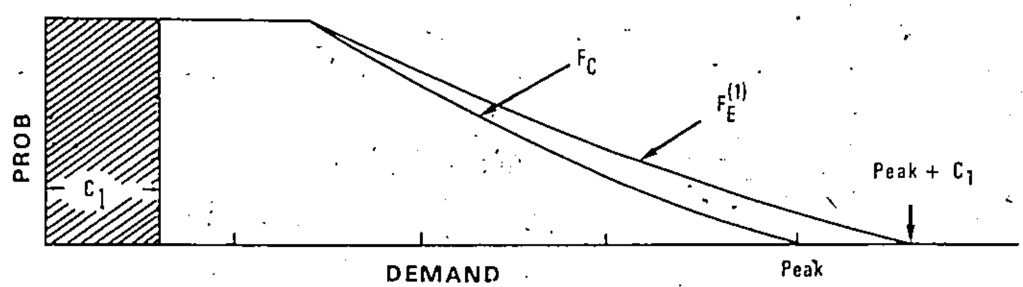


Figure 12d: The equivalent demand curve for the second unit is the sum of the two curves weighted by their respective probabilities.

Figure 12: Graphical Illustration of Convolution

Thus by performing successive convolution, the equivalent demand on the i-th unit due to forced outages of the first i-1 committed units and the customer demand is given by:

$$F_E^{(i)}(L_e) = p_{i-1} \cdot F_E^{(i-1)}(L_e) + q_{i-1} \cdot F_E^{(i-1)}(L_e - C_{i-1}) \qquad (3.44)$$

The distribution of the equivalent demand is central to the probabilistic model. As will be shown below, the loss of load probability can be computed from it, as can the expected energy generated by each unit.

3.3.3.3 Loss of Load Probability

After the last unit has been loaded, the final curve is the equivalent demand curve for the entire system. Since the loss of load probability is defined to be the percent of time that the customer peak demand cannot be met, its value can be read directly from the final curve. This is illustrated graphically in Figure 13. The loss of load probability is given by:

$$LOLP = F_E^{(n)}(IC) \qquad (3.45)$$

where n = number of generating units.

IC = total installed capacity of the system.

$$= \sum_{i=1}^{n} C_i$$

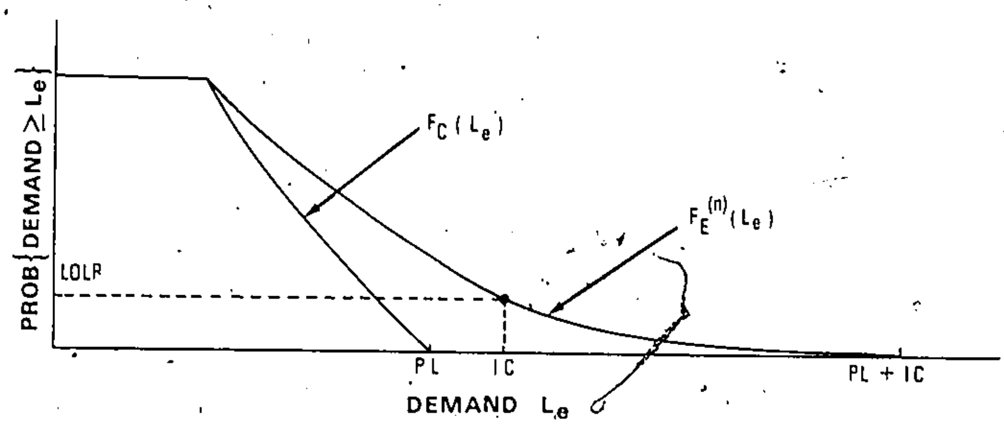


Figure 13: Final Equivalent Demand Curve

3.3.4 Production Costing Model

As have been dicussed earlier, the costs are used as the major criteria for selecting the optimal expansion schedule. Therefore it is essential, for system cost studies, to have for a particular expansion plan the expected value of the energy produced by each unit, as well as associated production costs. Production costs generally include both fuel and operation and maintenance costs (O&M). In order to achieve minimum operating costs, generating units must be loaded in the order of ascending incremental fuel costs. This particular order will be referred to as the merit order of loading.

3.3.4.1 Merit Order of Loading

In committing generating units to achieve the smallest production costs, the economic strategy is to first commit least expensive units. The economics of these units are governed by performance parameters such as the heat rate and the price of fuel used by the units. Generating units are segmented into several capacity blocks because it is rarely economical to commit one unit completely before calling on another.

The reason for segmented commitments is the basic shape of the heat rate curves; a typical heat rate curve is shown in Figure 14.

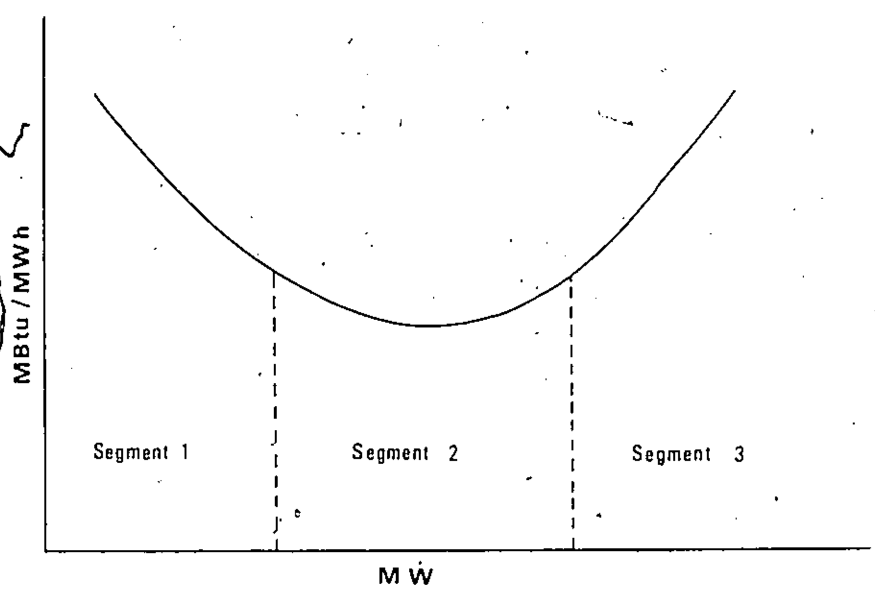


Figure 14: Typical Heat Rate Curve

Clearly, on this curve, the second segment corresponds to higher efficiency, since fewer Btus are required for each MWh of energy produced. From this basic heat rate curve, the input/output, I/O, curve can be obtained by multiplying every y-axis value by its corresponding x-axis value, a typical I/O curve is depicted in Figure 15.

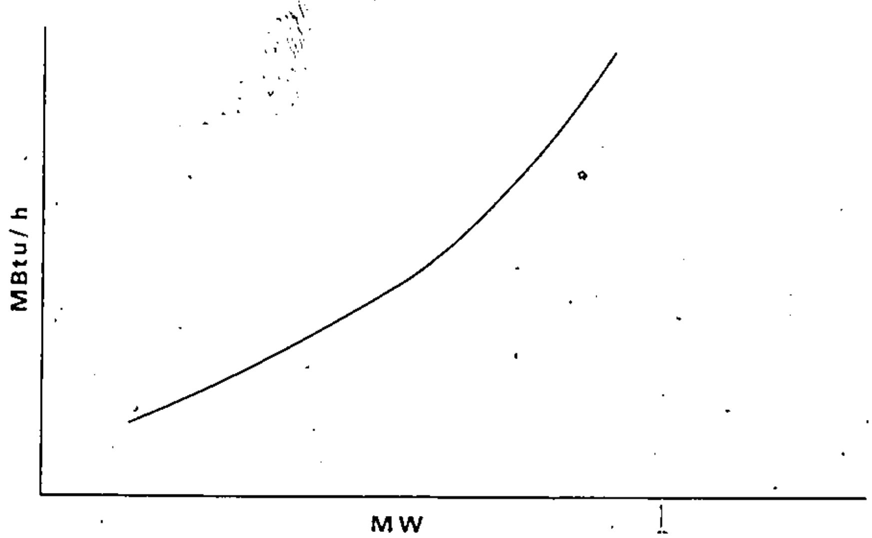


Figure 15: Typical Input/Output Curve

Finally, differentiating the I/O curve, one obtains the incremental heat rate, IHR, curve in Figure 16.
Thus:

$$\mathrm{IHR} = \frac{d(I/O)}{dP} \tag{3.46}$$

where IHR = incremental heat rate.

$\frac{d(I/O)}{dP}$ = differential of the input/output curve with respect to the power output.

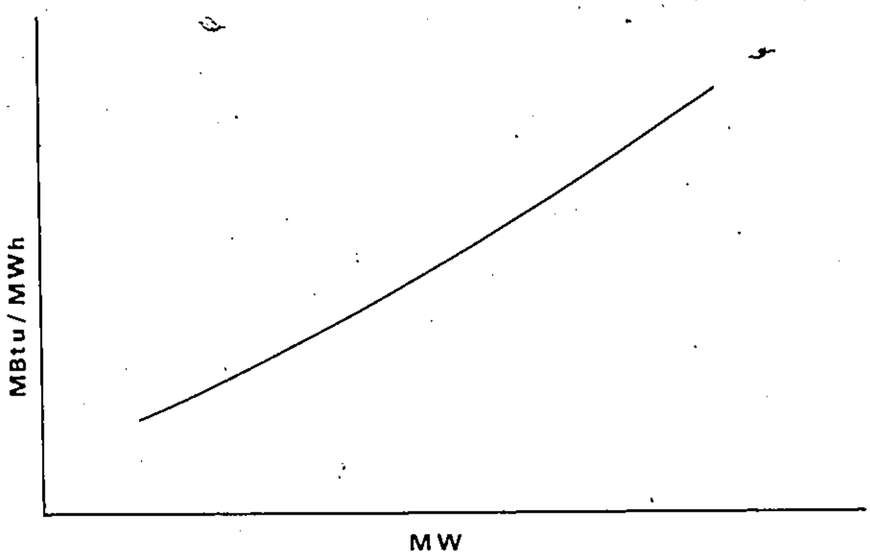


Figure 16: Typical Incremental Heat Rate Curve

In a special case where the heat rate curve is assumed constant, the incremental heat rate equals the heat rate, that is:

$$IHR = HR \tag{3.47}$$

Once the incremental heat rate is obtained, the incremental fuel cost, IFC, can be calculated by:

$$IFC = \frac{IHR \cdot \text{Unit Fuel Cost}}{\text{Heat Value}} \tag{3.48}$$

where IFC = incremental fuel cost in $/MWh.

Once the incremental fuel cost for each unit is obtained, the loading order can be determined by placing the unit with the smallest incremental fuel cost first in the loading order, followed by units with increasing incremental fuel cost.

In the multi-block representations of a unit, the unit is segmented into several capacity blocks and each block is committed separately [17]. Each block may have a different incremental fuel cost. A loading order of commitment of the block is prepared in the ascending order of their incremental fuel cost. At the same time, it should never be overlooked that the upper block of a unit cannot be committed before its lower blocks have been committed. Two consecutive blocks of a unit may not occupy adjacent positions in the loading order.

3.3.4.2 Expected Energy Generated by a Unit

The calculation of the expected energy generated by a unit proceeds in much the same way as the procedure outlined in Section 3.3.3.2. Generating units are loaded starting at the left of the equivalent demand curve. The equivalent demand on the first committed unit is the entire customer demand.

It has been shown by Booth [16] and others that the expected energy generated by a unit is the area the unit occupies under the equivalent demand curve. The vertical axis of the equivalent curve gives the probability that a unit operates at that capacity at any given time. Taking the integral over the capacity gives the expectation of the operating capacity for the unit at any given time. The expected capacity for the first unit is therefore:

$$K_1 = \int_0^{C_1} F_C(L_e)\, dL_e \qquad (3.49)$$

Using equation (3.38), equation (3.49) becomes:

$$K_1 = \int_0^{C_1} F_E^{(1)}(L_e)\, dL_e \qquad (3.50)$$

where C_1 = capacity of the first unit.

K_1 is the expected capacity required to meet the equivalent demand, without considering the availability of the unit. The total expected energy for the first unit, taking outages into account, is:

$$E_1 = p_1 \cdot T \cdot K_1 \tag{3.51}$$

where p_1 = availablity of unit 1.

T = total length of the time period.

Figure 12 illustrates graphically how this expected energy is obtained.

The equivalent demand of the second unit to be committed is the customer demand plus the demand due to outages of the first unit. Because of the way the equivalent load is defined, the loading point of the second unit on the equivalent load duration curve is the same whether or not the first unit fails. If the first unit fails, it creates a demand, C_1, so the second unit is loaded when the equivalent demand is C_1. If the first unit does not fail, there is no demand due to outage. The first unit supplies the demand until the demand exceeds C_1, at which point the second unit is loaded. This is illustrated graphically in Figure 12. The expected operating capacity of the second unit is therefore:

$$K_2 = \int_{C_1}^{C_1+C_2} F_E^{(2)}(L_e)\, dL_e \tag{3.52}$$

where C_2 = capacity of the second unit.

K_2 = expected running capacity of the second unit.

Hence the expected energy generated by the second unit is:

$$E_2 = p_2 \cdot T \cdot K_2 \tag{3.53}$$

where p_2 = availablity of unit 2.

T = total length of the time period.

Continuing in this way, it can be shown that for the i-th unit:

$$K_i = \int_{\sum_{j=1}^{i-1} C_j}^{\sum_{j=1}^{i} C_j} F_E^{(i)}(L_e)\, dL_e \tag{3.54}$$

and

$$E_i = p_i \cdot T \cdot K_i \tag{3.55}$$

The total cost of energy generated by unit i is given by:

$$EC_i = E_i \cdot IFC_i \tag{3.56}$$

where EC_i = energy cost of unit i.

E_i = expected energy generated by unit i.

IFC_i = average incremental fuel cost of unit i.

The production costs for unit i is therefore:

$$PC_i = EC_i + OM_i \qquad (3.57)$$

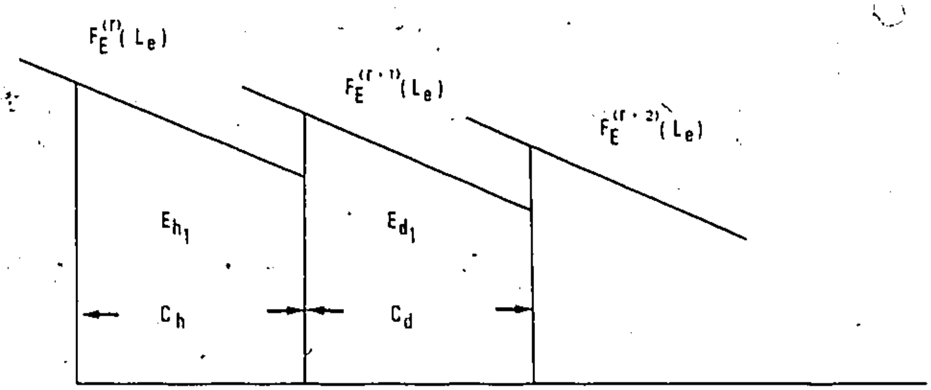
where PC_i = production costs of unit i.

OM_i = operation and maintenance cost of unit i.

3.3.4.3 Hydro Electric Plants

The inclusion of reservoir hydro-electric power complicates the problem of finding the minimum cost operating plan in probabilistic simulation. The marginal cost of hydro-electric energy is essentially zero, since there are only operation and maintainence (O&M) costs and no fuel costs. This implies that hydro plants should be loaded first in the merit order. However, the total amount of energy available is limited by the river flows and the reservoir size. Usually, the total energy available is not sufficient to run the hydro unit 100 percent of the time at full capacity. Therefore, it is necessary to find the loading point for the hydro electric unit such that, run at full capacity, the hydro energy is exactly equal to the area under the equivalent demand curve.

Consider a hydro-electric unit with capacity C_h, available energy E_h and finite outages whose trial loading order position is adjacent and to the left of the demand energy unit of capacity C_d as shown in Figure 17.



where E_h = energy delivered by the hydro unit.

E_d = energy delivered by the demand energy unit.

$F_E^{(r)}(L_e)$ = equivalent demand for the hydro unit.

$F_E^{(r+1)}(L_e)$ = convolution of $f_H(L_h) + F_E^{(r)}(L_e)$.

$F_E^{(r+2)}(L_e)$ = convolution of $f_D(L_d) + F^{(r+1)}(L_e)$.

Figure 17: Graphical Illustration of Loading of Hydro Unit

For each trial loading order position, the delivered energy, E_{h_1} of the hydro unit can be tested against the energy assigned for the hydro unit, E_h. If the value of E_{h_1} is greater than E_h, the hydro unit cannot be loaded in this position. This testing process is continue until the hydro energy delivered is less than the energy assigned. This implies that the previously loaded unit should be backed off to allow the hydro unit to discharge all its energy. Furthermore, the equivalent demand curve $F_E^{(r+2)}(L_e)$ is unchanged by reversing the loading order position of C_h and C_d, this implies that the sum of the energy delivered by both C_h and C_d is constant; regardless of their order.

Hence the expected energy delivered by the demand energy unit preceeding the hydro is given by:

$$E_d' = E_{h_1} + E_{d_1} - E_{h^-} \tag{3.58}$$

In most generation planning models, the hydro capacity is further divided into two types of hydro capacity: the base or run-of-the-river capacity and the peaking capacity. The base hydro capacity is first utilized in the base portion of the ELDC. Then the energy generated by the base hydro capacity is substracted from the total hydro energy. The remaining peaking energy is then dispatched according to the procedure described earlier.

If there is more than one reservoir hydro plant, the individual hydro electric plants are combined into a single pseudo unit whose capacity is equal to the sum of the hydro capacities. For planning purposes, it was not necessary to simulate all hydro units in detail, however, a full probabilistic treatment for multiple hydro units can be considered if desired.[1]

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[1] S. Chan, "A Discussion on the Techniques to Probabilistically Simulate the Operation of Single and Multiple Energy Limited Generating Units," A Personal Communication to Dr. K.F. Schenk, University of Ottawa, April, 1981

3.3.5 Optimization Model

Using the models developed in the previous sections, the reliability and production costs of various alternative expansion plans can be evaluated. A optimization model is then used to find the "best" expansion policy for the power systems. The "best" policy is interpreted to mean that policy which results in a system of desired reliability with minimum discounted cash flow expenditures over the study period. A dynamic programming (DP) algorithm [38] is used to calculate the best expansion policy.

To formulate the dynamic programming problem, the study period is divided into a number of subdivisions or "stages". Each stage is assumed to corresponding to a year. Between stages a decision must be made as to whether a particular type of unit should be added to the system, and this decision must be made for each expansion candidates. Let the vector D(t) represents the decision made between stage t-1 and stage t. Any decision to add units will change the configuration of the generating units in the power system or, expressing it in another way, will change the state of the power system at stage t. Let the vector X(t) represents the state of the power system at stage t. The value of the state variable in stage t is a function of the state variable in stages t-1 and t:

$$X(t) = X(t-1) + D(t) \tag{3.59}$$

Equation (3.59) may be applied successively to give:

$$X(t) = X(0) + \sum_{j=1}^{t} D(j) \tag{3.60}$$

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

Equation (3.60) simply says that the state of the system in stage t is equal to the initial state of the system plus the sum of all the decisions made prior to stage t.

The effects of the various decisions must be evaluated in order to determine whether one decision is better than another. This is accomplished by defining a performance criterion or an objective function. The objective function in this case is defined as the present-worth discounted summation of the capital costs, production costs, and salvage value. Obviously, the value of the objective function at a particular state in stage t is a function of the decision made prior to stage t. Hence:

$$L(X) = \sum_{j=1}^{t} \left(C_j(X) + O_j(X) \right), \tag{3.61}$$

where $L(X)$ = value of the objective function for reaching state X in stage t.

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

$O_j(X)$ = present worth of production costs in stage j for the state associated with the decision prior to stage j.

Any number of possible sets of decision could lead from state X(0) to state X(t), and it is necessary to find the particular set that will minimize the value of the objective function for reaching state X(t) at stage t. The set that results in the minumum value of the total objective function is selected as the basis for system expansion.

3.4 TOTAL IMPACT MODEL

The third and the final stage of the three stage model is the calculation of the long-term implications of electric space heating. This calculation is performed by comparing the system demand, installed generation requirements, fuel consumption and total utility system costs of the electric heating case with that of the reference case. From these comparisons the impact of electric space heating may be evaluated and assessed.

3.4.1 System Demand

One way of examining the effects of electric space heating is to investigate the changes in electricity demanded. By looking at the incremental electricity demand of heating versus the reference power system demand for that same period, effects of adding this increment can be observed.

3.4.1.1 Load Factor

The electric power utilities have been concerned with the effect of increased utilization of electricity for space heating on their load factor. This comes about because electric space heating necessarily entails some demand for electric space heating during periods of heavy load and system peak. Not only does this burden the utility's load, resulting in the deterioration of the system load factors, but it also may waste primary energy sources by necessitating the use of high cost peaking units. It is therefore important to investigate how the load factor will change as a result of increased penetration level of electric space heating.

3.4.2 Installed Capacity Requirements

In order to get a realistic idea of the impact of electric space heating on the electric utilities, generation expansion case that include electric space heating effect must be run and compared with the reference case. From these comparisions, the additional installed capacity requirements for electric space heating may be evaluated. Decisions could be made on what type of generating units to install to meet the additional demand for electric space heating.

3.4.3 Fuel Consumption

One of the major concern that electric power utilities have is the increased primary fuel requirements as a result of increased utilization of residential electric space heating. This is because electric space heating is an inefficient way of using our resources. This comes about because two thirds of the energy input to electric energy generation is lost in low-grade waste heat. On the other hand, increased utilization of electric space heating would increase the possibility of substituting nuclear and coal fuels for the more limited oil and natural gas fuels. This condition exists because as more nuclear and coal generation are installed to meet the load requirements, some other more expensive oil and gas generating units will generate less energy and as such fuel is saved. What value this savings in fuel has to the utility can be evaluated in terms of the amount of fuel displaced.

The yearly fuel consumption for electrical generation can be obtained directly from the energy cost of the generation units.

Let

EC = energy cost of the generating unit.

EQV = energy equivalent of the fuel used.

FC = fuel cost of the generating unit per unit energy.

then the fuel used is:

$$F = \frac{EC}{EQV \cdot FC} \tag{3.62}$$

In calculating the amount of oil and gas fuel not consumed by residential furnaces as a result of electric space heating, the energy difference between the two load duration curves were used as follows:

$$E_{DIFF} = E_{LDC}(EHC) - E_{LDC}(BC) \tag{3.63}$$

where

$E_{LDC}(EHC)$ = energy under the LDC with electric heat.

$E_{LDC}(BC)$ = energy under the LDC for the base case.

then the oil and gas fuel not consumed by residential furnaces are calculated as follows:

$$\text{Fuel not consumed} = \frac{REL \cdot E_{DIFF}}{EQV \cdot \eta} \tag{3.64}$$

where REL = relative percentage of fuel utilization.

EQV = energy equivalent of fuel.

η = efficiency of furnace.

The relative percentage of fuel utilization assumed [24] was:

Oil	54 %
Gas	46 %

The efficiency of the residential heating furnaces was assumed as:

Oil furnace	60 %
Gas furnace	80 %

The energy equivalent assumed was:

Nuclear	135.20×10^6 kcal/kgs
Coal	5.97×10^6 kcal/ton
Oil	1.57×10^6 kcal/bbls
Gas (barrel of oil eq.)	1.46×10^6 kcal/bbls

3.4.4 Financial Requirements

Financial requirements are defined as the revenues which must be obtained in order to cover all expenses incurred. These expenses are defined as the sum of the appropriate capital and operating expenditures. All expenditures are present-worthed values and may be escalated as time progresses. For capital and operating expenditures, the escalation and present-worth factors may be combined into a single factor:

$$PV = \left(\frac{1 + m}{1 + i}\right)^n \qquad (3.65)$$

where PV = combined present-worth and escalation factor for capital and operating expenditure.

m = escalation rate.

i = present worth discount rate.

n = number of years.

Therefore the total expenditure for year n is:

$$C = PV \times (CP + OP)$$

where CP = capital expenditure for year n.

OP = operating expenditure for year n.

Chapter IV

NUMERICAL EVALUATIONS AND RESULTS

4.1 INTRODUCTION

The methodologies described in the previous chapter were applied to the New Brunswick electric power system to evaluate the impact of electric space heating. The results of these evaluations are described and analysed at each of the three stages. Likely reasons why such results were obtained are discussed.

Sensitivity analysis on the base case were carried out to investigate the effects of changes in construction costs, discount rates, fuel cost escalation rates and the load growth rate will have on the stability of the optimum solution.

4.2 EVALUATION OF ELECTRIC HEATING REQUIREMENTS

In evaluating the requirements of electric space heating for residential dwellings, the procedure that was followed was divided into the following steps:

Step 1 : Evaluation of the overall heat transfer coefficient of the housing stock.

Step 2 : Evaluation of the incremental demand for electric heating.

Step 3 : Evaluation of the total system demand for electric heating.

Each of these steps will be considered in turn.

4.2.1 Evaluation of the Overall Heat Transfer Coefficient

The overall heat transfer coefficients of each type of dwelling were calculated using the electric space heating load calculation program (refer to Appendix C for the listing of the program). The proposed thermal resistances of the housing stock in New Brunswick were tabulated in Table 5.

The depth of the basement wall below grade is 1.83 m and the number of air changes per hour is 0.5.

The results are tabulated in Table 6 for the four dwelling types and for the different structural components of the dwelling. Table 7 presents a summary of these heat transfer coefficients.

Notice how more energy efficient row houses and apartments are as compared to single-detached and semi-detached dwellings. This clearly points out that an increase use of row house, or multi-family dwellings, are to be preferred for the effective utilization of resources.

TABLE 5

Thermal Resistance of the Housing Stock in New Brunswick

Component	Thermal Resistance (m^2 °C/W)
Ceiling	
Wood rafter	1.21
Insulation	5.90
Ceiling not including the rafter	0.23
Exterior Wall	
Wood stud	1.21
Insulation	3.08
Wall section not including the rafter	0.07
Basement Slab	
Based on a slab width of 8.5m	7.10
Basement Wall Above Grade	
Basement wall plus inside and outside surface	0.35
Basement insulation	1.76
Doors	
45 mm of solid wood door	0.50
Windows	
with double glazing	0.30

TABLE 6

Heat Loss Coefficient of Different Construction Components for Dwellings (W/°C)

Description of Component	Dwelling Type i			
	Single-Detached 1	Semi-Detached & Duplex 2	Row House 3	Apartment 4
Ceiling	25.74	18.04	12.63	8.69
Exterior Wall	36.20	26.01	16.99	9.42
Windows	66.33	44.67	33.67	12.70
Doors	7.20	7.20	7.20	7.20
Basement Slab	11.77	9.92	5.96	2.10
Basement Wall Above Grade*	7.88	4.80	2.23	0.52
Basement Wall Below Grade	33.63	20.44	9.51	2.17

* Exposed 300 mm above grade.

TABLE 7

Summary of Heat Loss Coefficients for Dwellings (W/°C)

Type of Heat Loss	Dwelling Type 1			
	Single-Detached 1	Semi-Detached & Duplex 2	Row House 3	Apartment 4
Fabric	188.76	131.07	88.19	42.80
Infiltration	95.51	86.29	84.75	53.01
Total	284.27	217.36	172.94	95.81

4.2.2 Evaluation of the Incremental Demand

The hour-by-hour on demand requirements for electric heating for each dwelling type are calculated using the electric space heating load calculation program (refer to Appendix C). The input to the program are the records of hourly temperature as well as solar radiation data on a horizontal surface. These weather data are obtained from Environment Canada [30]. The other input to the program are the thermal and structural characteristics of the dwelling type. The heating season is assumed to start on October 15 and to end on April 30. The indoor thermostat is assumed to be set at 22°C throughout the day.

The results of the calculations are tabulated in Table 8. Table 8 gives the maximum demand requirements for electric space heating for the different dwellings, on a monthly basis, and for the minimum outside temperature. Again, the energy efficiency of the row house or apartment is evident.

TABLE 8

Maximum Power Requirements for On-Demand
Electrical Space Heating (kW)

Month	Minimum Temperature DEG (C)	Dwelling Type ‡ Single-Detached 1	Semi-Detached & Duplex 2	Row House 3	Apartment 4
JAN	-26.3	12.95	9.79	7.76	4.27
FEB	-23.3	12.66	9.66	7.67	4.23
MAR	-16.1	10.62	8.10	6.43	3.54
APR	-6.8	8.16	6.22	4.93	2.70
MAY	1.2	0.0	0.0	0.0	0.0
JUN	1.9	0.0	0.0	0.0	0.0
JUL	5.7	0.0	0.0	0.0	0.0
AUG	6.4	0.0	0.0	0.0	0.0
SEP	-1.0	0.0	0.0	0.0	0.0
OCT	-3.8	7.20	5.49	4.35	2.39
NOV	-8.3	8.26	6.23	4.94	2.71
DEC	-22.8	12.45	9.44	7.46	4.11

4.2.3 Evaluation of the Total System Demand

With the assumption that 60% of the new housing stock will be electrically heated [5, 7, 21, 32, 33] and with the assumed proportions of the four dwelling types (as described in Chapter III), the total system demand for electric heating were obtained by using the electric load data processing program (refer to Appendix C for the listing of the program). Input to this program consist of the historic hourly loads, the forecast of the number of electrically heated dwellings and the hourly incremental electric space heating demand. From the hourly load description for each day of the study period, typical hourly loads for a week (168 hours) as shown in Figures 18 to 21 are obtained for the base case and for the assumed penetration of electric space heating. Typical load duration curves for the same period are also shown in Figures 22 to 25. Because of space limitation, only these typical hourly load and load duration curves are given.

An hour-by-hour examination of Figures 18 to 21 would indicate that the maximum incremental demand for electric heating occurs from 1 a.m. to 3 a.m., when the ambient temperature is the minumum. This clearly indicates that the weather condition has the most prominent effect on the demand for electric heating.

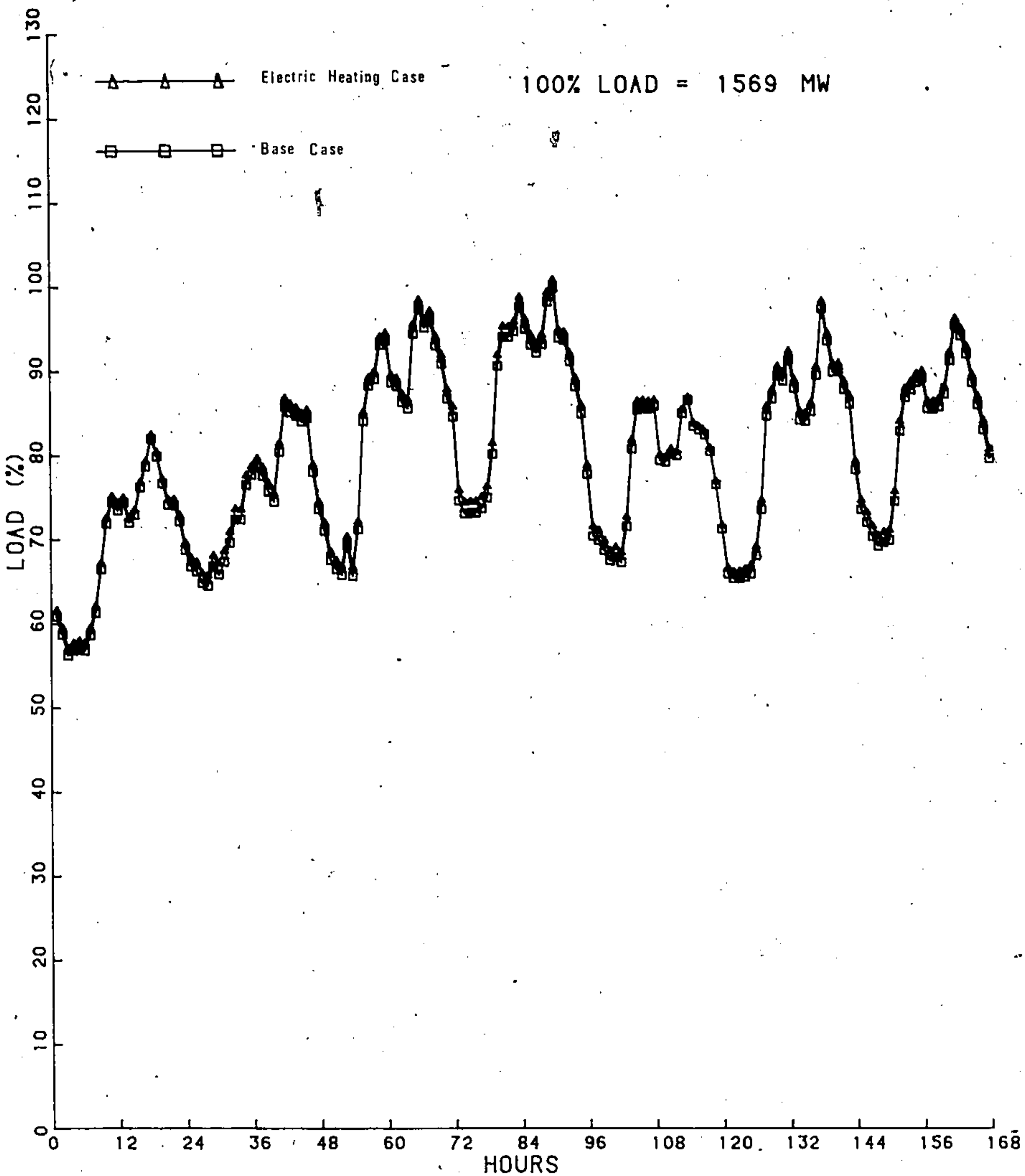

Figure 18: Hourly Demand for the Second Week of December 1981, for 2815 Additional All Electric Dwellings

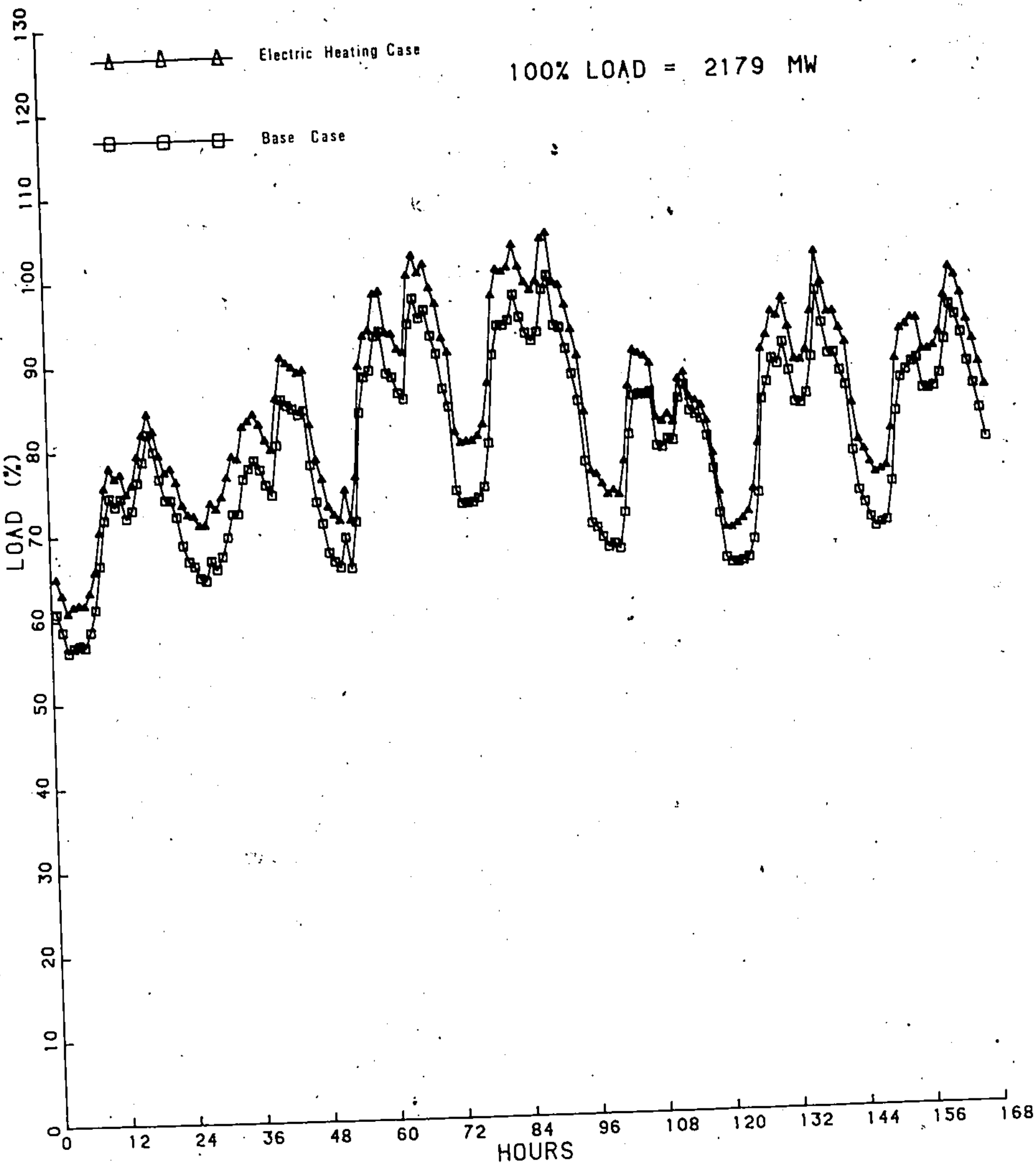

Figure 19: Hourly Demand for the Second Week of December 1990, for 21329 Additional All Electric Dwellings

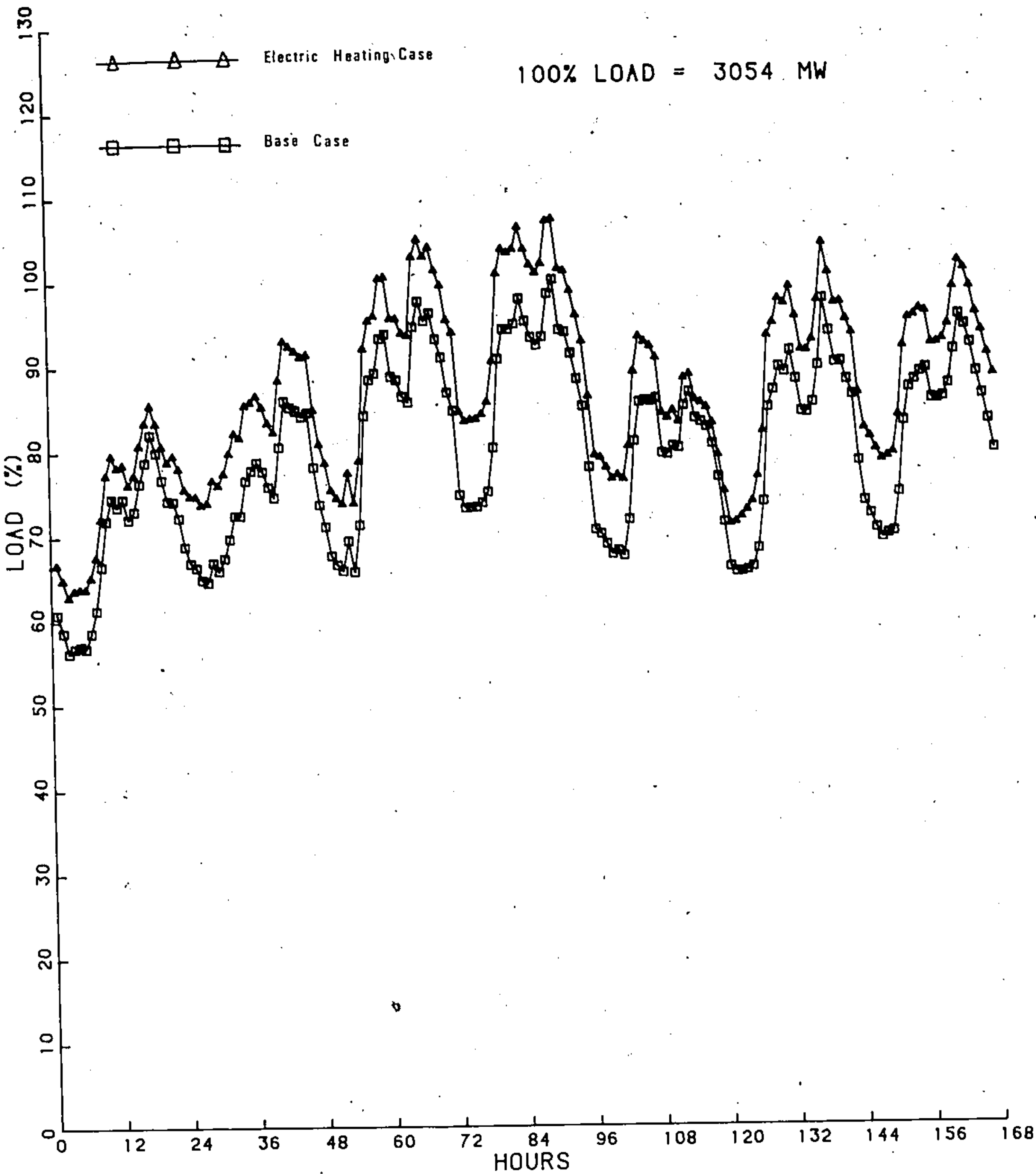

Figure 20: Hourly Demand for the Second Week of December 2000, for 42727 Additional All Electric Dwellings

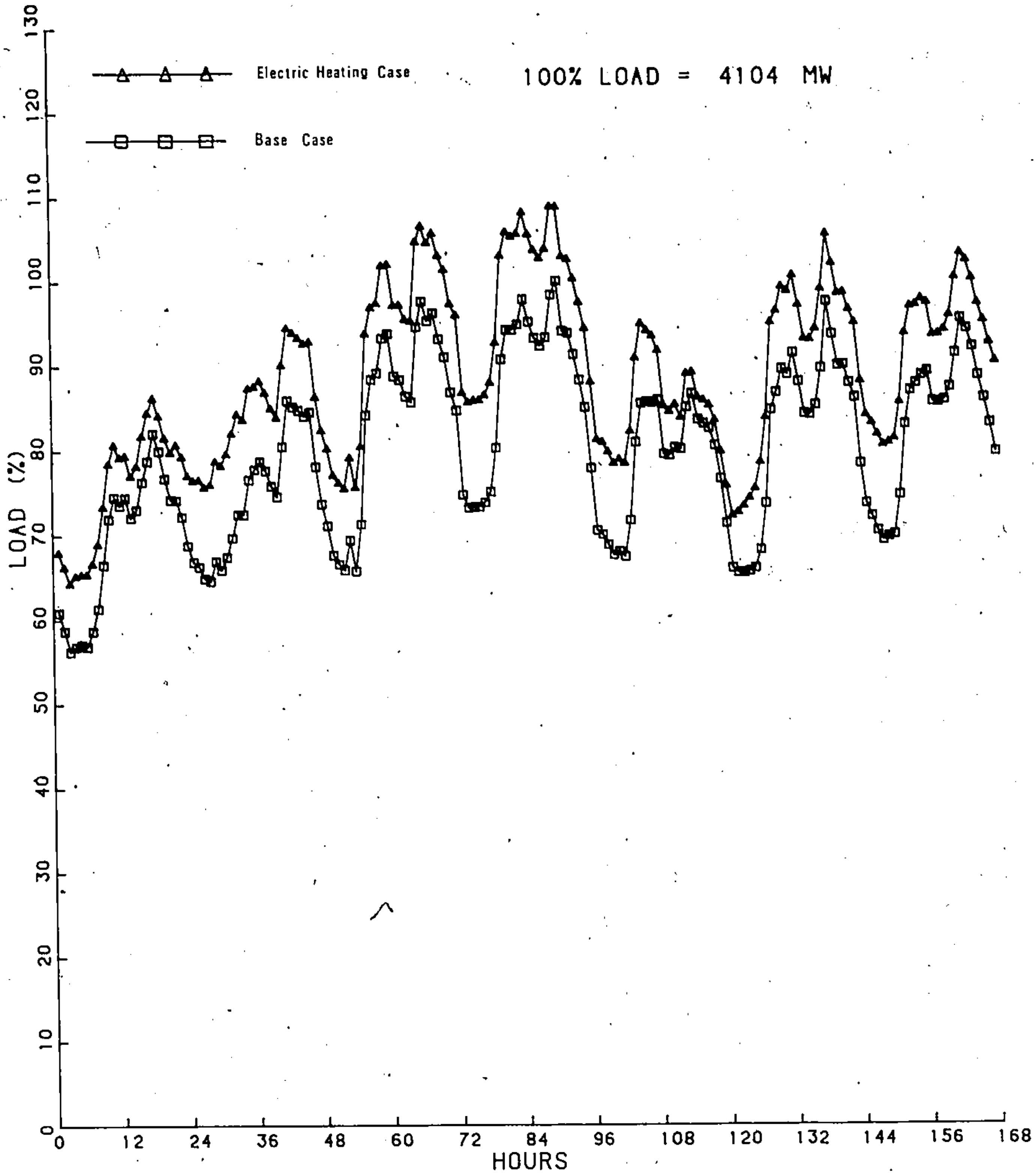

Figure 21: Hourly Demand for the Second Week of December 2010, for 69894 Additional All Electric Dwellings

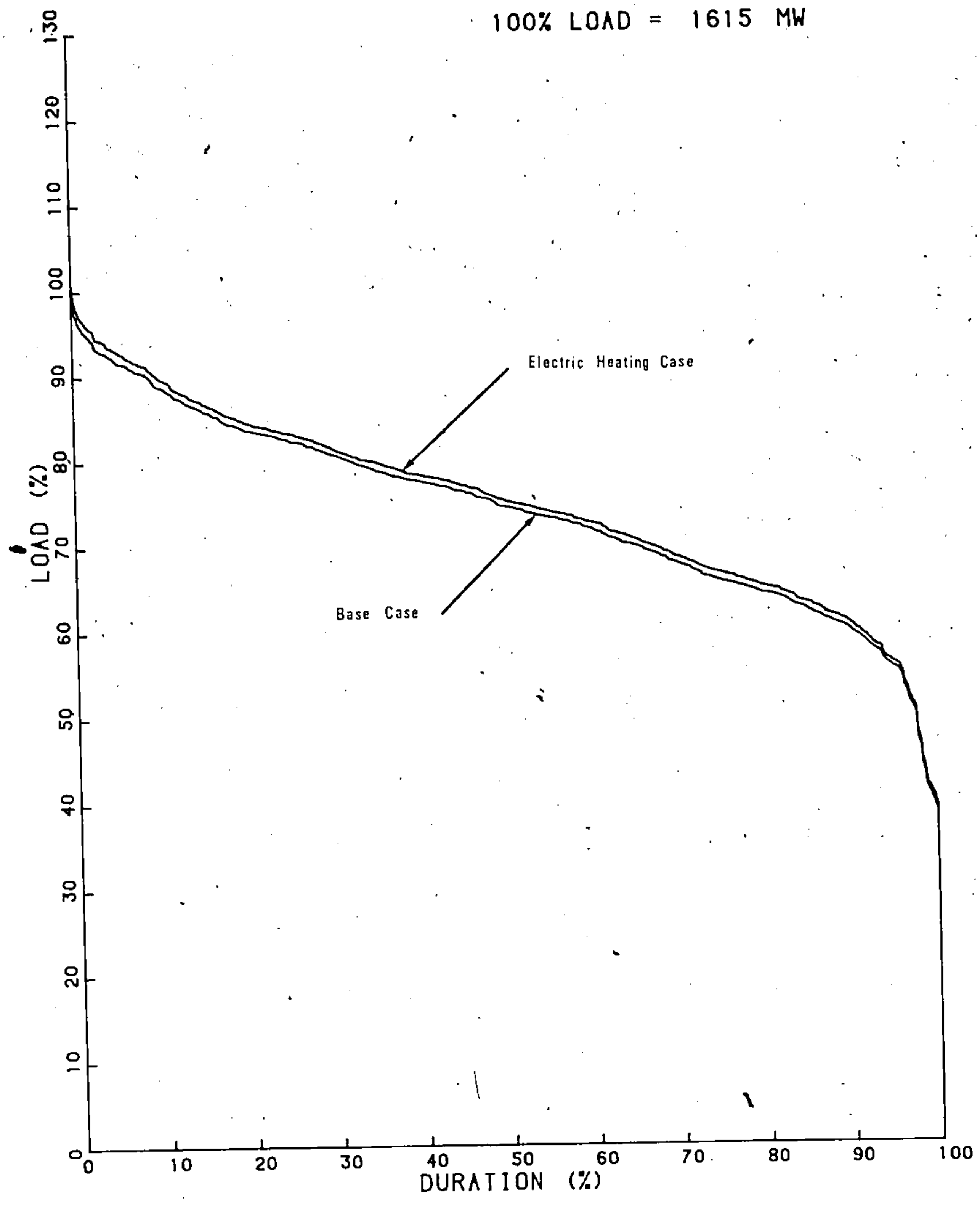

Figure 22: Load Duration Curve for December 1981, for 2815 Additional All Electric Dwellings

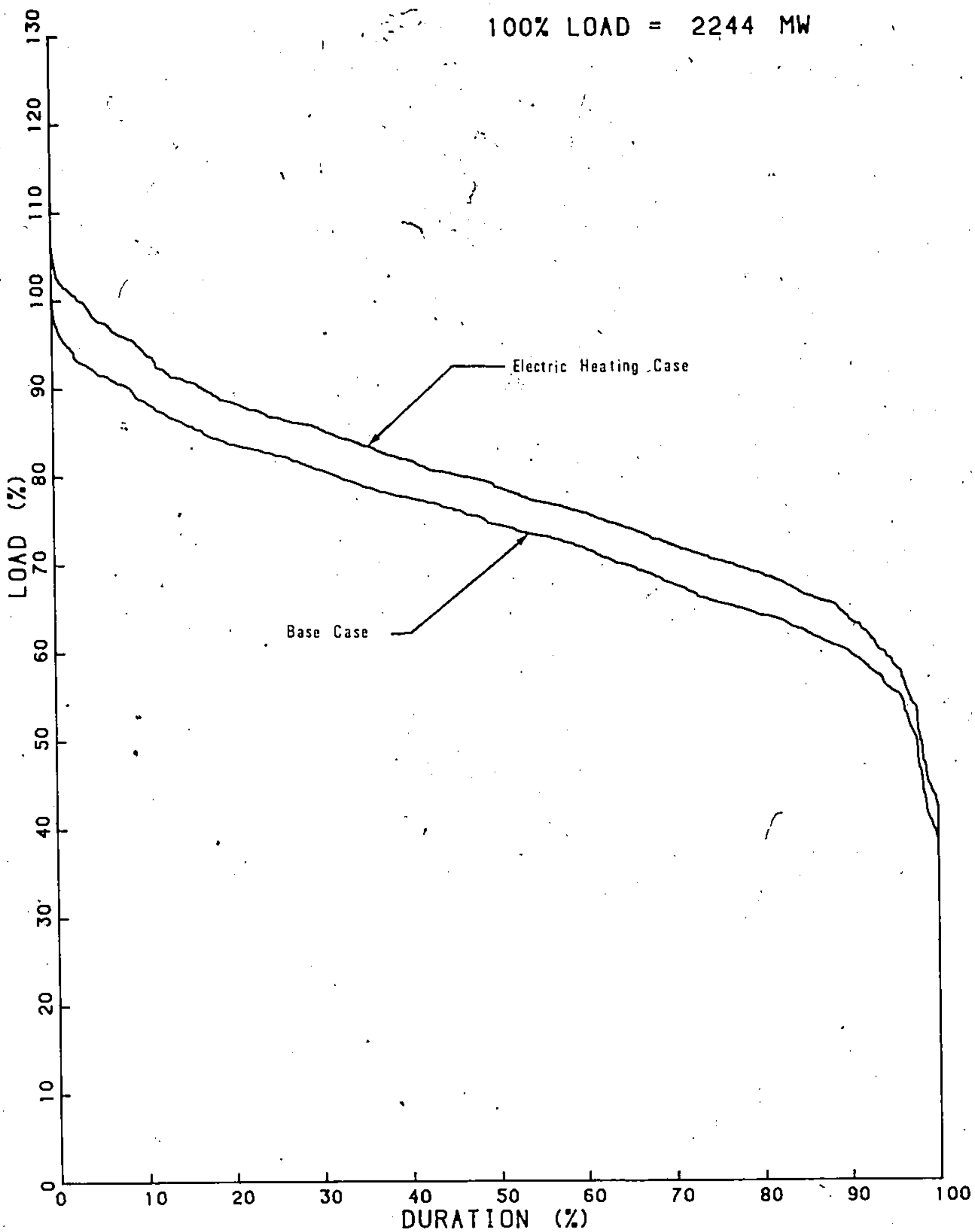

Figure 23: Load Duration Curve for December 1990, for 21329 Additional All Electric Dwellings

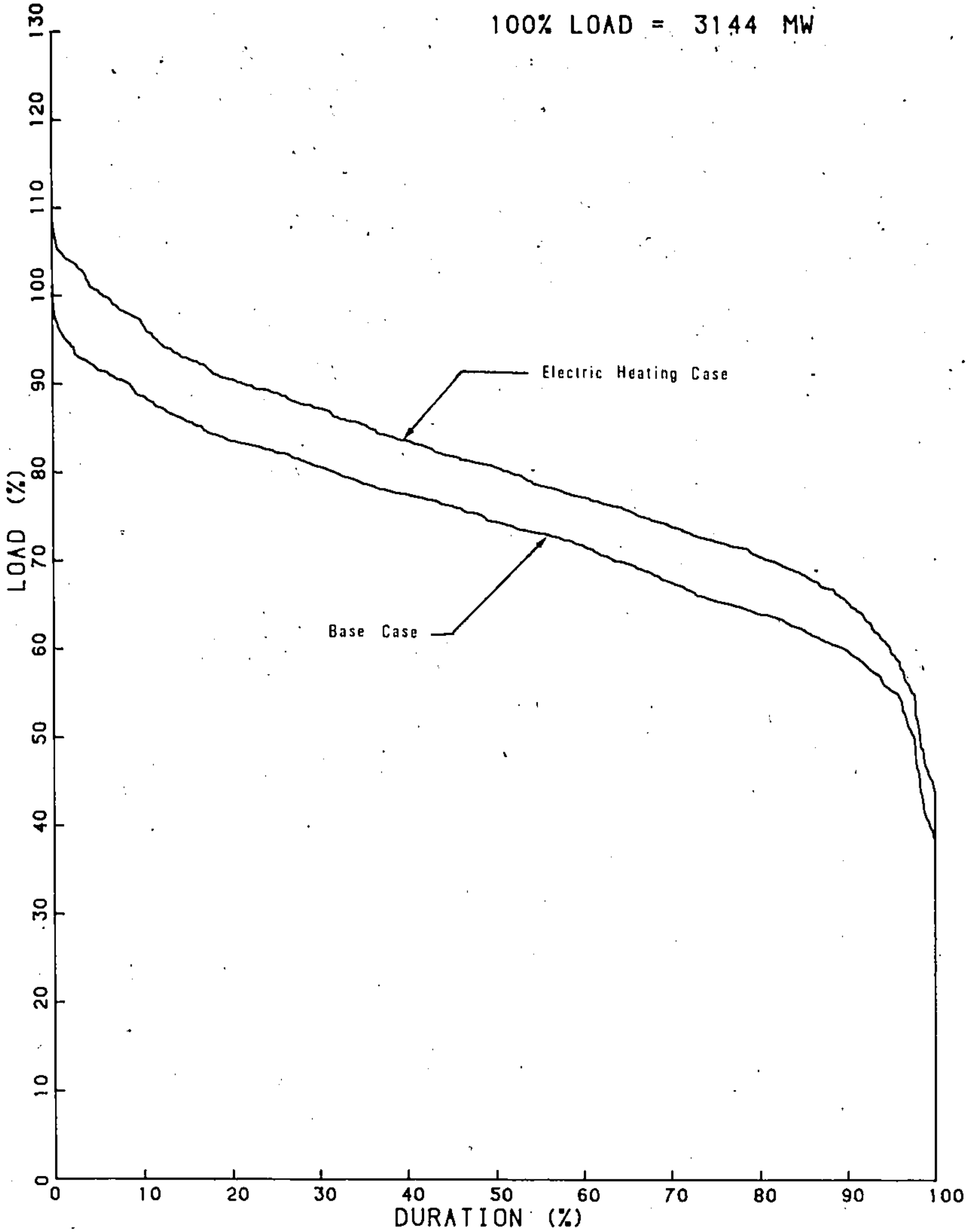

Figure 24: Load Duration Curve for December 2000, for 42727 Additional All Electric Dwellings

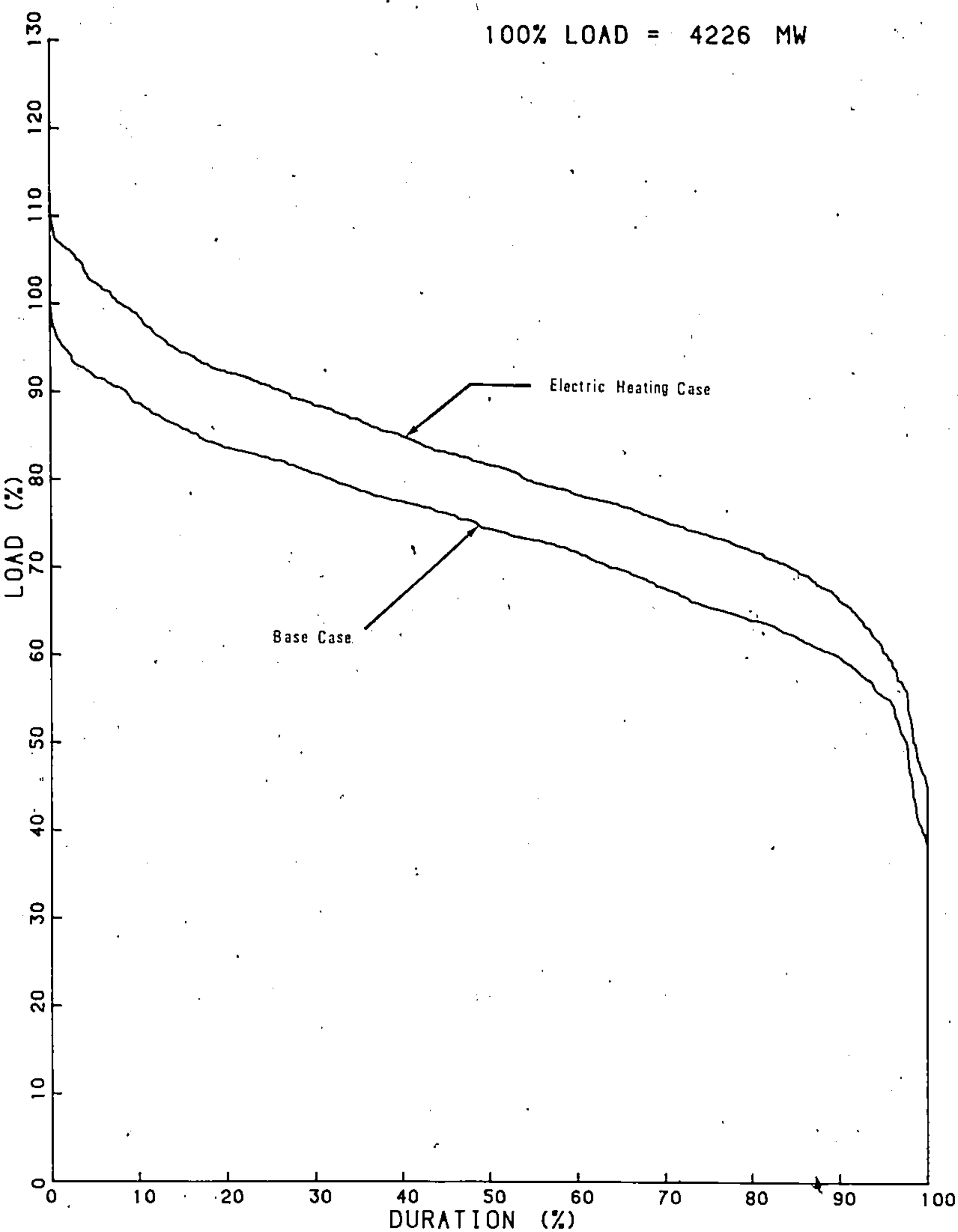

Figure 25: Load Duration Curve for December 2010, for 69894 Additional All Electric Dwellings

4.3 DETERMINATION OF OPTIMAL GENERATION EXPANSION PLAN

Computer runs were made to determine the optimal plan for expansion of the electricity generation system in New Brunswick for the base case and for the electric heating case.

The New Brunswick system is a winter peaking system which has a base capacity of 2141 MW and a peak demand of 1615.3 MW. The percentage mix at the base year (1981) is: Nuclear 0%, Coal 12.2%, Oil 47.7%, Gas 1.1% and Hydro 39.3%. The study period 1981-2010 is divided into two parts: a fixed part comprised of the installed units, the firmly committed units as well as retirements. A variable part in which the mix of generation is chosen from specified expansion candidates. The candidates for expansion are:

Name	Type	Capacity (MW)
N300	Nuclear	300*
N400	Nuclear	400*
C200	Coal	200
C300	Coal	300
C400	Coal	400
HY-1	Hydro	320
HY-2	Hydro	140
HY-3	Hydro	160

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* The nuclear candidates are in reality units of 600 MW and 800 MW of capacity. These nuclear units are to be used for participation sale to the US. Hence only half of the units' capacities are available to N. B. Power.

The LOLP constraint is fixed at LOLP = 0.00027 which corresponds to 0.1 days/year assuming 365 days/year. Additional data loaded into the generation expansion program (WASP) were given in Appendix B.

It should be pointed out that the solution obtained can only be considered as "near optimum", for the real optimum is unobtainable in practice owing to limitations of manpower and time available for the study, and to the fact that approximations are involved in the generation planning program mathematical models.

It should be understood that the results presented here were obtained on the basis of minimum total present-worth cost, without reference to practical considerations such as whether the required financing and manpower could actually be made available.

4.3.1 Results of the Base Case

Details of the optimum expansion schedule are shown in Table 9. Notice that no nuclear additions are required until 1996. A 400 MW nuclear unit is added in 1996. The first and second 300 MW nuclear units are scheduled for 2001 and 2003 respectively. The first coal-fired unit of 400 MW capacity is added in 2006. The second coal-fired unit of 300 MW capacity is scheduled for 2009. The two gas turbines, used mainly for peaking and fine tuning to maintain the reliability criterion are both installed in 2010. Notice also that all the available hydro projects are installed. The final solution calls for a generation mix of 29.6% (1630 MW) nuclear, 23.3% (1280 MW) coal, 18.3% (1005 MW) oil, 2.2% (123 MW) gas turbine and 26.6% (1462 MW) of hydro; with a combined capacity of 5500 MW. Up to the year 2010, the total additions are as follows:

Plant Type	Sets	Capacity per set (MW)
Nuclear	2	300
Nuclear	1	400
Coal	1	300
Coal	1	400
Gas turbine	2	50
Hydro	1	320
Hydro	1	140
Hydro	1	160

The total expenditure for the expansion plan, in terms of 1981 dollars, is $9,434.3 million, of which $2,882.7 million or 30.6% relates to construction costs and $6,551.6 million or 69.4% relates to operating costs.

4.3.2 Results of the Electric Heating Case

Details of the optimum expansion schedule for the electric heating case are given in Table 10. Notice that the number of nuclear units installed has increased from three to five. The first nuclear unit is scheduled for 1993; three years earlier than the first base case nuclear unit. The two gas turbines, instead of both units installed in 2010 as in the base case, are scheduled for 1992 and 2003. Notice again that all available hydro projects are installed. Notice also that only one coal-fired unit of 400 MW capacity is installed. The final solution calls for a generation mix of 42.2% (2630 MW) nuclear, 15.8% (980 MW) coal, 16.2% (1005 MW) oil, 2% (123 MW) gas turbine and 23.6% (1462 MW) of hydro; strongly in favor of nuclear expansion. The installed capacity in the year 2010 is 6200 MW; 700 MW greater than for the base case. The total additions up to the year 2010 is as follows:

Plant Type	Sets	Capacity per set (MW)
Nuclear	5	400
Coal	1	400
Gas turbine	2	50
Hydro	1	320
Hydro	1	140
Hydro	1	160

The total expenditure for this expansion plan, in terms of 1981 dollars, is $10,572.6 million, of which $4,385.3 million or 41.5% relates to construction costs and $6,187.3 million or 58.5% relates to operating costs. The increase in total expenditure over the base case is $1,138.30 million.

TABLE 9

Optimal Expansion Plan for the Base Case

Year	Peak Load (MW)	Units Installed N300	N400	C200	C300	C400	GT50	VHYD	Installed Capacity (MW)	Reserve Margin (%)	Total Expenditure (1,000,000$) Per Year	Cumulative
1981	1615								2141	32.6	208.9	208.9
1982	1684								2541	50.9	139.4	348.4
1983	1755								2541	44.8	159.4	507.8
1984	1813								2541	40.2	167.1	674.9
1985	1881								2541	35.1	179.2	854.1
1986	1949								2739	40.5	204.1	1058.3
1987	2021								2940	45.5	281.3	1339.6
1988	2095								2918	39.3	268.8	1608.4
1989	2174							1	3238	48.9	243.7	1852.0
1990	2244								3238	44.3	320.7	2172.7
1991	2317								3458	49.2	337.1	2509.8
1992	2393								3458	44.5	428.0	2937.8
1993	2472								3443	39.3	350.3	3288.1
1994	2558								3643	42.4	335.1	3623.2
1995	2648								3643	37.6	295.8	3919.0
1996	2740		1						4021	46.8	311.4	4230.4
1997	2836								4021	41.8	349.4	4579.8
1998	2935								4021	37.0	484.3	5064.1
1999	3038								4221	38.9	427.8	5491.9
2000	3144								4221	34.3	442.2	5934.1
2001	3239	1							4473	38.1	355.6	6289.7
2002	3336								4473	34.1	398.4	6688.1
2003	3436	1							4773	38.9	450.8	7138.8
2004	3539								4716	33.3	396.5	7535.3
2005	3645							1	4846	32.9	371.6	7906.9
2006	3755					1			5147	37.1	357.3	8264.3
2007	3867							1	5205	34.6	306.6	8570.8
2008	3983								5205	30.7	286.4	8857.2
2009	4103				1				5400	31.6	289.0	9146.2
2010	4226						2		5500	30.1	288.1	9434.3
	Total	2	1	0	1	1	2	3				

TABLE 10

Optimal Expansion Plan for the Electric Heating Case

Year	Peak Load (MW)	Units Installed N300	N400	C200	C300	C400	GT50	VHYD	Installed Capacity (MW)	Reserve Margin (%)	Total Expenditure (1,000,000$) Per Year	Cumulative
1981	1633								2141	31.1	210.7	210.7
1982	1719								2541	47.8	134.9	345.6
1983	1805								2541	40.8	157.7	503.3
1984	1876								2541	35.4	172.9	676.3
1985	1958								2541	29.8	222.5	898.8
1986	2039								2739	34.3	292.6	1191.4
1987	2123								2940	38.5	330.4	1521.8
1988	2210							1	3238	46.5	347.6	1869.4
1989	2300								3238	40.8	463.7	2333.2
1990	2381								3238	36.0	397.2	2730.4
1991	2466								3458	40.2	405.2	3135.6
1992	2553						1		3508	37.4	385.7	3521.4
1993	2645		1						3893	47.2	400.4	3921.8
1994	2744								4093	49.2	296.7	4218.5
1995	2848								4093	43.7	292.1	4510.6
1996	2954								4071	37.8	267.2	4777.8
1997	3065		1						4471	45.9	224.4	5002.2
1998	3179								4471	40.6	367.5	5369.7
1999	3297								4671	41.7	495.8	5865.4
2000	3419								4671	36.6	629.1	6494.6
2001	3530							1	4763	34.9	587.6	7082.2
2002	3647							1	4923	35.0	680.3	7762.4
2003	3767						1		4973	32.0	622.8	8385.2
2004	3891		1						5316	36.6	468.8	8854.0
2005	4017								5306	32.1	443.4	9297.4
2006	4147		1						5607	35.2	366.9	9664.3
2007	4274		1						5905	38.2	263.1	9927.4
2008	4404								5905	34.1	215.4	10142.8
2009	4538					1			6200	36.6	208.2	10351.0
2010	4676								6200	32.6	221.6	10572.6
Total		0	5	0	0	1	2	3				

4.3.3 Sensitivity Studies

To investigate the influence of the variation of several parameters on the optimum solution, a series of sensitivity studies were made. The parameters varied are (i) construction costs, (ii) discount rates, (iii) fuel cost escalation rates, and (iv) the load growth rate.

In designing cases for the sensitivity studies, parameters are varied so that the tendency would be to disfavor nuclear expansion. This is done for the following reasons. The base case called for expansion by three nuclear units. It is obvious that, since the base case already strongly favors nuclear expansion, any changes in the parameters that favors nuclear expansion more strongly will not result in a substantial change from the results of the base case, although some minor changes in the expansion plan may occur. It is, however, interesting to see if any other types of generating units are adopted when parameters are changed to the direction of disfavoring nuclear expansion.

The following cases will be considered:

Case	Description
S1	Higher construction costs for nuclear units.
S2	Higher discount rates.
S3	Higher fuel cost escalation rate for nuclear units.
S4	Higher peak load growth rate.
S5	Lower peak load growth rate.

4.3.3.1 Sensitivity to Higher Construction Cost for Nuclear Units

To test for changes in the construction cost for nuclear units, the relevant cost figure was raised by 10% as follows:

Plant	Construction Cost ($/kW) Base Case	10% increase
N300	1416.7	1558.4
N400	1328.1	1460.9

Consequently, the number of nuclear units decreased from three to two, while the number of coal-fired units increased from two to three. The 300 MW nuclear unit added in 2003 in the base case is replaced by a 300 MW coal-fired unit in the same year. The 400 MW coal-fired unit scheduled for 2006 in the base case is delayed one year, while the 160 MW hydro unit scheduled for 2007 in the base case is installed one year earlier. The installation date for the first nuclear unit remained 1996.

The results are summarized in Table 11. The optimal solution for this case calls for a generation mix of 24.2% (1330 MW) nuclear, 28.7% (1580 MW) coal, 18.3% (1005 MW) oil, 2.2% (123 MW) gas turbine and 26.6% (1462 MW) of hydro; with a combined capacity of 5500 MW.

4.3.3.2, Sensitivity to Higher Discount Rate

To test for the effect of higher discount rate on the optimum solution, the discount rate is increased from 13% to 16%. The results was summarized in Table 12. The final mix of generation consists of 29.6% (1630 MW) nuclear, 23.3% (1280 MW) coal, 18.3% (1005 MW) oil, 2.2% (123 MW) gas turbine and 26.6% (1462 MW) of hydro; which is identical to the base case. The difference between the two expansion plans is that the 400 MW coal-fired unit scheduled for 2006 in the base case is now delayed one year, while the 160 MW hydro unit scheduled for 2007 in the base case is installed one year earlier. This small difference between the two expansion plans indicates that the solution is quite stable to the changes in discount rate.

One would normally expect that if the cost of money increases, the nuclear units, with their higher capital cost, will become less competitive. This is apparently not the case for the New Brunswick system, indicating that the system is strongly in favor of nuclear expansion.

TABLE 11

Optimal Expansion Plan for Case S1

Year	Peak Load (MW)	Units Installed N300	N400	C200	C300	C400	GT50	VHYD	Installed Capacity (MW)	Reserve Margin (%)	Total Expenditure (1,000,000$) Per Year	Cumulative
1981	1615								2141	32.6	208.9	208.9
1982	1684								2541	50.9	139.4	348.4
1983	1755								2541	44.8	159.4	507.8
1984	1813								2541	40.2	167.1	674.9
1985	1881								2541	35.1	179.2	854.1
1986	1949								2739	40.5	204.1	1058.3
1987	2021								2940	45.5	281.3	1339.6
1988	2095								2918	39.3	272.3	1611.9
1989	2174							1	3238	48.9	248.6	1860.4
1990	2244								3238	44.3	334.1	2194.5
1991	2317								3458	49.2	357.1	2551.6
1992	2393								3458	44.5	459.6	3011.2
1993	2472								3443	39.3	368.0	3379.2
1994	2558								3643	42.4	351.4	3730.6
1995	2648								3643	37.6	304.0	4034.6
1996	2740		1						4021	46.8	309.0	4343.6
1997	2836								4021	41.8	343.7	4687.3
1998	2935								4021	37.0	430.8	5118.1
1999	3038								4221	38.9	396.7	5514.8
2000	3144								4221	34.3	369.7	5884.5
2001	3239	1							4473	38.1	309.3	6193.8
2002	3336								4473	34.1	341.7	6535.4
2003	3436				1				4773	38.9	450.1	6985.6
2004	3539								4716	33.3	498.6	7484.1
2005	3645							1	4846	32.9	437.1	7921.2
2006	3755							1	4907	30.7	396.8	8318.0
2007	3867					1			5205	34.6	331.7	8649.7
2008	3983								5205	30.7	311.8	8961.5
2009	4103				1				5400	31.6	310.5	9272.1
2010	4226						2		5500	30.1	316.4	9588.4
	Total	1	1	0	2	1	2	3				

TABLE 12

Optimal Expansion Plan for Case S2

Year	Peak Load (MW)	Units Installed N300	N400	C200	C300	C400	GT50	VHYD	Installed Capacity (MW)	Reserve Margin (%)	Total Expenditure (1,000,000$) Per Year	Cumulative
1981	1615								2141	32.6	208.9	208.9
1982	1684								2541	50.9	139.4	348.4
1983	1755								2541	44.8	159.4	507.8
1984	1813								2541	40.2	167.1	674.9
1985	1881								2541	35.1	179.2	854.1
1986	1949								2739	40.5	204.7	1058.9
1987	2021								2940	45.5	283.1	1342.0
1988	2095								2918	39.3	272.8	1614.8
1989	2174							1	3238	48.9	247.9	1862.6
1990	2244								3238	44.3	330.7	2193.3
1991	2317								3458	49.2	349.2	2542.5
1992	2393								3458	44.5	442.5	2985.0
1993	2472								3443	39.3	356.4	3341.4
1994	2558								3643	42.4	340.1	3681.5
1995	2648								3643	37.6	300.1	3981.6
1996	2740		1						4021	46.8	322.8	4304.4
1997	2836								4021	41.8	361.3	4665.7
1998	2935								4021	37.0	501.9	5167.6
1999	3038								4221	38.9	438.3	5605.9
2000	3144								4221	34.3	434.9	6040.8
2001	3239	1							4473	38.1	343.1	6383.9
2002	3336								4473	34.1	352.3	6736.2
2003	3436	1							4773	38.9	438.2	7174.3
2004	3539								4716	33.3	484.7	7659.0
2005	3645							1	4846	32.9	410.4	8069.4
2006	3755							1	4907	30.7	390.1	8459.5
2007	3867					1			5205	34.6	308.4	8767.9
2008	3983								5205	30.7	286.8	9054.7
2009	4103				1				5400	31.6	289.2	9343.8
2010	4226						2		5500	30.1	288.1	9631.9
	Total	2	1	0	1	1	2	3				

4.3.3.3 Sensitivity to Higher Fuel Cost Escalation Rate for Nuclear Units

In this case, the fuel cost escalation rate for nuclear units is increased from 10% to 12% to disfavor nuclear generation. Since only the escalation rate of nuclear fuel is varied without changing the basic cost value, the disadvantage to nuclear power grows stronger as time progresses. The results for this case were summarized in Table 13. Notice that this change in nuclear fuel escalation rate from 10% to 12% causes a major shift towards coal-fired expansion. The 300 MW nuclear units scheduled for 2001 and 2003 in the base case are now replaced by the 300 MW coal-fired units in the respective year. The final mix of generation consists of 18.7% (1030 MW) nuclear, 34.2% (1880 MW) coal, 18.3% (1005 MW) oil, 2.2% (123 MW) gas turbine and 26.6% (1462 MW) of hydro. The sensitivity of the expansion plan to fuel cost escalation rate emphasizes the importance of accurate fuel costs prediction.

4.3.3.4 Sensitivity to Higher Peak Load Growth Rate

To investigate the effect of higher peak load growth rate, the peak load growth rate is increased from its base value by 0.5%. The optimal expansion plan for this case is shown in Table 14. The amount of installed capacity required in the year 2010 is 850 MW greater than for the base case; indicating that the amount of additional capacity installed is very sensitive to the higher peak load growth. The final solution calls for a generation mix of 41.4% (2630 MW) nuclear, 18.6% (1180 MW) coal, 15.8% (1005 MW) oil, 1.2% (73 MW) gas turbine and 23.0% (1462 MW) of hydro. The cash flow in this case differs considerably from the base case. The cash flow increases by 16.2% from the base case. The strong effect of higher peak load growth rate emphasizes the importance of load forecasting for system expansion planning.

4.3.3.5 Sensitivity to Lower Peak Load Growth Rate

The peak load growth rate is decreased from its base value by 0.5% for this case. The results were summarized as shown in Table 15. The amount of installed capacity required for the year 2010 is 660 MW lower than for the base case. Only one nuclear unit is installed; its installation date is delayed by 8 years until 2004. Three coal-fired units are installed; one of 200 MW capacity; the other of 300 MW capacity. Only two hydro units are installed out of the three available. The mix of generation consists of 21.3% (1030 MW) nuclear, 28.5% (1380 MW) coal, 20.8% (1005 MW) oil, 2.5% (123 MW) gas turbine and 26.9% (1302 MW) of hydro. Again, the cash flow differs considerably from the base case. Cash flow decreases 10.1% when the peak load growth rate decreases 0.5%. Again, this strong effect of lower peak load growth rate on the optimum expansion plan emphasizes the importance of load forecasting.

4.3.3.6 Comparison of the 7 Cases

A comparison of the mix of generation, installed capacities and total expenditure of the 7 cases is given in Table 16.

TABLE 13

Optimal Expansion Plan for Case S3

Year	Peak Load (MW)	Units Installed N300	N400	C200	C300	C400	GT50	VHYD	Installed Capacity (MW)	Reserve Margin (%)	Total Expenditure (1,000,000$) Per Year	Cumulative
1981	1615								2141	32.6	208.9	208.9
1982	1684								2541	50.9	139.4	348.4
1983	1755								2541	44.8	159.4	507.8
1984	1813								2541	40.2	167.1	674.9
1985	1881								2541	35.1	179.2	854.1
1986	1949								2739	40.5	204.1	1058.3
1987	2021								2940	45.5	281.3	1339.6
1988	2095								2918	39.3	268.8	1608.4
1989	2174							1	3238	48.9	243.7	1852.0
1990	2244								3238	44.3	320.7	2172.7
1991	2317								3458	49.2	337.1	2509.8
1992	2393								3458	44.5	428.0	2937.8
1993	2472								3443	39.3	350.3	3288.1
1994	2558								3643	42.4	317.2	3605.3
1995	2648								3643	37.6	273.2	3878.5
1996	2740		1						4021	46.8	215.5	4094.0
1997	2836								4021	41.8	282.2	4376.2
1998	2935								4021	37.0	346.8	4723.0
1999	3038								4221	38.9	354.8	5077.8
2000	3144								4221	34.3	362.1	5439.9
2001	3239				1				4473	38.1	330.9	5770.8
2002	3336								4473	34.1	364.0	6134.8
2003	3436				1				4773	38.9	482.8	6617.6
2004	3539								4716	33.3	525.0	7142.6
2005	3645							1	4846	32.9	454.1	7596.8
2006	3755							1	4907	30.7	427.3	8024.0
2007	3867					1			5205	34.6	411.1	8435.4
2008	3983								5205	30.7	341.0	8776.4
2009	4103				1				5400	31.6	389.6	9166.0
2010	4226						2		5500	30.1	396.6	9562.6
Total		0	1	0	3	1	2	3				

TABLE 14

Optimal Expansion Plan for Case S4

Year	Peak Load (MW)	Units Installed N300	N400	C200	C300	C400	GT50	VHYD	Installed Capacity (MW)	Reserve Margin (%)	Total Expenditure (1,000,000$) Per Year	Cumulative
1981	1615								2141	32.6	208.9	208.9
1982	1691								2541	50.3	140.9	349.8
1983	1771								2541	43.5	162.5	512.3
1984	1838								2541	38.2	171.5	683.8
1985	1915								2541	32.7	221.1	904.9
1986	1996								2739	37.2	292.8	1197.7
1987	2077								2940	41.6	356.4	1554.1
1988	2164							1	3238	49.6	341.4	1895.5
1989	2258								3238	43.4	474.2	2369.6
1990	2341								3238	38.3	399.2	2768.9
1991	2430								3458	42.3	404.7	3173.6
1992	2523								3458	37.1	393.2	3566.8
1993	2619		1						3843	46.7	432.1	3998.9
1994	2723								4043	48.5	343.3	4342.2
1995	2832								4043	42.8	391.6	4733.8
1996	2946								4021	36.5	400.0	5133.8
1997	3063		1						4421	44.3	439.1	5572.9
1998	3186								4421	38.8	447.5	6020.4
1999	3313								4621	39.5	484.5	6504.8
2000	3446								4621	34.1	608.2	7113.1
2001	3566		1						4973	39.5	536.5	7649.6
2002	3691								4973	34.7	569.1	8218.6
2003	3820							1	5113	33.8	418.1	8636.7
2004	3954		1						5456	38.0	426.9	9063.7
2005	4093								5446	33.1	469.6	9533.3
2006	4236		1						5747	35.7	379.0	9912.4
2007	4384							1	5805	32.4	288.5	10200.9
2008	4537				1				6105	34.6	244.6	10445.4
2009	4696				1				6300	34.2	253.1	10698.6
2010	4861						1		6350	30.6	266.7	10965.3
Total		0	5	0	2	0	1	3				

TABLE 15

Optimal Expansion Plan for Case S5

Year	Peak Load (MW)	Units Installed N300	N400	C200	C300	C400	GT50	VHYD	Installed Capacity (MW)	Reserve Margin (%)	Total Expenditure (1,000,000$) Per Year	Cumulative
1981	1615								2141	32.6	208.9	208.9
1982	1675								2541	51.7	137.8	346.7
1983	1737								2541	46.3	155.8	502.6
1984	1786								2541	42.3	162.4	665.0
1985	1843								2541	37.9	172.6	837.5
1986	1902								2739	44.0	175.8	1013.3
1987	1961								2940	49.9	204.3	1217.7
1988	2024								2918	44.2	234.1	1451.7
1989	2090								2918	39.6	294.5	1746.2
1990	2147								2918	35.9	304.9	2051.1
1991	2207						1		3188	44.4	217.3	2268.4
1992	2269			1					3398	49.3	198.9	2467.3
1993	2332								3373	44.6	211.3	2678.6
1994	2402								3573	48.8	213.8	2892.4
1995	2474								3573	44.4	280.9	3173.4
1996	2548								3551	39.4	283.4	3456.8
1997	2625							1	3871	47.5	258.8	3715.6
1998	2704								3871	43.2	329.8	4045.5
1999	2785								4071	46.2	364.9	4410.3
2000	2868								4071	41.9	468.4	4878.8
2001	2940								4023	36.8	404.2	5282.9
2002	3013								4023	33.5	437.7	5720.6
2003	3089						1		4073	31.9	431.8	6152.4
2004	3166		1						4416	39.5	377.3	6529.6
2005	3245								4406	35.8	419.9	6949.5
2006	3326				1				4607	38.5	378.9	7328.4
2007	3409							1	4645	36.3	314.2	7642.6
2008	3495								4645	32.9	282.2	7924.9
2009	3582				1				4840	35.1	270.7	8195.5
2010	3672								4840	31.8	285.6	8481.2
Total		0	1	1	2	0	2	2				

TABLE 1.6

Comparison of the 7 Cases

Case	Installed Capacity (MW)	% Mix of Generation Nuclear	Coal	Oil	Gas	Hydro	Total Expenditure ($1,000,000)
Base	5500	29.6	23.3	18.3	2.2	26.6	9434.3
Electric Heating	6200	42.2	15.8	16.2	2.0	23.6	10572.6
S1	5500	24.2	28.7	18.3	2.2	26.6	9588.4
S2	5500	29.6	23.3	18.3	2.2	26.6	9631.9
S3	5500	18.7	34.2	18.3	2.2	26.6	9562.6
S4	6350	41.4	18.6	15.8	1.2	23.0	10965.3
S5	4840	21.3	28.5	20.8	2.5	26.9	8481.2

4.4 DETERMINATION OF INCREMENTAL IMPACT OF ELECTRIC HEATING

From the results of the optimal generation expansion plan for the base case and for the electric heating case, many useful comparisons can be made. From these comparisons, the incremental impact of electric heating in terms of system demand, generation capacity, primary fuel consumption and financial requirement may be evaluated.

4.4.1 Impact on System Demand

Table 17 describes the impact of the assumed penetration of residential space heating on the peak load. Clearly, as the number of electric heating dwellings increases, so do the peak load on the system. Notice that the increase in the peak load in the year 2010 is 450 MW or 10.6% over the base case. The results were further summarized graphically as shown in Figure 26.

4.4.1.1 Load Factors

The load factors for the base case and the electric heating case were summarized in Table 18 and graphically in Figure 27. The load factors for the base case were 64.15% in 1981 and 65.65% in 2010. For the electric heating case, the load factors were 63.8% in 1981 and 62.63% in 2010. Notice that only a slight deterioration of the system load factor has been effected. This is due to the fact that the New Brunswick system is already a winter peaking system, adding additional winter loads will not significantly change the load characteristics of the system. However, if a summer peaking system were considered, a much greater deterioration of the system load factor could be expected. Nevertheless, this deterioration of the system load factor is one of the penalties associated with the increased utilization of electric space heating.

TABLE 17

Summary of Peak Loads

Year	Additional Electric Dwellings	Peak Load (MW) Base Case	Electric Heat
1981	2815	1615	1633
1982	5418	1684	1719
1983	7701	1755	1805
1984	9789	1813	1876
1985	11916	1881	1958
1986	14001	1949	2039
1987	15944	2021	2123
1988	17840	2095	2210
1989	19569	2174	2300
1990	21329	2244	2381
1991	23125	2317	2466
1992	24956	2393	2553
1993	26904	2472	2645
1994	28940	2558	2744
1995	31069	2648	2848
1996	33284	2740	2954
1997	35569	2836	3065
1998	37915	2935	3179
1999	40275	3038	3297
2000	42727	3144	3419
2001	45195	3239	3530
2002	48324	3336	3647
2003	51445	3436	3767
2004	54608	3539	3891
2005	57760	3645	4017
2006	60958	3755	4147
2007	63183	3867	4274
2008	65416	3983	4404
2009	67637	4103	4538
2010	69894	4226	4676

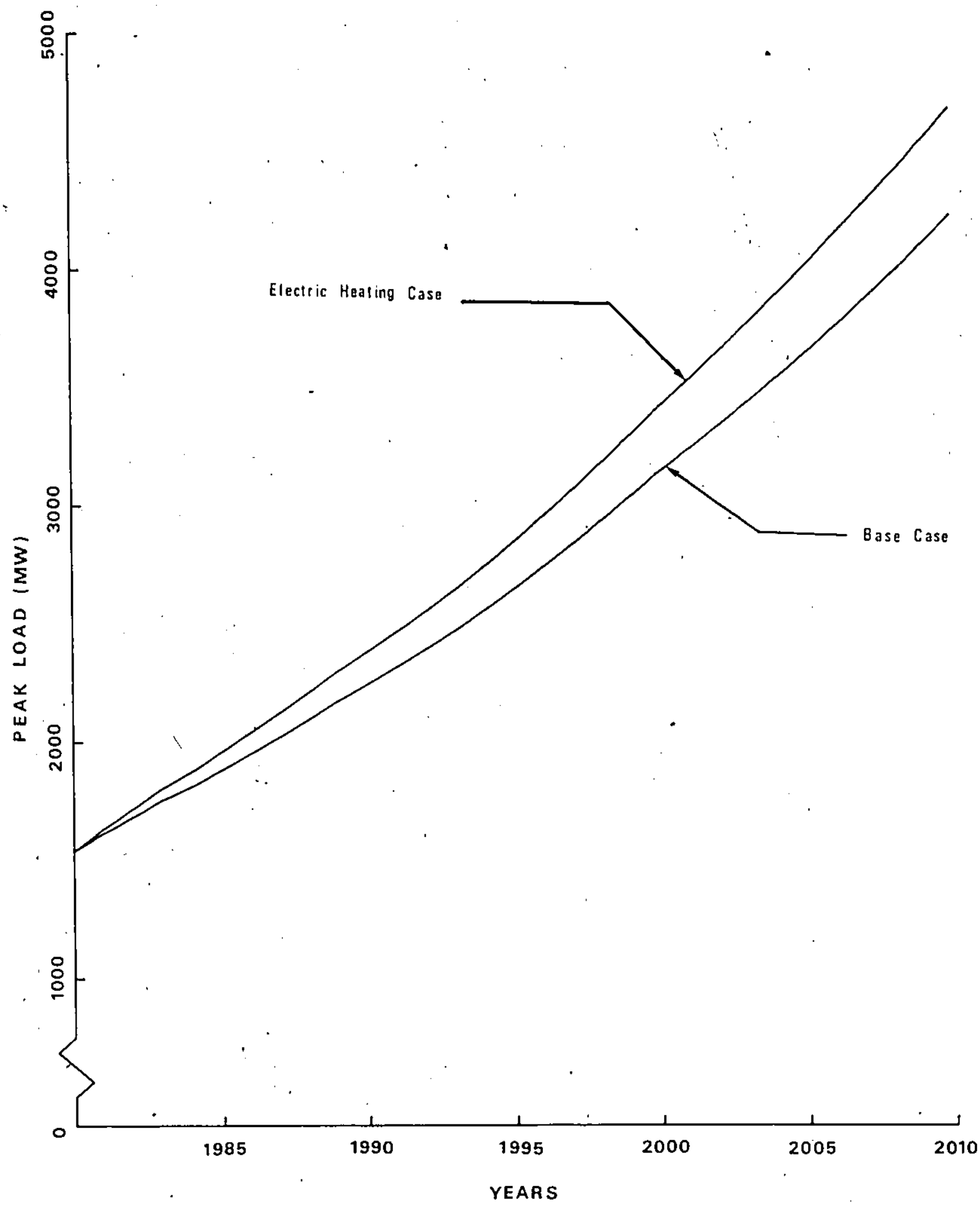

Figure 26: Peak Loads During Study Peaiod

TABLE 18

Summary of Load Factors

Year	Additional Electric Dwellings	Load Factor (%) Base Case	Electric Heat
1981	2815	64.15	63.80
1982	5418	64.25	63.63
1983	7701	64.44	63.60
1984	9789	64.79	63.75
1985	11916	64.87	63.66
1986	14001	65.05	63.68
1987	15944	65.18	63.67
1988	17840	65.27	63.65
1989	19569	65.34	63.63
1990	21329	65.43	63.63
1991	23125	65.51	63.62
1992	24956	65.59	63.61
1993	26904	65.65	63.59
1994	28940	65.65	63.51
1995	31069	65.65	63.44
1996	33284	65.65	63.37
1997	35569	65.65	63.30
1998	37915	65.65	63.24
1999	40275	65.65	63.18
2000	42727	65.65	63.12
2001	45195	65.65	63.05
2002	48324	65.65	62.97
2003	51445	65.65	62.88
2004	54608	65.65	62.81
2005	57760	65.65	62.74
2006	60958	65.65	62.68
2007	63183	65.65	62.66
2008	65416	65.65	62.64
2009	67637	65.65	62.63
2010	69894	65.65	62.63

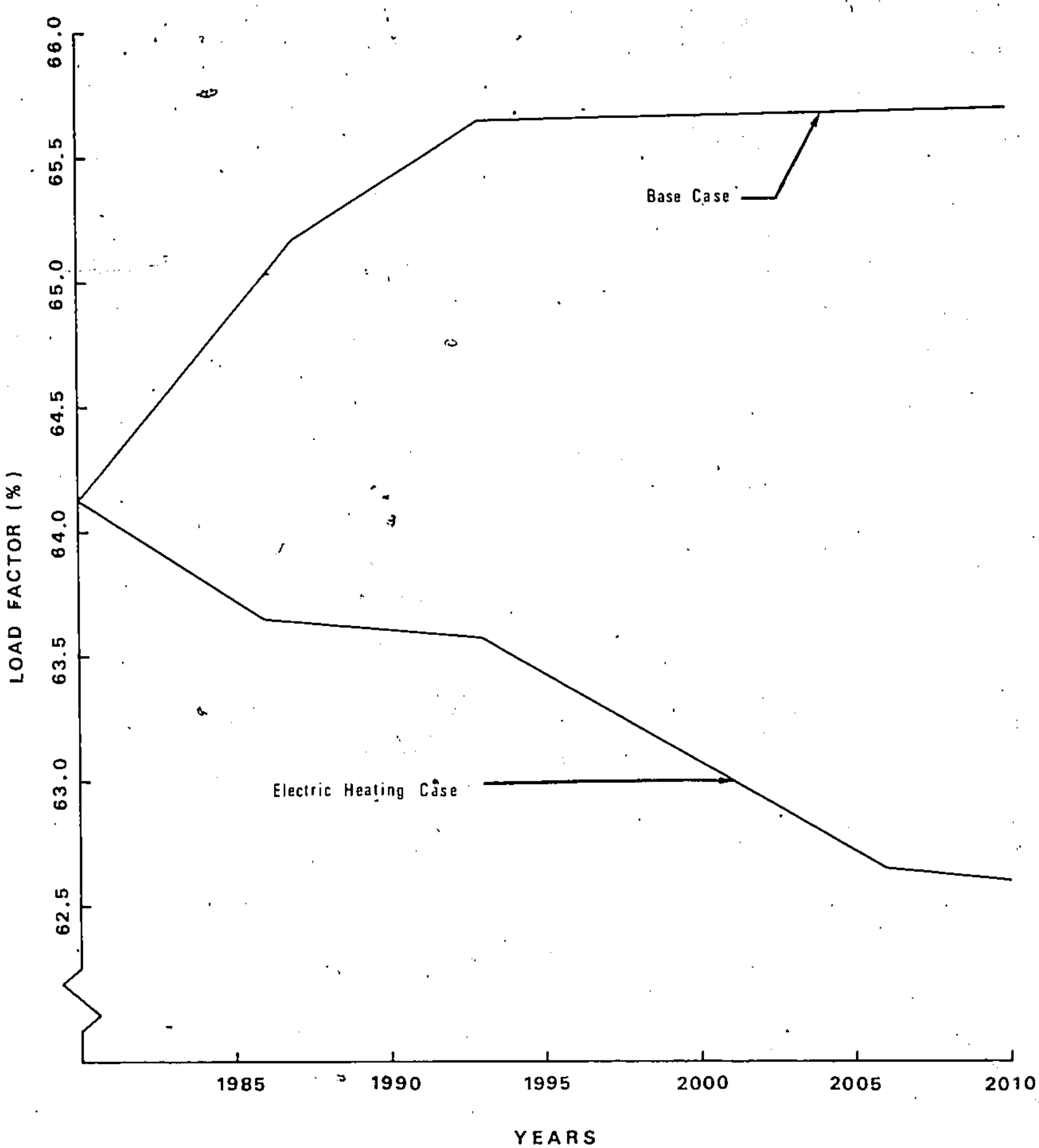

Figure 27: Load Factors During Study Period

4.4.2 Impact on Generation Capacity

The thermal generating capacities by fuel type for the base case and for the electric heating case are described in Tables 19 and 20 respectively. The results for the nuclear and coal capacity additions are depicted in graphical form in Figures 28 and 29 respectively. Note that the optimal plan for the electric heating case requires more nuclear capacity (1000 MW) than for the base case. Conversely, the electric heating case requires less coal (300 MW reduction) than the base case. Both plans require the same amount of gas and oil capacity. The oil capacity is the same since no oil-fired units were considered as expansion candidates. Notice also that the total thermal capacity for the electric heating case in 2010 is 700 MW greater than for the base case. Hence this is one of the penalties of electric space heating : increased generation capacity requirement.

4.4.2.1 Capacity Factors by Fuel Type

In order to find out how different types of generating units are utilized for electrical energy generation, their capacity factors must be compared. The capacity factors for the base case plan and the electric heating case plan are shown in Tables 21 and 22 respectively. Notice that for the base case, the average capacity factor of the nuclear units was 78%, indicating that the nuclear units will be base loaded throughout the planning period. For the coal-fired units with an average capacity factor of 68% will be loaded as intermediate cycling units most of the time, while the oil-fired units with a capacity factor of 20% will be loaded as intermediate-peaking units. Gas turbines will only be operated in a peaking mode. As for the electric heating case, the capacity factor of the nuclear units has decreased slightly to 74%, indicating that some of the nuclear units will be operating as load-carrying units. Notice that there is a substantial decrease in the capacity factors of the coal-fired and oil-fired units. This is due to the fact that as more nuclear comes on line, the coal and oil will be displaced to generate less energy. Consequently, as will be shown later, this will result in a reduction in the amount of coal and oil fuels consumed. Again, the gas turbines will operate in a peaking mode.

TABLE 19

Generating Capacity for the Base Case

Year	Total Thermal (MW)	Nuclear Power (MW)	Gas Turbine (MW)	Oil Fired (MW)	Coal Fired (MW)
1981	1299	0	23	1014	262
1982	1699	400	23	1014	262
1983	1699	400	23	1014	262
1984	1699	400	23	1014	262
1985	1699	400	23	1014	262
1986	1897	400	23	1212	262
1987	2098	400	23	1413	262
1988	2076	400	23	1391	262
1989	2076	400	23	1391	262
1990	2076	400	23	1391	262
1991	2296	630	23	1391	252
1992	2296	630	23	1391	252
1993	2281	630	23	1391	237
1994	2481	630	23	1391	437
1995	2481	630	23	1391	437
1996	2859	1030	23	1369	437
1997	2859	1030	23	1369	437
1998	2859	1030	23	1369	437
1999	3059	1030	23	1369	637
2000	3059	1030	23	1369	637
2001	3311	1330	23	1321	637
2002	3311	1330	23	1321	637
2003	3611	1630	23	1321	637
2004	3554	1630	23	1321	580
2005	3544	1630	23	1311	580
2006	3845	1630	23	1212	980
2007	3743	1630	23	1110	980
2008	3743	1630	23	1110	980
2009	3938	1630	23	1005	1280
2010	4038	1630	123	1005	1280

TABLE 20

Generating Capacity for the Electric Heating Case

Year	Total Thermal (MW)	Nuclear Power (MW)	Gas Turbine (MW)	Oil Fired (MW)	Coal Fired (MW)
1981	1299	0	23	1014	262
1982	1699	400	23	1014	262
1983	1699	400	23	1014	262
1984	1699	400	23	1014	262
1985	1699	400	23	1014	262
1986	1897	400	23	1212	262
1987	2098	400	23	1413	262
1988	2076	400	23	1391	262
1989	2076	400	23	1391	262
1990	2076	400	23	1391	262
1991	2296	630	23	1391	252
1992	2346	630	73	1391	252
1993	2731	1030	73	1391	237
1994	2931	1030	73	1391	437
1995	2931	1030	73	1391	437
1996	2909	1030	73	1369	437
1997	3309	1430	73	1369	437
1998	3309	1430	73	1369	437
1999	3509	1430	73	1369	637
2000	3509	1430	73	1369	637
2001	3461	1430	73	1321	637
2002	3461	1430	73	1321	637
2003	3511	1430	123	1321	637
2004	3854	1830	123	1321	580
2005	3844	1830	123	1311	580
2006	4145	2230	123	1212	580
2007	4443	2630	123	1110	580
2008	4443	2630	123	1110	580
2009	4738	2630	123	1005	980
2010	4738	2630	123	1005	980

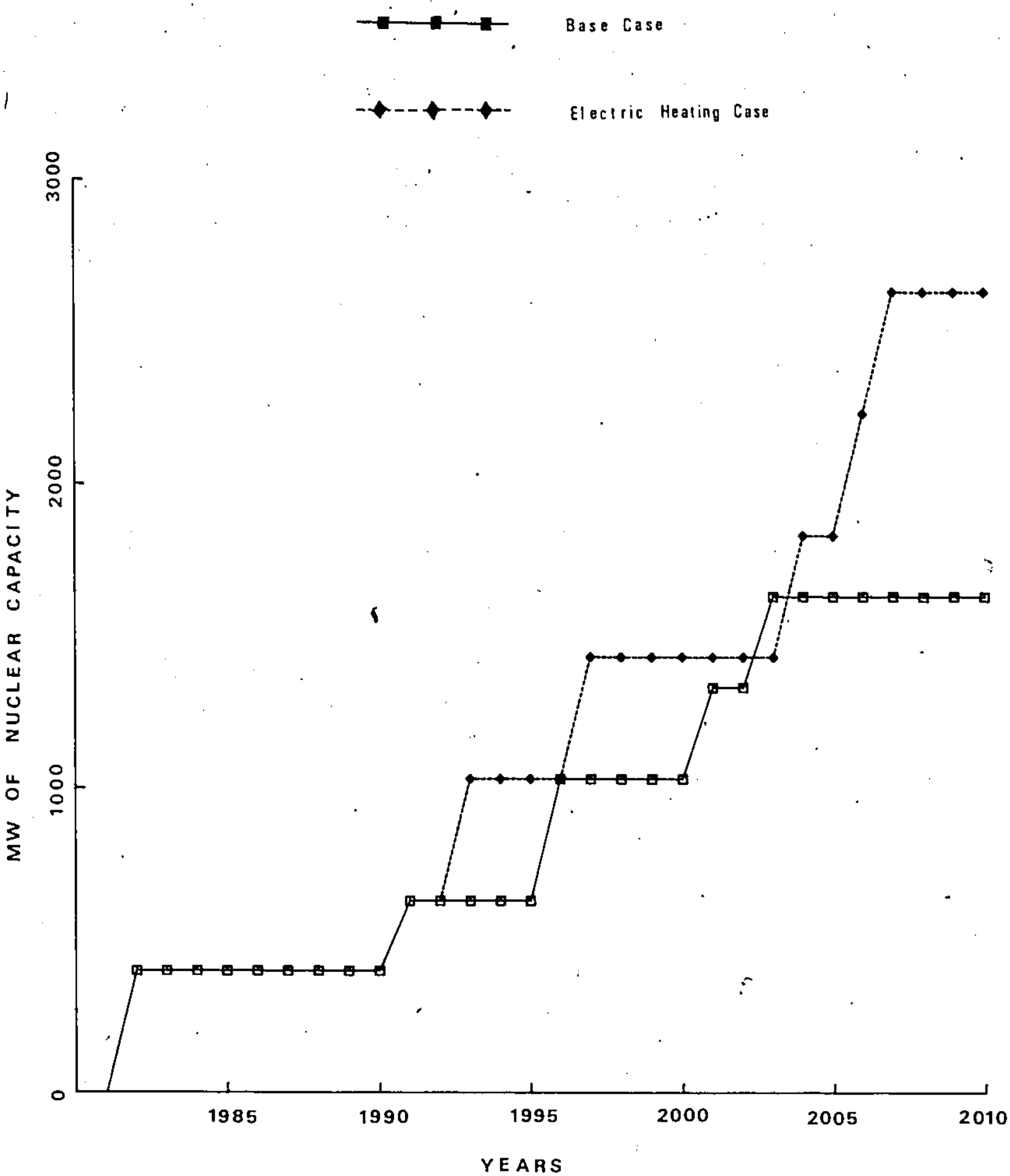

Figure 28: Nuclear Generating Capacity During Study Period

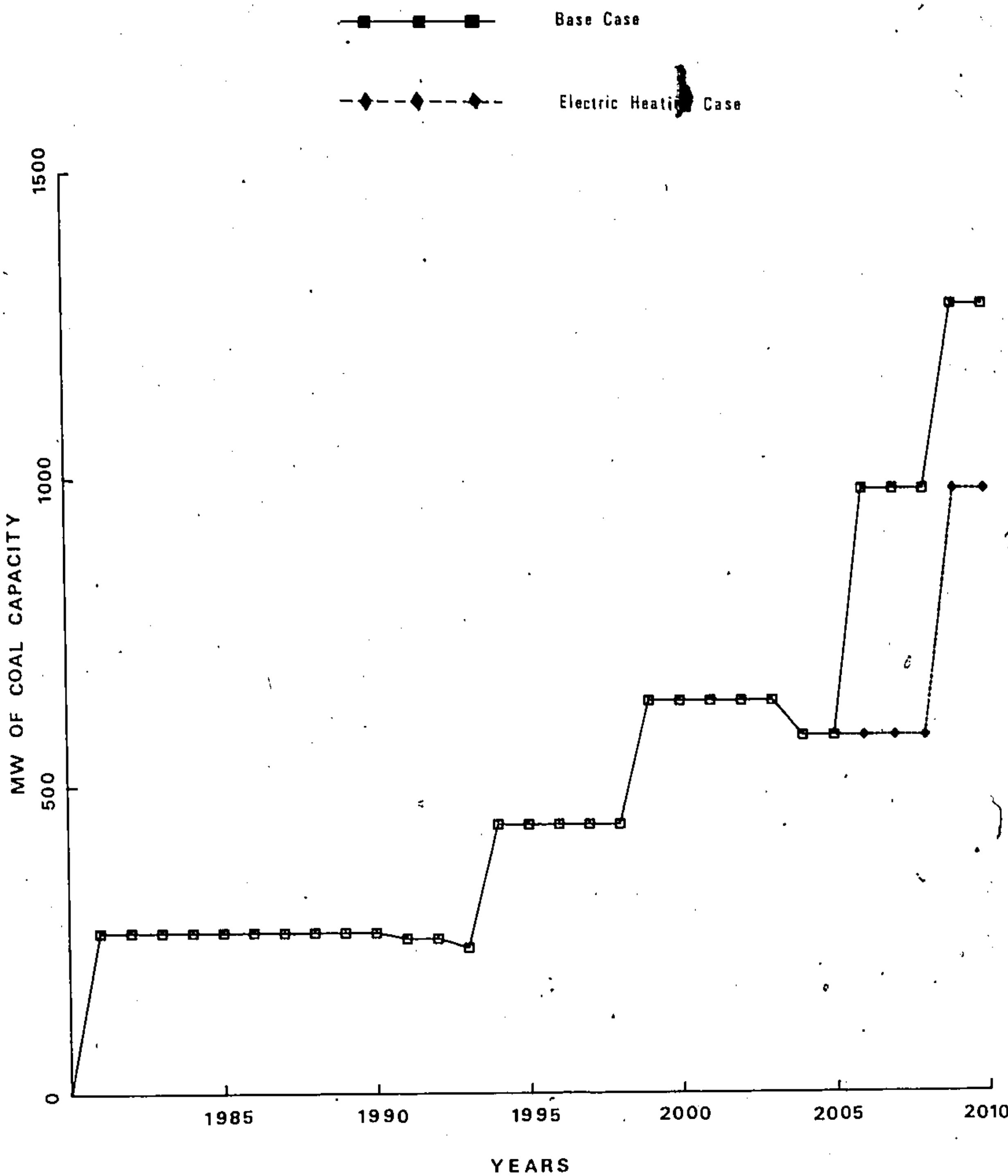

Figure 29: Coal Generating Capacity During Study Period

TABLE 21

Capacity Factors for the Base Case

Year	Nuclear Power (%)	Gas Turbine (%)	Oil Fired (%)	Coal Fired (%)
1981	0.0	0.01	49.64	82.86
1982	77.94	0.01	25.40	75.05
1983	73.33	0.00	31.17	78.51
1984	79.58	0.01	33.93	74.89
1985	80.33	0.01	37.93	75.68
1986	80.67	0.01	34.92	78.63
1987	73.33	0.01	34.34	84.76
1988	88.00	0.02	34.75	82.37
1989	84.11	0.01	35.95	72.35
1990	77.58	0.00	40.48	76.37
1991	73.61	0.01	33.79	75.15
1992	74.62	0.01	36.85	76.09
1993	75.21	0.02	40.90	78.01
1994	75.81	0.01	34.21	75.73
1995	76.26	0.02	37.63	77.61
1996	77.61	0.01	22.72	67.14
1997	79.79	0.01	25.01	69.21
1998	80.62	0.03	28.64	70.77
1999	76.97	0.02	25.14	72.55
2000	77.33	0.03	29.01	74.59
2001	75.96	0.02	22.38	66.69
2002	76.56	0.02	25.82	68.27
2003	75.52	0.01	16.20	65.14
2004	77.34	0.03	21.27	66.53
2005	77.67	0.02	23.47	67.33
2006	76.52	0.01	14.16	62.97
2007	77.09	0.01	17.23	65.97
2008	77.41	0.03	21.81	68.02
2009	76.26	0.02	15.99	66.02
2010	78.87	0.04	19.19	66.49

TABLE 22

Capacity Factors for the Electric Heating Case

Year	Nuclear Power (%)	Gas Turbine (%)	Oil Fired (%)	Coal Fired (%)
1981	0.0	0.01	50.24	82.78
1982	85.27	0.01	24.70	70.97
1983	78.82	0.01	30.61	78.51
1984	79.55	0.02	36.23	74.02
1985	80.30	0.02	40.37	76.01
1986	88.00	0.03	35.13	78.11
1987	88.00	0.02	33.65	79.31
1988	75.86	0.00	36.90	74.52
1989	76.83	0.01	40.37	76.34
1990	77.63	0.01	43.52	78.05
1991	74.03	0.02	36.99	76.54
1992	74.62	0.03	40.40	78.19
1993	72.78	0.01	26.76	69.49
1994	76.05	0.00	20.45	64.17
1995	74.61	0.01	24.93	67.75
1996	72.94	0.03	30.28	71.27
1997	71.97	0.01	16.81	65.30
1998	72.71	0.02	20.44	67.65
1999	73.45	0.01	15.74	66.20
2000	74.17	0.02	19.83	67.56
2001	74.42	0.02	22.68	67.98
2002	75.16	0.02	25.92	68.26
2003	75.50	0.03	30.31	69.78
2004	73.58	0.02	20.34	66.21
2005	74.31	0.03	24.37	68.35
2006	73.42	0.02	16.04	55.69
2007	72.25	0.02	9.60	39.08
2008	73.01	0.02	11.83	45.34
2009	73.67	0.02	8.30	38.43
2010	74.30	0.03	9.65	44.14

4.4.3 Impact on Primary Fuel Consumption

The primary fuel consumption schedule for electric power generation for the base case and the electric heating case are described in Tables 23 and 24 respectively. Note that these tables consider only the effects on fuel used for generation and do not consider the heating fuel that is displaced by electric space heating. Notice that in both cases, there is a gradual decrease in oil consumption as a result of new nuclear capacity lowering the capacity factors on oil fueled generation.

4.4.3.1 Yearly Incremental Primary Fuel Consumption

From Tables 23 and 24, Table 25 is evaluated. This table depicts the yearly incremental primary fuel requirement for electrical generation. A negative value in Table 25 signifies a savings; a positive value signifies an additional requirements. Notice that the additional requirement for uranium is clearly evident. There is, however, a substantial reduction in the tons of coal and barrels of oil needed for electrical generation. This is the right trend in line with the NEP's policy : substituting nuclear for the more limited oil fuel. This is exactly one of the benefits of the increased utilization of electric space heating. Notice that there is a small increase in the consumption of gas. This is due mainly to the fine tuning required to maintain the reliability criterion.

4.4.3.2 Oil and Gas Consumptions

The effects on oil and gas consumptions are described on a yearly basis in Tables 26 and 27 respectively. The first column of these tables gives the amount in barrels of oil or barrels equivalent of gas not consumed by the residential oil/gas furnace for electric space heating, the second column gives the extra consumption for electric energy production and the third the net savings caused by additional electric heating. A positive value signifies a savings; a negative value signifies an additional requirements. Notice that both tables show a cumulative savings. The cumulative amount of oil saved is about 21 million barrels over a 30 year period; while the cumulative amount of gas saved is about 6.5 million barrels equivelant for the same period. This clearly indicates one of the benefits of electric space heating : saving of limited oil and gas fuels.

TABLE 23

Yearly Fuel Consumption for Electrical Generation for the Base Case

Year	Uranium (K Kgs)	Gas (K Barrels)	Oil (K Barrels)	Coal (K Tons)
1981	0.0	0.028	7461.684	993.540
1982	64.214	0.040	4190.301	893.712
1983	60.325	0.016	5013.156	939.186
1984	65.583	0.058	5389.742	898.881
1985	66.134	0.048	5901.031	907.585
1986	66.357	0.056	6377.082	941.649
1987	60.325	0.023	7285.902	1014.915
1988	72.390	0.107	7192.094	986.583
1989	69.254	0.031	7343.156	869.737
1990	63.889	0.016	8170.113	916.562
1991	89.080	0.047	6951.254	852.101
1992	90.235	0.052	7506.402	864.820
1993	90.930	0.101	8240.660	822.518
1994	91.637	0.061	7026.777	1352.386
1995	92.134	0.075	7646.680	1387.935
1996	236.820	0.034	4853.070	1198.827
1997	240.197	0.065	5256.523	1237.633
1998	242.036	0.109	5905.426	1266.191
1999	234.931	0.074	5287.629	1831.080
2000	235.724	0.114	5980.109	1883.503
2001	358.161	0.066	4626.770	1678.154
2002	360.025	0.097	5233.215	1719.505
2003	481.593	0.064	3500.089	1635.101
2004	489.025	0.113	4412.742	1512.749
2005	490.292	0.087	4587.461	1531.459
2006	485.988	0.064	2633.976	2731.662
2007	488.179	0.047	2880.023	2854.880
2008	489.359	0.149	3581.813	2938.345
2009	484.953	0.100	2426.791	3921.329
2010	494.100	12.714	2850.577	3935.906
Total	6853.855	14.659	165711.688	46518.387

TABLE 24

Yearly Fuel Consumption for Electrical Generation for the Electric Heating Case

Year	Uranium (K Kgs)	Gas (K Barrels)	Oil (K Barrels)	Coal (K Tons)
1981	0.0	0.035	7539.590	992.059
1982	70.247	0.033	4040.998	844.821
1983	64.952	0.063	4913.086	938.267
1984	65.555	0.076	5665.883	886.229
1985	66.115	0.105	6218.293	909.698
1986	72.390	0.136	6412.141	936.513
1987	72.390	0.072	7050.055	950.018
1988	62.456	0.020	7499.324	895.576
1989	63.265	0.055	8125.582	915.780
1990	63.929	0.043	8698.387	934.737
1991	89.520	0.083	7513.406	869.647
1992	90.235	6.316	8132.586	889.781
1993	225.931	6.115	5686.586	731.830
1994	233.518	5.994	4458.313	1146.144
1995	229.871	6.110	5316.012	1210.469
1996	225.765	6.281	6253.156	1273.588
1997	361.094	6.131	3715.183	1166.116
1998	363.398	6.137	4415.461	1209.146
1999	365.719	6.057	3489.742	1667.686
2000	368.038	6.238	4298.148	1702.852
2001	368.850	6.256	4686.367	1714.000
2002	371.276	6.169	5252.344	1722.358
2003	372.398	12.447	6033.129	1762.699
2004	505.354	12.228	4224.734	1504.062
2005	508.402	12.477	4719.402	1554.560
2006	643.755	12.356	2939.917	1265.308
2007	775.788	12.266	1648.376	876.724
2008	780.379	12.421	1999.407	1025.805
2009	784.392	12.375	1298.453	1764.437
2010	788.168	12.497	1480.860	1987.555
Total	9053.137	167.594	153724.313	36248.414

TABLE 25

Yearly Incremental Fuel Consumption
for Electrical Generation

Year	Uranium (K Kgs)	Gas (K Barrels)	Oil (K Barrels)	Coal (K Tons)
1981	0.0	0.007	77.906	-1.481
1982	6.033	-0.007	-149.302	-48.891
1983	4.628	0.046	-100.070	-0.919
1984	-0.027	0.017	276.141	-12.653
1985	-0.019	0.057	317.262	2.114
1986	6.032	0.080	35.059	-5.136
1987	12.065	0.049	-235.848	-64.897
1988	-9.933	-0.087	307.230	-91.007
1989	-5.988	0.024	782.426	46.043
1990	0.039	0.027	528.273	18.175
1991	0.439	0.036	562.152	17.546
1992	-0.001	6.264	626.184	24.961
1993	135.001	6.014	-2554.074	-90.688
1994	141.881	5.933	-2568.465	-206.242
1995	137.737	6.035	-2330.668	-177.466
1996	-11.055	6.247	1400.086	74.761
1997	120.897	6.067	-1541.341	-71.518
1998	121.362	6.028	-1489.965	-57.045
1999	130.788	5.983	-1797.886	-163.395
2000	132.313	6.124	-1681.961	-180.651
2001	10.689	6.190	59.598	35.845
2002	11.251	6.072	19.129	2.853
2003	-109.195	12.383	2533.040	127.598
2004	16.330	12.115	-188.008	-8.687
2005	18.110	12.390	131.941	23.100
2006	157.768	12.292	305.941	-1466.353
2007	287.609	12.219	-1231.647	-1978.156
2008	291.020	12.271	-1582.405	-1912.540
2009	299.438	12.275	-1128.338	-2156.892
2010	294.068	-0.217	-1369.717	-1948.351
Total	2199.279	152.935	-11987.309	-10269.965

TABLE 26

Summary of Oil Consumption

Year	Oil Not Consumed by Pesidential Furnace (Barrel)	Extra Oil Consumed for Electric Energy Production (Barrel)	Net Oil Savings Impact of Extra Electric Heat (Barrel)
1981	25793	77906	-52113
1982	50409	-149301	199710
1983	72384	-100069	172453
1984	92104	276141	-184037
1985	112307	317262	-204955
1986	132187	35059	97128
1987	150690	-235847	386537
1988	168918	307230	-138312
1989	185771	782426	-596655
1990	202534	528273	-325739
1991	219160	562152	-342992
1992	236559	626184	-389625
1993	255350	-2554073	2809423
1994	274607	-2568463	2843070
1995	294697	-2330666	2625363
1996	316094	1400085	-1083991
1997	337955	-1541339	1879294
1998	360200	-1489963	1850163
1999	382223	-1797885	2180108
2000	405345	-1681959	2087304
2001	428675	59598	369077
2002	458765	19129	439636
2003	488178	2533039	-2044861
2004	518959	-188007	706966
2005	548765	131941	416824
2006	578961	305941	273020
2007	600219	-1231645	1831864
2008	621357	-1582404	2203761
2009	642619	-1128336	1770955
2010	664303	-1369715	2034018
Total	9826088	-11987306	21813394

TABLE 27

Summary of Gas Consumption

Year	Gas Not Consumed by Residential Furnace (Barrel)	Extra Gas Consumed for Electric Energy Production (Barrel)	Net Gas Savings Impact of Extra Electric Heat (Barrel)
1981	17720	7	17713
1982	34632	-6	34638
1983	49729	46	49683
1984	63278	17	63261
1985	77158	57	77101
1986	90816	80	90736
1987	103528	49	103479
1988	116051	-86	116137
1989	127629	24	127605
1990	139146	27	139119
1991	150568	36	150532
1992	162522	6264	156258
1993	175431	6014	169417
1994	188662	5933	182729
1995	202464	6035	196429
1996	217165	6247	210918
1997	232184	6067	226117
1998	247466	6028	241438
1999	262596	5983	256613
2000	278482	6124	272358
2001	294510	6190	288320
2002	315183	6072	309111
2003	335390	12383	323007
2004	356538	12115	344423
2005	377015	12390	364625
2006	397760	12292	385468
2007	412365	12219	400146
2008	426887	12271	414616
2009	441495	12275	429220
2010	456392	-216	456608
Total	6750762	152937	6597825

4.4.4 Impact on Financial Requirement

The cash flow for the base case and the electric heating case were tabulated on a yearly basis as shown in Table 28. Note that all expenditures are in terms of 1981 dollars. Notice that the cumulative operating costs for the electric heating case is $364.3 million lower than for the base case. This is due mainly to the increased utilization of nuclear energy in the electric heating case. Again, the oil fuel saved is reflected in the lower operating cost of the system. However, the construction costs for the electric heating case is $1,502.6 million greater than for the base case. This is a direct consequence of the higher construction costs of the nuclear units. The total increase in overall expenditures for the electric heating case is $1,138.3 million. This is again one of the penalties associated with increased utilization of electric heating : increase financial requirements on electric utility.

TABLE 28

Summary of Cash Flow

Year	Operating Costs (1,000,000$) Base Case	Operating Costs (1,000,000$) Electric Heat	Construction Costs (1,000,000$) Base Case	Construction Costs (1,000,000$) Electric Heat
1981	208.9	210.6	0.0	0.0
1982	139.4	134.9	0.0	0.0
1983	159.4	157.7	0.0	0.0
1984	167.1	172.9	0.0	0.0
1985	179.2	186.5	0.0	36.0
1986	191.4	192.8	12.7	99.7
1987	214.1	207.9	67.1	122.5
1988	212.6	214.6	56.2	132.9
1989	211.0	229.8	32.6	233.9
1990	230.9	243.7	89.7	153.5
1991	204.1	217.7	132.9	187.5
1992	217.5	232.9	210.5	152.8
1993	232.6	189.8	117.6	210.5
1994	225.8	179.1	109.3	117.6
1995	241.4	200.7	54.4	91.4
1996	190.4	223.9	120.9	43.2
1997	201.6	180.7	147.7	43.6
1998	217.8	198.7	266.5	168.8
1999	224.8	195.8	202.9	299.9
2000	242.8	216.0	199.4	413.1
2001	220.9	225.4	134.6	362.2
2002	236.6	238.9	161.7	441.3
2003	210.7	258.6	240.0	364.1
2004	227.8	225.8	168.6	242.9
2005	232.7	239.5	138.9	203.9
2006	234.5	206.5	122.8	160.4
2007	245.2	180.2	61.3	82.8
2008	264.7	194.7	21.7	20.7
2009	276.1	208.1	12.8	0.0
2010	288.0	221.6	0.0	0.0
Total	6551.6	6187.3	2882.7	4385.3

Chapter V

CONCLUSION

The objective of this thesis is to develop a computational procedure suitable for use by electric utilities to evaluate quantitatively the long-term implications and impact of electric space heating. This objective has been achieved by the development of a three stage computer model that permits realistic eveluations of the impact of electric space heating on system demand, generation capacity requirement, primary fuel consumption and financial requirement. Stage 1 is the electric heating demand model which calculates the incremental demand for electric heating; Stage 2 is the generation expansion model which calculates the optimal generation expansion schedule; and Stage 3 is the total impact model which calculates the incremental impact on elements of interest such as fuel consumption and utility costs. Several computer programs: HEATLOAD, LOADPROC and WASP have been implemented to manage the data and to perform the analysis.

These computer models have been applied to the New Brunswick electric power system and results have been obtained for penetrations of 60% of electric space heating dwellings in the new housing stock. The main conclusions that can be drawn from this study for the utility assumed are:

1. The incremental demand for electric space heating depends on factors such as type of dwellings, weather conditions, the insulation standards as well as the number of electrically heated dwellings.

2. Row houses and apartments are much more energy efficient as compared to single-detached and semi-detached dwellings. For the effective utilization of energy resources, an increase use of row houses or multi-family dwellings are to be preferred.

3. There is a slight deterioration of the system load factor as a result of the increased utilization of electric heating. For the system studied, the annual load factor has decreased from 63.8% in 1981 to 62.63% in 2010.

4. The long-term capability of electric heating to substitute nuclear and coal for scarcer oil and gas is significant for the utility studied. The cumulative amount of oil fuel saved is about 21 million barrels over a 30 year period; while the cumulative amount of gas fuel saved is about 6.5 million barrels equivalent for the same period.

5. There is a significant increase in the utilization of nuclear for electrical energy generation as a result of increase in electric heating. Consequently, more nuclear units are installed. These nuclear units, with their higher capital costs, increases the financial requirements on the electric utility. Decisions to discourage or encourage electric heating must be made based on other considerations such as the availability of capital and nuclear fuel for the next 25 to 30 years.

6. In order to obtain a realistic evaluation of the benefits and penalties associated with electric heating, a long-term study must be undertaken. A simplistic model based on one year study do not capture the subtle interaction between many economic and electric parameters.

7. Effects on individual utilities would vary depending on such factor as electric heating penetration level and climatic conditions in each utility's service area.

The last point emphasizes that individual utilities should evaluate the impact of electric space heating by the application of the models described and should not be based on results obtained by other utilities because results are utility specific.

5.1 FURTHER RESEARCH

A major drawback of electric space heating is that it necessarily entails some demand for electric heating during periods of heavy load and system peak, resulting in the deterioration of the system load factors. For this reason, many utilities are considering using load management schemes to ameliorate load factors. Load management essentially shifts some electrical demand from peak to off-peak periods. A reduction in peak demand leads to a more economical use of the generating units and transmission system and a more effective utilization of resources. Load management is particularly attractive in terms of its potential for conserving energy and capital in the production and distribution of electrical energy. It will hold down the cost of electricity by shifting a significant amount of fuel base from oil and gas to coal, nuclear and renewable resources. There is therefore the need to investigate the feasibilities and effects of different load management schemes on an electric utility.

Many assumptions have been made in the study which are necessary to conduct the analysis to a fruitful end. It is almost certain that many of these assumptions will have a significant effect on the results obtained. Sensitivity studies are therefore suggested since they may give additional insight into the characteristics of the final results. The parameteric studies recommended are:

1. The effects of the insulation standards of the dwelling stocks.

2. The effects of the thermal and structural characteristics of the dwelling stocks.

3. The effects of changes in dwelling mixes.

4. The effects of different penetration level of electric heating.

5. The effects of different escalation rates for the fuel considered.

6. The effects of discount rates.

7. The effects of load growth rates.

8. The effects of no nuclear or no coal expansion.

9. The effects of increasing or decreasing the forced outage rates of generating units.

10. The effects of decreasing the reliability level from 1 day/10 years to 5 day/10 years, 10 day/10 years and higher values.

11. The effects of export and import of power to and from neighbouring utilities.

12. The effects of overbuilding nuclear units specifically to sell power to the US.

Appendix A

BRIEF DESCRIPTION OF WASP

The Wien Automatic System Planning (WASP) package was developed by the Tennessee Valley Authority for the International Atomic Energy Agency. The WASP program utilizes the Baleriaux-Booth method for the probabilistic simulation of system operation satisfying user specified constraints. WASP can handle 100 multi-unit plants with hydro and pumped storage units each treated as a single composite plants. In addition, 20 expansion candidate plants, a 30 year study period and 200 alternative system configurations in any one year may be considered. The objective function is the present-worth discounted value of all operating costs plus all capital investment costs less a salvage value credit at the horizon for the remaining economic life of the candidate plants.

The WASP package is composed of six computer programs which can run either independently or in series. The modular structure of WASP permits the user to monitor intermediate results, so that any input data errors can be corrected before large amount of computer time are wasted in simulating and optimizing with erroneous data.

The six modules are:

1. A load description module LOADSY.

2. A fixed-committed system module FIXSYS.

3. A variable system module VARSYS.

4. An expansion configuration module CONGEN.

5. A probabilistic simulation module MERSIM.

6. A optimization module DYNPRO.

A brief description of each module follows:

LOADSY

This module accepts the load forecast and the shape of the LDC for each period and every year of the study. Specifically, it requires:

1. Number of periods per year.

2. Annual peak demand and the ratio of the period peaks to the annual peak, for each year of the study.

3. Load duration curve for each period in the study, expressed as the coefficients of a fifth-degree polynomial.

4. Number of terms required in the Fourier series approximation of the load duration curve.

FIXSYS

This module accepts the existing and firmly committed systems. In this module, the following information is required:

1. For each thermal plant:

    a) Number of units and type.
    b) Minimum and maximum operating levels.
    c) Heat rate at minimum level and average incremental heat rate between minimum and maximum levels.
    d) Unit domestic and foreign fuel costs.
    e) Forced-outage rate.
    f) Annual scheduled maintenance time requirements.
    g) Fixed and variable non-fuel operating costs.
    h) Year of addition of extra capacity.
    i) Year of retirement and number of units to be retired.

2. For the existing composite hydro system as well as committed projects:

    a) Annual minimum and maximum operating levels.

b) Base (run of the river) and peaking components for each period.

c) Annual energy available as well as period energy.

d) Unit fixed and variable non-fuel operating costs.

e) Number of hydrological conditions (low, high flows, etc.) and probability of their existence.

3. For the existing and committed emergency hydro systems (hydro capacity not normally used - a penalty is attached to its use):

a) Annual capacity and period capacities.

b) Hypothetical heat rate and fuel costs.

c) Unit fixed and variable non-fuel operating costs.

d) Number of hydrological conditions.

4. For the existing composite pumped storage system:

a) Generating capacity.

b) Electrical load imposed by the pumps.

c) Maximum energy generation per period.

d) Generating efficiency.

e) Pumping efficiency.

f) Unit fixed and variable non-fuel operating costs.

VARSYS

This modules accepts the candidate units for expansion. Up to 20 candidate types may be considered with hydro and pumped storage each counting as one. Within the hydro category up to 20 ranked projects can be considered - the user ranks the project in an economic order of merit. In this module the following information is required:

1. For each thermal plant the same information as in FIXSYS except the number of units is not specified.

2. For each hydro project, the same information as in FIXSYS. In addition, the first year when the project can be added must be specified.

3. For each pumped storage project, the same information as in FIXSYS.

CONGEN

This module is the heart of WASP since it generates all possible states of the expanded system within the user specified constraints. The input data required, for each year of the study period is:

1. Minimum and maximum acceptable values of reserve margin during the critical period.

2. Minimum number of units or hydro projects which are required to be installed (perhaps by political or economic reasons).

3. Maximum number of units or hydro projects which are permitted to be installed in addition to the number required.

4. Maximum permissible value of loss of load probability.

In addition to satisfying the input constraints, an acceptable configuration in a given year must be accessible from at least one of the acceptable configurations in the previous year.

MERSIM

This module probabilistically simulates system operation to obtain the expected generation and production costs for each unit for each feasible configuration generated in CONGEN. This module is computationally very efficient with the incorporation of the method of moments for the probabilistic simulation. Ths module requires:

1. The loading order for the thermal and pumped-storage plants. A two-block treatment of capacity is used. Normal and emergency hydro are handled automatically.

2. Base year for escalation calculations plus individual escalation factors on local and foreign costs for each fuel type.

The normal-hydro base capacity block is always first in the loading order and the remaining capacity is located at its proper place in the loading order to discharge the available energy. The loss of load probability calculated in this module includes the effects of maintenance.

DYNPRO

This module uses dynamic programming to carry out the economic evaluation of alternative expansion plans. Input data required is as follows:

1. Depreciable capital cost and economic plant life for each variable-system expansion candidate.

2. Non-depreciable capital cost for thermal plants.

3. Interest during construction.

4. Time of construction.

5. Escalation rates.

6. Discount rates

7. Type of depreciation (sinking fund or straight line) for salvage value calculations.

Appendix B

DESCRIPTION OF THE NEW BRUNSWICK ELECTRIC POWER SYSTEM

As described in Appendix A, the WASP computer package consists of six interrelated computer code modules. These modules serve to find the economically optimal generation expansion policy for an electric utility within user-specified constraints.

The New Brunswick electric power system will be described at each of the six modules.

LOAD DESCRIPTION (LOADSY)

Hourly historical data for the year 1979 were used to obtain the required monthly load duration curve. For WASP, these LDCs are given in terms of the coefficients of a fifth degree polynomial ($Y = a_0+a_1X+a_2X^2+a_3X^3+a_4X^4+a_5X^5$, where X is the fraction of time during the period that the load equals or exceeds the fraction Y of the period peak demand). The first coefficient (the constant term) is always unity. These coefficients are calculated by a least-square curve-fitting program. The LDCs are assumed to remain unchanged for each corresponding month for the base case over the study period.

The coefficient of the fifth degree polynomials are shown in Table 29.

TABLE 29

Coefficients of Fifth Degree Polynomial Describing the Load Duration Curves for Each Period

Period	a_1	a_2	a_3	a_4	a_5
1	-1.6133	7.4346	-17.9414	19.7348	-8.1631
2	-1.3137	4.8147	-10.2988	10.4419	-4.0879
3	-1.5919	7.1581	-16.6342	17.3731	-6.7272
4	-1.8025	7.7160	-17.8243	18.8258	-7.4161
5	-1.6880	7.9568	-18.4226	18.3519	-6.6591
6	-1.6675	7.6780	-18.0048	18.2308	-6.6924
7	-1.5205	7.7827	-20.7191	23.4610	-9.5187
8	-1.7437	8.3524	-20.1935	21.0402	-7.9118
9	-1.8100	10.3545	-27.9390	31.7013	-12.8334
10	-1.5263	6.7854	-15.3918	15.1339	-5.4637
11	-1.3681	5.7836	-13.8973	14.9008	-5.9003
12	-1.9360	9.3858	-23.7948	27.0594	-11.3013

FIXED SYSTEM (FIXSYS)

The fixed system comprises the units already installed, the firmly committed units as well as units to be retired. A summary of the fixed-committed system is given in Tables 30 and 31 which include some explanatory comments.

TABLE 30

Thermal and Nuclear Units

Station Name		Min. Load MW	Capa-city MW	Base Load Heat Rate kcal/kwh	Avge Incr Heat Rate kcal/kwh	FOR %
Grand Lake	5,6	10	10	4432	0	10
Grand Lake	7	15	15	3654	0	10
Grand Lake	8	18	57	3801	2527	6
Grand Lake	9	60	200	2865	2320	7
Grand Lake	10	60	200	2865	2320	7
Chatham	1	11	22	3714	3723	12
Chatham	2	11	22	3740	2225	10
Courtenay Bay	1	18	48	3549	2599	5
Courtenay Bay	2	10	10	6400	0	5
Courtenay Bay	3	30	99	3039	2326	7
Courtenay Bay	4	30	102	3021	2329	7
Dalhousie	1	30	105	3017	2192	5
Dalhousie	2	30	180	3161	2203	8
Coleson Cove	1	80	202	2799	2263	8
Coleson Cove	2	80	202	2799	2263	8
Coleson Cove	3	80	202	2799	2263	8
Point Lepreau	1	350	630	3261	2565	12
Moncton	1	23	23	3154	0	9

TABLE 31

Thermal and Nuclear Units (Continued)

Station Name		Fuel Costs	Sched. Maint-enance	O&M Costs Fixed	O&M Costs Variable
		cents/M kcal	days	$/kW-month	$/MWh
Grand Lake	5,6	655	21	0	0.53
Grand Lake	7	655	21	0	0.51
Grand Lake	8	655	28	0	0.21
Grand Lake	9	655	28	0	0.20
Grand Lake	10	655	28	0	0.20
Chatham	1	1508	21	0	0.19
Chatham	2	1508	21	0	0.19
Courtenay Bay	1	1452	27	0	0.31
Courtenay Bay	2	1452	28	0	0.31
Courtenay Bay	3	1452	28	0	0.22
Courtenay Bay	4	1452	28	0	0.22
Dalhousie	1	1508	28	0	0.22
Dalhousie	2	837	35	0	0.20
Coleson Cove	1	1452	35	0	0.20
Coleson Cove	2	1452	35	0	0.20
Coleson Cove	3	1452	35	0	0.20
Point Lepreau	1	103	42	0	0.00
Moncton	1	2079	7	0	0.00

Comments:

1. Coleson Cove units available at 202 MW each until November 1985, 268 MW until November 1986 and 335 MW thereafter because of participation sale with New England utilities.

2. The Point Lepreau nuclear station is a 630 MW station. The in service commerical date is November 1981. Until December 1990, 400 MW are available to New Brunswick. From January 1991 an additional 230 MW are available to the system.

3. Because of commitments for steam, unit 2 at Courtenay Bay must be run continuously. Hence, this 10 MW unit is loaded as a "must run" unit.

4. 80 MW of Coleson Cove 1 are to be run continuously. This lower block of 80 MW is loaded, therefore, as a "must run" block.

5. Some of these units will be retired as described later.

A description of the fixed hydro projects are described in Tables 32 and 33. All hydro units are available at the start of the study: January 1981.

The average energy provided by these hydro projects was given a probability of existence of 95%. The low hydro level was given a probability of 5%.

A summary of the Fixed System is given in Table 34.

TABLE 32

Hydro Units and Capacities

Station Name		Capacity MW
Mactaquac 1		105
Mactaquac 2		105
Mactaquac 3		105
Mactaquac 4		105
Mactaquac 5		105
Mactaquac 6		105
Beechwood 1		36
Beechwood 2		36
Beechwood 3		43
Tobique 1		10
Tobique 2		10
Grand Falls 1		15
Grand Falls 2		15
Grand Falls 3		15
Grand Falls 4		15
Milltown		4.2
Sisson		8
Musquash		4.8
	Total	842

TABLE 33

Description of Hydro System per period (monthly)

Month	Capacity Base	Capacity Peak	Energy Average (95%)	Energy Low (5%)
	MW	MW	GWh	GWh
JAN	15	842	156	73
FEB	15	842	135	61
MAR	15	842	181	88
APR	15	817	394	235
MAY	50	792	515	378
JUN	25	817	285	173
JUL	15	842	175	74
AUG	15	842	158	49
SEP	15	842	148	66
OCT	15	842	188	77
NOV	15	842	205	83
DEC	15	825	212	96

TABLE 34

Summary of Fixed System

Year	Installed Capacity MW	Comment
1981	2141	400 MW added at Point Lepreau
1982	2541	
1983	2541	
1984	2541	
1985	2541	
1986	2739	66 MW added to Coleson Cove 1,2,3
1987	2940	67 MW added to Coleson Cove 1,2,3
1988	2918	22 MW at Chatham 1 retired
1989	2918	
1990	2918	
1991	3138	230 MW added to Point Lepreau 10 MW at Grand Lake 5,6 retired
1992	3138	
1993	3123	15 MW at Grand Lake 7 retired
1994	3323	200 MW added at Grand Lake 9
1995	3323	
1996	3301	22 MW at Chatham 2 retired
1997	3301	
1998	3301	
1999	3501	200 MW added at Grand Lake 10
2000	3501	
2001	3453	48 MW at Courtenay Bay 1 retired
2002	3453	
2003	3453	
2004	3396	57 MW at Grand Lake 8 retired
2005	3386	10 MW at Courtenay Bay 2 retired
2006	3287	99 MW at Courtenay Bay 3 retired
2007	3185	102 MW at Courtenay Bay 4 retired
2008	3185	
2009	3080	105 MW at Dalhousie 1 retired
2010	3080	

VARIABLE SYSTEM (VARSYS)

The variable system describes the expansion candidates. The variable system is described in the tables that follow.

TABLE 35

Thermal and Nuclear Candidates

Station Name	Min. Load MW	Capa-city MW	Base Load Heat Rate kcal/kwh	Avge Incr Heat Rate kcal/kwh.	FOR %
N300*	300	300	3645	0	12
N400*	400	400	3542	0	13
C200	60	200	2728	2210	10
C300	90	300	2818	2608	10
C400	120	400	2816	2681	12
GT50	50	50	3150	0	10

* Important Note: The nuclear candidates are in reality units of 600 MW and 800 MW of capacity. These nuclear units are to be used for participation sale to the US. Hence only half of the units' capacities are available to N. B. Power. The data on Table 35 and subsequent table correspond to those for the actual unit capacities (600 MW and 800 MW).

TABLE 36

Thermal and Nuclear Candidates (Continued)

Station Name	Fuel Costs	Sched. Maint-enance	O&M Costs Fixed	O&M Costs Variable
	cents/M kcal	days	$/kW-month	$/MWh
N300	103	42	2.78	0
N400	103	42	2.78	0
C200	655	35	4.37*	0.22
C300	655	35	3.05*	0.21
C400	655	42	2.42*	0.20
GT50	2079	21	0.30	0

* The fixed operations and maintenance (O & M) costs for the coal fired expansion candidates includes 8 million dollars per year as fixed O & M for scrubbers. Thus, for the C200 MW unit, the fixed O & M costs for the scrubbers is:

$$8x10^6/(200000x12) = 3.33 \text{ \$kW-month.}$$

To this value must be added the fixed O & M costs for the unit of 1.04 $/kw-month giving 4.37 $/kW-month. Similarly for the other units.

The hydro candidates are shown in Table 37.

TABLE 37

Variable Hydro System

Month	Grand Falls RDT Base MW	Grand Falls RDT Peak MW	Grand Falls RDT Energy GWh	Morial Base MW	Morial Peak MW	Morial Energy GWh	Green River Base MW	Green River Peak MW	Green River Energy MWh
JAN	0	320	8.3	5	135	13.1	0	160	32.1
FEB	0	320	8.3	5	135	9.4	0	160	31.2
MAR	0	320	8.3	5	135	14.6	0	160	11.3
APR	0	320	191.7	5	135	33.0	0	160	10.3
MAY	0	320	283.3	5	135	40.3	0	160	14.0
JUN	0	320	65.3	5	135	32.2	0	160	9.9
JUL	0	320	19.0	5	135	24.1	0	160	6.1
AUG	0	320	11.2	5	135	21.2	0	160	4.6
SEP	0	320	8.3	5	135	19.3	0	160	4.6
OCT	0	320	22.7	5	135	25.3	0	160	4.8
NOV	0	320	41.0	5	135	31.3	0	160	9.4
DEC	0	320	17.7	5	135	23.5	0	160	6.9

It is assumed that the entire capacity of the unit is available throughout the year. That is, no variation of capacity per period is assumed. This is a reasonable assumption regarding capacity. As regards to energy, however, the average flow condition must be utilized in order to a get a reasonable plan. This average flow condition gives rise to the energies as depicted in Table 37.

CONFIGURATION GENERATOR (CONGEN)

Possible future electricity generation configurations for each year were defined by the CONGEN module of WASP, subject to certain appropriate constraints, some of which follow immediately from the input conditions, such as limiting LOLP and reserve capacity margin, while the others were carefully selected so as to enable the results to be obtained in the available time without any deleterious influence on their reliablity.

The LOLP constraint was fixed at LOLP = 0.00027 which corresponds to 0.1 day/year assuming 365 days in a year. This is reasonably light risk level for the system in isolation. Regarding the reserve capacity margin intervals bounding the optimal solution, these have been selected as:

YEARS	RESERVE MARGIN
1981 - 1987	Open
1988 - 2000	30 - 50 %
2001 - 2010	30 - 40 %

Tighter bounds will involve less feasible configurations with less computational requirements but would not be representative and realistic. The meaning of these bounds is that between the year 2001 - 2010, the optimal solution must have a LOLP less than 0.00027 and at the same time have a reserve capacity margin between 30 and 40%.

SIMULATION (MERSIM)

A probabilistic estimate of production costs, including fuel and operating and maintenance costs, for each configuration for each period of each year, is calculated by MERSIM module of WASP. The loading order of the generating units was specified with reference to the merit order of loading requirements. This particular order is given in Table 38.

The base component of the hydro capacity is loaded first in all cases. The peaking portion is fitted into the equivalent load duration curve so that it also covers outages of the thermal units. The peaking hydro component is fitted dynamically to discharge the entire energy available in the period.

TABLE 38

Loading Order of Units for Probabilistic Simulation

Loading Order	Comments
1	Base component of 80 MW at Coleson Cove
2	10 MW at Courtenay Bay 2
3	400 MW at Point Lepreau
4	230 MW at Point Lepreau additional
5	300 MW nuclear candidate
6	400 MW nuclear candidate
7	Base component of 60 MW of the 200 MW coal candidate
8	Peaking component of 140 MW of the 200 MW coal candidate
9	Base component of 60 MW at Grand Lake 9
10	Base component of 60 MW at Grand Lake 10
11	Base component of 90 MW of the 300 MW
12	Peaking component of 140 MW at Grand Lake 10
13	Base component of 90 MW of the 300 MW coal candidate
14	Base component of 120 MW of the 400 MW coal candidate
15	Base component of 18 MW at Grand Lake 8
16	Peaking component of 39 MW at Grand Lake 8
17	Peaking component of 210 MW of the 300 MW coal candidate
18	Peaking component of 280 MW of the 400 MW coal candidate
19	Base component of 30 MW at Dalhousie 2
20	Peaking component of 150 MW at Dalhousie 2
21	15 MW at Grand Lake 7
22	Base component of 30 MW at Dalhousie 1
23	Base component of 80 MW at Coleson Cove 2
24	Base component of 80 MW at Coleson Cove 3
25	Base component of 30 MW at Courtenay Bay 4
26	Base component of 30 MW at Courtenay Bay 3
27	10 MW at Grand Lake 5,6
28	Peaking component at Coleson Cove 1
29	Peaking component at Colwson Cove 2
30	Peaking component at Coleson Cove 3
31	Peaking component of 75 MW at Dalhousie 1
32	Peaking component of 69 MW at Courtenay 3
33	Peaking component of 72 MW at Courtenay 4
34	Base component of 18 MW at Courtenay 1
35	Peaking component of 30 MW at Courtenay 1
36	Base component of 11 MW at Chatham 2
37	Peaking component of 11 MW at Chatham 2
38	Base component of 11 MW at Chatham 1
39	23 MW at Moncton
40	Peaking component of 11 MW at Chatham 1
41	50 MW of gas turbine candidate

OPTIMIZATION (DYNPRO)

This module performs the optimization of the generation expansion plan using dynamic programming. The economic variables are inputted in this module. They are given as follows:

• Domestic discount rate for capital cost	13%
• Interest rate during construction	14%
• Domestic discount rate for operating cost	13%
• Escalation rate for operating costs for nuclear, coal, oil and gas fuel	10%
• Escalation rate for capital costs for all units (nuclear, coal, gas, and hydro)	11%
• Base year for present worth calculations	1981
• Study period	1981-2010

The capital costs in 1981 dollars, plant life and construction time are given in Table 39.

TABLE 39

Capital Costs, Plant Life and Construction Time of Expansion Candidates

Plant	Capital Costs $/kW	Plant Life years	Construction Time years
N300	1416.7	30	7
N400	1328.1	30	8
C200	900.0	30	5
C300	792.9	30	6
C400	803.6	30	6
GT50	200.0	20	1
Grand Falls	346.9	65	3
Morial	1142.9	65	4
Green River	612.5	65	4

Appendix C

THE COMPUTER PROGRAM

ELECTRIC SPACE HEATING LOAD CALCULATION PROGRAM

A listing of the computer program, written in FORTRAN IV, which evaluates the energy required per household for electric space heating on an hour-by-hour basis for the different assumed dwelling types is given in this Appendix. The program interfaces with interactive terminals and calls subprograms to read in data (from disk or buffer), make load calculations and generate an output file of the hourly demand per household for electric space heating.

```
C
C   ELECTRIC SPACE HEATING LOAD CALCULATION PROGRAM
C
C   THE FUNCTION OF THIS PROGRAM IS TO DETERMINE THE ENERGY REQUIRED
C   PER HOUSEHOLD  FOR  ELECTRIC  SPACE  HEATING ON AN  HOUR-BY-HOUR
C   BASIS IN A PARTICULAR TYPE OF  DWELLING.  THE PROGRAM INTERFACES
C   WITH INTERACTIVE TERMINAL  AND CALLS SUBPROGRAMS TO READ IN DATA
C   (FROM DISK  OR  BUFFER),  MAKE LOAD CALCULATIONS AND GENERATE AN
C   OUTPUT  FILE  OF  THE  HOURLY  DEMAND  PER  HOUSEHOLD FOR  SPACE
C   HEATING.
C
C   FILES USED IN THE PROGRAM :
C
C   5  - TERMINAL INPUT
C   6  - TERMINAL OR LISTING FILE OUTPUT (FOR DEBUGGING)
C   8  - TERMINAL OUTPUT
C   9  - OUTPUT FILE CONTAINING RECORDS OF HOURLY DEMAND (WATTS)
C   10 - INPUT FILE CONTAINING RECORDS OF HOURLY TEMP. (DEG(C))
C   11 - INPUT FILE CONTAINING RECORDS OF HOURLY  SOLAR RADIATION ON
C        A HORIZONTAL SURFACE (WATTS/M**2)
C
C   BY : S. CHAN
C        DEPT. OF ELECT. ENG.
C        UNIV. OF OTTAWA
C
C   DATE : 01/07/81
C
C   VERSION : 01
C
      INTEGER DAY,HOUR
      DIMENSION HLOAD(750),DRD(750),DTA(750),ARRAY(30),ULOAD(24),
     1          HWILD(24),NTHRS(12),NHRS(12),NDAYS(12),MON(12),
     2          UIJ(7)
      DATA NTHRS/0,744,1416,2160,2880,3624,
     1          4344,5088,5832,6552,7296,8016/,
     2     NHRS /744,672,744,720,744,720,744,744,720,744,720,744/,
     3     NDAYS/31,28,31,30,31,30,31,31,30,31,30,31/
      DATA MON/'JAN ','FEB ','MAR ','APR ','MAY ','JUN ',
     1         'JUL ','AUG ','SEPT','OCT ','NOV ','DEC '/,
     2     UIJ/2.33,1.25,0.88,0.68,0.54,0.45,0.39/,
     3     PI /3.1415926/,ICOUNT/1/,IDAY/1/
C
1000  FORMAT (' ENTER FIRST DATE OF HEATING SEASON (DD,MM)')
1010  FORMAT (' ENTER LAST DATE OF HEATING SEASON (DD,MM)')
1015  FORMAT (' ENTER THE TYPE NO. OF THE DWELLING')
1020  FORMAT (' ENTER DATA FOR THE FOLLOWING BUILDING COMPONENTS :'/
     1        ' (NOTE : ALL PARAMETERS ARE IN SI UNITS.)'/
     2        ' 1. WINDOW - AWIN , RWIN')
1030  FORMAT (' 2. DOOR - ADOR , RDOR')
1040  FORMAT (' 3. CEILING - ACEIL , PERC , RCEIL , RWOODC , RINSC')
1050  FORMAT (' 4. WALL - AWALL , PERW , RWALL , RWOODW , RINSW')
1060  FORMAT (' 5. BASEMENT SLAB - ASLAB , RSLAB')
1070  FORMAT (' 6. BASEMENT WALL ABOVE GRADE - AUG , RBASW , RINSB')
1080  FORMAT (' 7. BASEMENT WALL BELOW GRADE - ABG , DBG')
```

```
1090  FORMAT (' ENTER THE NO. OF AIR CHANGE/HR & HOUSE VOLUME (M**3)')
1100  FORMAT (' ENTER THE AVERAGE HOURLY WILD HEAT RATE (WH/H)')
1110  FORMAT (' ENTER THE HOURLY DEMAND OF UTILITY ON A TYPICAL SUNDAY')
C
2000  FORMAT (1H1//' * * * ELECTRIC SPACE HEATING LOAD CALCULATION ',
     1        'PROGRAM * * *'//)
2010  FORMAT (' HEATING SEASON : ',A4,I3,' - ',A4,I3)
2020  FORMAT (' HEATING SEASON : JAN   1 - ',A4,I3,' , ',A4,I3,
     1       ' - DEC  31')
2025  FORMAT (/' DWELLING TYPE :',I6)
2030  FORMAT (/' DWELLING CHARACTERISTICS :'//
     1        4X,'BUILDING COMPONENT :',6X,'HEAT TRANS. COEF.'/
     2        30X,'(WATTS/DEG(C))'/1X,45('-')/
     3        ' BASEMENT WALL BELOW GRADE',6X,F10.2/
     4        ' BASEMENT WALL ABOVE GRADE',6X,F10.2/
     5        ' BASEMENT SLAB',18X,F10.2)
2040  FORMAT (' WALL',27X,F10.2/' CEILING',24X,F10.2/
     1        ' WINDOW',25X,F10.2/' DOOR',27X,F10.2//
     2        ' FAB - HEAT TRANS. COEF. = ',F10.2,' WATTS/DEG(C)'//
     3        ' INF - HEAT TRANS. COEF. = ',F10.2,' WATTS/DEG(C)'//
     4        ' TOTAL HEAT TRANS. COEF. = ',F10.2,' WATTS/DEG(C)')
C
C  THIS SECTION OF THE PROGRAM IS FOR INPUT OF DATA
C
      WRITE (8,1000)
      CALL READIN (ARRAY,2)
      IDDS = ARRAY(1)+0.5
      IMMS = ARRAY(2)+0.5
      WRITE (8,1010)
      CALL READIN (ARRAY,2)
      IDDE = ARRAY(1)+0.5
      IMME = ARRAY(2)+0.5
      WRITE (8,1015)
      CALL READIN (ARRAY,1)
      NTYPE = ARRAY(1)+0.5
      CALL DEFINE (NTYPE)
      WRITE (8,1020)
      CALL READIN (ARRAY,2)
      AWIN = ARRAY(1)
      RWIN = ARRAY(2)
      WRITE (8,1030)
      CALL READIN (ARRAY,2)
      ADOR = ARRAY(1)
      RDOR = ARRAY(2)
      WRITE (8,1040)
      CALL READIN (ARRAY,5)
      ACEIL = ARRAY(1)
      PERC = ARRAY(2)
      RCEIL = ARRAY(3)
      RWOODC = ARRAY(4)
      RINSC = ARRAY(5)
      WRITE (8,1050)
      CALL READIN (ARRAY,5)
      AWALL = ARRAY(1)
```

```
      PERW = ARRAY(2)
      RWALL = ARRAY(3)
      RWOODW = ARRAY(4)
      RINSW = ARRAY(5)
      WRITE (8,1060)
      CALL READIN (ARRAY,2)
      ASLAB = ARRAY(1)
      RSLAB = ARRAY(2)
      WRITE (8,1070)
      CALL READIN (ARRAY,3)
      AUG = ARRAY(1)
      RBASW = ARRAY(2)
      RINSB = ARRAY(3)
      WRITE (8,1080)
      CALL READIN (ARRAY,2)
      ABG = ARRAY(1)
      DBG = ARRAY(2)
      WRITE (8,1090)
      CALL READIN (ARRAY,2)
      ACHG = ARRAY(1)
      VINF = ARRAY(2)
      WRITE (8,1100)
      CALL READIN (ARRAY,1)
      HDA = 24.*ARRAY(1)
      WRITE (8,1110)
      CALL READIN (ARRAY,24)
      DO 100 K=1,24
100   ULOAD(K) = ARRAY(K)
C
C  CALCULATION OF THE HEAT TRANSFER COEF. AND OTHER BASIC PARAMETERS
C
C  CALCULATE THE SPACE HEATING PERIOD COUNTER
C
      ION = NTHRS(IMMS)+24*(IDDS-1)
      IOFF = NTHRS(IMME)+24*IDDE
C
C  BASEMENT WALL BELOW GRADE HEAT TRANSFER
C
C  CALCULATE THE NO. OF ONE-FT INCREMENT
C
      NDBG = DBG/0.3048 + 0.5
      UBG = 0.
      DO 110 IJ=1,NDBG
110   UBG=UBG+1./(1./UIJ(IJ)+RINSB)
      HBG = ABG*UBG/NDBG
C
C  BASEMENT WALL ABOVE GRADE HEAT TRANSFER
C
      HBUG = AUG/(RBASW+RINSB)
C
C  BASEMENT SLAB HEAT TRANSFER
C
      HSLB = ASLAB/RSLAB
C
```

```
C  TOTAL BASEMENT HEAT TRANSFER
C
      HBAS = HBG+HBUG+HSLB
C
C  WALL HEAT TRANSFER
C
      HWALL = AWALL*(((1.-PERW)/(RWALL+RINSW))+PERW/(RWALL+RWOODW))
C
C  CEILING HEAT TRANSFER
C
      HCEIL = ACEIL*(((1.-PERC)/(RCEIL+RINSC))+PERC/(RCEIL+RWOODC))
C
C  DOOR HEAT TRANSFER
C
      HDOOR = ADOR/RDOR
C
C  WINDOW HEAT TRANSFER
C
      HWIN = AWIN/RWIN
C
C  TOTAL FABRIC HEAT TRANSFER
C
      HFAB = HBAS+HWALL+HCEIL+HDOOR+HWIN
C
C  INFILTRATION HEAT TRANSFER
C
      HINF = 0.361111*VINF*ACHG
C
C  TOTAL HEAT TRANSFER OF THE DWELLING
C
      HTRANS = HFAB+HINF
C
C  END OF BASIC PARAMETERS CALCULATIONS, PRINT THE NUMBERS FOR
C  CHECKING PURPOSE !
C
      WRITE (6,2000)
      IF (IOFF .GE. ION) WRITE (6,2010) MON(IMMS),IDDS,MON(IMME),IDDE
      IF (IOFF .LT. ION) WRITE (6,2020) MON(IMME),IDDE,MON(IMMS),IDDS
      WRITE (6,2025) NTYPE
      WRITE (6,2030) HBG,HBUG,HSLB
      WRITE (6,2040) HWALL,HCEIL,HWIN,HDOOR,HFAB,HINF,HTRANS
C
C  CALCULATION OF THE DAILY WILD HEAT GAIN
C
      TLOAD = 0.
      UMIN = 10.0E 10
      DO 120 IK=1,24
      IF (ULOAD(IK) .LT. UMIN) UMIN = ULOAD(IK)
120   TLOAD = TLOAD+ULOAD(IK)
      UAMIN = (UMIN-0.0035*TLOAD)/0.916
      DENOM = TLOAD-24.*UAMIN
      DO 130 IK=1,24
130   HWILD(IK) = HDA*(ULOAD(IK)-UAMIN)/DENOM
C
```

```
C   START OF LOOP
C
       DO 500 MONTH=1,12
C
C   READ IN HOURLY TEMP. AND SOLAR RADIATION DATA FOR MONTH 'MONTH'
C
       IHOUR = 1
       KHOUR = NHRS(MONTH)
       CALL VSRDR (DTA,KHOUR,10)
       CALL VSRDR (DRD,KHOUR,11)
C
C   START OF MONTHLY SIMULATION
C
       ND = NDAYS(MONTH)
       DO 550 DAY=1,ND
C
C   CALCULATE THE DAILY SOLAR INTENSITY
C
       SOLINT = 1.38-0.94*SIN(PI*IDAY/365.+0.0274*PI)
       DO 600 HOUR=1,24
       IF (ICOUNT .GT. IOFF .AND. ICOUNT .LE. ION) GO TO 650
C
C   CALCULATION OF PASSIVE SOLAR HEAT GAIN FOR THIS HOUR
C
       HSOL = 0.68*SOLINT*DRD(IHOUR)*AWIN
C
C   CALCULATION OF THE SPACE HEATING REQUIREMENT FOR THIS HOUR
C
       TDIF = 22.22-DTA(IHOUR)
       IF (TDIF .LE. 0.) GO TO 650
       HLOAD(IHOUR) = TDIF*HTRANS-HSOL-HWILD(HOUR)
       IF (HLOAD(IHOUR) .GT. 0.) GO TO 700
C
C   REACHING 650 MEANING THAT NO ELECTRIC SPACE HEATING REQUIRED
C   FOR THIS HOHR
C
650    HLOAD(IHOUR) = 0.
C
700    ICOUNT = ICOUNT+1
C
600    IHOUR = IHOUR+1
C
550    IDAY = IDAY+1
C
       WRITE (9) (HLOAD(IJ),IJ=1,KHOUR)
500    CALL OUTPUT (HLOAD,KHOUR,MON(MONTH))
       STOP
       END


       SUBROUTINE OUTPUT (DATA,NP,MONTH)
       DIMENSION DATA(NP)
1000   FORMAT ('1 *** HOURLY INCREMENTAL ELECTRIC SPACE HEATING DEMAND',
     1         ' IN WATTS FOR ',A4,' ***'//' DAY    HR')
```

```
1010  FORMAT (1X,I3,'  1-12',12F10.2/4X,'  13-24',12F10.2)
      J1=1
      J2=24
      NDAYS=NP/24
      WRITE (6,1000) MONTH
      DO 10 IDAY=1,NDAYS
      WRITE (6,1010) IDAY,(DATA(J),J=J1,J2)
      J1=J1+24
10    J2=J2+24
      RETURN
      END


      SUBROUTINE VSFDR (DATA,NP,LUR)
      DIMENSION DATA(NP)
      READ (LUR) DATA
      RETURN
      END


      SUBROUTINE DEFINE (NTYPE)
C
C  SUBROUTINE TO PERFORM THE TASK OF CMS FILE DEFINITION
C
      REAL*8 FNAME,FMODE,DDNAME
      DIMENSION FTYPE(2)
      DATA FNAME/'HEATLOAD'/,FMODE/'E'/,DDNAME/'09'/
      DATA FTYPE(1)/'TYPE'/
      CALL CONCAT (FTYPE(2),NTYPE)
      CALL DEF (FNAME,FTYPE,FMODE,DDNAME)
      RETURN
      END


      SUBROUTINE CONCAT (CHAR,NTYPE)
C
C  SUBROUTINE TO CONVERT A NUMBER TO A CHARACTER
C
      LOGICAL*1 CHAR,DIG
      DIMENSION DIG(10),CHAR(4),NUM(4)
      DATA DIG/'0','1','2','3','4','5','6','7','8','9'/
      NUMBER = NTYPE
      NUM(1) = NUMBER/1000.
      NUMBER = NUMBER-NUM(1)*1000
      NUM(2) = NUMBER/100.
      NUMBER = NUMBER-NUM(2)*100
      NUM(3) = NUMBER/10.
      NUM(4) = NUMBER-NUM(3)*10
      DO 1000 I=1,4
      NO = NUM(I)+1
      GO TO (10,20,30,40,50,60,70,80,90,100), NO
10    CHAR(I) = DIG(1)
      GO TO 1000
20    CHAR(I) = DIG(2)
```

```
      GO TO 1000
30    CHAR(I) = DIG(3)
      GO TO 1000
40    CHAR(I) = DIG(4)
      GO TO 1000
50    CHAR(I) = DIG(5)
      GO TO 1000
60    CHAR(I) = DIG(6)
      GO TO 1000
70    CHAR(I) = DIG(7)
      GO TO 1000
80    CHAR(I) = DIG(8)
      GO TO 1000
90    CHAR(I) = DIG(9)
      GO TO 1000
100   CHAR(I) = DIG(10)
1000  CONTINUE
      RETURN
      END


      SUBROUTINE READIN (ARRAY,NUMVAL)
C
C  SUBROUTINE READIN PERFORMS THE FUNCTION OF FREE FORMAT  READING FROM
C  LOGICAL  UNIT  LUR.   THE VALUES TO BE  READ IN  (FROM  80 CHARACTER
C  RECORDS) CAN BE IN ANY FORMAT. THEY MUST BE SEPERATED BY ONE OR MORE
C  COMMAS AND/OR BLANK SPACES.  E FORMAT IS PERMISSABLE.  THERE MUST BE
C  A DECIMAL  POINT AND  AT LEAST  ONE  NON-ZERO  DIGIT  BEFORE THE E.
C  MULTIPLE DATA  RECORDS WILL BE READ IF NECESSARY.  THIS  PROGRAM WAS
C  ORIGINALLY ADAPTED FROM FCHART.
C
C  BY : S. CHAN
C       DEPT. OF ELECT. ENG.
C       UNIV. OF OTTAWA
C
C  DATE : 01/07/81
C
C  VERSION : 01
C
      INTEGER E,DATAR
      DIMENSION ICARD(82),ARRAY(1),IDIG(10)
      DATA IDIG/1H0,1H1,1H2,1H3,1H4,1H5,1H6,1H7,1H8,1H9/
      DATA IBLK/1H /,ICOM/1H,/,IDP/1H./,NS/1H-/,E/1HE/,IPLUS/1H+/
      DATA ICARD(1)/1H /,ICARD(82)/1H /,LUR/5/,LUW/8/
      INIT=0
      J=1
5     READ(LUR,99) (ICARD(I),I=2,81)
99    FORMAT(80A1)
      IF(INIT.NE.0) GO TO 41
      DO 40 M=1,NUMVAL
40    ARRAY(M)=0.0
C
C  IF IPART=1, PROGRAM DETECTS DIGITS PRIOR  TO DECIMAL POINT.
C  IF IPART=2, PROGRAM DETECTS DIGITS AFTER THE DECIMAL POINT.
```

```
C  IF IPART=3, PROGRAM DETECTS DIGITS  IN   E-FORMAT EXPONENT.
C
41     IPART=1
C
C  SIGN1 IS THE SIGN OF THE MANTISSA OF THE NUMBER READ IN.
C  SIGN2 IS THE SIGN OF THE EXPONENT OF THE NUMBER READ IN.
C
       SIGN1=1.0
       SIGN2=1.0
       EX=0.0
       DO 60 K=2,82
       IF(ICARD(K).NE.IBLK.AND.ICARD(K).NE.ICOM)GO TO 42
       IF(ICARD(K-1).NE.IBLK.AND.ICARD(K-1).NE.ICOM)GO TO 58
       GO TO 60
42     GO TO (43,50,54),IPART
43     IF(ICARD(K).EQ.IPLUS)GO TO 60
       IF(ICARD(K).NE.NS)GO TO 44
       SIGN1=-1.0
       GO TO 60
44     IF(ICARD(K).NE.IDP)GO TO 45
       IPART=2
       LD=0
       GO TO 60
45     DO 46 N=1,10
       IF(ICARD(K).EQ.IDIG(N))GO TO 47
46     CONTINUE
       GO TO 65
47     ARRAY(J)=ARRAY(J)*10.0+FLOAT(N-1)
       GO TO 60
50     IF(ICARD(K).NE.E)GO TO 51
       IPART=3
       GO TO 60
51     DO 52 N=1,10
       IF(ICARD(K).EQ.IDIG(N))GO TO 53
52     CONTINUE
       GO TO 65
53     LD=LD+1
       ARRAY(J)=ARRAY(J)+FLOAT(N-1)*10.0**(-LD)
       GO TO 60
54     IF(ICARD(K).EQ.IPLUS)GO TO 60
       IF(ICARD(K).NE.NS)GO TO 55
       SIGN2=-1.0
       GO TO 60
55     DO 56 N=1,10
       IF(ICARD(K).EQ.IDIG(N))GO TO 57
56     CONTINUE
       GO TO 65
57     EX=EX*10.0+FLOAT(N-1)
       GO TO 60
58     ARRAY(J)=SIGN1*ARRAY(J)*10.0**(SIGN2*EX)
       IF(J.LT.NUMVAL)GO TO 59
       RETURN
59     J=J+1
       SIGN1=1.0
```

```
      SIGN2=1.0
      IPART=1
      EX=0.0
60    CONTINUE
      INIT=1
      GO TO 5
65    IF(J.GT.1) GO TO 68
      WRITE(LUW,1100)
      J=1
      INIT=0
      GO TO 5
68    WRITE(LUW,1200)J,NUMVAL,ARRAY(J-1)
      INIT=1
      ARRAY(J)=0.0
      GO TO 5
1100  FORMAT(' INPUT ERROR, PLEASE TRY AGAIN')
1200  FORMAT(' INPUT ERROR, RE-ENTER VALUE(S) STARTING WITH #',I3,
     .' IN A SEQUENCE OF ',I3,/' THE LAST VALUE READ IN WAS ',E14.6)
      END
```

ELECTRIC LOAD DATA PROCESSING PROGRAM

This program combines the hourly electric space heating demand data files generated by the electric space heating load calculation program with the historic hourly loads to determine the total system demand for electric heating.

```
C
C   ELECTRIC LOAD DATA PROCESSING PROGRAM
C
C   THE FUNCTION OF THIS PROGRAM IS TO COMBINE THE  HOURLY INCREMENTAL
C   ELECTRIC SPACE HEATING DEMAND DATA FILES GENERATED BY THE ELECTRIC
C   SPACE  HEATING  LOAD  CALCULATION PROGRAM WITH THE HISTORIC HOURLY
C   LOADS TO DETERMINE THE TOTAL SYSTEM DEMAND.
C
C   UPON EXECUTION,  THE  PROGRAM  ASKS THE  USER TO  INPUT THE NO. OF
C   HOUSEHOLDS WITH ELECTRIC SPACE HEATING FOR EACH TYPE OF DWELLINGS,
C   AND THE PEAK DEMAND  WITHOUT  ELECTRIC  HEATING FOR THE SAME YEAR.
C   THE  PROGRAM  THEN CALCULATES  THE HEATING STRATEGY MODIFIED TOTAL
C   HOURLY  LOADS  BY  ADDING  THE HOURLY  INCREMENTAL  ELECTRIC SPACE
C   HEATING DEMAND TO THE HISTORIC HOURLY LOADS.  A SORTING ROUTINE IS
C   THEN USED TO CONVERT THE MODIFIED HOURLY LOADS TO AN LOAD DURATION
C   CURVE  AND  GENERATE  AN OUTPUT FILE  FOR INPUT TO THE  GENERATION
C   PLANNING  PROGRAM (WASP-2).  A  PLOTTING  ROUTINE CAN BE  USED FOR
C   GRAPHICAL DISPLAY OF THE DATA.
C
C   FILES USED IN THE PROGRAM :
C
C   5  - TERMINAL INPUT
C   6  - TERMINAL OUTPUT OR FILE OUTPUT (FOR DEBUGGING)
C   8  - TERMINAL OUTPUT
C   9  - HOURLY INCREMENTAL ELECTRIC  SPACE  HEATING  DEMAND DATA FILE
C        FOR DWELLING TYPE # 1.
C   10 - SAME AS 9 BUT FOR TYPE # 2.
C   11 - SAME AS 9 BUT FOR TYPE # 3.
C   12 - SAME AS 9 BUT FOR TYPE # 4.
C   13 - HISTORIC HOURLY LOADS INPUT
C   14 - OUTPUT  FILE  FOR  INPUT  TO THE  GENERATION PLANNING PROGRAM
C         (WASP-2).
C
C   BY : S. CHAN
C        DEPT. OF ELECT. ENG.
C        UNIV. OF OTTAWA
C
C   DATE : 01/07/81
C
C   VERSION : 01
C
      DIMENSION HLOAD(750),SLOAD(750),HEAT1(750),HEAT2(750),HEAT3(750),
     1          HEAT4(750),XP(750),YP(750),XP1(750),YP1(750),IMON(12),
     2          IWK(12),NHRS(12),PKMON(15),ARRAY(6),JWEEK(4)
      EQUIVALENCE (HEAT1(1),XP(1)),(HEAT2(1),YP(1)),(HEAT3(1),XP1(1)),
     1          (HEAT4(1),YP1(1))
      DATA IMON/12*0/,IWK/12*0/,JWEEK/0,168,336,504/
      DATA NHRS/744,672,744,720,744,720,744,744,720,744,720,744/
C
1000  FORMAT (' ENTER THE PROCESSING YEAR')
1010  FORMAT (' ENTER THE BASE CASE PEAK DEMAND (MW) FOR EACH MONTH')
1015  FORMAT (' ENTER THE DWELLING TYPE NO.')
1020  FORMAT (' ENTER THE NO. OF ADDITIONAL HOUSEHOLDS WITH ELECTRIC',
     1        ' SPACE HEATING AND'/' THE PERCENTAGE DISTRIBUTION OF',
```

```
     2           ' EACH TYPE')
1030  FORMAT ('  ENTER THE NO. OF PLOTS TO BE PRODUCED')
1040  FORMAT ('  FOR PLOT #',I3,', ENTER WEEK,MONTH')
1050  FORMAT ('  WEEK = ',I2,' IS INVALID, PLEASE RE-ENTER')
1060  FORMAT ('  MONTH = ',I3,' IS INVALID, PLEASE RE-ENTER')
C
C  THIS SECTION OF THE PROGRAM IS FOR INPUT OF DATA
C
      WRITE (8,1000)
      CALL READIN (ARRAY,1)
      JAHR = ARRAY(1)+0.5
      WRITE (8,1010)
      CALL READIN (PKMON,12)
      WRITE (8,1015)
      CALL READIN (ARRAY,4)
      CALL INDEF (ARRAY)
      WRITE (8,1020)
      CALL READIN (ARRAY,5)
      NTYPE1 = ARRAY(1)*ARRAY(2)/100.+0.5
      NTYPE2 = ARRAY(1)*ARRAY(3)/100.+0.5
      NTYPE3 = ARRAY(1)*ARRAY(4)/100.+0.5
      NTYPE4 = ARRAY(1)*ARRAY(5)/100.+0.5
      WRITE (8,1030)
      CALL READIN (ARRAY,1)
      NPLOT = ARRAY(1)+0.5
      IF (NPLOT) 100,100,110
C
C  PLOT IS REQUIRED
C
110   CALL INIPLO (NPLOT)
      XORG = 0.
      DO 120 IP=1,NPLOT
150   WRITE (8,1040) IP
      CALL READIN (ARRAY,2)
      IWEEK = ARRAY(1)+0.5
      IMONTH = ARRAY(2)+0.5
      IF (IWEEK.GT.0 .AND. IWEEK.LE.4) GO TO 130
      WRITE (8,1050) IWEEK
      GO TO 150
130   IF (IMONTH.GT.0 .AND. IMONTH.LE.12) GO TO 140
      WRITE (8,1060) IMONTH
      GO TO 150
C
C  REACHING 140 MEANING THAT THE INPUT IS CORRECT
C
140   IMON(IMONTH) = 1
      IWK(IMONTH) = IWEEK
120   CONTINUE
C
C  START OF ANNUAL SIMULATION
C
100   CALL WASP (XP,YP,1,PKMON,PEAK,JAHR,1)
      DO 160 MONTH=1,12
      NH = NHRS(MONTH)
```

```
      PKMW = PKMON(MONTH)
C
C  READ IN DATA FILES
C
      CALL VSRDR (HLOAD,NH,13)
      CALL VSRDR (HEAT1,NH,9)
      CALL VSRDR (HEAT2,NH,10)
      CALL VSRDR (HEAT3,NH,11)
      CALL VSRDR (HEAT4,NH,12)
C
C  MERGE ALL DATA FILES HERE
C
      DO 170 IH=1,NH
      HLOAD(IH) = PKMW*HLOAD(IH)
170   SLOAD(IH) = HLOAD(IH)+1.0E-06*(NTYPE1*HEAT1(IH)+NTYPE2*
     1            HEAT2(IH)+NTYPE3*HEAT3(IH)+NTYPE4*HEAT4(IH))
C
C  PLOT OF LOAD VARIATION REQUIRED ?
C
      IF (IMON(MONTH) .EQ. 0) GO TO 180
C
C  REACHING THIS POINT MEANING THAT THE PLOT IS REQUIRED
C
C  NOW FIND OUT WHICH WEEK
C
      ISTART = JWEEK(IWK(MONTH))
      PKWEEK = 0.
      DO 190 IK=1,168
      XP(IK) = FLOAT(IK)
      YP(IK) = HLOAD(IK+ISTART)
C
C  FIND THE PEAK DEMAND FOR THIS WEEK
C
      IF (YP(IK) .GT. PKWEEK) PKWEEK = YP(IK)
190   CONTINUE
      DO 191 IK=1,168
191   YP(IK) = 100.0*YP(IK)/PKWEEK
C
C  INITIALIZE THE CALCOMP PLOTTER FOR PLOTTING
C
      CALL INICUR (XORG, JAHR, MONTH, IWK(MONTH), PKWEEK)
      XORG = 26.
C
C  PLOT THE BASE CASE LOAD VARIATION
C
      CALL CURPLO (XP,YP,168,0)
C
C  NOW THE MODIFIED LOAD VARIATION
C
      DO 210 IK=1,168
210   YP(IK) = 100.0*SLOAD(IK+ISTART)/PKWEEK
      CALL CURPLO (XP,YP,168,2)
C
C  NOW CONVERT THE HOURLY LOADS TO AN LOAD DURATION CURVE
```

```
C
C  FIRST, CONVERT THE HISTORIC HOURLY LOADS
C
      CALL BUBBLE (HLOAD,NH)
      CALL LOAD (HLOAD,XP,YP,NH,NLDC,PK1)
C
C  NOW INITIALIZE THE CALCOMP PLOTTER FOR PLOTTING OF THE LDC
C
      CALL INILDC (XORG, JAHR, MONTH, PK1)
      DO 220 IK=1,NLDC
      XP(IK) = 100.0*XP(IK)
220   YP(IK) = 100.0*YP(IK)
      CALL LDCPLO (XP,YP,NLDC)
C
C  NOW DO THE SAME FOR THE MODIFIED HOURLY LOADS
C
180   CALL BUBBLE (SLOAD,NH)
      CALL LOAD (SLOAD,XP,YP,NH,NLDC,PK2)
      PKMON(MONTH) = PK2
C
C  PLOT REQUIRED ?
C
      IF (IMON(MONTH) .EQ. 0) GO TO 230
C
C  REACHING THIS POINT MEANS PLOT REQUIRED
C
      FACTOR = PK2/PK1
      DO 240 IK=1,NLDC
      XP1(IK) = 100.0*XP(IK)
240   YP1(IK) = 100.0*FACTOR*YP(IK)
      CALL LDCPLO (XP1,YP1,NLDC)
C
C  TOO MANY POINTS FOR WASP-2, SELECT A FEW ONLY
C
230   CALL SELECT (XP,YP,NLDC)
C
C  OUTPUT TO WASP-2
C
160   CALL WASP (XP,YP,NLDC,PKMON,PEAK,JAHR,2)
C
C  END OF LDC PROCESSING, NOW CALCULATE THE PERIOD PEAK LOAD AS
C  A FRACTION OF ANNUAL PEAK
C
      CALL STPPLO (NPLOT)
      PEAK = 0.
      DO 250 IK=1,12
250   IF (PKMON(IK) .GT. PEAK) PEAK = PKMON(IK)
      DO 260 IK=1,12
260   PKMON(IK) = PKMON(IK)/PEAK
C
C  OUTPUT TO WASP-2
C
      CALL WASP (XP,YP,1,PKMON,PEAK,JAHR,3)
      STOP
```

```
      END

      SUBROUTINE VSEDR (DATA,NP,LUR)
      DIMENSION DATA(NP)
      READ (LUR) DATA
      RETURN
      END

      SUBROUTINE WASP (XP,YP,NLDC,PKMON,PEAK,JAHR,NCNTRL)
C
C  ROUTINE TO GENERATE AN OUTPUT FILE FOR INPUT TO WASP-2
C
      INTEGER ONE,TWO,THREE
      DIMENSION XP(NLDC),YP(NLDC),PKMON(12)
      DATA ZERO/0./,ONE/1/,TWO/2/,THREE/3/
C
1000  FORMAT (F8.1,I6,66X)
1010  FORMAT (I4,74X)
1020  FORMAT (10F8.6)
C
      GO TO (100,200,300), NCNTRL
C
100   CONTINUE
      CALL OUTDEF (JAHR)
      DEFINE FILE 14(300,80,E,NEXT)
      NEXT = 1
      WRITE (14'NEXT,1000) ZERO,JAHR
      WRITE (14'NEXT,1010) TWO
      RETURN
C
200   WRITE (14'NEXT,1010) NLDC
      WRITE (14'NEXT,1020) (XP(I),YP(I),I=1,NLDC)
      RETURN
C
300   WRITE (14'NEXT,1010) THREE
      WRITE (14'NEXT,1020) (PKMON(I),I=1,12)
      WRITE (14'NEXT,1010) ONE
      ENDFILE 14
      WRITE (14'1,1000) PEAK,JAHR
      RETURN
      END

      SUBROUTINE OUTDEF (JAHR)
C
C  SUBROUTINE TO PERFORM THE TASK OF CMS FILE DEFINITION
C
      REAL*8 FNAME,FMODE,DDNAME
      DIMENSION FTYPE(2)
      DATA FNAME/'LDC'/,FMODE/'E'/,DDNAME/'14'/
      DATA FTYPE(1)/'YEAR'/
      CALL CONCAT (FTYPE(2),JAHR)
```

```
      CALL DFN (FNAME,FTYPE,FMODE,DDNAME)
      RETURN
      END


      SUBROUTINE INDEF (ARRAY)
C
C  SUBROUTINE TO PERFORM THE TASK OF CMS FILE DEFINITION
C
      REAL*8 FNAME,FMODE,DD,DDNAME
      DIMENSION ARRAY(4),DD(4),FTYPE(2)
      DATA FNAME/'HEATLOAD'/,FMODE/'E'/,FTYPE(1)/'TYPE'/
      DATA DD/'09','10','11','12'/
      DO 100 I=1,4
      ITYPE = ARRAY(I)+0.5
      CALL CONCAT (FTYPE(2),ITYPE)
      DDNAME = DD(I)
100   CALL DEF (FNAME,FTYPE,FMODE,DDNAME)
      RETURN
      END


      SUBROUTINE CONCAT (CHAR,JAHR)
C
C  SUBROUTINE TO CONVERT A NUMBER TO A CHARACTER
C
      LOGICAL*1 CHAR,DIG
      DIMENSION DIG(10),CHAR(4),NUM(4)
      DATA DIG/'0','1','2','3','4','5','6','7','8','9'/
      NUMBER = JAHR
      NUM(1) = NUMBER/1000.
      NUMBER = NUMBER-NUM(1)*1000
      NUM(2) = NUMBER/100.
      NUMBER = NUMBER-NUM(2)*100
      NUM(3) = NUMBER/10.
      NUM(4) = NUMBER-NUM(3)*10
      DO 1000 I=1,4
      NO = NUM(I)+1
      GO TO (10,20,30,40,50,60,70,80,90,100), NO
10    CHAR(I) = DIG(1)
      GO TO 1000
20    CHAR(I) = DIG(2)
      GO TO 1000
30    CHAR(I) = DIG(3)
      GO TO 1000
40    CHAR(I) = DIG(4)
      GO TO 1000
50    CHAR(I) = DIG(5)
      GO TO 1000
60    CHAR(I) = DIG(6)
      GO TO 1000
70    CHAR(I) = DIG(7)
      GO TO 1000
80    CHAR(I) = DIG(8)
```

```
      GO TO 1000
90    CHAR(I) = DIG(9)
      GO TO 1000
100   CHAR(I) = DIG(10)
1000  CONTINUE
      RETURN
      END


      SUBROUTINE BUBBLE (ELOAD,N)
C
C     BUBBLE SORT
C
      INTEGER N,COUNT,BOTTOM,EXCH,CURRNT
      DIMENSION ELOAD(750)
      BOTTOM = N
 1    IF (BOTTOM .LE. 1) GO TO 99
      EXCH = 0
      CURRNT = 1
 2    IF (CURRNT .GE. BOTTOM) GO TO 98
      IF (ELOAD(CURRNT) .GE. ELOAD(CURRNT+1)) GO TO 97
      TEMP = ELOAD(CURRNT)
      ELOAD(CURRNT) = ELOAD(CURRNT+1)
      ELOAD(CURRNT+1) = TEMP
      EXCH = CURRNT
 97   CURRNT = CURRNT + 1
      GO TO 2
 98   BOTTOM = EXCH
      GO TO 1
 99   RETURN
      END


      SUBROUTINE LOAD (ELOAD,X,Y,N,NLDC,PKMW)
C
C     LDC GENERATOR
C
      DIMENSION ELOAD(750),X(750),Y(750)
      SUM = 0.0
      PKMW = ELOAD(1)
      DO 100 I=1, N
 100  ELOAD(I) = ELOAD(I) / PKMW
      TIME = 1.0
      NLDC = 1
      J = 1
 130  IF (J .GE. N) GO TO 200
      IF (ELOAD(J) .EQ. ELOAD(J+1)) GO TO 120
      X(NLDC) = TIME / N
      Y(NLDC) = ELOAD(J)
      NLDC = NLDC + 1
 120  TIME = TIME + 1.0
      J = J + 1
      GO TO 130
 200  X(1) = 0.0
```

```
      Y(1) = 1.0
      X(NLDC) = 1.0
      Y(NLDC) = ELOAD(N)
      RETURN
      END

      SUBROUTINE SELECT (X,Y,NLDC)
C
C     LDC GENERATOR (SUPPLEMENT TO SUBROUTINE LOAD)
C
      DIMENSION X(750),Y(750),XTEMP(100),YTEMP(100)
      CHECK=1.005
      NPTS=0
      DO 100 I=1,NLDC
      IF (Y(I) .GT. CHECK) GO TO 100
      NPTS=NPTS+1
      XTEMP(NPTS)=X(I)
      YTEMP(NPTS)=Y(I)
      CHECK=CHECK-0.01
100   CONTINUE
      DO 200 I=1, NPTS
      X(I)=XTEMP(I)
200   Y(I)=YTEMP(I)
C
C     IS X(NPTS) = 1.0 ?
C
      IF (X(NPTS) .EQ. 1.0) GO TO 300
      NPTS=NPTS+1
      X(NPTS)=1.0
      Y(NPTS)=Y(NLDC)
300   NLDC=NPTS
      RETURN
      END

      SUBROUTINE INIPLO (NPLOT)
C
C     ... SET UP THE PLOT SIZE ...
C
      CALL PLOTS (52.0*NPLOT , 27.5)
C
C     ... SET THE ORIGIN, RESERVE 2 CM MARGIN FOR AXIS ...
C
      CALL PLOT (2.0 , 2.0 , -3)
C
C     ... USE BLACK PEN FOR SUBSEQUENT PLOT ...
C
      CALL NEWPEN (1)
      RETURN
      END

      SUBROUTINE INICUR (XORG, JAHR, MONTH, IWEEK, PKWEEK)
```

```
C
C       ... THIS PROGRAM INITIALIZES THE CALCOMP PLOTTER FOR PLOTTING ...
C
C       ... RE-SET THE NEW ORIGIN ...
C
        CALL PLOT (XORG , 0. , -3)
C
C       ... DRAW THE X-AXIS ...
C
        X = 0.0
        XVAL = 0.0
        CALL NUMBER (X-0.1, -0.36, 0.21, XVAL, 0.0, -1)
        CALL PLOT ( X, 0.0, 3)
        DO 100 I=1 , 14
C
C       ... MOVE TO THE NEXT TIC MARK WITH PEN DOWN ...
C
        X = X + 1.2
        XVAL = XVAL + 12.
        CALL PLOT ( X, 0.0, 2)
C
C       ... DRAW THE TIC MARK ...
C
        CALL PLOT ( X , 0.15 , 2 )
C
C       ... DRAW THE NUMBER BELOW THE TIC MARK ...
C
        CALL NUMBER (X-0.1, -0.36, 0.21, XVAL, 0.0, -1)
C
C       ... MOVE TO THE LAST TIC MARK WITH PEN UP ...
C
100     CALL PLOT ( X, 0.0, 3)
C
C       ... DRAW THE TITLE ...
C
        CALL SYMBOL (7.7, -0.78, 0.28, 5HHOURS, 0.0, 5)
        CALL PLOT (0.0, 0.0, 3)
C
C       ... NOW THE Y-AXIS ...
C
        Y = 0.
        YVAL = 0.
        CALL NUMBEP (-0.15, Y-0.1, 0.21, YVAL, 90., -1)
        CALL PLOT (0.0, Y, 3)
        DO 200 I=1, 15
        Y = Y + 1.5
        YVAL = YVAL + 10.0
        CALL PLOT (0.0, Y, 2)
        CALL PLOT (0.15, Y, 2)
        CALL NUMBEP (-0.15, Y-0.1, 0.21, YVAL, 90., -1)
200     CALL PLOT (0.0, Y, 3)
        VJAHR = FLOAT(JAHR)
        VMONTH = FLOAT(MONTH)
        VWEEK = FLOAT(IWEEK)
```

```
      CALL SYMBOL (-0.50, 10., 0.28, 8HLOAD (%), 90., 8)
      CALL SYMBOL (8.5, 21.5, 0.28, 7HYEAR = , 0., 7)
      CALL NUMBER (10.5, 21.5, 0.28, VJAHR, 0., -1)
      CALL SYMBOL (8.5, 20.5, 0.28, 8HMONTH = , 0., 8)
      CALL NUMBER (10.8, 20.5, 0.28, VMONTH, 0., -1)
      CALL SYMBOL (8.5, 19.5, 0.28, 7HWEEK = , 0., 7)
      CALL NUMBER (10.5, 19.5, 0.28, VWEEK, 0., -1)
      CALL SYMBOL (8.5, 18.5, 0.28, 12H100% LOAD = , 0., 12)
      CALL NUMBER (12., 18.5, 0.28, PKWEEK, 0., -1)
      CALL SYMBOL (13.5, 18.5, 0.28, 2HMW, 0., 2)
      RETURN
      END


      SUBROUTINE CURPLO (XVEC, YVEC, NPTS, ISYM)
      DIMENSION XVEC(NPTS), YVEC(NPTS)
C
C     ... MOVE TO THE FIRST POINT WITH PEN UP ...
C
      CALL PLOT (XVEC(1)*0.1, YVEC(1)*0.15, 3)
C
C     ... START PLOTTING ...
C
      DO 100 I=1, NPTS
      XVAL = 0.1 * XVEC(I)
      YVAL = 0.15 * YVEC(I)
      CALL PLOT (XVAL, YVAL, 2)
100   CALL SYMBOL (XVAL, YVAL, 0.14, ISYM, 0.0, -1)
      RETURN
      END


      SUBROUTINE INILDC (XORG, JAHR, MONTH, PKMW)
C
C     ... THIS PROGRAM INITIALIZES THE CALCOMP PLOTTER FOR PLOTTING ...
C
C     ... RE-SET THE NEW ORIGIN ...
C
      CALL PLOT (XORG , 0. , -3)
C
C     ... DRAW THE X-AXIS ...
C
      X = 0.0
      XVAL = 0.0
      CALL NUMBER (X-0.1, -0.36, 0.21, XVAL, 0.0, -1)
      CALL PLOT ( X, 0.0, 3)
      DO 100 I=1 , 10
C
C     ... MOVE TO THE NEXT TIC MARK WITH PEN DOWN ...
C
      X = X + 1.5
      XVAL = XVAL + 10.
      CALL PLOT ( X, 0.0, 2)
C
```

```
C       ... DRAW THE TIC MARK ...
C
        CALL PLOT ( X , 0.15 , 2 )
C
C       ... DRAW THE NUMBER BELOW THE TIC MARK ...
C
        CALL NUMBER (X-0.1, -0.36, 0.21, XVAL, 0.0, -1)
C
C       ... MOVE TO THE LAST TIC MARK WITH PEN UP ...
C
100     CALL PLOT ( X, 0.0, 3)
C
C       ... DRAW THE TITLE ...
C
        CALL SYMBOL (5.8, -0.78, 0.28, 12HDURATION (%) , 0.0, 12)
        CALL PLOT (0.0, 0.0, 3)
C
C       ... NOW THE Y-AXIS ...
C
        Y = 0.
        YVAL = 0.
        CALL NUMBER (-0.15, Y-0.1, 0.21, YVAL, 90., -1)
        CALL PLOT (0.0, Y, 3)
        DO 200 I=1, 15
        Y = Y + 1.5
        YVAL = YVAL + 10.0
        CALL PLOT (0.0, Y, 2)
        CALL PLOT (0.15, Y, 2)
        CALL NUMBER (-0.15, Y-0.1, 0.21, YVAL, 90., -1)
200     CALL PLOT (0.0, Y, 3)
        VJAHR = FLOAT(JAHR)
        VMONTH = FLOAT(MONTH)
        CALL SYMBOL (-0.50, 10., 0.28, 8HLOAD (%) , 90., 8)
        CALL SYMBOL (7.5, 21.5, 0.28, 7HYEAR = , 0., 7)
        CALL NUMBER (9.5, 21.5, 0.28, VJAHR, 0., -1)
        CALL SYMBOL (7.5, 20.5, 0.28, 8HMONTH = , 0., 8)
        CALL NUMBER (9.8, 20.5, 0.28, VMONTH, 0., -1)
        CALL SYMBOL (7.5, 19.5, 0.28, 12H100% LOAD = , 0., 12)
        CALL NUMBER (11., 19.5, 0.28, PKMW, 0., -1)
        CALL SYMBOL (12.5, 19.5, 0.28, 2HMW, 0., 2)
        RETURN
        END


        SUBROUTINE LDCPLO (XVEC, YVEC, NPTS)
C
C       ... THIS PROGRAM PLOTS THE LDC ...
C
        DIMENSION XVEC(NPTS), YVEC(NPTS)
C
C       ... MOVE TO THE FIRST POINT WITH PEN UP ...
C
        CALL PLOT (XVEC(1)*0.15, YVEC(1)*0.15, 3)
C
```

```
C     ... START PLOTTING ...
C
      DO 100 I=1, NPTS
100   CALL PLOT  (XVEC(I)*0.15, YVEC(I)*0.15, 2)
      CALL PLOT  (XVEC(NPTS)*0.15, 0., 2)
      RETURN
      END


      SUBROUTINE STRPLO (NPLOT)
C
C     ... THIS PROGRAM STOPS THE CALCOMP PLOTTER ...
C
      IF (NPLOT .EQ. 0) RETURN
      CALL PLOT (0., 0., 999)
      RETURN
      END
```

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